COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

ELECTRONIC APPLICATION OF KENTUCKY UTILITIES COMPANY FOR AN ADJUSTMENT OF ITS ELECTRIC RATES, A CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY TO DEPLOY ADVANCED METERING INFRASTRUCTURE, APPROVAL OF CERTAIN REGULATORY AND ACCOUNTING TREATMENTS, AND ESTABLISHMENT OF A ONE-YEAR SURCREDIT	**)**	**CASE NO. 2020-00349**

In the Matter of:

ELECTRONIC APPLICATION OF LOUISVILLE GAS AND ELECTRIC COMPANY FOR AN ADJUSTMENT OF ITS ELECTRIC AND GAS RATES, A CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY TO DEPLOY ADVANCED METERING INFRASTRUCTURE, APPROVAL OF CERTAIN REGULATORY AND ACCOUNTING TREATMENTS, AND ESTABLISHMENT OF A ONE-YEAR SURCREDIT	**)**	**CASE NO. 2020-00350**

REBUTTAL TESTIMONY OF
WILLIAM STEVEN SEELYE
MANAGING PARTNER
THE PRIME GROUP, LLC

Filed: April 12, 2020

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I. INTRODUCTION AND SUMMARY

Q. Please state your name and business address.

A. My name is William Steven Seelye. I am the Managing Partner of The Prime Group, LLC. The Prime Group's business address is 2604 Sunningdale Place East, La Grange, Kentucky 40031.

Q. Did you submit direct testimony in this proceeding?

A. Yes. I submitted testimony on behalf of Kentucky Utilities Company ("KU") and Louisville Gas and Electric Company ("LG&E") (collectively "Companies") in support of the Companies' cost of service studies, proposed revenue allocation, proposed rates, and lead-lag studies.

Q. What is the purpose of your rebuttal testimony?

A. The purpose of my testimony is to rebut the direct testimonies of Joint Intervenors Mountain Association, Kentucky Solar Energy Society and Kentuckians for the Commonwealth's ("Joint Intervenors'") witness Karl R. Rábago regarding the Companies' proposed net metering schedule (NMS-2); Kentucky Solar Industries Association, Inc.'s ("KSIA's") witnesses Justin R. Barnes and Benjamin D. Inskeep regarding NMS-2; Attorney General's ("AG's") witnesses Glenn A. Watkins concerning class cost of service, revenue allocation, and rate design; the AG and Kentucky Industrial Utility Customers, Inc.'s ("KIUC's")(collectively "AG-KIUC") witness Stephen J. Baron concerning net metering, class cost of service, revenue allocation, and rate design; United States Department of Defense and all other Federal

Executive Agencies ("DOD-FEA's") witness Michael P. Gorman concerning class cost of service, revenue allocation, and rate design; Walmart Inc. ("Walmart's) witness Lisa V. Perry concerning class cost of service, revenue allocation and rate design; The Kroger Co.'s ("Kroger's") witness Justin Bieber concerning commercial rate aggregation; Lexington-Fayette Urban Government and Louisville/Jefferson County Metro-Government's ("Lou Metro & LFUCG's") witness Richard Bunch regarding revenue allocation and lighting rates; Joint Intervenors' witness James Owen regarding the Basic Service Charge; and AG-KIUC witness Lane Kollen regarding cash working capital.

Q. Please summarize your testimony.

A. My direct testimony addresses the following:

- **Net Metering.** Net metering customers are currently overcompensated for the energy that they supply to grid. Pursuant to KRS 278.466(3), KU and LG&E are proposing NMS-2 to address this overcompensation for new net metering customers. Under the Companies' proposed NMS-2, new net metering customers will be compensated at the non-time-differentiated avoided cost rate for small qualifying facilities under the Companies' Rider SQF, which is currently $0.02173/kWh. The avoided cost rate, which is updated every two years, reflects the Companies' avoided cost of energy and should be applied to as-available energy supplied from distributed generation facilities such as roof-top solar panels that generate energy intermittently, sit behind a customer's own load, are under no legally enforceable obligation, and might create more non-energy costs than it helps avoid (if any are avoided). The Companies have fully met their burden of proof in support of NMS-2.

  Because traditional net metering (NMS-1) provides compensation greater than the Companies' avoided costs, it results in increased rates for all customers and an increase in bills for non-participating customers, including low-income non-participating customers. *More precisely, current NMS customers are receiving about four times the price for renewable energy in the open market.* The KSIA and Joint Intervenors argue that level of overpayment—at other customers' expense—should continue not just for NMS-1 customers but also for NMS-2 customers.

Contrary to the positions of KSIA and the Joint Intervenors, the rate that should be paid for the energy that customer-generators supply to the grid should not include a capacity component, hedging value, or avoided line losses. Nor should the purchase rate for energy that customer-generators supply to the grid include the "full range of benefits" (i.e., externalities) that are being proposed by KSIA and the Joint Intervenors.

- **Electric Cost of Service Studies.** KU and LG&E submitted the results of three cost of service studies based on Loss of Load Probability ("LOLP"), 6 Coincident Peak ("6-CP"), and 12 Coincident Peak ("12-CP") methodologies. KIUC and DOD-FEA favor the 6-CP methodology over the LOLP methodology. It is KU and LG&E's position that the LOLP methodology more accurately reflects resource planning on the Companies' systems. However, the Companies do not oppose using the 6-CP methodology, which also reasonably reflects resource planning. As in past proceedings, the AG recommends a Probability of Dispatch ("POD") methodology. The Companies oppose the POD methodology because it gives improper weighting to kWh usage and improperly allocates large amounts of fixed production costs to customers' usage during off-peak periods.

- **Distribution of the Electric Revenue Increase.** The AG, Lou Metro & LFUCG, KIUC, and DOD-FEA offer widely divergent positions regarding the distribution of the revenue increases. The AG proposes to shift large portions of the revenue increases to large industrial customer classes and to lighting rates. In contrast, Lou Metro & LFUCG propose rate reductions for the lighting rates and to increase residential rates. KIUC proposes to lower the increases to certain large industrial classes. DOD-FEA proposes to shift large portions of the increases to the residential rate classes. After reviewing the widely varying positions of the intervenors, KU and LG&E recommend that the Commission accept the Companies' proposed distribution of the revenue increases.

- **Electric Rate Design.** The Companies are proposing a reasonable increase in the residential Basic Service Charges, which moves the charges in the direction of cost of service. The AG recommends keeping the Basic Service Charges for RS at their current levels, despite performing an analysis purporting to show that the charges should be much lower. The Commission has rejected the AG's customer cost analysis in previous proceedings. The AG's recommendation should be rejected again.

  KIUC and DOD-FEA recommend reducing the energy charges for TODP, RTS, and FLS to reflect variable operation and maintenance expenses based on marginal running costs of the generators. For decades the Companies have used the FERC

Predominance Method to classify generation operation and maintenance expenses in the Companies' cost of service studies.

Kroger proposes that the Commission order the Companies to perform a study of conjunctive demand for multi-site customers. Conjunctive demand billing has been fully addressed in earlier rate case proceedings. Therefore, there is no need to revisit the issue again.

KIUC presents a proposal to implement a Coal Mining Economic Development Rate to incentivize increased coal production in Kentucky. The Companies are open to considering an economic development rate for coal producers as long as the rate is properly structured to benefit all customers by spreading fixed costs over a larger kVA base.

Lou Metro & LFUCG propose to eliminate the light emitting diode ("LED") conversion fees that were implemented in the Companies' last rate case proceedings to protect against the creation of stranded costs from customers requesting the replacement of fully functional non-LED fixtures with LED fixtures. Lou Metro & LFUCG would replace the LED conversion fee with a regulatory asset that would socialize costs to customers who have not converted fully functional non-LED lights to LED fixtures. The Companies' proposed LED conversion fees should be approved.

- **Gas Cost of Service Study**. LG&E submitted a gas cost of service study that classifies the cost of mains using the zero-intercept methodology. The Commission has approved this methodology in prior rate case orders. As in prior cases, the AG submitted a gas cost of service study that allocates costs based on a Peak and Average methodology. The AG's cost of service study does not properly reflect cost incurrence on LG&E's distribution system.

- **Distribution of the Gas Revenue Increase.** The AG improperly proposes to shift cost recovery to Commercial Gas Service (CGS) and Industrial Gas Service (IGS) by relying on a flawed cost of service methodology that has not been accepted by the Commission.

- **Cash Working Capital.** AG-KIUC proposes to disallow Cash Working Capital related to non-cash expense items in connection with their recommended calculation of the rate base methodology for valuing the Companies' investment for ratemaking. The Commission has repeatedly rejected the AG-KIUC's approach in other rate case proceedings. The Commission has ruled that if non-cash items, such as depreciation and deferred taxes, are not included in the Cash Working Capital calculation, then the Companies do not have the opportunity to earn a full return on their investments.

II. NET METERING

A. KU AND LG&E'S NET METERING PROPOSAL

i. GENERAL CONSIDERATIONS

Q. Is there a consensus among the intervenors regarding KU and LG&E's net metering proposal?

A. No. KIUC, which represents the largest manufacturers in Kentucky along with Alliance Coal, and the AG, which represents all customers, support the Companies' proposed net metering service (NMS-2). AG-KIUC Witness Baron states:

> AG-KIUC generally agrees with the Companies' proposal to modify the rate that net metering customers are paid for their excess energy that is exported to the grid. The current price paid for such exported energy is not consistent with the value of this energy or avoided cost and therefore represents a subsidy that is paid by non-participating customers to solar net metering customers.[1]

It is not surprising that the AG, who is charged by the General Assembly with representing all consumer interests before the Commission, and KIUC support the Companies' proposal. NMS-2 reduces the subsidies that must be paid by other customers to customer-generators. The manufacturers represented by KIUC include Ford Motor Company, Toyota, and North American Stainless. They provide high paying jobs in Kentucky. Because they compete in international markets, they must

[1] Baron Direct, at page 9.

keep their energy costs down. KIUC also represents Alliance Coal. Coal is an important industry in Kentucky, providing jobs in economically distressed regions of the state. It is understandable that a coal producer would not support paying subsidies to its renewable competitors.[2] KSIA and the Joint Intervenors insist that subsidies must continue to be paid to renewable generation customers, thereby encouraging the reduced use of coal generation in Kentucky. At the same time, KIUC is urging the implementation of an economic development rate for coal producers operating in Kentucky. This underscores the cross purposes evident in these proceedings. While KSIA and the Joint Intervenors are actively supporting policies to decrease the use of coal in Kentucky, KIUC is proposing an economic development rate to support the coal industry and keep coal mining jobs in the state.

Q. What is the primary objective of the Companies' proposed net metering compensation rate under NMS-2?

A. The primary objective of NMS-2 is to provide the appropriate level of compensation for the energy that customer-generators supply to the grid. Under the current net metering rider (NMS-1), compensation takes the form of a one-to-one kWh-denominated energy credit for all excess energy. For Residential Service (RS) and General Service (GS) schedules, the energy charges reflect the full cost related to

[2] Referring to renewables as a competitor of coal is not an exaggeration. The Joint Intervenors' witness Karl R. Rábago co-authored a paper titled "Achieving 100% renewables: supply-shaping through curtailment," *Power PVTech*, May 2019. Obviously, 100% renewables, as promoted by Mr. Rábago, would likely mean a severe curtailment or the end of coal production in Kentucky. Also, see Justin Barnes, "Policy: Solar for Everyone", Solar Power World Online, April 5, 2012. Mr. Barnes states, "So solar for everyone? Not yet – but we just might be headed in the right direction." The U.S. solar sector set a record 19.2 gigawatts of installed capacity in 2020. *The Energy Daily*, March 17, 2021.

distribution, transmission, production and general plant, including the cost of office buildings. These costs are obviously not ***avoided*** when net metering customers supply energy to the grid. The only costs that are avoided when customer-generators supply energy to the grid, which do not provide a continuous or predictable output of energy, are avoided fuel expenses, energy-related purchased power costs, and variable operation and maintenance expenses. The Companies can generate or purchase power in the energy market at a far lower cost than the price that is being paid to customers under NMS-1. The fact that the Companies are currently overcompensating net metering customers has not been refuted by the intervenors in these proceedings. It is also evident from the $0.02782 per kWh price that the Companies agreed to pay Rhudes Creek Solar, LLC, for renewable energy[3] that KU should not be paying $0.08963/kWh and LG&E should not be paying $0.09278/kWh for the energy that customer-generators flow to the grid, which NMS-1 requires for legacy net metering customers to comply with KRS 278.466(6). KSIA and the Joint Intervenors have provided no evidence-based quantification of the value they contend customer-generators supply to the grid. While NMS-1 clearly overcompensates customer-generators for the energy they supply to the grid, neither KSIA nor the Joint Intervenors provide cost support for compensating NMS-2 customer-generators based

[3] The purchased power Agreement to purchase renewable energy from Rhudes Creek Solar, LLC, was filed with the Commission in Case No. 2020-00016 and is attached to the Rebuttal Testimony of Robert M. Conroy as Rebuttal Exhibit RMC-1 in these proceedings. This agreement is discussed later in my testimony and is also discussed in Mr. Conroy's Rebuttal Testimony. For the $0.02782 per kWh price, the Companies also receive the Renewable Energy Credits (RECs), which will be sold and the proceeds returned to customers, thus further lowering costs.

on energy charges that include a multitude of cost components which have nothing whatsoever to do with the value of the energy that customer-generators supply to the grid. Solar power is being called the “cheapest electricity in history,”[4] but with traditional net metering, this low-cost energy does not translate into savings to ratepayers, who are forced to pay customer-generators the *full delivered retail price* of $0.08963/kWh to $0.09278/kWh for this “cheap energy”.

ii. DISTINCTION BETWEEN PURCHASE TRANSACTIONS AND SALES TRANSACTIONS IN THE NET METERING STATUTES

Q. How is “net metering” defined in KRS 278.465 and 278.466, pursuant to which the Companies are proposing NMS-2?

A. KRS 278.465(4) defines “net metering” to be the difference between the dollar value of “all electricity generated by an eligible customer-generator that is fed back to the electric grid” and the dollar value of “all electricity consumed ….” Furthermore, KRS 278.465(3) defines “kilowatt hour” to be “a measure of electricity defined as a unit of work of energy ….” KRS 278.466(2) requires an electric utility to supply a net metering customer with “a standard kilowatt-hour meter capable of registering the flow of electricity in two (2) directions.” Finally, KRS 278.466(3) requires an electric utility to compensate a net metering customer for “all electricity produced by the customer's eligible electric generating facility that *flows to the retail electric supplier*

[4] International Energy Agency, *World Energy Outlook 2020*. See also https://reneweconomy.com.au/solar-power-is-now-cheapest-electricity-in-history-says-iea-39195/.

…." (Emphasis added.) Thus, the electric energy that the customer-generator supplies to grid is what is being addressed with the Companies' proposed NMS-2 schedule. From an avoided cost perspective, the ***value*** of the energy that flows to the retail electric supplier by a customer-generator as defined by KRS 278.466, and which is provided on a strictly as-available basis with no legally enforceable obligation, is no different from the value of energy purchased from a small qualifying facility under SQF.

Q. Do KRS 278.465 and 278.466 make a clear distinction between the energy *purchased from* the customer-generator and the electric service *provided to* the customer-generator?

A. Yes. Just as I noted above that KRS 278.465(4) distinguishes between compensation paid by a customer-generator for service received from a utility and compensation paid by a utility to a customer-generator for energy the customer-generator flows onto the utility's system, so KRS 278.466 clearly distinguishes the two separate transactions. Regarding compensation paid by a utility to a customer-generator, KRS 278.466(3) states:

> A retail electric supplier serving an eligible customer-generator shall compensate that customer for all electricity produced by the customer's eligible electric generating facility that flows to the retail electric supplier, as measured by the standard kilowatt-hour metering prescribed in subsection (2) of this section. The rate to be used for such compensation shall be set by the commission using the ratemaking processes under this chapter during a proceeding initiated by a retail electric supplier or generation and transmission cooperative on behalf of one (1) or more retail electric suppliers.

In contradistinction and in an entirely separate section, KRS 278.466(5) addresses rates charged to customer-generators for service they receive from utilities:

> Using the ratemaking process provided by this chapter, each retail electric supplier *shall be entitled to* implement rates to recover from its eligible customer-generators all *costs necessary to serve* its eligible customer-generators, including but not limited to fixed and demand-based costs, without regard for the rate structure for customers who are not eligible customer-generators. (Emphases supplied.)

Therefore, KRS 278.465 and 278.466 establish a clear and bright distinction between the price paid for the *energy supplied from* net metering customers and the cost of *service provided to* the customer-generator. In their testimony, KSIA and the Joint Intervenors' witnesses conflate these two distinct transactions. While KU and LG&E are "entitled to implement rates to recover from its eligible customer-generators all costs necessary to serve its eligible customer-generators" the Companies are choosing not to address the *costs necessary to serve* the customer-generators at this time, as would be permitted under, but not required by, the statutes. KU and LG&E are only addressing the value of net metering *purchases* for the energy that flows to the Companies, energy for which all customers must pay.

Q. Do the Joint Intervenor and KSIA witnesses acknowledge the clear distinction between purchase transactions and sales transactions made in KRS 278.465 and 278.466?

A. No. They conflate the two, avoiding the express distinction in the statute's language. Joint Intervenors witness Rábago states:

> The Companies make a category error in treating customer generators as if they were wholesale generators that are in the business of generating power for ultimate resale. Customer-

> generators generate for use, not for sale, and exports are incidental to an investment objective of managing energy costs.

The Companies obviously understand that customer-generators use energy from their distributed generation facilities to supply their own use of energy. But the Companies do not make a "category error". As already stated, an unambiguous distinction between the energy that customer-generators flow to the grid is made in KRS 278.465 and 278.466. To be clear, KRS 278.465(4) defines "net metering" to be the difference between the dollar value of "all electricity generated by an eligible customer-generator *<u>that is fed back to the electric grid</u>*" and the dollar value of "all electricity consumed by the eligible customer generator." Therefore, net metering according to KRS 278.465 and 278.466 relates to the energy that flows to the grid. More important still, KRS 278.466(2) and KRS 278.466(3) state:

> (2) Each retail electric supplier serving a customer with eligible electric generating facilities shall use a standard kilowatt-hour meter capable of registering the flow of electricity in two (2) directions. Any additional meter, meters, or distribution upgrades needed to monitor the flow in each direction shall be installed at the customer-generator's expense. If additional meters are installed, the net metering calculation shall yield the same result as when a single meter is used.
>
> (3) ***<u>A retail electric supplier serving an eligible customer-generator shall compensate that customer for all electricity produced by the customer's eligible electric generating facility that flows to the retail electric supplier</u>***, as measured by the standard kilowatt-hour metering prescribed in subsection (2) of this section. The rate to be used for such compensation shall be set by the commission using the ratemaking processes under this chapter during a proceeding initiated by a retail electric supplier or generation and transmission cooperative on behalf of one (1) or

more retail electric suppliers.

(Emphasis supplied.)

As is crystal clear from the law stated above, the Companies are not the ones making the "category error". Net metering, as defined by KRS 278.465 and KRS 278.466, deals only with the electric energy that "flows to the retail electric supplier." In compensating customer-generators for the energy they supply to the grid, only the value of that energy should, or need, be considered by the retail electric supplier. However, if the utility wanted separately to consider the cost of <u>*serving*</u> customer-generators, then KRS 278.465(5) would apply:

> (5) Using the ratemaking process provided by this chapter, each retail electric supplier <u>***shall be entitled***</u> to implement rates to recover from its eligible customer-generators all costs necessary <u>***to serve its eligible customer-generators***</u>, including but not limited to fixed and demand-based costs, without regard for the rate structure for customers who are not eligible customer-generators.

(Emphasis supplied.)

The Companies chose not to implement new <u>*sales service*</u> rates specifically designed to apply to customer-generators. As explained in my direct testimony, the Companies plan to continue to study implementing three- or four-part rates to properly reflect the cost of <u>*serving*</u> customer-generation, as they would be eligible to do under KRS 278.465(5). Therefore, it is not the Companies who are making a "category error" but the Joint Intervenors and KSIA witnesses. KRS 278.465 and KRS 278.466 make a clear and bright ontological or categorical distinction between a <u>*purchase transaction*</u>

and a *sales transaction*. It is the Joint Intervenors and KSIA who are conflating and commingling the two distinct types of transactions clearly established in KRS 278.465 and KRS 278.466.

iii. SUBSIDIES CURRENTLY PROVIDED TO NET METERING CUSTOMERS

Q. Are non-participating customers currently subsidizing net metering customers?

A. Yes. Net metering customers are being overcompensated for the energy they supply to the grid. Non-participating customers are currently subsidizing customer-generators.

Q. Are there two types of subsidies currently being provided to customer-generators by non-participating customers?

A. Yes. Customer-generators are being provided subsidies for both the energy they supply to the grid and for the sales service that they receive from KU and LG&E. As explained above, KRS 278.465 and 278.466 identify two types of transactions involved with customer-generators – *purchases from* customer-generators and *sales service to* customer-generators. When a customer-generator supplies energy to the grid, KU or LG&E realizes a *purchase transaction with* the customer, but when the customer-generator takes electric service from KU or LG&E there is a *sales transaction to* the customer. These two types of transactions are plainly distinguished in KRS 278.465 and 278.466. Under the current net metering tariff (NMS-1), two types of subsidies are provided to net metering customers – one subsidy related to the purchase transaction for the energy supplied by customer-generators to the grid and another subsidy related to the sales transaction for electric service to the customer-generators. In KU's response to PSC 2-108 and LG&E's response to PSC 2-122, which are attached as Rebuttal Exhibit WSS-1, the two types of subsidies are calculated for KU and LG&E's residential customer-generators.

For KU, the annual subsidies currently provided for *energy purchased from* residential customer-generator customers is $139,143 for the 12 months ended November 2020. *This first subsidy is not an estimate.* It corresponds to the difference between the amount that customer-generators were compensated for the energy that they provide to KU and the avoided cost based on the Companies' tariffed avoided energy cost rate. The annual subsidies currently provided to KU's customer-generators related to the *sales service* provided to the customer-generators is $46,399 for the 12 months ended November 2020. This second subsidy is an estimate based on the Companies' load research data for residential net metering customers. It is an estimate because the Companies do not have load research data for all net metering customers. However, it is a reasonable estimate based on the calculation shown in Rebuttal Exhibit WSS-1.

For LG&E, the annual subsidies currently provided for *energy purchased from* residential customer-generator customers is $148,668 for the 12 months ended November 2020. Again, this first subsidy is not an estimate. It corresponds to the difference between the amount that customer-generators were compensated for the energy they provide to LG&E and the avoided cost based on the Company's tariffed

SQF rate. The annual subsidies currently provided to the customer-generators related to LG&E's sales service to the customer-generators is $95,175 for the 12 months ended November 2020. Again, this amount represents a reasonable estimate, which is supported in the calculation shown in Rebuttal Exhibit WSS-1.

Q. Have there been other studies demonstrating customer-generators are subsidized under traditional net metering?

A. As will be discussed later in my testimony, the *Net-Energy Metering 2.0 Lookback Study* conducted for the California Public Utilities Commission ("CPUC") found that customers not participating in net metering provide significant subsidies to net metering customers.[5] Also, a 2019 article in The Electricity Journal titled "Qualifying Net Energy Metering Subsidies" found that net metering results in large subsidies being paid by non-participants.[6]

Q. Are low-income customers subsidizing customer-generators under the current net metering framework?

A. Yes, they are. According to the Companies' customer records, on KU's and LG&E's systems, not a single customer participating in the Low-Income Home Energy Assistance ("LIHEAP") is a net metering customer. LIHEAP customers are non-participants in net metering.[7] This is not surprising because low-income customers

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[5] Verdant Associates LLC et al., *Net-Energy Metering 2.0 Lookback Study*, January 21, 2021, at p. 94. Attached as Rebuttal Exhibit WSS-3.
[6] Sergici, Yang, Castaner, Faruqui, "Qualifying Net Energy Metering Subsidies", *The Electricity Journal*, August 21, 2019.
[7] See response to KSIA 2-13 for KU and KSIA 2-13 for LG&E, attached hereto as Rebuttal Exhibit WSS-2.

typically do not have the financial resources to install costly solar panels. Furthermore, low-income customers living in rental housing would not likely install solar panels, inverters, etc. in property they do not own. A number of studies have found that customers installing solar cells are "disproportionately wealthy" and the adoption of solar technologies is "dominated by the heaviest electricity consuming households."[8] One study found that, with the exception of those in Arizona, adopters of behind-the-meter solar "are more likely to have income over $150K/year than GPS [general population survey] respondents."[9] Researchers at Berkley Lab found directionally similar results nationally, with median annual incomes of $113,000 for solar adopters compared to a median annual income of $64,000 for all households.[10] The *Net-Energy Metering 2.0 Lookback Study* conducted for the CPUC also found that low-income customers subsidize net metering customers.[11] The current net metering scheme is skewed in a way that provides subsidies to wealthy, high income adopters of solar technology.

Q. Did KSIA or the Joint Intervenors dispute the methodology or the component values that were used in the calculations of the subsidies shown in WSS-1?

A. No, they did not. KSIA witnesses Barnes and Inskeep do not address the Companies'

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[8] Severin Borenstein, "Private Net Benefits of Residential Solar PV: The Role of Electricity Tariffs, Tax Incentives and Rebates", Journal of the Association of Environmental and Resource Economists, September 2017.

[9] Moezzi et al., "A Non-Modeling Exploration of Residential Solar Photovoltaic (PV) Adoption and Non-Adoption", National Renewable Energy Laboratory, September 2017, at p. 10. Attached as Rebuttal Exhibit WSS-4.

[10] See Galen Barbose, Sydney Forrester, Eric O'Shaughnessy, and Naïm Darghouth, "Residential Solar-Adopter Income and Demographic Trends: 2021 Update", Berkeley Lab. Attached as Rebuttal Exhibit WSS-4.

[11] Verdant Associates LLC et al., *Net-Energy Metering 2.0 Lookback Study,* January 21, 2021, at p. 94.

analysis of the subsidies under NMS-1 provided in PSC 2-108 (KU) and PSC 2-122 (LG&E). While Joint Intervenors witness Rábago does reference these data request responses,[12] he does not take specific issue with the amounts calculated, nor does he dispute the methodology used to calculate the subsidies. He simply decries the Companies' "neglect" to perform a cost-of-service study specifically identifying net metering customers as a separate class. I will discuss the issue of a cost of service study for customer-generators more thoroughly later, and I will present the results of a cost of service study breaking out customer-generators. But I will mention now that the KSIA and Joint Intervenors' demand for a cost of service study for customer-generators is simply a red herring. *A cost of service study is not needed to determine the avoided cost of the energy that customer-generators are supplying to the grid and is being paid for by other customers.* The Companies' avoided cost for as-available energy is $0.02173/kWh. The Companies already have approved tariffed rates reflecting the value of energy that as-available small generation facilities supply to the grid. KSIA and the Joint Intervenors' witnesses do not offer a numerical alternative to the $0.02173/kWh value of as-available generation calculated by the Companies. In accordance with the SQF rate schedule, this avoided cost energy charge for as-available energy will continue to be updated every two years.

[12] See footnotes #24 and #49 to Mr. Rábago's direct testimony.

iv. KU AND LG&E HAVE ADEQUATELY SUPPORTED NMS-2

Q. Have the Companies adequately supported their recommended rates for NMS-2?

A. Yes. In accordance with KRS 278.465 and 278.466, the Companies are proposing to implement NMS-2, which deals only with the purchase transaction for the energy that customer-generators supply to the grid. Because customer-generators are providing energy to the grid on an as-available basis with no legally enforceable obligation to provide firm energy or capacity, the appropriate compensation for such as-available energy is the Companies' avoided energy cost rate of $0.02173/kWh set forth in SQF. Customer-generators should not be compensated for the energy they deliver to the grid at a rate that is higher than the avoided energy cost rate applicable to small qualifying facilities served under SQF. When customer-generators are compensated for energy they deliver to the grid at rates higher than the utility's cost to provide the energy, all customers who are not customer-generators pay higher rates.

Q. Therefore, have the Companies met their burden of proof for NMS-2?

A. Yes, they absolutely have. The energy that customer-generators supply to the grid is provided on a strictly as-available basis with no legally enforceable obligation to provide firm capacity. Individual customer-generators may or may not be supplying energy to the grid at any given time. Whether a customer-generator can supply energy to the grid at any given time depends on a host of factors, such as whether there is sufficient sunlight to generate energy, whether the customer is using the energy from its solar panels for its own usage requirements, whether the solar panels are covered by snow or ice on a peak day, whether solar panels are covered by dirt or debris, whether the inverters are functioning properly, whether the solar panels have been damaged, whether there are problems with wiring on the solar panels, whether the customer has removed some of its solar panels, etc. For all these reasons – but particularly because there is frequently insufficient sunlight to produce energy from solar panels – the energy supplied from solar panels is fundamentally "as available". Section 7(2)(a) of 807 KAR 5:054, applicable to purchases from Small Qualifying Facilities states that "[r]ates for power offered on an 'as available' basis shall be based on the purchasing utility's avoided energy costs estimated at the time of delivery."[13] This definition and approach have been used by LG&E and KU for almost 40 years to determine the value of purchases from Small Qualifying Facilities. In its Order in Case No. 8566, the Commission stated:

> "Avoided energy costs" are defined in 807 KAR 5:054, Section 5(2)(a), of the Commission regulation. Each QF [Qualifying Facility] has the option of providing energy on an "as available" basis or pursuant to "legally enforceable obligation." Conceptually, these options are similar to "non-firm" power (as available) and "firm" power (legally enforceable obligation). ***Power delivered at the QF's convenience is as available power. When QFs select this option it results in a utility being able to avoid only variable fuel cost and operation and maintenance expense.*** Power delivered subject to a legally enforceable obligation would be delivered on a scheduled or planned basis. If a utility is able to schedule the delivery of electricity then it would have the ability to make better use of the energy in meeting its load requirements and hence, the energy could have greater value to the utility. The utility could avoid the use of both "emergency" and peaking power generally resulting in savings from the decreased use of higher cost energy.

[13] This provision of the Commission's regulations was adopted from Section 210 of the Public Utilities Regulatory Policies Act (PURPA).

> The Commission is of the opinion that the differences in the types of power should be reflected in a utility's final purchase rates.[14]

From an economic perspective, this is precisely the approach that should be used in valuing purchases from customer-generators. In terms of the energy that customer-generators supply to the grid, the purchase of energy by KU and LG&E from customer-generators is no different from as-available energy purchased from Small Qualifying Facilities. The intervenor witnesses try to make a distinction between a Small Qualifying Facility and a customer-generator, but there is none.

Q. What do KSIA and the Joint Intervenors provide in way of criticisms of NMS-2?

A. Nothing in terms of any numerical analysis. Mainly they criticize the Companies for not taking into consideration the "full range of benefits" of distributed energy resources. KSIA and the Joint Intervenors insist that there are "societal benefits", "host customer benefits", "gas utility and other fuel system benefits" and many other benefits that must need be considered in establishing the compensation for customer generators. But they make no attempt to quantify those "benefits".[15] Indeed, KSIA stated in response to the Companies' requests for empirical analysis and numerical support for its positions that such requests were "annoying" and "oppressive".[16]

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[14] Commission Order in Case No. 8566, June 28, 1984, at p. 23 (emphasis supplied).

[15] In fact, Mr. Rábago and Mr. Inskeep acknowledge that they have not actually ever performed a benefit-cost analysis of distributed energy resources. See responses to JI 1-9 and KSIA 1-20.

[16] In multiple responses to data requests to KSIA in which the Companies asked KSIA's witnesses to provide detailed analysis or numerical support of its positions, KSIA objected stating that the request "appears calculated to annoy, oppress, unduly burden, and unduly cause expense" to KSIA. See KSIA's responses to the Companies' requests 4(c), 7, 8, 10, 12, 28, 29, and 30. In responses to data requests in which the Companies ask Mr. Rábago to provide numerical support for his positions, he simply refuses to provide any analysis. See Joint Intevenor's responses to LGE/KU DR 15 and 17.

Instead they offer strong rhetoric, particularly by Joint Intervenors' witness Rábago. Calling the Companies and their positions "willfully blind"[17], "blinded"[18], "designed to punish the customer"[19], "extreme"[20], "miserly"[21], a "let them eat cake"[22] approach, not "competent"[23], "confused"[24], "obsessed"[25], "punitive and confiscatory"[26] are not, in my opinion, a substitute for empirical analysis and well-reasoned positions. I will address the witnesses' more germane comments below.

B. THE PRICE FOR ENERGY UNDER SQF AND NMS-2

Q. Under NMS-2, KU and LG&E propose to compensate customer-generators at the SQF rate, currently $0.02173/kWh, which is based on the Companies' avoided energy cost. Do any of the Joint Intervenors or KSIA witnesses address the SQF avoided cost rate?

A. Yes. The SQF avoided cost rate is addressed by KSIA witness Barnes.

Q. Please explain the context for Mr. Barnes's discussion of the SQF rate.

A. SQF sets forth the rates that KU and LG&E shall pay to qualifying small cogeneration and small power production facilities. For SQF, a "small power production facility"

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[17] Direct Testimony of Karl R. Rábago, at p. 9.
[18] *Id*., at p. 11.
[19] *Id*., at p. 10.
[20] *Id*., at pp. 8, 9, 20.
[21] *Id*., at p. 17.
[22] *Id*., at p. 16.
[23] *Id*., at pp. 22, 26, 32, 39, 52.
[24] *Id*., at p. 19,
[25] *Id*., at p. 21.
[26] *Id*. at. P. 23.

is an electric generation facility no larger than 100 kW that is powered at least 75 percent by a renewable resource. Clearly, a small solar or wind electric generation facility would satisfy the definition of a small power production facility. The Companies are therefore proposing to use the purchase energy rate set forth in SQF for the purchase of energy from customer-generators under NMS-2. In terms of the energy that flows to the grid, there are no cost differences between the energy provided by a qualifying small power production facility under SQF and the energy provided by a customer-generator under NMS-2. Thus, the Companies are proposing to compensate both at the same rate.

KU and LG&E's Schedule SQF was filed pursuant to the Commission's regulations set forth in 807 KAR 5:054, which were promulgated as part Commission's review and consideration of provisions established in Section 210 of the Public Utilities Regulatory Policies Act ("PURPA"). Section 7(2) of 807 KAR 5:054 requires each electric utility to "prepare standard rates for purchases from qualifying facilities with a design capacity of 100 kilowatts or less." Section 7(2)(a) of these regulations states, "Rates for power offered on an 'as available' basis shall be based on the purchasing utility's avoided energy costs at the time of delivery." The rates set forth in SQF are updated by KU and LG&E every two years. The Companies utilize a production cost model to calculate their avoided energy costs. In the model, production energy costs are calculated based on the energy costs of the Companies' generation resources reflecting the heat rate curves, availability factors, scheduled outages, fuel costs, variable operation and maintenance expenses, etc. for each resource. The same general approach has been consistently used by the Companies for approximately 40 years.[27]

Q. What are Mr. Barnes's criticisms of SQF avoided energy cost rate?

A. He makes three criticisms: (1) SQF does not provide a capacity payment;[28] (2) SQF does not include a hedging value;[29] and (3) SQF does not include a line loss value.[30]

i. CAPACITY VALUE OF SOLAR

Q. Under the current net metering framework (NMS-1), is a capacity credit provided for energy that customer-generators provide to the grid?

A. Yes, under NMS-1, customer-generators are provided *a full capacity credit* for the energy they supply to the grid, including costs related to distribution facilities and general plant (e.g., office buildings). This is precisely the problem with the current net metering pricing scheme.

Q. Should SQF and NMS-2 provide a capacity payment?

A. No. As explained earlier, SQF applies to energy purchases from small qualifying facilities that are provided on an "as-available" basis, with no legally enforceable obligation to provide energy or capacity. Customer-generators under NMS-2 stand in exactly the same relation to the Companies: they provide as-available, non-firm energy only, with no legally enforceable obligation to provide either energy or

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[27] See KU's response to PSC 5-14 and LG&E's response to PSC 5-15.
[28] Direct Testimony of Justin R. Barnes, at p. 7.
[29] *Id*., at pp. 8-9.
[30] *Id*. at pp. 9-10.

capacity. Indeed, unlike utility-scale solar facilities to which some would ascribe a capacity value—albeit at a significant discount to the nameplate capacity, even during summer peak periods, due to its intermittency and lack of dispatchability—net metering customer-generators' facilities are often less efficient, less optimally positioned, less well maintained, and are more intermittent because they sit behind customer-generators' own loads, which often consume most or all of the generators' output. But perhaps most importantly, they are under no obligation at all to continue in service at any level; they cannot be counted upon even to exist from moment to moment. For example, if a customer-generator changes residences and the new owner removes the solar panels, there is no consequence to the customer-generator and no recourse for the Companies. Under such circumstances, there is no reason to expect that a customer's generator will provide energy in any quantity at any moment; therefore, there is no justification for providing a financial capacity value to net metering customers' generators.

Behind-the-meter solar energy supplied to the grid does not have a compensable capacity value because:

(1) **Solar is fundamentally "as available" energy.** Solar energy is available when there is sufficient sunlight to produce photo-voltaic energy and unavailable otherwise.

(2) **Solar energy is intermittent.** Even during summer months, energy supplied from solar panels will vary throughout the day, especially due to cloud cover. It is widely recognized in the industry that the intermittency of solar generation and wind generation requires buttressing these renewable resources with combustion turbines, combined-cycle

generation, or long-duration energy storage (LDES).[31]

(3) **There is no legally enforceable obligation on the part of solar customer-generators to provide capacity.** Unlike a combustion turbine, combined-cycle generation, steam generation, nuclear generation or a solar-plus-storage facility, the customer-generator operating solar panels cannot commit to a legally enforceable obligation to provide capacity because solar panels can only operate during daylight hours and then only when the sunlight is not obscured by clouds, snow, dirt, debris, etc.

(4) **Behind-the-meter solar panels do not have the same attributes to support grid operation as conventional capacity resources, and therefore are not comparable in value to conventional capacity resources.** For example, behind-the-meter solar panels do not have the inertial force to supply short-circuit strength to supply power for large manufacturing and other large loads on KU and LG&E's systems. The lack of this capability and other important attributes limits the usefulness and diminishes the value of solar power, particularly in comparison to large-frame combustion turbines and steam generation stations.

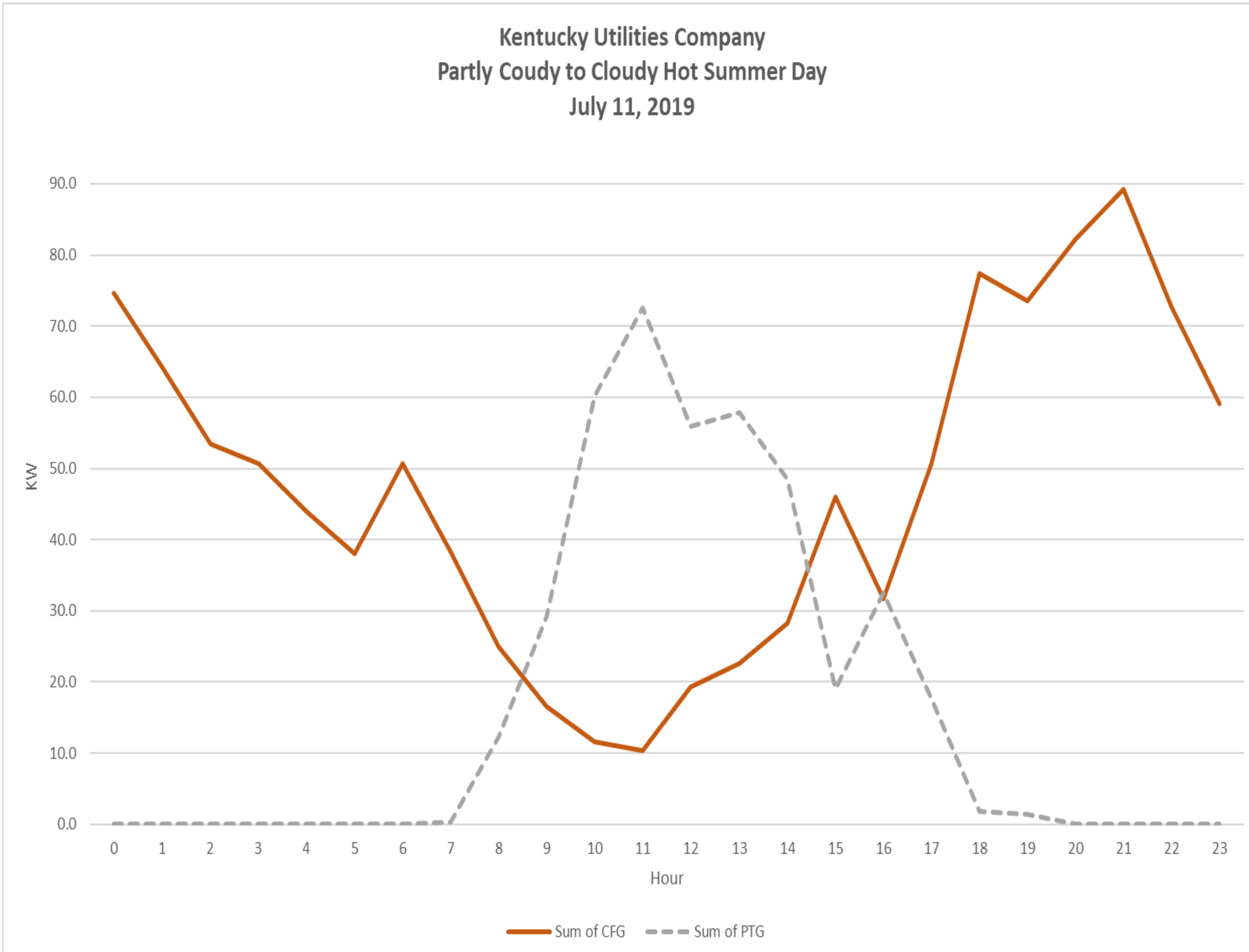
(5) **Distributed energy resources are more likely to add costs than avoid capacity costs on KU and LG&E's transmission and distribution systems.** Distributed energy can create congestion on the transmission system requiring the investment in distributed energy management systems (DERMS) to manage distributed generation resources on the system.

Q. Can you illustrate the intermittent nature of net metering generation on a cloudy summer day?

A. Yes. The intermittency of net metering generation is illustrated in the following graph (GRAPH 1) showing the energy consumed form the grid (CFG) and the energy

[31] See Sepulveda, et al., "The design space for long-duration energy storage in decarbonized power systems," *Nature Energy*, March 29, 2021. LDES systems include redox flow batteries, pumped hydro storage, compressed air, and power-to-gas-to-power hydrogen energy storage systems. The energy supply duration of Li-ion batteries is typically insufficient to be considered an LDES technology.

provided to the grid (PTG) from KU's residential customer-generators that are also participating in the Companies' AMI pilot program on July 11, 2019. On this hot summer day, with temperatures over 90 °F, the weather in Kentucky was alternately cloudy to partly cloudy. As clouds drifted through KU's system, sunlight obstructed residential solar panels and reduced the energy that the customer-generators provided to the grid (PTG), simultaneously increasing the energy that customer-generators consumed from the grid (CFG). In the graph, the solid line shows the energy that customer-generators consume from the grid (CFG), and the dashed line shows the energy that the customer-generators provide to the grid (PTG). Because of the cloudiness, between 11:00 to 3:00 P.M., the amount energy that the customer-generators consumed from the grid (CFG) increased significantly and the energy that the customer-generators provided to the grid (PTG) dropped precipitously. During this period, the energy provided to the grid by residential customer generators decreased 74% from 11:00 A.M. to 3:00 P.M. (a decrease of 53.4 kW, from 72.5 kW to 19.1 kW). Therefore, 74% of the power that customer-generators supplied to grid disappeared exactly during the hours when KU's system load was increasing. In Kentucky, it is not uncommon for peak conditions to occur on hot, partly cloudy days. On those days, generation from customer-generators cannot be relied on to provide firm capacity.


Kentucky Utilities Company
Partly Coudy to Cloudy Hot Summer Day
July 11, 2019
KW
90.0
80.0
70.0
60.0
50.0
40.0
30.0
20.0
10.0
0.0
0 1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23
Hour
Sum of CFG
Sum of PTG

GRAPH 1

Q. Can behind-the-meter solar facilities provide firm, legally enforceable capacity that should be compensated by other customers?

A. No. Behind-the-meter solar facilities cannot be called upon to provide firm capacity. In terms of their ability to provide capacity on demand, roof-top solar installations cannot be compared to large-frame combustion turbines, combined cycle combustion turbines, coal-fired steam generation facilities, nuclear[32] generation facilities, or solar-plus-storage facilities. These generation technologies will have availabilities in the 90 to 100% range. Combined cycle combustion turbines, coal-fired steam generation facilities, and nuclear generation facilities often operate continuously with few forced outages. Large-frame combustion turbines can be called upon whenever needed to provide reliable capacity. Large-scale solar-plus-storage platforms can also provide capacity on demand. Therefore, it is inappropriate to assign a financial capacity value to roof-top solar based on the capacity costs of any of these generation or generation-plus-storage technologies. Roof-top solar is an "as available" technology and should not be assigned a compensable capacity value.

Q. Do you have other concerns about imputing a compensable capacity value for behind-the-meter solar generation for which other customers must pay?

A. Yes. Besides their intermittent supply of energy, another problem with placing a capacity value on roof-top solar and other residential- and small-commercial scale

[32] KU and LG&E have no nuclear generation.

solar generation is that they cannot provide the inertial force necessary to drive large loads such as large manufacturers in Kentucky.[33] Rooftop solar facilities simply cannot provide the short circuit strength[34] to furnish the frequency support needed for the large manufacturing loads supported by KU and LG&E, and should not be compensated as though they could.

Q. Has net metering created challenges in other states?

A. Yes. While there is currently a cap on net metering in Kentucky of 1% of each electric supplier's single peak hour load during a calendar year, it is instructive to consider challenges encountered in other states regarding the integration "high penetrations of distributed resources"[35] into the grid. High net metering adoption have clearly created challenges for utilities to balance supply and demand on the grid. Recent challenges experienced in California are due to the increased need for electric generators to quickly ramp up energy production when the sun sets and the contribution from solar generation falls. The inability to ramp up generation can lead to blackouts.

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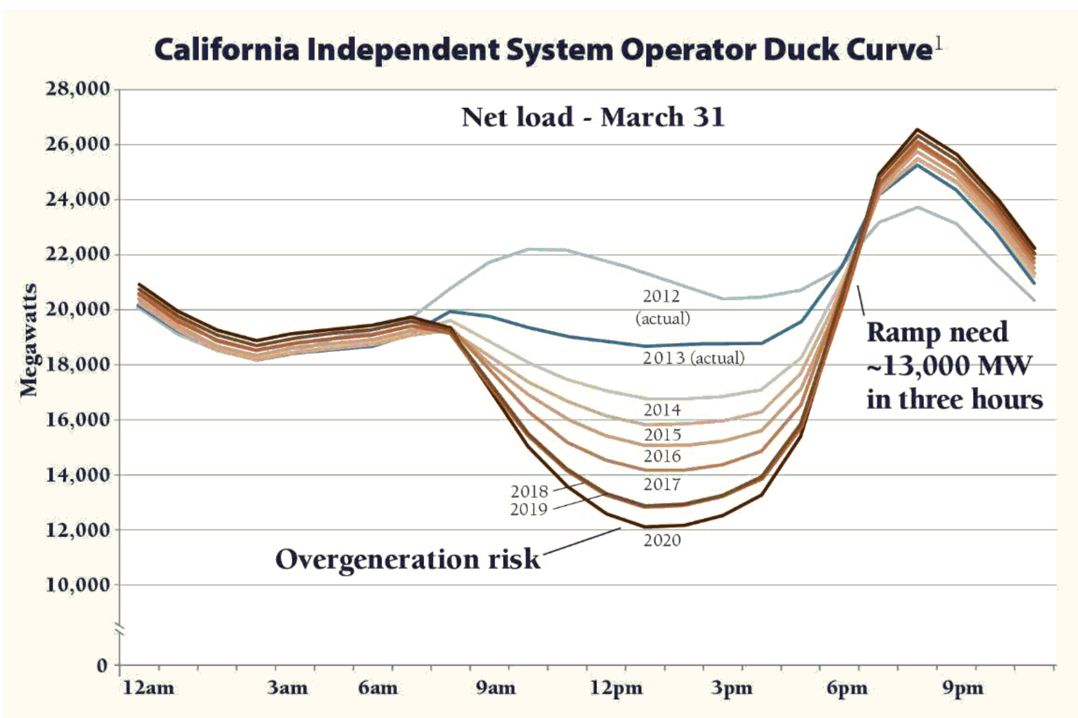
[33] Theoretical papers have been written suggesting that large-scale solar farms and utility grade battery storage could provide the inertial capacity to drive large industrial loads, but so far this approach has not been put into practice to serve large industrial loads.

[34] The short circuit strength of a network is measured by the *short circuit ratio*, which is the ratio of (i) the field current required to generate rated voltage on an open circuit to (ii) the field current required to provide armature current (AC current) on a short circuit. The short circuit ratio can be calculated at each point on the grid. Large generators have high short circuit ratios, i.e., well above 1.0. Solar panels provide negligible short circuit current. See ERCOT, "Planning and Operations Standards for Solar," ERCOT, Solar Workshop, April 25, 2011. Synchronous condensers must be added to support systems with large amounts of renewables and insufficient inertial force to maintain short circuit strength. See https://www.ge.com/power/steam/synchronous-condenser.

[35] Strategen Question No. 14 asked the Companies to discuss "how wholesale markets and utility planning processes are evolving to integrate high penetrations of distributed energy resources throughout the United States."

Yet another challenge with high solar adoption is the potential for solar generation to produce more energy than can be used at one time. This has led to system operators in California being forced to curtail solar generation. In 2013, the California Independent System Operator (CAISO) published a graph that has entered the vocabulary about large-scale deployment of solar power. The so-called "Duck Curve", which is named after its resemblance to a duck, shows the difference in electric demand and the amount of available solar energy throughout the day. When the sun is shining, solar energy floods the market and then drops off as electric demand peaks in the evening. The Duck Curve is illustrated in the following graph (GRAPH 2) created by the CAISO:

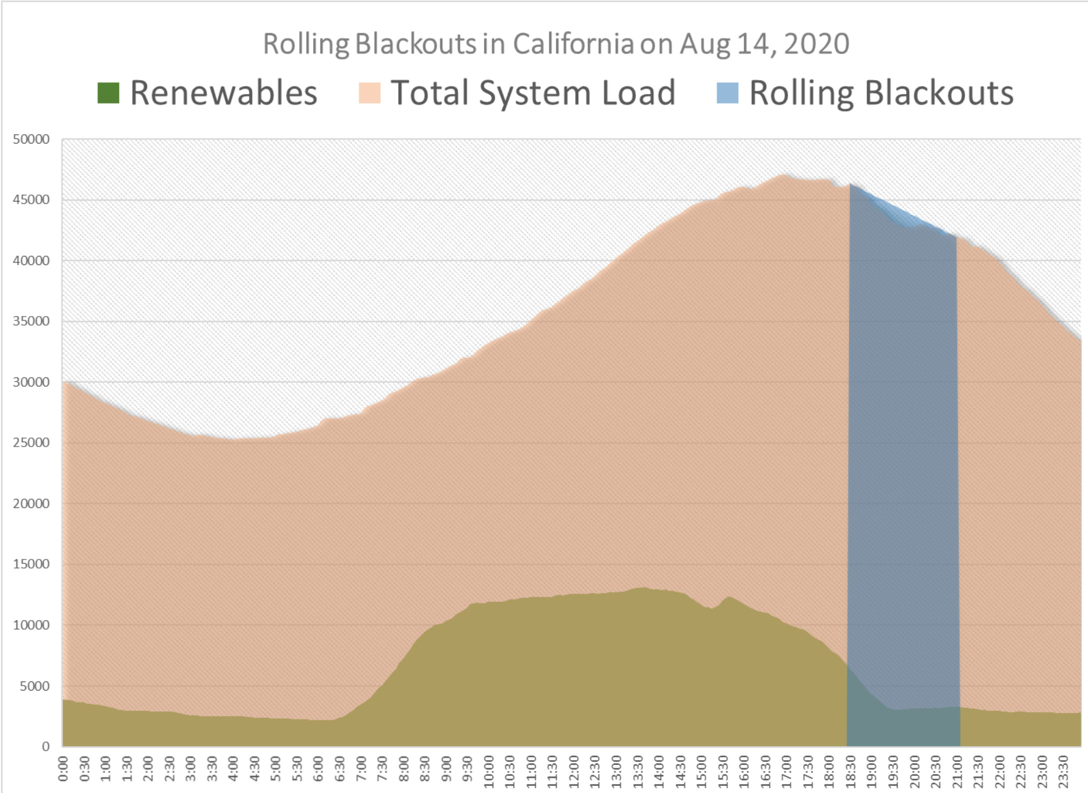
GRAPH 2



Other states integrating large amounts of solar generation, such as Massachusetts and Hawaii, are also seeing this same Duck Curve pattern.

Although there has been much finger pointing about the mismanagement of the grid in California, the problems illustrated by the Duck Curve played a major role in the recent rolling blackout in California that occurred on August 14, 2020. The integration of large amounts of solar in the state has shifted the net peak system demand later into the evening. With loads still elevated due to high temperatures, CAISO was forced to implement rolling blackouts, as illustrated in the following graph from CAISO data:

GRAPH 3



As seen from the above graph (GRAPH 3), the system loads remained elevated due to high temperatures as the output from solar generation dropped, causing CAISO to institute rolling blackout from 6:30 PM to 9:00 PM on August 14, 2020. By 7:00 PM, solar generation had essentially disappeared, with only wind providing renewable generation to the grid. California's rolling blackouts provide a cautionary example of the challenges of integrating an intermittent energy source into the electric grid.

Q. Is California currently addressing the overcompensation provided to customer-generators from net metering?

A. Yes. The California Public Utilities Commission (CPUC) is currently conducting its first review of net metering tariffs since 2016.[36] The CPUC has acknowledged that it has concerns about overcompensating customer-generators with net metering.[37] At the request of the CPUC, a comprehensive review of net metering in California was conducted by Verdant Associates, LLC ("Verdant") of Berkeley, California.[38] Verdant's report is titled *Net-Energy Metering 2.0 Lookback Study* ("*Lookback Study*"), and was filed with the CPUC on January 21, 2021. The *Lookback Study* is included as Rebuttal Exhibit WSS-3. The *Lookback Study* found that net metering is not cost-effective from the perspective of ratepayers but is only cost-effective to participants.[39] The study found that the Ratepayer Impact Measure ("RIM") ratio for net metering was less than 1, which results "in an increase in rates for all customers and an increase in bills for non-participating customers." The *Lookback Study* also indicated that net metering failed the Total Resource Cost ("TRC") test. Because net metering failed both the RIM and TRC tests, the *Lookback Study* found that net metering had a negative distributional impact on non-participating customers, but particularly low-income customers who were unlikely to be able to afford to install solar panels. The *Lookback Study* also notes that customer classes with demand charges have better alignment with cost.[40] Regarding the adoption of solar facilities

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[36] *Order Instituting Rulemaking to Revisit Net Energy Metering Tariffs Pursuant to Decision D.16-01-044, and to Address Other Issues Related to Net Energy Metering*, Rulemaking 20-08-020, Filed August 27, 2020.
[37] *The Energy Daily*, March 18, 2021, at p. 3. See also "California looks to reboot rooftop solar payments amid affordability concerns", S&P Global Market Intelligence, March 24, 2021 (attached as Rebuttal Exhibit WSS-6.
[38] See Verdant Associates LLC et al., *Net-Energy Metering 2.0 Lookback Study*, January 21, 2021. Verdant was assisted by Energy and Environmental Economics and Itron, Inc.
[39] *Id*., at p 4.
[40] *Id*., at p. 13.

by low-income customers, the *Lookback Study* states:

> 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 finding presented above show that NEM 2.0 system also provide lower bill savings to these households and have a longer payback period.[41]

It appears that the CPUC is on track to significantly reform or abolish net metering for new customer-generators in California. In comments filed in the California net metering proceeding, Solar Energy Industries Association and Vote Solar (strong advocates for solar) proposed to replace a *net metering framework* with a *net billing framework* for compensating customer-generators, stating that, "Under net billing, the customer with renewable distributed generation (DG) would pay a different rate for energy received from the utility (i.e., imports) than for the excess generation that the DG customer delivers to the utility (i.e., export)."[42] Solar Energy Industries Association and Vote Solar did not dispute the fact that there should be a difference in the rate paid by customer-generators for "imports" and the rate paid by utilities for "exports".

Q. Do the generation and loads of customer-generators in Kentucky exhibit the Duck Curve pattern that has caused the major problems in California?

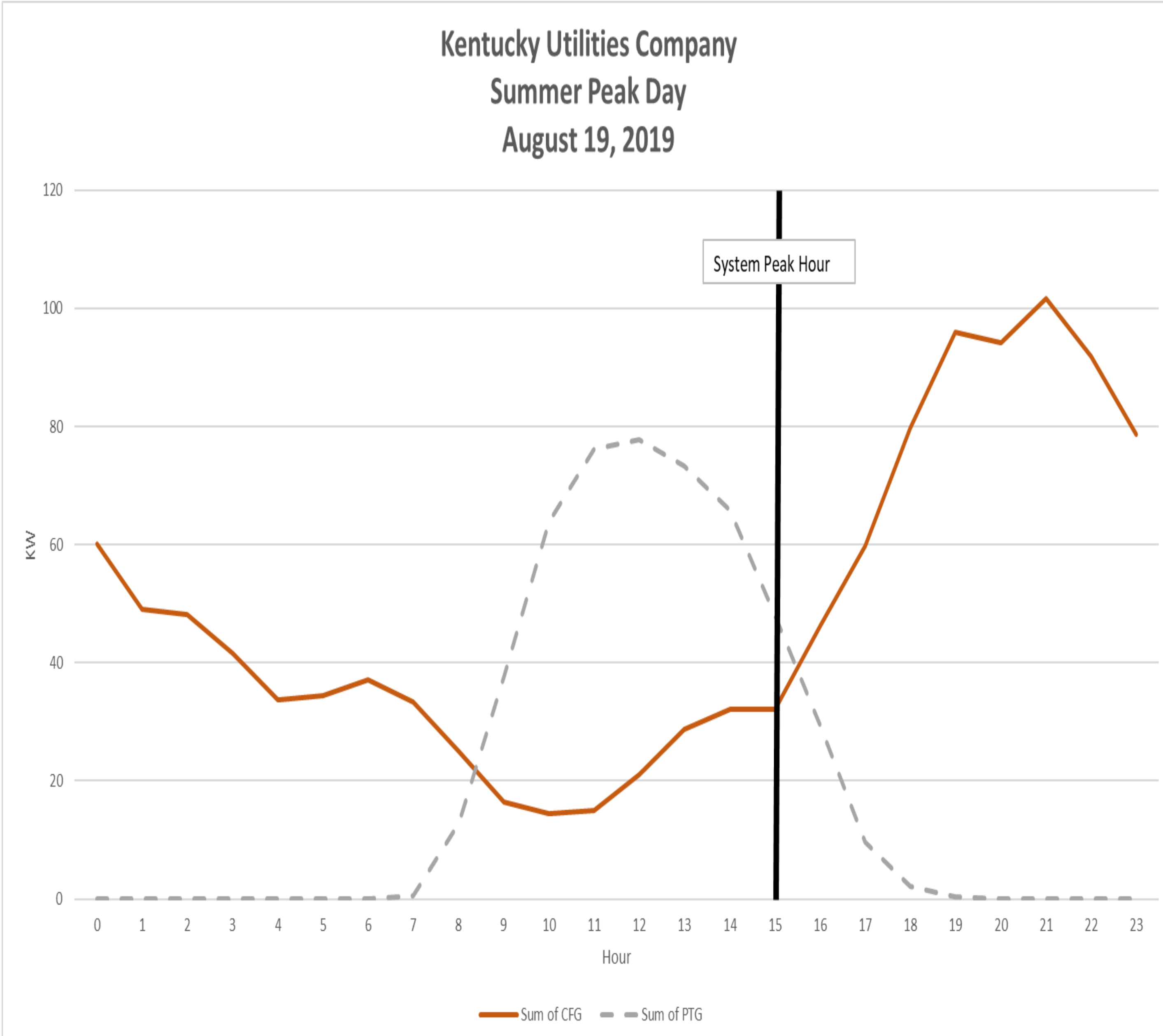
A. Yes. The following graph (GRAPH 4) shows the energy consumed from the grid and

[41] *Id*., at p. 94.
[42] Comments filed by Solar Energy Industries Association and Vote Solar on March 15, 2020, in Rulemaking 20-08-020.

the energy provided to the grid for KU AMI pilot customer-generators on August 19, 2019,[43] which was the system summer peak day. The solid lines in the graph show the energy that customer-generators consumed from the grid (CFG), and the dotted line shows the energy that the customer-generators provided to the grid (PTG). The solid lines of the graph showing the energy that customer-generators consume from the grid (CFG) exhibit the Duck Curve. After hour 12 (Noon), the energy supplied from customer-generators begins to drop off and the energy consumed from customer-generators rises until the late evening hours. The Companies' system peak during the summer typically occurs around 3:00 to 4:00 P.M. (Hours 15 to 16). As can be seen from the graph, at 3:00 P.M., the energy provided to the grid has dropped off significantly, and the energy consumed from the grid is on its way up. Therefore, at the time of the Companies' system peak, customer-generators are providing relatively little support to the grid. It is also important to note that this was a mostly sunny day. If there had been clouds passing through the system on this hot summer day, which is not an unusual occurrence, the situation would have been much worse.

[43] The graph for LG&E has the same shape. The graph for LG&E is omitted so as not to add to the length of the rebuttal testimony.

GRAPH 4


Kentucky Utilities Company
Summer Peak Day
August 19, 2019
System Peak Hour
KW
120
100
80
60
40
20
0
0 1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23
Hour
Sum of CFG
Sum of PTG

Q. During winter months, do customer-generators provide capacity at the time of the peak?

A. No. During the winter, the Companies' system peak will occur around 7:00 to 8:00 A.M. in the morning or around 8:00 P.M. in the evening. Customer-generators' solar panels are typically not generating energy during the Companies' winter peaks. Winter peak demands are critical in the Companies' resource planning efforts. The Companies most recent Integrated Resource Plan explained:

> Because of the potential for cold winter temperatures and the increasing penetration of electric heating, the Companies are somewhat unique in the fact that annual peak demands can occur in summer and in winter months. The Companies' highest hourly demand occurred in the summer of 2010 (7,175 MW in August 2010). Since then, the Companies have experienced two annual peak demands in excess of 7,000 MW and both occurred during winter months (7,114 MW in January 2014 and 7,079 MW in February 2015).[44]

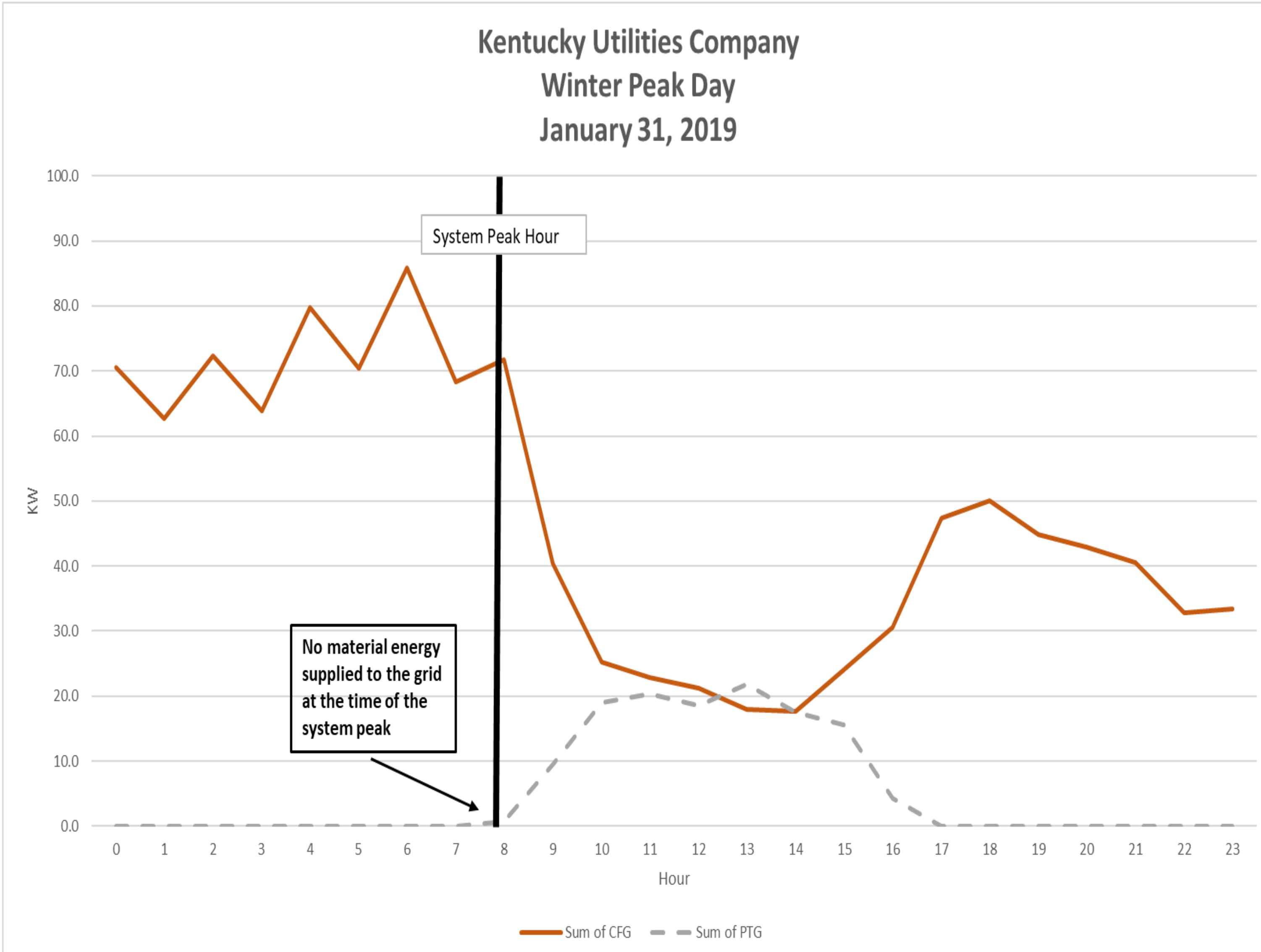
With the compound growth rate for peak winter demands being higher than for summer demands,[45] the Companies' winter system peak demands are projected to be nearly as large as the summer peak demands.[46] Due to the increasing penetration of electric heating, winter peak demands in the Companies' IRP are projected to grow at a faster rate than summer peak demand from 2020-2033.[47] Also, the variability in

[44] KU and LG&E's 2018 Integrated Resource Plan, at p. 5-2.
[45] *Id*., at p. 5-26.
[46] *Id*., at p. 8-24.
[47] *Id*., at p. 6-11.

peak demands is much higher in the winter than in the summer.[48] Furthermore, the 6-CP cost of service methodology recommended by KIUC and DOD-FEA gives significant weight to the winter system peaks.

The following graph (GRAPH 5) shows the energy consumed from the grid and the energy provided to the grid for KU AMI pilot customer-generators on January 21, 2019,[49] which was the winter peak day. Again, the solid lines in the graph show the energy that customer-generators consumed from the grid (CFG), and the dotted line shows the energy that the customer-generators provided to the grid (PTG). As can be seen from the graph, at 8:00 A.M., which was the hour of the Companies' system peak, customer-generators were supplying a negligible amount energy to the grid. Therefore, at the time of the Companies' system peak, customer-generators were providing no material support to the grid. But, at the time of the peak, customer-generators were consuming significant amounts of energy, creating demands on Companies' distribution, transmission, and generation systems. For KU and LG&E, the winter system peak is as critical as the summer system peak,[50] but customer-generators supply essentially zero energy and no capacity during the winter system peak demand.

[48] *Id*. at p. 5-27.
[49] The graph for LG&E has the same shape. Again, the graph for LG&E is omitted so as not to add to the length of the rebuttal testimony.
[50] In terms of human health and safety, the winter system peak is arguably more critical, considering the health threats posed by extreme winter temperatures.


Kentucky Utilities Company
Winter Peak Day
January 31, 2019
System Peak Hour
No material energy supplied to the grid at the time of the system peak
KW
100.0
90.0
80.0
70.0
60.0
50.0
40.0
30.0
20.0
10.0
0.0
0 1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23
Hour
Sum of CFG
Sum of PTG

GRAPH 5

Q. Do customer-generators provide a capacity value to the transmission and distribution system?

A. That is unclear. Adding distributed resources will certainly complicate grid operations. High penetrations of solar can cause the ampacity rating of circuits and components to be exceeded. They can mask load and thereby overload circuits if the solar facilities disconnect.[51] Solar can exacerbate cold load pickup problems by increasing the difference between the pre-fault load and post-fault cold load pickup current.[52] Fluctuating solar generation can cause voltage surges and variations.[53] Distributed generation can add to grid congestion, particularly in areas on the system with high concentrations of distributed generation, thus adding to grid management costs. Additionally, depending on the location-specific grid conditions, distributed generation can add to the cost of voltage management and increase maintenance requirements on voltage control assets. Addressing problems with integrating large amounts of distributed generation on the distribution system would require the implementation of Distributed Energy Resources Management Systems (DERMS). Distributed energy resources can provide value to transmission and distribution systems only when centralized monitoring and control capabilities with DERMS are implemented by the utility. Benefits such as reactive power support, net energy reductions, and increases in distributed generation hosting capacity can be achieved

[51] National Renewable Energy Laboratory, *High Penetration PV Integration Handbook for Distribution Engineers* (January 2016), at p. 4. See Rebuttal Exhibit WSS-7.
[52] *Id.*, at p. 5.
[53] *Id.*, at p. 6

only with adequate coordination and control. Without such controls, distributed generation can create possible disturbances on the transmission or distribution system, depending on the relative penetration of the distributed resources. This has been realized in states such as California and Texas during load shed events or other grid disturbances (e.g., wildfires).

Q. Could a properly managed solar-plus-storage system provide capacity value?

A. Yes, I believe it could. A managed solar-plus-storage system is an altogether different proposition. A properly managed,[54] sufficiently sized solar-plus-storage system could provide a capacity value to the system. But this underscores the problem with the current net metering arrangement. *Under the current net metering framework (NMS-1), there is zero incentive for a customer-generator to install a managed solar-plus-storage system*. Under NMS-1, customer-generators with as-available solar facilities receive the full retail price of energy (which grossly exceeds avoided costs), the same full retail price of energy they would receive if they also installed energy storage (i.e., battery storage). Standalone net metering solar energy (without battery storage) is a low-cost, low-value product, but under NMS-1 customer-generators are being paid the full retail price for the as-available energy they supply to the grid. Under NMS-1 there is no incentive whatsoever for customer-generators to install solar-plus-storage when the payment they receive from the Companies under NMS-1 would be same they would receive for just installing solar, even though solar-plus-storage provides far

[54] "Properly managed" behind-the-meter solar-plus-storage systems would likely require the implementation of distributed energy resource management systems (DERMS) to provide capacity value.

more value to the system. This highlights a major problem with compensating an as-available resource as if it were a firm resource. Solar-plus-storage offers a strong potential to provide *energy and capacity* for a large portion of our country's electric power needs,[55] but distributed solar by itself does not have that potential because it cannot reliably supply capacity. Managed energy storage, particularly long-duration energy storage (LDES), is critical to the integration of high penetrations of distributed energy resources into the grid.[56] Under traditional net metering, customer-generators with standalone-solar are being overpaid for the energy they supply to the grid.

Q. How would renewable resources have to be supplemented to provide the capacity value of traditional generation resources?

A. By themselves, solar and wind generation do not provide capacity, only energy. To provide a capacity value equivalent to traditional generation resources (such as large-frame combustion turbines, combined cycle combustion turbines, or steam generators), renewable generation would have to be supplemented with at least three

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[55] For example, see BloombergNEF, *How PV-Plus-Storage Will Compete with Gas Generation in the U.S.*, November 23, 2020.

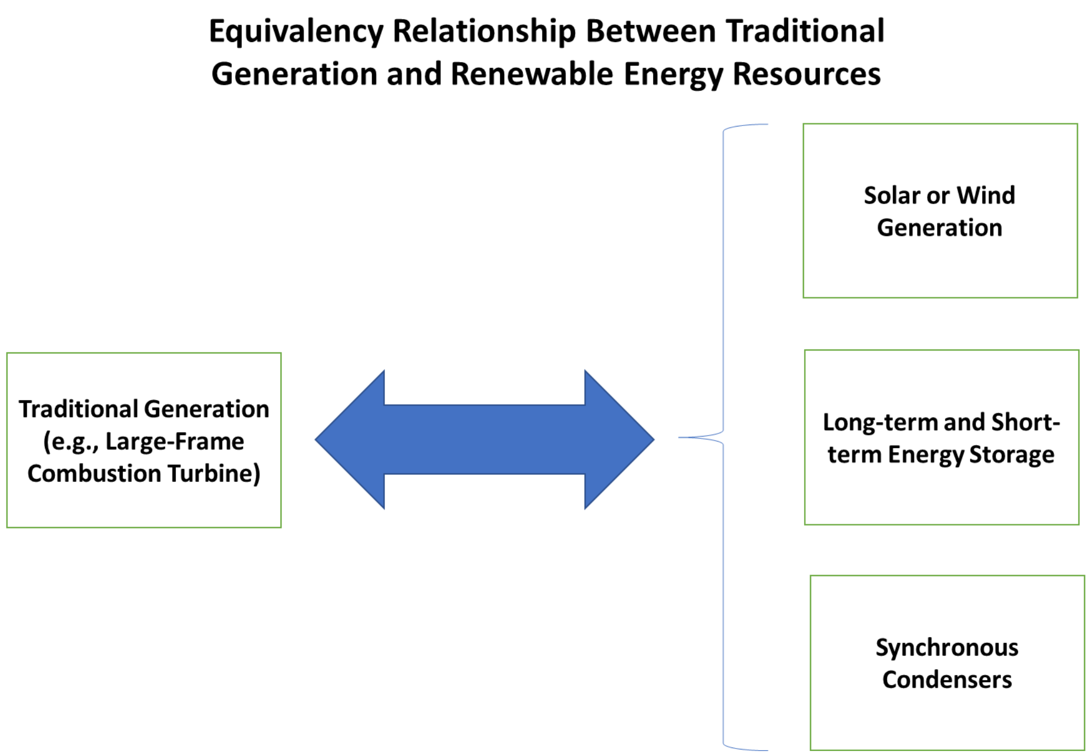
[56] LDES systems are typically large-scale energy storage systems that can provide energy continuously for ten hours or longer. Li-ion Batteries typically supply energy for 4 hours or less. See Dowling et al., "Role of Long-Duration Energy Storage in Variable Renewable Electricity Systems", *Joule*, September 16, 2020, at pp. 1-22. The article states:

> [R]eliable electricity systems based on variable energy sources, such as wind and solar must accommodate the variability with, for example, energy storage or ''firm'' generators, such as hydroelectricity, nuclear, natural gas with carbon capture and storage (CCS), geothermal, and bioenergy.

See also Sepulveda, et al., "The design space for long-duration energy storage in decarbonized power systems," *Nature Energy*, March 29, 2021.

additional resource technologies: (1) short and long term energy storage to deal with the intermittency of the energy provided by distributed energy resources, (2) equipment such a synchronous generators to provide the inertial force to drive large manufacturing load, and (3) equipment to provide reactive power to the grid.[57] The following figure (FIGURE 1) illustrates what is necessary for renewable energy resources to provide ***a capacity value*** equivalent to traditional generation resources with current technologies:

FIGURE 1



[57] Both short circuit strength and reactive power can be provided by synchronous generators. It may be possible, with future advances in battery storage technologies, that both strong short circuit strength and reactive power could eventually be provided with a combination of battery storage and inverters at some point in the future.

To put financial values to this illustration, Exhibit WSS-2 to my direct testimony shows that for residential customers the full suite of energy and capacity value provided by Traditional Generation is between about $0.065/kWh and $0.07/kWh. On the right-hand side of Figure 1, Solar or Wind Generation provides only about $0.022/kWh of energy-only value. What the cost will be of the other components necessary to create equivalent value between traditional and renewable resources is not fully known, but this much is clear: renewable generation standing alone does not provide the capacity value of traditional generation.

ii. HEDGING VALUE OF SOLAR

Q. Should the SQF rate include a hedging value as suggested by Mr. Barnes?

A. No. Including a hedging value in the SQF rate is an arcane concept that has no actual relevance to KU and LG&E. Mr. Barnes does not provide any details in his direct testimony about how a hedging value would be calculated. Furthermore, he did not calculate a "hedging value" for KU or LG&E. Thus, his testimony on this topic lacks the support to be seriously considered. But as I understand the concept, a Black Scholes model, a modified Black Scholes model, a binomial options model, or some other financial options model would be used to calculate the hedging value. Mr. Barnes cites North Carolina as a jurisdiction that requires the inclusion of a hedging value for cogeneration rates. In its Order in Docket No. E-100, Sub 158, the North Carolina Utilities Commission stated as follows:

> It is appropriate to require DEC and DEP to recalculate their avoided energy costs to include the value of ***<u>their current hedging programs</u>***

> using the Black-Scholes Model or a similar method that values the added fuel price stability gained through each year of the entire term of the QF power purchase agreement. (Order at p. 11. Emphasis supplied.)

The problem with applying this concept to KU and LG&E is that unlike Duke Energy Carolinas and Duke Energy Progress, KU and LG&E do not have financial hedging programs for their fuel purchases; therefore, the concept does not apply to KU or LG&E. Furthermore, even for Duke Energy Carolinas and Duke Energy Progress, the hedging value appears to be quite small. In Comments submitted by Cube Yadkin Generation, LLC, which operates qualifying facilities in North Carolina with 30 to 40 MW of capacity, Cube Yadkin Generation indicated that the hedging value for Duke Energy Carolinas and Duke Energy Progress was only $0.00028/kWh.

iii. AVOIDED LOSSES OF SOLAR

Q. Should the SQF rate include a loss factor as suggested by Mr. Barnes?

A. No. Avoided losses for distributed generation is a very complex issue, and it is not practicable to assign a specific loss value for all customer-generators. Whether distributed generation adds to or decreases line losses on the system is determined by a multitude of factors on the system which are ultimately affected by customer-specific and locational considerations. Clearly, distributed generation facilities can never fully avoid losses on the distribution system. For example, distributed generation will not avoid "core losses"[58] in transformers, which are unaffected by current flows. A significant portion of the losses on any transmission and distribution system relate to core losses. Furthermore, because it always necessary for any energy that a customer-generator supplies to the grid to be transmitted across the distribution system, I^2R losses[59] are always involved in the delivery of energy from a customer-generator and will thus never be entirely avoided by the purchase of energy from the customer-generator. The amount of distribution and transmission losses realized to deliver energy from a customer-generator or qualifying facility depends on a host of factors, including the amount of distributed generation delivered to the grid in a particular location, congestion on the system, the length of primary and secondary lines serving distributed generation customers, and many other factors.

Ultimately, the actual effect of line losses resulting from purchasing energy from customer-generators would depend on circumstances related to serving each individual customer-generator, which cannot be reasonably estimated. In all cases, the energy produced by a customer-generator must be transmitted through multiple transformers and across multiple segments of distribution lines and customer services, resulting in transformer and line losses. Consider a kWh that is sent back to the distribution system due to over-generation. That kWh experiences losses when up-

[58] Core losses include hysteresis and eddy current losses in transformers. These losses are considered fixed and are present regardless of the direction of current flow in a transformer. Consequently, core losses cannot be avoided by distributed distribution.

[59] I^2R losses relate to resistance in conductor and transformer windings and are proportion to the square of the current. Because any energy generated by customer-generator must flow through conductor and transformers windings, such energy will always create I^2R losses. Consequently, these I^2R losses will not be avoided by customer-generators supplying energy to the grid.

converted to primary voltage and again when it is down-converted back to secondary voltage. Therefore, a kWh of over-generation may result in only a fraction of a kWh to another customer. The way SQF is structured, the customer receives credit as if the kWh were generated at the Companies' power plants, even though the kWh generated at the power plant only experiences the conversion losses once, not twice.

iv. MARKET VALUE OF SOLAR ENERGY

Q. The Companies are proposing to pay customer-generators $0.02173/kWh for the energy they provide to the grid. Is this comparable to what the Companies would pay a solar farm for power supplied to KU and LG&E?

A. Yes. The SQF rate is comparable to what the Companies would pay for such energy in the marketplace. KU and LG&E are proposing to pay customer-generators $0.02173/kWh for the energy they supply to the Companies. It is important to observe that customer-generators will first use their solar panels or other generation equipment to supply their own needs, thereby realizing savings on their electric bills. If at times they generate more energy than they use, then they will supply the energy to the grid. Because their own energy needs are most likely to be at their highest when other residential customers' energy needs are at their highest, customer-generators most likely supply energy to the grid either before or after the Companies' system peak demands. (This was illustrated by the Duck Curve addressed earlier.) Consequently, the energy that customer-generators supply to grid is inherently less valuable than the energy that could be supplied from solar farms. The Companies recently entered into

20-year solar purchase power agreement to satisfy customer requests for a renewable energy source under the Companies' Green Tariff. The agreement, which Mr. Conroy also addresses in his rebuttal testimony, is with Rhudes Creek Solar, LLC ("Rhudes Creek"), a wholly owned subsidiary of ibV Energy Partners, LLC. ibV Energy Partners is a wholly owned subsidiary of ib vogt GmbH of Berlin, Germany that has developed, built, and commissioned more than 80 projects while investing in and developing more than 29 GW of solar photovoltaic systems around the world. The cost of power from the agreement is $0.02782 per kWh, which is a levelized, non-time-differentiated amount that will remain the same for the full 20 years of the agreement.[60] This price would fully reflect both the hedging value and any capacity value for the power. The agreement also requires Rhudes Creek to transfer the renewable energy certificates ("RECs") produced by the facility at no additional charge to the Companies, which will be sold and the revenue used to reduce customer costs. Under the agreement, Rhudes Creek would provide the entire output of the solar facilities to the Companies, and not just residual amounts of energy in excess of their energy needs, such as with customer-generators. Clearly, the energy provided by Rhudes Creek is more valuable than the residual energy that is provided by customer-generators. But the KSIA and Joint Intervenors' witnesses maintain that the Companies should continue to compensate customers at the energy charges set forth in Rate RS, which is currently $0.08963/kWh for KU and $0.09278/kWh for LG&E.

[60] Order in Case No. 2020-00016, dated December 16, 2020, at page 6.

<u>The witnesses are therefore arguing that the Companies' customers should continue to pay customer-generators about four times the price for renewable energy in the open market.</u> Obviously, there is no basis for the intervenors' position.

Q. Is there a difference between the reliability of a solar farm and the reliability of roof-top solar installations?

A. Yes. Contrary to what Mr. Barnes claims,[61] there is a major difference between the reliability and dependability of energy provided from a large solar farm and the energy provided from small roof-top solar installations on people's homes. In the case of a roof-top solar, the equipment may not be in proper working order or the solar panels could be covered with snow during a winter storm, precisely when a utility's winter system peak would likely occur. As the Companies stated in response to PSC 4-14:

> [R]esidential-grade solar panels or residential energy storage equipment will not likely be able to provide the same level of reliability as coal-fired generating stations, combined cycle gas turbines, large scale solar panels or large-scale energy storage facilities. Consider a rooftop solar system compared to a utility grade solar array. If there were a major snowstorm followed by a significant drop in temperature, such as occurred in Kentucky on January 17, 1994, roof-top solar panels would be practically useless in supplying power to the grid, precisely when the utility would be realizing its winter system peak. In a situation like this, it is extremely unlikely that residential customers with roof-top solar panels would be willing or able to climb on their roofs and clear 16 to 22 inches of snow from the solar panels, so that the solar panels could operate during daylight hours. A utility or energy company operating a large-scale solar array, on the other hand, would almost certainly be in a much better position to clear the snow and clean the solar panels to operate during daylight hours. Furthermore, such utility grade solar panels would likely be located in areas with easier access for maintenance.

[61] *Id*. at p. 8.

The Companies should not be compensating customer-generators at a purchase rate that is greater than it would pay in the market for energy from a solar farm.

C. COST-BENEFIT ANALYSIS AND COST OF SERVICE

Q. KYSIA and the Joint Intervenors' witnesses criticize the Companies for not submitting a cost-benefit or a cost-of-service study for customer-generators. Are these valid criticisms?

A. No. The issue is a diversion. The Companies' NMS-2, which is filed pursuant to KRS 278.465 and 278.466, is solely about compensating customer-generators for the energy that they flow to KU and LG&E. KRS 278.466(3) states that "retail electric supplier serving an eligible customer-generator shall compensate that customer for all electricity produced by the customer's eligible electric generating facility that ***flows to the retail electric supplier***, as measured by the standard kilowatt-hour metering." (Emphasis suppled.) This is precisely what the Companies are doing by proposing NMS-2. Including customer-generators as a class in the Companies' cost of service study is not needed to determine the appropriate compensation for customer-generators under NMS-2.

A cost of service study can determine what the cost is of *serving* a customer-generator and the appropriate charges to collect those costs. It does not determine the cost that a utility should *pay* for any energy the customer-generator would sell back to the utility. A cost of service study is an embedded cost calculation that would account for all of the utility's costs associated with ***serving*** the customer-generator. An avoided cost calculation that determines what cost the utility could have otherwise supplied the energy provided by the customer-generator. All that is required is to determine the avoided cost of the energy that customer-generators supply to grid. The Companies have done this and have therefore met their burden of proof in these proceedings. Evaluating the price that the Companies agreed to pay Rhudes Creek for green energy from a solar farm also supports the reasonableness of the purchase rate for energy under NMS-2. The Companies have provided support for the specific charge that should be paid to customer-generators for the energy they supply to the grid. KSIA and the Joint Intervenors have provided nothing by way of numerical analysis supporting what they believe should be paid.

Q. Can a cost of service study be used to determine the compensation for the energy that customer-generators supply to the grid?

A. No. *A cost of service study has nothing whatsoever to do with energy that net metering customers supply to the grid, which is the sole purpose of NMS-2.* A cost of service study is not needed to calculate avoided costs. A cost of service study has never been used in the past to calculate the Companies' avoided costs for SQF. Avoided cost is a marginal cost calculation. Embedded cost of service studies do not contain, or attempt to estimate, marginal costs for any category of cost. Again, as I said earlier, this is a diversion. The Companies are proposing to set the purchase rate for new customer-generators at the SQF rate, which is currently $0.02173/kWh. If KSIA and the Joint Intervenors believe that a capacity component should be included in this purchase rate, then it is incumbent on them to recommend what that component should be based on the wealth of the cost data that have been provided in these proceedings. That the Companies have not provided evidence to support the nebulous compensation components and externalities desired by KSIA and the Joint Intervenors – components and externalities that are plainly inappropriate and inapplicable – does not mean the Companies have not met their burden in this case; rather, the intervenors arguing for such compensation have failed to meet theirs.

Furthermore, KSIA and the Joint Intervenors did not perform any type of cost of service analysis themselves, calculating the capacity value that customer-generators are purported to provide from the energy they supply to the grid. The Companies provided detailed cost data in these proceedings, which could have been used by the KSIA's and the Joint Intervenors' witnesses to perform a cost analysis for the value they recommend for solar energy. They did not provide a description of a methodology that they would recommend for calculating a capacity value. The energy credit that customer-generators currently receive under NMS-1 is fundamentally excessive. Instead of proposing what they believe is an appropriate capacity credit, they complain that because the Companies did not submit a cost of service study with customer-generators broken out as a separate rate class, the Companies have not met their burden of proof.

Q. Although a cost of service study is not needed to determine the price the Companies should pay for the energy that customer-generators *<u>supply to the grid</u>*, have the Companies prepared cost of service studies for customer-generators

that consider the service provided to those customers?

A. While a cost of service study is not needed to determine price that KU and LG&E should pay for the energy that customer generators flow to the grid, I have conducted cost of service studies that refute KSIA's and the Joint Intervenors' notion that a cost of service study would somehow support the extension of NMS-1 to new customers. These cost of service studies clearly show that traditional net metering (NMS-1) should be discontinued for new customers. I will discuss these results in detail later in my testimony.

Q. Is a *cost-benefit analysis* required to determine the appropriate price for purchasing energy under NMS-2?

A. No. KRS 278.455 and 278.466 do not require that a cost-benefit analysis be performed, nor is one necessary. Again, the only analysis required to determine the compensation for the energy that flows to the Companies under NMS-2 is an analysis of avoided costs. The Companies have done this. The cost-benefits for the energy that flows to the grid are defined by these avoided energy costs. However, I will discuss what a cost-benefit analysis would show later in my testimony.

Q. But KSIA and the Joint Intervenors' witnesses argue for a more "holistic" approach for measuring benefits. What is your objection with that?

A. I have several objections to this concept. First, as discussed earlier, such an approach goes far beyond the clear distinction made in KRS 278.465 and 278.466 between the determination of avoided costs for a *purchase transaction* for energy supplied by customer-generators and the cost of the *sales service transaction*. KRS 278.465 and

278.466 make a clear distinction between the two types of transaction. Second, I strongly disagree with the "benefits" that the KSIA and the Joint Intervenors would incorporate into a cost-benefit analysis. Both Mr. Inskeep and Mr. Rábago cite the *National Standard Practice Manual: For Benefit-Cost Analysis of Distributed Energy Resources* ("*National Standard Practice Manual*") as a guide for determining benefits. Of course, Mr. Rábago is one of the authors of this guide. It should be pointed out that calling a document a "national standard practice manual" does not make it one. Mr. Rábago argues that the Companies' reliance on an avoided cost approach "disregards all of the benefits provided by solar generation to the utility, ratepayers, and society"[62] and that the Companies have failed to "objectively evaluate the full range of impacts associated with the operation of distributed generation."[63] But the full range of benefits that the KSIA and the Joint Intervenors want the Commission to consider have been rejected by the Commission in consideration of demand-side management (DSM) programs.

Q. What are the "full range of impacts" that Mr. Rábago is referring to?

A. According to the *National Standard Practice Manual*, co-authored by Mr. Rábago, the full range of benefits include "utility system impact", "gas utility and other fuel system impacts", "host customer impacts", and "societal impacts". Considering that this broad array of factors, most of which are externalities, is what Mr. Rábago and Mr. Inskeep regard as the "full range of impacts" for the evaluation of rates to be paid

[62] Direct Testimony of Karl R. Rábago at p. 13.
[63] *Id*. at p. 9.

to customer-generators, it is not surprising that they feel that the Companies have fallen short in their analysis of avoided costs for NMS-2.

Q. What are included as "societal impacts" in the *National Standard Practice Manual*?

A. Under the rubric of "societal impact", the *National Standard Practice Manual* identifies "low-income benefits," which include "poverty alleviation, local environmental justice benefits, improving low-income community strength and resiliency, and reduced home foreclosures." Also, under the heading of "societal benefits," the *National Standard Practice Manual* includes "resilience impacts beyond those experienced by utilities or host customers," "greenhouse gas emissions created by fossil-fueled energy resources," "other air emissions, solid waste, land, water, and other environmental impacts," "incremental economic development and job impacts", "health impacts, medical costs, and productivity affected by health". I certainly do not dispute the importance of these objectives as broad personal and societal goals, but I cannot envision a cost-benefit analysis of distributed energy resources for an electric utility that could possibly evaluate all these impacts in any realistic manner. Moreover, these impacts are not part of the Companies' primary duty, which is to serve all customers safely, reliably, and at the lowest reasonable costs. KU and LG&E also try to be good corporate citizens. But it is unrealistic to expect any utility (or regulatory agency) to try and solve – or even adequately address – these "impacts" in developing purchase rates for distributed generators. Moreover, these same societal benefits, whatever their value, are equally well provided by utility-scale renewable generation like the ibV contract; there is no added value provided by net metering, and therefore no reason to compensate such customers in excess of what similar energy would cost on the market.

Q. What does the *National Standard Practice Manual* mean by "host customer benefits"?

A. The *National Standard Practice Manual* lists the following host customer benefits:

Table S-4. Potential Benefits and Costs of DERs: Host Customer

Type	Host Customer Impact	Description
Host Customer	Host portion of DER costs	Costs incurred to install and operate DERs
	Host transaction costs	Other costs incurred to install and operate DERs
	Interconnection fees	Costs paid by host customer to interconnect DERs to the electricity grid
	Risk	Uncertainty including price volatility, power quality, outages, and operational risk related to failure of installed DER equipment and user error; this type of risk may depend on the type of DER
	Reliability	The ability to prevent or reduce the duration of host customer outages
	Resilience	The ability to anticipate, prepare for, and adapt to changing conditions and withstand, respond to, and recover rapidly from disruptions
	Tax incentives	Federal, state, and local tax incentives provided to host customers to defray the costs of some DERs
	Host Customer NEIs	Benefits and costs of DERs that are separate from energy-related impacts
	Low-income NEIs	Non-energy benefits and costs that affect low-income DER host customers

This table indicates that "host customer benefits" would necessitate evaluating costs incurred by customer-generators "to install and operate distributed energy resources [DERs]," "benefits and costs of DERs that are separate from energy-related impacts," "non-energy benefits and costs that affect low-income DER host customers" and a host of other benefits and impacts. None these so-called "benefits" are relevant to anyone except the potential net metering customers. It is not at all clear why any of these "benefits" should influence what other customers are forced to pay for energy. Non-net-metering customers should not be forced to compensate net metering customers for the cost incurred by net metering customers to install and operate distributed energy resources.

Q. What does the *National Standard Practice Manual* mean by "gas utility and other fuel system impacts"?

A. The *National Standard Practice Manual* explains that "when electric utilities implement or otherwise support DERs there are sometimes impacts on natural gas and other fuels."[64] The manual further explains that "Examples of gas and other fuel impact from electric DERs include reduced consumption of natural gas space heating that results from electric utility EE [energy efficiency] programs that provide air sealing to reduce air conditioner loads, the increased consumption of natural gas or other fuels from DR [demand response] programs that rely upon back-up generators, the increased consumption in natural gas or other fuels resulting from an electric utility CHP [combined heat and power] program, and the reduced consumption in gasoline as a result of electric utility EV [electric vehicle] programs."[65] So, a cost-benefit analysis that considers the "full range of impacts" would not only consider KU and LG&E's costs but also the impact on Columbia Gas Company, Atmos, and Delta Natural Gas Company, if the customer-generators are also served by one of those utilities in the state. The analysis would also have to evaluate the reduced consumption of gasoline if the customer-generator owns an electric vehicle. Of course, this would involve an impossibly unrealistic analysis, no doubt resulting in the temptation in

[64] *National Standard Practice Manual*, at p. 4-11.
[65] *Id*., at p. 4-12.

some jurisdictions to incorporate swag values in the evaluation to satisfy the proponents of DERs. Again, utility scale solar has these same (or even greater) impacts, so there is no excuse for paying net metering customer-generators more than ibV or SQFs.

Q. Are the full range of impacts that Mr. Rábago proposes to be considered in the evaluation of distributed energy resources typically referred to as "externalities"?

A. Yes. Mr. Rábago is careful not to use the word "externalities" to describe these "full range of impacts", but that is precisely what they are. Ultimately, what Mr. Rábago recommends is to incorporate frameworks that have been used in California, New York and other jurisdictions in the evaluation of demand-side management programs giving full consideration to externalities.

Q. Has the Commission rejected the consideration of externalities in the evaluation of demand-side management programs?

A. Yes. In the Commission's Order regarding the Companies' most recent DSM program plan application, the Commission stated:

> In evaluating the cost-effectiveness of the proposed DSM/EE programs, ***the Commission disagrees with MHC's recommendation to include the cost of non-energy factors and benefits.*** KRS Chapter 278 creates the Commission as a statutory administrative agency empowered with "exclusive jurisdiction over the regulation of rates and service of utilities." The Commission has no jurisdiction over environmental impacts, health, or other non-energy factors that do not affect rates or service. ***Lacking jurisdiction over these non-energy factors, the Commission has no authority to require a utility to include such factors in benefit-cost***

analyses of DSM programs.[66]

Despite the Commission making it perfectly clear that it will not consider externalities in the evaluation of DSM programs, here we are again with the parties proposing to use precisely the same types of non-energy factors and benefits – which were just recently rejected by the Commission – to set the purchase price of energy supplied by customer-generators. In the current proceedings, it is my recommendation that the Commission reject KSIA's and the Joint Intervenors' proposal to delay implementing NMS-2 subject to the completion of a benefit-cost analysis that addresses the "full range of impacts" (i.e., externalities) identified in the *National Standard Practice Manual*. The Commission's rejection of these externalities need not be revisited in the context of distributed generation.

Q. Have the Companies properly considered the costs and benefits of the energy that customer-generators provide to the grid?

A. Yes, they have. As I have explained, the proper consideration of costs and benefits of purchasing energy from customer-generators is the evaluation of avoided costs and the associated subsidies that are currently being provided to customers under the net metering tariff (NMS-1). As shown in Rebuttal Exhibit WSS-1, KU is currently providing subsidies of $139,143 to its residential net metering customers for the energy they supply to the grid, and LG&E is providing subsidies of $148,668 to its residential net metering customers. This analysis, which has not been refuted by the

[66] Commission Order in Case No. 2017-00441, dated October 5, 2018, at p. 28 (emphases supplied).

intervenors' witnesses, demonstrates that purchasing energy from customer-generators at the energy charges set forth in the Companies Rate RS is not cost effective. In the terminology used in the application of the California Tests for DSM programs, NMS-1 does not pass the Ratepayer Impact Measure (RIM) test.[67] NMS-1 causes rates to other customers to be higher than they otherwise would be if the Companies were not purchasing energy from customer-generators. Because the compensation for the energy that customer-generators supply to the grid under NMS-1 exceeds avoided cost, NMS-1 results in a RIM benefit-cost ratio of less than 1.0 and thus fails the RIM test. Because NMS-2 compensates customers on the basis of avoided costs, NMS-2 would neither pass nor fail the RIM test. The RIM benefit-cost ratio for NMS-2 would be precisely 1.0 because the compensation provided to customer-generators exactly matches the Companies' avoided costs.

Q. But this only considers the energy that customer-generators flow to the grid. What are the subsidies involved with providing service to customer-generators?

A. With respect to NMS-2, the only cost-benefit that needs to be considered is related to the avoided cost of the energy *purchased from* customer-generators. But the Companies also estimated the subsidies related to the *sales transaction to* customer-generators. That subsidy to residential customer-generators served by NMS-1 is $46,399 for KU and $95,175 for LG&E. See Rebuttal Exhibit WSS-1. From the

[67] The *California Standard Practice Manual: Economic Analysis of Demand-Side Programs and Project,* at p. 13, states that the "benefits calculated in the RIM test are the savings from avoided supply costs … The avoided supply costs are a reduction in the total costs or revenue requirements and are included for both fuel and fuel substitution program."

perspective of the California Test, this means that continuing to serve customer-generators under Rate RS would result in a RIM ratio of less than 1.0. The reason for this is that based on the Companies' load data for net metering customers, customer-generators show load factors significantly lower than residential customers on average. This means that the cost of serving customer-generators is higher than residential customers on average. Therefore, if both the ***purchase transaction*** and the ***sales transaction*** for customer generators are considered together, as the KSIA and the Joint Intervenors assert should be done, customer-generators provide a benefit-cost ratio below 1.0 – i.e., costs exceed the benefits. Obviously, this analysis is purely from the perspective of the RIM test. The only way that NMS-1 could possibly be supported with a benefit-cost analysis is with the inclusion of a broad range of externalities, which the Commission has made clear should not be considered.

D. LEVELS OF SOLAR INSTALLATIONS

Q. Are the system impacts of solar distributed energy resources all the same?

A. No. Under the traditional net metering scheme, the subsidies provided to customer-generators are heavily dependent on the amount of solar generation that customer-generators install. Customer-generators can install a relatively small number of solar panels to offset a portion of energy that the purchase from the utility, or they can install a large solar array that totally offsets the energy that provided by the utility. These customers are referred to as "net-zero customer-generators".

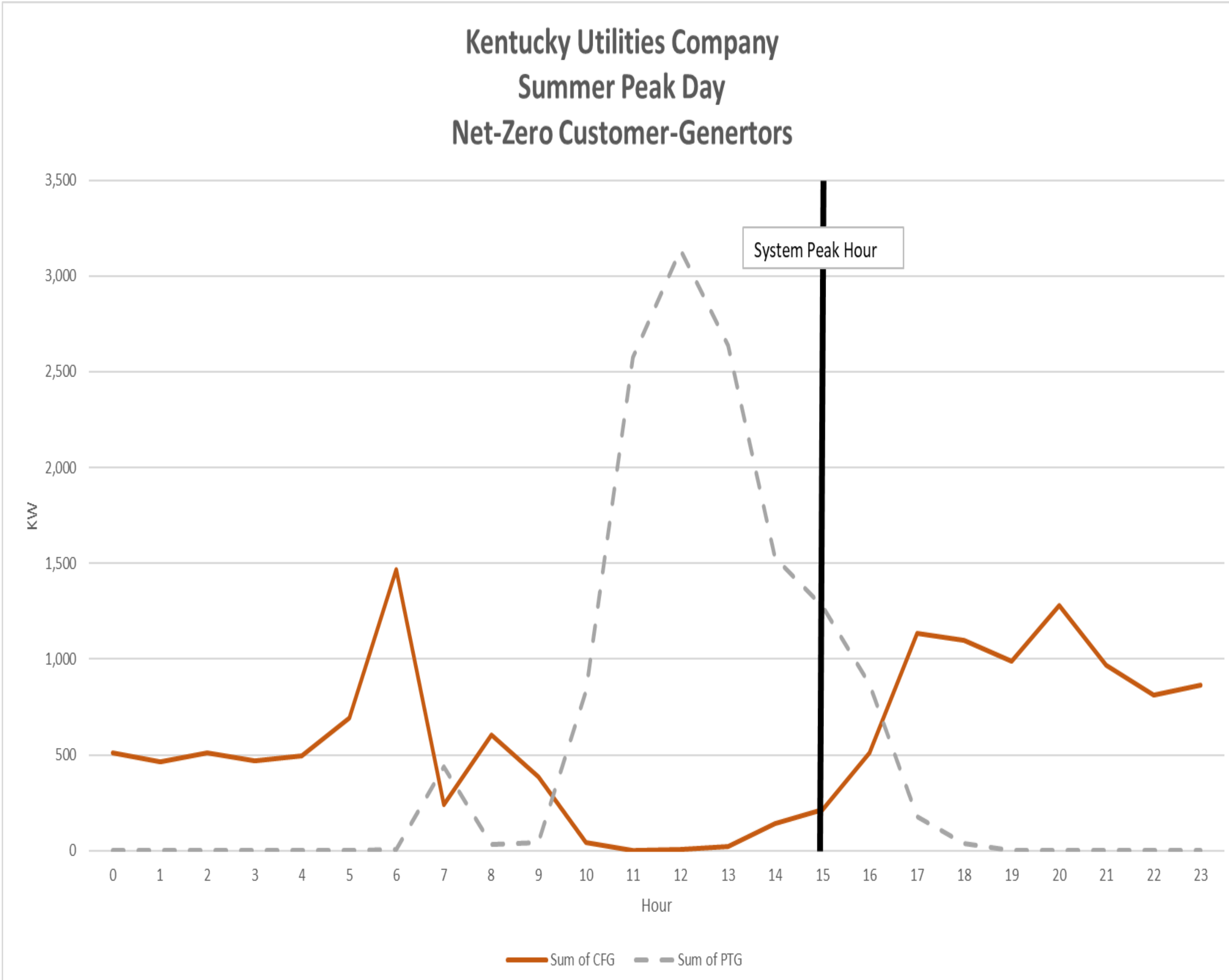
Q. Are these net-zero customer-generators currently billed an energy charge?

A. No, on an annual basis they are not. Under the current net metering scheme (NMS-1), the customer-generators can carry over the credits for their excess generation; therefore, the customers can end up purchasing no electric energy (0 kWh) from the Companies. Obviously, generation, transmission, and distribution facilities are required to serve these net-zero customers. However, these net-zero customer-generators are not charged for the distribution, transmission and generation facilities installed to provide electric to them when the solar facilities aren't operating. Customers that over-generate during daylight hours and bank the energy credits during the non-daylight hours pay only the Companies' Basic Service Charge. But the Basic Service Charge comes nowhere close to covering the cost of the facilities installed to serve these customers when their solar panels are not generating power. These customers are essentially using LG&E and KU as a free battery fully funded by non-participating customers to store excess energy credits during daylight hours and using the credits to supply their own energy needs when their solar facilities do not generate power.

Q. Do you have a graph of a net-zero customer-generator's hourly energy profile on a summer day?

A. Yes. The following graph (GRAPH 6) shows the hourly energy profile for net-zero customer generator on a peak day. Again, the solid lines in the graph show the energy that customer-generators consumed from the grid (CFG), and the dotted line shows the energy that the customer-generators provided to the grid (PTG).

GRAPH 6



Kentucky Utilities Company
Summer Peak Day
Net-Zero Customer-Genertors
System Peak Hour
KW
3,500
3,000
2,500
2,000
1,500
1,000
500
0
0 1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23
Hour
Sum of CFG
Sum of PTG

As can be seen from the above graph, these net-zero customer-generators are over-generating during daylight hours, and falling back on the Companies for generator, transmission and distribution capacity during hours when the customer-generators' solar facilities do not generate enough energy to supply the customer-generators' own load requirements. But despite relying on the Companies' generation, transmission and distribution capacity to supply power when the solar panels are not operating, the customer-generators only pay the Basic Service Charge.

Q. Therefore, are the subsidies paid to net-zero customers greater than the subsidies paid to customer-generator that do not bank energy?

A. Yes, they are much greater. The problem is that customer-generators that over-generate should not be compensated at the full retail energy charge. Customer-generators should be compensated at avoided energy cost for the energy they supply to the grid. The difference in the subsidies provided to net-zero customer-generators will be addressed in the next section of my testimony.

E. RESULTS OF COST OF SERVICE STUDIES FOR KU AND LG&E'S NET METERING CUSTOMERS

Q. Was it necessary for the Companies to file a cost of service study for customer-generators for KU and LG&E to meet their burden of proof for NMS-2?

A. No. NMS-2 was filed pursuant to KRS 278.466(3), which states: "A retail electric supplier serving an eligible customer-generator shall compensate that customer for all electricity produced by the customer's eligible electric generating facility that flows to the retail electric supplier." A cost of service study is not necessary to determine the appropriate value of the energy that customer-generators flow to the grid. Only avoided costs are needed determine the appropriate value of the as-available energy that customer-generators provide to grid.

Q. But have the Companies performed cost of service studies for net metering customers?

A. Yes. I have created a new rate class in the Companies' cost of service studies showing the cost of service results for residential net metering customers. I will be presenting cost of service results – i.e., class rates of return -- for both the LOLP and 6 CP cost of service studies. I am presenting three groups of studies: (1) cost of service studies reflecting the current net metering framework (NMS-1); (2) cost of service studies for net metering customers assuming that the Companies' proposed NMS-2 applied to all residential customers; and (3) a cost of service studies showing the results for net-zero customers. My work-papers supporting these cost of service studies are being filed in original Excel format along with this testimony.

Q. Why are the Companies submitting cost of service studies for customer-generators?

A. <u>*The Companies are submitting cost of service studies for customer-generators solely to refute KSIA's and the Joint Intervenors' assertion that a cost of service study might show that net metering customers are not being subsidized.*</u> The Companies are submitting cost of service studies for net metering customers to refute KSIA and the

Joint Intervenors' notion that when the sales service transactions to customer-generators are considered together with the purchase transactions from customer-generators, the two transactions taken together somehow support continuation of NMS-1, or perhaps it would support a rate higher than NMS-2.

Although the intervenors' argument is erroneous on its face, the Companies do not want this plainly incorrect notion to be remain unrebutted. It is clearly not necessary to the Companies' burden of proof to submit cost of service studies that consider the energy provided to the customer-generators. KSIA and the Joint Intervenors have raised cost of service as something unknown – a question mark, a specter, a stone unturned – that might possibly persuade the Commission to leave a plainly over-compensatory net metering scheme in place for new net metering customers. The Companies want to bring clarity to the issue and show that, from the perspective of a cost of service study, customer-generators are not providing a benefit to non-participating customers but are being heavily subsidized under the current net metering framework (NMS-1) even when both the sales and purchase transactions are considered together.

Q. Are the AMI load data for customer-generators statistically valid?

A. The load data for KU's net metering customers are statistically valid, i.e., they meet the accuracy requirements for load research data established by Section 133 of the Public Utilities Regulatory Policy Act (PURPA). For most months, the load data for LG&E's net metering customers are also statistically valid with respect to the PURPA requirements for statistical accuracy.[68] The most noticeable difference between net metering customers on LG&E's system than on KU's system is that LG&E's net metering customers tend to have a very large energy usage. Many seem to be located on large horse farms in Shelby and Oldham counties. These are not low-income customers. Except for the larger energy usage of customer-generators on LG&E's system, the cost of service studies for LG&E's net metering customers indicate results that are directionally similar to the studies for KU.

i. COST OF SERVICE STUDY RESULTS BASED ON NMS-1

Q. Please describe the cost of service studies based on NMS-1.

A. In this group of studies, residential customers served by KU and LG&E were broken out into a separate rate class. This group of studies assumes that all customer-generators are served under the current net metering framework (NMS-1). Cost of service studies were performed for both KU and LG&E using the LOLP and 6-CP methodologies. Because none of intervenors recommends the 12-CP, cost of service studies using that methodology were not performed.

Q. What are the results of this group of studies?

A. The class rates of return are summarized in the following table (Table 1). The results for the residential net metering customers are highlighted.

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[68] See KU's response to PSC 5-15 and LG&E's response to PSC 5-16. The PURPA required a ±10 percent accuracy at the 90 percent confidence level.

TABLE 1

Cost of Service Study With Traditional Net Metering (NMS-1)				
	KU		LG&E	
Customer Class	**LOLP**	**6-CP**	**LOLP**	**6-CP**
Rate RS	2.68%	2.15%	0.60%	1.32%
Res Net Metering (NMS-1)	-0.69%	-1.25%	-2.21%	-2.25%
General Service Rate GS	11.06%	11.22%	10.96%	9.68%
All Electric Schools Rate AES	5.89%	3.68%	N/A	N/A
Power Service Secondary Rate PSS	9.95%	10.05%	10.31%	8.94%
Power Service Primary Rate PSP	17.92%	19.00%	14.44%	12.68%
Time of Day Secondary Rate TODS	3.96%	4.68%	5.34%	4.46%
Time of Day Primary Rate TODP	3.21%	4.27%	6.47%	6.03%
Retail Transmission Service Rate RTS	3.54%	4.65%	7.25%	5.78%
Fluctuating Load Service Rate FLS	2.76%	5.41%	N/A	N/A
Special Contract	N/A	N/A	5.53%	3.31%
Lighting Rate LS & RLS	12.32%	10.54%	9.75%	8.02%
Lighting Rate LE	28.08%	10.04%	31.92%	9.83%
Lighting Rate TE	12.40%	13.18%	15.02%	13.91%
Outdoor Sports Lighting Rate OSL	30.33%	30.29%	89.11%	92.64%
Overall	4.81%	4.81%	4.34%	4.34%

As can be seen in the above table, the rates of return for net metering customers are significantly below the rates of return for RS and all other classes. This indicates that under NMS-1, residential net metering customers are being significantly subsidized by other customers in other rate classes.

ii. COST OF SERVICE STUDY RESULTS BASED ON NMS-2

Q. Please describe the cost of service studies based on NMS-2.

A. In this group of studies, residential net metering customers were assumed to take service under NMS-2. It was assumed for this study that all customer-generators would be compensated at avoided cost (i.e., the SQF rate) for the energy that they supply to the grid. Therefore, it is assumed that one of the two subsidies identified in KU's Response to PSC 2-108 and LG&E's Response to PSC 2-122 (see Rebuttal Exhibit WSS-1) would be eliminated. Again, cost of service studies were performed for both KU and LG&E using the LOLP and 6-CP methodologies.

Q. What are the results of this group of studies?

A. The class rates of return are summarized in the following table (Table 2). The results for the residential net metering customers are highlighted.

TABLE 2

Cost of Service Study With All Customer-Generators Under Proposed Net Metering (NMS-2)				
	KU		LG&E	
Customer Class	**LOLP**	**6-CP**	**LOLP**	**6-CP**
Rate RS	2.67%	2.15%	0.60%	1.32%
Res Net Metering (NMS-1)	1.22%	0.57%	4.35%	4.28%
General Service Rate GS	11.05%	11.22%	10.96%	9.67%
All Electric Schools Rate AES	5.89%	3.68%	N/A	N/A
Power Service Secondary Rate PSS	9.95%	10.05%	10.30%	8.93%
Power Service Primary Rate PSP	17.92%	19.00%	14.43%	12.67%
Time of Day Secondary Rate TODS	3.95%	4.68%	5.33%	4.45%
Time of Day Primary Rate TODP	3.21%	4.27%	6.45%	6.02%
Retail Transmission Service Rate RTS	3.53%	4.65%	7.23%	5.77%
Fluctuating Load Service Rate FLS	2.76%	5.40%	N/A	N/A
Special Contract	N/A	N/A	5.52%	3.29%
Lighting Rate LS & RLS	12.32%	10.54%	9.74%	8.02%
Lighting Rate LE	28.06%	10.04%	31.89%	9.82%
Lighting Rate TE	12.39%	13.18%	15.01%	13.90%
Outdoor Sports Lighting Rate OSL	30.33%	30.29%	89.11%	92.64%
Overall	4.81%	4.81%	4.34%	4.34%

As can be seen in the above table, the rates of return for net metering customers have improved over the returns based on NMS-1. This indicates that class rate subsidies would be decreased by introducing NMS-2. Subsidies would still be provided to customer-generators, but the subsidies are lower. For KU, even if all customer-generators were served under NMS-2, net metering customers would still have the lowest rate of return for any class. For LG&E, with NMS-2 assumed to apply to all customer-generators, the rate of return for net metering customers still is one of the lowest class rates of return. The reason that the rate of return for net metering customers under NMS-2 is higher for LG&E than KU is due to the fact that LG&E's customer-generators have much larger usage on average than KU's customer-generators have.

iii. COST OF SERVICE STUDY RESULTS FOR NET-ZERO CUSTOMER GENERATORS

Q. Please describe the cost of service study for net-zero customers.

A. In this group of studies, we analyze the class rates of return for net-zero customers. As discussed earlier, these customers produce enough energy on an annual basis to supply all of their energy needs. Consequently, these customers pay no energy charge. But they still require generation, transmission and distribution capacity from KU and LG&E to meet their own energy needs when their solar panels are not generating energy. In other words, they are effectively using KU and LG&E as a cost-free storage bank. These net-zero customers receive the most substantial subsidies from non-participating customers.

Q. What are the results of this group of studies?

A. The class rates of return are summarized in the following table (Table 3). The results for the residential net-zero customer-generators are highlighted.

TABLE 3

Cost of Service Study With Net Zero Customer-Generators Under NMS-1				
	KU		LG&E	
Customer Class	**LOLP**	**6-CP**	**LOLP**	**6-CP**
Rate RS	2.68%	2.15%	0.61%	1.33%
Res Net Metering (NMS-1)	-3.30%	-3.20%	-12.90%	-12.61%
General Service Rate GS	11.06%	11.23%	10.97%	9.69%
All Electric Schools Rate AES	5.90%	3.69%	N/A	N/A
Power Service Secondary Rate PSS	9.96%	10.05%	10.32%	8.95%
Power Service Primary Rate PSP	17.93%	19.01%	14.45%	12.69%
Time of Day Secondary Rate TODS	3.97%	4.69%	5.35%	4.47%
Time of Day Primary Rate TODP	3.22%	4.28%	6.48%	6.05%
Retail Transmission Service Rate RTS	3.55%	4.66%	7.26%	5.79%
Fluctuating Load Service Rate FLS	2.77%	5.42%	N/A	N/A
Special Contract	N/A	N/A	5.55%	3.32%
Lighting Rate LS & RLS	12.33%	10.55%	9.75%	8.02%
Lighting Rate LE	28.10%	10.06%	31.97%	9.85%
Lighting Rate TE	12.41%	0.13%	15.03%	13.93%
Outdoor Sports Lighting Rate OSL	30.34%	30.30%	89.21%	92.75%
Overall	4.81%	4.81%	4.34%	4.34%

As can be seen in the above table, net-zero customers receive significant subsidies from non-participating customers. These customers tend to be high-usage and require generation, transmission and distribution facilities to serve them when they are not generating electric energy from their solar panels, but they are not paying for any of the capacity because they are not paying an energy charge, but only the Basic Service Charge in Rate RS.

F. FOUR PART RATE DESIGN FOR CUSTOMER-GENERATORS

Q. How could the subsidies related to sales service provided to customer-generators be addressed?

A. The subsidies related to the *sales service* provided to customer generators could be addressed with the implementation of a four-part rate design.

Q. Do KSIA and the Joint Intervenors have any misconceptions about four-part rates?

A. Yes. Although a few utilities have implemented three-part rates for residential customers consisting of a customer charge, energy charge, and demand charge applied to the customer's maximum monthly demand, that is not a rate structure that the Companies would consider. As I explained in my direct testimony, a four-part rate consisting of a customer charge, energy charge, base demand charge, and peak demand charge would be more appropriate for distributed generation customers. KSIA's and the Joint Intervenors' witnesses do not seem to understand that with a four-part rate there would be two demand charges – one demand charge (*base demand charge*) would recover delivery costs and would be applied to the customer's maximum monthly demand, and the other demand charge (*peak demand charge*) would only be applied to the customer's demands during peak periods. <u>*With a four-part rate design, customer-generators would achieve bill reductions for any reduced demands due to their installation and use of distributed energy resources.*</u> If a customer can reduce its demand during peak periods, then the customer would see a reduction in its peak period demand charges. For a customer-generator, if its solar panels are operating during the peak period then the customer would see lower demand charges. It is likely that with a four-part rate, customer-generators with solar generation would see lower demand charges during summer peak months than customers without solar generation. However, customer-generators would likely see the similar base demand charges as customers without solar generation, assuming the two groups have similar usage patterns. The intervenor witnesses apparently are unwilling to acknowledge that the peak demand charge would only apply during peak periods.

Q. Are there other reasons that the Companies did not propose a four-part rate for customer-generators besides the fact that they are not widely used by utilities for residential customers at this time?

A. Yes. Even though a different rate design for the electric service provided to customer-generators is certainly permitted under KRS 278.466(5), the Companies determined that introducing NMS-2 and requiring customer-generators to take service under a four-part rate for the electric service they receive would be too much of a move at one time. Recall that KRS 278.466(5) states that:

> Using the ratemaking process provided by this chapter, each retail electric supplier *shall be entitled to implement rates to recover from its eligible customer-generators all costs necessary to serve its eligible customer-generators*, including but not limited to fixed and demand-based costs, without regard for the rate structure for customers who are not eligible customer-generators. (Emphasis supplied.)

Therefore, pursuant to KRS 278.466(5), the Companies could propose, and the Commission could authorize, a cost-based four-part rate that properly reflects the cost of ***serving*** customer-generators. Likewise, the Companies could propose sales service rates for customer-generators that simply have higher energy charges than for Rate RS. Given the lower load factors of customer-generators, the service rate for distributed generators would necessarily be higher than standard residential customers. While either would be permissible under KRS 278.466(5), a four-part rate would do a better job reflecting the actual cost of serving customer-generators than a two-part rate.

Q. Could a properly designed four-part rate be used for all residential customers?

A. Yes. This is a point that the intervenor witnesses seemed to misunderstand, particularly Mr. Rábago. Specifically, Mr. Rábago states that "the Companies' consultant witness uses the cost of service study for non-generating residential customers as a basis for asserting, without substantiation, that the per-unit costs to serve customer generators and non-generators is the same." Mr. Rábago is referring to the Companies' response to MA 2-23 and MHC 2-24, which states:

> If the unit costs are calculated based on appropriate units, the costs for a DG customer are no different than for a non-DG customer. For example, the customer-related costs when unitized as a cost per customer would not be any different for a DG residential customer than for a non-DG residential customer. Likewise, the unit energy-related cost, calculated as a cost per kWh, would not be any different for a DG residential customer than for a non-DG residential customer. Furthermore, the demand-related unit costs, if calculated as a cost per kW of demand, would not be any different for a DG residential customer than for a non-DG customer. Therefore, with a properly designed four-part rate consisting of a Basic Service Charge, Energy Charge, Peak Demand Charge, and Base Demand charge, the rates for a DG and a non-DG residential customer would be the same.

Mr. Rábago appears to misunderstand this very basic and fundamental cost-of-service principle.[69] It is a logical necessity (a tautology) that when costs that are allocated to customer classes on the basis of number of customers, kWh, or kW of demand, if *unit costs* are then calculated for different classes of customers based on those same number of customers, kWh, and kW, the *unit costs* for the rate classes will be exactly the same. Therefore, a properly structured four-part rate for non-DG residential customers *would be exactly the same* as the four-part rate that should be used for DG customers, and a properly structured four-part rate could be used for *both* customer-generators *and* standard residential customers.

This brings us to another concern that the Companies have with implementing a four-part rate for customer-generators at this time. Although KRS 278.466(5) would certainly permit charging a different rate structure for customer-generators, the Companies plan to study the idea more thoroughly before introducing a different sales service rate for residential customer-generators and standard residential customers. I will note that some distribution cooperatives in the country, including one of my clients in Colorado, have introduced three- and four-part rates for all customers, including residential customers. One large electric cooperative in South Carolina that implemented a three-part rate for residential reported that it encountered no problems with customers understanding demand charges. But this utility implemented an

[69] In the Joint Intervenors' response to the Companies' data requests, Mr. Rábago indicated that he has never actually performed an embedded cost of service study (DR 7), a marginal cost of service study (DR 8), or a benefit-cost study for distributed energy resources (DR 9). See Joint Intervenors' Responses to LG&E/KU DR 7, DR 8, and DR 9.

education campaign explaining demand charges prior to implementing a three-part rate for residential customers.

III. ELECTRIC COST OF SERVICE STUDIES

A. SUMMARY OF POSITIONS OF THE PARTIES

Q. Please provide a high-level summary of the positions of the parties regarding the Companies' electric cost of service studies.

A. The Companies' cost of service studies were addressed by KIUC witness Baron, Walmart witness Perry, DOD-FEA witness Gorman, and AG witness Watkins. The electric cost of service studies are not addressed by Kroger, KSIA, Joint Intervenors, or Lou Metro & LFUCG. Sierra Club did not file testimony in these proceedings.

Walmart's witness accepts the Companies' electric cost of service studies. KIUC's witness Baron and DOD-FEA's witness Gorman prefer the six coincident peak ("6-CP") cost of service study over the loss-of-load probability ("LOLP") methodology favored by the Companies. Mr. Gorman also proposes changes to the classification of steam production maintenance expenses and the allocation of transmission costs. As he has in the past, AG's witness Watkins recommends the use of his probability of dispatch "POD" methodology. As an alternative, Mr. Watkins also recommends the base-intermediate-peak ("BIP") methodology. The LOLP, 6-CP, and POD methodologies represent alternative methodologies for allocating fixed production costs. Mr. Gorman also proposes to change to the way that transmission costs are allocated in the Companies' cost of service studies. Furthermore, Mr.

Watkins recommends a different methodology for allocating distribution costs.

Q. Do the studies proposed by the parties result in different class rates of return?

A. Yes. KIUC recommends the 6-CP cost of service study, which results in class rates of return that are similar to the LOLP cost of service study recommended by the Companies. DOD-FEA recommend that the 6-CP methodology be used for both production fixed costs and transmission costs. DOD-FEA's cost of service study also results in class rates of return that are similar to the Companies' LOLP cost of service study. Mr. Watkins' POD study, which makes major changes to allocation of production fixed costs, transmission costs, and distribution, is the outlier. His study produces the most widely variant class rates of return among the cost of service studies submitted by the parties in these proceedings.

Q. Have you prepared tables showing the results of the various cost-of-service studies recommended by the parties?

A. Yes. The class rates of return for KU produced by the various studies are shown in in the following table (TABLE 4):

TABLE 4

Kentucky Utilities Company Cost of Service Study Positions of Parties				
Rate Class	LG&E/Walmart	KIUC	DOD-FEA	AG
	LOLP	Prod 6 CP	Prod & Tran 6 CP	POD
Residential Rate RS	2.67%	2.14%	1.85%	4.40%
General Service Rate GS	11.05%	11.21%	11.17%	12.53%
All Electric Schools Rate AES	5.89%	3.68%	4.04%	3.90%
Power Service Secondary Rate PSS	9.95%	10.05%	9.94%	8.78%
Power Service Primary Rate PSP	17.91%	18.99%	19.20%	10.79%
Time of Day Secondary Rate TODS	3.95%	4.68%	4.79%	2.89%
Time of Day Primary Rate TODP	3.20%	4.26%	4.65%	0.77%
Retail Transmission Service Rate RTS	3.53%	4.65%	5.37%	0.45%
Fluctuating Load Service Rate FLS	2.75%	5.40%	8.89%	0.62%
Lighting Rate LS & RLS	12.32%	10.54%	11.30%	11.02%
Lighting Rate LE	28.05%	10.03%	15.49%	3.65%
Lighting Rate TE	12.39%	13.18%	13.24%	11.66%
Outdoor Sporting Lighting Rate OSL	30.32%	30.28%	55.72%	20.50%

As can be seen in the table, the results of Mr. Watkins's POD cost of service studies are significantly different from the studies proposed by the other parties, particularly with respect to the rate of return for the Residential Service Rate RS and the large power rates, which are highlighted in the above table. Mr. Watkins' study shows much lower rates of return for Time-of-Day Primary Service Rate TODP, Retail Transmission Service Rate RTS, and the Fluctuating Load Service Rate FLS. Mr. Watkins' study essentially shifts costs from the residential rate class to the large customer rate class.

The following table (Table 5) shows the class rates of return for LG&E produced by the various studies:

TABLE 5

Louisville Gas and Electric Company Cost of Service Study Positions of Parties				
Rate Class	LG&E/Walmart	KIUC	DOD-FEA	AG
	LOLP	Prod 6 CP	Prod & Tran 6 CP	POD
Residential Rate RS	0.60%	1.33%	1.10%	3.76%
General Service Rate GS	10.96%	9.67%	9.28%	11.05%
Power Service Primary Rate PSS	14.43%	12.67%	12.64%	10.32%
Power Service Secondary Rate PSP	10.30%	8.93%	8.75%	6.63%
Time of Day Primary Rate TODS	6.45%	6.02%	6.79%	0.72%
Time of Day Secondary Rate TODP	5.33%	4.44%	4.62%	2.35%
Retail Transmission Service Rate RTS	7.23%	5.76%	6.95%	0.88%
Special Contract	5.52%	3.29%	4.20%	-1.54%
Lighting Rate LS & RLS	9.74%	8.02%	8.67%	7.33%
Lighting Rate LE	31.88%	9.82%	14.92%	-1.05%
Lighting Rate TE	15.01%	13.90%	14.56%	8.40%
Outdoor Sporting Lighting Rate OSL	89.10%	92.63%	155.99%	52.17%

Again, the results of Mr. Watkins' study diverge from the other studies, particularly for Residential Service Rate RS and the large power rates. Mr. Watkins' study shows much lower rates of return for Time-of-Day Primary Service Rate TODP, and Retail Transmission Service Rate RTS.

Q. In your opinion, is Mr. Watkins' study sound?

A. No. There are a number of major errors in Mr. Watkins' POD model with respect to the Companies' generation resources. But besides the numerous errors regarding the capacity and operation of KU and LG&E's generating units, I do not agree with his cost of service methodology, as I will discuss below.

B. FIXED PRODUCTION COST ALLOCATION

Q. Please describe the methodologies used to allocate fixed production costs in the cost of service studies submitted by KU and LG&E in these proceedings.

A. The Companies filed three electric cost-of-service studies in these proceedings, using three different methodologies to allocate fixed production costs – loss-of-load probability (LOLP) methodology, six coincident peak (6-CP) methodology, and the twelve coincident peak (12-CP) methodology. In brief, the LOLP methodology allocates fixed production costs on the basis of hourly LOLP weighted by the hourly load for each customer class. The 6-CP methodology allocates fixed production costs based on the class coincident peak demands for the 4 summer peak months (June, July, August, September) and 2 winter peak months (December, January). The 12-CP methodology allocates fixed production costs based on the average class coincident peaks for all 12 months.

Q. Do any of the parties accept the Companies' LOLP methodology?

A. Yes, Walmart's witness accepts it.

Q. What were KIUC's and DOD-FEA's recommendations regarding the allocation of fixed production costs?

A. KIUC witness Baron and DOD-FEA witness Gorman both recommend the use of the 6-CP methodology for allocating fixed production costs. Both witnesses object to the LOLP methodology because of the complexity of the model and the amount of data required to develop the allocation factors for the methodology. Mr. Baron states that the 6 CP methodology reflects resource planning in a manner similar to the LOLP study and "is a widely recognized cost of service approach used by many electric utilities, including AEP affiliate Appalachian Power Company in its Virginia jurisdiction, Indiana and Michigan Power Company and East Kentucky Cooperative."[70]

Q. What is your response to Mr. Baron's and Mr. Gorman's criticisms?

A. I agree that the LOLP methodology is a more complex model and requires much more data to develop the allocation factors. But largely due to the complexity of the model, it is a far more robust model than the 6-CP methodology. The LOLP model analyzes loads for all hours of the year, thus providing a more accurate reflection of the cost of serving each rate class. Both PJM and MISO use Loss of Load Expectation (LOLE), which is determined by the timing of LOLP hours, for calculating the amount of generation resources needed in their capacity markets.

Q. Do you have strong objections with using the 6-CP methodology to allocate fixed production costs?

A. No. The 6-CP is a reasonable methodology and produces results similar to the LOLP methodology. While the Companies use the LOLP in their generation resource planning activities, they also consider reserve margins during the summer and winter system peak months for capacity planning purposes. Although I prefer the LOLP methodology because of its integral relationship to generation system planning and because it is a more robust model, 6-CP is a reasonable methodology and also reflects

[70] Direct Testimony of Stephen J. Baron, at pp. 20-21.

resource planning in a manner similar to the LOLP.

Q. AG's witness Watkins recommends using with the Probability of Dispatch (POD) methodology or the Base-Intermediate-Peak (BIP) Methodology. Do you agree with either of these methodologies?

A. No. KU and LG&E do not use either the POD methodology or the BIP methodology in generation resource planning. Furthermore, neither PJM nor MISO use Mr. Watkins' POD or BIP methodologies in evaluating generation resources in their respective regions. But, as mentioned earlier, PJM and MISO both use LOLP for these purposes. In fact, the POD and BIP methodologies have nothing whatsoever to do with how production resources are planned. While LOLP is widely used by utilities and ISOs for purposes of resource planning, I am unaware of any utility or ISO that uses POD or BIP for resource planning. The POD and BIP methodologies are results-oriented approaches purposely designed to allocate a significant portion of costs to the rate classes essentially on the basis of a kWh allocator.

Q. Did Mr. Watkins make any errors in performing his POD calculations?

A. Yes. Mr. Watkins' testimony and his POD calculations are rife with errors and misunderstandings. For example, he states that the Companies have a reserve margin of 50.3%. The Companies' reserve margin is nowhere close to this level. The Companies' forecasted summer reserve margins are 24.4% for 2021; 23.6% for 2022; 23.8% for 2023; 23.9% for 2024, and 24.1% for 2025.[71] In calculating his overstated

[71] See Direct Testimony of Lonnie E. Bellar, Exhibit LEB-2; also, see Direct Testimony of David S. Sinclair at 26.

reserve margin, Mr. Watkins used the nameplate ratings of each generating unit instead of the net capacity of the units. In both his reserve margin and POD calculations Mr. Watkins also failed to include FERC regulated sales to municipal customers which the Companies have an obligation to serve. Mr. Watkins also mishandled capacity under the Curtailable Service Rider, which the Companies consider a resource.

Furthermore, in his POD calculations, Mr. Watkins makes numerous errors about the operability of certain generating units. For example, in his POD calculations, Mr. Watkins incorrectly assumes that Mill Creek Units 1 and 2 can be operated simultaneously during peak summer months, when in fact these large coal-fired steam generating cannot be operated simultaneously during April through October because they are located in Jefferson County, Kentucky, which is a marginal non-attainment zone for ozone levels. The inability to operate Mill Creek Units 1 and 2 simultaneously during the summer months significantly reduces the Companies' available generation capacity during the summer months.

In addition, Mr. Watkins did not properly model curtailments under the Curtailable Service Rider (CSR). He was apparently unaware of the provision in CSR requiring the unit commitments must be met before physically curtailing CSR customers.

Mr. Watkins took none of these factors into consideration in developing his POD allocation model.

Q. In his POD model, Mr. Watkins assigns capacity based on hourly plant output

but he incorrectly assumes that Mill Creek Units 1 and 2 can operate simultaneously when they are not permitted to do so due to requirements in Jefferson County, where the units are located. How many hours during the year does he make this error?

A. During April through October, Mr. Watkins assumed that Mill Creek 1 and 2 could operate simultaneously 4,289 hours during these months, when the units are not allowed to operate at the same time pursuant to the District Board Order in Jefferson County. Therefore, Mr. Watkins makes an erroneous cost allocation for almost half of the hours during the year. It should be noted that Mr. Watkins makes the same error in the application of his BIP methodology.

Q. Besides all the errors Mr. Watkins makes regarding KU and LG&E's generation resources, do you agree conceptually with the POD methodology proposed by the AG's witness?

A. No. The POD methodology assigns the fixed costs for each power plant ratably to each hour of the year based on the unit's output for the hour. These hourly fixed costs are then allocated to each rate class on the basis of the hourly loss-adjusted load for each rate class. Thus, the POD methodology allocates fixed production costs based purely on the hourly *utilization* of each power plant to serve the load. The POD methodology therefore does not reflect the cost incurred to serve each customer class because the methodology does not consider the capacity installed to serve each customer class. The POD Methodology considers the utilization of the generation plants, which has nothing to do with the amount of capacity installed. Although the utilization of generation resource certainly affects variable operation and maintenance expenses, it does not drive the amount of generation capacity needed to provide service to customers. Cost of service studies should reflect the cost each class imposes on the system, not the *utilization* of system resources.

The POD methodology favors rate classes that have high peak demands (kW) but low amounts of energy usage (kWh) and penalizes rate classes that have high energy usage (kWh) but lower relative demands (kW). In other words, the POD methodology penalizes classes that have high load factors, e.g., more constant load patterns. (*Load factor* is the ratio of average demand to peak demand.) In defiance of basic economics, the POD methodology penalizes customer classes for their off-peak usage. The POD methodology does not assign costs in a manner that reflects how generation capacity was installed or how the costs were planned. The POD methodology is a perfect example of a study that adheres to the perspective that fixed production costs should be allocated on the basis of *utilization*. Consequently, the POD methodology does not provide useful information concerning cost of service, but instead attempts to address *fairness*. But the POD methodology addresses fairness in a counter-intuitive and counter-productive way, by penalizing customers that improve their load factors by using more energy during off-peak peaks.

Q. Are you saying the Mr. Watkins' POD methodology penalizes customers that increase load during off-peak periods?

A. Yes. For rate classes such as large power customers that have significant usage during off-peak periods, Mr. Watkins' methodology allocates essentially a proportionate amount of fixed costs to off-peak usage. This clearly defies economic principles. It is simply a way to shift a larger portion of fixed costs to high load factor customers, customers with significant loads during low-cost off-peak periods.

Q. Why is it problematic to consider the utilization of the power plants in allocating costs?

A. The ***utilization*** of the power plant has little or no bearing on the Companies' fixed production costs that have been installed to serve customers. To demonstrate this, consider the situation where a customer or customer class increases its off-peak usage of electric energy. Increasing usage during the off-peak period will not increase the Companies' fixed production costs. Increases in off-peak usage can be served with existing generating resources and will not result in the need for additional generation capacity. If anything, increased utilization during off-peak periods will lower generation costs over the long run. This is not the case with increases in demand during on-peak periods. Because utilities install generation capacity to meet maximum on-peak demands, increases in on-peak demands will ultimately result in additional capacity and in additional fixed costs. Because the AG's POD methodology allocates a significant portion of fixed costs to the off-peak utilization of the Companies' generation resources, the methodology fails to accurately reflect cost of service. As I have indicated, the POD methodology has more to do with the concept of fairness, an abstract and ultimately subjective idea, rather than with cost of service.

Q. Has the Commission ever approved Mr. Watkins' POD methodology for KU and LG&E?

A. No. In the Companies' last rate case proceedings, the Commission accepted the LOLP methodology as a guide for allocating the revenue increase to the customer classes. However, the Commission directed the Companies to submit alternative cost of service studies. Accordingly, the Companies submitted 6-CP and 12-CP cost of service studies in these proceedings.

C. STEAM PRODUCTION MAINTENANCE EXPENSES

Q. Please describe the change that DOD witness Gorman makes to the classification of steam production expenses.

A. Mr. Gorman modified the classification of steam production maintenance expenses in the cost of service study so that these costs are classified as 100% demand.

Q. How were steam production maintenance expenses classified in the Companies' cost of service study?

A. In its electric cost of service studies, the Companies used the Federal Energy Regulatory Commission ("FERC") Predominance Methodology to classify production operation and maintenance expenses fixed or variable. KU and LG&E have used the FERC Predominance Methodology in their cost of service studies for decades to classify production operation and maintenance expenses. The Predominance Methodology is a standard methodology used to classify production operation and maintenance expenses as either fixed (demand-related) or variable (energy-related) in electric cost of service studies. Under the FERC Predominance Methodology, production operation and maintenance accounts that are predominantly fixed, i.e., expenses that the FERC has determined to be ***predominantly*** incurred independently of kilowatt hour levels of output, are classified as demand related. Production operation and maintenance accounts that are predominantly variable, i.e., expenses that the FERC has determined to vary predominantly with output (kWh), are considered to be energy related. The predominance methodology has been accepted in FERC proceedings for over 40 years and is a standard methodology for classifying production operation and maintenance expenses.[72] The FERC prescribes the Predominance Methodology for classifying production operation and maintenance expenses in both cost of service studies and production formula rates. KU uses the Predominance Methodology in its jurisdictional separation studies and in its FERC approved generation formula rates for wholesale serve to municipal utilities in Kentucky.

Q. Does the Companies' methodology for classifying production operation and maintenance affect rate design for the large industrial rate schedules (TODS, TODP, RTS, and FLS)?

A. Yes. Unit costs from the cost of service studies are used to determine the Companies' proposed Energy Charges for Rates TODS, TODP, RTS, and FLS. Recall that these rates are four-part rates consisting of a Basic Service Charge, Base Demand Charge, Peak Demand Charge, and an Energy Charge. The Companies proposed Energy

[72] *See, e.g.*, Public Service Company of New Mexico, 10 FERC ¶ 63,020 (1980), Illinois Power Company, 11 FERC ¶ 63,040 (1980), Delmarva Power & Light Company, 17 FERC ¶ 63,044 (1981), and Ohio Edison Company, 24 FERC ¶ 63,068 (1983).

Charges for these rate schedules are determined based on the energy costs from the cost of service studies. Consequently, the production operation and maintenance expenses classified as variable costs would end up being recovered through the Energy Charge in the Companies' proposed rates for these large customer rate schedules.

Q. What is Mr. Gorman's argument for classifying all steam production maintenance expenses as variable in the cost of service study?

A. Mr. Gorman states as follows:

> Normal maintenance expense does not vary in any appreciable way with kilowatt-hour energy purchases by retail customers. Production maintenance expense is normally scheduled and budgeted on a fixed basis to keep the plant on-line and available to meet daily demands. There is no showing that production maintenance expense varies directly with retail customer sales. In fact, boilers are often kept warm during nights (low load periods) in order to meet next day demands. Also, the dispatch of plants is often a function of running costs versus alternative sources, off-system sales and purchases, renewable energy contracts and not directly related to sales to retail. As such, these steam O&M expenses are more fixed and budgetary in nature, and do not vary with energy generation. For this reason, these costs should be allocated in line with the actual fixed costs of the production facility, or should be classified as demand charges.[73]

AG-KIUC witness Baron expresses a similar concern with respect to rate design with respect to the energy charge for Rates TODP and RTS. Mr. Baron states:

> **Q. Are you objecting to the Companies' functional and class cost of service study results that form the basis for the TODP and RTS unit energy charges?**
>
> A. No, not for class cost of service purposes. The Companies have followed a traditional production cost classification approach in

[73] Direct Testimony of Michael P. Gorman, at pp. 38-39.

> their cost of service studies (LOLP, 12 CP, 6 CP) that ***classifies a portion of production O&M maintenance expenses as energy related, in addition to fuel expenses and purchased power energy costs that are directly related to energy generation*** . . . However, I don't believe that it is appropriate or economically efficient to include these maintenance costs and rate base costs in the energy charges themselves. From an economic standpoint, customers should receive price signals in their rates that better represent the economic costs of consuming an additional kWh.[74]

Therefore, Mr. Baron is making essentially the same argument but instead of proposing a modification to a cost of service methodology that has been used for decades by the Companies, he proposes to accomplish this objective through lowering the energy charge for these rates.

Q. What is your response to Mr. Gorman's and Mr. Baron's arguments?

A. I agree that from a *marginal cost perspective* the short-run production expenses for variable operation and maintenance expenses would almost certainly be lower than what is assigned in the Companies' fully allocated *embedded* cost of service studies. The arguments made by both Mr. Gorman and Mr. Baron approach the determination of variable operation and maintenance expenses from a marginal cost perspective. With the cost of service studies filed in these proceedings, the Companies submitted *embedded* cost of service studies, not *marginal* cost of service studies.

Q. For an embedded cost of service study, is there a reasonable basis for using the FERC Predominance Methodology?

[74] Direct Testimony of Stephen J. Baron, at pp. 41-42 (emphasis added).

A. Yes, I believe there is. Over the years, I have had extensive discussions with the FERC Staff concerning the use of the Predominance Method. The FERC Staff's position, which also reflected the FERC's position on this matter and was addressed in a number of FERC orders, was that the actual operation of power plants over time correlates directly with the amount of maintenance needed for power plant equipment. The more a power plant is operated, the FERC Staff would argue, the more maintenance that is required. Over the years, I have also tried to run multi-variable regression analysis to verify this position. While some of these analyses did tend to confirm the FERC's conclusion, the confidence levels of the parameter estimates were never high. Nevertheless, since the Predominance Method was used in the Companies' FERC filings, decades ago KU and LG&E determined that for the sake of consistency in the studies for the various jurisdictions, it was reasonable to use this standard methodology for purposes of the Companies' embedded cost of service studies. Consequently, the Predominance Methodology has been utilized in the Companies' cost of service studies since the 1990s.

Q. Even though you believe it is reasonable to continue to use the Predominance Methodology for allocation of embedded costs to rate classes in the electric cost of service studies, what is your view on using a marginal cost approach for rate design, as proposed by Mr. Baron?

A. I have a softer view on Mr. Baron's proposal, but I still do not believe that it is necessary to lower the energy charges for TODP, RTS, and FLS to reflect marginal costs. In other words, if marginal production operations and maintenance expenses are to be considered, then they should be considered in rate design, as suggested by Mr. Baron, and not in the embedded cost of service study. Nevertheless, I believe that the Companies' proposed energy charges for TODP, RTS, and FLS are reasonable. Many electric utilities -- perhaps most -- have some degree of tilting[75] in their rate designs. I do not believe that the costs classified as variable expenses in the cost of service study, which end up being included in the Companies' proposed energy charges for TODP, RTS and FLS, are unreasonable, particularly in comparison to other electric utilities which recover a portion of fixed costs through their energy charges.

C. TRANSMISSION COST ALLOCATION

Q. Please describe Mr. Gorman's modification to the transmission plant allocator.

A. DOD-FEA proposes to change the transmission allocation factor from a non-coincident demand allocator to a 6-CP allocator. DOD-FEA is the only party that proposes this change. Mr. Gorman's proposed modification has a very small effect on the results of the cost of service studies. In supporting his change, Mr. Gorman cites the following response to DOD-FEA 2-9, which states:

> The loads at the distribution points on the LG&E and KU's transmission system are an important factor in designing capacity on the transmission system. ***<u>Ultimately, the loads at the distribution points determine the level of capacity needed to deliver power on the transmission system from the generation system to the load centers</u>***. (Emphasis supplied.)

[75] "Tilting" refers to recovering fixed costs through the energy charge, usually in defiance of the classification of demand costs in a cost of service study.

Mr. Gorman also cites the Companies' responses to DOD-FEA 2-11, which state:

> Q-2-11. Concerning the production and transmission functionalization of electric service, does LG&E agree that to the extent one customer modifies their demands on the system which reduces demands on production and transmission facilities, would that free up production and transmission capacity that can be used to provide service to other customers. Please explain your answer.
>
> A-2-11. No, not without certain qualifications. ***Depending on the location of the customer's load***, reductions in demand may not free up capacity on the transmission system. Furthermore, depending on the time period during which a customer reduces its demand, any such reduction may not provide additional benefits to the generation or transmission system. For example, if the customer reduces its demand during off-peak periods, or when either the transmission or generation system is not operating at full capacity, then any capacity that is freed up would not necessarily be used to provide service to other customers.

But in modifying his transmission allocator, Mr. Gorman ignores the emphasized portions of the Companies' responses shown above. The responses make it clear that the planning and operation of Companies' transmission system takes into consideration the delivery locations for the power, not just the 6 CPs as proposed by Mr. Gorman.

Q. Which demand allocator is used to allocate transmission costs in the Companies' cost of service studies?

A. The Companies use class peak demands to allocate transmission costs, which is a reasonable allocator for transmission costs. Planning the transmission system cannot be isolated to a single demand measurement, such as the 6 CP allocator proposed by Mr. Gorman. Locational load considerations play a significant role in transmission planning. For example, independent system operators allocate most costs of new projects on basis of local load considerations. FERC requires ISOs to allocate the cost of transmission additions to the local loads that receive the benefits of the transmission facilities.[76] The Companies' use of a transmission allocator based on maximum class demands is fully consistent with this principle.

Q. Therefore, do you agree with Mr. Gorman's proposed change to the transmission allocator?

A. No. A transmission system is constructed to consider a host of factors, including localized loads at transmission substations. Although a single allocation factor cannot capture all of the considerations that drive the design of a transmission system, the maximum class allocator utilized in the Companies' cost of service studies reasonably reflects the loads of the customers receiving the benefit of the transmission system.

D. DISTRIBUTION COST ALLOCATION

Q. Do any of the intervenor witnesses modify the allocation of distribution costs in the cost of service studies?

A. Yes. As in prior proceedings, Mr. Watkins is proposing changes to the allocation of distribution costs in the cost of service studies.

[76] For example, see *Southwest Power Pool, Inc.*, Docket No. ER 10-1069-001, Order on Rehearing, issued October 20, 2011,

Q. Are the methodologies used in Companies' cost of service studies consistent with the studies used by KU and LG&E in prior rate cases?

A. Yes. KU and LG&E have consistently used the same methodology for the allocation of distribution costs since the 1980s. As with prior rate cases, in the cost of service studies filed by Companies in these proceedings, primary distribution costs, secondary distribution costs, and line transformers were classified as demand- and customer-related using the zero-intercept methodology. With the zero-intercept analysis, a statistical analysis is performed to determine the fixed-cost components of overhead conductor, underground conductor, and transformers that do not vary with demand, but would still vary with the number of customers. This methodology has been used for decades for both KU and LG&E. The zero-intercept methodology has also been accepted by the Commission in a number of rate cases. The Commission found LG&E's cost of service studies utilizing the zero-intercept methodology submitted in Case No. Case No. 90-158 to be reasonable. The Commission also found the embedded cost of service study submitted by Union Light Heat and Power in Case No. 2001-00092, which utilized the zero-intercept methodology, to be reasonable. Furthermore, the zero-intercept methodology has been used in every cost of service study filed by both KU and LG&E since the early 1980s, including the cost of service studies filed in Case Nos. 2018-00294 and 2018-00295, the Companies' last general rate case filings. In his cost of service study, the AG's witness accepts the Company's classifications of secondary distribution costs and transformer costs, which were based on zero-intercept calculations. Instead of classifying a portion of primary distribution lines as customer-related and a portion as demand-related, as in previous cost of service studies approved by the Commission, Mr. Watkins allocated primary distribution lines entirely as demand-related. The consequence of his proposal is to allocate proportionately more primary distribution costs to the customer classes with large users, particularly classes with large manufacturing customers.

Q. What reasons does Mr. Watkins give for changing the allocation of primary distribution costs?

A. Mr. Watkins tries to link differences in the "mix of customers" across "customer density levels" to the notion that no portion of primary distribution lines is customer related. By "mix of customers", Mr. Watkins is referring to the percentages of customers in a region that are either residential (Rate RS), small commercial (Rate GS), medium commercial and industrial (Rate PS), large industrial (Rate TODS, TODP, RTS), etc. He states that "the only reason why it may be appropriate to allocate a portion of distribution plant expenses based on number of customers, rather than peak demand, is due to the possibility that the mix of customers varies significantly across the customer density levels within each service territory."[77] But Mr. Watkins fails to explain why either the *mix of customers* or *customer density levels* have anything to do with allocating distribution facilities on the basis of the number of customers.

Q. Does either the *mix of customers* or *customer density levels* have anything to do

[77] Watkins testimony at page 50, lines 24-27.

with classifying distribution costs as customer-related?

A. No. When new customers are added to KU's distribution system, the Company will typically install primary lines, transformers, secondary lines, service lines, meters and other equipment. As new customers are added, the Company will typically install both primary and secondary lines, particularly as customer growth radiates away from urban centers, which is how KU experiences most of its customer growth. Furthermore, primary and secondary lines must be installed regardless of the customer's rate classification. Thus, *customer mix* has nothing to do with whether primary lines are installed. The appropriateness of classifying primary and secondary lines as customer-related therefore does not hinge on "the possibility that the mix of customers varies significantly across the customer density levels within KU's service territory."

Q. In reaching his conclusion did Mr. Watkins analyze costs?

A. No. He constructs a graph of customers per square mile versus class percentage of total customers by zip code. He then claims that because the correlation coefficients between the customers per square mile versus the percentage of residential or general service customers to total customers is zero that there is no basis for classification of distribution plant on the basis of the number of customers. He also constructs a table cross referencing the number of customers in various customer density strata by rate schedule and comes to a similar conclusion. But he provides no information whatsoever on whether <u>*costs*</u> increase with the addition of customers. In fact, his analysis does not examine costs at all. Mr. Watkins posits that there *may be* a relationship between customer density and costs, but he is careful not to claim that there is in fact any such relationship. Mr. Watkins states, "***<u>While it is possible</u>*** that it technically costs more to serve a rural customer versus an urban customer, regulatory policy in the United States has generally been not to price discriminate based on customer densities, urban versus rural, or other geographic differences."[78] This statement underscores the fact that Mr. Watkins did not perform a cost analysis by density level.

Furthermore, it is unclear what his measure of customer density (customers per square mile) tells us about electric service. A proper density measure for an electric utility is *customers per conductor mile*, not *customers per square mile*. Customers per square mile is a purely topographical measurement that is unrelated to electric service. Customers per square mile should not be used as a proxy for customers per conductor mile because some sub-regions within a zip code may not be located near electric service lines.

Q. Is there any merit to the AG's proposal to classify primary distribution plant entirely as demand-related?

A. No. Mr. Watkins has not demonstrated that the cost of primary distribution facilities is invariant to the number of customers. The principal idea behind the zero-intercept methodology used by KU is to classify distribution costs based on the portion of distribution costs that are statistically unrelated to the load carrying capability of the

[78] Watkins testimony at page 48, lines 18-21. Emphasis added.

facilities and are thus related to serving additional customers. In other words, the zero-intercept approach determines the portion of the cost of primary lines, secondary lines and transformers that do not vary with increases in demand. The validity of this approach is borne out by the fact that the Company installs primary lines, secondary lines and transformers when it adds new customers. For example, when the Company installs primary underground conductor to serve new customers, the cost of the trenching work and conduit installation does not vary with the customers' demand but with the fact that the customers were added to the system. These costs, which do not vary with demand, are incurred whenever a customer is added to the underground system. Therefore, it is inappropriate to classify all of the costs as demand-related as Mr. Watkins has done.

It should also be pointed out that there are numerous other internal inconsistencies with the various methodologies that Mr. Watkins uses in his proposed cost of service study. For example, as discussed earlier, he proposes to allocate fixed production costs based on the ***utilization*** instead of ***peak demand***, but for primary and secondary distribution plant, he ignores the concept of ***utilization*** in favor of allocation on the basis of ***peak demand***.

Q. Do you have any other comments concerning Mr. Watkins' allocation of distribution costs?

A. Yes. In case after case for KU and LG&E, Mr. Watkins has put forth these same arguments for modifying the allocation of distribution costs in the cost of service studies. The Commission has never approved Mr. Watkins' methodology in any of those rate cases. In the Companies' most recent rate cases, the Commission relied on the

Companies' cost of service studies for supporting its Basic Service Charges. There is no merit to Mr. Watkins' approach.

E. RECOMMENDATION

Q. What is your recommendations regarding cost of service studies?

A. I recommend that the Commission utilize the Companies' LOLP cost of service study as a guide for allocating the revenue increases and developing rate design However, the Companies' 6 CP cost of service, which is supported by the KIUC, could also be used as a reasonable guide for allocating the revenue increases and developing rate design. While I believe that the LOLP study is more closely aligned with how the Companies' generation resources are planned, the Companies' 6-CP studies, as recommended by Mr. Baron, also provide useful information. In my opinion, Mr. Watkins' POD and BIP studies and Mr. Gorman's proposed modifications to the allocation of steam production maintenance expenses and transmission costs should not be considered.

IV. DISTRIBUTION OF ELECTRIC REVENUE INCREASE

Q. Do the intervenor witnesses offer different approaches to distributing the Companies' revenue increases in these proceedings?

A. Yes, AG, KIUC, DOD-FEA, and Lou Metro & LFUCG propose different spreads of the revenue increases for KU and LG&E. Walmart does not oppose the Companies' proposed distribution of the revenue increase.

Q. How did KU and LG&E propose to spread the increase?

A. KU proposed to increase revenue for all rate classes, except for the lighting rates, by approximately the same percentage (approximately 10.68%). Based on the results of the cost of service studies, KU proposed no net increase for Lighting Service (Rate LS), Restricted Lighting Service (RLS), Lighting Energy Service (Rate LE) and Traffic Energy Service (Rate TE). KU proposed a rate reduction for Outdoor Sports Lighting (Rate OSL) of approximately 5%.

LG&E also proposed to increase revenue for all rate classes, except for the certain lighting rates, by approximately the same percentage (approximately 11.80%). Based on the results of the cost of service studies, LG&E proposed no net increase for Lighting Energy Service (Rate LE) and Traffic Energy Service (Rate TE). LG&E proposed a rate reduction for Outdoor Sports Lighting (Rate OSL) of approximately 10%.

A. AG'S PROPOSED DISTRIBUTION OF THE INCREASE

Q. How does the AG propose to spread the increase for KU?

A. Mr. Watkins offers two options for the Commission's consideration. In his first option for KU, Mr. Watkins proposes to spread the increase in a manner very similar to the Company's proposal, except he would increase KU's street lighting rates (Rates LS, RLS, LE, and TE) by the same percentage as most of the other rate classes. Where KU is proposing no increase to these street lighting rates, Mr. Watkins would increase the rates for these lighting schedules by 10.46%. Obviously, Mr. Watkins' proposal would result in an increase in the rates applicable to Lexington-Fayette Urban County

Government's (LFUCG's) streetlights. Under his first option, the principal difference between KU's proposal and Mr. Watkins' proposal is that he would shift the increase to the municipal street lighting customers such as LFUCG.

Under Mr. Watkins' second option for KU, he spreads the increase based on the results of his cost of service studies. This results in substantial increases to the large customer rate schedules (TODS, TODP, RTS, FLS) and to Lighting Energy Service (LE).

The following table (TABLE 6) compares KU's proposed increases to Mr. Watkins' two options:

TABLE 6

Kentucky Utilities Company			
	KU's Proposed	AG'S Proposed Percent Increase	
Rate Schedule	**Percent Increase**	**Option 1**	**Option 2**
Rate RS	10.68%	10.46%	10.31%
Rate GS	10.68%	10.46%	7.84%
Rate AES	10.68%	10.46%	10.31%
Rate PS – Secondary	10.67%	10.46%	7.84%
Rate PS – Primary	10.68%	10.46%	7.84%
Rate TOD – Secondary	10.69%	10.46%	13.07%
Rate TOD – Primary	10.68%	10.46%	13.07%
Rate RTS	10.68%	10.46%	13.07%
Rate FLS	10.69%	10.46%	13.07%
Rate LS & RLS	0.00%	10.46%	7.84%
Rate LE	0.00%	10.46%	13.07%
Rate TE	0.00%	10.46%	7.84%
Rate OSL	-4.97%	-4.97%	-4.97%
Total Company	**10.57%**	**10.57%**	**10.57%**

As highlighted in the above table, AG's Option 1 would impact lighting rates and Option 2 would impact both lighting rates and large customer rates (TODS, TODP, RTS, FLS).

Q. How does AG propose to spread the increase for LG&E?

A. Again, Mr. Watkins offers two options for the Commission's consideration. In his first option for LG&E, Mr. Watkins proposes to spread the increase in a manner very similar to the Company's proposal, except he would increase certain lighting rates (Rates LE and TE) by the same percentage as most of the other rate classes. Where LG&E is proposing no increase to these lighting rates, Mr. Watkins would increase the rates for these lighting schedules by 11.80%.

Under Mr. Watkins' second option for LG&E, he spreads the increase based on the results of his cost of service studies. This results in substantial increases to the large customer rate schedules (TODS, TODP, RTS, FLS) and to Lighting Energy Service (LE).

The following table (TABLE 7) compares LG&E's proposed increases to Mr. Watkins' two options:

TABLE 7

Louisville Gas and Electric Company			
	KU's Proposed	AG'S Proposed Percent Increase	
Rate Schedule	**Percent Increase**	**Option 1**	**Option 2**
Rate RS	11.80%	11.80%	11.24%
Rate GS	11.81%	11.80%	8.85%
Rate PS – Primary	11.81%	11.80%	8.85%
Rate PS – Secondary	11.81%	11.80%	11.24%
Rate TOD – Primary	11.81%	11.80%	14.75%
Rate TOD – Secondary	11.82%	11.80%	14.75%
Rate RTS	11.80%	11.80%	14.75%
Special Contract	11.80%	11.80%	14.75%
Rate RLS & LS	11.90%	11.80%	8.85%
Rate LE	0.00%	11.80%	14.75%
Rate TE	0.00%	11.80%	8.85%
Rate OSL	-10.00%	-10.00%	-10.00%
Total Company	**11.63%**	**11.63%**	**11.63%**

As highlighted in the above table, AG's Option 1 would impact two lighting rates (LE and TE) and Option 2 would impact these lighting rates and large customer rates (TODS, TODP, RTS and the Special Contract).

Q. Do you agree with either of Mr. Watkins' options?

A. No. Both of Mr. Watkins' options, but especially his Option 2, are guided by his flawed cost of service assumptions and models. In his Option 1, he proposes significant increases to lighting rates because of his underlying belief that off-peak kWh usage should be assigned a significant amount of fixed production resources. Lighting customers utilize energy mostly during off-peak periods, particularly during summer and shoulder months.[79] In the Companies' LOLP and 6 CP cost of service studies, street lighting is allocated relatively little production fixed costs in the Companies' cost of service studies. In Mr. Watkins' cost of service studies, off-peak usage is assigned a large proportionate share of production demand-related costs. As I discussed earlier, Mr. Watkins' assumptions defy economic logic.

In his Option 2, Mr. Watkins relies more heavily on his flawed cost of service methodologies and also penalizes large customer rate classes (TODS, TODP, RTS, and FLS) that use significant amounts of power during off-peak periods. As I mentioned earlier, Mr. Watkins' POD and BIP cost of service studies are seriously flawed. Not only do they contain errors about the Companies' generation resources, but they are also conceptually flawed. A fundamental difference between the Companies', KIUC's, DOD-FEA's and Walmart's preferred cost-of-service methodologies and the AG's recommended approach is how production resources are allocated based on off-peak usage in the AG's cost of service studies. The AG's POD

[79] During the winter months, lighting customers' loads are operating during the Companies' system peak hours, which typically occur either in morning around 6 A.M. or during the evening around 8 P.M. During the summer months, street and outdoor lighting typically do not operate during system peak hours.

and BIP methodologies inappropriately allocate large portions of fixed production costs based on off-peak usage. From an economic perspective, the AG's approach is unsound.

B. KIUC'S PROPOSED DISTRIBUTION OF THE INCREASE

Q. How does KIUC propose to spread the increase?

A. For KU, Mr. Baron proposes to eliminate current subsidies that the large customer classes are paying based on the 6-CP cost of service study. Mr. Baron states:

> For these industrial rate classes, whose customers must compete regionally, nationally and internationally, eliminating the current subsidies they pay in electric power rates would encourage continued operation and expansion of production facilities and help to maintain and grow jobs in Kentucky. While it is true that commercial customers on other general service rate schedules are also paying subsidies, these customers generally compete locally with other customers on the LG&E and KU system taking service on the same rate schedules. For these commercial customers, electric cost is competitively neutral.

Clearly, Mr. Baron's position is diametrically opposed to Mr. Watkins' perspective. Mr. Baron recommends adopting the Companies' 6-CP cost of service study and proposes to focus on eliminating subsidies paid by the large customer rate classes. Mr. Watkins proposes POD and BIP cost of service studies that shifts large amounts of costs to off-peak usage and recommends large increases to large customer rate classes, particularly with his Option 2.

Q. Does Mr. Baron make cogent points regarding the importance of low energy costs for large industrial customers that must compete nationally and internationally?

A. Yes, he does. Large industrial customers are very important to KU, LG&E and their customers. To be eligible for Rates TODS, TODP or RTS, a customer must have a 12-month average demand of at least 250 kVA. To be eligible for Rate FLS, a customer must have a monthly demand of at least 20,000 kVA. These rates are therefore only available to the largest customers on KU's and LG&E's systems. Thus, these rates would be applicable to large businesses looking to locate their operations in KU's and LG&E's service territories. Large businesses, such as manufacturers (e.g., North American Stainless, Ford Motor Company, and Toyota), shipping companies (e.g., United Parcel Service) and internet-based suppliers (e.g., Amazon), will often have options for where they locate their operations and will decide on a location based on an array of factors, including the prices of electric energy and natural gas. In many cases, the price of electricity is one of the more important considerations in determining the location of a large new business facility or where a business will choose to expand its existing operations. Clearly, businesses have choices regarding where they locate or expand their operations, and the price of energy is a critical consideration in their decision-making process about where to locate their operations. Kentucky coal producers must also compete nationally and internationally. They are struggling to survive from competition from natural gas and renewable generation resources and from forces that are opposed to the use of coal.

Adding large commercial and industrial sales generally allows a utility to spread its fixed costs over a larger sales base. Likewise, losing existing large commercial and industrial customers will generally have the opposite effect, resulting in fixed costs being spread over a smaller sales base. Furthermore, for many large commercial or industrial customers, the business considerations for making siting decisions are often quite different from small to medium-size customers. Small and medium-size customers are often located in a particular area because that is where their customers are located. A convenience store, for example, will locate its operations in an area because its customers are located in *that area*. Large customers will usually have greater optionality regarding their siting decisions than small and medium-size customers. In a sense, small and medium-size customers can be viewed as *anchored customers* in comparison to large customers which are often less *moored* to a specific regional market. Even after locating at a site, studies have shown that large industrial consumers, especially metal, chemical, and plastic/rubber manufacturers, exhibit significantly higher price elasticity than residential, government, and small commercial and industrial consumers.

Q. How does Mr. Baron's proposed distribution of the revenue increase compare to KU's proposed increases?

A. The following table (TABLE 8) compares KU's proposed increases to Mr. Baron's recommendation:

TABLE 8

Kentucky Utilities Company		
Rate Schedule	**KU's Proposed Percent Increase**	**KUIC's Proposed Percent Increase**
Rate RS	10.68%	10.72%
Rate GS	10.68%	10.73%
Rate AES	10.68%	10.72%
Rate PS – Secondary	10.67%	10.72%
Rate PS – Primary	10.68%	10.72%
Rate TOD – Secondary	10.69%	10.73%
Rate TOD – Primary	10.68%	10.73%
Rate RTS	10.68%	10.73%
Rate FLS	10.69%	8.57%
Rate LS & RLS	0.00%	0.00%
Rate LE	0.00%	0.00%
Rate TE	0.00%	0.00%
Rate OSL	-4.97%	-4.97%
Total Company	**10.57%**	**10.57%**

As can be seen, the only significant change proposed by Mr. Baron with respect to the distribution of the increase for KU is for FLS.

Q. **How does Mr. Baron's proposed distribution of the revenue increase compare to LG&E's proposed increases?**

A. The following table (TABLE 9) compares LG&E's proposed increases to Mr. Baron's recommendation:

TABLE 9

Louisville Gas and Electric Company		
Rate Schedule	**LG&E's Proposed Percent Increase**	**KUIC's Proposed Percent Increase**
Rate RS	11.80%	12.73%
Rate GS	11.81%	12.73%
Rate PS – Primary	11.81%	12.74%
Rate PS – Secondary	11.81%	12.73%
Rate TOD – Primary	11.81%	7.32%
Rate TOD – Secondary	11.82%	12.74%
Rate RTS	11.80%	8.49%
Special Contract	11.80%	12.72%
Rate RLS & LS	11.90%	12.83%
Rate LE	0.00%	0.00%
Rate TE	0.00%	0.00%
Rate OSL	-10.00%	-10.01%
Total Company	**11.63%**	**11.63%**

As can be seen, the most significant changes proposed by Mr. Baron with respect to the distribution of the increase for LG&E are for TODP and RTS. It should be noted that Mr. Baron's proposed spread of the increase results in a larger increase for LG&E's residential customers.

Q. Do you agree with Mr. Baron's recommendation?

A. Not totally. While I recognize the cogency of his argument about the importance of eliminating subsidies paid by large manufacturers and coal producers, Mr. Baron's recommendation depends heavily on whether the LOLP or 6-CP cost of service methodology is utilized. For LG&E, the LOLP methodology supports Mr. Baron's position more than the 6-CP methodology. As shown in Table 9 above, for LG&E the

LOLP methodology results in higher rates of return for the two classes for which Mr. Baron proposes lower increases (TODP and RTS). On the other hand, for KU the 6-CP methodology supports Mr. Baron's position more than the LOLP methodology. As shown in Table 8 above, for KU the 6-CP methodology results in higher rates of return for FLS than in the LOLP methodology. Mr. Baron's position might be supported if both the LOLP and 6-CP are considered together. Ultimately it is up to the Commission to decide whether competitive considerations for large industrial customers, which I agree are important, support Mr. Baron's recommendation.

C. DOD-FEA'S PROPOSED DISTRIBUTION OF THE INCREASE

Q. How does DOD-FEA propose to spread the increase?

A. For both KU and LG&E, Mr. Gorman proposes to spread the increase to move each rate class toward his cost of service study, with a mitigation cap of any costs to be no more than 125% of the system average increase, but with no class receiving a rate decrease. Mr. Gorman's approach to distributing the increase is a very straight-forward subsidy reduction methodology, based on his recommended cost of service study.

Q. How does Mr. Gorman's proposed distribution of the revenue increase compare to KU's proposed increases?

A. The following table (TABLE 10) compares KU's proposed increases to Mr. Gorman's recommendation:

TABLE 10

Kentucky Utilities Company		
Rate Schedule	**KU's Proposed Percent Increase**	**DOD-FEA's Proposed Percent Increase**
Rate RS	10.68%	13.70%
Rate GS	10.68%	4.00%
Rate AES	10.68%	10.00%
Rate PS – Secondary	10.67%	4.00%
Rate PS – Primary	10.68%	4.00%
Rate TOD – Secondary	10.69%	13.70%
Rate TOD – Primary	10.68%	13.70%
Rate RTS	10.68%	13.70%
Rate FLS	10.69%	13.70%
Rate LS & RLS	0.00%	4.00%
Rate LE	0.00%	0.00%
Rate TE	0.00%	0.00%
Rate OSL	-4.97%	4.00%
Total Company	**10.57%**	**10.57%**

Mr. Gorman's proposed spread of the revenue increase results in significantly larger increases to the residential rate class (Rate RLS) and to the large customer rate classes (Rates TODS, TODP, RTS, and FLS).

Q. How does Mr. Gorman's proposed distribution of the revenue increase compare to LG&E's proposed increases?

A. The following table (TABLE 11) compares LG&E's proposed increases to Mr. Gorman's recommendation:

TABLE 11

Louisville Gas and Electric Company		
Rate Schedule	**LG&E's Proposed Percent Increase**	**DOD-FEA's Proposed Percent Increase**
Rate RS	11.80%	15.40%
Rate GS	11.81%	8.60%
Rate PS – Primary	11.81%	8.60%
Rate PS – Secondary	11.81%	8.60%
Rate TOD – Primary	11.81%	10.90%
Rate TOD – Secondary	11.82%	15.40%
Rate RTS	11.80%	8.60%
Special Contract	11.80%	14.00%
Rate RLS & LS	11.90%	8.60%
Rate LE	0.00%	0.00%
Rate TE	0.00%	0.00%
Rate OSL	-10.00%	8.60%
Total Company	**11.63%**	**11.63%**

Mr. Gorman's proposed spread of the revenue increase results in significantly larger increases to the residential rate class (Rate RLS), to Rate TOD-Secondary and the Special Contract customer.

Q. Do you have any comments about the DOD-FEA's proposed distribution of the increase?

A. Yes. As already mentioned, Mr. Gorman's proposed spread is based on his cost of service study, which, as already noted, is problematic. Also, he proposes large, likely unacceptable, increases to the residential rate customer classes. Mr. Gorman also proposes large increases to the large customer rates, placing additional cost pressures on large manufacturers and coal producers in Kentucky. Mr. Gorman's proposal is diametrically opposed to the position of the KIUC.

Q. Are there any other problems with Mr. Gorman's proposal?

A. Yes. The filed contract with the Special Contract customer identified in the cost of service studies and rate design schedules (Schedule M in the Application) explicitly precludes LG&E from seeking to place into effect a greater percentage increase for the Special Contract than for Rate TOD-P (the successor rate schedule to Large Power Rate LP). Consequently, LG&E cannot agree with Mr. Gorman's recommendation regarding his higher increase to the Special Contract rate.

D. LOUISVILLE METRO & LFUCG'S PROPOSED DISTRIBUTION OF THE INCREASE

Q. How does Louisville Metro & LFUCG propose to spread the increase?

A. For both KU and LG&E, Mr. Bunch proposes significant rate *decreases* in the Companies' lighting rates (RLS, LS, LE, and TE).

Q. How does Mr. Bunch's proposed distribution of the revenue increase compare to KU's proposed increases?

A. The following table (TABLE 12) compares KU's proposed increases to Mr. Bunch's recommendation:

TABLE 12

Kentucky Utilities Company		
Rate Schedule	**KU's Proposed Percent Increase**	**LFUCG's Proposed Percent Increase**
Rate RS	10.68%	11.16%
Rate GS	10.68%	10.68%
Rate AES	10.68%	10.68%
Rate PS – Secondary	10.67%	10.67%
Rate PS – Primary	10.68%	10.68%
Rate TOD – Secondary	10.69%	11.17%
Rate TOD – Primary	10.68%	11.16%
Rate RTS	10.68%	11.16%
Rate FLS	10.69%	11.17%
Rate LS & RLS	0.00%	-19.00%
Rate LE	0.00%	-26.00%
Rate TE	0.00%	-12.00%
Rate OSL	-4.97%	-4.97%
Total Company	**10.57%**	**10.57%**

Lexington-Fayette Urban County Government's proposed spread of the revenue increase results in larger increases to the residential rate class (Rate RLS) and to the large customer rate classes (Rates TODS, TODP, RTS, and FLS). LFUCG proposes large rate decreases in lighting rates.

Q. Did KU propose a revenue increases for RLS, LS, LE, and TE?

A. No. However, LFUCG is proposing large decreases for these classes.

Q. How does Mr. Bunch's proposed distribution of the revenue increase compare to LG&E's proposed increases?

A. The following table (TABLE 13) compares LG&E's proposed increases to Mr. Bunch's recommendation:

TABLE 13

Louisville Gas and Electric Company		
Rate Schedule	**LG&E's Proposed Percent Increase**	**Lou Metro's Proposed Percent Increase**
Rate RS	11.80%	12.72%
Rate GS	11.81%	11.81%
Rate PS – Primary	11.81%	11.81%
Rate PS – Secondary	11.81%	11.81%
Rate TOD – Primary	11.81%	11.81%
Rate TOD – Secondary	11.82%	11.82%
Rate RTS	11.80%	11.80%
Special Contract	11.80%	11.80%
Rate RLS & LS	11.90%	-6.10%
Rate LE	0.00%	-27.00%
Rate TE	0.00%	-14.00%
Rate OSL	-10.00%	8.60%
Total Company	**11.63%**	**11.63%**

Louisville Metro Government's proposed spread of the revenue increase results in significantly larger increases to the residential rate class (Rate RLS) and large decreases to lighting rates.

Q. Do you agree with Mr. Bunch's recommendation?

A. No. Mr. Bunch proposes large rate reductions for the lighting rates based on his reading of the Companies' cost of service studies. He argues that since the class rates of return for RLS and LS are higher than the overall rate of return, the rates for RLS and LS should be reduced. Yet, Mr. Bunch completely ignores the even higher rates of return for other rate classes. For LG&E, General Service (GS), Power Service Primary (PSP), Power Service Secondary (PSS) have significantly higher rates of return than RLS and LS, but Mr. Bunch proposes large *increases* for GS, PSP, and

PSS. For KU, Power Service Primary (PSP) has a significantly higher rate of return than RLS and LS, but he proposes a large increase for PSP.

Q. How do LFUCG and Louisville Metro's proposed revenue distributions contrast with the AG's?

A. LFUCG and Louisville Metro are proposing significant ***decreases*** to the lighting rates while the AG is proposing significant ***increases*** to those rates, particularly KU's lighting rates.

D. RECOMMENDATION

Q. Have you prepared an exhibit showing a side-by-side comparison of the positions of all parties?

A. Yes. Rebuttal Exhibit WSS-8 shows the positions of all parties in these proceedings regarding the distribution of the revenue increases. This exhibit illustrates the diversity of views among the parties regarding the distribution of the revenue increase.

Q. What is your recommendation?

A. It is my recommendation that the Commission rely on the Companies' proposed distribution of the revenue increase. For all of the reasons discussed above, it is the most balanced approach.

V. ELECTRIC RATE DESIGN

A. RESIDENTIAL BASIC SERVICE CHARGE

Q. Do any of the intervenor witnesses address the Basic Service Charge for Rate

RS?

A. Yes, it is addressed by MA-MHC witness Owen and AG witness Watkins.

Q. What are the proposed increases in the Basic Service Charges for RS in these proceedings?

A. KU is proposing to increase the Basic Service Charge from $0.53 per day to $0.61 per day. The charge proposed by KU is significantly less than the $0.82 per day unit cost calculated from its cost of service study. LG&E is proposing to increase the Basic Service Charge from $0.45 per day to $0.52 per day. LG&E's proposed Basic Service Charge is also significantly less than the $0.69 per day unit cost calculated from its cost service study.

Q. What does Mr. Owen have to say about the Companies' proposed increase in the Basic Service Charge?

A. Mr. Owen makes several unsubstantiated claims regarding the increases in the Companies' Basic Service Charge. For example, Mr. Owen makes the bold claims that the Basic Service Charge would harm low-income customers and would reduce the incentive for energy efficiency. However, he offers no empirical data showing the percentage of low-income customers that use less energy than the average residential customer. The Companies' data for Low Income Heating Energy Assistance Program ("LIHEAP") customers indicate that customers receiving LIHEAP assistance use more energy than the average residential customer. Clearly, many low-income customers use more energy than the average residential customer. If a low-income customer use more energy than an average residential customer, then recovering more costs through the energy charge rather than the Basic Service Charge will increase the bills to the low-income customer. Furthermore, Mr. Owen claims that increasing the Basic Charge will have a detrimental impact on energy conservation. Again, he offers no empirical data supporting this claim. For example, he provides no data or analysis demonstrating that customers respond to the level of individual rate components of their bills (e.g., Basic Service Charge or Energy Charge), or whether customers respond to the total amounts of their bills, or whether customers respond to any of these. Mr. Owen provides nothing in terms of an elasticity-of-demand analysis that would support his assertion.

Q. What is Mr. Watkins' recommendation regarding the Basic Service Charge for Rate RS?

A. Mr. Watkins proposes to leave the Companies' Basic Service Charges for Rate RS at their current levels -- $0.53 per day for KU and $0.45 per day for LG&E. In support of his proposal, Mr. Watkins relies on an analysis that was rejected by the Commission in the Companies' last rate cases (Case Nos. 2018-00294 and 2018-00295).

Q. Did Mr. Watkins provide valid cost justification that supports leaving the current Basic Service Charges at their current levels?

A. No. He provides calculations that omit significant amounts of customer-related costs and arrives at a monthly customer cost of $4.57 ($0.15 per day) for KU and $4.15 ($0.14 per day) for LG&E.[80] He provides no explanation for why he is proposing a

[80] See Direct Testimony of Glenn A. Watkins, Schedule GAW-25.

$0.53 per day Basic Service Charge for KU and $0.45 per day Basic Service Charge of LG&E, when his cost analysis only supports $0.15 per day for KU and $0.14 per day for LG&E. Either he has little faith in his own analysis, or he feels that proposing such low customer charges would diminish the credibility of his rate proposals.

Q. Did the Companies use a standard cost of service methodology to calculate customer costs?

A. Yes. In the cost of service studies filed by KU and LG&E, distribution costs were classified as demand- and customer-related using the zero-intercept methodology. With the zero-intercept analysis, a statistical analysis is performed to determine the fixed-cost components of overhead conductor, underground conductor, and transformers that do not vary with demand, but would still vary with the number of customers. This methodology has been used for decades for both KU and LG&E. The Commission found LG&E's cost of service studies utilizing the zero-intercept methodology submitted in Case No. 90-158 and in Case No. 2000-080 to be reasonable. The Commission also found the cost of service study submitted by Union Light Heat and Power in Case No. 2001-00092, which also utilized the zero-intercept methodology, to be reasonable. Furthermore, the zero-intercept methodology has been used in every cost of service study filed by both KU and LG&E since the early 1980s, including the cost of service studies filed in Case Nos. 2016-00370 and 2016-00371. Most recently, in Case Nos. 2018-00294 and 2018-00295, the Commission approved KU and LG&E's Basic Service Charges based on the results of the Companies' cost of service study.

Q. Did Mr. Watkins rely on the results of the Companies' zero-intercept analysis when he performed his analysis of customer costs?

A. No. Mr. Watkins ignored the results of the zero-intercept analysis when he performed his customer cost analysis that excluded numerous customer-related costs. The analyses that he included in his Schedule GAW-25 excluded cost components for overhead conductor, underground conductor and line transformers which the Commission has traditionally considered to be customer related. The Commission has rejected this minimalist and non-conforming approach in past orders. For example, see the Commission's Order in Case No. 2000-080 dated September 27, 2000, at pages 75-76.

Q. Did Mr. Watkins' own study utilize the Companies' zero-intercept analysis for the classification of secondary distribution costs in own cost of service study?

A. Yes. On page 56 of his testimony, Mr. Watkins states: "I have accepted Mr. Seelye's classification of secondary voltage plant as partially customer-related and partially demand-related." But he completely ignores this classification of secondary distribution costs into customer-related and demand related components when he calculates his customer costs in Schedule GAW-25. In GAW-25, he excludes the costs of transformers (Account 368), overhead lines (Accounts 364 and 365), and underground lines (Accounts 366 and 367) that he classified as customer costs in his own cost of service studies. In the calculations he performs in GAW-25, he simply ignores the costs that he classifies as customer related in his own cost of service studies. The following table (TABLE 14) compares the costs identified as customer-related in Mr. Watkins' cost of service study with the costs that he considered customer-related for purposes of developing the basic service charge:

TABLE 14

COST ITEM	**IDENTIFIED AS CUSTOMER-RELATED IN WATKINS' COST OF SERVICE STUDIES**	**IDENTIFIED AS CUSTOMER-RELATED IN CALCULATING HIS BASIC SERVICE CHARGE**
Poles	Yes	***No***
Overhead Conductor	Yes	***No***
Underground Conductor	Yes	***No***
Transformers	Yes	***No***
Services	Yes	Yes
Meters	Yes	Yes
Meter Reading	Yes	Yes
Records and Collection	Yes	Yes
Customer Accounts Supervision Expenses (Account 901)	Yes	***No***
Uncollectible Accounts (Account 904)	Yes	***No***
Miscellaneous Customer Accounts Expenses (Account 905)	Yes	***No***
Customer Service Supervision (Account 907)	Yes	***No***
Customer Assistance Expense (Account 908)	Yes	***No***
Customer Information and Instruction (Account 909)	Yes	***No***
Miscellaneous Customer Service	Yes	***No***
A&G Expenses	Yes	***No***

In calculating his proposed basic service charge, Mr. Watkins specifically excludes a large number of costs identified as customer-related in his own cost of service study. Thus, his calculation of customer costs in GAW-25 is inconsistent with his own cost of service studies.

Q. Has the Commission rejected this type of selective interpretation of the cost of service study in prior rate orders?

A. Yes. In its Orders in Case No. 2018-00294 and in Case No. 2018-00295, the Commission accepted the Companies' proposed Basic Service Charges, which were supported by KU and LG&E's cost of service studies. Mr. Watkins presented the same analysis in the last rate case[81] that he presents in the current case. In the orders in those proceedings, the Commission did not accept the same analysis of customer costs that he presents in the current proceedings. But in its Order dated September 27, 2000, in Case No. 2000-080 (an LG&E rate case), the Commission specifically rejected this type of selective and attenuated approach for determining basic service charges. Just as Mr. Watkins has done in the current proceeding, the AG's cost of service witness in Case No. 2000-080 proposed a basic service charge that ignored costs identified as customer-related in the zero-intercept analysis. In its order in that case, the Commission rejected the AG's calculation of customer costs that ignored the classification of costs as customer-related in its own cost of service study.[82]

[81] In Mr. Watkins' direct testimony in Case Nos. 2018-00294 and 2018-00295, his analysis was provided in Schedule GAW-5.
[82] Order in Case No. 2000-080, dated September 27, 2000, at pp. 75-76.

B. TODP, RTS AND FLS ENERGY AND DEMAND CHARGES

Q. Is DOD-FEA witness Gorman proposing changes to the TODP rate design?

A. Yes. He essentially proposes three changes. First, he proposes reducing the energy charge to reflect recovery of less production operation and maintenance expenses through the energy charge. I discussed this recommendation earlier with respect to the cost of service study, and I do not believe that it is necessary. Second, he proposes to the move the recovery of transmission costs into the peak and intermediate demand charges. Third, he proposes to lower the ratchet for the base demand charge from a 100% ratchet to a 75% ratchet.

Q. What is a demand ratchet?

A. A "ratchet" refers to a mechanism in which a percentage is applied to the monthly recorded demands in kW (or kVA where appropriate) for the previous 11 months for purposes of determining the billing demand for the current month. The word "ratchet" is a metaphor based on the tool or wrench – a ratchet – that tightens a bolt in one direction but will not loosen the bolt in the opposite direction. With a 75% ratchet, for example, the billing demand for the current month is equal to the greater of (i) the metered demand for the current month or (ii) 75% of the maximum monthly demand for the previous 11 months. TODP includes a 50% ratchet for the Peak Demand Charge and the Intermediate Demand Charge and a 100% ratchet for the Base Demand Charge. The weighted effect of these demand ratchets for TODP is equivalent to a 69% ratchet, which is not out of line with the ratchets used by other utilities. See

Rebuttal Exhibit WSS-9. For example, Duke Energy Kentucky's Primary Distribution Voltage Rate DP includes an 80% demand ratchet for all demand costs.

Q. Do you agree with Mr. Gorman's proposal to recover transmission costs through the peak and intermediate periods and to reduce the base period ratchet?

A. No. In evaluating Mr. Gorman's proposed changes to Rate TODP, it is important to review the history behind the key elements of the Companies' rate design that Mr. Gorman is proposing to change, and the DOD-FEA's involvement in, and relationship to, those changes. The current structure for TODP was introduced in connection with the elimination of the Companies' Supplemental or Standby Service (Rider SS) in Case Nos. 2016-00370 and 2016-00371. Rider SS was a service rider applicable to customers with their own generation facilities but wanted to rely on KU and LG&E to provide backup service whenever the customers' generation facilities were unable to operate. With a total behind-the-meter generation supply capacity of 46.5 MW, DOD-FEA operates the single largest collection of behind-the-meter generation facilities[83] on the Companies' system. At that time, DOD-FEA objected to Rider SS. In response, the Companies proposed to allow customers with their own generation such as DOD-FEA to take service under standard sales service rates. But in conjunction with this change, the Companies proposed to modify the demand ratchet provisions of their large customer rates (TODS, TODP, RTS, and FLS) so the rates could be utilized by customers that required back-up service as well as regular sales service

[83] The DOD-FEA customer is served by LG&E.

customers.[84] DOD-FEA is now trying to undo what it essentially agreed to Case Nos. 2016-00370 and 2016-00371 to move away from the more restrictive Rider SS. DOD-FEA is the only party in this proceeding objecting to the demand ratchets. Both DOD-FEA's proposal to reduce the base demand ratchet and its proposal to shift costs out of the Base Demand Charge to the Peak and Intermediate Demand Charges are designed to reduce the cost that DOD-FEA pays for back-up service and shift costs to other customers.

Q. Is the Companies' proposed rate design for TODP reasonable?

A. Yes. The recovery of transmission costs through the base demand charge is reasonable. As discussed earlier, these costs are related to the locational loads that customers place on the Companies' transmission facilities; therefore, recovering these costs through a non-coincident demand charge is appropriate. Furthermore, the current demand ratchets are appropriate. The Peak and Intermediate Demand Charges only include a 50% ratchet. For KU and LG&E, the weighted ratchet for all three demand charge components (i.e., the Base, Intermediate and Peak Demand Charges) is equivalent to approximately 69%. See Rebuttal Exhibit WSS-9. This overall ratchet level is not out of line of ratchets for most other utilities.

Q. Are there other problems with Mr. Gorman's proposed rates for TODP?

A. Yes. In his Exhibits MPG-3 and MPG-4, Mr. Gorman presents his proposed charges for TODP, but in developing his demand charges he fails to recognize that the

[84] See Case Nos. 2016-00370 and 2016-00371, Direct Testimony of William Steven Seelye, at pp. 41-50, which are attached as Rebuttal Exhibit WSS-10.

application of a 100% demand ratchet for the Base Demand Charge would result different billing units (kVA) than for the 75% ratchet that he proposes. Specifically, using a 75% ratchet would decrease the Base billing demands. But in his Exhibits MPG-3 and MPG-4, Mr. Gorman does not revise the billing demands to reflect the application of his proposed 75% ratchet. For example, in his Exhibit MPG-3, page 1 of 3, Mr. Gorman uses Base demands for LG&E of 5,354,606 kVA for both the 100% ratchet demand charge proposed by LG&E and the 75% ratchet demand charge that he proposes. A 75% ratchet would result in a lower demand charge; therefore, his proposed charges would under-recover LG&E's costs. Likewise, in his Exhibit MPG-4, page 1 of 3, Mr. Gorman uses Base demands for KU of 10,620,000 kVA for both the 100% ratchet demand charge proposed by KU and the 75% ratchet demand charge that he proposes. A 75% ratchet would result in a lower demand charge; therefore, his proposed charges would under-recover KU's costs. The billing units based on a 100% ratchet cannot be the same as the billing demands for a 75% percent ratchet.

Q. Do you have any other comments regarding Mr. Gorman's proposal?

A. Yes. If the Commission determines that the base demand ratchet for Rate TODP should be modified, then the Companies would respectfully request that they be allowed to re-introduce backup and standby service rates for the KU and LG&E. As mentioned earlier, the current demand ratchets were introduced in conjunction with the elimination of Rider SS. Without appropriate ratchets the Companies do not believe that TODP can be used to provide backup to large power customers that have extensive behind-the-meter generation facilities such as those operated by DOD-FEA.

C. CONJUNCTIVE DEMAND BILLING

Q. Kroger witness Bieber recommends that the Commission order the Companies to study and propose a conjunctive billing demand pilot program in their next rate cases. Has this issue been addressed in prior rate cases?

A. Yes. The concept of a multi-site aggregation rate was raised by Kroger in Case Nos. 2008-00251 and 2008-00252. Section 3.11 of the Settlement Agreement, Stipulation and Recommendation in those proceedings stated the Companies would "agree to work with interested parties to study the feasibility of measuring demand for generation service to multi-site customers based on conjunctive demand, where 'conjunctive demand' herein refers to the measured demand at the time that the total demand of a multi-site customer's load, measured over a coinciding time period, has reached its peak during the billing period."[85] The issue was addressed in direct testimony that I filed in the subsequent KU and LG&E Case Nos. 2009-00548 and 2009-00549. My direct testimony regarding conjunctive demand filed in those proceedings is included as Rebuttal Exhibit WSS-12.

Q. Is the Companies' position now any different from what was articulated in Case Nos. 2009-00548 and 2009-00549?

A. No. As explained in my testimony in those proceedings, the Companies would be willing to consider conjunctive billing for the production demand component of the

[85] Section 3.11 of the Settlement Agreement, Stipulation and Recommendation in Case Nos. 2008-00251 and 2008-00252 is included in Rebuttal Exhibit WSS-11.

rates if the peak and intermediate demand charges are applied on a coincident peak demand basis. Under that arrangement, the base demand charge would be applied to the maximum monthly demand at each site.

Q. Is it necessary for the Commission to order the Companies to study conjunctive billing and propose a pilot program in its next general rate case?

A. No. If Kroger is interested in conjunctive service pilot program, the Companies are willing to work with Kroger on developing a pilot conjunctive rate design along the lines discussed in my testimony filed in Case Nos. 2009-00548 and 2009-00549, and attached as Rebuttal Exhibit WSS-12. Of course, any such pilot rate design would have to be revenue neutral. However, the Companies do not have a desire to perform yet another study of conjunctive demand billing if there is no actual interest on the part of customers in the concept, particularly as described in Rebuttal Exhibit WSS-12.

D. COAL MINING ECONOMIC DEVELOPMENT RATE

Q. Please address KIUC's proposed Coal Mine Economic Development Rate.

A. KIUC witnesses Baron and Lovell address the need for an economic development rate for coal mines in Kentucky. Mr. Baron recommends an economic development rate specifically focused on the Companies' coal mining customers. The Companies are not opposed to some form of economic development rate specifically designed for large coal producers in the state. Coal mining jobs are extremely important to economically depressed regions of Kentucky, and to the extent that an economic development rate provides for increased recovery of fixed costs from expanded coal production, then the Companies would support such a proposal as it would benefit all customers.

Q. Mr. Baron proposes an economic development rate in the form of a $/kWh credit applied to a coal mine's incremental kWh usage. Do you agree with this approach?

A. No. The coal mines served by KU typically take service under Rates RTS and TODP.[86] The energy charges for Rates RTS and TODP are designed to recover only variable energy costs. As discussed earlier in the context of the electric cost of service study, KIUC and DOD-FEA are both proposing to lower the energy charges for RTS and TODP to include only fuel plus marginal operation and maintenance expenses. Regardless, there is little or no room -- or flexibility -- to provide a coal mining economic development rate denominated in the form of a $/kWh credit without reducing the energy charge below marginal fuel and variable operation expenses.

Q. What is your recommendation?

A. To extent that a special economic development rate is offered to coal mines, then certain requirements and principles should be established.

First, any such coal mining economic development rate should be based on increases in demand, not energy. As explained above, there is little or no room to offer a $/kWh credit without driving the rate below marginal energy costs. For

[86] For example, River View, LLC, ("River View") takes service under Rate RTS.

example, a coal mining economic development rate could be based on increases in average demands above what were either included in Schedule M for a coal mine, as in the case of River View, or based on demands for the most recent 2 or 3 years of history for smaller mines or mining. Any credit would need to be a demand credit in the form of a $/kVA credit.

Second, the credit may have to be reduced if the customer takes service under a Curtailable Service Rider (CSR), which would already provide a large $/kVA credit for curtailable service.

Third, any such coal mining economic development rate would need to set forth a relatively short time frame during which the credit would apply, with a firm, non-negotiable, sunset provision for the credit. For example, the Companies should not be offering a credit when they are adding generation capacity.

Fourth, the additional load by the coal mine cannot result in the addition of any new facilities by KU or LG&E to serve the load.

Finally, any such coal mining economic development rate, to the extent that it differs from what is provided under the Companies' standard Economic Development Rider (EDR), would obviously have to be approved by the Commission. In its Order in Administrative Case No. 327 dated September 24, 1990, the Commission established guidelines for offering economic development rates. The Companies' EDR fully complies with those guidelines. To the extent a special economic development rate is developed for coal mines, as was implemented by Kentucky Power Company with its special contract tariff, "C.S.-Coal", then the Commission would have to approve the rate schedule or special contract.

E. LIGHTING RATES

Q. Did LFUCG and Louisville/Jefferson Country Metro Government submit testimony regarding the Companies' lighting rates?

A. Yes. Lou Metro & LFUCG witness Bunch recommends that the Commission should replace the light emitting diode (LED) conversion fees with a regulatory asset for purposes of recovering stranded costs associated with customer-requested replacement of high-pressure sodium (HPS) and other traditional fixtures with LEDs. Mr. Bunch also asks the Commission to order the Companies to track capital and operation and maintenance expenses by fixture type. Additionally, Mr. Bunch asks the Commission to order the Companies to adopt unmetered lighting tariff that charge for the same amount of light rather than the energy used by the lights.

Q. Is it necessary or even feasible for the Companies to establish a regulatory asset to track the stranded costs created by customer-requested conversion of HPS lights to LEDs?

A. No. When a customer requests an HPS or other traditional lighting fixture that is in good working order with an LED light, Mr. Bunch recognizes that a stranded investment is created. When a customer requests that a fully functional HPS light is removed and replaced with an LED light, then the fully functional HPS fixture must be discarded and an LED fixture installed in its place. In the absence of the LED conversion fee, the plant costs of the discarded HPS fixture, which do not simply disappear, would be recovered from other customers. To prevent shifting such stranded costs to other customers, the Companies implemented an LED conversion fee to recover the stranded costs from the customer requesting an existing light to be replaced by an LED fixture. This is clearly an equitable approach.

Mr. Bunch proposes instead that the Companies establish a cumbersome regulatory asset approach to capture the costs of the individual lights being replaced. The problem with Mr. Bunch's proposal is that while the purpose of the regulatory asset would be to track stranded costs, such an approach cannot be any more accurate than the conversion fee currently in place. Whether a conversion fee or a regulatory asset is utilized, the Companies have no way of knowing what the actual costs were of the lighting fixtures being replaced. Even if a regulatory asset were used, the Companies do not have accounting information for the individual lights being replaced. A regulatory asset is no more accurate, but significantly more burdensome, than the conversion fee currently in place. A regulatory asset approach would simply lift the cost off of the current customer desiring the replacement of a working fixture with an LED and defer recovery of the stranded costs until they can be collected from customers that did not create the stranded cost. Instead of assessing an LED conversion fee to customers requesting the replacement of a fully functional non-LED with a new LED light, Mr. Bunch's approach would socialize the costs by recovering the stranded costs from all customers. Mr. Bunch's approach is not only no more accurate, but it shifts costs away from customers who are creating the stranded costs.

Q. What is your reaction to Mr. Bunch's proposal for the Companies to establish

FERC sub-accounts for each size and type of light?

A. It is unduly burdensome and costly. I have worked with hundreds of electric utilities across the United States. I am unaware of any electric utility that has created individual sub-accounts for each type of fixture offered by the utility. Mr. Bunch is proposing something that is way outside of the norm of utility practices. Mr. Bunch did not name a single utility that has established a FERC sub-account for each size and type of fixture. Such a system would be costly. KU and LG&E offers numerous different lighting fixtures, each of which would require an individual sub-account to be established, and the Companies would have to create detailed procedures track the fixture types in the property records systems. Mr. Bunch's proposal would require major software upgrades to the Companies' plant accounting systems and would add administrative costs to the installation of lights and to operation and maintenance of existing lights. Field employees would have to be retrained to book time based on the light type for which they are performing maintenance. Mr. Bunch clearly has not demonstrated that savings would result from making this costly change to the Companies' accounting systems and operational practices. I do not disagree that the information that Mr. Bunch is looking for would be nice to have. But he has not demonstrated that any the benefits would justify the costs of this endeavor.

Q. What about Mr. Bunch's proposal to adopt an unmetered lighting tariff that charges for the same amount of light produced without regard to the energy used by the individual lights?

A. On page 28 of his Direct Testimony, Mr. Bunch states that the "Commission should order the Companies to adopt unified, unmetered lighting tariffs that charge the same tariff for the same amount of light, *regardless of* the light source, *cost basis, or energy used*, but continuing to differentiate by installation and wiring type." (Emphasis supplied.) I am unaware of any service offered by the Companies that disregards the *cost basis* or *amount of energy used* by the customer. The cost of the energy associated with the unmetered lights offered by the Companies reflect the actual energy costs used by the lights. Some customers pay more for lighting fixtures that offer higher end aesthetics compared with other fixtures. While I understand the importance Mr. Bunch places on the amount of light produced by streetlighting equipment, the Companies should not and cannot simply ignore the amount of energy used by the lights or the lights' cost, as Mr. Bunch seems to be proposing.

VI. GAS COST OF SERVICE STUDY

Q. Do any of the intervenor witnesses address LG&E's gas cost of service study?

A. Yes, the gas cost of service study is addressed by DOD-FEA witness Gorman and AG witness Watkins. Mr. Gorman indicates that he reviewed the gas cost of service study and found it to be reasonable. Mr. Gorman states:

> Q. DO YOU BELIEVE MR. SEELYE'S GAS COSS WAS CONSTRUCTED REASONABLY?
>
> A. Yes. I believe his allocation of transmission costs on the basis of design day demand is appropriate and reasonable. Further, his separation of distribution costs into functional areas of both demand and customer also reasonable reflects the cost causation

> of these facilities. [87]

Mr. Watkins, on the other hand, proposes an alternative methodology for allocating the cost of distribution mains. Specifically, Mr. Watkins uses the "Peak and Average" methodology for allocating distribution mains in the cost of service study. He also presents the results of an alternative cost of service study that allocates distribution mains 100% on the basis of demand. However, Mr. Watkins states that the Peak and Average study is his preferred approach.

Q. Do you agree with his Peak and Average approach?

A. No. In its gas cost of service study, LG&E classified distribution mains as either customer- or demand-related using the zero intercept methodology. Costs classified as customer-related are then allocated to the customer classes based on the number of customers for each customer class, and costs classified as demand-related are then allocated on the basis of maximum class demands. This is the same methodology used to classify overhead and underground conductor in the electric cost of service study. It is important to note that Mr. Watkins also used the zero intercept analysis to classify overhead and underground conductor in the cost of service study that he performed for LG&E's electric operations. For a gas utility, mains serve exactly the same function as overhead conductor and underground conductor for an electric utility – they both transport the product (electric energy or natural gas) to the customer. Mains and conductors are also similar in another key respect – the capacity to transport the

[87] Direct Testimony of Michael P. Gorman, at p. 56.

product varies in direct proportion to the size (cross-sectional area) of the main or the conductor. It is for this reason that the zero intercept methodology has been used for over 30 years to classify mains on the gas side of LG&E's business and to classify overhead and underground conductor on the electric side of the business. If it is appropriate to use a zero intercept analysis for classifying electric distribution lines, then it must also be appropriate to use a zero intercept analysis for classifying gas distribution mains. Therefore, Mr. Watkins' gas cost of service study is fundamentally at odds with his electric cost of service study. Because Mr. Watkins' gas cost of service study is entirely inconsistent with his electric cost of service study, Mr. Watkins appears to be recommending the Peak and Average methodology merely because it would support assigning a larger portion of the revenue increase to LG&E's non-residential customers. This is not a valid reason for recommending a flawed cost of service methodology.

Q. Has the zero intercept methodology traditionally been used by LG&E to classify distribution mains?

A. Yes. The zero intercept methodology has been used by LG&E for at least 35 years.

Q. Has the Commission found the zero intercept methodology to be reasonable in gas cost of service studies?

A. Yes. The Commission has found the zero intercept methodology to be reasonable in numerous rate cases, including LG&E's last rate case for which a settlement agreement was not reached by the parties – Case No. 2000-080, Order dated September 27, 2000. In addition, NARUC's *Gas Distribution Rate Design Manual*, June 1989, identifies the zero intercept approach as a standard methodology for classifying gas distribution costs.[88]

Q. Besides being inconsistent with the methodology that Mr. Watkins uses to allocate conductor in his electric cost of service study and being inconsistent with a methodology that the Commission has found to be reasonable in numerous rate case orders, what objection do you have with using the Peak and Average Method for allocating gas distribution mains?

A. The Peak and Average Method allocates a portion of mains on the basis of demand and a portion on the basis of Mcf sales, and none on the basis of customers. While customers' maximum demand and the number of customers a utility serves has a direct impact on a utility's distribution costs, including the cost of mains, the annual quantity of gas sold by a utility has no effect whatsoever on cost of mains. From a distribution planning perspective, the installation of distribution mains is unaffected by amount of gas sold on an annual basis to its customers. A gas utility installs pipe to reach its customers and to meet the peak load conditions of those customers. As long as the maximum demand requirements do not change, increases or decreases in annual throughput volumes do not have any impact on a utility's distribution costs, particularly the cost of mains. Because annual Mcf sales (or throughput volumes) do not have any effect on LG&E's investment in distribution mains, annual Mcf sales

[88] Although NARUC's *Gas Distribution Rate Design Manual* also mentions the Peak and Average Methodology, the manual indicates on pp. 27-28 that it is a "compromise" methodology adopted because it "tempers the apportionment of costs between high and low load factor customers."

should not be used to allocate the cost of distribution mains. In its Order in Case No. 2000-080, the Commission specifically rejected a cost of service study that allocated a portion of mains on the basis of Mcf sales. Even though it has been recommended on numerous occasions, the Commission has never approved a cost of service study for LG&E that allocated the cost of distribution mains on the basis of Mcf sales.

VII. DISTRIBUTION OF GAS REVENUE INCREASE

Q. Do any of the intervenor witnesses address the distribution of the gas revenue increase for LG&E?

A. Yes, both DOD-FEA witness Gorman and AG witness Watkins address the issue. Mr. Gorman states that "Mr. Seelye's proposed revenue spread and gas COSS are reasonably constructed and his proposal for a gradual movement to cost of service is appropriate."[89] Mr. Watkins proposes an alternative distribution of the gas revenue increase. Specifically, he objects to the large revenue increases for Rates AAGS and FT. Ignoring the results of his own cost of service study, he also proposes the same percentage increase to Rate CGS and IGS (which have lower rates of return than RGS in his own Peak and Average cost of service study) as Rate RGS (which has a higher rate of return).

Q. Do agree with Mr. Watkins' spread of the revenue increase?

[89] *Op. cit.*, at p. 56.

A. No. Mr. Watkins' proposed distribution of the revenue increase is based on his flawed cost of service study. Furthermore, even under his own cost of service studies, the rates of return for AAGS and FT are negative. In fact, both his Peak and Average and his 100% Demand cost of service studies indicate class rates of return for AAGS and FT that are lower (i.e., more negative) than the Company's cost of service study. The following table (TABLE 15) compares the rates for return for AAGS and FT under LG&E's cost of service study to Mr. Watkins' two studies:

TABLE 15

	LG&E COS	AG P&A	AG 100% Demand
AAGS	-3.24%	-5.72%	-5.32%
FT	-1.75%	-3.70%	-2.80%

As seen from the above table, Mr. Watkins' cost of service studies show lower (i.e., more negative) rates of return for AAGS and FT than LG&E's cost of service study, but he allocates a smaller increase to these rate classes than proposed by LG&E.

Q. Did LG&E apply the principle of gradualism in developing the proposed increases for these rate classes?

A. Yes. LG&E is proposing only to eliminate 25% of the rate subsidies for FT and AAGS. LG&E's proposal thus gives appropriate recognition to the principle of gradualism.

Q. What is your recommendation regarding the distribution of the gas revenue

increase?

A. It is my recommendation that LG&E's proposed distribution of the revenue increase, which was supported by DOD-FEAE, should be used rather than Mr. Watkins' approach.

VIII. GAS RATE DESIGN

Q. Do any of the intervenors address LG&E's proposed gas rate design?

A. Yes. AG witness Watkins opposes any increase to the Basic Service Charge for Rate RS. LG&E is proposing to increase the Basic Service Charge for RS from $0.65 per day to $0.78 per day. LG&E's cost of service study indicates that customer-related costs are $0.98 per day. Mr. Watkins proposes to keep the Basic Service Charge at the current level. By performing an analysis that excludes large amount customer-related costs, Mr. Watkins claims that customer related costs are no more than $0.43 per day. Yet, he recommends maintaining the charge at the current level of $0.65. In its Order in Case No. 2018-00295, the Commission accepted the Company's cost of service support for the Basic Service Charge. Mr. Watkins made the same recommendation in LG&E's last rate case. The Commission rejected Mr. Watkins' approach that exclude large portions of customer-related costs from his analysis.

IX. CASH WORKING CAPITAL

Q. What is AG-KIUC witness Kollen's position regarding cash working capital?

A. Mr. Kollen argues that in calculating the rate base non-cash expenses should be excluded from the Working Capital calculation because "the expenses never are paid in cash."[90]

Q. Is Mr. Kollen correct?

A. No. The Commission has rejected the AG's positions for decades. KU and LG&E have only recently begun calculating Cash Working Capital using a lead-lag study, but Kentucky-American Water Company ("Kentucky-American") has been performing lead-lag studies for decades. From what I have been able to determine, the AG has raised the issue of including non-cash items in the determination of Cash Working Capital in each case Kentucky-American rate case since at least the early 1990s. Specifically, the AG made essentially the same recommendation in Kentucky-American Case Nos. 92-452, 95-554, 97-034, 2004-00103, 2012-00520, and 2018-00358.[91] In each case, the Commission denied the AG's proposal to exclude non-cash items and found that Kentucky-American's inclusion of non-cash items in the determination of Cash Working Capital was appropriate. In the Commission's Order in Kentucky-American's most recent rate case (Case No. 2018-00358), the Commission stated:

> We agree with Kentucky-American that the Attorney General has consistently presented, and the Commission has consistently refused to adopt, the arguments raised here regarding the inclusion of non-

[90] Direct Testimony of Lane Kollen at p. 50.

[91] Although it did not address the detailed calculations involved in Kentucky American Water's lead-lag study, in its judgment in 90-CI-01304, the Franklin Circuit Court affirmed the Commission's finding regarding the reliance on Kentucky-American's lead-lag study in Case No. 90-321, stating: "The Commission's determination on this issue is both reasonable and supported by evidence in the record."

> cash items in the calculation of working capital…Therefore, consistent with precedent and based upon the evidence in the record, we find the Attorney General/LFUCG's proposal regarding cash working capital should be denied.[92]

If non-cash items, such as depreciation and deferred taxes, are not included in the Cash Working Capital calculation, then the Companies do not have the opportunity to earn a full return on their investments.

Mr. Kollen states that "there inherently is no cash working capital requirement for the non-cash" expenses such as depreciation and amortization.[93] Mr. Kollen's position was rejected by the Commission in its order in Kentucky-American Case No. 92-452, which stated:

> The depreciation expense represents their recovery of that investment from the customers over the respective plant lives. There is a considerable delay in the recovery of depreciation charges from the customers…The AG/LFUCG are correct that depreciation, amortization, and deferred taxes are noncash items, but noncash items can produce a need for cash working capital. Depreciation expense does not require a cash payment, although cash was expended at the time the property was acquired, and the recorded depreciation is used to offset the investment in property even though it has yet to be received from the customer through rates. The same applies to amortization and deferred taxes.[94]

The Commission rejected the AG's position in each subsequent Kentucky-American

[92] Case No. 2018-00358, *Application of Kentucky-American Water Company for an Adjustment of Rates*, (Ky. PSC June 27, 2019) at pp. 8-9.
[93] Direct Testimony of Lane Kollen, at p. 50.
[94] Case No. 92-452, *Notice of Adjustment of the Rates of Kentucky-American Water Company*, (Ky. PSC November 19, 1993) at pp. 18-19.

rate case.

Mr. Kollen claims that the "correct lag days for the depreciation and amortization expense are infinity days."[95] Mr. Kollen provides no explanation of what he means by this peculiar notion of "infinity days", but he seems to mean that the Companies should wait forever to receive their cash. Regardless, Mr. Kollen made the same odd argument in Kentucky-American Case No. 20018-00358, and the Commission properly ignored it.[96] Mr. Kollen further suggests that if depreciation and amortization expenses are included in the determination of Cash Working Capital, then the depreciation lag days need to be adjusted to 27.92 to reflect the over-counting. But the Commission has made clear there is no double counting.

Q. Does inclusion of plant in rate base account for the lag related to depreciation?

A. No, it does not. Including plant in rate base does not recognize the subsequent lag from the provision of service to customers to the receipt of cash for that service. By including depreciation expenses in the calculation of Cash Working Capital with zero lead days, the lead-lag study properly recognizes the subsequent revenue lag on recovering cash related to investment in plant assets. The investment in an asset is included in rate base as plant in service until depreciation is recorded for the asset. Recording depreciation expense removes the asset ratably from rate base, even though cash has not been received concurrently to pay for the service provided by the asset. The revenue lag for depreciation is necessary to reflect the lag corresponding to the

[95] Op cit., at p. 50.
[96] *Op. cit.*, at p. 8.

difference between (i) when the expenses are recorded and (ii) when the revenue requirements related to those revenue requirements are recovered from customers. As in all Kentucky-American Water proceedings, Mr. Kollen's proposal to exclude lag days for non-cash item should be rejected.

Q. Does this conclude your rebuttal testimony?

A. Yes, it does.

VERIFICATION

STATE OF NORTH CAROLINA)
)
COUNTY OF BUNCOMBE)

The undersigned, **William Steven Seelye**, being duly sworn, deposes and states that he is a Principal of The Prime Group, LLC that he has personal knowledge of the matters set forth in the foregoing testimony and exhibits, and the answers contained therein are true and correct to the best of his information, knowledge and belief.

William Steven Seelye

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 8 day of April 2021.

_________________ (SEAL)
Notary Public

Notary Public ID No. 20130360018

My Commission Expires:

01/30/2023

Susannah L. Haskell
Notary Public
Buncombe County, NC

KENTUCKY UTILITIES COMPANY

Response to Commission Staff's Second Request for Information
Dated January 8, 2021

Case No. 2020-00349

Question No. 108

Responding Witness: William Steven Seelye

Q-108. Refer to the Seelye Testimony, page 47, line 12. Provide the subsidy that KU residential customers are paying to current net metering customers.

A-108. KU's residential customers (non-net metering residential customers) are currently paying two types of subsidies to net metering customers.

(1) With the first type of subsidy, residential and other non-net-metering customers are currently paying subsidies to net metering customers because of the overcompensation provided by the Companies for the energy that net metering customers supply to the grid. If a net metering customer generates more power than the customer uses during the month, the customer is currently compensated at a rate equal to the energy charge in the customer's underlying rate.

If the customer is a residential customer served by KU, the customer is currently compensated at an energy rate of approximately $0.09950 per kWh, including cost trackers. However, this is several times the cost for which KU could otherwise generate the energy itself or purchase the energy from a third party in the wholesale power market. Based on its avoided cost-based rate set forth in the Small Capacity Cogeneration and Small Power Production Qualifying Facilities (Rate SQF), KU could generate or procure the energy at a cost of only $0.02173 per kWh. Therefore, KU is currently overcompensating net metering customers $0.07777 per kWh for the energy that they supply to the grid, which is a cost other customers ultimately bear. For the 12 months ended November 30, 2020, KU residential net metering customers supplied 1,789,151 kWh to the grid at an average credit of $0.09950, and thereby received billing credits of $178,021. But KU could have generated the power for only $38,878 (1,789,151 kWh x $0.02173 per kWh = $38,878). Therefore, KU overcompensated its net metering customers by $139,142 ($178,021 - $38,878 = $139,143).

Although the question does not ask about subsidies received by net metering customers served under Rate GS, the amount is $59,611. The subsidies received by net metering customers in other rate classes are negligible.

Therefore, the total subsidies provided to KU's net metering customers served under Rates RS and GS by overcompensating these customers for the power they put on the grid are $198,754.

With the introduction of NMS-2, this first subsidy will be eliminated for all new net metering customers. While these subsidies are relatively small in relation to KU's total revenue, they would be expected to increase significantly without the introduction of NMS-2. In the past three years, the amount of net metering generation nameplate capacity for Rates RS and GS has more than tripled on the KU system (from 1,677.0 kW in 2017 to 5,135.9 kW as of November 2020). KU is currently experiencing a 45% growth in the amount of net metering capacity on its system. Under KRS 278.466, net metering capacity is capped at 1% of KU's peak load during a calendar year. If this cap is reached on KU's system, then this first subsidy would increase to over $1.5 million annually. If the current rate of growth in distributed generation nameplate capacity on KU's system were to continue to increase at the current rate, the 1% cap would be reached in approximately 6 years. The large increase in the past few years illustrates how quickly costs can be shifted from one group of customers to another without regard to the underlying cost of service and the associated subsidies.

(2) With the second type of subsidy, residential customers are also currently paying subsidies due to the inability of a two-part rate (consisting of only a customer charge and energy charge) to reflect the actual cost of providing service to net metering customers. As explained in Mr. Seelye's direct testimony, net metering customers can reduce the amount of energy they purchase without reducing the maximum demands they place on the system. With a two-part rate consisting of only a customer charge and an energy charge, a net metering customer will pay lower demand costs recovered through the energy charge even though the demand costs incurred to serve a net metering customer are not typically lower than for a non-net-metering customer. This second type of subsidy is addressed on pages 46-64 of Mr. Seelye's direct testimony.

KU estimates that residential net metering customers are currently receiving $46,399 in annual subsidies from this second type of subsidy, which again is a subsidy other customers ultimately pay. (It should be noted that this estimate is based on a limited amount of load data that KU has for residential net metering customers. The load data used to develop these estimates are not based on a statistically valid sample, particularly considering the large variance in the usage patterns for net metering customers.)

Kentucky Utilities

Annual Fixed Demand Related Costs to Service Residential Net Metering Customer	$	907.09
Average kWh of Net Metering Customer		12,023.95
Proposed Infrastructure Charge	$	0.0675
Revenue Received per Net Metering Customer		811.62
Cost Subsidy Receive by Net Metering Customers	$	95.47
Number of Net Metering Customers		486
Annual Subsidy from Lower Residential Net Metering Customer Load Factor	$	46,399

As explained in Mr. Seelye's direct testimony, KU is not proposing to address this second subsidy at this time but plans to continue to study the issue in the future. However, KU expects these subsidies to increase as more customers install solar panels and possibly other distributed generation facilities. If the 1% cap on net generation capacity is reached on KU's system, then this second subsidy would increase to over $400,000 annually. As noted previously, if the current rate of growth in distributed generation nameplate capacity on KU's system were to continue to increase at the current rate, the 1% cap would be reached in approximately 6 years. This again illustrates how quickly costs can be shifted from one group of customers to another without regard to the underlying cost of service and the associated subsidies.

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Commission Staff's Second Request for Information
Dated January 8, 2021

Case No. 2020-00350

Question No. 122

Responding Witness: William Steven Seelye

Q-122. Refer to the Seelye Testimony, page 47, line 12. Provide the subsidy that LG&E residential customers are paying to current net metering customers.

A-122. LG&E's residential customers (non-net metering residential customers) are currently paying two types of subsidies to net metering customers.

(1) With the first type of subsidy, residential and other non-net metering customers are currently paying subsidies to net metering customers because of the overcompensation provided by the Companies for the energy that net metering customers supply to the grid. If a net metering customer generates more power than the customer uses during the month, the customer is currently compensated at a rate equal to the energy charge in the customer's underlying rate.

If the customer is a residential customer served by LG&E, the customer is currently compensated at an energy rate of approximately $0.10482 per kWh, including cost trackers. However, this is several times the cost for which LG&E could otherwise generate the energy itself or purchase the energy from a third party in the wholesale power market. Based on its avoided cost-based rate set forth in the Small Capacity Cogeneration and Small Power Production Qualifying Facilities (Rate SQF), LG&E could generate or procure the energy at a cost of only $0.02173 per kWh. Therefore, LG&E is currently overcompensating net metering customers $0.08309 per kWh for the energy that they supply to the grid, which is a cost other customers ultimately bear. For the 12 months ended November 30, 2020, LG&E residential net metering customers supplied 1,789,238 kWh to the grid at an average credit of $0.10482, and thereby received billing credits of $187,548. But LG&E could have generated the power for only $38,880 (1,789,238 kWh x $0.02173 = $38,880). Therefore, LG&E overcompensated its net metering customers by $148,668 ($187,548 - $38,880 = $148,668).

Although the question does not ask about subsidies received by net metering customer served under Rate GS, the amount is $31,753. The subsidies received by net metering customers in other rate classes are negligible.

Therefore, the total subsidies provided to LG&E's net metering customers served under Rates RS and GS by overcompensating these customers for the power they put on the grid are $180,421.

With the introduction of NMS-2, this first subsidy will be eliminated for all new net metering customers. While these subsidies are relatively small in relation to LG&E's total revenue, they would be expected to increase significantly without the introduction of NMS-2. In the past three years, the amount of net metering generation nameplate capacity has almost tripled on the LG&E system (from 1,820.8 kW in 2017 to 4,871.9 kW as of November 2020). LG&E is currently experiencing a 39% growth in the amount of net metering capacity on its system. Under KRS 278.466, net metering capacity is capped at 1% of LG&E's peak load during a calendar year. If this cap is reached on LG&E's system, then this first subsidy would increase to over $1.0 million. If the current rate of growth in distributed generation nameplate capacity on LG&E's system were to continue to increase at the current rate, the 1% cap would be reached in approximately 6 years. The large increase in the past few years illustrates how quickly costs can be shifted from one group of customers to another without regard to the underlying cost of service and the associated subsidies.

(2) With the second type of subsidy, residential customers are also currently paying subsidies due to the inability of a two-part rate (consisting of only a customer charge and energy charge) to reflect the actual cost of providing service to net metering customers. As explained in Mr. Seelye's direct testimony, net metering customers reduce the amount of energy that they purchase without typically reducing the maximum demands they place on the system. With a two-part rate consisting of only a customer charge and an energy charge, a net metering customer will pay lower demand costs recovered through the energy charge even though the demand costs incurred to serve a net metering customer are not typically lower than for a non-net metering customer. This second type of subsidy is addressed on pages 46-64 of Mr. Seelye's direct testimony.

LG&E estimates that residential net metering customers are currently receiving $95,175 in annual subsidies from this second type of subsidy, which again is a subsidy other customers ultimately pay. (It should be noted that this estimate is based on a limited amount load data that LG&E has for residential net metering customers. The load data used to develop these estimates are not based on a statistically valid sample, particularly considering the large variance in the usage patterns for net metering customers.)

Louisville Gas and Electric Company

Annual Fixed Demand Related Costs to Service Residential Net Metering Customer	$	776.18
Average kWh of Net Metering Customer		8,461.67
Proposed Infrastructure Charge	$	0.0724
Revenue Received per Net Metering Customer		612.37
Cost Subsidy Receive by Net Metering Customers	$	163.81
Number of Net Metering Customers		581
Annual Subsidy from Lower Residential Net Metering Customer Load Factor	$	95,175

As explained in Mr. Seelye's direct testimony, LG&E is not proposing to address this second subsidy at this time but plans to continue to study the issue in the future. However, LG&E expects these subsidies to increase as more customers install solar panels and possibly other distributed generation facilities. If the 1% cap on net generation capacity is reached on LG&E's system, then this second subsidy would increase to over $500,000 annually. As noted previously, if the current rate of growth in distributed generation nameplate capacity on LG&E's system were to continue to increase at the current rate, the 1% cap would be reached in approximately 6 years. This again illustrates how quickly costs can be shifted from one group of customers to another without regard to the underlying cost of service and the associated subsidies.

KENTUCKY UTILITIES COMPANY

Response to Kentucky Solar Industries Association, Inc.'s Supplemental Requests for Information Dated February 5, 2021

Case No. 2020-00349

Question No. 13

Responding Witness: Robert M. Conroy / William Steven Seelye

Q-13. Please refer to your response in KYSEIA 1-19.

a. Please confirm that NMS-2 relative to NMS-1, holding other variables constant, will result in an increase in the payback period and a decrease in the net present value to a customer that invests in a new net-metered DG facility, assuming the DG facility's electricity exports to the grid are greater than zero. If the response is anything other than an unqualified confirmation, please explain in detail why this would not be the result.

b. Is the Company aware that customers can finance an investment in a DG facility and that financing can make investments in rooftop solar accessible to customers that otherwise would not have been able to afford the full upfront cost of a system?

c. Does the Company agree that, holding other variables constant, a change in the Company's net metering tariff that results in an increase in the payback period and a decrease in the net present value to a customer that invests in a new net-metered DG facility is more likely than not to reduce the number of low- and moderate-income customers that can afford to install a DG facility, including through financing the DG facility?

A-13. Two of the parts of this request concern the "payback period" for net metering customers' generating facilities. That period is irrelevant for ratemaking purposes; it is not addressed in KRS 278.465 or 278.466. What is relevant is how much all customers must pay for the energy net metering customers provide to the Company's system. The Company believes customers should pay only the Company's truly avoided costs for such energy, namely the non-time-differentiated Rider SQF rate.

a. Confirmed. As explained in Mr. Seelye's direct testimony, the purpose of implementing NMS-2 is to prevent overcompensating net metering customers for the energy that they supply to the grid, energy for which all other customers must pay. Eliminating the subsidies that are provided to net metering customers will affect the economics of implementing DG facilities. It is the Company's position that other customers should not be forced to subsidize net metering customers.

b. The Company is aware that customers could possibly finance their investments in DG facilities. The Company has no knowledge of whether relying on financing ultimately makes the facilities more "affordable" to low-income customers, whether relying on financing would otherwise benefit low-income customers in the long run, whether low-income customers could even obtain such financing, or whether a low-income customer who resides in rental property would likely install solar panels in rental housing.

   But it should be observed that, according to the Company's records, none of the Company's customers who participate in the Low-Income Home Energy Assistance Program (LIHEAP) are net metering customers. This suggests that the low-income customers who arguably have the most incentive to engage in net metering (because they tend to have above-average usage) either cannot install distributed generation equipment or do not desire to do so, even under the current Rider NMS. Therefore, continuing to overcompensate net metering customers for the energy they put on the grid burdens customers in the greatest need (as well as all other non-net-metering customers).

c. Holding all other variables constant, the introduction of NMS-2 would affect the payback period or net present value to a customer that is supplying energy to the grid. The Company does not possess information about the effect, if any, of a projected payback period on the ability of a customer to finance a distributed generation facility. But it seems likely that the ability for a customer to finance the cost of a distributed generating facility would depend more on the customer's credit, collateral, and income than on the customer's energy usage or the terms of Rider NMS-2.

   Note that customers of all income levels interested in renewable generation can avoid the financing issue entirely, as well as the difficulty involved with constructing a generating facility at their homes, by subscribing to the Solar Share Program. Customers can currently participate for less than $6 per month with no credit checks and a commitment of only 12 months; all that is required is that the customer have no arrearage at the time of application.

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Kentucky Solar Industries Association, Inc.'s Supplemental Requests for Information Dated February 5, 2021

Case No. 2020-00350

Question No. 13

Responding Witness: Robert M. Conroy / William Steven Seelye

Q-13. Please refer to your response in KYSEIA 1-19.

a. Please confirm that NMS-2 relative to NMS-1, holding other variables constant, will result in an increase in the payback period and a decrease in the net present value to a customer that invests in a new net-metered DG facility, assuming the DG facility's electricity exports to the grid are greater than zero. If the response is anything other than an unqualified confirmation, please explain in detail why this would not be the result.

b. Is the Company aware that customers can finance an investment in a DG facility and that financing can make investments in rooftop solar accessible to customers that otherwise would not have been able to afford the full upfront cost of a system?

c. Does the Company agree that, holding other variables constant, a change in the Company's net metering tariff that results in an increase in the payback period and a decrease in the net present value to a customer that invests in a new net-metered DG facility is more likely than not to reduce the number of low- and moderate-income customers that can afford to install a DG facility, including through financing the DG facility?

A-13. Two of the parts of this request concern the "payback period" for net metering customers' generating facilities. That period is irrelevant for ratemaking purposes; it is not addressed in KRS 278.465 or 278.466. What is relevant is how much all customers must pay for the energy net metering customers provide to the Company's system. The Company believes customers should pay only the Company's truly avoided costs for such energy, namely the non-time-differentiated Rider SQF rate.

a. Confirmed. As explained in Mr. Seelye's direct testimony, the purpose of implementing NMS-2 is to prevent overcompensating net metering customers for the energy that they supply to the grid, energy for which all other customers must pay. Eliminating the subsidies that are provided to net metering customers will affect the economics of implementing DG facilities. It is the Company's position that other customers should not be forced to subsidize net metering customers.

b. The Company is aware that customers could possibly finance their investments in DG facilities. The Company has no knowledge of whether relying on financing ultimately makes the facilities more "affordable" to low-income customers, whether relying on financing would otherwise benefit low-income customers in the long run, whether low-income customers could even obtain such financing, or whether a low-income customer who resides in rental property would likely install solar panels in rental housing.

   But it should be observed that, according to the Company's records, none of the Company's customers who participate in the Low-Income Home Energy Assistance Program (LIHEAP) are net metering customers. This suggests that the low-income customers who arguably have the most incentive to engage in net metering (because they tend to have above-average usage) either cannot install distributed generation equipment or do not desire to do so, even under the current Rider NMS. Therefore, continuing to overcompensate net metering customers for the energy they put on the grid burdens customers in the greatest need (as well as all other non-net-metering customers).

c. Holding all other variables constant, the introduction of NMS-2 would affect the payback period or net present value to a customer that is supplying energy to the grid. The Company does not possess information about the effect, if any, of a projected payback period on the ability of a customer to finance a distributed generation facility. But it seems likely that the ability for a customer to finance the cost of a distributed generating facility would depend more on the customer's credit, collateral, and income than on the customer's energy usage or the terms of Rider NMS-2.

   Note that customers of all income levels interested in renewable generation can avoid the financing issue entirely, as well as the difficulty involved with constructing a generating facility at their homes, by subscribing to the Solar Share Program. Customers can currently participate for less than $6 per month with no credit checks and a commitment of only 12 months; all that is required is that the customer have no arrearage at the time of application.

NET-ENERGY METERING 2.0 LOOKBACK STUDY

Submitted to:
California Public Utilities Commission
Energy Division

With assistance from:
Energy and Environmental Economics
Itron, Inc.

Verdant Associates, LLC
Berkeley, CA
www.verdantassoc.com

January 21, 2021

VERDANT

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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

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.

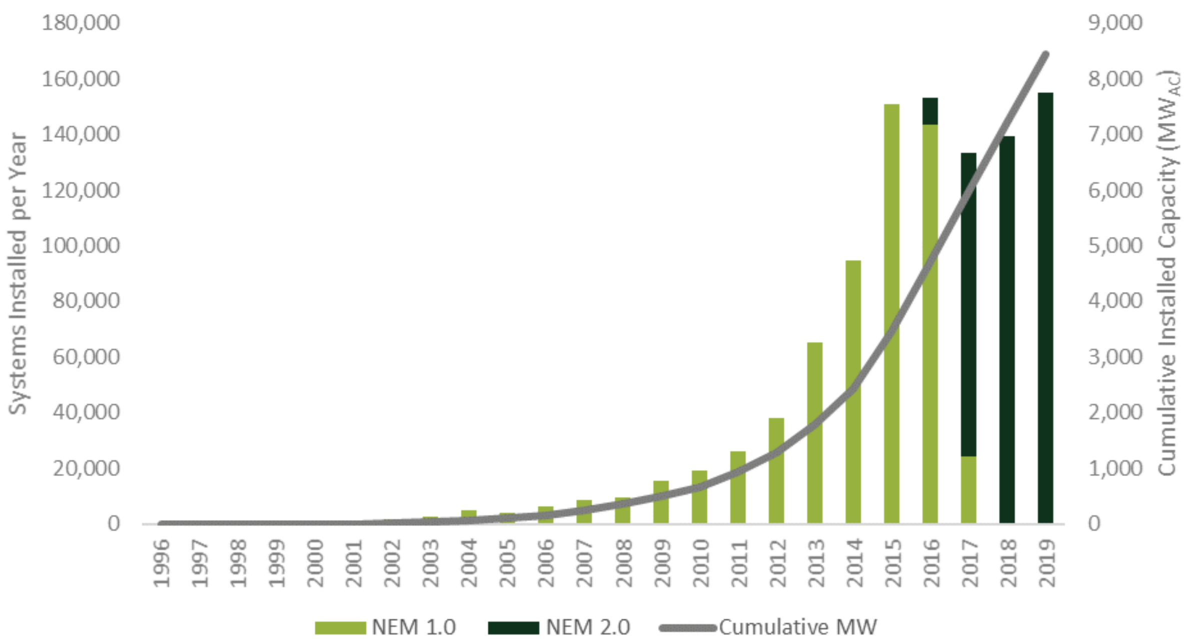
1.3 NEM POPULATION OVERVIEW

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

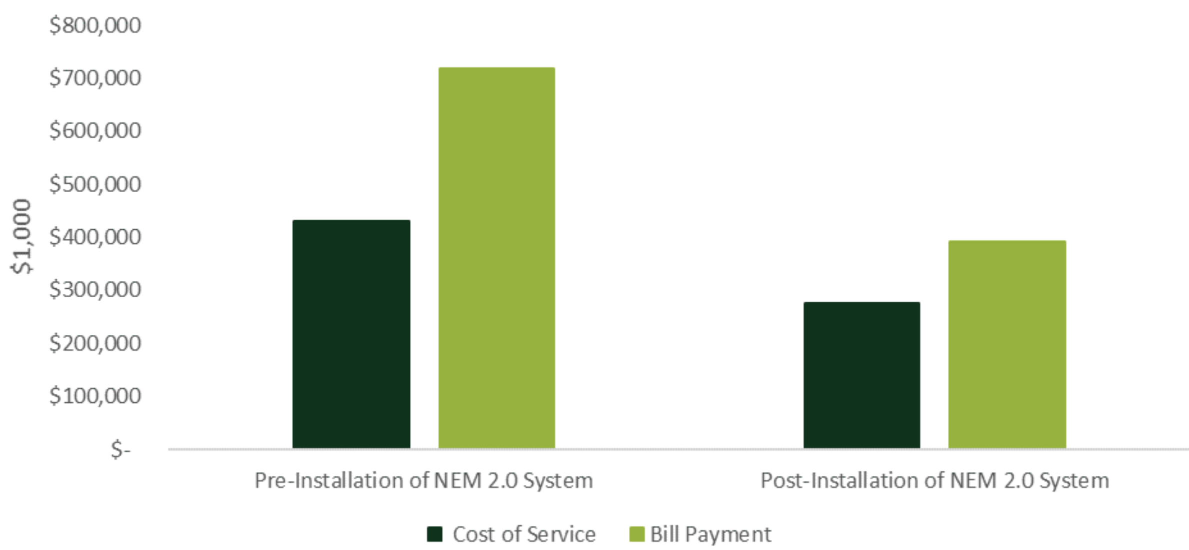
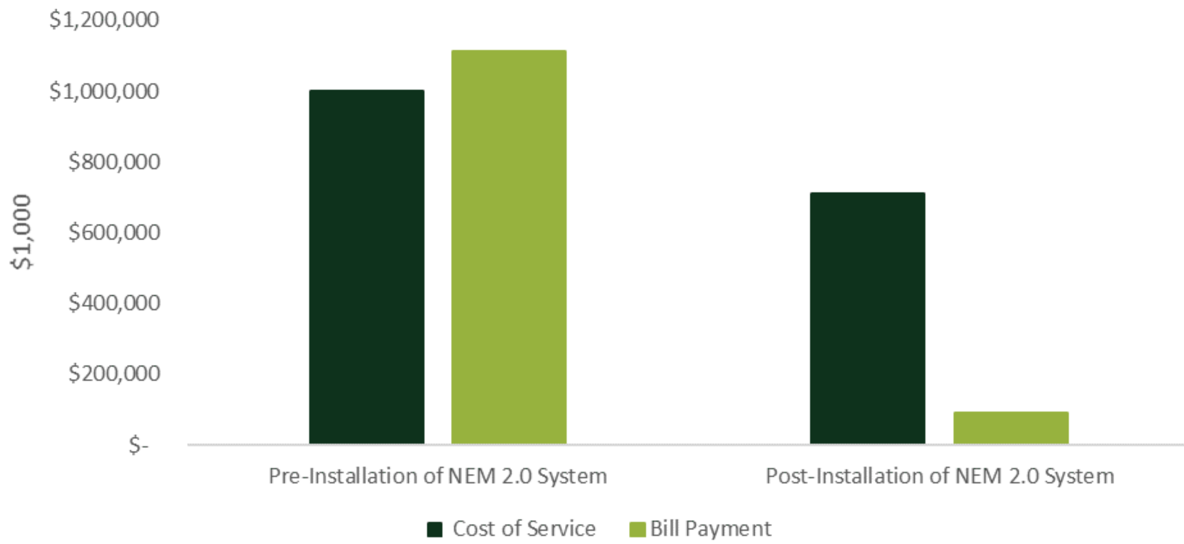


FIGURE 1-3: RESIDENTIAL AGGREGATE FIRST YEAR BILL PAYMENT AND COST OF SERVICE PRE AND POST NEM 2.0



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

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.

[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

[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

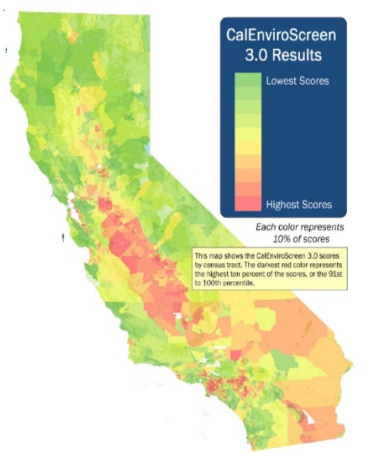
[27] HUD USPS ZIP Code Crosswalk File | HUD USER. https://www.huduser.gov/portal/datasets/usps_crosswalk.html

[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

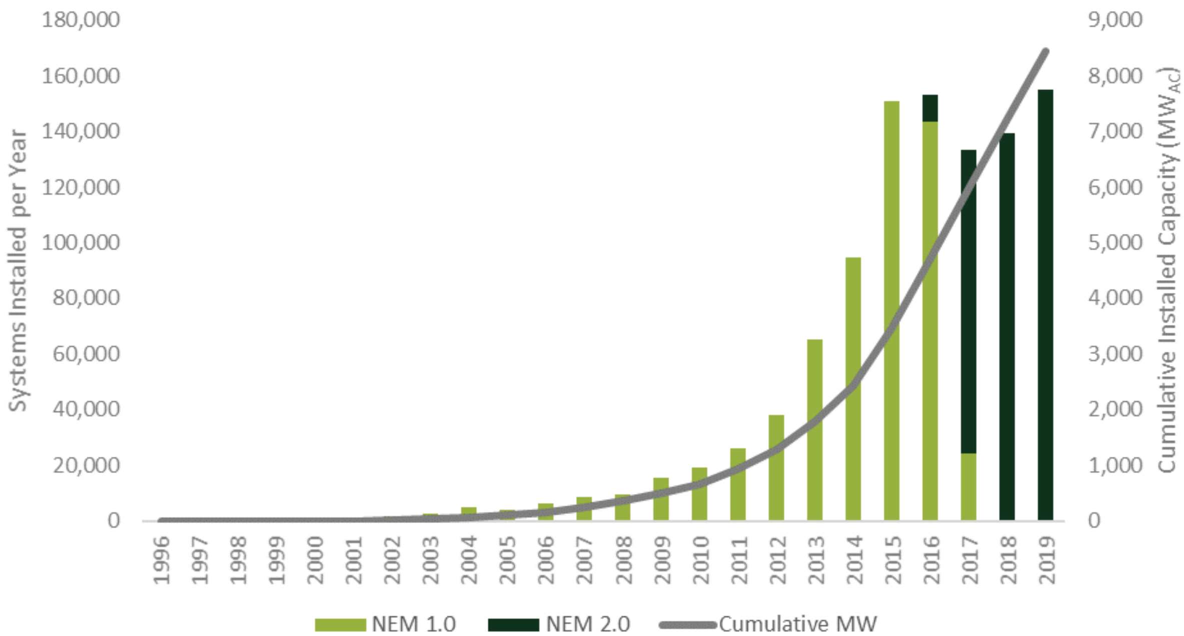
31 SB 535 Disadvantaged Communities | OEHHA. https://oehha.ca.gov/calenviroscreen/sb535

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

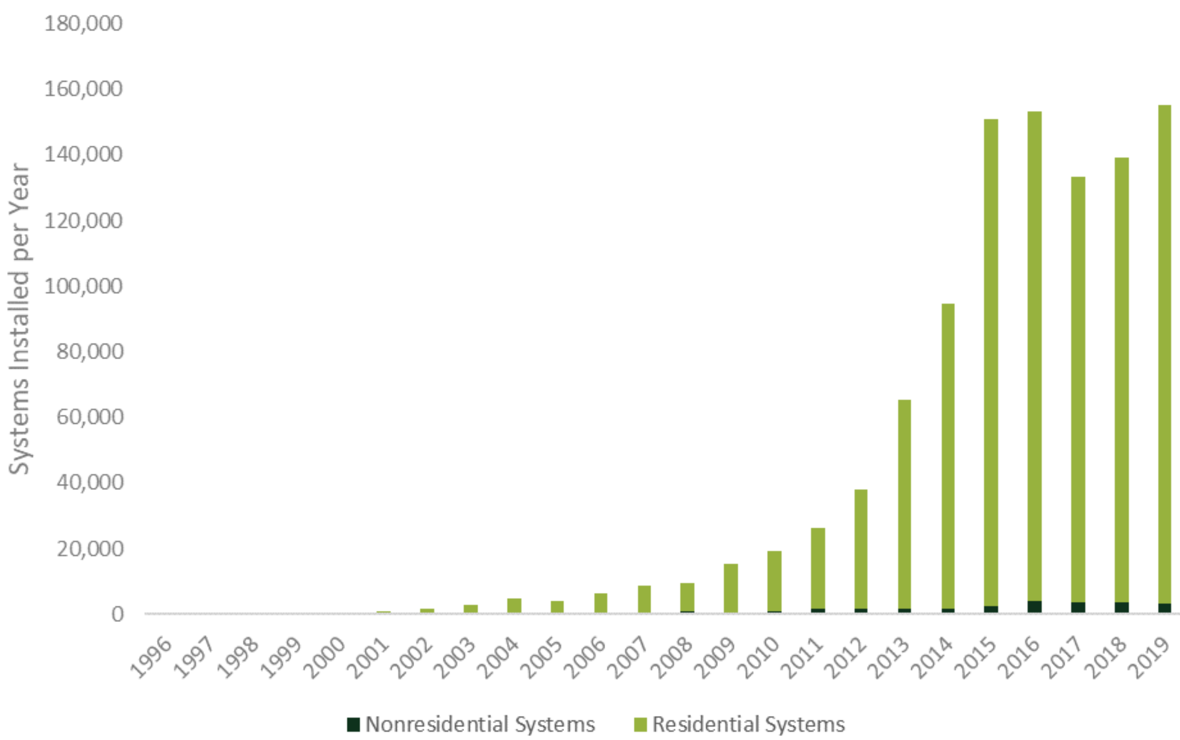


The number of interconnections accelerated in 2007 (coincident with the launch of the California Solar Initiative program) and showed the first year over year decrease in 2017. The growth in the number of systems has been largely driven by residential customer adoption. Figure 3-2 shows annual NEM

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."

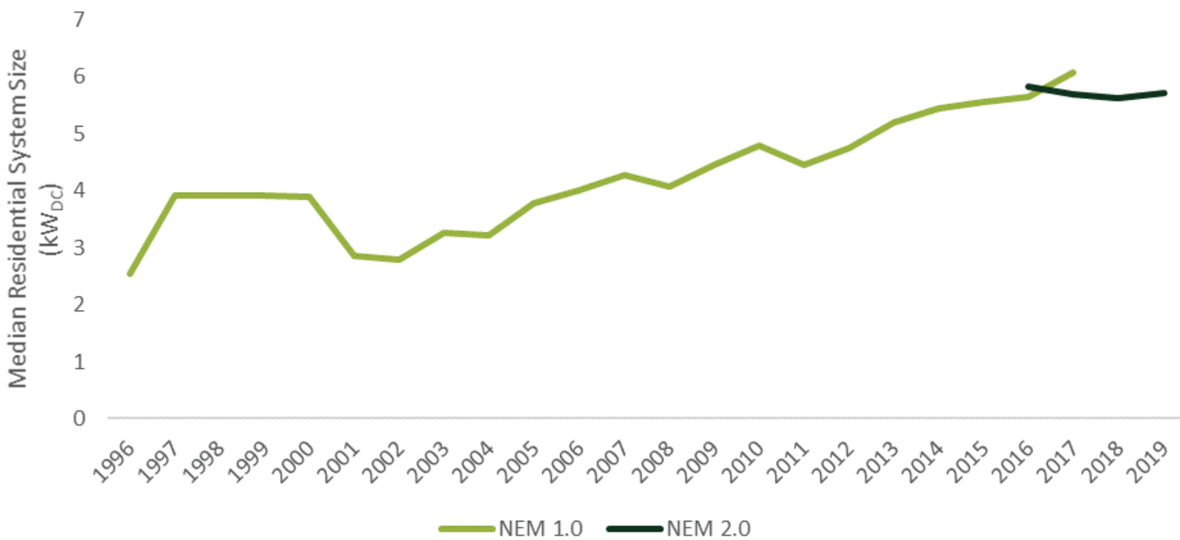
interconnections by sector (residential vs. nonresidential). Year after year, residential projects represent the vast majority of total NEM interconnections. Almost 98 percent of NEM systems interconnected during 2019 were residential. That proportion has remained relatively constant since 2013.

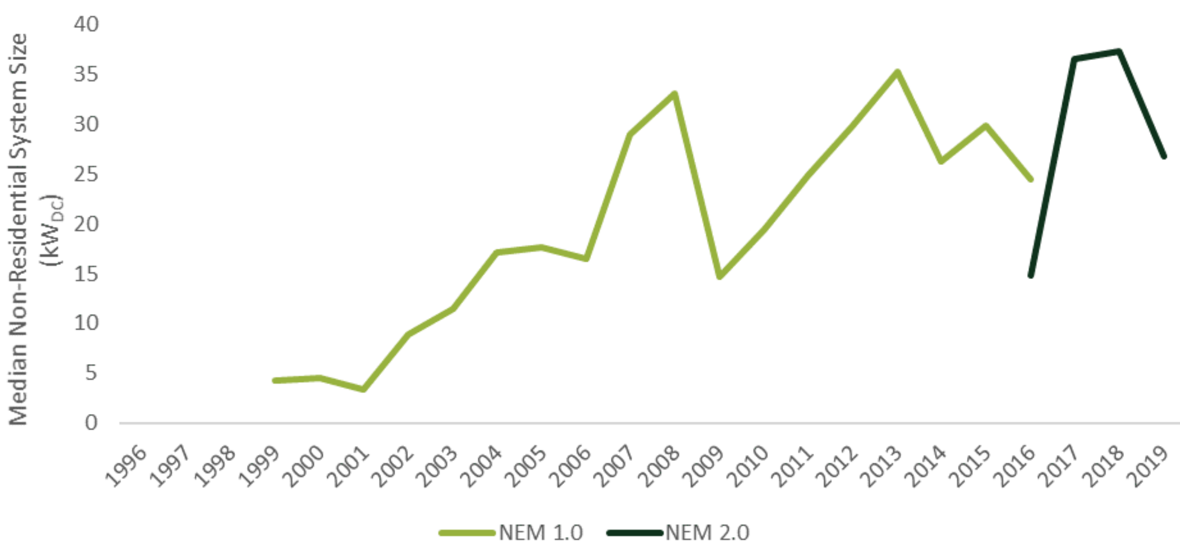
FIGURE 3-2: NUMBER OF NEM SYSTEMS INSTALLED BY SECTOR



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

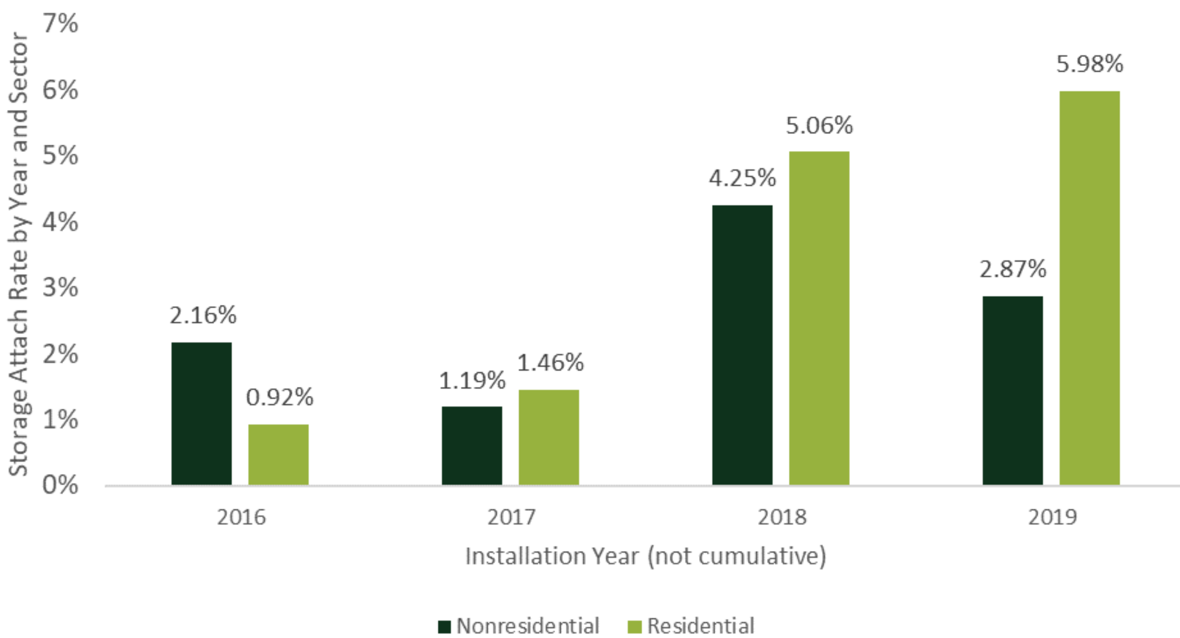
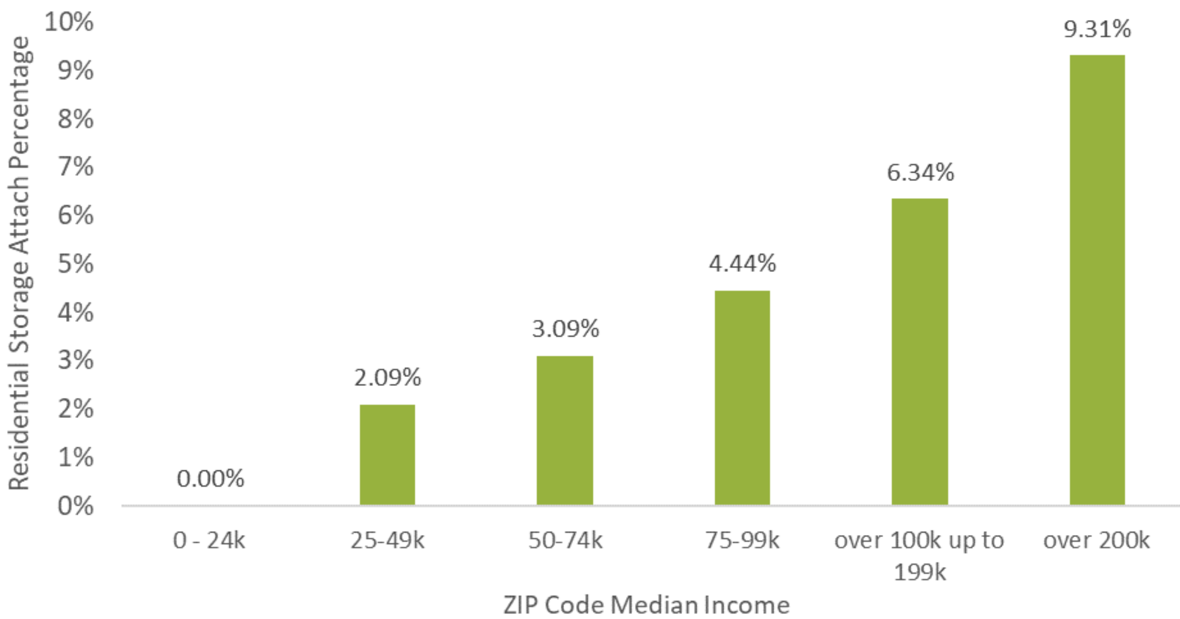


Figure 3-5 shows residential energy storage attachment rates by median customer income. Residential customers at the highest income levels (over $200,000) installed energy storage at higher rates (9.31 percent) relative to those at the lower income brackets.

[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	N/A	416
	Change in consumption after interconnection (kWh)	2,520		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	N/A	9,661
	% Pre-Interconnection Consumption Supplied by PV	115%		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

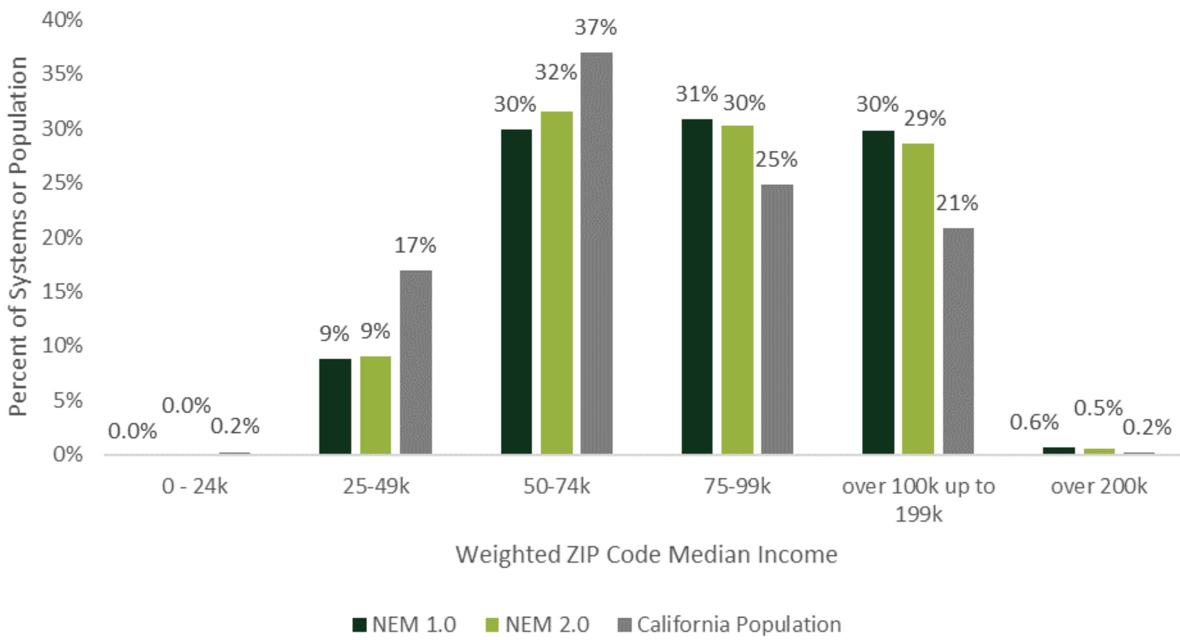
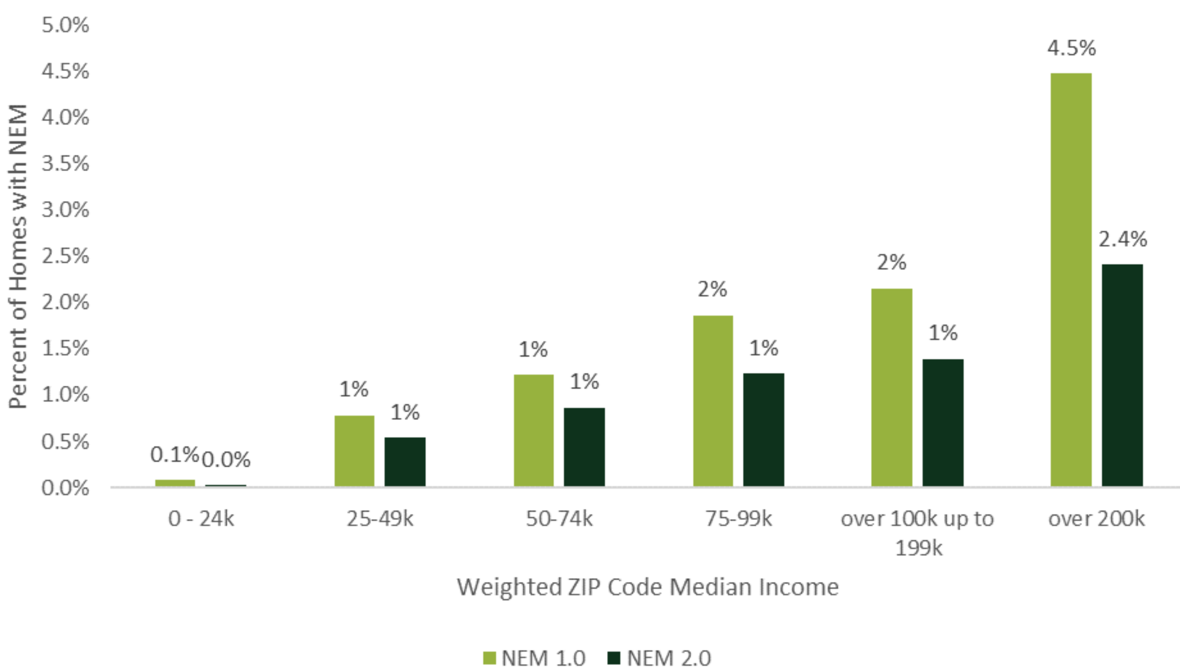


Figure 3-7 presents the percentage of homes with NEM systems by ZIP code median income.

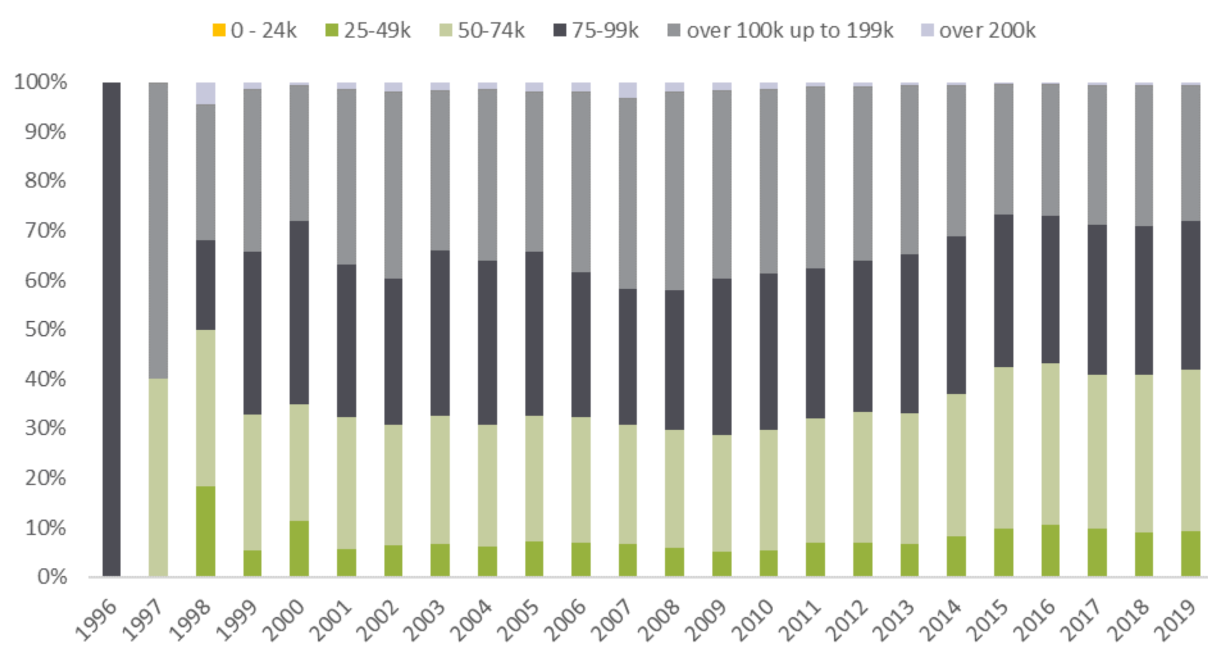
FIGURE 3-7: RESIDENTIAL NEM SYSTEM PERCENTAGES BY ZIP CODE MEDIAN INCOME



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.

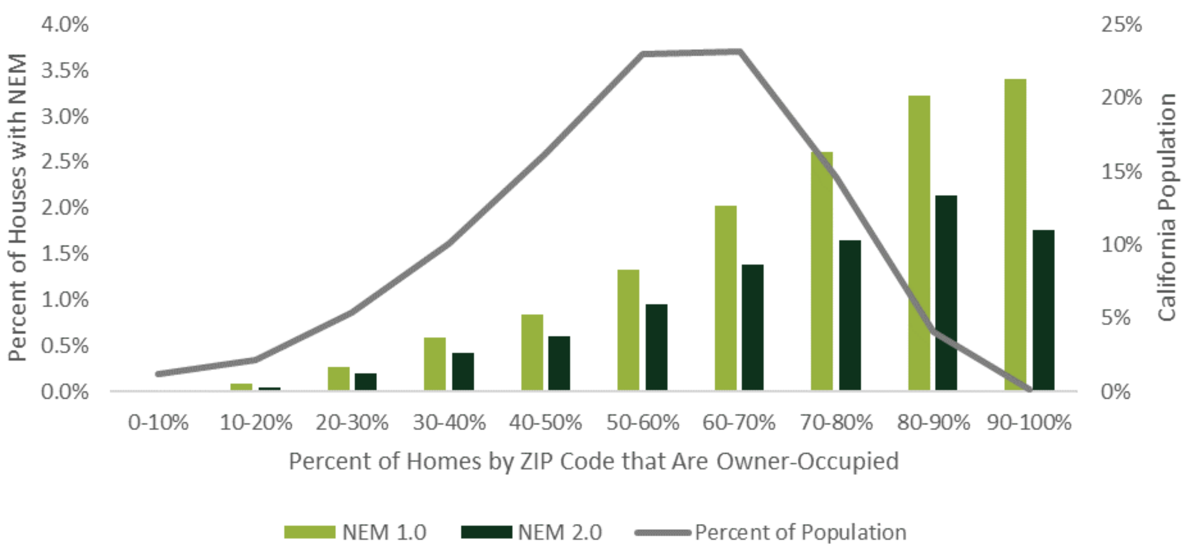
FIGURE 3-8: PERCENT OF SYSTEMS INSTALLED BY MEDIAN INCOME BRACKET BY YEAR



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

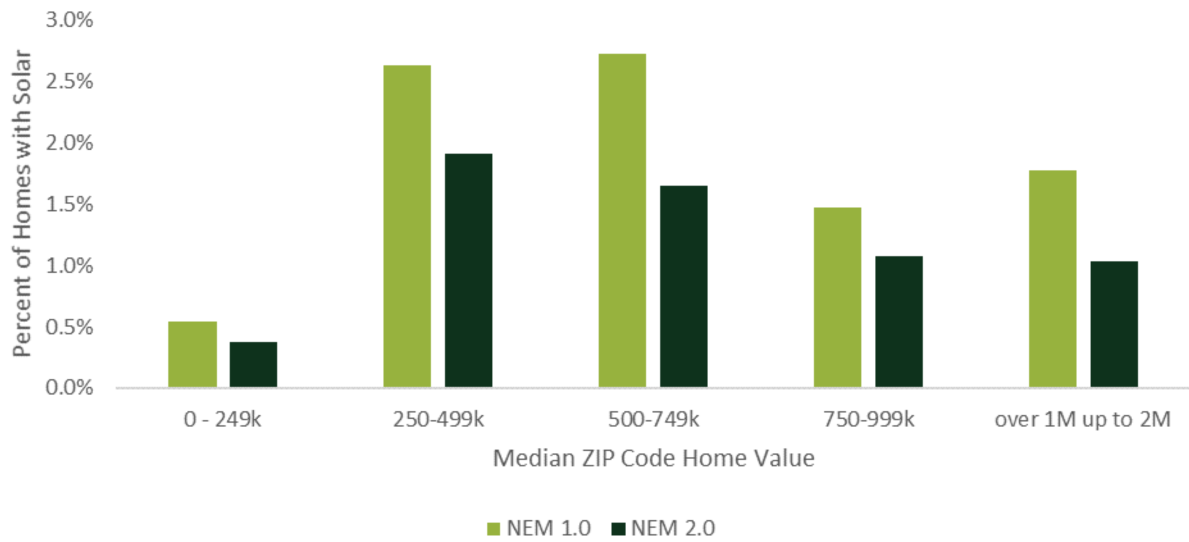
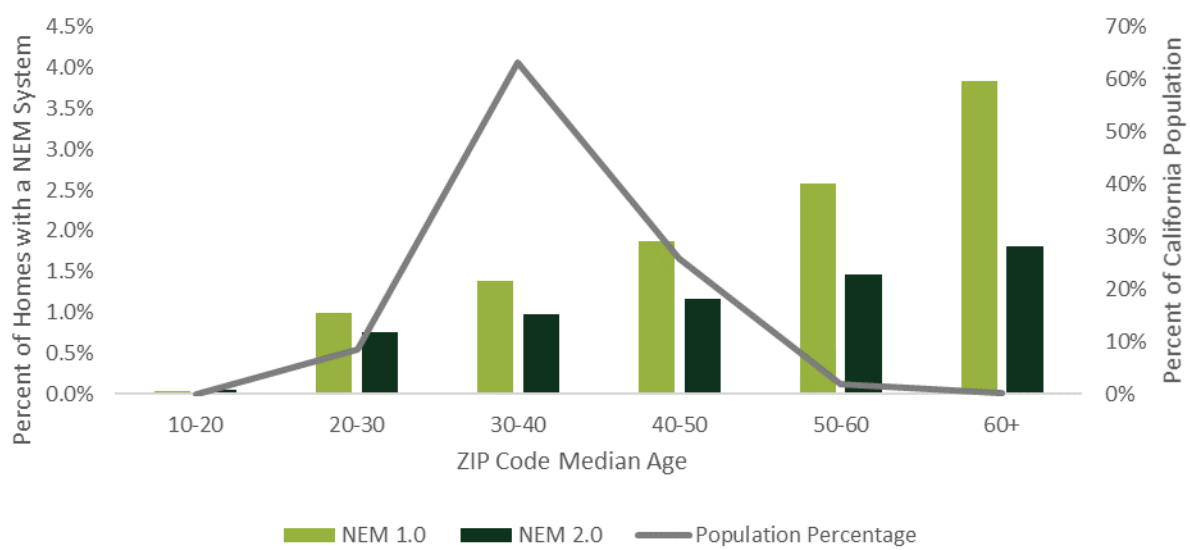


Figure 3-11 below shows the percentage of NEM installations and California's population as a function of median age in the census tract. The percentage of homes with NEM systems installed increases with increasing age, far out of proportion with the percentage of California's population at those higher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

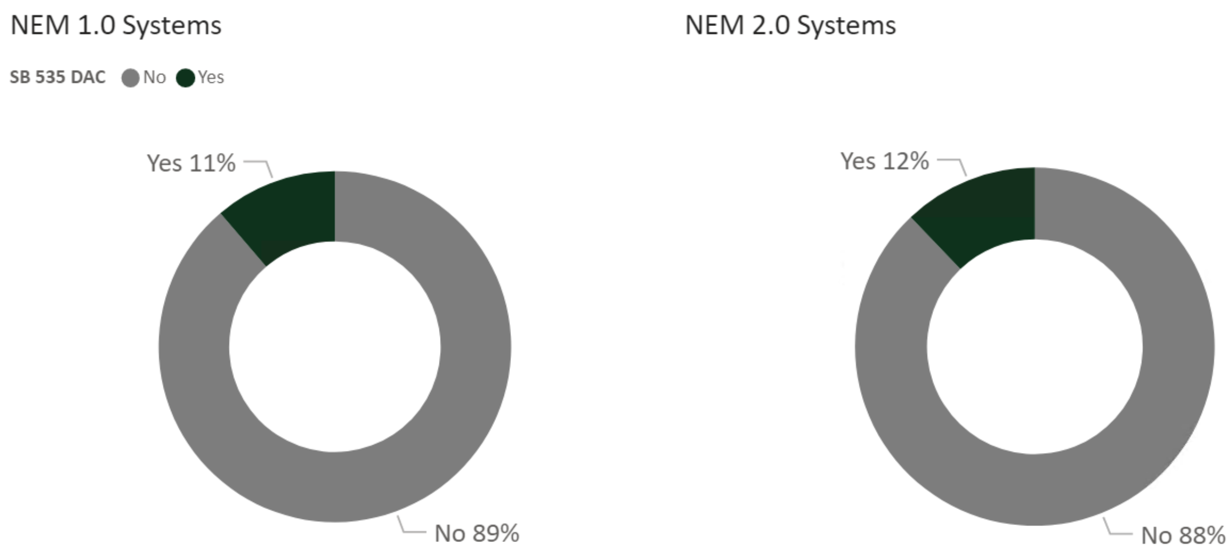
FIGURE 3-11: NEM SYSTEMS AND CALIFORNIA POPULATION BY MEDIAN AGE



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.

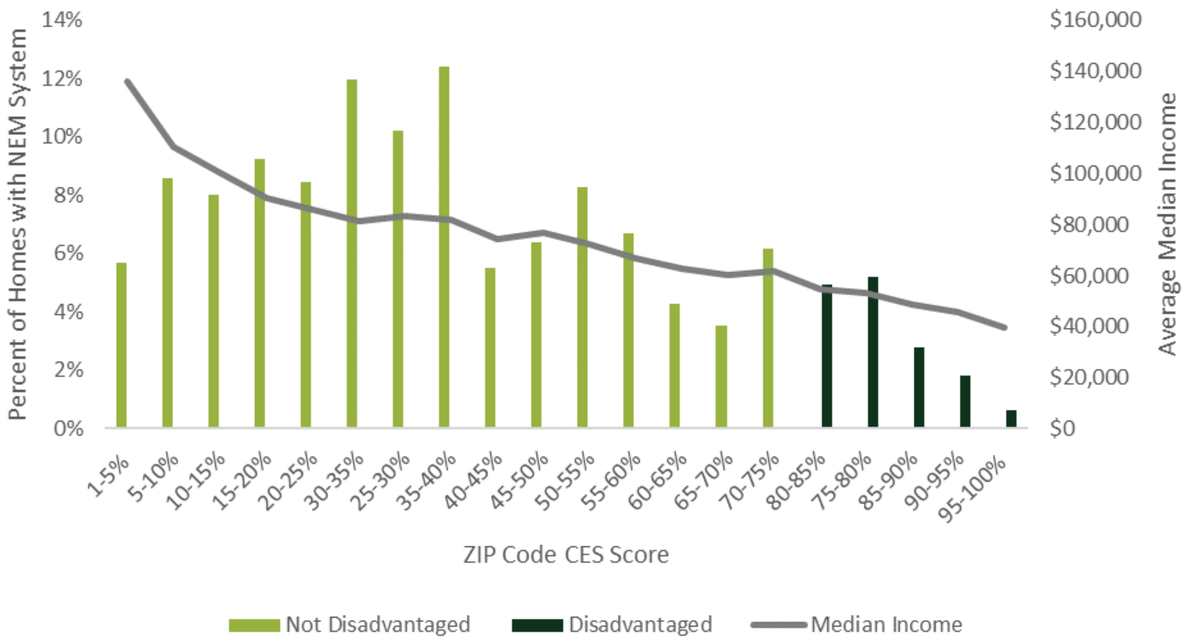
[45] SB 535 Disadvantaged Communities | OEHHA. https://oehha.ca.gov/calenviroscreen/sb535

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

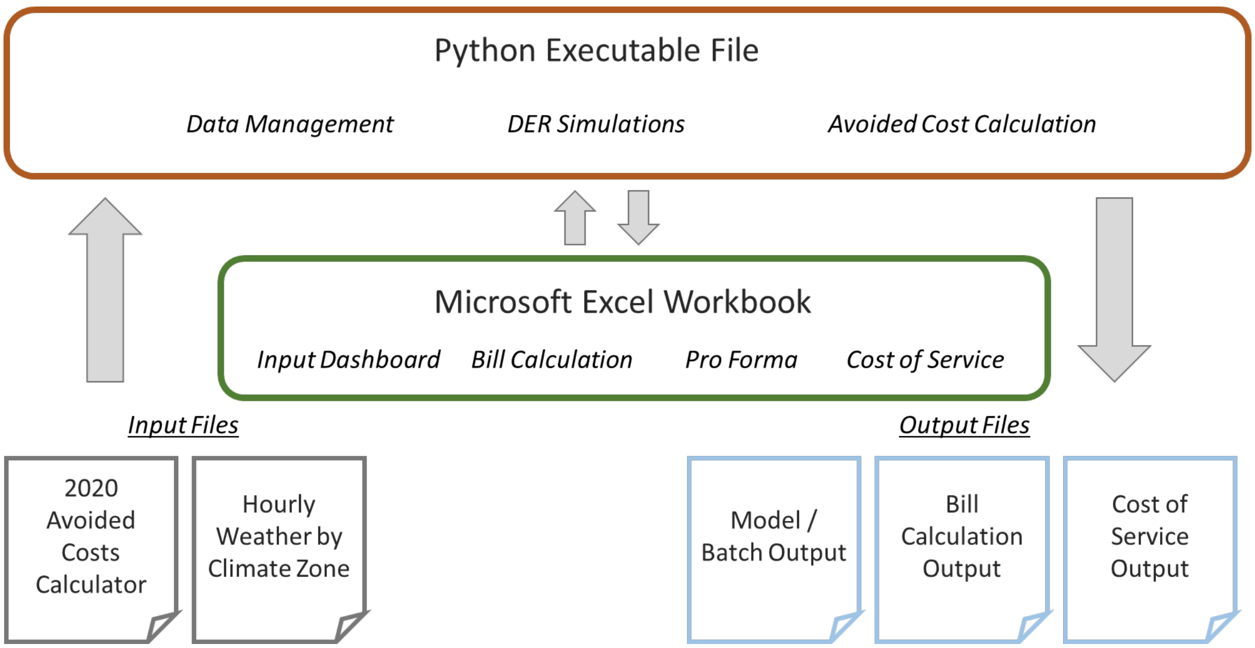
Verdant calculated the cost-effectiveness and cost to serve NEM 2.0 customers using a model built for this study. The model accounts for a customer's consumption, retail rate (including changes to retail rates over time), and distributed energy resource (DER) characteristics when calculating bill savings, 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).

[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

<table>
<tr><th rowspan="2">Component</th><th colspan="2">Participant Cost Test (PCT)</th><th colspan="2">Program Administrator (PA) Test</th><th colspan="2">Total Resource Cost (TRC) Test</th><th colspan="2">Ratepayer Impact Measure (RIM) Test</th></tr>
<tr><th>Benefit</th><th>Cost</th><th>Benefit</th><th>Cost</th><th>Benefit</th><th>Cost</th><th>Benefit</th><th>Cost</th></tr>
<tr><td>Electricity Avoided Costs</td><td></td><td></td><td>X</td><td></td><td>X</td><td></td><td>X</td><td></td></tr>
<tr><td>Electric Bill Savings</td><td>X</td><td></td><td></td><td></td><td></td><td></td><td></td><td>X</td></tr>
<tr><td>State (SGIP) Rebate*</td><td>X</td><td></td><td></td><td></td><td></td><td></td><td></td><td></td></tr>
<tr><td>REC Revenue</td><td>X</td><td></td><td></td><td></td><td>X</td><td></td><td></td><td></td></tr>
<tr><td>Equity Investment</td><td></td><td>X</td><td></td><td></td><td></td><td>X</td><td></td><td></td></tr>
<tr><td>Net Finance Costs</td><td></td><td>X</td><td></td><td></td><td></td><td>X</td><td></td><td></td></tr>
<tr><td>O&M Costs</td><td></td><td>X</td><td></td><td></td><td></td><td>X</td><td></td><td></td></tr>
<tr><td>Partial Equip. Replacement Cost</td><td></td><td>X</td><td></td><td></td><td></td><td>X</td><td></td><td></td></tr>
<tr><td>Insurance Costs</td><td></td><td>X</td><td></td><td></td><td></td><td>X</td><td></td><td></td></tr>
<tr><td>State Tax Refund / Paid**</td><td colspan="2">X</td><td></td><td></td><td></td><td></td><td></td><td></td></tr>
<tr><td>Federal Tax Refund / Paid**</td><td colspan="2">X</td><td></td><td></td><td colspan="2">X</td><td></td><td></td></tr>
</table>

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.

$$Cost = Primary\ Distribution\ Cost + Primary\ New\ Business\ Cost + Secondary\ Distribution\ Cost$$

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

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

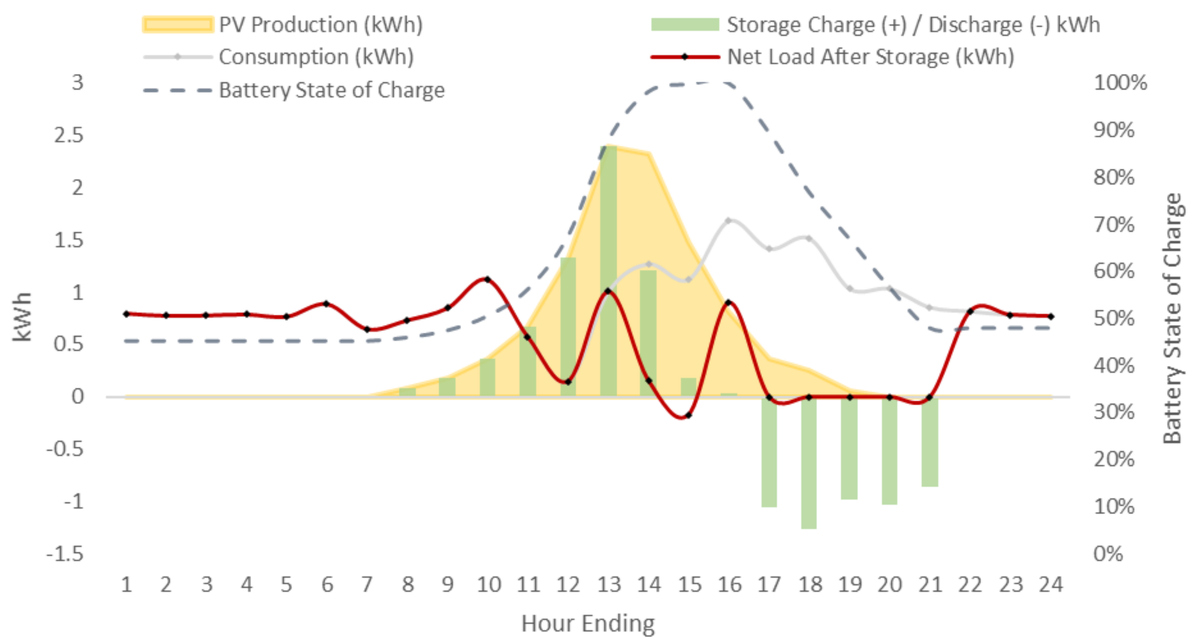
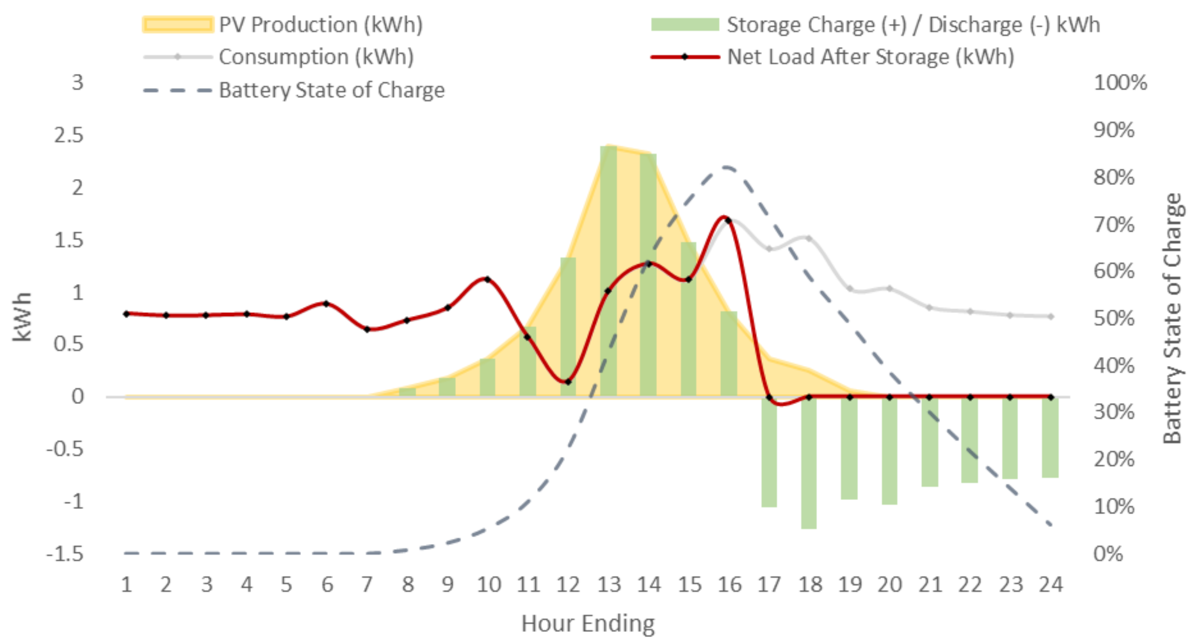


Figure 4-3 on the following page shows the storage dispatch algorithm on the same day in PV Self-Consumption mode. In this example, the energy storage system begins to charge at 8 am as in the previous example. However, the system discharges well beyond hour ending 9 pm (the on-peak period) and continues 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.

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.

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.

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,

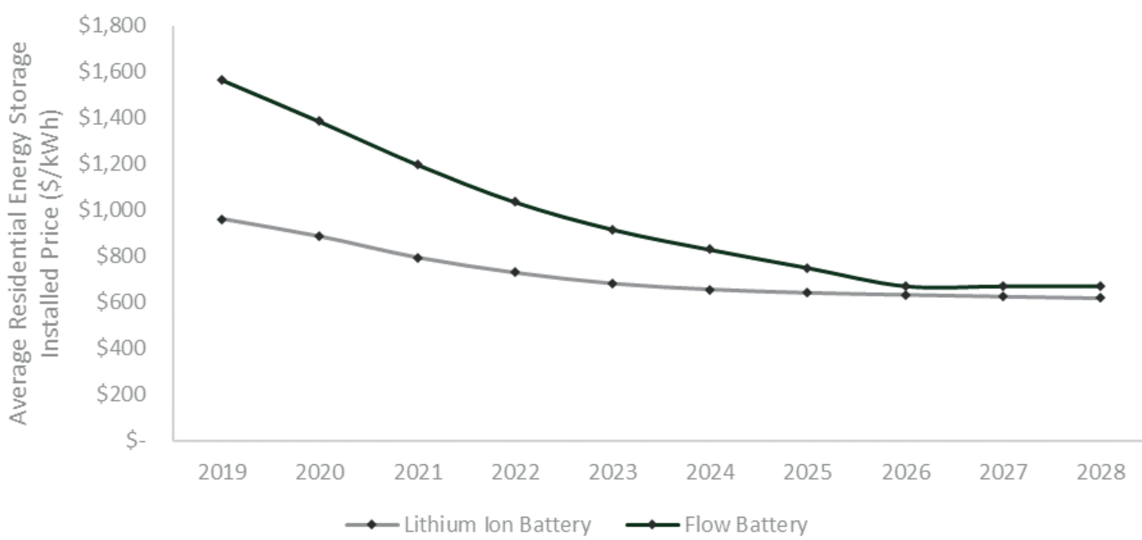
93 Tracking the Sun. Lawrence Berkeley National Lab. October 2019. https://emp.lbl.gov/tracking-the-sun

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)



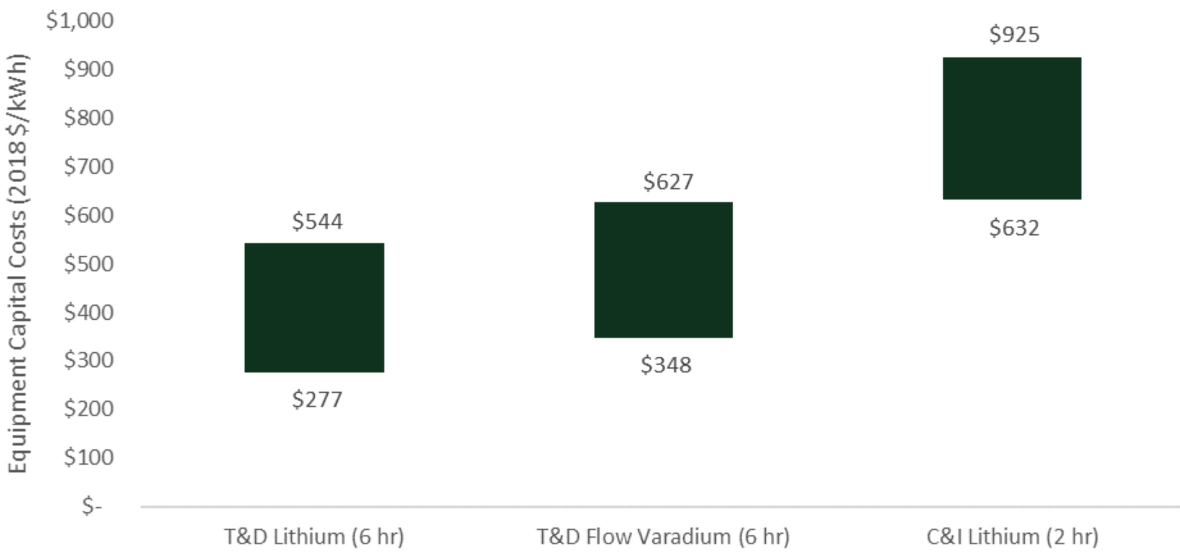
* Adapted from Navigant Research Residential Energy Storage Research Report. Q1 2019.

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

[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 25th and 75th 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

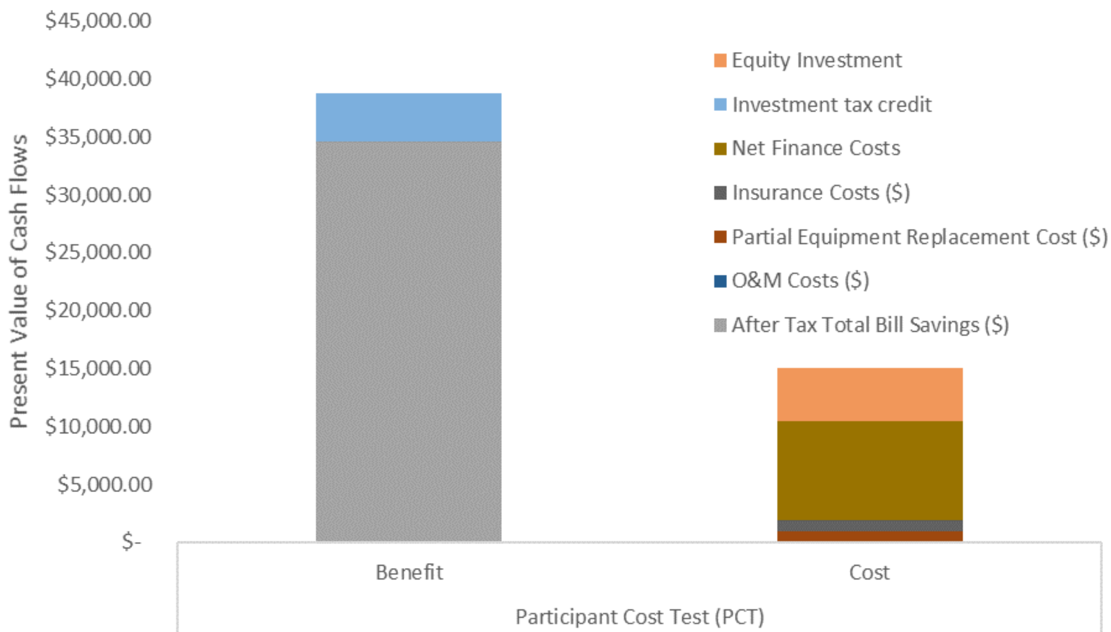
The PCT benefit-cost ratio is higher for solar PV customers relative to those who installed solar PV + storage. This suggests that the incremental bill savings from storage TOU rate arbitrage are less than the incremental costs of installing energy storage. Additional details on the PCT are presented 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.

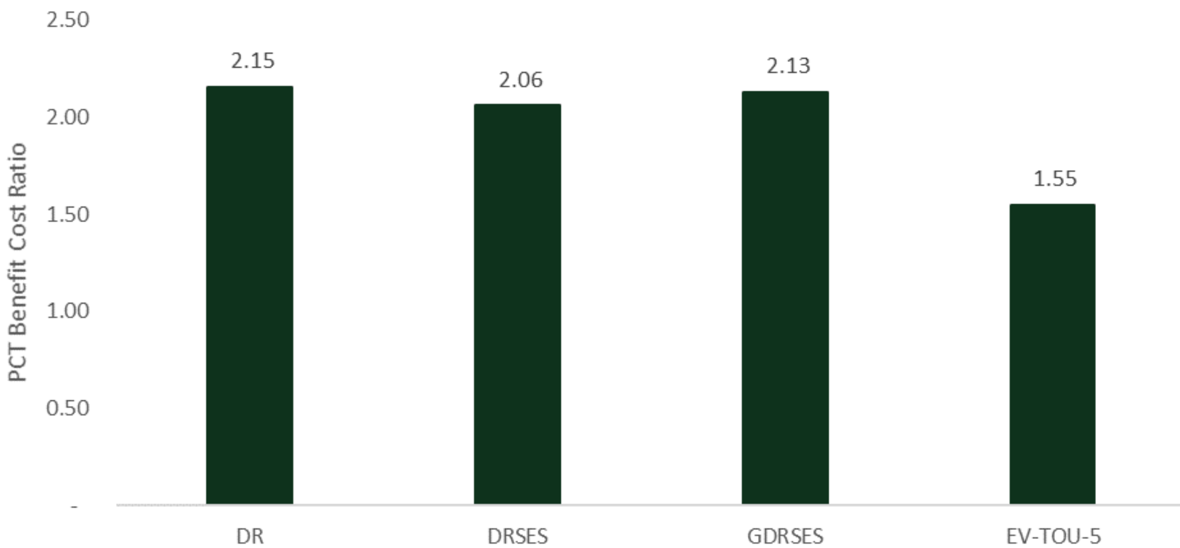
Figure 5-2 presents weighted average results for different SDG&E residential customers on different rates. Note, this is not a scenario analysis because the results are based on customers who were on these rates. In the first case, the customers are on the tiered volumetric domestic rate (DR) prior to 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)

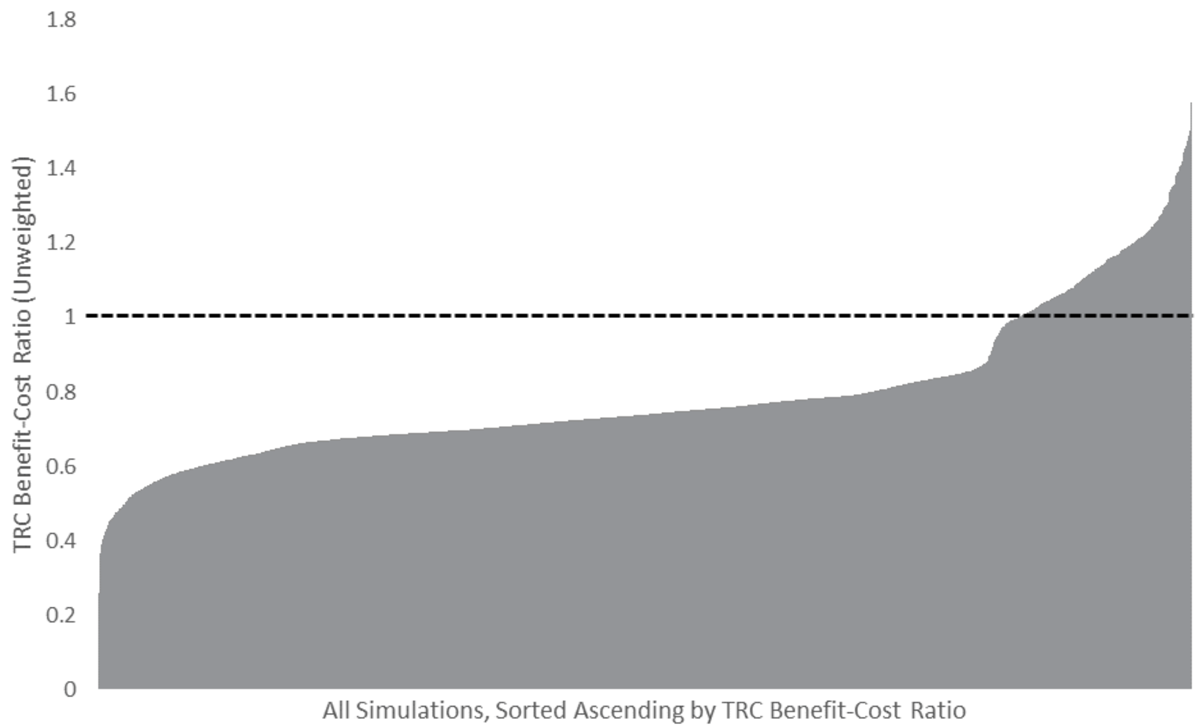
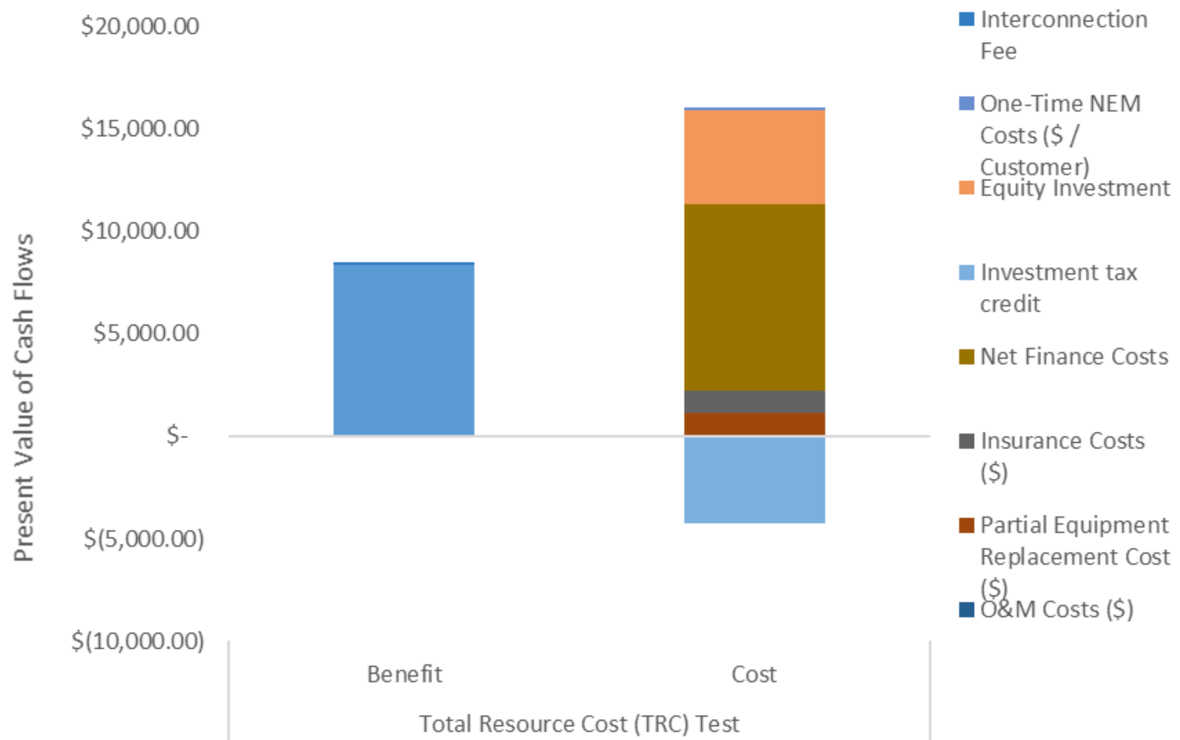


Figure 5-4 on the following page shows an illustrative example of the TRC calculation. The column on the left shows the net present value of benefits, which for a residential customer are the avoided costs. The column on the right shows the total costs, which include the equipment acquisition costs, 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

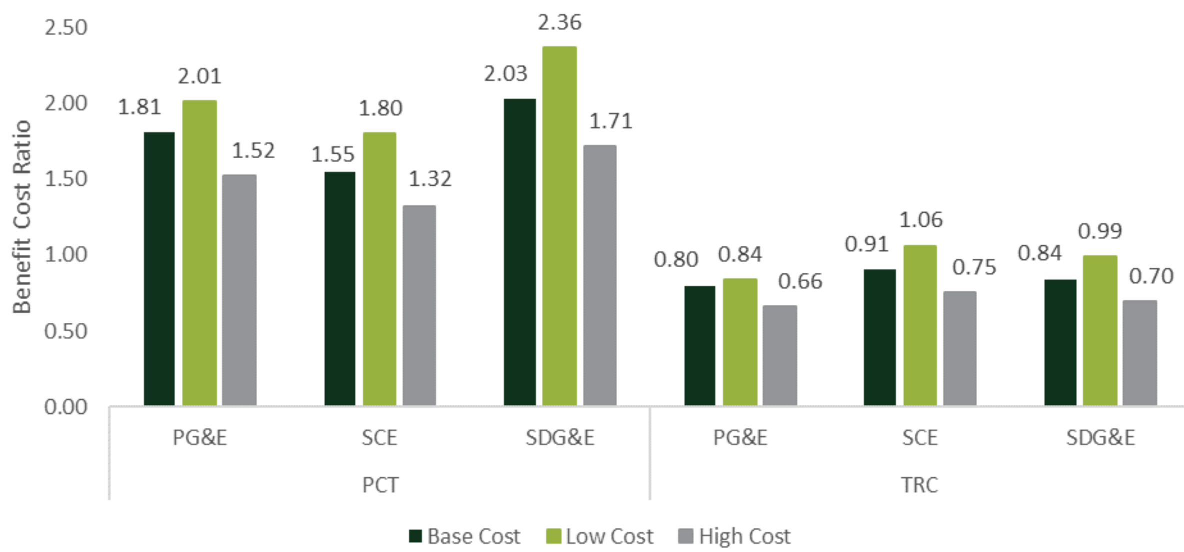
SCE's nonresidential rates are grouped by agriculture (rates with PA in the name), commercial (GS rates) and large commercial/industrial (TOU-8 rates). SCE's rates also include Option D and Option E. The Option D rates tend to have higher demand charges and lower energy rates while the Option E rates 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.

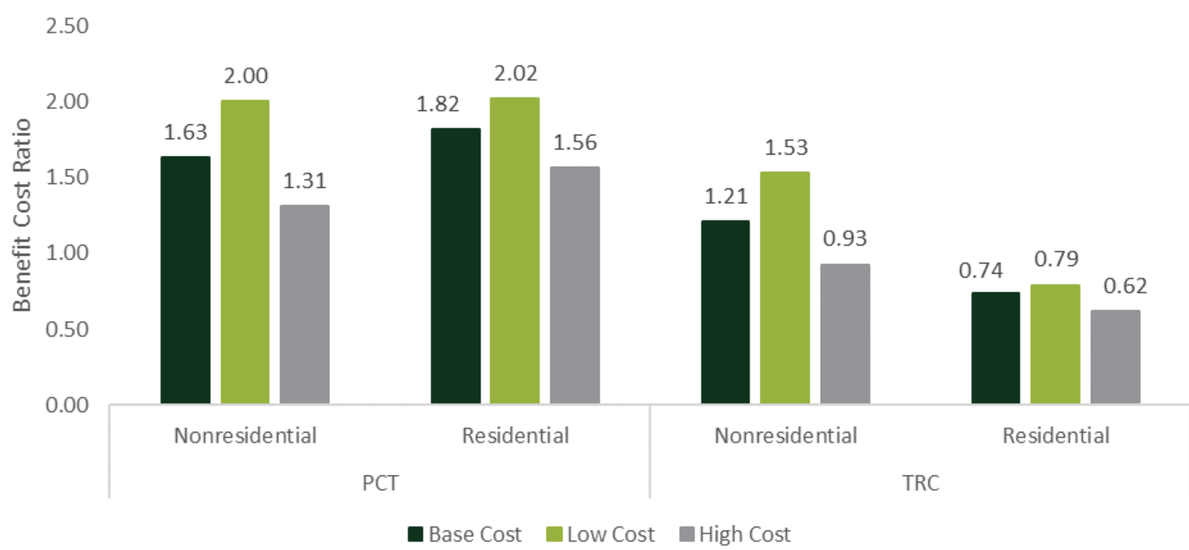
FIGURE 5-5: SENSITIVITY TO PV SYSTEM COST, COST-EFFECTIVENESS BY IOU



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.

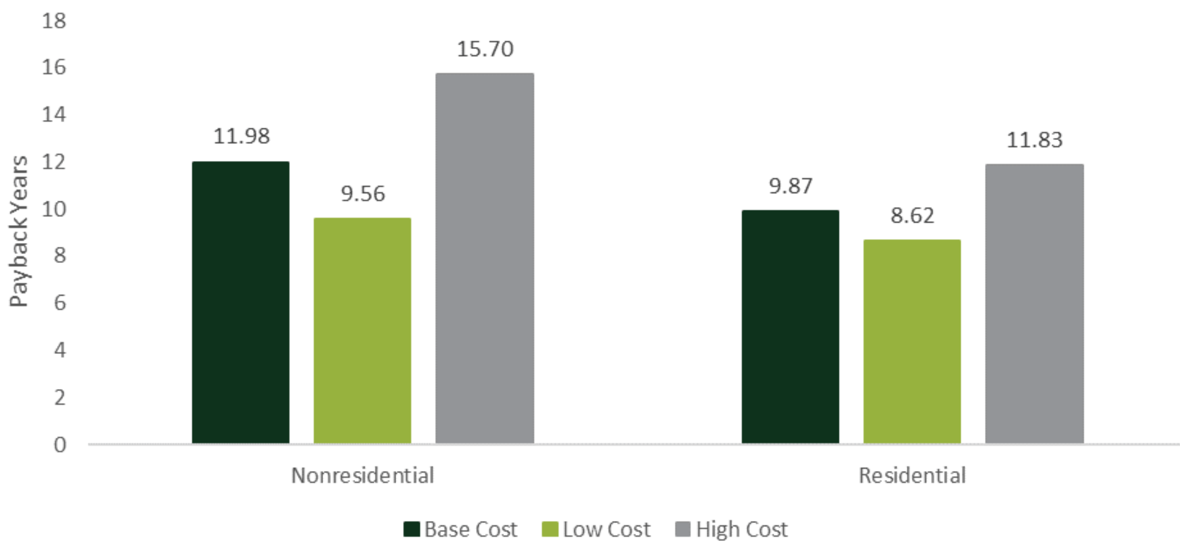
FIGURE 5-6: SENSITIVITY TO PV SYSTEM COST, COST-EFFECTIVENESS FOR NONRESIDENTIAL AND RESIDENTIAL CUSTOMERS



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

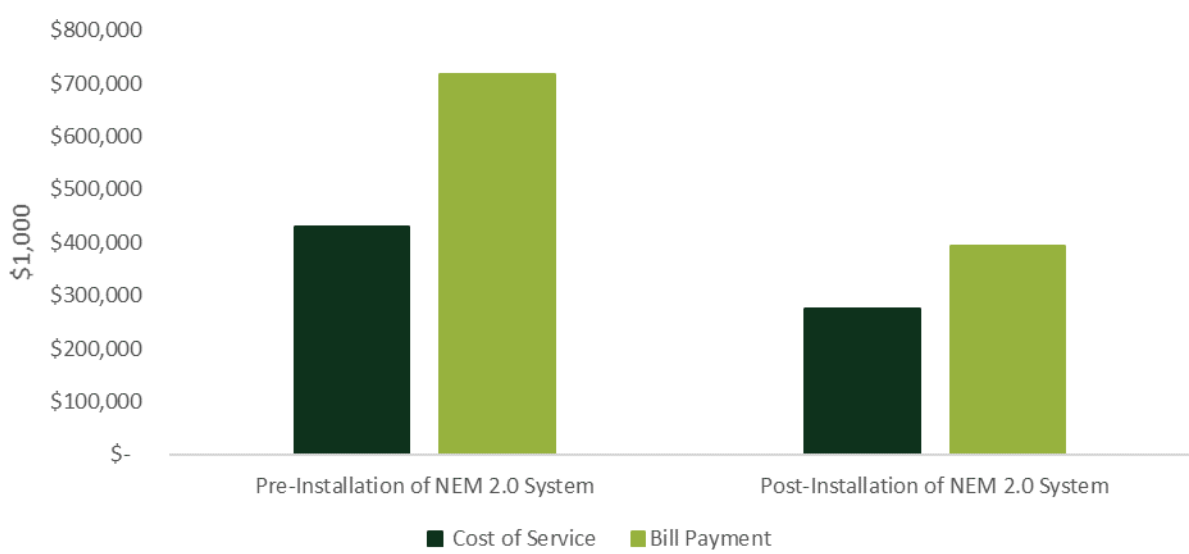


Figure 5-9 below illustrates the residential aggregate pre- and post-installation utility billing versus cost of service estimates. Prior to the installation of the customer-sited renewable generator, residential NEM 2.0 customers overpay on their bills by approximately $112.5 million. Post-installation, 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

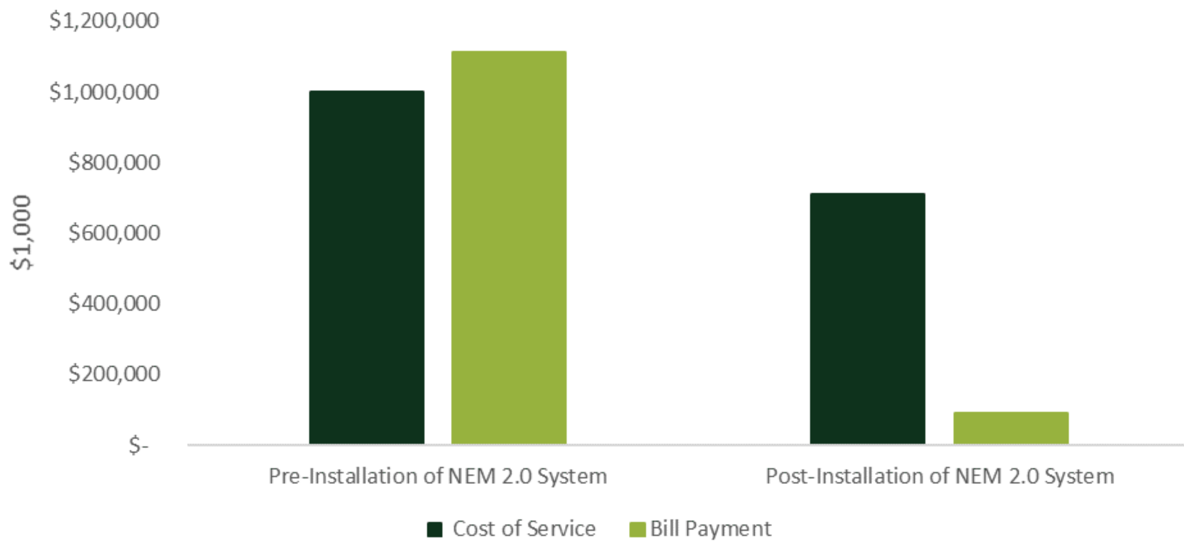


Table 5-11 presents the aggregate bill payment divided by the estimated aggregate cost of service, both pre- and post-NEM generator installation. Numbers greater than 100 percent indicate that customers were overpaying relative to their cost of service. For example, the 178 percent value for SDG&E nonresidential 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

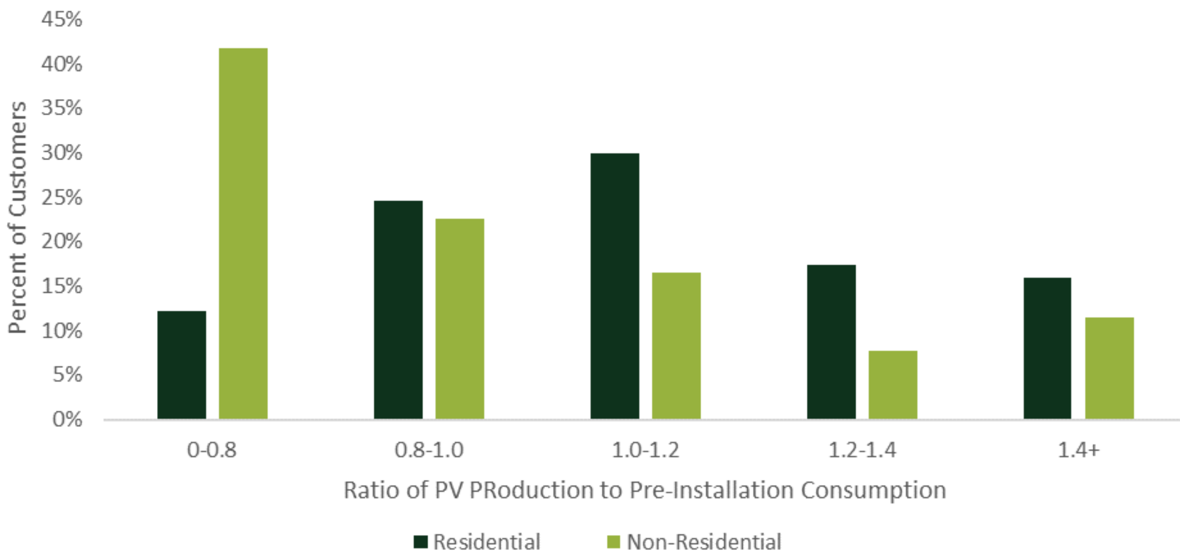


Figure 5-10 shows that only 42 percent of residential customers have PV systems sized to their load or smaller (extra small and small sized bins) while 63 percent of nonresidential customers sized their systems to their load or smaller. With the dramatic increase in PV sizing relative to load under NEM 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

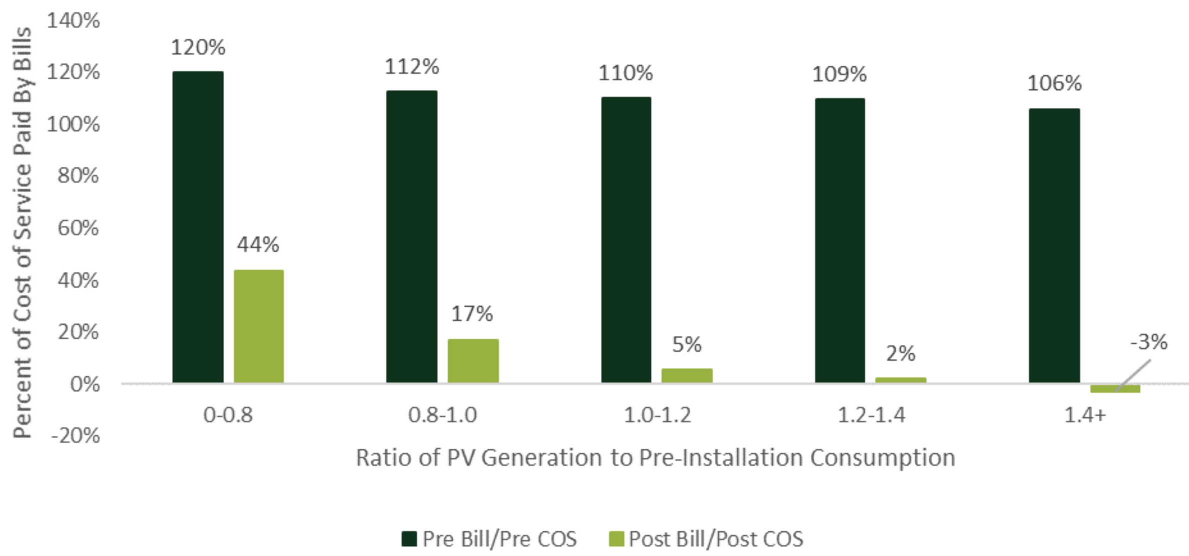
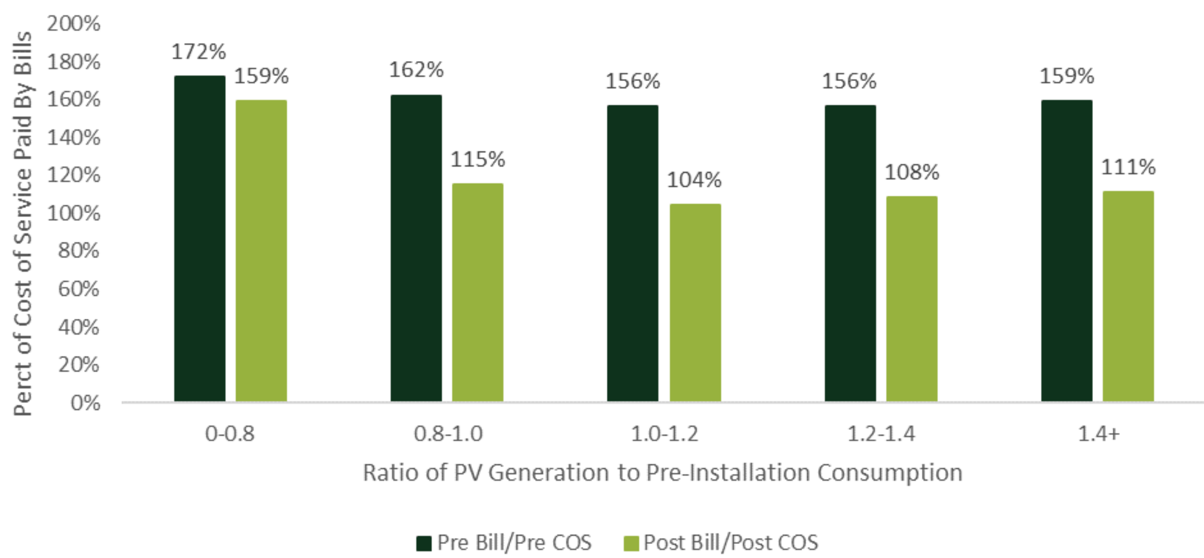


Figure 5-12 illustrates the relationship between bills and cost of service by system sizing relative to consumption for nonresidential NEM 2.0 customers.

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.

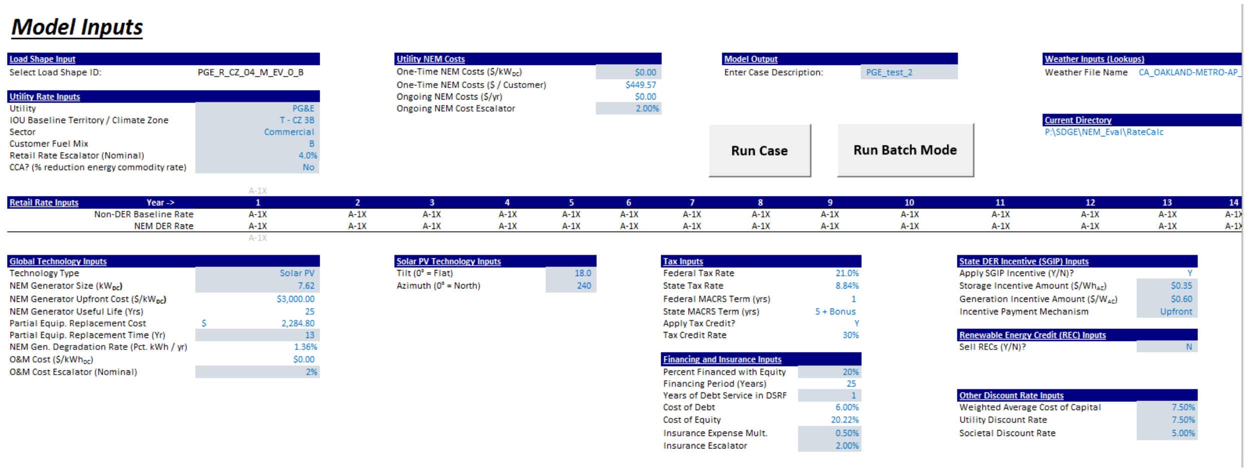
FIGURE A-1: MODEL DIRECTORY

Name	Date modified	Type	Size
_Input_AC	6/26/2020 12:12 PM	File folder	
_Input_WX	6/28/2020 3:23 PM	File folder	
_Output_Batch	7/28/2020 5:06 PM	File folder	
_Output_BillCalc	7/27/2020 5:18 PM	File folder	
_Output_COS	7/27/2020 4:34 PM	File folder	
_Output_Model	7/27/2020 4:49 PM	File folder	
_BillCalc	7/13/2020 9:22 AM	Application	33,044 KB
_InputLoadShapes	7/28/2020 4:23 PM	Microsoft Excel Worksheet	1,769 KB
NEM2_Model	7/28/2020 8:05 PM	Microsoft Excel Macro-Enable...	12,061 KB

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.

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.

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.

Comment #	Commenter	Page or "Overarching" for general comments	Comment/feedback/change requested	Evaluator's Response
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

Comment #	Commenter	Page or "Overarching" for general comments	Comment/feedback/change requested	Evaluator's Response
			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.

Comment #	Commenter	Page or "Overarching" for general comments	Comment/feedback/change requested	Evaluator's Response
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

Comment #	Commenter	Page or "Overarching" for general comments	Comment/feedback/change requested	Evaluator's Response
			$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.

Comment #	Commenter	Page or "Overarching" for general comments	Comment/feedback/change requested	Evaluator's Response
			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.

Comment #	Commenter	Page or "Overarching" for general comments	Comment/feedback/change requested	Evaluator's Response
			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

Comment #	Commenter	Page or "Overarching" for general comments	Comment/feedback/change requested	Evaluator's Response
			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.

Comment #	Commenter	Page or "Overarching" for general comments	Comment/feedback/change requested	Evaluator's Response
			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.

Comment #	Commenter	Page or "Overarching" for general comments	Comment/feedback/change requested	Evaluator's Response
			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.

Comment #	Commenter	Page or "Overarching" for general comments	Comment/feedback/change requested	Evaluator's Response
			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.

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A Non-Modeling Exploration of Residential Solar Photovoltaic (PV) Adoption and Non-Adoption

09/18/13 - 07/15/16

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List of Acronyms

AC	air conditioning
EIA	U.S. Energy Information Administration
GPS	general population survey
PV	photovoltaic(s)
TPO	third-party ownership

Executive Summary

Although U.S. deployment of residential rooftop solar photovoltaic (PV) systems has accelerated in recent years, PV is currently installed on less than 1% of single-family homes. Most research on household PV adoption has focused on scaling initial markets and modeling predicted growth, rather than on considering more broadly why, socio-culturally, adoption does or does not occur. Studies that have investigated PV adoption have typically collected data from adopters only or otherwise treated non-adopters as a largely undifferentiated group. Yet, the vast majority of Americans are non-adopters of PV, and not just "pre-adopters." They have widely varying attitudes toward PV, varying levels of consideration, and varying circumstances (Figure ES-1). Understanding their ways of evaluating PV adoption is thus important to understanding future adoption and how it might evolve. In addition, little research has investigated the experiences of households after installing PV. This report helps fill some of these gaps in the existing literature. The results inform a more detailed understanding of residential PV adoption, consideration, and non-adoption, as well as attitudes and experiences with PV overall.

The report draws on a diverse set of survey data to examine residential PV adoption and non-adoption, the varieties of adopters and non-adopters, and the roles of policies and marketing in shaping these segments. The survey data were collected from nearly 3,600 single-family, owner-occupied households across four different states: Arizona, California, New Jersey, and New York. We divided the survey respondents into four groups: (1) the general population survey (GPS) "Not Thought" group, which had not considered installing PV, (2) the GPS "Thought Not Bought" group, which had considered installing PV "seriously" but had not installed it, (3) "Considerers," which had previous contact with a solar installer for their home but chose not to proceed with adoption, and (4) the PV Adopter group. Figure ES-1 depicts the group characteristics. Comparing survey results across these groups enables an improved understanding about what influences adoption and non-adoption of residential PV.

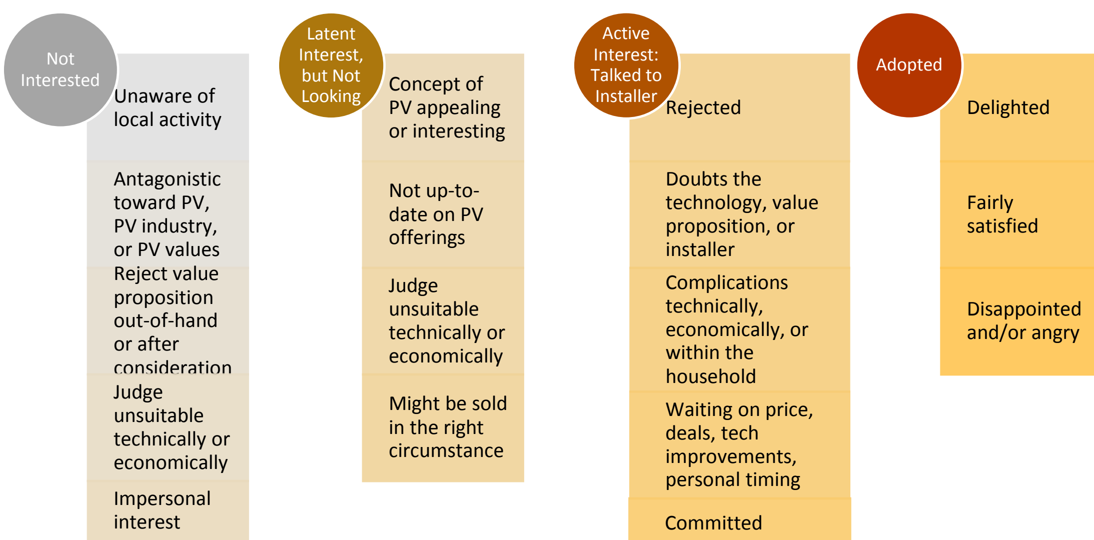

Figure ES-1. Summarized categories of household statuses with respect to rooftop PV

We interpret these data through a social scientific lens in the context of current theories and literature about PV adoption. Our deliberately open and exploratory approach provides a relatively natural view of household PV experiences and contrasts with prediction-centered statistical or simulation-modeling approaches.

PV Non-Adopters: Lack of Awareness, Financial Skepticism, and Other Factors

Most of the general population surveyed who reported not having considered PV said they were largely unaware of local PV activities and were not interested in learning more about PV. A third of the general population surveyed (representing all households other than PV adopters) said that they had not encountered recent PV advertising, had not received calls about PV, knew no more than one person with PV, had not talked to anyone who had PV, and did not know of friends or neighbors who had it. To the extent that awareness is a prerequisite for adoption, a large group of households has not yet been made palpably aware of the technology. While this is likely partly because the technology is not salient to their situation, it may also represent a certain narrowness of information channels about PV.

On the other hand, about half of the general population who said they had thought about installing PV more or less seriously (the GPS-Thought Not Bought group) were interested in talking to an installer or hearing of local homeowners' experiences with PV. What is striking is that few (9%) had actually talked to an installer. This indicates a potentially large untapped interest in PV assessment; many households are aware of PV and may be quite receptive to a PV installer approaching them but had not yet been approached.

To clarify why non-adopters had not considered or not adopted PV, we analyzed the prevalence of conditions and concerns that might discourage adoption (Table ES-1). The most common factor was the lack of a compelling financial rationale, followed by a more specific concern about possibly not staying in the home long enough for the PV investment to pay off. The latter speaks both to the long time scale of investment as well as personal uncertainties. The importance of financial considerations to non-adoption is underscored by a comparison of the general population group who had not thought about PV versus Adopter group. Only 17% of the former said PV would provide a great return on investment, compared with 64% of Adopters. That is, many non-interested households reject the value proposition out of hand.

Table ES-1. Percentage of General Population Survey (GPS) Groups Potentially Dissuaded from PV Installation

Percentage Dissuaded From Adoption by Concern	General Population Survey	
	Not Thought (About Solar)	Thought (About Solar), Not Bought
Financial		
Not compelling financially	66%	59%
Cannot afford	35%	27%
Not at all interested in savings	27%	4%
Low bills (average electricity bill under $100/m)	36%	24%
Long-Term Involvement		
May not be in home long enough	57%	45%
Age over 75	20%	13%
Technical/Pragmatic		
Perceive technical conditions to be unsuitable	24%	17%
Think it is better to wait	41%	43%
Information		
Low trust in information sources	49%	28%
Risks and Burdens		
Concerned with maintenance	19%	18%
Perceived as hassle to install	32%	30%
Concerned with damage to roof	16%	15%
Perceive solar as risky	34%	31%
Social, Political, or Personal		
Not aligned w/environmental/climate causes	27%	11%
Embarrassed to have panels visible on roof	9%	5%
Family/friends would not support	15%	8%

As Table ES-1 shows, a substantial portion of non-adopters thought it was better to wait for PV technology improvements or price reductions. A lack of trust in PV-related information sources was commonly cited as a reason for not considering adoption. In fact, most of the general population surveyed expressed very low levels of trust in information from PV installers, solar industry organizations, and utilities. Environmental organizations and government were trusted only moderately overall. The most trusted information sources were friends, family, and neighbors; yet peers experienced with PV are rare in certain geographies and social groups.

A variety of perceived technology-related risks and burdens also discouraged adoption of PV, including uncertainty about performance, installation difficulties, and concerns about maintenance and roof damage. Social, political, and personal influences also play roles. Most strikingly, while the environmental aspects of PV are often assumed to encourage its adoption, many (27% of those who said they had not thought about PV) described themselves as opposed to or unaligned with environmental or climate change causes. In contrast, of those who *had* thought about PV, less than half of that proportion (11%) said the same. Environmental beliefs—

which can encourage PV adoption among some groups—might discourage it among others. Similarly, peers can discourage as well as encourage adoption. Even if all technical or economic conditions are conducive from an outside perspective, some individuals are not interested in adopting PV, whether because they see no need, view the adoption process as being a hassle, have high levels of distrust, or are against PV or the symbolic interpretations they give it.

Deciding to Adopt: Saving Money while Helping the Environment

Saving money was the most prominent reason stated for PV adoption, followed by wanting to reduce one's environmental impacts. Table ES-2 shows the percentages of Adopters who marked "extremely important" for a variety of motives.

Table ES-2. Strong Adopter Motivations for Considering PV

Motivations	Percent of Adopters Responding "Extremely Important"
Lowering your total electricity costs	78%
Protection from rising electricity prices in the future	62%
Being able to use renewable energy	50%
Reducing your environmental impact	43%
Getting a good return on investment	33%
Being able to use a promising new technology	30%
Setting a positive example for others in your community	26%
Adding to your home's market value	23%

Behind these overall statistics, adopters exhibit a variety of combinations of motivations. One third of PV Adopters ranked *both* saving money and reducing environmental impact as extremely important, while the highest proportion (45%) of the total prioritized saving money. Only 9% prioritized the environment over saving money, and less than 1% said that only the environment, not saving money was important. Reducing environmental impact was rarely the dominant stated motivation, whereas saving money often was. Concerns about money, can take various forms—from initial investment and on-going costs to ensuring a healthy rate of return, protecting against rising electricity prices, reducing energy-related financial stresses at home, and more. Simple economic metrics cannot capture these complexities well.

Across our surveys, non-adopters who had at least considered installing PV designated themselves pro-environmental as frequently as PV Adopters, whereas those who had not considered PV were far less likely to do so. The environmental associations of PV may play a more important role in initial PV interest or disinterest than in later stages of consideration. In addition, social values, such as being able to use a promising new technology or setting a positive example for others were considered very important more often than even increasing home value. So, it is clear that PV adoption is not just an objective proposition based on technical and economic considerations but can also be emotional and symbolic.

PV Adoption-Decision Processes: Deliberative or Opportunistic?

PV may often be in a "sold, not bought" category of goods. This status contrasts with a common storyline that assumes most PV adoption starts with marked interest and a relatively tight accompanying rationale, such as saving money while protecting the environment. Some households in our study seem deliberative about deciding *to* adopt PV, carefully weighing costs and benefits. But our data suggest that a substantial portion of adoption decisions may be more impressionistic or opportunistic, in particular arising when an installer connects to a homeowner who was not actively seeking PV. These relatively casual adopters may be very satisfied with their decision. Thus modeling PV adoption in a strictly deliberative framework may overlook these more opportunistic adoption decisions. The general population survey results suggest high levels of latent interest in PV (GPS-Thought not Bought group), though, given our results on more opportunistic purchases, even some of those who said they had not thought about PV (GPS-Not Thought group) might as easily be sold on it.

Considering but Not Adopting PV

We also looked at cases where households seriously consider PV but had not (at the time of the survey) installed it. Only 11% of such households said they had rejected PV outright or were not currently considering installing it, whereas 60% said they were still considering or undecided. Most of the rest (23%) said they had decided to install but had not yet acted. As shown in Table ES-3, directly financial concerns—doubts about affordability, the sufficiency of bill savings ("enough bang for the buck"), the wisdom of the financial decision, and taking on debt or signing a lease—were all stopping points for more than half of those who had seriously considered PV. Concerns about the aesthetics of PV or selling a home with PV were the least common, with about half saying they had little to no concern in these regards. Even so, aesthetics and impact on the home's sales value remained bothersome enough to nearly a third of those who considered PV to stop consideration.

Table ES-3. Percentages of Considerers Expressing Various Concerns about PV Adoption

How concerned were you about…?	"Not at All or Slightly"	"Stopped Consideration of PV"
Affordability	19%	58%
Taking on debt or signing a lease	25%	55%
Whether solar was a good financial decision	18%	53%
Whether panels offered enough bang for buck	17%	50%
Equipment quality and reliability over time	16%	44%
Risk of damaging your roof	30%	40%
Having to perform regular maintenance	25%	37%
Might be harder to sell home with solar panels	54%	30%
Might detract from home's "curb appeal"	49%	29%

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1 Introduction

Renewable electricity generation has proliferated in the United States and other countries in recent years, and government policies have been encouraging further growth. In the United States, residential rooftop solar photovoltaic (PV) systems are a favored consumer-level route to increased renewable penetration, declining PV prices, government incentives, and third-party ownership options that require little or no upfront investment by the homeowner and have made systems more financially attractive (Drury et al. 2012; Rai and Sigrin 2013). Still, less than 1% of U.S. single-family households had rooftop PV in 2015.[1] Penetration levels vary dramatically by locale, but PV "adopters" are still a highly select group.

This report draws on a diverse set of survey data to examine residential PV adoption and non-adoption, the varieties of adopters and non-adopters, and the roles of policies and marketing in shaping these segments. The survey data were collected in three separate streams, according to household PV status: (1) the general population, excluding PV adopters, (2) households that had talked to a PV installer but had not yet installed PV (PV "Considerers"), and (3) PV adopters ("Adopters"). The data set includes survey data from nearly 3,600 single-family, owner-occupied households across four different states: Arizona, California, New Jersey, and New York. Parallel data were collected across the three surveys where applicable. This data-collection strategy, though limited in its suitability for statistical inference enables a wide variety of exploratory comparisons across geography, PV status, and demographic characteristics.

We use these survey data to analyze PV-related experiences, motivations, knowledge, and characteristics of PV adopters, PV considerers, and the general population of owner-occupied households. The results are interpreted through a social scientific lens in the context of current theories and literature about PV adoption. We use the data to identify major storylines without making broader claims about causation or precise population-level estimates. This approach provides a relatively natural view of household PV experiences, in contrast to prediction-centered statistical or simulation-modeling approaches, which generally incorporate implicit assumptions about adoption processes but may miss insights from data that are not or cannot be modeled.[2] The current report complements the model-centered work that has been completed with these same survey data (Dong and Sigrin 2017; Henry and Brugger 2015; Wolske, Stern, and Dietz 2017).

1.1 Research Background

The academic social science literature on renewable energy technology diffusion, household renewables adoption, and renewables use is narrow in scope (Sommerfeld and Buys 2014). Most work on household PV adoption focuses on how to scale initial markets rather than considering more broadly why adoption does or does not occur, or on what happens after adoption. Analyses of PV adoption tend to rest on rational actor economics; psychological notions of attitudes, values, and sentiments; the assumption that PV is fundamentally "about the environment"; or a

[1] Based on EIA 861 data retrieved December 2016

[2] In addition, both statistical modeling and inferences from more descriptive approach used in this report depend on sample representativeness, though statistical modeling does so more explicitly.

combination of these framings. Research has often centered on modeling, in which adoption is characterized as an interactive effect of quantified vectors, often along few dimensions, oriented to yielding estimates of statistical effect sizes for various factors.

Despite these limitations in focus, a wide variety of research contributes to the understanding of household PV adoption decisions. Approaches taken include agent-based modeling (Rai and Robinson 2015; Palmer et al. 2015), diffusion of innovations (Faiers and Neame 2006), economic framing (Borenstein 2015; Maloney 2016; Drury et al. 2011), geographic clustering and peer effects (Bollinger and Gillingham 2012; Graziano and Gillingham 2015), environmental values (Chen 2013), improving the breadth of data collection (Caird et al. 2008), sociotechnical transitions (Palm and Tengvard 2011), and sociological attention to the political valences and social context of PV based on household interviews (Schelly 2014, 2015; Sommerfeld, Buys and Vine 2017) or surveys (Simpson and Clifton 2015; Keirstead 2007). There is a longer-running body of work on residential microgeneration in general, particularly covering biomass and solar thermal (Balcombe et al. 2013; Labay and Kinnear 1981; Ornetzeder 2001). Less research has focused on what happens in households after PV is installed; exceptions include Schelly's work on PV adopters (2014, 2015) and several studies investigating how energy use changes post-installation (e.g., Keirstead 2007; Rai and McAndrews 2012).

It might be expected that the large literature on consumer energy efficiency choices would inform social science analysis of PV adoption (e.g., Stern et al. 2016). However, relatively little of that research focuses on major home retrofits, which are most similar to PV adoption. Differences in the costs, visibility, and other technology characteristics of energy efficiency upgrades as compared to rooftop PV complicate comparisons. From a policy perspective, both energy efficiency and PV adoption are typically seen as household investments that reduce the cost of energy services while benefitting the environment. From a homeowner's perspective, however, generating electricity may often be much different than saving energy through efficiency upgrades. PV is more "productive," more visible, less uncertain, usually larger in scale, and usually more highly incentivized. Efficiency upgrades, in turn, often have palpable non-energy effects in the home (such as comfort and functional differences), in contrast to PV, which is largely a different *source* of the functionally non-differentiated product of electricity, albeit with a different cost structure.

A modest body of research, including some of the modeling studies above has investigated the characteristics of individuals and households who install PV. Most of these studies collect data from PV adopters, sometimes with additional non-adopter data from the general population and rarely from people who considered but did not adopt PV (Balcombe et al. 2014; Vasseur and Kemp 2015). Reporting by journalists and industry specialists often covers consumer perceptions of PV and choices (e.g., PV aesthetics and how to convert PV leads into sales), though most often without a statistical or quantitative basis or formal summary of evidence. Our analysis helps fill some of these gaps via analysis of a large and formal, albeit non-statistical set of survey data.

1.2 What PV Represents

The first PV-powered residences in the United States were constructed in 1973, about 20 years after the invention of PV cells in 1954 (EERE n.d.). The social interpretations and policy purposes of PV have varied over time and include providing off-grid electricity supply, reducing air pollution and greenhouse gas emissions reductions, reducing consumer electricity costs, improving energy security, and contributing to renewable energy generation. These emphases and interpretations will continue to evolve in light of debates about the systemic configurations of electricity supply, pricing, utility roles, environmental politics, and equity, in turn affecting which households install and why.

Governments, environmental organizations, and many adoption-oriented studies have regularly tended to see residential PV as an "environmental" consumer product, reflecting common policy rationales. Recent studies have found that financial benefits of lower electricity costs and expectations of increased home value often dominate (e.g., Balcombe et al. 2013). Schelly (2014) notes that "while it may seem commonsensical to assume that all residential PV adopters are earth-loving environmentalists, this simply may not be the case."

Our informal review of contemporary U.S. residential PV marketing material shows an emphasis on a multitude of alternative, mostly financial, motives— utility bill savings, discounted system installation, generous state-level incentives such as solar renewable energy credits, the value of "taking control" of energy costs and production, and using technology to capture the sun's free energy. In short, PV now appears to be sold primarily as a consumer good delivering primarily personal benefits, especially monetary savings, if often with implicit or explicit environmental associations. Even the non-financial benefits highlighted in marketing often do not focus on greenhouse gas emissions or pollution reductions but rather orient to psychic benefits of producing one's own power, contributing power to the grid, or generic environmental values. As we show below, though most households we surveyed placed some importance to the environmental associations of PV, few said that they prioritized the environmental benefits of adoption over financial benefits. For some—including some PV adopters—the environmental associations of PV were even seen as a negative attribute.

The association of PV with saving money is underscored by the degree and variety of incentives offered to household adopters. Households do make substantial investments in PV systems even without incentives, but survey respondents clearly saw incentives as important to their decision, with some even describing their installations as "free." The point here is not to debate these subsidies, which may be key to jump-starting a longer-term PV market. Rather, from a data-analysis perspective, the effects of these subsidies are inherently entangled with who adopts PV and why. So, caution is required in translating the adoption dynamics of subsidized PV to those of unsubsidized PV at current prices.

Finally, there is the issue of who adopts PV and why, in terms of demographics, values, and interests. Despite the increasing proportion of moderate-income households that install PV, adoption is still decidedly higher among upper-income households (Borenstein 2015). To increase residential PV penetration and address equity concerns, policy initiatives have included a concerted effort to increase access to PV for middle- and lower-income households, including bolstering community solar, creating partnerships aimed at increasing installation, and instituting new financing options.[3] These initiatives leads to questions about possible changes during the transition from PV's use by early adopters to its use by the vast numbers of U.S. households that do not currently have PV. These non-adopters are often very different from adopters in terms of energy use, financial circumstances, location, demographics, and other factors. What might change about how PV is offered and the information provided about it to suit these non-adopters? What happens in states where PV is not popular today, as PV moves from being unusual to being commonplace, or as the environmental and other benefits of PV shift as electricity supply and demand shifts? To inform these questions, our analysis offers information for a contemporary view of what U.S. households are thinking, saying, and doing with respect to rooftop PV adoption, and it examines some conventional assumptions about PV adoption.

1.3 Report Organization

The remainder of the report is organized as follows. Section 2 describes our data and analytical approach. Section 3 details non-adopter and adopter groups and characteristics. Section 4 analyzes the general population of non-adopters. Section 5 examines the consideration and adoption of PV, including what factors motivate and inhibit adoption. Section 6 discusses experiences PV adopters reported after installation of their PV systems. Section 7 provides a summary of our findings, and Section 8 offers questions about PV's future as well as questions specifically geared toward future research.

[3] The White House, "Increasing Solar Access for All Americans," July 7, 2015, https://www.whitehouse.gov/blog/2015/07/07/increasing-solar-access-all-americans

2 Data and Analytical Approach

This section describes the data collection and analysis methods, and concludes with a roadmap of the report's results.

2.1 Survey Data Collection

The research team fielded surveys to three different groups of single-family homeowners based on homeowner status with respect to PV: the General Population Survey (GPS) group, or households that had not adopted PV; households that actively considered getting rooftop PV for their current home, but had not installed it (Considerer Survey); and households that had installed rooftop PV on their current homes (Adopter Survey). To compare regional markets at different levels of development and different market structure, the surveys were conducted in four states: Arizona, California, New Jersey, and New York. This resulting data was used to develop agent-based models of PV adoption, which simulated the effects of household demographic characteristics, social influences, financial circumstances, and attitudes and beliefs about the environment, PV, and energy use on PV adoption (see Henry and Brugger 2015; Rai and Henry 2016). Considerer and Adopter survey respondents were asked to report their average winter and summer electricity bills, motivations for considering PV, and other experiences in their consideration, decision, and (for Adopters) installation. The surveys also collected open-ended comments on respondents' thoughts about and experiences with PV. This report focuses on some of the less model-friendly data collected in these surveys, including the open-ended comments.

The three surveys were conducted between June 2014 and April 2015. Table 1 summarizes the sampling details. Samples were drawn from a combination of paid respondents (i.e., panelists recruited through a web panel company) and, for the Considerer and Adopter surveys, voluntary respondents identified from installer and lead-generator contact lists obtained from companies that collaborated on the research project. In the Adopter sample, 71% of respondents lived in California, reflecting the market focus of installers who shared their contact lists as well as California's dominance in PV installations. A minimum of 100 responses per state were collected. The panelist responses in the GPS and Considerer samples were distributed fairly equally across the four states, whereas the Considerer lead-generator and installer responses were weighted more heavily toward California and New York. Thus, data collection involved different types of populations (i.e., four states and three different statuses with respect to PV) as well as different sampling frames across, and sometimes within, populations. This was necessary given the nature of the questions and normal resource limits for sampling costs. It renders the data statistically complex and thus limits the ability to make statistical inferences, especially for the Considerer and Adopter populations.[4]

In addition to these household surveys, the research team conducted 72 interviews with professionals from PV installation companies, who were selected to provide a relatively

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[4] For example, though post-hoc sample weights could be developed, the Considerer and Adopter survey respondents are still drawn from a convenience sample.

comprehensive and diverse sample of installers in the four states. These interviews talked to the installers as experts about PV adoption, asking for their perceptions of customer views on PV, customer decision processes, referrals and leads, and other market issues. We use insights from some of this interview data below.

Table 1. Survey Data Sample Descriptions

Survey	Recruitment Source	When Fielded	Response Rate	Responses Passing Data-Quality Checks				
				AZ	CA	NJ	NY	Total
GPS	Panelists	June/July 2014	N/A	351	338	315	337	1,341
Considerers (non-adopters)	Lead generators, installers	Dec 2014 to April 2015	1.4%	13	90	9	41	153
Adopters	Panelists	March 2015	N/A	100	97	98	141	436
	Installers	Dec 2014 to April 2015	8.5%	34	1,181	185	187	1,587
	Panelists	March/April 2015	N/A	75	0	0	0	75
			Total[a]	573	1,706	607	706	3,592

[a] The actual number of households surveyed was more than 3,600; data-quality checks (primarily eliminating respondents who failed attention-check criteria) reduced the number of responses used in the analysis.

2.2 Analyzing the Survey Data

This report takes a non-modeling, non-statistical approach to data analysis.[5] Considerable insight can be gleaned by asking who is and who is not interested in or actively adopting PV, and then analyzing the characteristics of these groups. In addition, our analyses do not focus on prediction, in part because adoption and non-adoption (perhaps especially at this early stage of diffusion) are likely sensitive to an intricate and changing set of conditions and concepts about PV rather than a more deterministic process. The economics of PV will continue to shift due to factors such as changes in incentive levels, PV and installation costs, and electricity tariffs.

Decisions to adopt PV can hinge on a constellation of detailed considerations difficult to capture via a survey or integrate into a regression-based model, even with large samples. For example, considering just the economics of adoption decisions, Borenstein (2015) points to the intricacies

[5] Some of the data collected are not suitable for regression modeling, but still provide insight if carefully analyzed and summarized. Furthermore, decision dynamics are complex in relationship to the limited sample size, forcing a relatively simple statistical model. And as noted above it would be difficult, at best, to fairly assign sampling weights, with the possible exception of the General Population Survey. For discussion of some of the shortcomings of incorrectly applying statistical techniques to social data and non-statistically sampled data, see, e.g., Freedman (1991), Freedman (2008), and Smith (1983).

of assessing the private net benefits of PV, which depend on tax advantages, complex tariffs, and various incentives. Other economic circumstances (e.g., bundling with roof upgrades, who in the household pays), in addition to many non-economic issues, complicate the precision of household-level decision modeling that can be achieved. And some economic aspects may be interpreted non-economically (e.g., if incentives are considered a "call to action" or endorsement from the government).

Our analysis emphasizes segments, clusters, and variety while providing summaries of central tendencies. Given the complexity of PV adoption factors—and the diversity of contexts and circumstances even just among single-family, owner-occupied households—taking variety seriously can help draw a clearer picture of where and how PV fits, does not fit, or might eventually fit for individual homeowners and in the residential electricity landscape overall. Our analysis also interprets the "small data" (Lindstrom 2016) from the open-ended survey comments, taking these comments offered by respondents as valuable non-statistical evidence.

2.3 State Differences

The four-state data-collection approach was designed to cover a broad geographic range and establish how markets and PV adoption decisions differ depending on the circumstances, trends, and cultures that vary with geography and market development. The histories of PV and PV markets are different in all of these states.

Although this report does not detail these state histories, it recognizes that relationships among the various "factors" (i.e., measured survey variables) may be different across states, in a way that does not reduce to a "fixed effect" in terms of a regression model. In addition, there are many unmeasured variables, such as the shifting political dimensions of solar, the details of incentive structures, the particular utilities at play and ongoing debates about tariffs, the nature of the housing stock, and so forth. Overall, the data reveal both similarities and differences across the four states. To avoid an overly complex presentation of results, however, most results are aggregated across the four states, with some notable state-level differences highlighted.[6]

[6] As noted in Section 2.1, sampling strategies differed by states for the Considerer and Adopter surveys; these differences can also contribute to the observed differences across states as well as the particularities of the sample.

3 Non-Adopter and Adopter Groups and Characteristics

Most studies of PV diffusion and adoption focus on the characteristics of adopters, sometimes using various types of non-adopters as contrast. Even in California only roughly 5% of owner-occupied, single-family households had rooftop PV as estimated in early 2016.[7] Penetration rates are lower in New Jersey and New York than in California and Arizona, and there are hot spots and cold spots within states, but nationwide less than 1% of households had rooftop PV systems. Within Everett Rogers' Diffusion of Innovations framework (2010), which is commonly invoked in discussing PV adoption, the United States as a whole is still in the "innovators" (first 2.5%) or "early adopter" (next 13.5%) phase, depending on how eligibility for adoption is defined. The point here is not to integrate the Diffusion of Innovations framework into the analysis, but to note that "next adopters" may be different than current adopters (Sigrin et al 2015). To better delineate the types of non-adoption, we split "non-adopters" into three different groups, which can each be contrasted with the adopter group in different ways.

3.1 Analysis Groups

The populations represented by the three different surveys can be interpreted as falling into one of four statuses with respect to PV exposure, as sketched in Figure 1. PV adopters, who have had PV installed on their current home or signed a contract with an installer to do so, are represented by the Adopter survey. Those who have given at least somewhat serious consideration to installing PV on their current home, but who had not installed at the time of the survey, were recruited for the Considerer survey. The general population of single-family households that have not installed PV is represented by the GPS. GPS respondents were queried about whether they had considered PV for their home but not for the seriousness of their consideration. Likely some GPS respondents considered PV seriously—in particular those who had already talked to an installer—and could have qualified for the Considerer survey. Thus, the Considerer and GPS populations overlap, as depicted in Figure 1.

[7] Based on the Energy Information Administration's Form EIA-861 data.

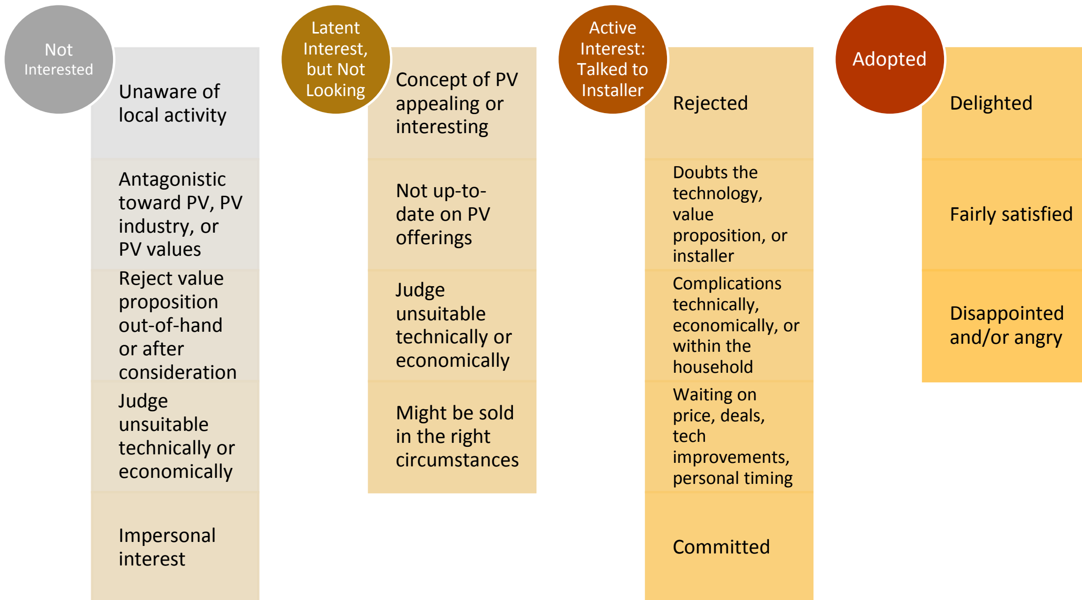

Figure 1. Household status with respect to consideration and adoption mapped to survey data source

The GPS included questions about interest, experience, and plans with respect to installing PV. Over the four states, 37% of GPS respondents said they had not thought about installing PV on their homes; these are called the "GPS-Not Thought" group. This leaves 63% in a "GPS-Thought Not Bought" group, consisting of GPS respondents who said they had thought about PV for their homes. Nine percent of GPS respondents who said they had seriously considered PV also said they had already talked to an installer, making them the most similar to the Considerer survey respondents. Most of the GPS respondents who had talked to an installer but not adopted it had no near-term plans to talk to an installer again (8% of the total GPS population). This group might be considered as having "rejected PV" for the time being. Varieties of interest and non-interest are discussed further in Section 4. Comparing survey responses from the GPS-Not Thought group to those from the GPS-Thought Not Bought group suggests where, how, and why PV, as perceived, does not appeal to the general population. Comparing the GPS-Thought Not Bought group with those who have installed PV (Adopter survey) and to more serious considerers who have not (Considerer survey) indicates which conditions and characteristics favor or inhibit PV adoption.

3.2 Basic Comparison of Group Characteristics

PV adoption is rare, so we would expect the characteristics of PV adopters to be quite different from those of the rest of the population. Table 2 provides an aggregate profile of Adopters ("A" in the table) in terms of simple demographic, social, and energy-use characteristics and compares them to similar characteristics for the two GPS respondent groups, GPS-Not Thought ("NT") and GPS-Thought not Bought ("TNB"). Differences between these groups can provide clues about PV consideration and decision processes. Many of the patterns in these variables echo those found in Balcombe et al.'s (2013) review of literature on motivations and barriers to residential microgeneration. For the most part, the results confirm what would be expected: overall, Adopters have higher electricity bills and more education than GPS respondents. Arizona aside, Adopters are more likely to have income over $150K/year than GPS respondents. Arizona is exceptional in some demographic respects.[8] There, Adopters are much more likely to be retirees and overall have lower income than in the other states, though this does not necessarily mean they have lower net wealth.

Table 2. Percentage of PV Adopter (A), GPS-Thought Not Bought (TNB), and GPS-Not Thought (NT) Respondents with Various Characteristics, by State

	Arizona	California	New Jersey	New York
Electricity bill average $100/month or less[9]	12% A 13% TNB 21% NT	14% A 38% TNB 58% NT	21% A 20% TNB 28% NT	19% A 26% TNB 40% NT
Summer *or* winter electricity bill average above $275/month	39% A 28% TNB 15% NT	43% A 14% TNB 6% NT	36% A 28% TNB 18% NT	31% A 15% TNB 11% NT
Household income over $150K	9% A 10% TNB 12% NT	25% A 11% TNB 14% NT	23% A 17% TNB 11%, NT	27% A 18% TNB 13% NT
Household income under $75K	53% A 54% TNB 44% NT	28% A 37% TNB 52% NT	27% A 30% TNB 32% NT	23% A 43% TNB 48% NT
Respondent sex (% female)	45% A 61% TNB 63% NT	36% A 58% TNB 59% NT	33% A 57% TNB 70% NT	36% A 50% TNB 64% NT
% Retired	51% A 32% TNB 56% NT	37% A 28% TNB 50% NT	30% A 30% TNB 41% NT	34% A 28% TNB 43% NT
% Over age 50	84% A 60% TNB 81% NT	71% A 58% TNB 80% NT	65% A 61% TNB 69% NT	66% A 60% TNB 78% NT
Have children at home	15% A 23% TNB 8% NT	30% A 27% TNB 9% NT	43% A 31% TNB 16% NT	32% A 31% TNB 14% NT
Education above bachelor's degree	32% A 16% TNB 9% NT	26% A 20% TNB 17% NT	29% A 25% TNB 16% NT	32% A 22% TNB 23% NT

[8] In the case of the Adopter population, this may be partly due to the sampling frame, which was primarily panelists, versus the installer customer lists used for the other states; see Table 1.
[9] Both average summer bills and average winter bills were less than $100/month.

As to electricity bills, 31%–43% of Adopters reported average summer or winter electricity bills over $275/month prior to installing PV. GPS respondents with average bills over $275/month were also more likely to have thought about installing PV (14%–28%) than not (6%–18%).[10] Households that leased PV had lower bill levels than those that purchased (not shown in table), but the differences were modest.

Anecdotally, installers are said to target households with electricity bills above certain thresholds (e.g., >$100/month). The logic is that customers with higher bills have larger electrical loads, and thus greater potential for utilizing solar generation for their direct use. Additionally, for tiered retail electricity plans, solar generation offsets electricity at a higher marginal value. However, not all of the Adopter households that we surveyed had high bills. In Arizona and California, 12%–14% of Adopters reported average monthly summer and winter electricity bills of $100/month or less prior to installing PV; in New York and New Jersey, 19%–21% of Adopters reported the same. Table 3 aggregates results across states to compare the percentages of respondents with low and high summer bills among each group. Low electricity bills clearly make considering or adopting PV less interesting, while high bills seem to make it *much* more interesting (as well as more common). If the goal is to increase PV adoption and the diversity of adopters, lower-bill households—which constitute most households—may merit more research and marketing attention.[11]

Table 3. Percentage of Respondents in Each Group with Low or High Electricity Bills, All States

	Average Summer Electricity Bill Below $100/Month	Average Summer Electricity Bill Above $275/Month
GPS-Not Thought	39%	6%
GPS-Thought Not Bought	25%	12%
Considerer	27%	25%
Adopter	16%	38%

As to individual and family characteristics, the GPS-Not Thought and GPS-Thought Not Bought groups were similar as to overall levels of educational attainment and income. The GPS-Not Thought group had a relatively high proportion of older homeowners, smaller households (without children), and retired homeowners. Adopters and Considerers were more likely to have children at home than GPS respondents who said they had not thought about PV. While households with children are generally larger and use more electricity than those without, there may be more at play than pure economics. Children not only use electricity, but also may make controlling energy use more difficult than in small households, possibly leading to family

[10] For example, of the 46% of New Jersey General Population Survey respondents with average summer or winter electric bills over $275/month, most (28% of the total) said that they had thought about installing PV, while only 18% of the total had not.
[11] EIA estimates the 2015 average monthly residential electricity bill at $114/month, based on data collected in Form EIA-861 (see http://www.eia.gov/electricity/sales_revenue_price/pdf/table5_a.pdf); the median bill would be lower (i.e., more than half of households have average electricity bills of less than $114/month). This estimate includes multi-family dwellings as well as the single-family, owner-occupied dwellings that are the subject of our study.

tensions (see, e.g., Barkenbus 2013; Carlsson-Kanyama and Lindén 2007). Reducing the marginal cost of electricity could be seen as alleviating these tensions, though this topic was not directly queried or reflected in the survey data.

Installing PV is typically thought of as a joint household-level decision. The survey results suggest an interesting gender dimension to household adoption and debates within the home. Respondents to the Adopter survey—which asked that household members who were personally involved in PV decisions complete the survey—were much more likely to be male than were GPS respondents.[12] For example, in New Jersey the representation of females in the Adopter survey was less than half of the representation in the GPS-Not Thought group (Table 2). Differences were smaller in California and Arizona, where overall adoption levels are higher. Given conventional associations of new technology and big investments as the realms of men, and the presence of solar marketing in hardware stores and other construction-related venues more frequented by men, these patterns might not be surprising. There has been little discussion of the gender dimensions of PV (or even electricity) in work centered in the United States, Europe, and Australia, while in developing countries PV is often associated with women—via decentralization, localization, control, family care, and expected contributions of electricity to easing domestic labor (Munien 2014). "Environmental care" is often gendered female (Merchant 2014) though the environmental aspects of PV are not necessarily the dominant feature in current markets and purchasing decisions (see Section 5). The gender breakdown in our survey responses suggests that women could be an under-tapped market for PV.

Adopters were also queried about whether they had any of several items with potentially high electricity use: air conditioning, pools, and electric vehicles.[13] These results are shown in Table 4.

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[12] For household surveys in general, women are more likely to respond than men. This was the case in the GPS survey, which had approximately 60% female respondents. The Considerer and Adopter surveys were sampled differently from the GPS survey, so the contributions of sampling to the observed gender differentials cannot be completely disentangled from differences in interest between men and women.

[13] The survey asked, "Which of the following do you have? 1-Swimming Pool; 2-Air Conditioning; 3-Plug-in electric vehicle; 4-Hybrid vehicle, 5-None of the above." The question did not specify whether the air conditioning was central air conditioning, nor if the electric vehicle was a car (as opposed to another plug-in vehicle such as a golf cart or wheelchair).

Table 4. Percentage of PV Adopters with Potentially High-Electricity-Use Items

	Arizona	California	New Jersey	New York
Have air conditioning[a]	83%	95%	93%	85%
Have pool[a]	32%	37%	26%	33%
Have plug-in electric vehicle	9%	6%	2%	4%
Do not have pool, AC, hybrid vehicle, or electric vehicle	3%	9%	6%	10%

[a] The survey asked whether the respondent had air conditioning, rather than specifying central air conditioning. Based on our analysis of the RECS 2009 microdata (EIA 2009), the levels of central air conditioning for single-family, owner-occupied households in 2009 were 89% (Arizona), 54% (California), 49% (New Jersey), and 36% (New York).

[b] These pool saturations are very high compared to those for single-family, owner-occupied homes in the RECS 2009 microdata (EIA 2009). The survey did not ask whether the pool was heated. According to the RECS 2009 microdata, pools are rarely heated with electricity; the maximum across these states is for Arizona (5% electricity). Pool pumps can use considerable amounts of electricity. A report for EIA on miscellaneous electricity use estimated the 2011 Unit Energy Consumption for pool pumps at 2,460 kWh/year (EIA 2013); this is $320/year assuming an average electricity price of $0.13/kWh.

For some households, these particular electric end uses may be an entrée to PV, especially electric vehicles (Rai et al 2016). Even if they did not currently have an electric vehicle, some Considerers and Adopters mentioned that they were planning to buy one and that their consideration of PV was linked to that plan. The open-ended comments demonstrate some of this texture. One survey respondent commented:

> *If I get an electric car in the future, I will definitely get solar.*

Though actual costs will vary widely depending on electricity rates and mileage, the annual cost for charging an electric car is about $320/year, which amounts to $27/month.[14] The actual economics of adding PV to accommodate an electric vehicle are not necessarily compelling for a given household, but households may be making a different type of connection, perhaps reflecting the widespread policy interest in syncing electric vehicles and PV (see, e.g., Denholm et al. 2013; Rai et al. 2016), or simply identifying electric vehicles strongly with electricity and its costs because it is a high-profile and explicitly "electric" technology.

Some Adopters highlighted prompts to installation beyond the standard "our bills are high" argument; for example, because of specific end uses:

> *It was the swimming pool pump that got me to install solar. We live in a very mild climate and don't use heating or cooling.*

or sudden spikes in bills:

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[14] This estimate is based on a unit energy consumption of 2,520 kWh/year and the average residential electricity price in 2015 as reported in Form EIA-861 (EIA 2016).

My decision to go solar was based on a couple of huge utility bills that were never explained.

4 PV in the General Population of Non-Adopters

To understand adoption in the future, non-adopters need to be seen as a much source of information than simply a homogenous baseline contrast to adopters. This section examines characteristics and sentiments of this non-adopting population on their own terms, summarizing differences in how non-adopters say they perceive PV, what they say about their current and potential future interest in PV and how it might depend on changing conditions, and what seems to be missed by current marketing efforts and even technology characteristics. These results can inform potential changes in the way that residential PV is marketed that might increase adoption as well as help ensure that adoption is sufficiently beneficial to those who adopt it, and ideally, in its consequences for those who do not.

4.1 From Antagonism to Interest: Levels of Interest in the General Population

Table 5 (next page) summarizes varieties of disinterest and interest among the general population, based on GPS responses to a battery of questions about interest and plans with respect to residential rooftop PV.[15] Among the 37% of GPS respondents that constitute the GPS-Not Thought group, nearly half seemed unaware of local PV activity. These respondents stated that they had not seen or heard advertising about PV in the past few months, had not received calls, knew no more than one person with PV, had not talked to anyone who had installed PV, and did not know of any friends or neighbors who had installed PV. If active awareness and familiarity with PV is a gateway to considering it, a large proportion of households seem far from this gateway. Others seemed decidedly uninterested (11% overall) in talking to an installer, in how PV could work for their home, or in learning about the potential savings from PV.

In the middle ground between the GPS-Not Thought and Adopter groups, members of the GPS-Thought Not Bought group were currently or had previously been interested in adopting PV, but had not done so. Only 11% of the GPS-Thought Not Bought group had actually talked to an installer, though 22% said they would be "very interested" in learning how solar could work for their home. Even recognizing that survey respondents may be overstating their interest owing to the context of the survey itself, these results suggest there is a large untapped interest for PV assessment: many households might be waiting for a PV installer to come talk to them. The extent to which "interested" households are actually good leads is an open question.

[15] The GPS was intended to represent everybody but PV adopters. Because Adopter households are such a small percentage of single-family, owner-occupied households, the percentages shown in the table also nearly represent the population of all single-family households in these states.

Table 5. Varieties of Disinterest and Interest in PV among GPS Respondents[a]

Percentage by Group	All GPS Respondents	Not Thought Responses	Thought Not Bought Responses
Not Interested/Antagonistic Not at all interested in talking to an installer	13%–29%	11%–18%	2%–11%
Not at All Interested Not at all interested in how solar can work for my home	13%	11%	2%
Unaware Have not noticed much about solar recently	32%	17%	15%
Very Interested Personally Very interested in how solar could work for my home	25%	3%	22%
Already talked Have already talked to an installer	11%	0%	11%
Plan to Talk Plan to talk to installer in next six months	11%	0%	11%

[a] "Have already talked to an installer" is a yes/no question. The other questions were collected on a 5-point rating scale, with the upper two ranks ("Agree" and "Strongly Agree") counted as yes and the lower two ranks ("Disagree" and "Strongly Disagree") counted as no; those who answered "neutral" or did not answer are excluded from the percentages. The GPS excluded households that already had installed PV. The rows of the table are not mutually exclusive. For these reasons the percentages do not sum to 100%

4.2 Perceived Incompatibilities

To further understand why current non-adopter households might not be interested in installing PV or be able to install it, we combined responses across a set of survey questions to estimate the prevalence of conditions and concerns that might generally discourage installation. Table 6 presents the results, comparing the GPS-Not Thought and GPS-Thought Not Bought groups. In most cases, percentages were similar between these two groups, albeit often slightly higher for the GPS-Not Thought group, as would be expected. These similarities suggest that the itemized concerns and conditions generally did not stop people from *thinking* about PV for their home. The remainder of this subsection discusses these perceived impediments in more detail, grouped into four clusters of concerns: financial and payback issues, waiting for technology improvements or price reductions, risks and burdens, and social, political, and personal influences.

Table 6. Percentage of GPS Groups Potentially Discouraged from PV Installation by Various Concerns and Conditions

Concern or Condition	GPS-Not Thought	GPS-Thought Not Bought
Financial		
Not compelling financially	66%	59%
Cannot afford	35%	27%
Not at all interested in savings	27%	4%
Low bills (average electricity bill under $100/mo. summer and winter)	36%	24%
Long-Term Involvement		
May not be in home long enough	57%	45%
Age over 75	20%	13%
Technical/Pragmatic		
Perceive technical conditions to be unsuitable	24%	17%
Think it is better to wait	41%	43%
Information		
Low trust in information sources	49%	28%
Risks and Burdens		
Concerned with maintenance	19%	18%
Perceived as hassle to install	32%	30%
Concerned with damage to roof	16%	15%
Perceive solar as risky	34%	31%
Social, Political, or Personal		
Not aligned w/environmental and/or climate change causes	27%	11%
Embarrassed to have panels visible on roof	9%	5%
Family/friends would not support	15%	8%

4.2.1 Financial and Payback Issues

The two most commonly cited impediments to adopting PV involve the nature of the investment. The lack of a compelling financial motivation was noted by 66% of the GPS-Not Thought group and 59% of the GPS-Thought Not Bought group. These results are consistent with many other studies on microgeneration adoption (see the review by Balcombe et al. 2013). Further analyses show that the small percentage of respondents who had already talked to an installer were much less likely to claim that PV was not compelling; this could be related to cause (why these respondents decided to talk to an installer) or effect (something the installer said). Incidentally, some Considerers noted that their conversations with installers made them aware of unanticipated expenses or other costs, such as the need to remove trees or problems with the roof that could make installation much more expensive.

The second most commonly cited impediment was also related to investment, in particular, to hesitations about payback period. The possibility of not being in their home long enough to recoup the benefits of PV was noted by about half of GPS respondents (57% of the GPS-Not Thought group and 45% of the GPS-Thought Not Bought group). The average tenure in an owned home is 13 years (U.S. Census Bureau 2016). Simply calculated, a household with that average tenure would garner less than two-thirds of the lifecycle energy savings benefit, home sales value aside. Concern about the impact of a PV system on home value was evident among GPS respondents, who were mixed as to whether PV would increase or decrease the home's value at sale.[16] Presumably, part of a PV salesperson's work is to frame the economic decision in a way that resonates with a particular household's decision makers, while keeping the equation favorable in terms of choosing to install.

4.2.2 Waiting for Technology Improvements or Price Reductions

As shown in Table 6, over 40% of both GPS groups said they thought it was better to wait for technology improvements or price decreases. Presuming that a relatively aware portion of the public perceives that the value-to-price ratio of residential PV has increased in the past few years, the flip side of this realization could be the expectation that value-to-price conditions will only get more favorable. For Considerers (not shown), expectations about future improvements loomed even larger, with 62% saying it was better to wait for better technology or lower prices.

Conversely, in a rapidly changing market, those with little or only casual interest in installing PV may not keep up. Some who think the time is not right might be prompted to reconsider if they encounter updated information on current conditions, at least if this information seems trustworthy. As one Adopter commented:

> *If we had known how much we were going to save, we would have made this decision much sooner. But that information wasn't available.*

This comment also points to the difficulty consumers face in reliably assessing pros, cons, and opportunities about PV installation in highly consumer- and sales-focused markets, where the information provided may be seen as more self-interested than trustworthy; issues of trust are explored in Section 5.4.2.

4.2.3 Risks and Burdens

Concerns about unknowns, time, hassle, and other stresses of installing were also very common, with little difference between the two groups. These concerns include the hassle factor of installation (30%–32%), uncertainty about performance (31%–34%), concerns about maintenance (18%–19%), and concerns about roof damage (15%–16%). As public experience with PV continues, some of these concerns could dissipate if peer experiences could be better shared and are positive overall. But, PV's reputation might not be so positive today. One Adopter commented that their household had gleaned a strongly negative perception of PV prior to talking to an installer:

[16] For some Adopters, however, concerns about the effect of PV on home value at point of sale were a showstopper (see Section 5.5).

> *Until we were contacted by an installer, everything we heard about solar was negative. But our experience has been great!*

Thus the PV industry faces the challenge of building positive experiences, which can run counter to shorter-term gains, like those made from quick sales or "fly by night" companies, as some survey respondents noted.

Despite the perceived risks that trouble non-adopters, a scan of PV information available on the web suggests that these technical and administrative concerns are not particularly well addressed. Dismissing or not acknowledging problems avoids providing a "worry list" to potential customers. But, households that are risk-aware and risk-averse may be a large proportion of future customers, so it may be useful to treat existing concerns in a balanced and direct fashion rather than ignoring them.

4.2.4 Social, Political, and Personal Influences

In academic research, the environmental benefits of rooftop PV are usually thought of as a plus, something that helps sway households to consider PV and install it, even under economic conditions that are not particularly favorable. In open-ended comments, however, some respondents explicitly, and sometimes disdainfully, distanced themselves from the environmental associations of PV that were implicit in the survey instruments:

> *Many of your questions had nothing to do with solar… global climate change, etc.*

And from one PV adopter:

> *Installation was free. But with higher costs of electricity, my costs are twice what I expected. I am not some stupid environmentalist.*

As shown in Table 6, over a quarter (27%) of GPS-Not Thought respondents indicated that they were not aligned with environmental or climate change causes, versus only 11% of GPS-Thought Not Bought respondents. Schelly (2014, 2015) analyzes discussions with PV adopters in Wisconsin, showing that homeowners have political perceptions of PV that shape installation decisions and the interpretation of PV post-installation. These perceptions might be highly important in understanding PV adoption, even if the decision appears to hinge on engineering and economic characteristics alone. These political perceptions are not necessarily closely linked to party affiliations.[17] Schelly's 2015 study found that the politics of PV was most strongly linked to the politics of environmentalism, though other political interpretations—decentralization, fossil fuel-centered "politics-as-usual," and wealth redistribution—were also evident. These politics, entangled with assessments of technical characteristics of the installation and use,[18] can both encourage and inhibit PV adoption. Our data-collection methods do not allow definitive estimation of how important environmental interpretations of PV were in persuading

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[17] Political party and other political leanings were collected in the surveys but are not analyzed in this report.
[18] Such technical assessments include, for example, questions that even experts debate, such as the extent to which a particular household's use of PV offsets carbon emissions and which baseline should be used in the comparative calculation.

and dissuading adoption. In terms of attitudes about the environment and climate change, however, the GPS-Thought Not Bought group was similar to Adopters and Considerers (see Sections 5.2 and 5.3). Thus, positive environmental associations for PV may often align with interest in PV but have less effect on whether PV is actually installed.

Modest proportions of households may be deterred from considering or installing PV owing to disagreements in the family or the influence of neighbors and other peers (Table 6). Among the GPS-Not Thought group, 15% indicated that they thought people in their family or in their social circles would not support their decision to install PV. Social antagonism or skepticism about PV and its politics could be an important deterrent in some social contexts and geographies (Strauss et al. 2013). This is worth stressing, because, in the academic literature, PV is often presumed to have positive associations, such as commitment to environmental sustainability, technical or community leadership, or wealth. The peer-effects literature on rooftop PV adoption focuses on geographic clustering associated with positive (pro-adoption) influences (e.g., Bollinger and Gillingham 2012). However, peer effects can likely work both ways, and anti-PV is also a form of peer effect, as hinted in the survey results and implied in Schelly's work. Individuals interested in PV might be able to convince family members that PV is a good idea; overcoming social censure may be harder and require a broader strategy.

4.3 Perceptions of PV Economics in the General Population

Table 7 compares the GPS-Not Thought group versus Adopters (the two most contrasting major groups) in terms of their endorsement of three different financial aspects of PV as well as the generic assertion that "using solar would help meet my family's needs." In terms of the economic proposition of PV, Adopters were far more positive in their assessment than was the GPS-Not Thought group. Although their adoption decision itself suggests Adopters hold a more positive view of PV economics, the differences could also indicate different ways of assessing or framing these economics, as well as the fact that households who have not thought about PV will have at most done impressionistic rather than formal assessment. Many in the GPS-Not Thought group indicated that they thought PV would have positive financial characteristics; for example, 37% say that PV would help protect them from rising electricity prices. Still, less than half as many judged PV a great investment, whereas two thirds of Adopters endorsed this view. Only 18% of the GPS-Not Thought group said they thought PV would meet *their* family's needs. Many said they did not know, and some were clear that it would not.

Table 7. Comparison of GPS-Not Thought versus Adopter Groups in Terms of Economic Assessment of PV for Their Homes

	Percent of Group Agreeing or Strongly Agreeing	
Statement	**GPS-Not Thought[a]**	**Adopter**
"Using solar will help protect my family from rising electricity prices in the future."	37%	87%
"Installing solar provides a great return on a family's investment."	17%	64%
"Using solar would save me money."	27%	87%
"Using solar would help meet my family's needs."	18%	79%

[a] There were relatively high percentages of "don't know" responses (9%–14%) for this question.

4.4 Perceptions of Non-Economic, Non-Environmental PV Attributes in the General Population

Table 8 (next page) summarizes how non-adopters assessed PV for a selection of non-economic, non-environmental aspects of PV. All but the last row of the table are statements about PV that speak to a level of comfort with, or positive assessment about, the general value or viability of PV for the respondent's home. The GPS-Thought Not Bought group clearly had a more positive assessment of PV than the GPS-Not Thought group. Over half of the GPS-Thought Not Bought group said that they thought PV would protect their family from blackouts (55%) and would meet their family's needs (72%). The assumption that rooftop PV usually protects individual homes from blackouts is a misperception, based on the typical electrical configuration in the U.S., but apparently a very common one. Some Adopters, in fact, said that they were surprised and disappointed when they found out that their system did not work during blackouts. Disabusing potential adopters of this notion, in the interest of accuracy and fair information, would presumably reduce proclivity to adopt. Alternatively, improving the ability of PV systems to provide at least some blackout protection at relatively low additional cost to the homeowner could provide a powerful benefit that many current customers expect to receive.

Few respondents claimed that they would be embarrassed by visible PV on their rooftops. Even among those who had thought about PV (GPS-Thought Not Bought), clear social support for adopting PV was mixed. About half said that they thought that people important to them would support their adopting PV, with almost all of the rest (48% of the total) neither disagreeing nor agreeing.[19] Among the GPS-Not Thought group, however, only 15% agreed that people important to them would be in favor of their installing PV (Table 8); as noted above, this perceived social censure is a peer effect that may impede adoption.

[19] This figure combines the "don't know" (12%) and "neutral" responses (36%).

Table 8. Non-Adopter Assessments of Non-Economic, Non-Environmental Aspects of PV

	Percent of Group Agreeing or Strongly Agreeing	
	GPS-Not Thought	**GPS-Thought Not Bought**
"Using solar would protect my family from electricity blackouts."	29%	55%
"Using solar panels on my home would help meet my family's needs."	18%	72%
"Solar panels nowadays have become very dependable."[a]	13%	35%
"People who are important to me would be in favor of installing solar panels."	15%	46%
"I would feel embarrassed to have solar panels on my roof where others can see them."	9% (68% disagree or strongly disagree)	5% (81% disagree or strongly disagree)

[a] This question yielded high levels of "don't know" responses: 34% of the GPS-Not Thought and 27% of the GPS-Thought Not Bought group answered "don't know."

5 Consideration and Adoption of PV

Electrical systems across the United States generally operate reliably and affordably. In discussing household adoption of PV, Zhai and Williams (2012) note, "Electricity is easily available and inexpensive. In fact, it is hard to notice the existence of the power grid." So, why would households choose alternatives from this system? Which households would make such a choice, and what savings are required?

Social scientists argue that technological transitions are not about any objective supremacy of one technology over another (Palm and Tengvard 2011). Accepting a conventional "rational decision-making" vantage point for the sake of argument, the question is less about barriers to installing PV, but rather about the perceived advantages of PV and for whom, where, and why these seem enough to shoulder the costs, risks, effort, and perceived disadvantages and alternatives. This list would include conditions such as the following:

- Electricity bills are perceived as high, and PV offers sufficient savings.
- It is perceived that electricity bills *would be* high if the household used substantially more energy services than they already do (e.g., if they are normally conservative with central air conditioner use but want to use air conditioning freely, or if they add a major electricity end use such as an electric vehicle).
- Electricity reliability is poor, and PV is perceived to improve this reliability.
- Environmental advantages are perceived.
- A compelling offer, such as large incentives, is appealing.
- Various psychic and social advantages result, such as social capital, pleasure, alleviation of guilt, reduction of household tensions, and feelings of security and/or community.
- Policies or situations make it difficult *not* to have PV (which is rare currently).

There is a similar list of disadvantages to be weighed against the advantages. To tease out these perceived advantages and disadvantages of PV, we asked Adopter and Considerer survey respondents about their motivations and concerns for considering installing rooftop PV, as well as the difficulties they encountered while considering installation.

In the 1970s through 1990s, the installation of residential PV technologies may have been largely associated with environmental benefits, environmental showmanship, grid independence, energy security, and being on the technological cutting edge. These aspects of PV presumably remain to some extent, but contemporary marketing of residential PV emphasizes energy cost savings. Environmental benefits are sometimes mentioned, but usually vaguely. As one PV company's advertising puts it, "You save money, the earth saves valuable resources. And we all feel less guilty about the way we consume energy in the process." These motives—including saving money or meeting other financial objectives, protecting the environment, assuaging guilt and obligation, gaining security, and taking pleasure—are explored in this section.

Adopters rated the importance of each of a series of motives for looking into PV on a 5-point scale from “not at all” to “extremely” important. Table 9 shows the percentages of respondents who marked “extremely important” for each of these motives.[20] For Adopters, lowering total electricity costs was of top importance overall, with 78% rating it as “extremely important.” Far fewer focused on getting a good return on investment (33%) or adding to the home’s market value (23%).

Table 9. Strong Adopter Motivations for Considering PV

Motivations	Percent of Adopters Responding “Extremely Important”
Lowering your total electricity costs	78%
Protection from rising electricity prices in the future	62%
Being able to use renewable energy	50%
Reducing your environmental impact	43%
Getting a good return on investment	33%
Being able to use a promising new technology	30%
Setting a positive example for others in your community	26%
Adding to the home’s market value	23%

5.1 Saving Money While Helping the Environment

Saving money on household energy costs is the most common stated motivation for considering PV among Adopters (Table 9). Saving money could mean lower bills or lower net expenditures on energy than prior to PV, which are fairly easy for individuals to track. Or it could mean spending less than the alternative if other uses have changed (e.g., acquiring an electric vehicle), which is less easy to track. Among Adopters, 62% said that protection from electricity price increases in the future was an extremely important motivation; this hedging is in part financial but may also often align with other concerns, such as a sense of independence from the control of the utility. Return on investment and especially adding to the home’s market value are difficult for individuals to assess.

A much smaller proportion of Adopters rated “reducing your environmental impact” as extremely important (43%) compared with saving money (78%), though few rated it as unimportant. Table 10 and Table 11 compare the economic and environmental motivations of Adopters. One third ranked *both* saving money and reducing environmental impact as extremely important, while 45% of the total (including 6% who said that the environment was not an important or only a slightly important motivation) prioritized saving money. Only 9% prioritized the environment over saving money, and less than 1% said that only the environment, not saving money, was important.

[20] In general, these statements were highly endorsed. In most cases, fewer than 15% responded with anything less than “moderately.”

These stated motives do not necessarily translate to evaluation criteria, but it is clear that reducing environmental impact was rarely the dominant motivation, whereas saving money often was. It is unclear to what degree buyers evaluate the *degree* of environmental benefits of PV, if at all, or if environmental benefits are just seen as a fixed quality of the technology.

Table 10. Comparing Environmental vs. Economic Motivations of Adopters

Relative importance of "reducing your environmental impact" vs. "lowering your total electricity cost"	Percent of Adopters
Environment and not money	0%
Environment over money	9%
Environment and money equal	45%
Money over environment	39%
Money and not environment	6%

Table 11. Percentage of PV Adopters Rating Environmental and Money-Saving Motivations at Various Levels of Importance

Importance of…		Reducing environmental impact		
		"Not at all" or "Slightly"	"Moderately" or "Very"	"Extremely"
Lowering total electricity cost	"Not at all" or "Slightly"	0%	0%	0%
	"Moderately" or "Very"	1%	12%	9%
	"Extremely"	5%	39%	33%

The pragmatic "relative good" assessment may be key in examining how customers think about the balance between environment and money. In describing the decision to adopt PV, one respondent commented:

> *We wanted to help the environment while maintaining our lifestyle.*

In a sense, for this respondent, vaguely conceptualized environmental benefits associated with PV seem to serve as a (moral) ticket to less guilty consumption and perhaps higher levels of consumption as well. Section 5.3 discusses guilt further.

These results illustrate a tension between the older notion of PV as environmental and resource conserving versus the current marketing focus on PV saving money. A review by Balcombe et al. (2014) presents a similar finding, namely that a "desire [to be environmentally friendly] does not translate to a willingness to pay extra for it." A finances-first evaluation is not inevitable; people make decisions that do not save them money all the time. Rather, framing PV as a mass consumer product with the main benefit of saving money encourages consumers to interpret it within this frame. Clearly, different companies highlight different elements of PV, and salespeople may pitch PV to persuade individual clients. Overall, however, the perception that "PV is about saving money," along with a generic assumption that PV is "environmental" in some sense, is cultural rather than natural law.

5.2 Depth of Environmental Interest, Concern, and Commitment

Most Adopters endorsed several general environmental values as well as those specific to energy use and renewable energy, whereas a solid proportion did not. We examined the extent to which Adopters characterized themselves as more aligned with environmental values than non-adopters by classifying respondents as "pro-environmental" if they responded positively to at least six of the nine environmental values survey questions and as "non-environmental" if they responded neutrally or negatively to three or more of these variables.[21] About half of Adopters met this "pro-environmental" criterion, but so too did about half of Considerers and GPS-Thought Not Bought respondents (Table 12). Only 21% of the GPS-Not Thought group met the "pro-environmental" criterion, implying that environmental concern (or lack thereof) is a screening criterion for seriously considering PV.

The percentage of "non-environmental" respondents was similar among the GPS-Thought Not Bought, Consider, and Adopter groups (11%–14%), compared with 27% for the GPS-Not Thought group. The aforementioned work by Schelly (2014) on Wisconsin PV adopters argues that environmental debates have increasingly positioned PV politically and that this alignment inhibits some households from adopting PV.

Table 12. Pro- and Non-Environmental Stance by PV Adoption Status

	Percentage of Group			
	GPS-Not Thought	GPS-Thought Not Bought	Considerer	Adopter
Pro-environmental	21%	47%	53%	53%
Non-environmental	27%	11%	12%	14%

5.3 Pleasure, Protection, Guilt, and Obligation

Although our results indicate the importance of saving money and protecting the environment to PV-adoption decisions, these motivation categories encompass substantial complexity. For example, financial concerns might be less about economic calculations and more about other issues, including tensions about money (i.e., "How much will the bill be this month if we use air conditioning?" or "What if utility rates keep going up? How can we reduce the arguments in the household about who deserves to use what and when and how energy must be conserved?")

[21] In this scheme, not everybody is classified. In particular, cases in which the corresponding responses were neutral ("neither agree nor disagree") or "don't know" are omitted. Also, Adopters may sometimes be more likely to endorse various environmental values after they install PV than they did before – that is, the installation may lead to the endorsement.

Households with PV may also get pleasure out of their installations. Open-ended comments in the Adopter survey show clear signs of this pleasure (e.g., "I love my solar panels."). Our surveys did not directly investigate this possibility, but they did query respondents on attitudes toward topics that may lead to pleasure: a sense of security, family/home protection, financial security, technological or environmental leadership, energy security, climate change mitigation or general environmental protection, financial savvy, fun and interest, independence from the utility, and so on.

Feelings of guilt and obligation may also be at play. Table 13 summarizes the percentage of each of the four groups who agreed that they felt guilty when wasting energy, felt a personal obligation to prevent climate change, and felt a personal obligation to contribute to a renewable energy future. Feeling guilty about wasting energy was the norm, although fewer respondents who had not thought about installing PV felt this way. Feeling guilty about wasting energy is sometimes interpreted as a motivator for "pro-environmental" behavior.[22]

Table 13. Percentage Agreeing to Guilt and Personal Obligation Statements, by PV Adoption Status

	GPS-Not Thought	GPS-Thought not Bought	Considerer	Adopter
"I feel guilty when I waste energy."	60%	73%	68%	69%
"I feel a personal obligation to do my part to prevent climate change"	42%	60%	63%	62%
"I feel a personal obligation to do my part to move the country to a renewable energy future."	32%	57%	65%	79%

Guilt dynamics might be important to perceptions about PV's environmental benefits. In particular, is rooftop PV electricity relatively exempt from concepts of guilt-inducing waste? This situation has implications for estimating greenhouse gas emissions savings from PV.[23] In particular, does cheaper or even "free" (at the margin) electricity encourage higher use? The data collected for this project cannot be used to estimate this possibility. Comments from the Adopter households surveyed, however, hint that this could sometimes happen:

> *We pay a few dollars a month for connection and have an annual bill of about $400. We run the AC all summer long. Everybody in this area should have solar panels.*

According to this PV adopter, PV can be a great deal when evaluated on a sunk investment basis. That is, if the energy generated appears to be without environmental consequences and with minimal incremental financial costs, why not use it?

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[22] See Turaga et al. (2010) for a review of the concept of pro-environmental behavior.
[23] Evidence of the impact of adoption of energy durables on household energy consumption is mixed, and referred in economic literature as the "rebound" or "ripple" effect; see, e.g., Gillingham et al. 2016.

An alternative interpretation of household energy consumption is that households are conserving energy all the time, rather than just choosing desired levels of comfort and convenience, and paying accordingly. For example, many households in warmer areas may reduce air conditioning to save on energy bills or assuage feelings of guilt or personal obligation. Summer energy bills do not necessarily reflect "comfortable" conditions within a home. Thus PV could improve summer comfort more affordably, concretely, and immediately than could energy efficiency upgrades. The energy generated may have substantial advantages in terms of health and comfort for a household but not reduce greenhouse gas emissions or even total energy consumption.

In contrast to the results for guilt about wasting energy, Adopters were much more likely to say that they felt a *personal obligation* to prevent climate change or to "do [their] part to move the country to a renewable energy future" compared with the GPS-Not Thought group. Thus, feeling a personal obligation to contribute to slowing climate change may encourage adoption, or at least become a rationalization for it. Non-adopters who had considered PV (GPS-Thought Not Bought and Considerer groups) were as likely as Adopters to feel a personal obligation to "do my part to prevent climate change." Adopters were even more likely (79%) to feel personally obligated to support a renewable energy future. Those who had only thought about installing PV were less likely to say they felt such a personal obligation (57%–65%), and still fewer (32%) of those who had not thought about installing PV stated such an obligation. At least at this early stage of PV diffusion, wanting to support a renewable energy future appears more strongly aligned with adopting PV than are concerns about climate change.

5.4 Deliberative Decision Styles and Alternatives

A classic decision-making model for installing PV starts with an initial level of interest based on the perceived value of PV. This leads into a deliberative decision-making process in which the homeowner actively investigates PV—weighing benefits, costs, and risks—and, if an adoption decision is made, deliberates further to choose among various options such as buying versus leasing, system size, timing, installer, and so forth (Faiers and Neame 2006). It is convenient to frame decisions in this deliberative, model-friendly, fashion. Based on our survey data, however, some decisions appeared to fit a deliberative framework, whereas others may have been barely deliberative at all.

Adopters were asked what prompted them to consider PV, using a list of 15 options shown in Table 14.[24] The most commonly reported prompts involved information seeking or hearing about PV: 79% of Adopters said they were looking for ways to reduce energy bills, while 63% had heard it was more affordable, and 23% had heard about low-money-down options. These responses are consistent with a "deliberative" model of PV adoption, with respondents saying they were initially prompted to consider solar by a perception of the value of PV.

[24] The median number of cited prompts was three.

Table 14. Prompts for Considering PV Cited by Adopters

Prompt	% of Adopters
Looking for a solution	
Looking for ways to reduce energy bills	79
Intrigued by the possibility	
Heard it was more affordable	63
Heard about low-money-down options	23
Social	
Saw advertising or news article	22
Saw solar being installed on a home	21
Installer interactions	
Approached by an installer	54
Offered at a retail store, home show, or community event	7
Planning, events	
Planning for retirement	10
Came in to some money	2
Had group purchase opportunity	2
Home changes	
Considering a major new energy use	6
Planning/doing other work on home	5
Bought a home/moved	4

On the other hand, many Adopters also stated that coincidental or non-deliberative interactions prompted them to consider PV, including talking with installers; talking within social circles; seeing ads, news, or a new installation; or experiencing household events or circumstances (Table 14). The large fraction of Adopters that were prompted by external influences suggests that, for most Adopters, self-driven interest alone may not have been sufficient to lead to more serious consideration. By implication, many in the GPS-Not Thought group may actually be more amenable to considering PV than might be assumed. So, there may be a large latent interest that can be activated through external influence.

At the opposite extreme from interest-driven consideration were the 20% of Adopters (primarily leasers) who reported not considering PV before talking to an installer, indicating that "talking to the installer got me interested."[25] That is, many "opportunist" Adopters seized an opportunity provided by their installer, even if it just started by a knock on the door. Sigrin (2015) also discusses such a "sold, not bought" aspect of PV, further discussed below.

[25] As shown in Table 14, 54% said they were approached by an installer. Over half of these indicated that they had been thinking about PV before this approach.

From the perspective of predicting and increasing PV sales, these relatively opportunist segments are interesting. Some households that have adopted PV were "natural" candidates for PV from the economic and technical perspectives, but overall they have been targeted, both directly and indirectly. Policies, instruments, marketing, and technical offerings *create* adopter niches and voids. Marketing differently could change who buys and even what is offered, just as third-party ownership (TPO) has changed the demographics of adoption.

Social or peer influences on adoption increasingly have been recognized in the literature (see, e.g., Bollinger and Gillingham 2012), and our survey data indicate that this peer effect was often important for prompting consideration. However, installer interactions and influences have often been missed when analyzing PV adoption, although clearly they have not been missed in marketing or "lead generation" practice. Installer influences appear in our results to be of prime importance, and they infiltrate the "social influence" category. For example, in 72 interviews with individuals from PV companies across the four study states, almost all reported incentivizing or at least asking their customers to refer other interested people to them. As noted in Table 5, over half of GPS respondents said they had thought about PV, and, of the GPS respondents who had thought about PV, two thirds said they were interested in talking to an installer but had not yet done so. Thus there is some circularity in assuming that the characteristics of current PV adopters represent a fundamental nature of adopters, rather than reflecting—to some extent—marketing efforts.

5.4.1 Getting Enough Information

Installing rooftop PV involves a long-term commitment and often a substantial amount of money, and it comes with complex economic and technical performance considerations. In the context of deliberative decision-making, deciding whether to install PV, and selecting options for the installation, can be highly complex. There is little long-run social experience for residential PV systems and little in the way of performance reviews, such as are available for cars (e.g., *Consumer Reports*, True Car, and other websites). Utility reactions and tariff arrangements are in a public, sometimes contentious phase of debate in a number of states, with potentially high stakes for households with PV, utilities, and the PV industry. Current net-metering arrangements are not necessarily intuitive. How much electricity the system will generate is uncertain, as are future electricity rates and household electricity use. There are often various types of financial incentives from different layers of government and with varied rules and deadlines. Buying or leasing a car is more straightforward and partially reversible. So, how do households judge the quality of the PV information they are faced with? The perceived trustworthiness of information sources is important.

5.4.2 Trust

GPS respondents were asked about how much they trusted various groups and organizations to provide accurate information about residential PV.[26] As shown in Figure 2, trust in information

[26] The actual question was, "To what extent would you trust each of the groups and organizations listed below to provide accurate information about residential solar energy"? While the question asks specifically about information, this might sometimes be conflated with trust of the organization overall.

sources other than friends, family, and neighbors was low. Most respondents said they highly trust the information provided by friends and family (75% trust "quite a bit" or "completely") and neighbors (55% trust "quite a bit" or "completely"). On the other extreme, trust of the solar industry (installers and trade organizations) was very low, with12% of respondents stating that they "do not trust at all" each of these groups. Trust levels were lowest among those who said they had not thought about installing, so a low sense of trust may be a big barrier to even thinking about installing.[27] Nor did many trust utilities, though that distrust could also be motivation *for* installing PV. Government and environmental organizations were judged similarly; 23%–27% of respondents stated they trusted these sources "quite a bit" or "completely," and a substantial proportion expressed distrust. There was a cautious level of trust expressed for university researchers, with more than one-third of respondents expressing high trust and few completely distrusting them. Trust levels of particular sources likely depend on knowledge levels, as suggested by a recent study covering the public's view on the trustworthiness of information by fracking by information source (Theodori et al. 2014).

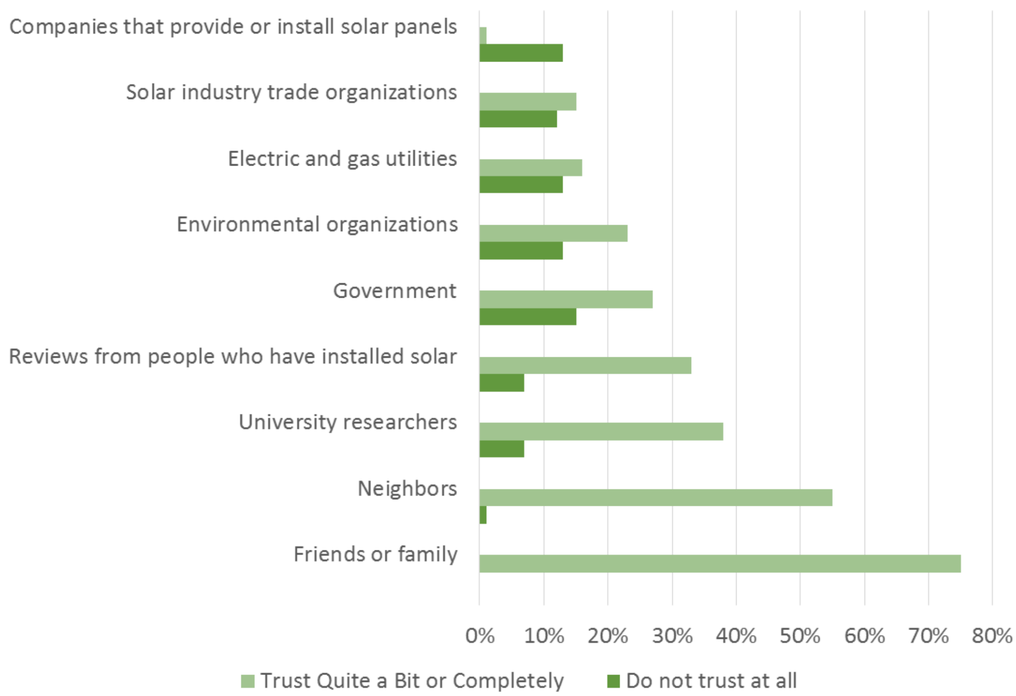

Figure 2. Reported levels of trust in PV information provided by various organizations and groups, according to GPS respondents

Survey respondents often brought up issues of trust and confusion in their open-ended comments. One non-adopter said:

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[27] Among the GPS-Not Thought group, 20% said they did not trust installers at all, and 19% said they did not trust trade organizations at all.

> *Expensive. Very confusing in regards to lease vs. buy. So many solar companies out there.* ***Do not know who to trust, who is the best value, who will be around for years, or if they are a fly-by-night company****. Government incentives are not enough, always change, and have too many deadlines. [Bold added for emphasis]*

Another commented:

> *Contacted a company, received some additional data about them. They had conflicting information about how to install solar on a house with a cement tile roof and sounded like they did not know what they were talking about. Said whole roof would have to be replaced if I got solar. That's incorrect.*

The conflicting information adds confusion and may stop or stall customers who would otherwise buy. A 2016 industry survey of installers found that confusion caused by competitors was considered the top challenge in closing sales, lowering consumer confidence (EnergySage 2017); 53% of surveyed installers considered this to be a problem.

While some respondents said that they had very positive interactions with installers, others were irritated by "constant contact" and sales tactics. Some respondents expressed their skepticism clearly. For example, one Adopter said:

> *Overall I think the solar companies are dishonest, opportunistic, and unethical.*

Several of the installers we interviewed noted this skepticism among potential buyers as well.

Despite low levels of trust noted by the general population (Figure 2), in action, installers are obviously often very influential. How the interactions between households and installers plays out will depend on homeowner decision-making styles (as well as more momentarily varying mood, financial circumstances, etc.) and installer sales style. Adopters reported shopping around less than one might expect given the reported mistrust. Most Adopters (68%) said they talked to only one or two solar companies, with leasers talking to fewer companies than buyers. Leasing may be less deliberative or simply appear to be a less risky, easier decision. For those who purchased their system outright, more than half (55%) reported talking to three or more installers.

As another example of deviations from the deliberative ideal, most Considerers and Adopters did not appear to consider seriously both buying and leasing options. Instead, many seemed to consider only one option, depending on the offerings of the installers they spoke with. Referrals may help explain the lack of shopping around. Thirty percent of Adopters reported having been referred to a particular installer, and most (84%) of these referred households selected that installer. This bears out the expectation that referrals from friends, families, and neighbors can be very influential.

At least for a deliberative decision-making path, there is a bind: information from industry sources is not trusted, and there is not enough of it from trusted sources. Recent work in Australia (Simpson and Clifton 2015) and the United Kingdom (Balcombe et al. 2014) emphasizes how difficult some households say it is to find trustworthy information. Our survey respondents sometimes commented that detailed information was hard to find, or that processing it was difficult:

> *Actual results would have helped me make my move sooner. Instead we had no such figures.*
>
> *Very hard to figure out all the options.*

As Owens and Driffill (2008) note in the context of energy efficiency research, information on its own does not automatically transform consumers and their actions. And, as suggested by the juxtaposed quotes just above, having too many choices can also make things more difficult.

Installing PV exemplifies the difficulties of the dilemma of modern consumer choice, where so much information is potentially available that it becomes overwhelming (Broniarczyk and Griffin 2014). PV is not necessarily a good decision for all households. More effort to develop an up-to-date "Buyer's Guide" addressing processes, risks, and doubts could help. Rather than trying to provide customized answers for individual households, this guide could lay out contours of the decision, and provide a "frequently asked questions" section, covering topics such as the reasons for and expected ranges of true-up (net-metering reconciliation) bills, the roles of tariffs, buying and leasing considerations, system options (e.g., size, roof vs. ground mounting), maintenance requirements, the nature of guarantees, and other questions that affect the experience and economics of PV. However, such a guide would also need to incorporate local market nuances, such as incentives offered, building and electrical codes, etc.

In summary, some households may take a deliberative approach to deciding whether to adopt PV, while many appear to act more impulsively or in reaction to sales calls or other opportunities. For the deliberative, constraints on trusted information and social experience, complexity, and uncertainty about the future suggest that satisficing[28] (Simon 1947) was more common than not. A refined and deliberative decision-making process for PV could be exhausting. For careful decision makers, at least those who are concerned with risk, the effort and uncertainties may stymie adoption. Relatively impulsive buying may be far easier, particularly when the product can be presented in a fashion that leverages decision shortcuts and reduces certain common uncertainties, as appears to be often possible with TPO (e.g., "save $30/month" vs. "we will save you $30/month off your current electricity bill, with minimal or no money down, with guaranteed system performance, and we'll do any maintenance necessary"). The next subsection addresses the concerns and difficulties reported by Considerers stalled out in the decision-making process.

5.5 Stalled or Stopped by Concerns and Difficulties

What happens to those who seriously consider PV but do not, at least for the time being, install it? As indicated in Figure 1, only 11% of Considerers said they had rejected PV outright or were

[28] Simon proposed the concept of "satisficing" to describe how real-world choices made under intrinsic uncertainty differ from the idealized model of rationality in that available alternatives are searched *until* an acceptable (non-optimal) threshold is met.

not currently considering it,[29] whereas 60% said they were still considering or undecided, and 23% said they had decided to install but had not yet acted.

To understand the details of how interest stalled or stopped, the Considerer survey asked about specific concerns that respondents experienced while considering PV.[30] As shown in Table 15, directly financial concerns—affordability, sufficiency of bill savings ("enough bang for buck"), the wisdom of the financial decision, and the taking on of debt or signing of a lease—were each stopping points for more than half. Concerns about the aesthetics of PV or selling a PV home were the least common, with about half saying they had little to no concern in these regards. Even so, aesthetics and impact on the home's sales value remained bothersome enough to nearly a third of Considerers to stop their consideration of PV. These results underscore what are, in many cases, high uncertainties associated with adopting PV as well as the variety of different circumstances that shape assessment. Economic evaluation itself relies on uncertain assumptions and unfamiliar and potentially transient accounting schemes. Potential savings are not always large, but the commitment to PV is long and essentially irreversible. Societal experience over the long term is still scarce. PV may be perceived as complicating the household's relationship with their utility, and interpretations will depend on each individual's personality and circumstances.

Table 15. Percentages of Considerers Expressing Various Concerns about PV Adoption

How concerned were you about…?	"Not at All or Slightly"	"Stopped Consideration of PV"
Affordability	19%	58%
Whether panels offered enough "bang for buck"	17%	50%
Equipment quality and reliability over time	16%	44%
Whether solar was a good financial decision	18%	53%
Taking on debt or signing a lease	25%	55%
Having to perform regular maintenance	25%	37%
Risk of damaging your roof	30%	40%
Might detract from home's "curb appeal"	49%	29%
Might be harder to sell home with solar panels	54%	30%

[29] One third of these respondents said they were at least somewhat likely to reconsider PV within the next 2 years. Recall that Considerer respondents were largely drawn from installers' lists, so the statistics reported here depend on how the installers compose and maintain these lists.
[30] Respondents were asked to select from five levels (not at all/not applicable, slightly, somewhat, very, extremely) for a fixed set of concerns and from five levels (none/not applicable, a little, some, a lot, a great deal) for a fixed set of difficulties. Those who responded positively ("slightly" or "a little" or higher) were asked a follow up yes/no question on whether that issue or concern stopped them from getting PV.

Considerers were also asked about the difficulties they encountered while thinking about installing PV. Their responses are summarized in Table 16. Coming up with enough money to install PV was the top difficulty cited, stopping just over half of respondents from considering installation. Other reasons for stopping consideration included trouble finding trustworthy, competent installers (37%), technical concerns with home suitability (36%), disagreements within the household (28%), finding an installer to do the work (26%), and encountering permitting, zoning, or neighborhood restrictions (22%).

In summary, some households that considered PV were simply unable to make the proposition work. Perhaps their home was not suitable, electricity bills were too low, their credit rating was insufficient, there was no way they could come up with the money, and so forth. These could be considered "hard stops," at least for the time being. Most Considerers, instead, were hesitating. Half identified at least five concerns and difficulties as having stopped them from adopting. Their interest might be reactivated in the future, and some are still actively considering but delaying action. The number and variety of concerns and difficulties reported suggest that reactivating this group likely would require more than simply asking them to reconsider, absent other changes in arrangements.

Some opportunities for progress are readily apparent. The effect of PV on the sale of a home (see Hoen et al. 2013, for example) or the risk of roof damage are at least subject to empirical examination, which can reduce uncertainty over these issues as evidence builds. Other issues may be addressed in novel product or financial configurations, as in the TPO systems, where responsibility for equipment reliability and maintenance has been shifted from households to PV companies. That shift was often reported as a deciding factor in leasing a system for the subset of surveyed Adopters who also considered purchasing. General societal familiarity and experience with PV will continue to unfold, as will various institutional adjustments (such as changes in incentive design and levels, a settling of utility tariffs, regulations, etc.). The results and *perceptions* of results will be critical for adoption going forward.

Table 16. Percentages of Considerers Reporting Various Difficulties Related To PV Adoption

How much difficulty did you have with …?	"None or A Little"	"Stopped Consideration of PV"
Coming up with the money to get solar	35%	55%
Finding a trustworthy and competent installer	36%	37%
Suitability of your home site	43%	36%
Finding an installer who would agree to do the work	58%	26%
Permitting, zoning, or neighborhood restrictions	58%	22%
Not everyone in your household being convinced	62%	28%

6 Experiences Post Installation

PV Adopters were asked several questions about their post-installation experience. Most had their systems for less than two years and some for only a few months. Overall, reported experiences among survey respondents were good.[31] Asked whether they had any regrets about installing PV, only 9% said they had. Regrets were more common among those who had leased their system (11% stated regrets) than purchased it (5% stated regrets).

Some PV adopters were enthusiastic about the low-risk, low-upfront cost of their installation, even noting that the deal was so good it was hardly believable:

> *Absolutely FREE solar panel installation, warranty for 20 years.*
>
> *With the state payment, federal tax credit, and loan …this was a no-brainer. It took me two months to believe it.*
>
> *I tell other people that my panels were free, but nobody believes it.*
>
> *I can't understand why everybody doesn't do it.*

Adopters usually said PV was paying back about as fast (39%) or even faster (27%) as than expected, as shown in Table 17. Thus two thirds thought they were getting at least what they expected in terms of financial payback. Only 13% said that payback was slower or much slower than expected. The rest (21%) said it was too early to tell or that they did not know.

Table 17. Adopter's Assessments of Actual Payback Time Compared to Expected Payback Time

Actual Payback Time Compared to Expected	Percent of Adopters
Slower or a lot slower than expected	13%
About as expected	39%
Faster or much faster than expected	27%
Too early to tell	14%
Don't know	7%

Some respondents expressed disappointment with savings:

> *Expected better savings, highly disappointed.*

A realization that long-term savings were lower than expected could take several years:

> *For the first two years, we had savings. Then the utility put in a new meter, and our electricity kept going up, $670 the first year, then $950. And they don't buy electricity from us. The utility is sapping the value of solar. The meter lies.*

[31] Because this is a convenience sample, the estimates do not necessarily apply to the population of PV adopters at large.

Still, some households that saved less than expected (but still saved something) said they were contented by the environmental benefits:

> *Although we are saving only half of what we had hoped with solar, it's better for the environment.*

This last comment suggests that, though environmental benefits are invisible, the idea of them can provide ongoing value to PV adopters.

Dissatisfied buyers can influence others against PV. Setting up appropriate expectations for PV system performance and savings could reduce the number of dissatisfied customers. Some of the lukewarm comments that Adopters made about their experience with PV may help provide a way forward. For example:

> *Although I have seen savings, I struggle to understand the breakdown of savings and the reason for a lump sum payment every year.*
>
> *I am still pleased with the panels, and enjoyed the integrity and expertise of the installers. But I wish it could have been better and more rewarding. I wish I had a professional explain options and ramifications of the investment.* ***Maybe there could be a better way****.*

But, what would be a better way? More research attention—in particular, in-depth discussions with PV adopters, along with measurement of private and personal financial results and environmental benefits—to household experiences in *using* PV systems, both good and bad, could provide a useful supplement to the current research focus on buying and selling PV. Given the long expected lifespan of PV, adoption is not the end of the PV cycle, nor should it be the end of the research cycle. This post-installation attention could help ensure that future Adopter experiences are as good as possible and find ways to improve the experience. Are households happy with the installation? How have their electricity bills and electricity use changed? What, if anything, would they do differently? Solar thermal water heating, which in the past has been fairly popular in some locales, has suffered from poor reputation in past installations (Stryi-Hipp 2001).

7 Summary

This report provides a data-based interpretive view of contemporary PV adoption and non-adoption in U.S. single-family households. The report covers attitudes, knowledge, experiences, and assessments of households that have installed rooftop PV, those who seriously considered adopting PV but have not installed it, and the "general population" of households without rooftop PV. This section summarizes our results.

7.1 Diversity

Households are never average. Our analyses aim to keep the texture of PV adoption and non-adoption processes rather than generalize by focusing on central tendencies or general relationships. The survey data collected show that motivations, conditions, and experiences related to PV vary widely. Economic conditions are an important component of that variation, but not the only one. For example, some households see the environmental associations of PV as a reason to consider installing it, while others seek to distance themselves from environmental and related political aspects of PV and possibly even avoid considering PV because of them. Some households value the blackout protection that they think PV provides, even though few current installations actually provide such blackout protection—and so on, regarding aesthetics, the importance of resale value, whether installers should be trusted, and the effects of opinions of friends and neighbors, and how economics are assessed. Some Adopters thought installing PV was an easy decision, while others, including those who did not consider PV were put off by assessing its benefits, costs, and uncertainties. Attempts to generalize through statistical models can collapse across this diversity.

7.2 PV as a Consumer Product

We have tried to step back from normative assumptions about PV, especially those that cast it as a universal good (e.g., energy efficiency). PV is a peculiar consumer product. Its main purpose is to provide electricity, which most people already have. PV environmental benefits are invisible; some people value these benefits, whereas others do not even believe in them or are antagonized by the surrounding environmental claims or politics. Incentives aside, PV installation is often expensive. At least for purchased systems, favorable expected investment performance usually depends on having high baseline electricity use. Even then, there are considerable uncertainties over the long and largely irreversible product lifespan. While often sold as a financial investment, there are non-financial costs, risks, and benefits even beyond the environmental ones.

7.3 Selling PV

How PV is marketed and who it is marketed to shapes who buys it. It may often be in a "sold, not bought" category of goods. As Sigrin et al. (2015) note, even in California, some households must be recruited to adopt PV. The "sold, not bought" characterization contrasts with the storyline that PV adoption starts with active interest and a tight accompanying rationale in hand, such as saving money while protecting the environment. We saw that some households are deliberative about deciding on PV, carefully weighing costs and benefits. But, many seem more impressionistic or opportunistic, in particular when an installer sells to a homeowner who was not actively seeking PV. Similarly, satisfaction with the PV experience also keys to the level of detail (and accuracy) used in evaluating performance—did people get what they thought they would? Deliberation-based frameworks to understanding PV adoption may gloss over these consumer-level processes.

7.4 Financial, Environmental, and Other Motives

Over the past four decades, residential PV technologies have shifted from technological novelty, countercultural symbol, contributor to energy independence, and environmental symbol to what seems to be a chiefly financial proposition today. Saving money was the most prominent reason for PV adoption in our surveys. The array of incentives available, and the apparent importance of these in increasing PV sales, underscores the financial nature of PV adoption.

Money is a highly social concept and there is no singular way of figuring what is a good deal or not. The classic economic framing of energy efficiency as well as PV sees purchases as an investment with a payback period or rate of return on investment, so that a "good" decision depends on these estimates. Yet, nearly as many surveyed households named protection against future price increases as an important motivation for interest in, and adoption of, PV—despite the fact that retail electricity prices and tariffs are unpredictable over a 10–20 year horizon. PV adopters can know the future levelized cost of PV, so they can hedge against electricity price increases—which may provide a sense of comfort—but they cannot hedge against price decreases.

Deciding to install PV may also involve judgments about how PV could reduce stress and discomfort in the home, for example, by making bills more predictable, reducing the need to try to conserve energy, or reducing arguments families have about energy use. These are indirectly related to money but are not economic considerations traditionally applied to investments. In addition, some people might consider the pleasure derived from PV of using electricity from the sun or of being part of a solar community.

After money, the next most important motivation for most Adopters and many Considerers was the environmental properties of PV. For many households, these properties may be vague or symbolic rather than about a specific property, such as reducing greenhouse gas emissions due to the displacement of fossil fuels. The survey data indicated that few households prioritized environmental benefits over financial ones. Furthermore, the environmental associations of PV may play a more important role in initial PV interest rather than at later stages of consideration. And for some, the environmental association of PV was a negative. An increasing politicization of PV and environmental causes may heighten this tension.

7.5 Deliberation and Information

For anyone taking a classically economically rational approach to installing PV, a proper private cost-benefit analysis is complex and uncertain. This would involve assumptions about how much the system generates over time, future rates, net-metering, changes in demand, and so on. This kind of calculation is probably quite rare. In practice, different households will estimate expected savings differently and have different criteria for deciding whether PV is worth the costs and risks. One of the most common pathways may be relying on installers or trade industry calculator estimates to determine utility bill savings (Rai and Sigrin 2013). Where upfront costs are low (as in leasing situations) or heavily discounted (for those who get generous incentives), households may expend less effort in these calculations. Assessing the environmental benefits of a PV system is even harder. Such an assessment likely entails simply evaluating whether PV is "good for the environment" or helps with climate change, or deciding whether this question is immaterial or more about politics.

In our collected data, adopters and potential adopters of PV sometimes said that they wanted better information about PV but could not find it. There is a need for trustworthy information on PV, yet the tendency or perceived tendency of installers, trade organizations, and environmental organizations to present only largely positive information can present an incomplete picture. Keeping information about solar simple and positive likely makes adoption decisions easier for many households, but it may deter or mislead others.

In light of these complexities and uncertainties, households may often make decisions that are impressionistic and opportunistic rather than deliberative. Such impressionistic adoption may be becoming more common with the availability of TPO systems, because TPO requires less upfront commitment and generally has clearer costs and benefits than purchases. Decisions *against* PV, or complete disinterest in considering it, may also often be impressionistic.

7.6 After Adoption

There is little research on how households that have installed PV view their systems and what may have changed about energy use after installation. The PV adopters we surveyed largely reported being happy with the results, sometimes even when savings were less than expected. However, 9% said they had regrets about the systems they installed. Some were disappointed by their energy savings or frustrated by unexpected aspects of PV, problems with the installation, long wait times for incentives, big true-up bills, or the feeling they were being treated unfairly by the utility. Others had reservations about how leasing unfolded. Even without changing what is actually being offered, letting potential PV adopters know what to expect may reduce dissatisfactions,

7.7 What about Non-Adopters?

We argued that to understand future adoption, it is important to pay close attention to the diversity of non-adopters on their own terms, rather than just as "pre-adopters." The vast majority of U.S. households *are* non-adopters of PV. Some are demographically similar to adopters, but overall non-adopters have much lower average income and electricity costs than do adopters to date. To depict their diversity, we identified a number of non-adopter groups or tendencies. Some non-adopters were largely unaware of PV. Some were antagonistic. Some seemed to see little value in PV. Others judged PV as not economically, technically, or socially viable for their situation. However, *nearly two thirds of the general population surveyed* said they had thought about installing PV. This interest did not often translate to contacting an installer, even among those who said they would be happy to talk to one. Rather, most seem to be "waiting," whether for an installer to contact them, for improvements in technologies, price reductions, more attractive incentives, a better understanding of the entire process of installation, or more societal and peer experience.

8 Questions about PV's Future, Questions for Future Research

Drawing from a particularly expansive set of survey data collected from U.S. households, we have tried to offer some new starting points for deliberations about PV adoption, and understanding the household circumstances within which PV operates, provides benefits, and entails costs. Our analyses were not focused on how to increase PV adoption, but the results can clarify that challenge and inform the development of marketing, development, and marketing strategies to better account for the diversity among consumer segments and speak to an evolution from "early adopters" to a broader market. Below, based on the survey data analysis, we offer suggestions about how research could help shape this future for the better.

Questions about the future of PV

- *Value beyond the financial.* What are the costs and benefits of promoting PV based primarily on its economic attributes? Are there other framings, technical attributes, or business models that could be enticing to a wider range of households? For example, what might encourage PV electricity to be perceived as worth more than normal grid-supplied electricity?
- *Futures which may have vastly different consumer costs.* What happens if and when PV incentives diminish or vanish? How will lower incentives sync with moderate-income and moderate-electricity-use households in terms of the economic proposition of PV? Conversely, what happens if PV costs decline further as the industry matures? Given the already high incomes and electricity use of most current PV adopters, why and how could PV appeal to lower-income and lower-energy-use households, where the value equation and methods of assessment might be different from those used by adopters in the past?
- *Visions of future supply systems.* Controversies now surrounding PV—related to rate structures and rules, long-term electricity-supply planning, environmental politics, equity, and other matters—could further complicate already-complex adoption decisions. How can these issues be managed to minimize the derailing of interest in PV?

Research questions

- *Assessing the information landscape.* Some households said they had enough information about PV to make their decision, others said that weighing the possibilities was complex and burdensome, and some said that the information they had was misleading or too selective. The complexity of the decision can inhibit households from installing, or even considering, PV. This has led to an information landscape that seems focused on simple, positive renditions of PV's costs, benefits, and risks. How can government, environmental organizations, research institutions, or other non-sales entities provide up-to-date, balanced, and more trusted guidance? A detailed analysis of PV information search and decision processes among consumers could help.
- *Using existing trust and connections.* Most survey respondents said that, when it came to information on PV, they had far higher trust in friends, family, and other peers than in institutions. How can this peer experience be shared more broadly without being or appearing fake? In contrast to normal customer endorsements, which are normally highly

positive, could wider availability of balanced reports—including lessons learned and things that went wrong—on the experience of PV purchase and use improve system adoption choices, expectations, and satisfaction?

- *Monitoring post-PV experience to better understand the public benefits of PV.* What happens after households adopt PV? How do PV adopters change how they think about energy, and how much energy they use? For example, if PV makes using additional central air conditioning very cheap, do households use more air conditioning, and with what (if any) consequences to the environmental benefits of PV?
- *Monitoring post-PV experience to improve future offerings and experiences*. Tracking households' longer-term experiences with PV could also help both marketing and system performance. These experiences, if systematically collected, could inform improvements to product offerings, technical characteristics and options, marketing, expectation setting, or benefits estimates. Given the common misperception that rooftop PV will protect homes from losing power during a blackout, could technological developments in inverters or battery backup increase interest in, and satisfaction with, PV? Could do-it-yourself installation options (mentioned by some respondents; see also Dóci and Vasileiadou 2015) help bring in a different type of PV customer largely missing from current markets?
- *What PV adoption niches do current systems and sales techniques miss?* As is, different PV installation companies specialize in particular consumer interests, circumstances, and geographies, but some potential segments may be overlooked. For example, to what extent are people being alienated by current solar marketing or solar politics? Are women being relatively neglected in PV offerings? Could ground-mounted systems or positive renditions of community solar help deliver PV-based electricity to households that are otherwise not suited to it?

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Residential Solar-Adopter Income and Demographic Trends: 2021 Update

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Report Outline

1. Introduction

- Overview and key findings
- Data sources and geographic coverage

2. Solar-Adopter Income Trends

- Temporal and geographic trends
- Solar-adopter incomes compared to the broader population
- Low-to-moderate income (LMI) shares of solar adopters
- Income trends based on:
  - Third-party ownership (TPO)
  - Installer
  - Battery-storage pairing
  - Multi- vs. single-family housing

3. Other Socio-Economic Trends for Solar Adopters

- Home value
- Credit score
- Education
- Occupation
- Rural vs. urban
- Race and ethnicity
- Age

4. Conclusions

5. Appendix

Overview

Report describes income- and other demographic trends among U.S. residential solar photovoltaic (PV) adopters

- Pairs Berkeley Lab's *Tracking the Sun* dataset and other sources of PV addresses with *household-level* income and demographic data: unique in both its level of market coverage and granularity
- Updates and expands previous reports with data on adopters through 2019 and an expanded range of demographic trends, beyond the prior focus primarily on income
- Intends to be descriptive and data-oriented; complements and informs other ongoing work at Berkeley Lab surrounding issues of solar energy access and equity, including:
  - An online data visualization tool that allows users to further explore the underlying dataset in this report
  - In depth analyses around drivers and potential solutions to solar energy adoption inequities
  - Institutional support to organizations working on solar energy access and equity

For further information on related research at Berkeley Lab, see:
solardemographics.lbl.gov

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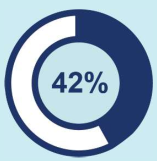
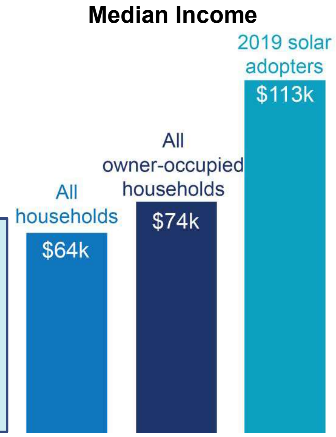
High-Level Findings

Solar adopter incomes vary considerably, but are generally higher than population averages

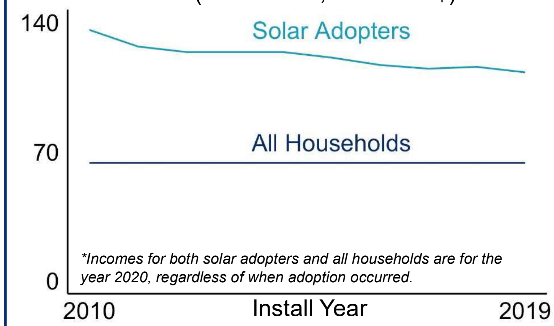
- The median solar adopter income was about $113k/year in 2019, compared to a U.S. median of about $64k/year
- The skew toward high incomes is particularly stark among adopters that own their systems and for those with paired solar-plus-storage systems



Low- and Moderate-Income Adoption
While solar adoption skews toward high-income households, low- and moderate-income households are also adopting. In 2019, about 42% of adopters earned less than 120% of their area's median income. (120% is a threshold sometimes used to include both low and moderate income)



Over time, solar adopters increasingly resemble the broader population



- The difference in income between solar adopters and the broader population fell from $72k/year in 2010 to $49k/year in 2019, at the median
- Solar adopters have become more reflective of the broader population in terms of education levels, race, and occupation
- These trends reflect the effects of falling solar prices and the emergence of policies and business models that support broader adoption, among other factors

Solar adopters vary along other demographics

Compared to the broader population, solar adopters tend to:

- Live in higher-value homes
- Have higher credit scores
- Have more education
- Live in majority-white block groups
- Be older
- Work in business and finance-related occupations

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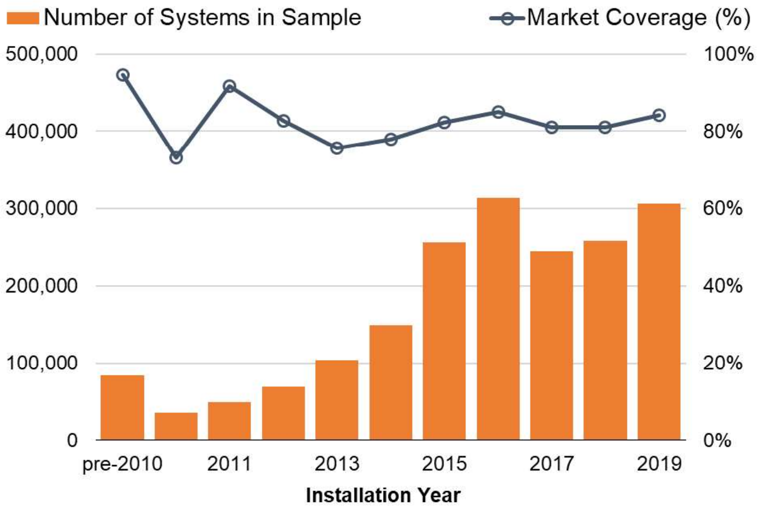
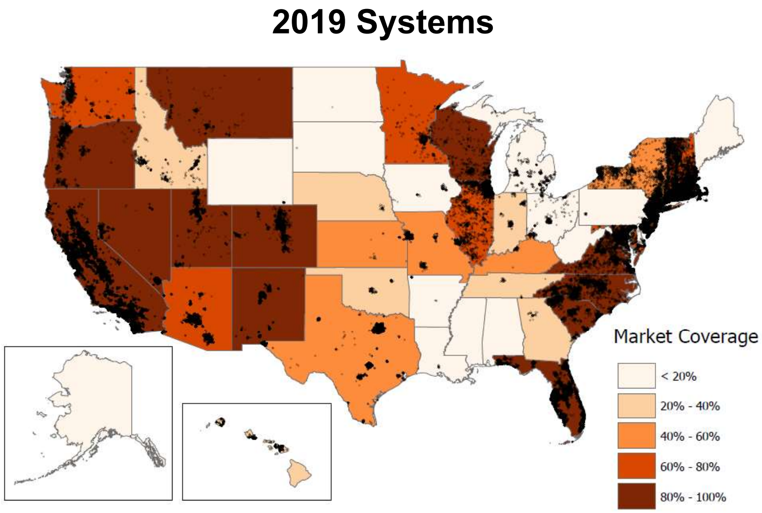
Data Sources

PV Street Addresses & System Data	Income & Other Socio-Economic Data
◻ Berkeley Lab's ***Tracking the Sun*** dataset: Primary data source; includes addresses and other data for roughly 1.5 million systems, obtained primarily from utilities and state agencies ◻ **BuildZoom** and **Ohm Analytics**: Purchased PV permit datasets; provide a supplementary source of PV street addresses for roughly an additional 400,000 systems	◻ **Experian ConsumerView**: Purchased dataset providing modeled household-level income estimates for solar adopters and for population as a whole; as well as household data on other socio-economic attributes ◻ **U.S. Census** and **Bureau of Labor Statistics**: Used for comparison purposes to characterize demographics of total U.S. population

See appendix slides 38-39 for further details on income and other socio-economic data sources

Sample Coverage





Sample consists of **1.9 million systems**, covering **82%** of all U.S. residential systems through 2019 and **84%** of systems installed in 2019

See appendix slides 40-41 for further details on sample sizes

General Points on the Data and Descriptive Approach

- We focus here on national and state-level trends, with an emphasis on PV systems installed in 2019; additional data, including county- and Census tract-level trends, as well as data for earlier years, are available through Berkeley Lab's online data visualization tool
- Temporal trends are shown starting from 2010; data are available for earlier years but tend to be noisy, due to small sample size, and are heavily dominated by California
- Income estimates from Experian are based on the first quarter of 2020, regardless of the date of installation, and thus represent current incomes, rather than incomes at the time of adoption
- For all state-level figures, we present trends only if the underlying sample consists of at least 100 systems and at least 10% market coverage for the applicable state and year; see appendix slide 40
- Sample sizes vary across different elements of the analysis, depending on the underlying data sources and completeness of the associated data fields; see appendix slide 41 for details
- All comparisons of solar adopter incomes to Area Median Incomes (AMI) are based on household size; as used throughout this report, "Area" refers to the applicable U.S. Census Core-Based Statistical Area or county (for rural areas)

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Solar-Adopter Income Trends

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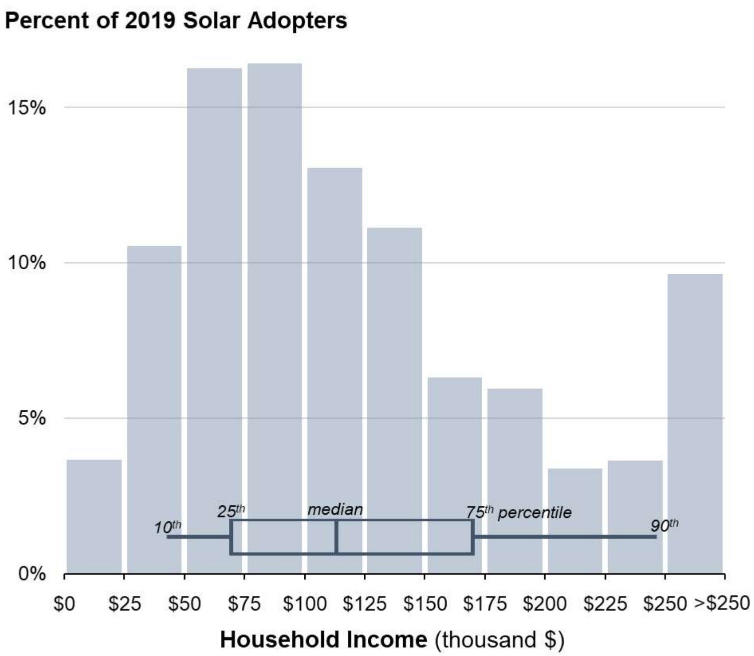
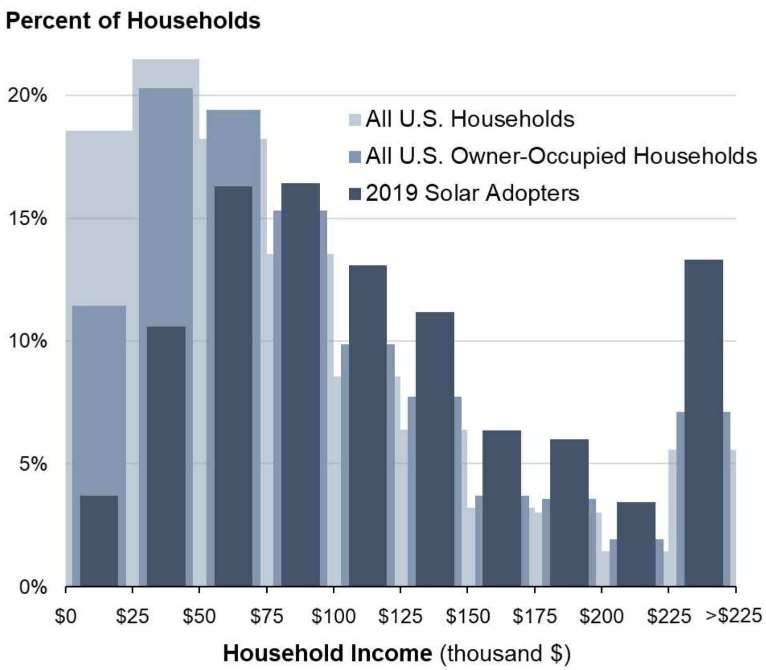
Solar-Adopter Income Distribution



- Solar-adopter household (HH) incomes span all income ranges
  - Distribution peaks at $50-100k, but with a long upper tail
- Median solar-adopter HH income was $113k in 2019
  - Half of 2019 solar adopters (the 25-75th percentile range) had incomes of $69-170k
  - While the large majority (10-90th percentile range) fell between $42-247k

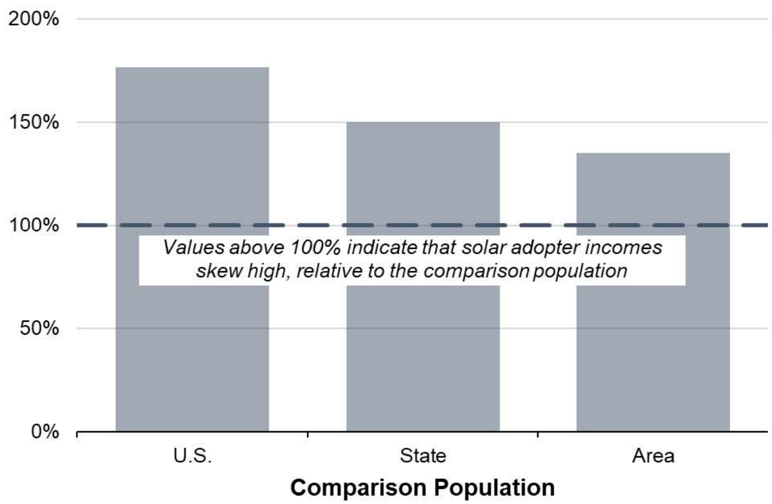
Solar-Adopter Incomes Compared to Total U.S. Population



- Solar-adopter incomes skew high relative to the population at large
  - Median income of all U.S. HHs is $64k, compared to $113k for 2019 solar adopters
  - Disparities are most pronounced at the low and high ends of the income spectrum
  - The next set of slides provide a more refined set of metrics to characterize the degree of skew
- Skew is less pronounced if comparing to only owner-occupied households (OO-HHs)
  - Median income of all OO-HHs is $74k
  - Solar adopters in this study are almost entirely OO-HHs (due to owner-control of rooftop, owner/tenant split incentive)

Solar-Adopter "Relative Income"

Median Solar-Adopter Relative Income (2019 Adopters)
% of Comparison Population Median Income



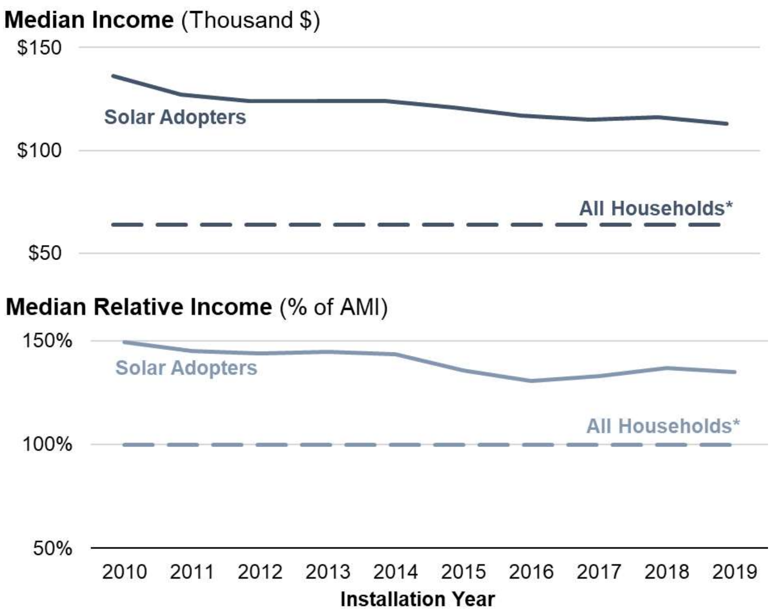
Note: To calculate these values, we first calculate each solar adopter's household income as a percentage of the median household income for each comparison population, and then take the median of those percentage values across all solar adopters.

Relative Income: Solar adopter HH income *as a percentage* of the median income of all HHs

- Provides a simple metric to characterize the degree to which solar adopter incomes differ from the rest of the population
- Can be based on comparison populations at different geographical scales: here we compare to national, state, and area medium incomes
- Solar-adopter incomes skew high, regardless of how broadly defined the comparison region, though the skew is smaller the more localized the comparison

Going forward, we default to Area Median Income (AMI) as the basis for calculating relative incomes

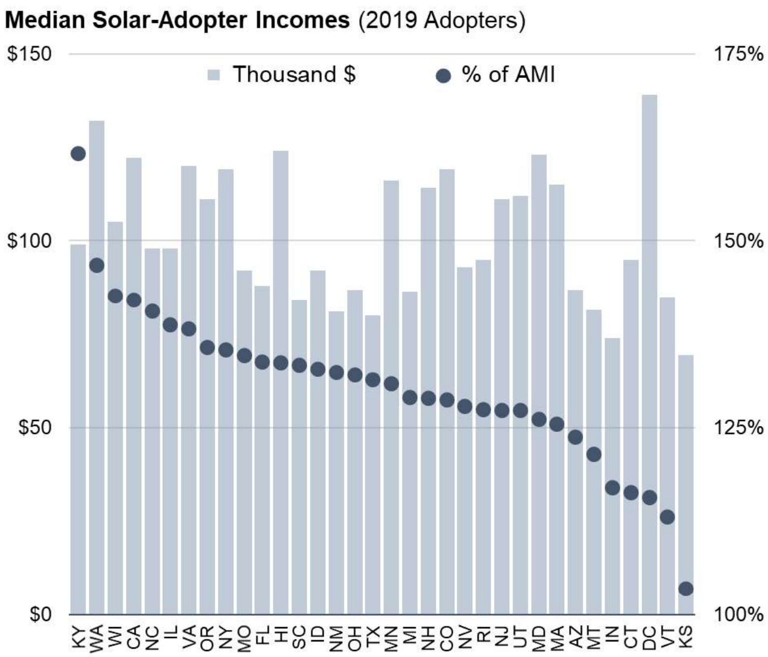
Solar-Adopter Income Trends over Time



**The flat lines for "All Households" reflect incomes in Q1 2020 and simply serve as a reference level for the solar-adopter incomes, which are based on the same timeframe.*

- Solar adoption has been slowly migrating toward lower incomes over time
- We see this in terms of both absolute and relative incomes, though the trend in relative incomes has flattened in recent years
- Long-term trends reflect some combination of:
  - Falling PV prices
  - Maturing PV markets
  - Expansion of PV financing options
  - Programs targeting LMI households
- Recent trends impacted by shifting market share of TPO, as shown later in slide 20

Solar-Adopter Income Trends across States



- Solar-adopter median incomes vary widely across states, as expected, given general differences in income levels across states
- All states exhibit some skew toward higher incomes, with median relative incomes typically ranging from 120-140% of AMI
- Some of that variation (especially at the extremes) may be idiosyncratic, though may also reflect fundamental drivers, such as:
  - Relative levels of solar market maturity
  - Solar policies and programs
  - Availability of financing
  - Income inequality within the broader population

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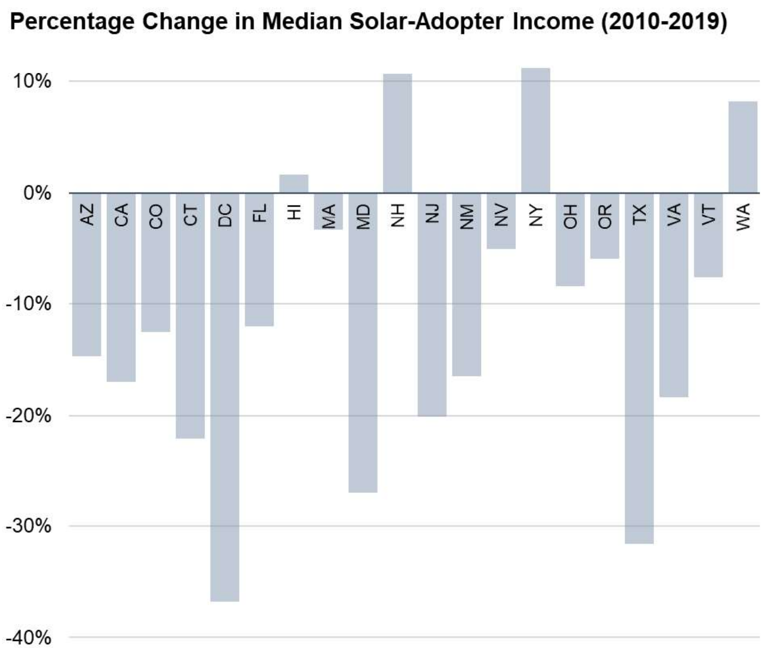
Solar-Adopter Income Trends over Time by State



- Virtually all states show a trend toward lower income adopters over time, with generally about a 5-20% drop in median adopter incomes over the 2010-2019 period
- Though not shown here, similar trends occur at the county-level as well
- Trends reflect both *deepening* and *broadening* of solar markets (O'Shaughnessy et al. 2021)
  - ***Deepening***: Solar adoption within existing markets progressively moving toward lower incomes
  - ***Broadening***: Solar adoption expanding into previously under-served, lower-income areas within each state

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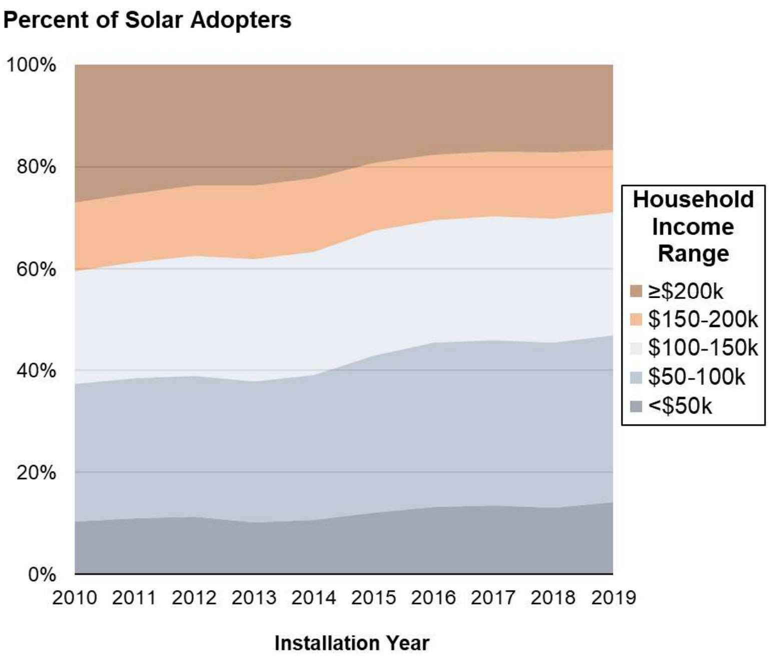
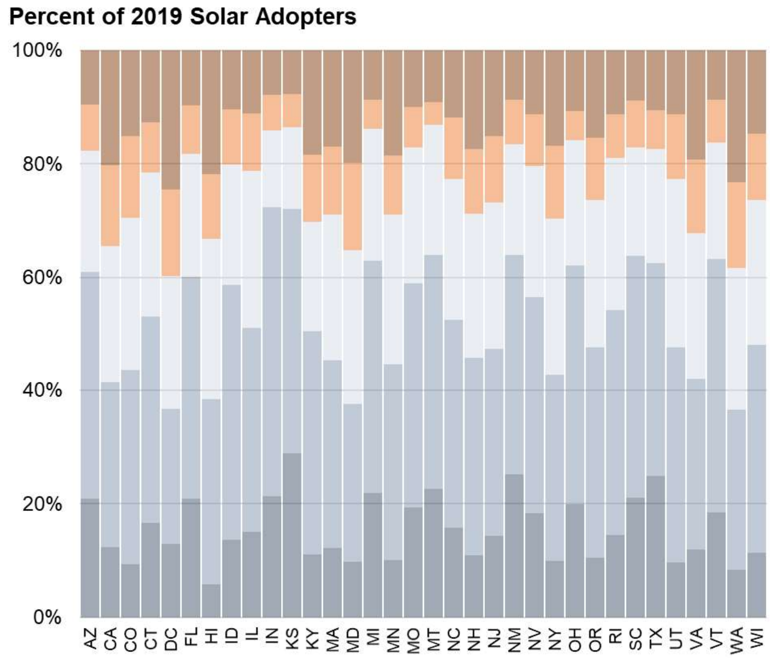
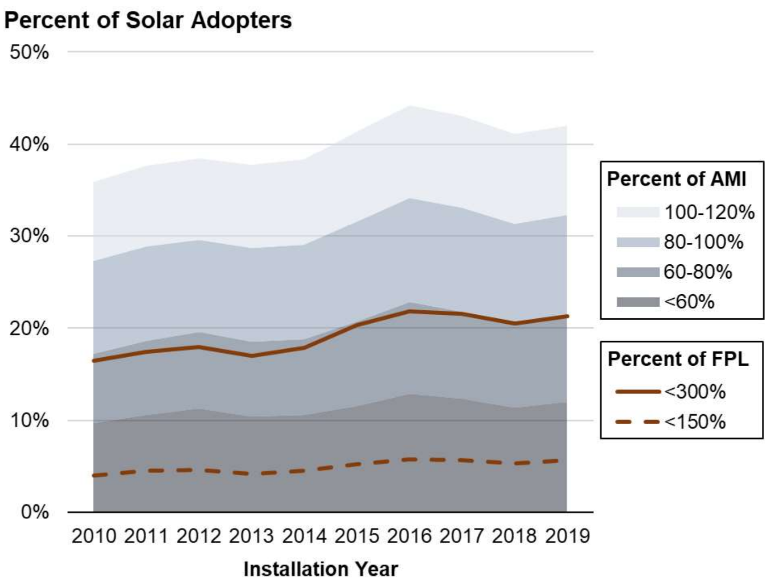
Solar-Adopter Income Distributions over Time and by State

Similar trends to median incomes, but highlighting the spread in adopter incomes





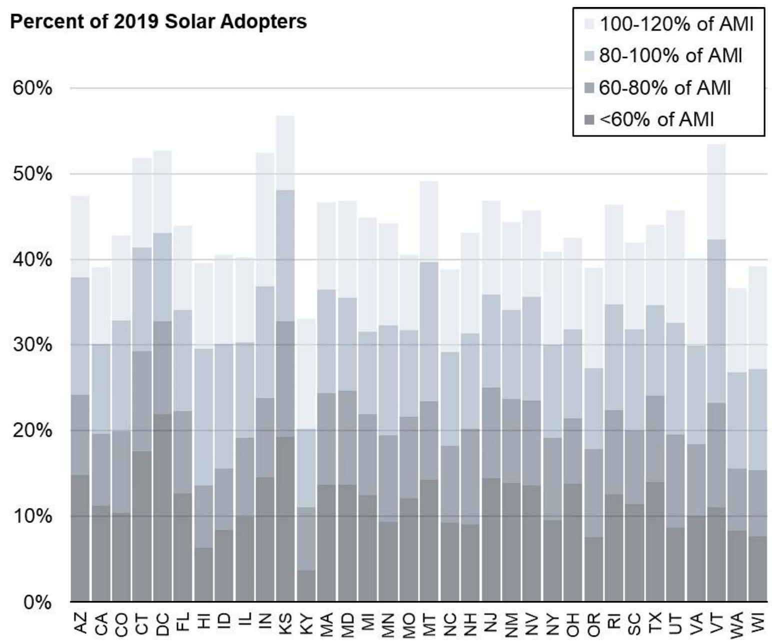
LMI Share of U.S. Solar Adopters over Time

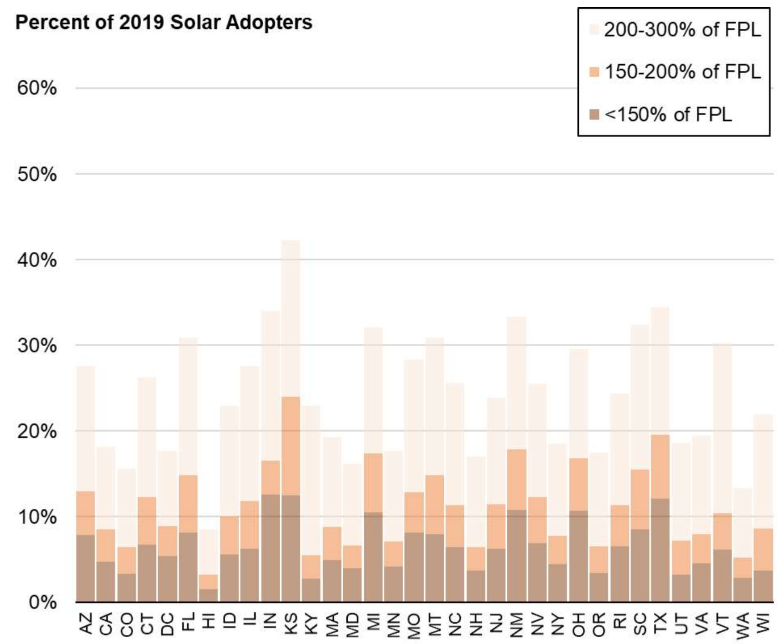


Notes: Both AMI and FPL vary by household size. For a family of three, the FPL for the contiguous 48 states was $21,330 in 2019.

- Various income metrics and thresholds can be used to define "low-to-moderate income" (LMI):
  - 150% of Federal Poverty Level (FPL) is common, especially in federal programs
  - 80% of AMI is also frequently used
  - Higher thresholds (e.g., 300% of FPL, 100-120% of AMI) are sometimes used to include "moderate" income
- Regardless of how its defined, LMI shares of U.S. solar adopters are trending up over time
  - Consistent with earlier trends in absolute income levels, and notwithstanding some variability in changes year-over-year
- Across all U.S. solar adopters in 2019:
  - **AMI:** 21% were <80% of AMI, 42% were <120% of AMI
  - **FPL:** 6% were <150% of FPL, 21% were <300% of FPL

LMI Share of Solar Adopters by State

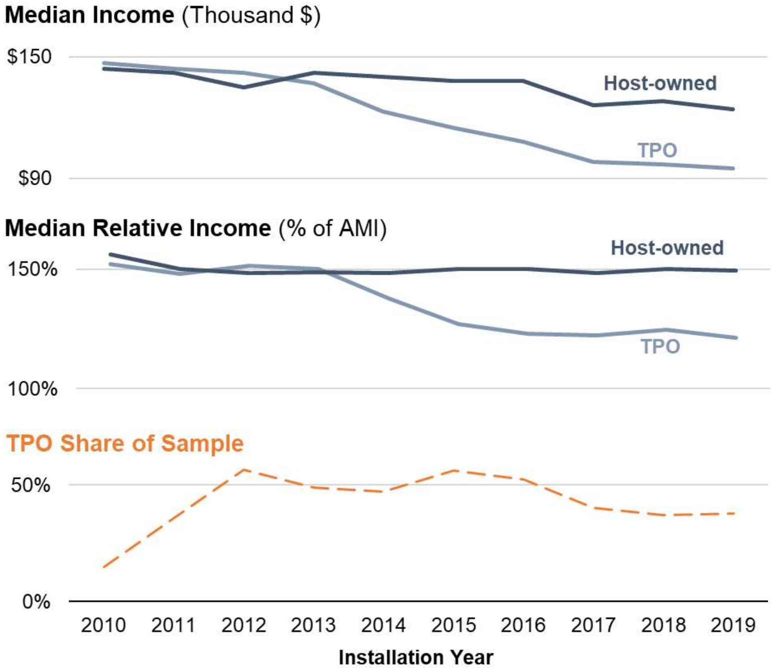




Solar-Adopter Income Trends by Segment

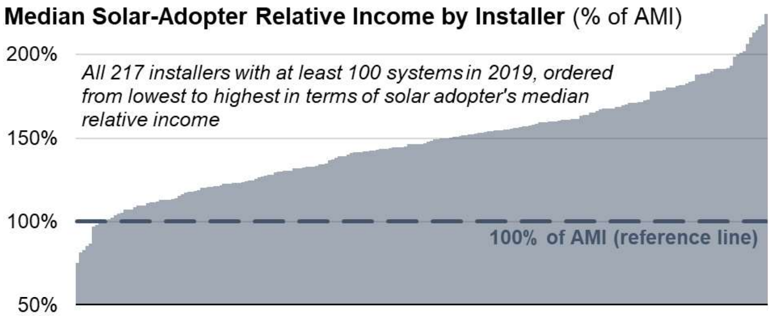
- Beyond looking at how solar-adopter incomes vary over time and geography, we can also evaluate differences by market segment
- Here, we focus on several segmentations:
  - Third-party vs. host-owned systems
  - Differences across solar installers
  - PV systems installed with battery storage vs. stand-alone PV systems
  - PV systems installed on multi-family vs. single-family homes
- Each comparison is based on the subset of the sample for which data on the relevant segmentation are available (see slide 41 for applicable sample sizes)
- Comparisons are made primarily in terms of relative incomes, though the same basic trends apply in terms of absolute income levels as well

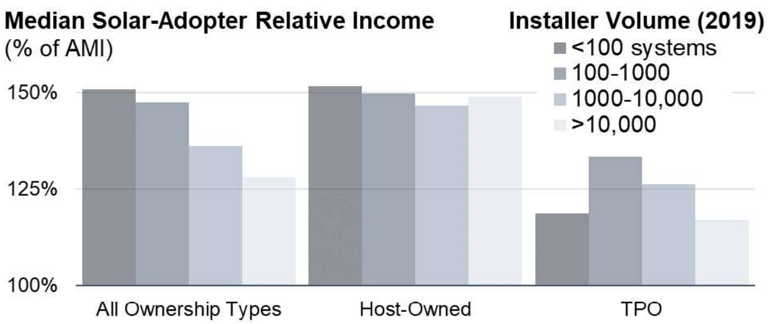
Third-Party vs. Host-Owned Systems



- Solar adopter incomes for third-party owned (TPO) systems are presently lower, and have declined much more significantly over time, compared to host-owned systems
  - Though not shown here, state-level comparisons generally exhibit the same basic trends
- O'Shaughnessy et al. (2021) found that TPO has driven adoption by lower income HHs
- Implication is that the general trend toward lower income solar adopters, observed earlier, can be substantially attributed to TPO
- The recent decline in TPO market share has likely dampened the overall trend toward lower income solar adopters

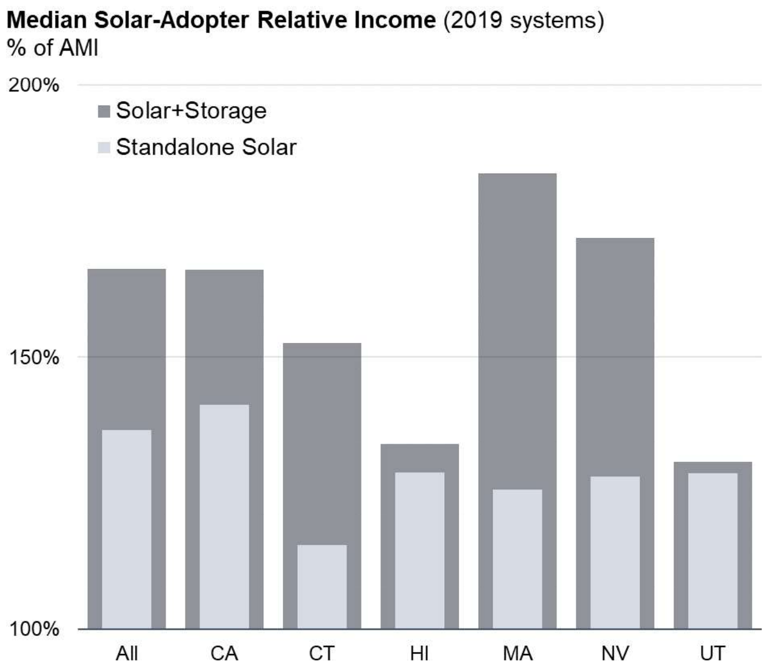
Installer-Level Trends





- Solar-adopter relative income varies considerably across installers, though virtually all skew higher than AMI
- Among the small set of installers (8 firms) with median incomes below AMI are several with business models focused specifically on LMI
- Larger volume installers exhibit lower relative income, primarily because they tend to more heavily favor TPO
- Among host-owned systems, installer size has no bearing on relative income; among TPO systems, the relationship is ambiguous (relative incomes are generally lower the larger the installer, except for the smallest installers)

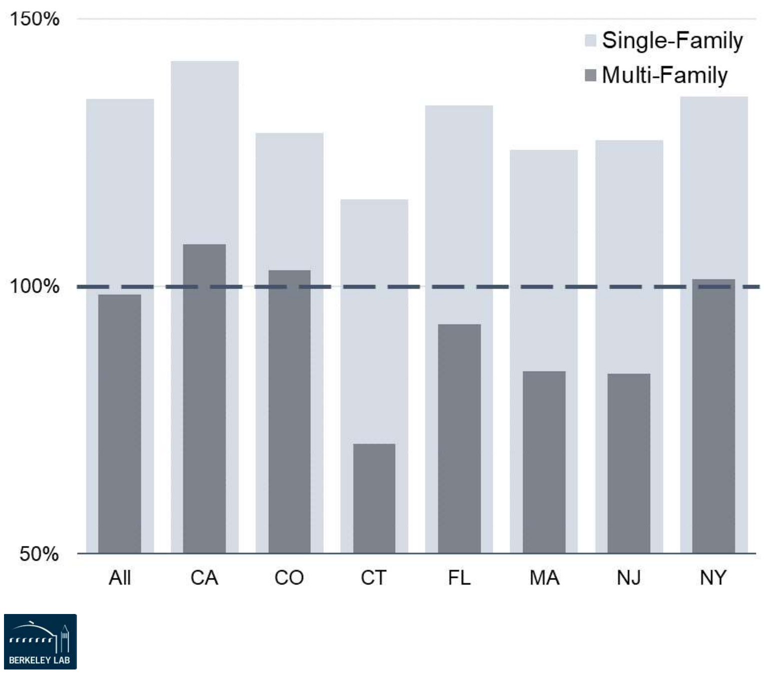
Paired Solar+Storage vs. Stand-alone Solar



- Roughly 4% of the PV systems in the sample were paired with storage in 2019, but that rate is growing (Barbose et al. 2021)
- Paired solar+storage systems typically cost about 30% more than stand-alone PV systems, for standard system sizes
- Not surprisingly, given the price differential, solar+storage adopters tend to have higher incomes (roughly 22% higher) than stand-alone solar adopters
- The solar+storage sample is dominated by CA, but the general trend in income differences between paired vs. stand-alone systems is consistent across other states as well

Multi-Family vs. Single-Family

Median Solar-Adopter Relative Income (2019 systems)
% of AMI



- Roughly 2% of all solar systems in the 2019 sample were installed on multi-family buildings
  - Most are owner-occupied; includes condos
- Multi-family solar adopter incomes are considerably and consistently below those of single-family adopters
- Across all multi-family systems in the dataset, incomes are roughly equivalent to AMI, but are well below AMI in several states
- Data on participation in income-qualifying solar programs is incomplete, but suggests higher participation by multi-family than single-family households, though still a minority overall
  - In CA, 20% of multi-family vs. 1% of single-family solar adopters participated in LMI programs

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Other Socio-Economic Trends for Solar Adopters

Approach to Describing Other Socio-Economic Trends

- Going beyond household income, we describe trends in other demographic and financial attributes of solar adopters (*see slides 38-39 for details on these variables*):
  - Home Value
  - Credit Scores
  - Education Level
  - Occupation
  - Rural vs. Urban
  - Race and Ethnicity
  - Age
- Trends describe the distribution of solar adopters nationally, changes over time, and comparison to the broader (in most cases, total U.S.) population
- Many of these trends illustrate a consistent theme: solar adopters more closely resembling the broader US population over time, but still exhibit some skew
- Some of these attributes may be correlated to income, leading to parallel trends

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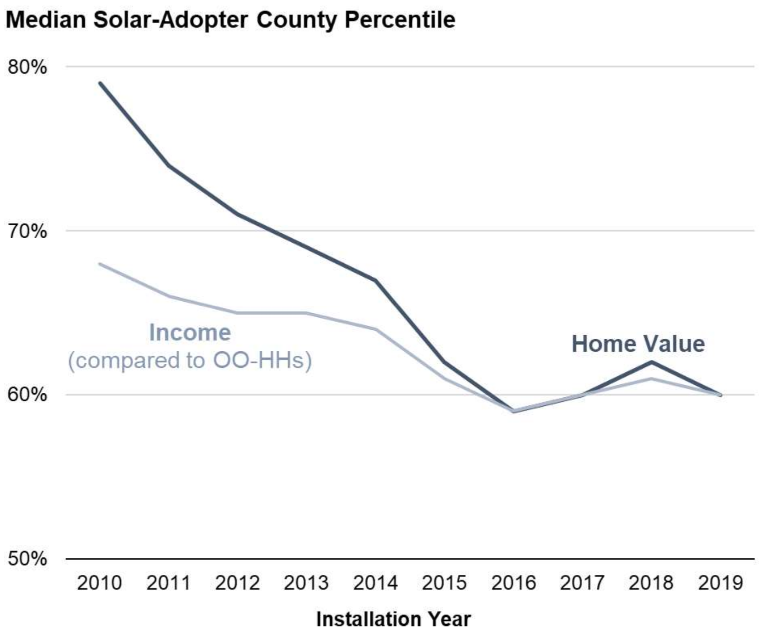
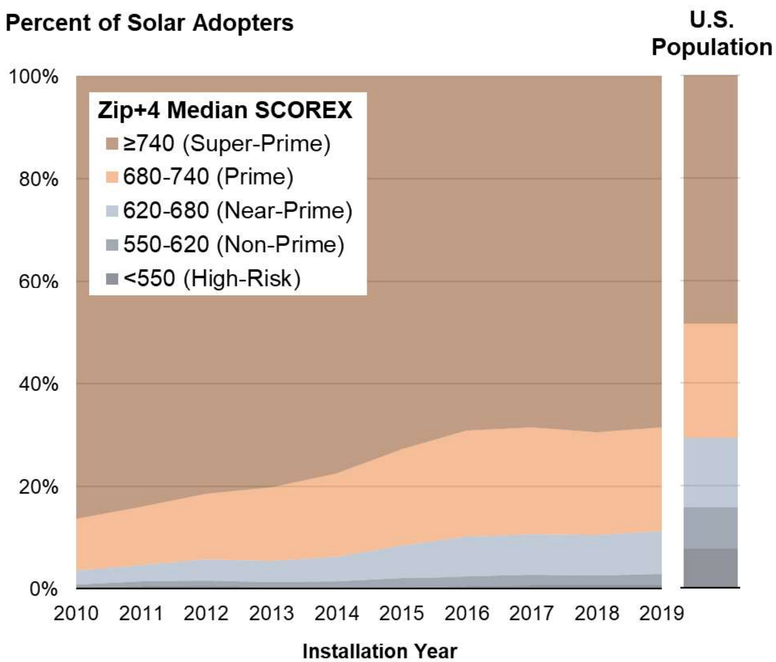
Home Value



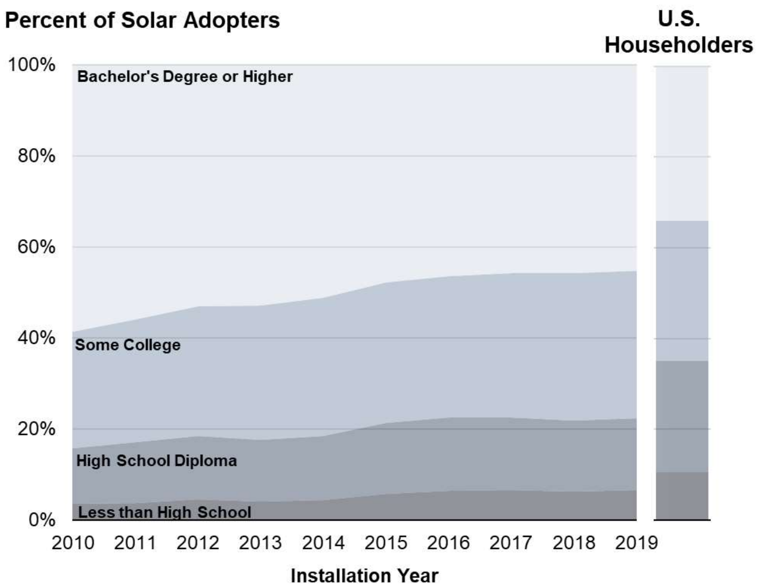
- Home value provides a measure of household *wealth*, as distinct from income—albeit only for households that own their home
- Solar-adopter home value data are expressed as a *percentile* of all homes in the same county (a different metric for expressing relative value)
- Solar-adopter home values are generally higher than others in the same county (above the 50th percentile), though that skew has declined substantially over time
- And has converged to resemble the skew in income among owner-occupied households (OO-HHs)
- A more comprehensive metric of wealth is needed to fully assess how solar adopters compare to the broader population, which includes renters

Credit Scores



- Due to privacy issues, credit score data consist of median values for all individuals in each solar adopter's zip+4, rather than individual or HH-level scores
- Solar adopters skew toward higher credit-score zip+4s, with a disproportionately large share of Super-Prime and virtually none with credit scores in the lower two groups—no doubt highly related to home ownership
- The skew has diminished over time as solar adopters within the middle tiers (Prime and Near-Prime) have comprised a larger share, though that trend has flattened in recent years

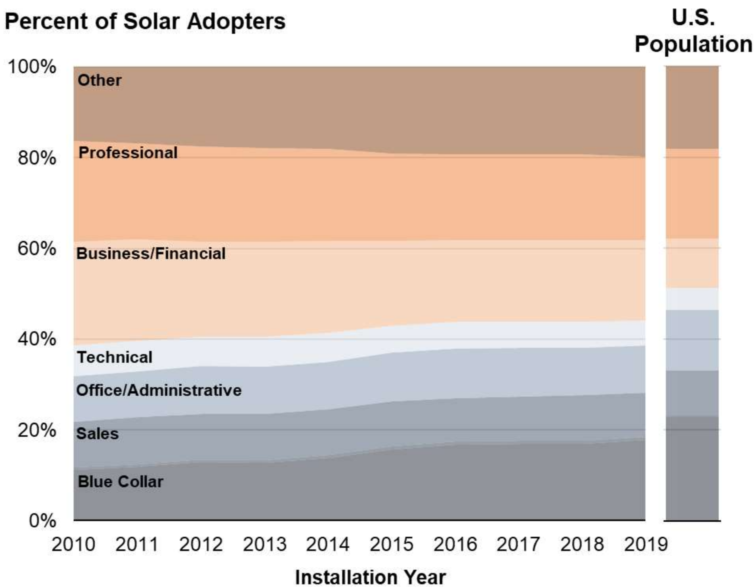
Education Level



Notes: Education level for each solar adopter is based on the highest known education level among adult household members, and for the U.S. population is based on the education level of householders.

- Almost half (45%) of all solar adopters in 2019 had a bachelor's degree or higher, while 22% had a high school diploma or less, and the remainder in between
- Solar-adopter educational levels are generally higher than the population at large, where 34% have at least a bachelors degree and 35% have no more than a high school diploma
- That skew has diminished somewhat over time: in 2010, 59% of solar adopters had a bachelors degree, while 16% had no more than a high school diploma
- As with income, the trends in educational levels have flattened in recent years

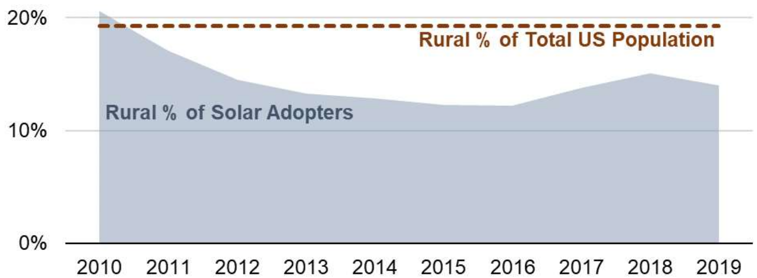
Occupation

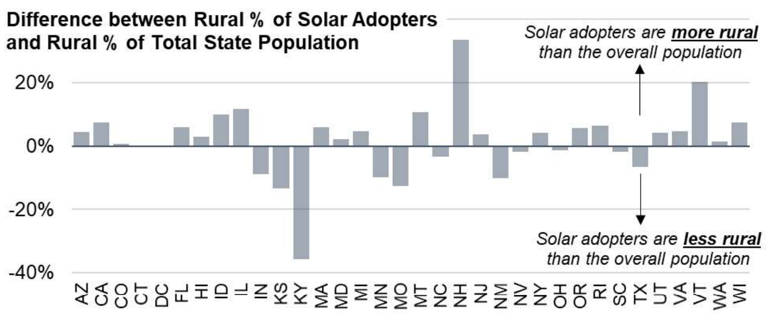


Notes: Occupation statistics for solar adopters are based on all adult household members. Statistics for U.S. population are based on data from the U.S. Bureau of Labor Statistics, consolidated and mapped on to the Experian's occupational categories.

- Similar shares of 2019 solar adopters came from professional, business & financial, and blue-collar occupational categories, as well as the catch-all "other" category
- Compared to the broader U.S. population, solar adopters are over-represented by business & financial occupations and under-represented by blue-collar occupations
- However, that skew has diminished greatly over time, as blue-collar occupations comprise increasingly larger shares of new adopters

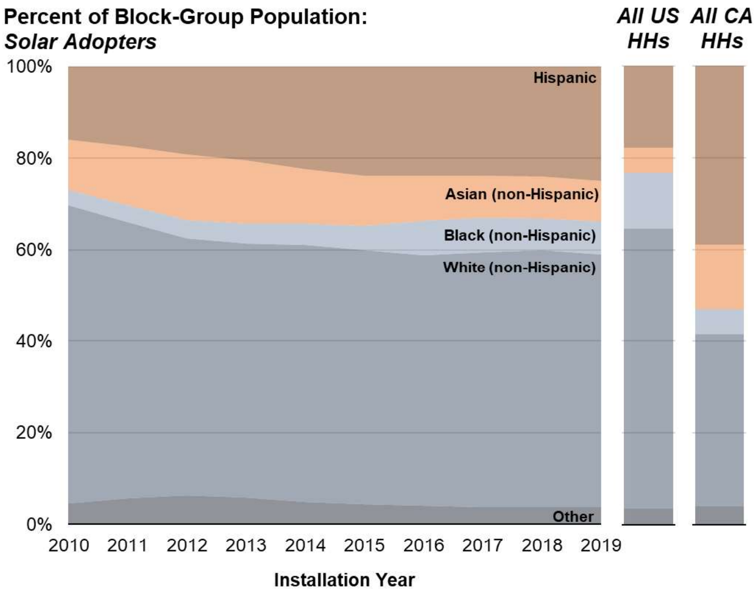
Urban vs. Rural





- U.S. Census defines "rural" vs. "urban" areas based on population density; urban areas often include surrounding suburbs/exurbs
- Solar adopters are slightly less rural than the U.S. as a whole: 14% of solar adopters in 2019 vs. 19% of the total U.S. population
- Temporal trend is mixed: solar adopters were less rural in 2019 than in 2010, but trends have shifted over the intervening years
- National trends reflect the fact that solar adoption skews towards less rural states
- At the individual state level, solar adopters may be more or less rural than the state as a whole (if anything, they tend to skew rural)

Race and Ethnicity:
National Trends

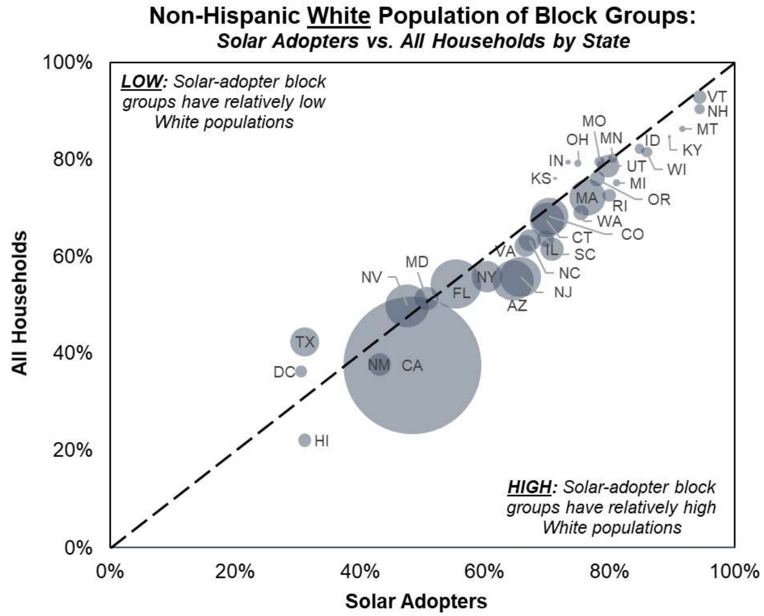


Notes: To construct the figure, each household (solar adopter or otherwise) is assigned the racial/ethnic composition of its block group, and the values plotted are the averages across all applicable set of households.

- Data on race and ethnicity of individual solar adopters were unavailable for this study; we instead characterize solar adopters based on the composition of their block group
- Compared to all U.S. households, solar adopters live in block groups with larger Hispanic and Asian populations, and with correspondingly smaller White or Black populations
- To a significant degree, this reflects broad geographical trends in solar adoption: specifically, roughly half are in CA, which has relatively large Hispanic and Asian populations

Race and Ethnicity:

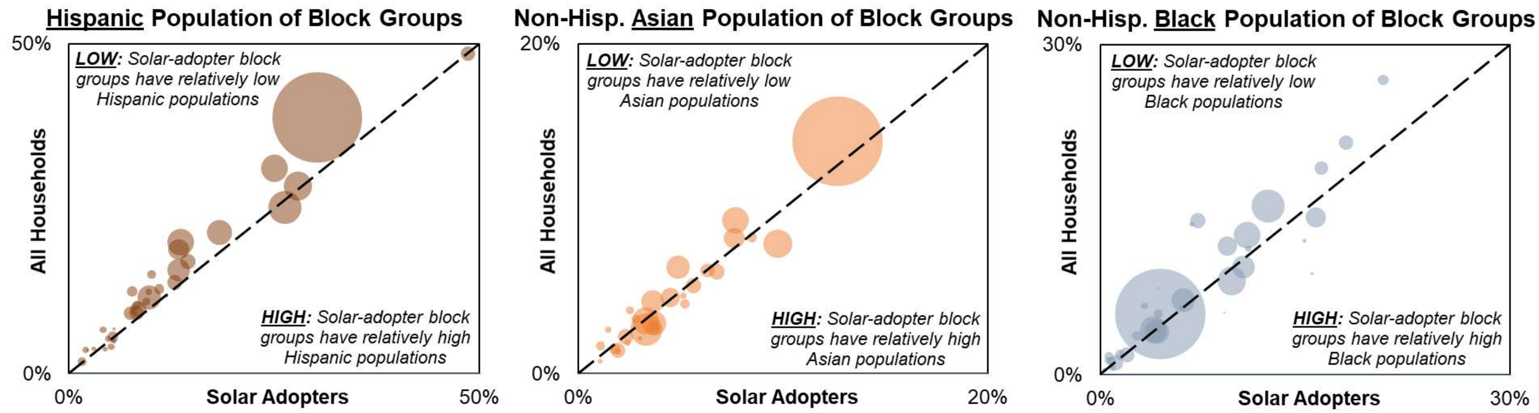
State-Level Differences in Non-Hispanic White Population



Notes: The size of the bubbles represents the solar-adopter sample size. See the previous slide for a description of how the plotted values were calculated.

- State-level comparisons show that solar adopters generally skew towards block groups with relatively high White population
- The figure compares the percentage of the block group population that is White (non-Hispanic) for solar adopters vs. all households in each state
- As shown, in most states, solar adopters skew toward block groups with larger White populations (i.e., are below the diagonal line)
- In CA, the disparity is relatively high: solar adopters live in block groups where, on average, 48% of the population is White, compared to 38% for all HHs in the state

Race and Ethnicity:
State-Level Differences in Hispanic, Black, and Asian Populations



- Solar adoption generally skews toward block groups with relatively low Hispanic and Black populations, with somewhat larger and more consistent disparities for Hispanic populations
- In contrast, solar adoption skews toward block groups with relatively high Asian populations in most states (roughly two-thirds), though not in California, and the skew is much smaller than that observed for non-Hispanic White populations on the previous slide

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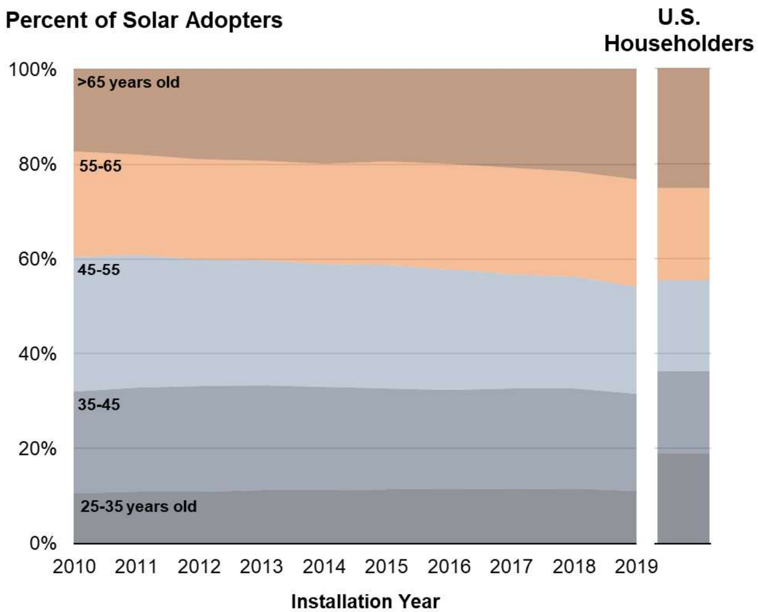
Age



Notes: Ages for solar adopters are based on the primary household member, adjusted to reflect age at the time of adoption, and for the U.S. population are based on the householder.

- As a general matter, solar adopters skew slightly older than the broader population (comparing among adults 25+)
- This is largely due to under-representation among the youngest group (25-35), which is not surprising, given lower home ownership rates and incomes
- The most notable shift over time has been an increasing share of solar adopters within the oldest age group (65+), which had previously been under-represented
- That trend is consistent with growing technology acceptance (less perceived risk), and likely fueled by greater availability of financing (key for individuals on fixed-incomes)

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Conclusions

ENERGY TECHNOLOGIES AREA | ENERGY ANALYSIS AND ENVIRONMENTAL IMPACTS DIVISION

Conclusions

- Solar adopters are heterogeneous in terms of their income and demographics
- Solar adopters diverge from the general U.S. population in many ways, skewing, for example, toward higher income, more urban, and more educated households
- Those differences are diminishing over time, albeit slowly
- The degree of disparity between solar adopters and the broader population varies significantly across states, and also tends to be smaller the more localized the comparison
- We highlight the role of third-party ownership in driving some of these trends, and speculate about other potential drivers, but further analysis would help to better understand the underlying dynamics—especially around the effects of policy interventions aimed at addressing adoption inequities

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Appendix

Key Experian Data Elements Used in this Analysis

- **Estimated Household Income**: The total estimated income for a living unit, incorporating several highly predictive individual and household level variables. The income estimation is determined using multiple statistical methodologies to predict the income estimate for the living unit.
- **SCOREX PLUS** : Predicts the likelihood of future serious delinquencies on any type of account. Due to limitations related to the Federal Fair Credit Reporting Act, data provided for each address represent the corresponding Census block medians, rather than the credit score of the specific individual or household.
- **Date of Birth/Combined Adult Age:** Date of Birth is acquired from public and proprietary files. These sources provide, at a minimum, the year of birth. The birth month is provided where available. Estimated ages are acquired from proprietary data sources and Experian models which estimate the adult age.
- **Dwelling Type:** Each household is assigned a dwelling type code based on United States Postal Service (USPS) information; could be either Single Family Dwelling Units, Multi-Family, Marginal Multi Family, P.O. Boxes, or Unknown.
- **Occupation Group:** Compiled from self-reported surveys, derived from state licensing agencies, or calculated through the application of predictive models.
- **Individual Education:** Compiled from self-reported surveys, derived based on occupational information, or calculated through the application of predictive models.

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Key Public Data Elements Used in this Analysis

- **U.S. Census American Community Survey 5-Year Data (2014-2018):** Educational attainment by householder (Table B25013); Hispanic or Latino origin by race – population (Table B03002); Age of householder (Table B25007)
- **U.S. Census 2010** Urban-rural classification: Rural, urban, and urban cluster populations by state; and definition by latitude/longitude for classification of solar adopters
- **Bureau of Labor and Statistics:** Occupational Employment Statistics Survey, May 2019

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State Sample Sizes: *TTS=Tracking the Sun, BZ=BuildZoom, Ohm=Ohm Analytics; Market Coverage based on comparison to Wood Mackenzie's Solar Market Insight report*

State	All Years					2019 Installations				
	TTS	BZ	Ohm	Total	Market Coverage	TTS	BZ	Ohm	Total	Market Coverage
AK	0	1	0	1	0%	0	0	0	0	0%
AL	0	2	0	2	2%	0	0	0	0	0%
AR	88	39	0	127	10%	0	27	0	27	5%
AZ	0	26,616	52,873	79,489	53%	0	1,252	12,512	13,764	70%
CA	981,359	47,200	0	1,028,559	96%	141,764	11,762	0	153,526	97%
CO	0	23,063	28,845	51,908	84%	0	1,034	10,461	11,495	100%
CT	37,651	1,247	0	38,898	94%	9,247	293	0	9,540	100%
DC	4,445	500	0	4,945	88%	889	301	0	1,190	70%
DE	0	966	0	966	15%	0	66	0	66	12%
FL	3,760	13,368	31,120	48,248	94%	894	4,377	15,231	20,502	100%
GA	0	124	0	124	13%	0	35	0	35	27%
HI	0	46,428	0	46,428	57%	0	1,398	0	1,398	38%
IA	0	273	0	273	9%	0	81	0	81	10%
ID	0	3,290	0	3,290	55%	0	848	0	848	32%
IL	7,092	173	0	7,265	74%	4,315	103	0	4,418	67%
IN	0	61	350	411	17%	0	4	202	206	30%
KS	0	69	301	370	77%	0	11	93	104	46%
KY	0	41	203	244	33%	0	18	91	109	40%
LA	0	1,888	0	1,888	12%	0	12	0	12	1%
MA	88,661	2,775	0	91,436	90%	9,660	883	0	10,543	77%
MD	0	9,577	38,613	48,190	73%	0	849	3,815	4,664	79%
ME	0	0	0	0	0%	0	0	0	0	0%
MI	0	1,292	1	1,293	19%	0	448	0	448	16%
MN	1,070	2,797	0	3,867	82%	0	746	0	746	65%
MO	0	399	1,812	2,211	26%	0	41	826	867	48%
MS	0	0	0	0	0%	0	0	0	0	0%

State	All Years					2019 Installations				
	TTS	BZ	Ohm	Total	Market Coverage	TTS	BZ	Ohm	Total	Market Coverage
MT	0	253	675	928	61%	0	11	339	350	80%
NC	12,212	1,022	0	13,234	99%	3,472	421	0	3,893	90%
ND	0	8	0	8	47%	0	1	0	1	13%
NE	0	122	0	122	56%	0	29	0	29	31%
NH	6,258	14	0	6,272	83%	847	9	0	856	77%
NJ	107,726	244	1	107,971	99%	13,293	26	0	13,319	88%
NM	20,381	1,086	0	21,467	99%	3,671	623	0	4,294	100%
NV	49,337	2,506	1	51,844	100%	14,708	609	0	15,317	100%
NY	71,619	2,743	0	74,362	61%	7,762	135	0	7,897	51%
OH	2,042	694	0	2,736	56%	59	334	0	393	19%
OK	0	18	110	128	17%	0	2	94	96	35%
OR	16,444	2,674	0	19,118	100%	1,158	833	0	1,991	100%
PA	5,980	1,908	0	7,888	30%	0	402	0	402	8%
RI	6,813	0	0	6,813	100%	1,487	0	0	1,487	88%
SC	0	819	11,735	12,554	64%	0	125	2,104	2,229	80%
SD	0	2	0	2	9%	0	1	0	1	6%
TN	0	224	0	224	15%	0	30	0	30	21%
TX	1,362	26,388	1	27,751	45%	49	6,885	0	6,934	44%
UT	13,031	4,516	0	17,547	48%	3,977	304	0	4,281	92%
VA	9,323	387	0	9,710	100%	3,599	158	0	3,757	98%
VT	12,326	3	0	12,329	100%	1,527	0	0	1,527	100%
WA	7,018	4,866	1,928	13,812	70%	1,144	113	777	2,034	70%
WI	3,284	207	0	3,491	81%	852	83	0	935	100%
WV	0	0	0	0	0%	0	0	0	0	0%
WY	0	25	0	25	4%	0	19	0	19	7%
US	1,469,282	232,918	168,569	**1,870,769**	**82%**	224,374	35,742	46,545	**306,661**	**84%**

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Sample Sizes by Analysis Element

Vary depending on data availability and unit of observation

Analysis Element	Unit of Observation	Sample Size	
		2019	All Years
Income (single-family)	Household	306,658	1,870,718
TPO vs. host-owned	Household	207,670	1,318,524
Installer name	Household	170,391	n/a
With or without storage	Household	186,839	n/a
Multi- vs. single-family	Household	312,836	n/a
Home Value	Household	258,079	1,555,724
Credit Score	Household	306,660	1,870,745
Education	Household	306,658	1,870,718
Occupation	Individuals	708,984	4,601,798
Urban vs. Rural	Individuals	902,298	5,860,654
Race/Ethnicity	Household	299,700	1,822,326
Age	Household	192,824	1,240,172

General Notes:

- With the exception of the multi- vs. single-family comparison, all other elements of the analysis are based only on single-family solar adopters
- The unit of observation for most analysis elements is the household, but for several elements (occupation and urban vs. rural), data for the overall U.S. population are available only at the individual level. In those cases, solar adopters summary statistics are based on all individuals in each household in order to allow for comparison to the U.S. population.
- Analysis elements related to TPO, installer name, and battery storage are based almost entirely on solar adopter addresses from Tracking the Sun

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California looks to reboot rooftop solar payments amid affordability concerns

Wednesday, March 24, 2021 11:17 AM ET

By Garrett Hering
Market Intelligence

A cluster of solar homes in San Francisco, Calif. The state has begun revising rooftop solar incentives.
Source: S&P Global Market Intelligence

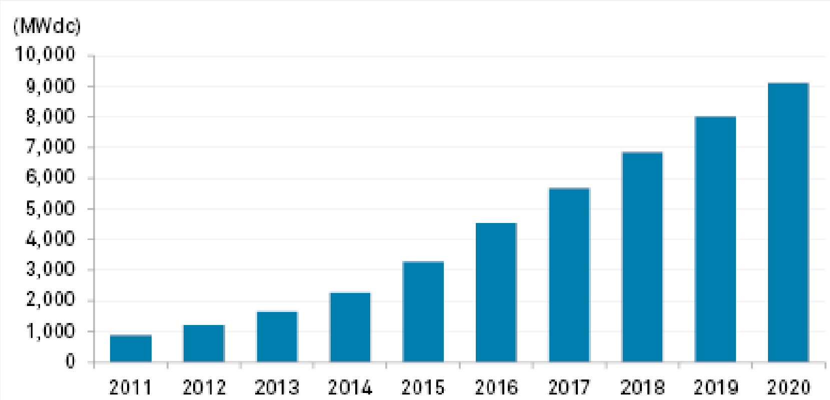
As California accelerates its clean energy transition, the state is considering a sweeping revision of solar incentives under its 25-year-old net energy metering policy to help keep overall electricity costs in check.

Amid rising rates and a jump in past-due utility bills during the COVID-19 pandemic, solar companies, investor-owned utilities, environmental groups, ratepayer advocates and regulators all agree that the time has arrived to reconsider incentive levels under the nation's most successful customer-sited solar policy. But there is widespread disagreement over how far the changes should go. An array of groups including the California Public Utilities Commission's Public Advocates Office, the AARP, the Natural Resources Defense Council, the California Wind Energy Association and investor-owned utilities is calling for big changes to address what the groups say is a multibillion-dollar annual shift in the cost of maintaining the power grid from solar-powered customers to ratepayers who do not have solar.

"If we don't fix the cost-shifting problem now, it's going to get exponentially worse, and we are going to end up with a true crisis in the coming years," said Matt Freedman, staff attorney for The Utility Reform Network, a nonprofit ratepayer advocacy group known as TURN, March 23 during a CPUC meeting about a variety of proposals. "And it's going to be a crisis of affordability that will primarily hit moderate- and lower-income ratepayers."

Under current net energy metering in the state, utility customers who install solar electric systems and other forms of on-site generation at homes and businesses are able to produce a large share of their own power needs while receiving a credit on their bills at the full retail electric rate for excess energy fed back into the grid. The alternative system that TURN proposed involves an upfront payment to be funded by sources other than lower-income Californians. One such source could be the state's cap-and-trade program, which is focused on reducing greenhouse gas pollution from major industrial emitters, according to Freedman.

Cumulative net-metered solar capacity in California



Data compiled March 18, 2021.
2020 data is through Nov. 20, 2020.
Source: California Public Utilities Commission

'Current tariffs are unsustainable'

The Public Advocates Office estimated the annual cost imposed on nonsolar customers at $2.85 billion and growing. "The current tariffs are unsustainable, and if the commission does not reform the tariffs, the cost burden to be paid for by non-participants will grow to $6.62 billion annually (in 2021 dollars) by 2030," the advocate said in a regulatory filing ahead of the meeting.

Investor-owned utilities Pacific Gas and Electric Co., Southern California Edison Co. and San Diego Gas & Electric Co. have jointly proposed a series of far-reaching changes to the existing net-metering program. Those include slashing compensation for electricity exported to the grid to levels aligned with less expensive large-scale solar power, rather than higher retail rates, as well as new monthly grid-use fees for solar-powered customers and discounts for low-income customers.

"Our proposal is meant to be a complete package," Erica Brown, senior manager of commercial policy at Pacific Gas and Electric, the operating arm of PG&E Corp., said at the March 23 meeting. "And we're really focused on reducing the cost shift [and] the impact to nonparticipants."

Utilities have not made an assessment of how their proposal would impact the solar market, Brown added.

'Utilities are always after us'

California solar installers oppose the utilities' proposal, saying it could destroy jobs and stall their market just as rooftop solar becomes more affordable to more low- and middle-income residents.

"Rooftop solar helps cut down on the need to build these expensive transmission lines which is why the utilities are always after us," said Bernadette Del Chiaro, executive director of the California Solar and Storage Association, in a statement on the utilities' proposal. "Solar roofs save everyone money by reducing the need to pave over the desert with power plants and build the wires to carry those electrons to our homes and businesses. Those savings work well for ratepayers but cut against utility profit."

The industry group, which represents roughly 600 companies, pitched a "reasonable glidepath" of declining net-metering rates based on deployment targets. Their proposal is designed to open access to solar for more lower-income Californians and to support growing volumes of battery storage coupled with solar arrays, viewed as critical tools for providing backup power during wildfire-driven outages and additional flexibility for an increasingly dynamic grid.

"This is, in my view, about energy storage," Brad Heavner, policy director of the California Solar and Storage Association, said at the meeting. "As we electrify our vehicles, our buildings, there's going to be a lot more load at the end of the line, and it will be really beneficial to have customer-sited energy storage that's helping to shape that curve and make the whole grid more manageable with that increased customer load."

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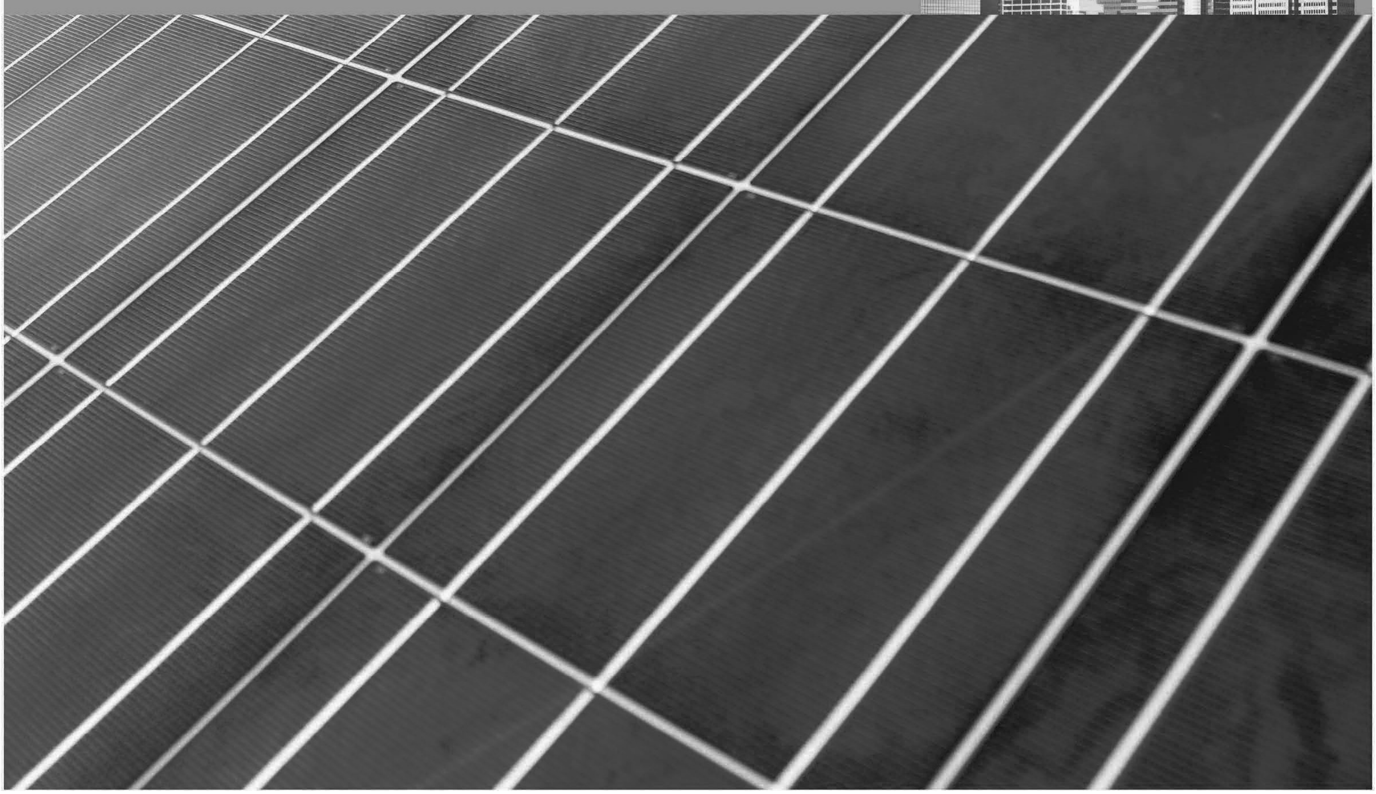
HIGH-PENETRATION PV INTEGRATION

HANDBOOK

FOR DISTRIBUTION ENGINEERS



2 High-Penetration PV Distribution-Level Impacts

2.1 Introduction

Traditionally, the distribution system has been designed to operate in a radial fashion, with flow in one direction from the substation source to the load. Starting with the passage of the Public Utility Regulatory Policies Act in 1978, distributed generation (DG) has begun to appear more frequently on the distribution system. Recently, because of improving economic viability, incentives, public utility commissions requiring the consideration of DG as an alternative to traditional circuit upgrades and state renewable portfolio standards, distributed photovoltaic (PV) systems have become more common. Although distribution engineers are more familiar today with the design and operation challenges posed by DG, high penetrations of PV, which has relatively unpredictable and sometimes highly variable output, represent a less familiar challenge.

Unlike traditional distribution analysis, which is done at a few meaningful time points (e.g., heaviest load), impacts of high penetrations of PV should be investigated using time-varying analysis, which captures the interactions among load, generation, and control equipment that are difficult to predict using a single time point analysis. Time-varying analysis should include the behavior of fast-acting inverters, dynamic loads, and automatic voltage control devices on the feeders.

This chapter documents potential impacts caused by high-penetration PV scenarios. Many definitions of high-penetration PV exist. For the purposes of this handbook, high-penetration PV is defined as the level at which the distribution network has a high likelihood of experiencing voltage, thermal, and/or protection criteria violations.

2.2 Overload-Related Impacts

High penetrations of PV systems can cause the ampacity ratings of circuit elements to be exceeded in a number of ways. Perhaps most intuitively, the total generation from attached PV systems can overload circuit elements located between PV systems and load centers on a given circuit. Additionally, PV can mask load that can overload circuit elements if the PV disconnects.

Also, although load is often quite diverse, PV systems located relatively close to each other are generally fairly coincident (depending on their orientation). In such cases, multiple instances of PV systems that are sized to offset the attached load (e.g., in a residential subdivision) may overload circuit elements because of the coincident nature of the peak PV output relative to the diverse nature of the peak load.

When examining overloads, consideration should be given to both normal system conditions and a contingency loss of circuit segments.

2.2.1 Ampacity Ratings

The location of PV can significantly impact the loading of feeder sections; therefore, it is necessary to verify that the feeder sections located between the PV and the substation have enough available capacity to distribute the PV's surplus power (after subtracting local and downstream load). At high penetrations, particularly during light load conditions with high PV output, the line section loading may increase as the PV contribution becomes larger than the native base load. The flow in some instances may increase above that of the peak native load (no PV output).

2.2.2 Masked Load

Masked load refers to load that is hidden from upstream components by PV or other sources of generation. Because many forms of DG are not monitored and can be disconnected or otherwise absent without prior utility knowledge, it is important that the total load is considered in design and operation practices. For the purposes of this report, the load attached to the circuit is referred to as native load.

Figure 2.1 shows the measured load, native load, and PV generation for a peak load day. The native load (gray line) of this circuit is much higher than the measured flow (light blue line) on the circuit, because the measured circuit flow is the combination of the native load and the PV generation (dark blue line). If decisions are made based on the measurements instead of the native load calculations, significant overloads of circuit elements may occur if the PV disconnects unexpectedly. This example illustrates the issue with basing design and operation practices on measured load.

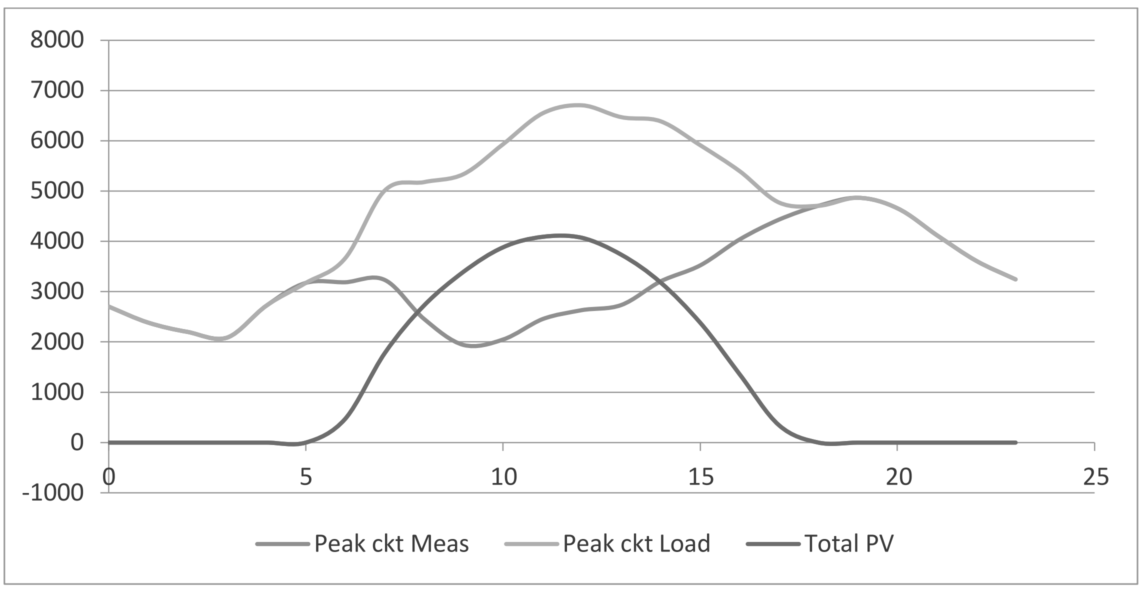


Figure 2.1. Masked load—difference between measured load and native load on a peak load day (Mather et al. 2014)

2.2.3 Cold Load Pickup

Cold load pickup takes place when a distribution circuit is reenergized after a long outage. In this situation, the loss of load diversity coupled with inrush currents can result in feeder current levels that may be much higher than the feeder's annual peak load. This may result in overloads and low voltages if the protection system does not trip first.

PV can exacerbate the cold load pickup problem by increasing the difference between the pre-fault measured load current and the post-fault cold load pickup current. Solar PV is typically tripped when a fault occurs. If the PV cannot reconnect to the system automatically after the fault is cleared (or system operators who could do so are not on standby), or if pre-fault generation levels are no longer available, the load picked up by the substation or the feeder's primary power source is a larger multiple of the pre-fault load compared to a scenario in which the feeder does not have solar PV.

Therefore, an assessment of the cold load pickup may be necessary when considering integrating large amounts of PV into the distribution system. Thus, again, determining the native load is of prime importance in designing circuits with high penetrations of PV.

More information about cold load pickup, as it pertains to system protection impacts, can be found in section 2.5.11.

2.3 Voltage-Related Impacts

High penetrations of PV can impact circuit voltage in a number of ways. Voltage rise and voltage variations caused by fluctuations in solar PV generation are two of the most prominent and potentially problematic impacts of high penetrations of PV. These effects are particularly pronounced when large amounts of solar PV are connected near the end of long and lightly loaded feeders. Real and reactive power production from the PV system can impact the steady-state circuit voltage, and rise and fall of PV output can result in voltage fluctuations on the circuit. This, in turn, impacts power quality and voltage control device operation. Potential PV impacts on voltage are discussed below.

2.3.1 Feeder Voltage Profile

With the addition of another power source internal to the distribution circuit, the voltage profile along the circuit may improve when the PV is operating.

2.3.2 Overvoltage

The extent to which voltage rise is experienced on a feeder depends on multiple factors, including the configuration of the feeder and the location of the PV and voltage control equipment, such as capacitor banks and voltage regulating transformers. Figure 2.2 shows an example of the impact of solar PV on the voltage profile of a feeder.

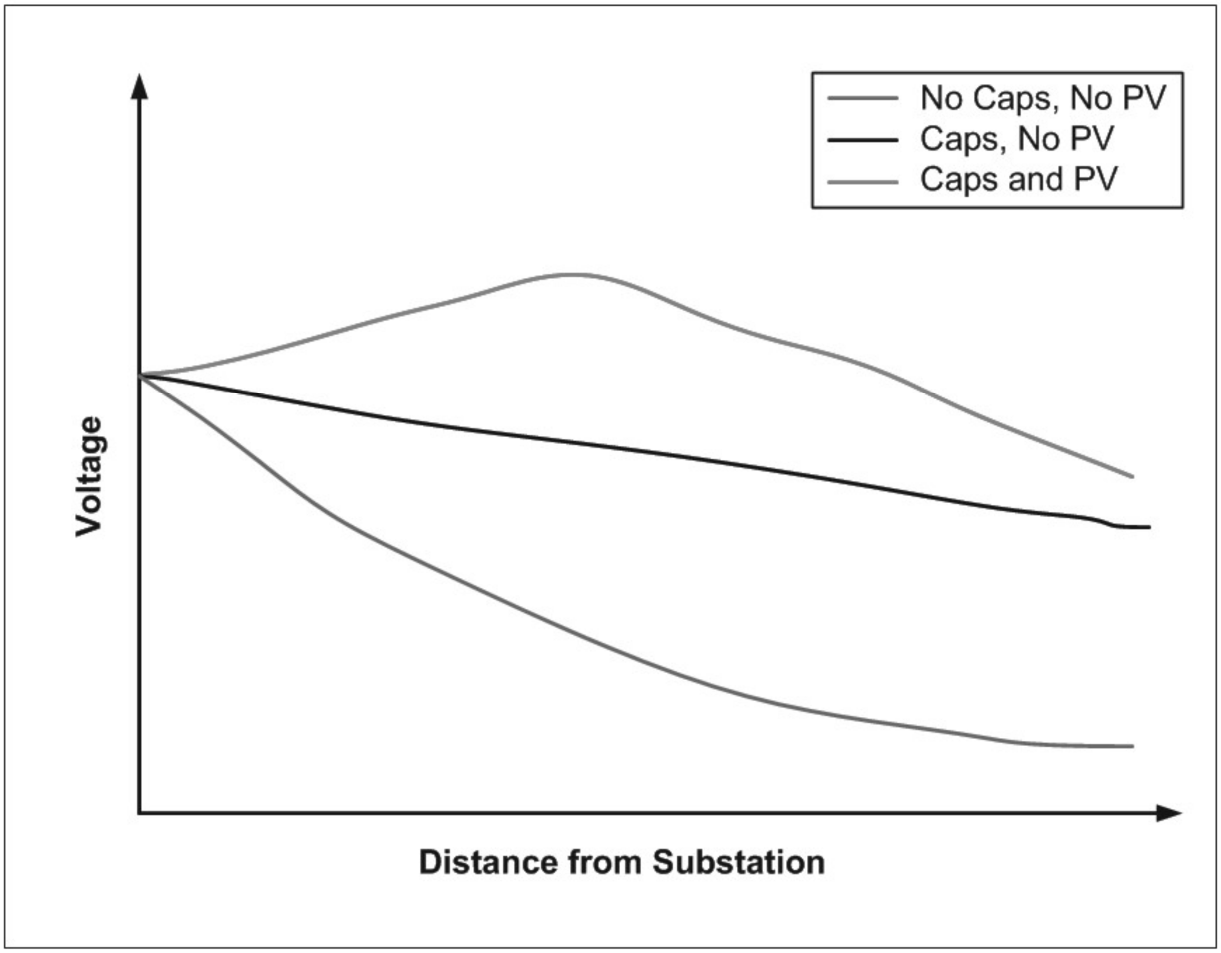


Figure 2.2. Impact of solar PV on the voltage profile of a feeder

Pockets of high voltage can occur on the distribution circuit during low-load conditions, particularly in places that have a single large PV system or a cluster of PV systems. Voltages should stay below the permissible high-voltage thresholds; otherwise, they can reduce the life of electrical equipment and cause DG (including PV inverters) to trip off-line.

2.3.3 Potential for Increased Substation Voltage

If a regulator or a load tap changer (LTC) transformer is not available at the substation, feeder head voltage may start to rise above acceptable limits. Even with the availability of substation regulation, studies should determine whether sufficient headroom (regulation room) exists to allow the regulator or the LTC to maintain the voltage within permissible limits over the entire load spectrum.

2.3.4 Flicker

The Institute of Electrical and Electronics Engineers (IEEE) Standard 1453TM-2011 explains voltage flicker as follows:

> Voltage fluctuations on electric power systems sometimes give rise to noticeable illumination changes from lighting equipment. The frequency of these voltage fluctuations is much less than the 50 Hz or 60 Hz supply frequency; however, they may occur with enough frequency and magnitude to cause irritation for people observing the illumination changes.

Variations in PV output resulting from cloud cover or shading can cause fluctuations in customer service voltage. Although not common, these voltage violations can cause flicker, which may be irritating to customers and may also result in malfunctioning appliances. Maximum PV power generation on a particular feeder should be constrained to prevent unacceptable flicker; this could set an upper limit on the total connected PV capacity on that feeder. Solar PV impact studies should be performed to assess the potential of voltage flicker due to high penetrations of solar PV.

2.3.5 Automatic Voltage Regulation Equipment

Voltage regulation practices used in radial power distribution systems have traditionally been designed with the assumption that the substation is the only power source in the system (McGranaghan et al. 2008), which implies that all flow is outward from the substation toward the end of the feeder. Voltage on such feeders is typically regulated by the LTC at the substation, voltage regulators at the start of the feeders and sometimes distributed throughout the feeders, and switched capacitor banks distributed throughout the feeders. The control settings of these devices are coordinated to maintain the desired voltage profile along the feeder (McGranaghan et al. 2008).

After PV is added to the distribution system, the assumption that the substation is the only power source no longer holds true, and the problems of voltage rise/fall and flicker associated with solar PV as discussed earlier can lead to frequent operation of LTCs, voltage regulators, and switched capacitor banks, resulting in additional step-voltage changes. Further, more frequent operation of these devices may shorten their life cycles and increase maintenance requirements (Katiraei and Agüero 2011).

Voltage regulation equipment that uses line drop compensation to control the feeder voltage profile can be particularly affected by the addition of large amounts of solar PV concentrated at the front of a feeder or immediately after a midline voltage regulator. This is because high concentrations of solar PV at the start of a feeder can mask the actual load current and result in inadequate voltage compensation by the regulator (McGranaghan et al. 2008). Figure 2.3 illustrates the impact of PV on the operation of line drop compensation voltage regulators. In this scenario, if the voltage regulation device regulates the local voltage to 125 V, low voltages are experienced by the customers near the end of the line, and particularly by the last customer. To avoid these low voltages, the voltage regulation device uses line drop compensation to regulate the first customer voltage to 125 V, which allows the last customer voltage to remain in an acceptable voltage range, as shown by the middle diagram.

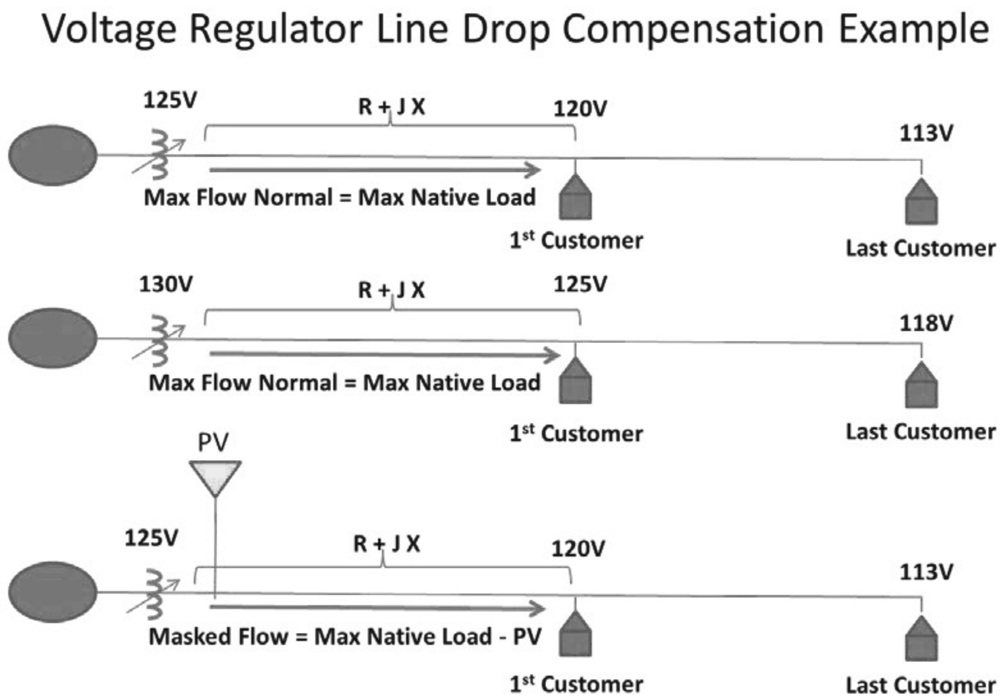


Figure 2.3. Impact of solar PV on voltage compensation provided by line drop compensation.

As indicated by the third diagram in Figure 2.3, when PV is located near the voltage regulation device, some of the load current is masked, which can impact the line drop compensation scheme. This impact can result in low voltages farther down the feeder. Figure 2.4 shows how the voltage profile can be shifted down as a result of the PV system's interaction with the compensation settings.

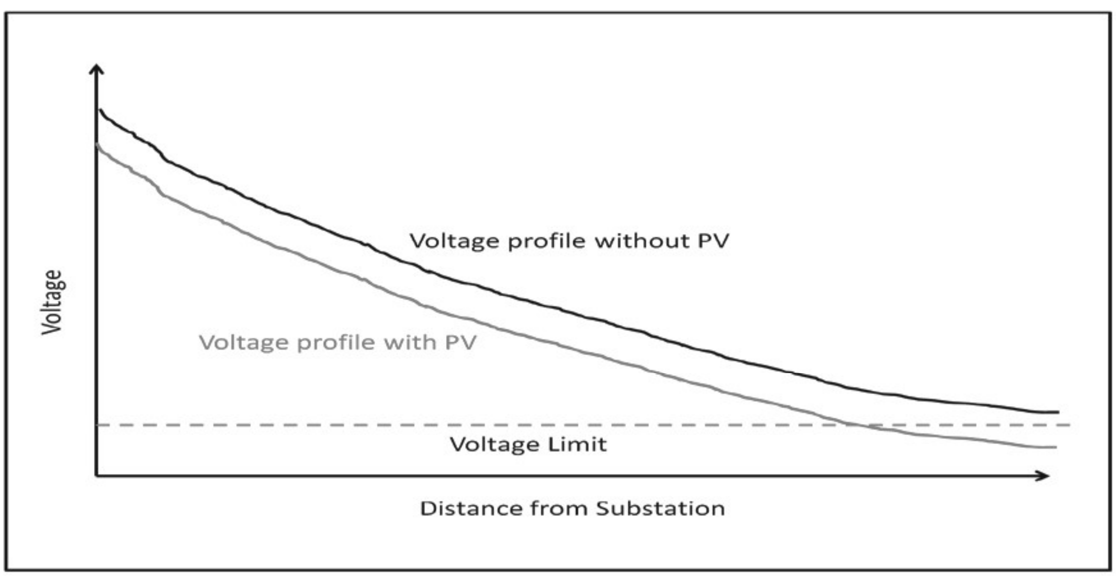


Figure 2.4. Peak load voltage profiles—PV compared to no PV

2.4 Reverse Power Flow Impacts

Reverse power flow on a distribution system upstream of a PV system may occur during times of light load and high PV generation. Reverse flow can cause problems for the protection system, as previously noted, and for the voltage regulators. Voltage regulators may be unidirectional and not designed to accommodate reverse flow (see Section 2.4.3). If voltage regulators are bidirectional, modifications to the regulator control may still be necessary to accommodate the reverse flow.

2.4.1 Substation and Bulk System Impacts

Impacts depend on factors such as penetration level, aggregated output characteristics, and system characteristics (e.g., amount and type of other generation sources). Most common concerns include increases in cost because of regulation, ramping generation, scheduling generation, and unit commitment, which may degrade balancing authority area performance and wear and tear on regulating units.

2.4.1.1 Reverse Power Flow to Adjacent Circuits

Protection concerns, arising from significant reverse power flows, such as exceeding interruption ratings of circuit protection elements and sympathetic tripping of adjacent circuits are two of many ways in which distribution-connected PV or other forms of DG-caused fault current contributions lead to problems on the distribution system.

2.4.1.2 Reverse Power Flow Through the Substation Transformer

Reverse power flows resulting from PV generation could possibly cause reverse power relays at a substation to operate, disconnecting the associated circuit. The resulting outages ultimately reduce system reliability.

2.4.2 Temporary and Transient Overvoltage

IEEE C62.82.1-2010 defines temporary overvoltage (TOV) as follows:

> An oscillatory phase-to-ground or phase-to-phase overvoltage that is at a given location of relatively long duration (seconds, even minutes) and that is undamped or only weakly damped. Temporary overvoltages usually originate from switching operations or faults (e.g., load rejection, single-phase fault, fault on a high-resistance grounded or ungrounded system) or from nonlinearities (e.g., ferroresonance effects, harmonics), or both. They are characterized by the amplitude, the oscillation frequencies, the total duration, or the decrement.

The above definition mentions load rejection as a potential cause of TOV. Because isolation of a section with PV caused by the operation of an upstream sectionalizing device is similar to a load-rejection scenario, it is important to study the potential for TOV in sections in which the amount of connected PV is close to or greater than the nominal load. Figure 2.5 shows an example of TOV due to load rejection where the waveforms shown are a PV inverters AC output voltage, AC output current and DC input voltage during a load rejection event. Also see (Durbak, 2006) for a discussion of TOV due to transformer energization which may be relevant for large PV systems.

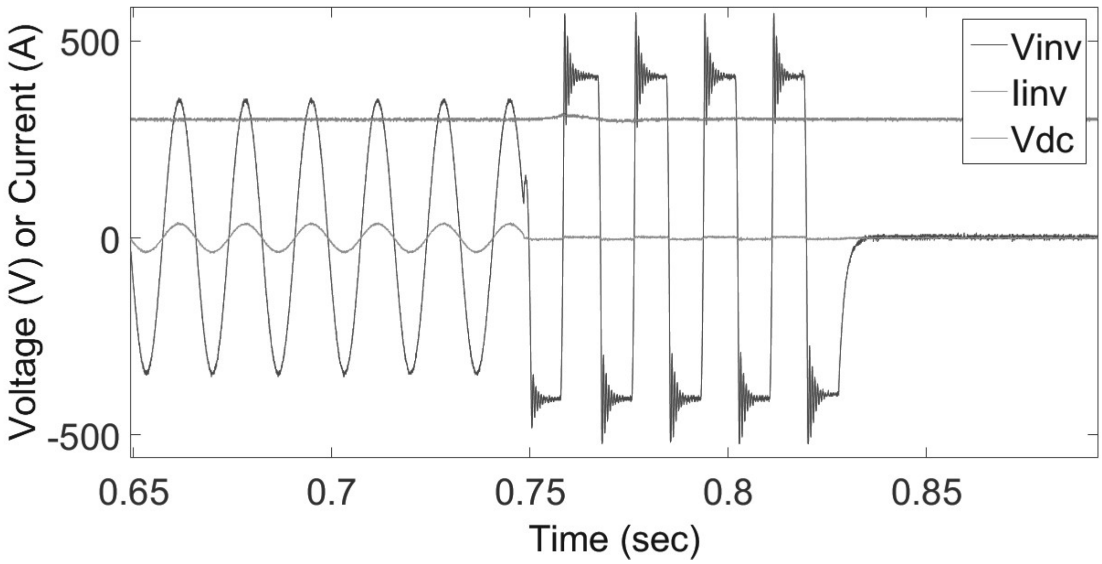


Figure 2.5. Example of TOV due to load rejection (Nelson et al. 2015)

In contrast to TOV, transient overvoltage is defined by IEEE C62.82.1-2010 as follows:

> A short-duration highly damped, oscillatory or non-oscillatory overvoltage, having a duration of a few milliseconds or less. Transient overvoltage is classified as one of the following types: lightning, switching, and very fast front, short duration.

The example waveform in Figure 2.6 shows a diagram of a transient overvoltage and depicts that transient overvoltages are of much shorter duration than the TOV.

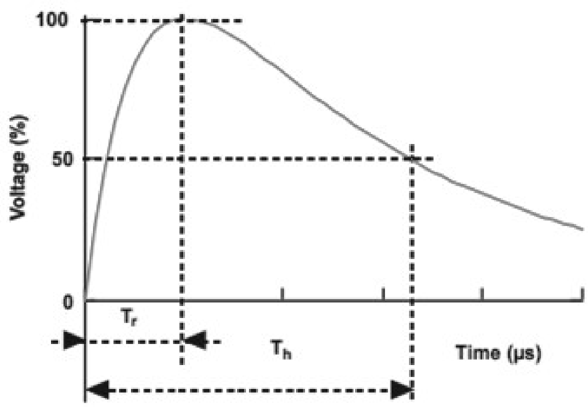


Figure 2.6. Example of transient overvoltage

If the operation of upstream sectionalizing devices (such as fuses or reclosers) results in the formation of an island with PV as an active power source, TOV may result, particularly when load in the islanded section is lower than the PV output. Depending on the magnitude of overvoltage and how fast a PV inverter trips after the detection of overvoltage, it is possible that other equipment installed on the islanded segment may be damaged.

The operation of a protective device or other switchable device that isolates an amount of load with an aggregate amount of PV in excess of the load may result in an overvoltage condition. Studies that show reverse flow through a protective device should alert the planning engineer to this possibility, because there is more generation than load on the section beyond the protective device.

A steady-state network analysis that assumes an unchanged current output from the PV into an unchanged amount of isolated load can provide a conservative estimate of the possible overvoltage. For example, if a fixed current associated with a PV output of 1.1 MW is isolated with 1 MW of load at a power factor of 1, this approach will calculate an approximate 10% overvoltage.

Parameters needed for a detailed transient overvoltage analysis are often not known or are difficult to obtain. A standardized methodology for performing such a study is beyond the scope of this handbook.

2.4.3 Automatic Voltage Regulation Equipment

A “runaway tap changer” may be encountered with large penetrations of solar PV. This situation can occur in feeders in which the regulator is set such that it reverses the direction of voltage regulation with reversal in the direction of power flow. When this happens, the voltage regulator attempts to regulate the voltage on the substation side of the regulator. In the absence of solar PV, such a control setting of the voltage regulator helps in voltage regulation if the auto loop feature of the distribution system operates; however, if power reversal happens because of the presence of solar PV and not because of the operation of the auto loop, the voltage regulator may start regulating the voltage of the section on its substation side and try to bring the substation voltage to the set point voltage. The substation is a strong source and will not respond to the change in tap settings, and the regulator will keep changing the tap position until it reaches its limits, at which stage it is possible that the output on the PV side of the regulator may experience higher or lower than permissible voltages, depending on the direction in which the taps are moved.

If there is a potential for a runaway tap changer, control settings of the voltage regulator should be modified or new voltage regulation schemes should be implemented to maintain the voltage levels in the distribution system according to the standards followed by the utility. See Figure 2.7.

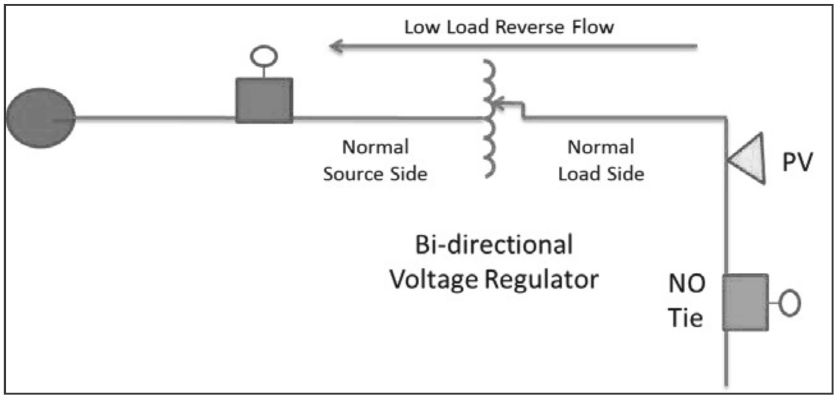


Figure 2.7. Runaway voltage regulator

2.5 System Protection Impacts

High penetrations of PV can change the fault current levels and also make it necessary to review the protection coordination currently implemented in the distribution network. In this section, the key impacts of high penetrations of PV on the distribution system protection are discussed.

2.5.1 Fault Current and Interrupting Rating

The addition of PV increases the fault current levels at all points on the system; therefore, it is important to verify that the maximum fault current through each protective device does not exceed its interrupting rating. Typically, utilities require the interrupting rating to exceed the maximum fault current by a safety margin of approximately 10%, but any applicable margins for this area should be considered. In addition, direct-current offsets that occur when the X/R ratio of the Thevenin impedance is high should also be considered. Some manufacturers specify their interrupting ratings at an X/R ratio of 15 or less. Equipment interruption ratings in most cases are given for the symmetrical fault level and list the maximum X/R ratio.

Fault current contribution from PV is typically approximately 1.1 times the rated current. The addition of a single 100-kVA PV unit will add only approximately 5 A of fault current on nearby 13.2-kV equipment; however, as more PV is added, the aggregate effect must be considered. If the PV interconnection transformer provides a ground source, its contribution to ground faults will be higher than the PV inverter contribution to faults, and that should also be considered. Fault current studies should be run with all PV "on" to determine the aggregate effect on fault current. Figure 2.8 below shows a large (5-MVA rated) PV installation contributing 240 A to an existing fault level of 7,800 A. This may cause the interruption rating of the local fuses to be exceeded, because fuse links typically have interruption ratings of 8,000 A. A fuse with a higher interruption rating may need to be used when PV is added.

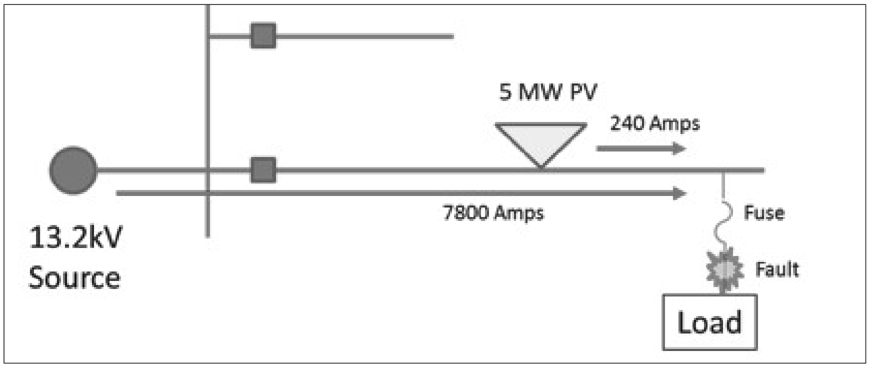


Figure 2.8. Impact of PV on fuse interruption ratings

Note that the aggregate fault contribution from PV on a single circuit may impact fault current on other circuits fed from the same bus. The interruption rating of those breakers fed from the same bus should be checked against the increased level of fault current at that breaker. Similarly, protective devices on those circuits should be checked. Figure 2.9 shows 240 A from the 5 MW of PV added to the fault current from the utility's 13.2-kV source. The breaker is subjected to a total of 8,040 A of fault current (three phase) with the addition of the PV. In this case, the fault and the PV are assumed to be electrically close to the source; therefore, the line impedance is considered negligible. Note that the impact of the PV can change depending on the type of fault, the interconnection transformer grounding configuration, etc.

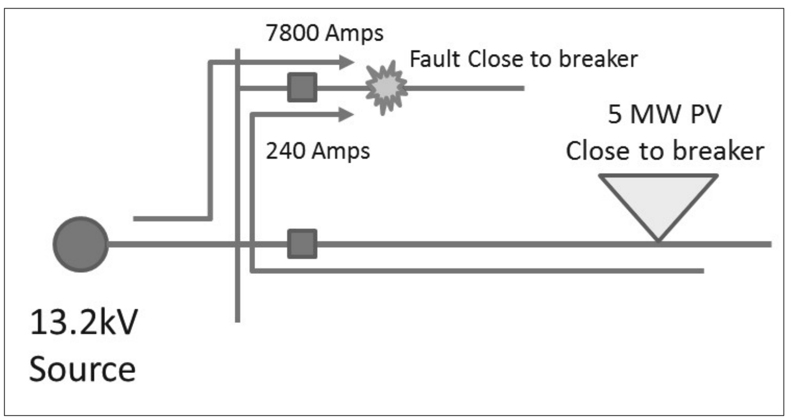


Figure 2.9. Impact of PV on breaker interruption ratings

2.5.2 Fault Sensing

The circuit should be checked to verify that all the protective devices can sense faults within their respective protective zones. Relay pickup is the relay tap times the current transformer ratio. Fuse minimum melt value is typically equal to approximately 200% of its nominal rating. For example, a 100-A fuse will begin to melt at less than 200% of its 100-A rating, or 200 A. A relay with a tap of 5 A and a current transformer ratio of 200:1 will not operate for a current less than 1,000 A.

Assume that a utility requires a protective device to operate for 50% of the lowest fault current in its zone. If the lowest fault current for the breaker at the recloser is 2,000 A, the setting on the breaker shown below in Figure 2.10 just meets the 50% requirement without PV. The addition of PV can serve to desensitize the relay. Note that when the utility requires full backup protection, a breaker such as that shown in Figure 2.10 must sense faults in the breaker zone as well as the recloser zone. This should be checked before and after the addition of PV.

Fault-sensing practices vary from utility to utility; the applicable practice for the local utility should be used. For example, if the utility has a design practice of sensing ground faults limited by fault resistance up to a specific level, that condition should be evaluated as well for desensitization.

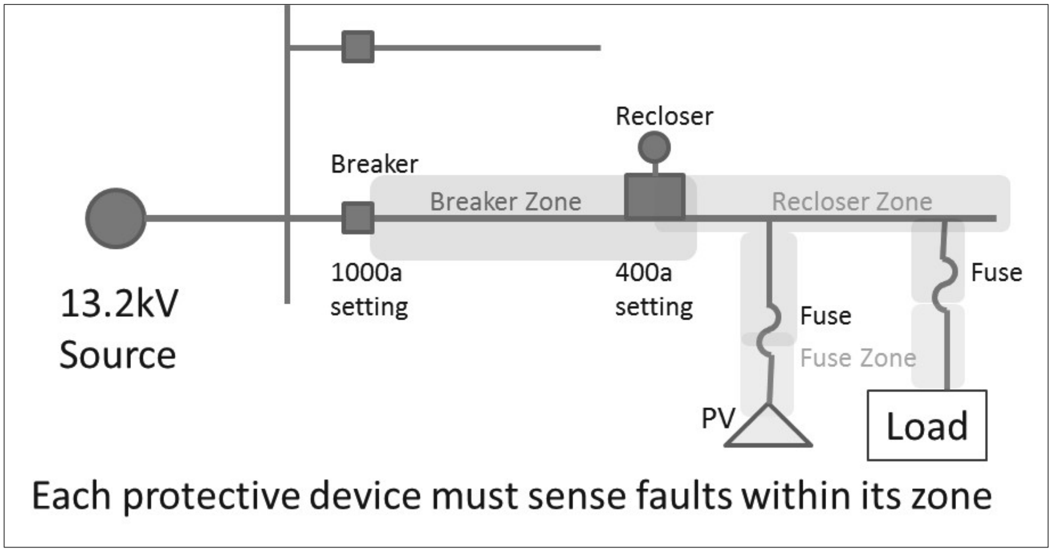


Figure 2.10. PV may desensitize protection devices to faults

2.5.3 Desensitizing the Substation Relay

When fault current from PV combines with substation fault current on a branch, the fault current is effectively reduced from the substation breaker. This reduction in current will desensitize the relay at the source. The factor by which the current is reduced may be approximated as

$$1-(I_P/E_S)*Z_B$$

Where I_p = relay pickup current,

E_s = phase-to-neutral voltage magnitude of the source, and

Z_B = impedance magnitude of the branch.

Note that the contribution from the PV will also be reduced by the system current. In a worst-case calculation, the maximum contribution from the PV can be used (200 A for this example). See Figure 2.11.

For example, if Es = 13,200/√3 = 7,620 V, I_P = 200 A, and Z_B = 0.5 Ω (approximate for 3,000' #2Cu), the current would be reduced to 0.986 of the original value (0.986 = 1-200/7,620*0.5). Typically, this small reduction would not be a concern; however, the reduction in fault current should be checked to verify that systems are adequately protected if they have longer branches, more PV capacity, or lower system voltages. As shown in Figure 2.11, the installation of a fuse may be desirable on the branch at Node N_B to ensure that it has adequate protection.

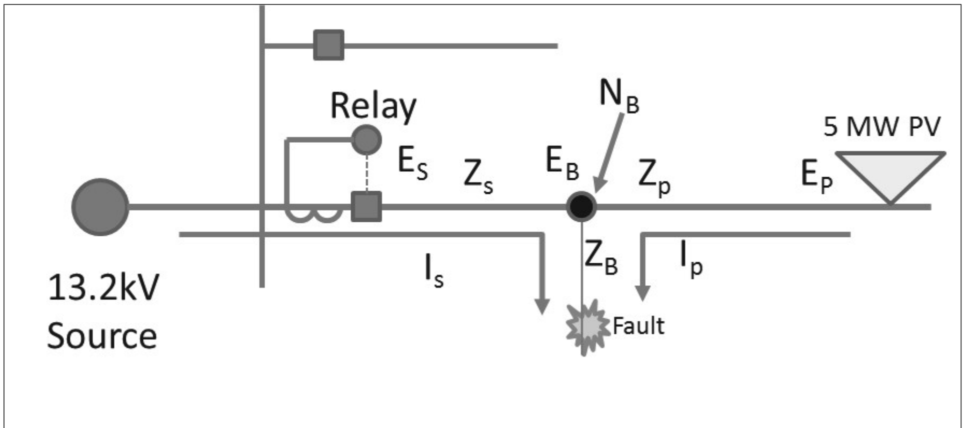


Figure 2.11. Reduction in fault current through substation relay because of PV

2.5.4 Line-to-Ground Utility System Overvoltage

If the PV is connected via a delta-wye transformer, or even a wye-wye transformer in cases when the utility side of the transformer is ungrounded, then ground faults upstream of the PV may result in high voltages on the unfaulted phases. This is typically a utility concern, because it can affect other customers. The utility is normally obligated to address the problem by informing the PV owner of the issue. Once informed, it should become the PV owner's responsibility to install equipment to detect overvoltage and isolate the PV. Overvoltages caused by ungrounded secondary systems or inverters are not addressed in this document and are the responsibility of the PV owner.

Figure 2.12 shows a line-to-ground fault on Phase C and the events that cause the high voltage as follows:

1. A line-to-ground fault effectively grounds Phase C.
2. The breaker opens and isolates the PV with the grounded Phase C.
3. The PV continues to run.
4. The delta primary (13.2 kV) on the transformer applies 13.2 kV* to the unfaulted phases.
5. If so equipped, the 59N (zero-sequence overvoltage) relay senses the overvoltage to ground and trips the PV. Islanding protection should also trip the PV, but that may take longer.

*Note that load on Phase A and Phase B will draw current from the PV and will likely cause the voltage to be less than 13.2 kV. Also, if there is an impedance in the fault, the voltage will be less than 13.2 kV.

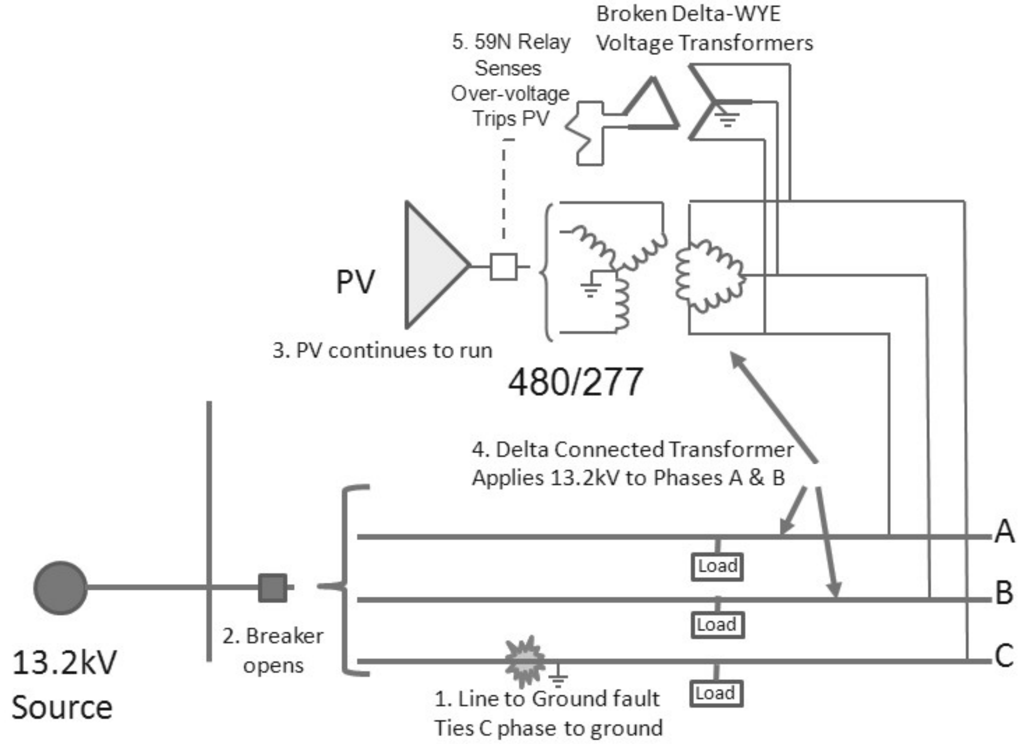


Figure 2.12. PV may cause line-to-ground overvoltage

2.5.5 Nuisance Fuse Blowing

Fault contribution from PV may cause a fuse to blow that would have otherwise remained intact. Consider Figure 2.13. For a temporary fault beyond the 50-k fuse, the recloser operates on a “fast” curve that is intended to clear the fault before the 50-k fuse blows. When the recloser opens and the arc is extinguished, automatic reclosing of the recloser should restore service; however, if the PV continues to provide current to the fault, the fuse could blow before the PV trips off due to the 59N or islanding detection. In this case, the addition of the PV compromises the fuse-saving capability intended for the recloser. In other words, what would have been a momentary outage for the customers downstream of the fuse is now a permanent/sustained outage. Typically, these problems occur only for larger PV systems.

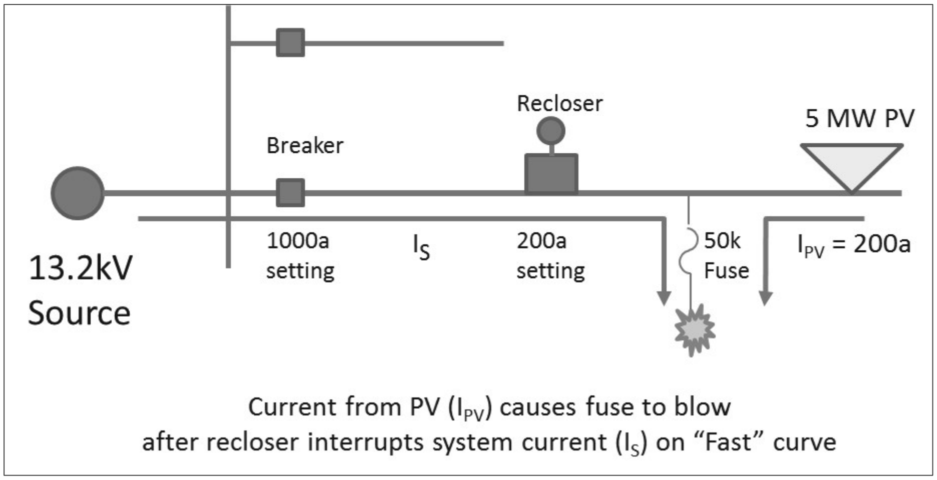


Figure 2.13. Illustration of nuisance fuse-blowing caused by large PV penetration

2.5.6 Reclosing Out of Synchronism

As shown in Figure 2.14, if reclosing times are too fast after a fault, the PV may still be online and have lost synchronism with the utility system. Practices should be reviewed to ensure that reclosing does not cause conditions to be out of synchronism. This is true for any generating source, including synchronous, induction, and PV connected to the system. If automatic reclosing is used, some utilities have increased the open time between breaker or recloser closings to ensure that PV has been shut down by the local protective systems. Voltage sensing on the PV side of the breaker or recloser can help ensure that no PV source is online when the breaker or recloser is closed. IEEE 1547 requires that PV systems be shut down and isolated within 2 s or less during island conditions. A strict reading of the standard shows that PV should disconnect faster than 2 s when the utility uses automatic reclosing times less than 2 s. This requirement is independent of the islanding detection requirement.

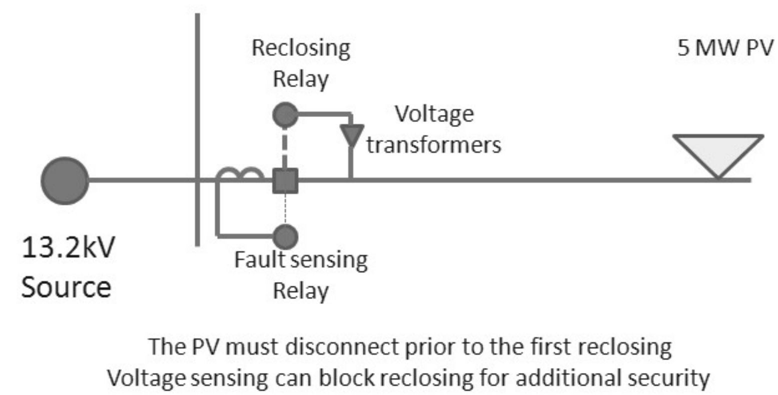


Figure 2.14. Reclosing out of synchronism

2.5.7 Islanding

When DG such as PV continues to serve load via a utility's lines when it is isolated from the utility source, an island condition has occurred. PV may not be designed to maintain voltage and frequency for customers in the absence of a utility source and poses a threat to equipment connected to the island. Additionally, an island condition may present a hazard to utility workers in the area. For these reasons, islands are typically prohibited, except in special cases when an island has been preplanned to provide service continuity. When an islanded condition occurs that is not preplanned, it is often referred to as an unintentional island.

2.5.8 Sectionalizer Miscount

Sectionalizers work with reclosers to isolate a line section downstream of a recloser as the recloser goes through its operating sequence. Depending on utility practice, sectionalizers are sometimes used close to the substation or far from the substation when fuse coordination is difficult or impossible. See Figure 2.15. When a fault is downstream of the sectionalizer, pulses of fault current flow through the sectionalizer. After a specified number of current pulses (e.g., two or three), the sectionalizer opens as the recloser opens.

Sectionalizers that require the current to fall to a relatively low value (e.g., below 1 A) to identify fault current pulses before opening may undercount because of current provided from PV.

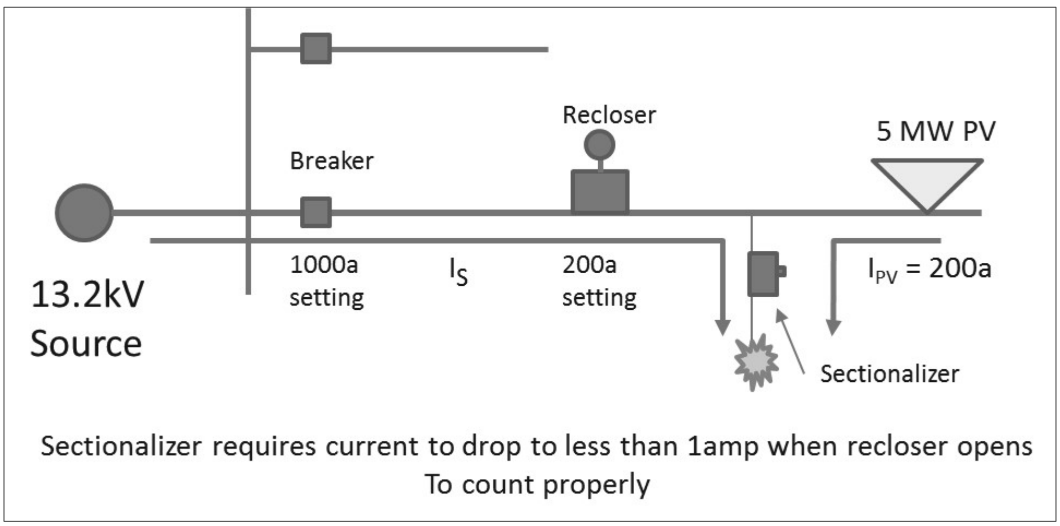


Figure 2.15. Illustration of sectionalizer miscount because of PV

2.5.9 Reverse Power Relay Operation—Malfunctions on Secondary Networks

Reverse power relay operation is primarily a concern for 120/208-V or 480/277-V secondary network systems in which a parallel secondary grid is fed from multiple transformers. Each transformer is equipped with a network protector relay that is set to open for a small value of power flowing from the 120/208-system to the medium-voltage level—for example, 4.8 kV, 4.16 kV, or 13.8 kV. See Figure 2.16.

During light load periods, power can flow from the PV into the secondary grid and back into the primary distribution system through a few network protectors. The magnitude of the reverse flow is determined by the local loads and phase angle between the primary and 120/208-V secondary network systems at the protector. Protectors electrically close to the PV generation are likely to open first. The primary voltage magnitudes on nearby protectors are similar, but the phase angle between the two secondary voltages can become significant as the generation from the PV increases.

Some network protectors will open when sufficient reverse current flows (approximately 5% of the protector rating). These protectors will eventually close automatically, based on the voltage phase angle difference, when the network load increases or the PV generation decreases sufficiently.

If generation in a network area exceeds the total load in that network area at any time, it is likely that all the protectors will open and isolate the entire area. This may cause the PV and network load to operate as an island should the PV stay online.

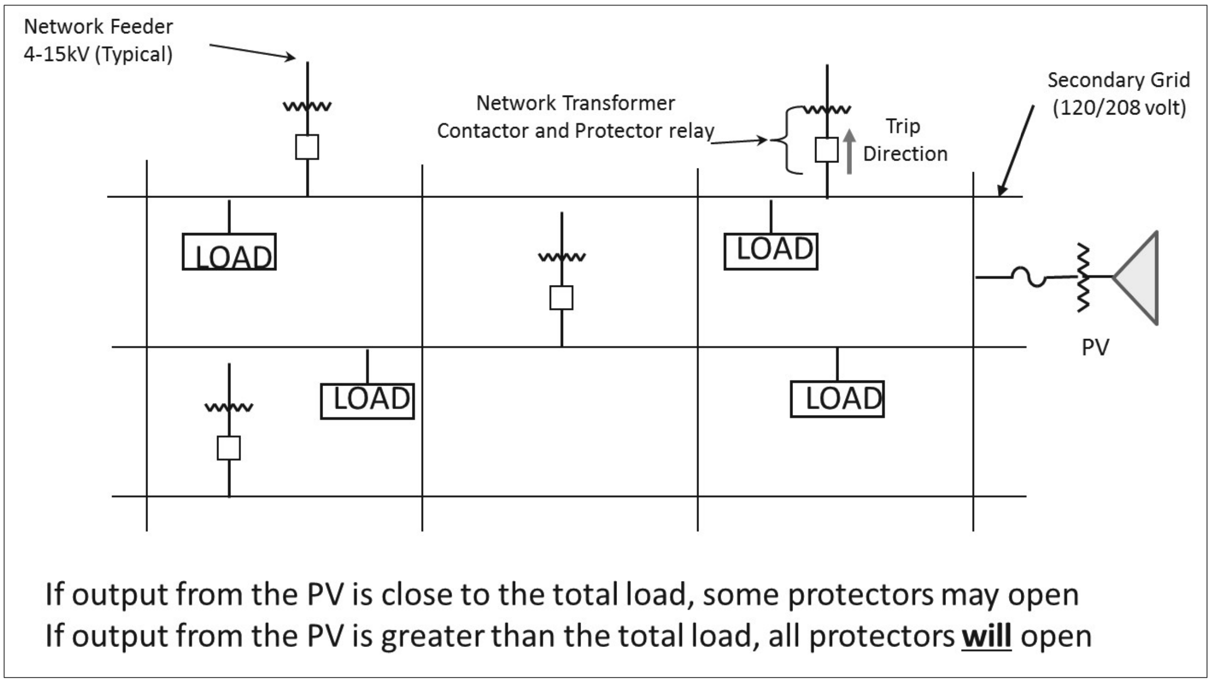


Figure 2.16. Reverse power relay operation because of PV

2.5.10 Reverse Power Relay Operation—Substation

In a case with very large PV, which may have a dedicated feeder, the protection system would normally be set to accept reverse flow; however, if reverse flow through the substation transformer is undesirable, the transformer relay may be set to trip the dedicated feeder.

2.5.11 Cold Load Pickup With and Without PV

As discussed in section 2.2.3, cold load is the amount of load experienced by equipment after a load (circuit or partial circuit) has experienced an outage for a long period of time. IEEE 1547 requires inverters to have an adjustable or (usually) fixed 5-min delay before they can be tied back to the grid after a grid disturbance or an outage. The entire load that was partially masked by the PV units will increase the cold load demand on the system.

The cold load demand on the system is typically highest during the first few minutes after the power comes back on following an extended outage. Motors may all start simultaneously. In the winter, the heating load to be picked up may be very large because of loss of diversity. The cold load demand will depend upon the duration of the outage. Various tables and curves are available showing the expected increase in initial cold load to be picked up in multiples of pre-outage load. This information is available for different classes of loads and provides the characteristic of the time-varying load restored after an extended outage. Output from PV will affect the amount of normal load actually measured or calculated. Figure 2.17 shows a sample of the time-varying characteristic of cold load.

Note that the data are typically based on pre-outage normal load. The effect of PV may mask what the normal load actually is at the start-of-circuit or any monitoring point. This effect should be taken into account when determining the load to be picked up. Also, during daylight hours any automatic return of PV to the system may impact and actually mitigate the effect of cold load pickup. Equipment and protective devices should be rated for the increased amount of expected cold load without considering potential cold load pickup mitigation from PV as the availability of PV to mitigate cold load pickup is not certain. Whenever possible, protective devices should be sized to not operate for this increased amount of load.

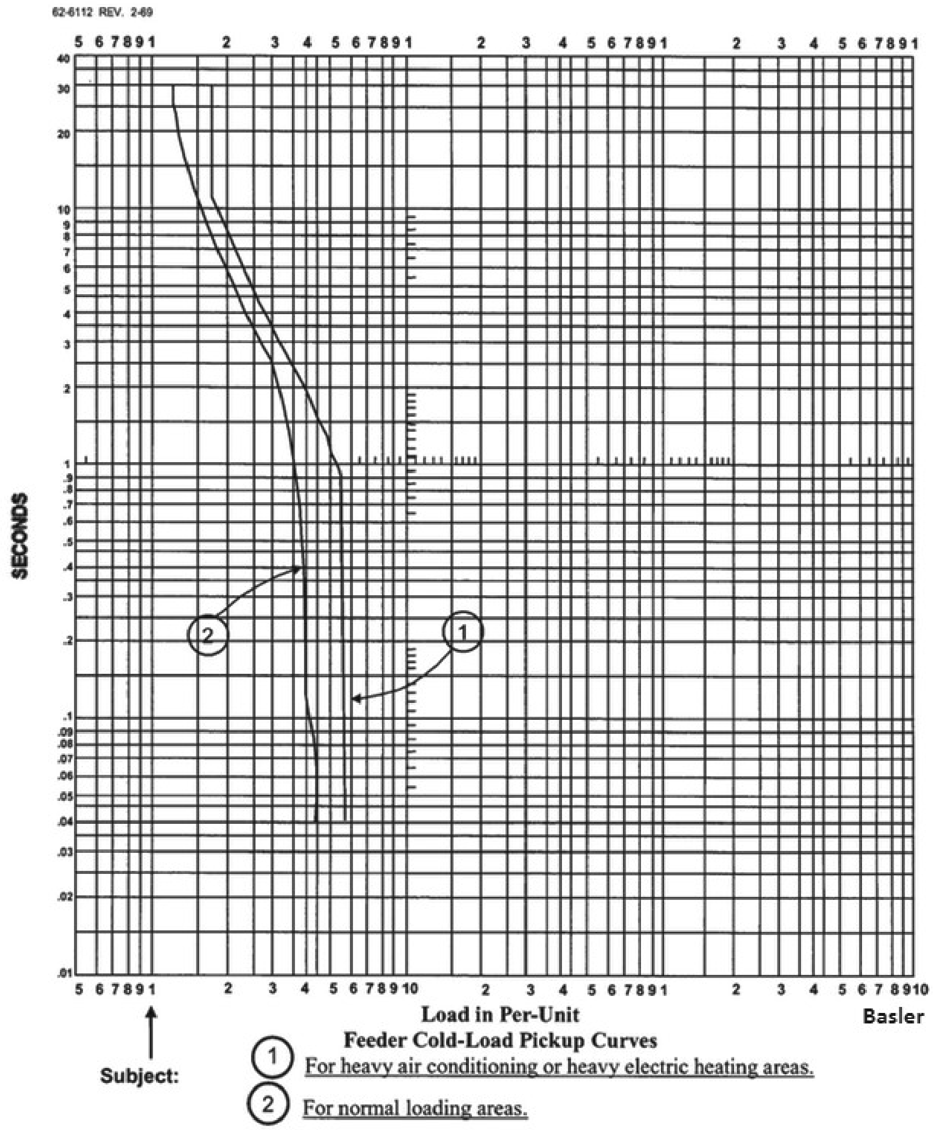


Figure 2.17. Time-varying characteristic of cold load (Lawhead at el. 2006)

2.5.12 Faults Within a PV Zone

Coordination between the utility-owned protective device nearest the PV and the next protective device within the PV zone should be verified. The utility-owned protective device should not operate for faults beyond the next protective device within the PV zone except when required for backup operation (consult applicable utility design practices). The utility-owned device must sense faults up to the next protective device within the PV zone. When backup is required, the utility-owned device should be able to detect faults within its protective zone as well as adjacent downstream protective zones. Operation margins accepted by the utility should be employed. For example, if the utility requires that protective devices operate for 50% of the calculated bolted fault within its zone (or within the backup zone if backup is required), fault studies should verify that a utility-owned cable pole fuse will indeed operate for any fault that is 50% of the calculated bolted fault. Protection for faults within the PV installation is the responsibility of the owner/developer.

2.5.13 Isolating PV for an Upstream Fault

Although it is unlikely for PV installations, the operation of an upstream device for a fault upstream of that device may isolate the PV and the load. See Figure 2.18. Note that if the 200-A recloser beyond the fault can carry the full output of the PV, it is not likely to trip for the upstream fault shown. For the 5 MW of PV shown in Figure 2.18, it is unlikely that a recloser less than 200 A per phase would be installed in this location. Current-carrying capability and trip-setting checks should avoid this problem.

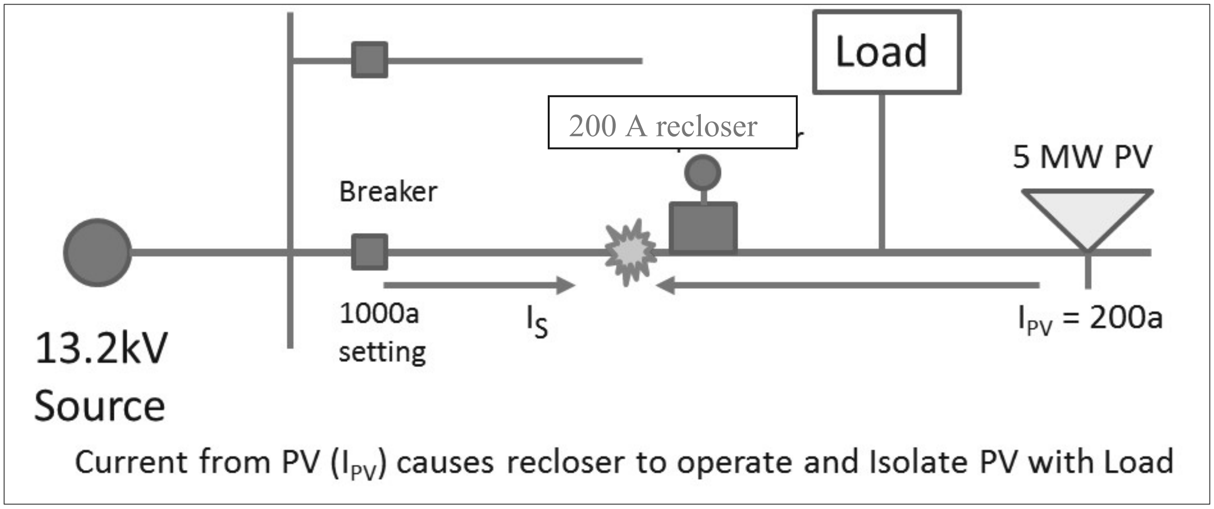


Figure 2.18. PV may be isolated for an upstream fault

Note that if the voltage sag is low enough, the PV may separate. For example, the current version of IEEE 1547 requires the PV to trip within 0.16 s if any monitored (phase-to-phase or phase-to-neutral) voltage drops below 50%.

2.5.14 Fault Causing Voltage Sag and Tripping PV

Undervoltage may cause the PV to trip off-line for voltage sags during temporary faults. Voltage sags may be as short as a fraction of a cycle and up to 1 s or 2 s long. Currently, inverters compliant with UL 1741 are required to detect undervoltage and disconnect from the grid. Planning and protection design personnel should be aware of this effect, which causes loss of generation from the PV system. It may be desirable for PV to ride through voltage sags by extending the trip times to the maximum permissible. Also, fast automatic reconnection may be desirable as determined by the local utility. Advanced PV inverters may have functionality that includes low-voltage ride-through so that PV generation can come back online quickly and/or ride through voltage sags without being tripped for adjacent fault conditions .

2.5.15 Distribution Automation Studies and Reconfiguration

If a circuit can be reconfigured for emergency service or maintenance, each variation should be studied to ensure proper operation if PV is permitted to continue. Figure 2.19 is an example of a reconfigured system. The system should first be studied for adequate voltage, loading, and fault sensing. It should then be studied for all other configurations, such as to ensure that Breaker 1 and Recloser 1 are open and that the tie recloser is closed (after a permanent fault).

Similarly, circuits involving PV that are reconfigured by jumper to other circuits must be studied. In some cases, it may be necessary for the PV to stay off-line if voltage, loading, and fault sensing requirements cannot be met. Reconfiguration will be discussed in greater detail in the next section.

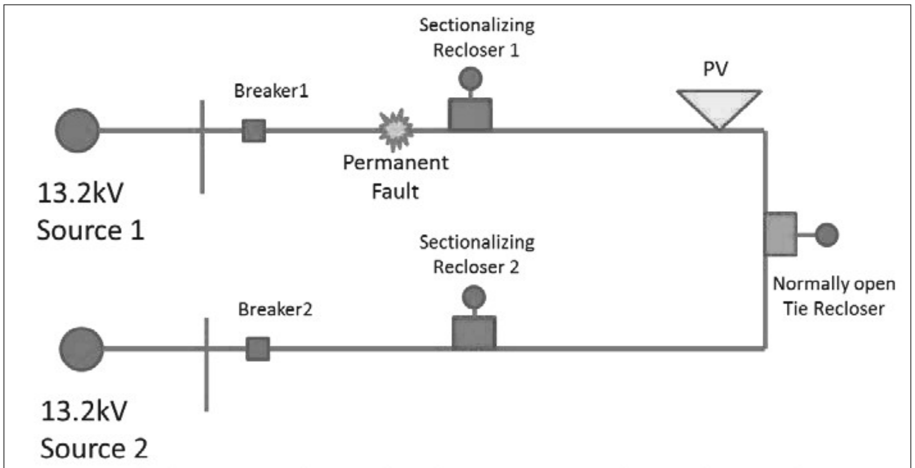


Figure 2.19. Reconfiguration in the presence of PV

2.6 Circuit Configurations

2.6.1 Normal System Configuration

A PV system should be evaluated for its normal configuration. A normal system configuration is also referred to as the "as-built" system configuration. The as-built configuration should be evaluated throughout the entire load spectrum of the circuit to assess the effects of the PV addition.

2.6.2 Abnormal System Configuration

A PV system should also be evaluated for abnormal configurations. Abnormal configurations are the various reconfigurations that are possible involving adjacent circuits. These include potential planned circuit reconfigurations of which a PV system may or may not be a part, such as auto loops, two feeds to a single customer, single contingencies, and switching plans. Ideally, abnormal configurations should be evaluated throughout the entire load spectrum of the circuits involved to assess the effects of the addition of PV. Operating restrictions should be noted, including cases when the PV must stay offline. Note that the criteria (such as for overvoltages, overloads, etc.) for abnormal system configurations may differ (they may be somewhat more relaxed) from that used for normal system configurations.

2.6.3 Future/Planned System Configurations

PV installations should be analyzed for known future configurations as well. The future/planned configuration should be evaluated throughout the entire load spectrum of that circuit to assess potential criteria violations resulting from the addition of PV.

2.6.4 Contingency Conditions

Contingency conditions refer to abnormal system conditions that may arise because of events such as loss of load, tripping of a line, or failure of protective devices.

The need to analyze the impact of PV during normal and abnormal circuit configurations and also during contingency conditions is illustrated with two examples.

2.6.4.1 Example 1

An example of an auto loop system configuration is shown in Figure 2.20. Figure 2.20 (a) shows an auto loop circuit in its normal configuration; Figure 2.20 (b) shows the same auto loop in an abnormal configuration in which a fault has been isolated and the tie reclosed to automatically pick up a portion of the circuit that had experienced an outage. Because all PV is disconnected during a feeder outage, when the tie recloser is closed, the feeder-loading capability could be exceeded. This is particularly a problem if the decision to close the tie recloser was made based on the flow through the isolating line recloser. Thus, as demonstrated before, it is important to determine the actual native load when reviewing the potential impact on switching plans, both with and without PV.

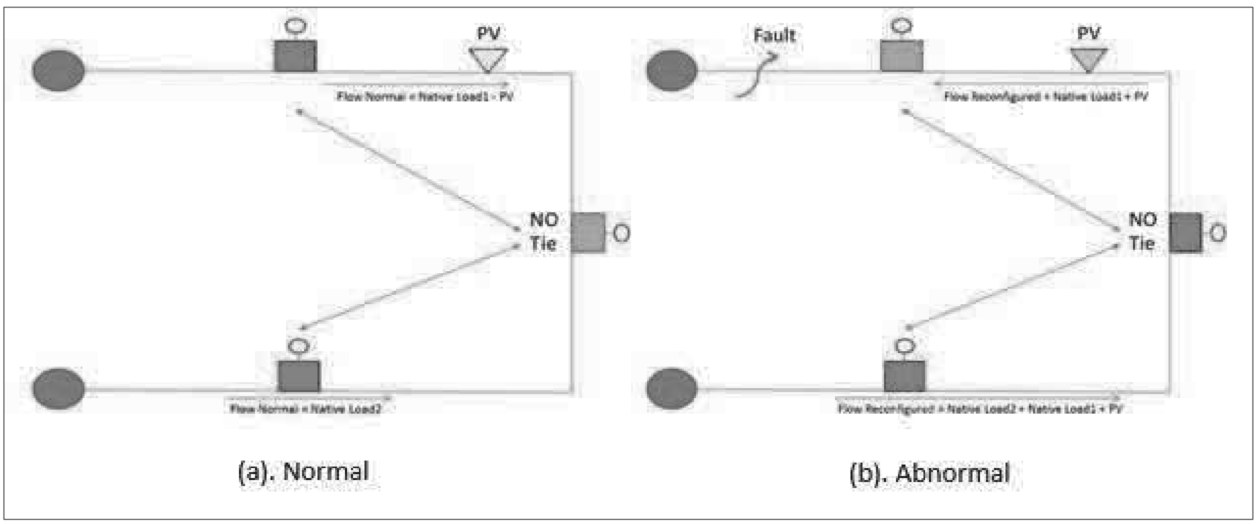


Figure 2.20. (a) Normal and (b) abnormal configuration of an auto loop system, red indicates a closed switch, green indicates an open switch

2.6.4.2 Example 2

Figure 2.21 shows three scenarios: an example for peak load, light load, and contingency loading. In the peak load example (top), no overloads are noted; however, in the light load example (middle), an overload could occur on the smallest conductor. (An example of #6 Cu with a normal rating of 138 A is given.) In the contingency example (bottom), which has a loss of downstream load, an emergency overload would exist. (An example of #6 Cu with an emergency rating of 185 A is given.)

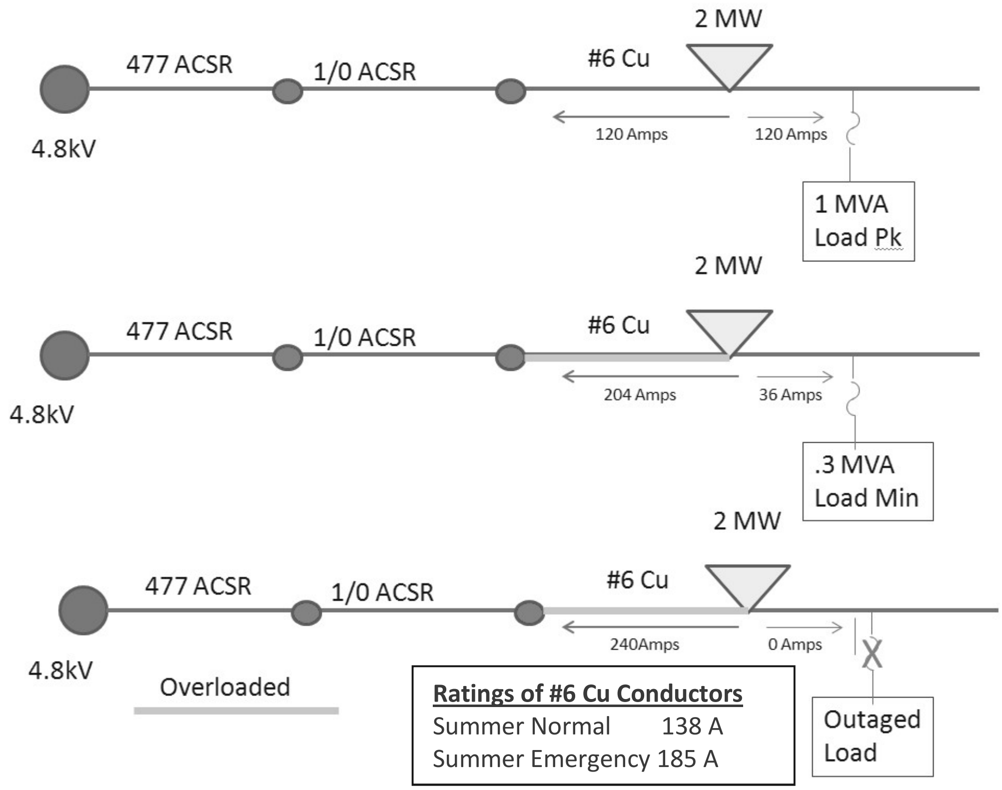


Figure 2.21. Overload during normal and contingency conditions

When considering installations of additional PV on a circuit, it is necessary to ensure that the upstream capacities are sufficient to handle the full output of the combined PV installations. This will help ensure that there are no overloads at light load or during downstream outages. Also, note that the system losses often increase because of PV generation.

Kentucky Utilities Company							
Rate Schedule	**KU's Proposed Percent Increase**	**Walmart's Proposed Percent Increase**	**AG'S Proposed Percent Increase Option 1**	**AG'S Proposed Percent Increase Option 2**	**KUIC's Proposed Percent Increase**	**DOD-FEA's Proposed Percent Increase**	**LFUCG's Proposed Percent Increase**
Rate RS	10.68%	10.68%	10.46%	10.31%	10.72%	13.70%	11.16%
Rate GS	10.68%	10.68%	10.46%	7.84%	10.73%	4.00%	10.68%
Rate AES	10.68%	10.68%	10.46%	10.31%	10.72%	10.00%	10.68%
Rate PS – Secondary	10.67%	10.67%	10.46%	7.84%	10.72%	4.00%	10.67%
Rate PS – Primary	10.68%	10.68%	10.46%	7.84%	10.72%	4.00%	10.68%
Rate TOD – Secondary	10.69%	10.69%	10.46%	13.07%	10.73%	13.70%	11.17%
Rate TOD – Primary	10.68%	10.68%	10.46%	13.07%	10.73%	13.70%	11.16%
Rate RTS	10.68%	10.68%	10.46%	13.07%	10.73%	13.70%	11.16%
Rate FLS	10.69%	10.69%	10.46%	13.07%	8.57%	13.70%	11.17%
Rate LS & RLS	0.00%	0.00%	10.46%	7.84%	0.00%	4.00%	-19.00%
Rate LE	0.00%	0.00%	10.46%	13.07%	0.00%	0.00%	-26.00%
Rate TE	0.00%	0.00%	10.46%	7.84%	0.00%	0.00%	-12.00%
Rate OSL	-4.97%	-4.97%	-4.97%	-4.97%	-4.97%	4.00%	-4.97%
Total Company	**10.57%**	**10.57%**	**10.57%**	**10.57%**	**10.57%**	**10.57%**	**10.57%**

Louisville Gas and Electric Company							
Rate Schedule	**KU's Proposed Percent Increase**	**Walmart's Proposed Percent Increase**	**AG'S Proposed Percent Increase Option 1**	**AG'S Proposed Percent Increase Option 2**	**KUIC's Proposed Percent Increase**	**DOD-FEA's Proposed Percent Increase**	**Lou Metro's Proposed Percent Increase**
Rate RS	11.80%	11.80%	11.80%	11.24%	12.73%	15.40%	12.72%
Rate GS	11.81%	11.81%	11.80%	8.85%	12.73%	8.60%	11.81%
Rate PS – Primary	11.81%	11.81%	11.80%	8.85%	12.74%	8.60%	11.81%
Rate PS – Secondary	11.81%	11.81%	11.80%	11.24%	12.73%	8.60%	11.81%
Rate TOD – Primary	11.81%	11.81%	11.80%	14.75%	7.32%	10.90%	11.81%
Rate TOD – Secondary	11.82%	11.82%	11.80%	14.75%	12.74%	15.40%	11.82%
Rate RTS	11.80%	11.80%	11.80%	14.75%	8.49%	8.60%	11.80%
Special Contract	11.80%	11.80%	11.80%	14.75%	12.72%	14.00%	11.80%
Rate RLS & LS	11.90%	11.90%	11.80%	8.85%	12.83%	8.60%	-6.10%
Rate LE	0.00%	0.00%	11.80%	14.75%	0.00%	0.00%	-27.00%
Rate TE	0.00%	0.00%	11.80%	8.85%	0.00%	0.00%	-14.00%
Rate OSL	-10.00%	-10.00%	-10.00%	-10.00%	-10.01%	8.60%	8.60%
Total Company	**11.63%**	**11.63%**	**11.63%**	**11.63%**	**11.63%**	**11.63%**	**11.63%**

Louisville Gas and Electric Company
Weighted Ratchet for All Three Demand Components of TODP

	Demand	Demand Ratchet	Weighted
Demand kVA Base	5,354,606	1	5,354,606
Demand kVA Intermedia	4,410,142	0.5	2,205,071
Demand kVA Peak	4,306,226	0.5	2,153,113
Total	14,070,974		9,712,789.88
Weighted Demand Ratchet			69%

Kentucky Utilities
Weighted Ratchet for All Three Demand Components of TODP

	Demand	Demand Ratchet	Weighted
Demand kVA Base	10,620,000	1	10,620,000
Demand kVA Intermedia	8,647,332	0.5	4,323,666
Demand kVA Peak	8,522,176	0.5	4,261,088
Total	27,789,508		19,204,754.09
Weighted Demand Ratchet			69%

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In Re the Matter of:

APPLICATION OF KENTUCKY UTILITIES COMPANY FOR AN ADJUSTMENT OF ITS RATES AND FOR CERTIFICATES OF PUBLIC CONVENIENCE AND NECESSITY	))))))	CASE NO. 2016-00370

DIRECT TESTIMONY OF WILLIAM STEVEN SEELYE MANAGING PARTNER THE PRIME GROUP, LLC

Filed: November 23, 2016

customer's maximum load. This means that a 75% demand ratchet applies to the Base Demand Charge. A higher ratchet was implemented for the Base Demand Charge because the charge was designed to recover transmission and distribution demand-related costs which must be adequately sized to meet the customer's maximum demand whenever the demand occurs.

Q. What changes is KU proposing to the rate structure?

A. KU proposes to keep the same basic rate structure but to increase the demand ratchet for the Base Demand Charge to 100%. The Company is not proposing to change the demand ratchets for the Peak and Intermediate Charges at this time.

Q. Why is KU proposing this change?

A. The modification to the demand ratchets for the large customer rates is being proposed in conjunction with the elimination of the Company's standard rider for Supplemental or Standby Service (Rider SS). The Company has concluded that Rider SS is not adequate in light of fundamental changes that are taking place in the electric utility industry. Rider SS is available to customers who are regularly supplied with electric energy from generating facilities (distributed generation) owned by the customer and who desire to contract with KU for reserve, breakdown, supplemental or standby service. Fundamental changes are taking place in the electric utility industry whereby more customers are installing distributed generation to meet their power needs and falling back on the utility to supply power when their facilities are not operating. In some jurisdictions, there has been a surge in the installation of customer-owned renewable distributed generation such as solar generation or wind generation. In general, utilities are supportive of these initiatives as long as the utility's other customers are not subsidizing customers that install distributed generation facilities. Therefore, it is important for utilities to have a rate structure that prevents the subsidization of distributed generation by customers who have chosen not to install distributed generation.

It is also important for a utility to implement rates that allow the utility to recover the appropriate amount of fixed costs associated with serving customers who have installed distributed generation facilities but who want to rely on the utility to provide generation, transmission and distribution service when the distributed generation facilities are not operating. But KU also wants to offer a rate design that provides reasonable cost recovery while not discriminating against customers who install distributed generation and that isn't excessively harsh or onerous to customers who install distributed generation but want backup service.

Q. Why is the current standby rate inadequate?

A. In addition to the administrative problems with the rider that are addressed in the Direct Testimony of Robert M. Conroy, there has generally been an unwillingness on the part of customers with distributed generation to sign up under the rider because it is viewed as "too harsh" or "too onerous". Rider SS, which is a rider that would generally be applicable to customers served under Rates PS, TODS, TODP, RTS, or FLS, requires a standby customer to establish a contract demand for its entire load. The customer would then be billed a minimum demand charge that is the greater of (1) the customer's total demand charge billed under the customer's primary rate schedule (PS, TODS, TODP, RTS, or FLS), or (2) the demand charge calculated by applying the demand charges set forth in Rider SS to the customer's contact demand. Currently, the demand charges set forth in Rider SS are as follows:

Secondary Voltage:	$12.84 per kW (or kVA) per month
Primary Voltage:	$11.63 per kW (or kVA) per month
Transmission Voltage:	$10.58 per kW (or kVA) per month

These charges were designed to provide full recovery of all production, transmission, and distribution fixed costs. Therefore, for a customer who has installed its own distributed generation facilities, the customer will have paid for its own generation facilities plus the full fixed costs per kW (or kVA) of KU's generation facilities on a monthly basis. From the customer's perspective, under this arrangement the customer will view this as paying for the cost of generation assets twice.

Q. But if the utility is standing ready to provide generation backup service to customers who have installed their own generation, then shouldn't the customer pay a portion of the fixed costs?

A. Yes, they should. The challenge, though, is determining the appropriate level of fixed costs that the customer should pay. The amount that a distributed generator should pay largely depends on the operating characteristics of the distributed generation facilities that are installed. In all cases, a standby customer should pay for all of the transmission and distribution plant installed to serve the customer's maximum demand. As discussed earlier in the portion of my testimony addressing the demand ratchet for Rate PS, sufficient transmission and distribution capacity needs to be installed to deliver power to the customer whenever the customer needs it. For a customer who has installed distributed generation facilities, the utility must have transmission and distribution capacity to deliver sufficient power to meet the customer's load requirements whenever the customer's distributed generation facilities aren't operating. But for generation capacity, the cost of backing up the customer depends on the operating characteristics of the customer's generating facilities. For example, if the customer has installed solar generation, then the utility would be called upon to provide backup power whenever there isn't sufficient sunlight to energize the solar panels, which is likely to occur during periods when the utility is experiencing peak load conditions, such as during a winter system peak which typically occurs during nighttime hours. Likewise, if the customer has installed wind generation, then the utility would be called upon to provide backup power whenever the wind isn't blowing, which is also likely to occur during summer and winter system peak load conditions. Therefore, for these types of distributed generation facilities, it is highly likely that the utility would be called upon to provide backup power during time periods when the utility is experiencing peak load conditions. On the other hand, if the customer has installed a coal- or gas-fired generating facility that operates basically continuously at a low forced outage rate, then it is less likely that the utility would be called upon to provide generation backup power during peak load conditions. Therefore, it would, in general, be less costly to provide generation backup service to a customer who has a generating facility that is operated 24 hours per day, seven days per week, but with a random forced outage rate than to provide generation backup service to a customer whose generating facility is subject to wind conditions and available sunlight.

Q. How will the costs of providing backup service be addressed if Rider SS is eliminated?

A. Under KU's proposal, a customer with distributed generation facilities who relies on KU to provide backup service to its generating facilities would be served on the same rate as any other customer. Therefore, the Company will not discriminate between a customer who has distributed generation facilities and any other customer with similar fluctuating load requirements. If a customer with distributed generation meets the load requirements for one of the Company's standard rate schedules, then the customer will be served under that rate schedule. However, this policy necessitates a change in the demand ratchet for Rates TODS, TODP, RTS, and FLS.

Q. Please explain how serving standby customers under TODS, TODP, RTS, and FLS and changing the ratchet will help provide proper recovery of fixed generation, transmission, and distribution demand-related costs.

A. As explained earlier, generation fixed costs are essentially recovered through the Peak and Intermediate Demand Charges. A 50% demand ratchet is applied in determining the billing demand for these rate components. Importantly, the billing demands are based on measured demands during the Peak and Intermediate Billing Periods. Therefore, if a standby or other customer has a demand that occurs during the peak and intermediate hours (and most customers do), then the Peak and Intermediate Demand Charges will apply to those demands. But if the customer's demand occurs outside of the Peak and Intermediate Billing Periods, then there will be no measured demands during those periods and the Peak and Intermediate Demand Charges will not apply.

Furthermore, the 50% ratchet will be applied based on the maximum demands that have occurred during the preceding 11 months. ***KU is not proposing to change the ratchet percentages applicable to the Peak and Intermediate Demand Charges at this time.*** The structure for determining the billing demand allows the Company to recover at least 50% of a maximum demand that occurred during the peak and intermediate periods for the current and preceding 11 months. This demand ratchet therefore provides recovery of at least 50% of the annual fixed generation costs that the Company has incurred to supply generation capacity to the customer. At this point, the Company believes that the 50% demand ratchet, along with the change to the proposed ratchet for the Base Demand Charge, strikes a reasonable balance *between* (i) providing a pricing structure for recovering a reasonable portion of the annual fixed generation costs incurred to provide service to standby customers and to customers with intermittent loads that fluctuate from month to month *and* (ii) offering a pricing structure that isn't unduly harsh or onerous to standby or customers with intermittent loads. It should be kept in mind that the two components that provide recovery of generation fixed costs – the Peak and Intermediate Demand Charges – represent most of the total demand charges billed under Rates TODS, TODP, RTS, and FLS. Under KU's current rates, the peak and intermediate demand charges represent from approximately 67% to 75% of the total demand charges. (For example, by calculating a simple percentage of the peak and intermediate demand charges to the total of the peak, intermediate and base demand charges for Rate TODS, the percentage is 67% [(\$4.53 + \$6.13) ÷ (\$4.53 + \$6.13 + \$5.20) = 67%]. For Rate TODP, the percentage to the total is 75% [(\$4.39 + \$5.89) ÷ (\$5.89 + \$4.39 + \$3.34) = 75%]. Therefore, peak and intermediate demand charges, which represent most of the demand charges for these rate schedules, will be unaffected by the proposed change in the ratchet.

For transmission and distribution costs, it is important to increase the ratchet percentage to provide assurance that the fixed costs of the transmission and distribution facilities installed to deliver power to customers any time they need the power are appropriately recovered from standby customers and from customers with large month-to-month fluctuations in their loads. As explained in the portion of my testimony dealing with the demand ratchets for Rate PS, transmission and distribution facilities must be sized to deliver the maximum load that the customer creates on the system. Unlike generation facilities, transmission and distribution facilities are designed to meet localized demands placed on the system by customers. The Company is therefore proposing to implement a 100% ratchet for the component of the demand charge that provides for recovery of transmission and distribution fixed costs. The 100% ratchet will only apply to the Base Demand Charge which currently represents between 25% and 33% of the total demand charges (based on the above calculations).

Q. What is the effective *overall* demand ratchet if you consider all three rate components?

A. As I explained, for TODS, TODP, RTS, and FLS, the 100% ratchet would only apply to the Base Demand Charge and the current 50% ratchet would continue to apply to the Peak and Intermediate Demand Charges. Based on a simple analysis, since the 50% ratchet would apply to the demand charge components (Peak and Intermediate Demand Charge) that represent between 67% to 75% of the demand charges, whereas the 100% ratchet would apply to the demand charge component (Base Demand Charge) that represents between 25% and 33% of the cost, the simple weighted effect of both ratchets works out to be equivalent to a demand ratchet of 62.5% to 66.5%. [75% x 50% + 25% x 100% = 62.5% and 67% x 50% + 33% x 100% = 66.5%.] These effective ratchet percentages are not out of line with demand ratchet percentages typically included in rates applicable to large commercial and industrial customers.

Q. Will changing the demand ratchet for the Base Demand Charge have a large impact on customer's bills?

A. Because the impact will be factored into the determination of the revenue requirement for the rate classes, the change will not result in any more or any less revenue calculated for the class. Specifically, the revenues calculated at the proposed rates are determined by applying the proposed Base Demand Charges for TODS, TODP, RTS and FLS to billing demands for the test year that are reflective of the revised ratchet.

In other words, in determining the proposed revenue for the Base Demand Charges the charges are multiplied by billing demands that are higher than what would otherwise be billed during the forecasted test year. Therefore, from the Company's perspective, the change is revenue neutral. The Company is not expected to collect any more revenue from customers as a result of making this change. While the proposed demand ratchet may protect against revenue erosion if customers install distributed generation, it is not anticipated that the Company will collect additional revenues coming out of the rate case as a result of this change. However, on an individual customer basis, the change will affect some customers more than others. Specifically, the change will result in larger increases to customers with large fluctuations in their monthly demands and in smaller increases to customers with steady demands that don't fluctuate from month to month. A number of manufacturing customers on KU and LG&E's system will benefit from the change, particularly high-load-factor manufacturing or commercial customers with relatively constant demands from month to month. Of course, customers with intermittent loads will see a larger increase.

Q. Do you have any other comments about the proposed change in the demand ratchet?

A. Yes. It is important to note that this proposal will create a level playing field for customers who install distributed generation and rely on KU for backup service and customers with large fluctuations in their monthly demands. From the utility's perspective there is not much difference between serving either type of customer.

Therefore, the proposed rate structure represents a non-discriminatory approach to serving both types of customers while helping to ensure that the utility's other customers are not subsidizing standby customers or customers with large swings in their monthly demands.

G. CURTAILABLE SERVICE RIDER (CSR)

Q. Please describe the proposed changes to CSR.

A. The Curtailable Service Rider is a rider that provides a credit to industrial or commercial customers that will interrupt a portion of their load when called upon by KU. Curtailable customers receive a discount in the form of a credit to their demand charges in exchange for their willingness to receive curtailable service on a designated portion of their load. A customer taking service under CSR is subject to a maximum of 375 hours of curtailment (or interruption) during a 12-month period. KU is proposing to lower the CSR credit from $6.40 to $3.20 per kVA of curtailable billing demand for transmission voltage service and from $6.50 to $3.31 per kVA for primary voltage service. As also discussed in Mr. Conroy's testimony, the Company is proposing to restrict the rider so that it will only be available to customers served under the schedule as of the date new rates go into effect as a result of this proceeding.

Q. What is the basis for the proposed credit?

A. As also discussed in the Direct Testimony of David S. Sinclair, KU is proposing to determine the credit based on the fixed carrying costs of the large-frame combustion

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In Re the Matter of:

APPLICATION OF LOUISVILLE GAS	)	
AND ELECTRIC COMPANY FOR AN	)	
ADJUSTMENT OF ITS ELECTRIC AND	)	CASE NO. 2016-00371
GAS RATES AND FOR CERTIFICATES	)	
OF PUBLIC CONVENIENCE AND	)	
NECESSITY	)	

DIRECT TESTIMONY OF
WILLIAM STEVEN SEELYE
MANAGING PARTNER
THE PRIME GROUP, LLC

Filed: November 23, 2016

Charges. The billing demands for the Base Demand Charge is determined as the greater of (a) the maximum measured load during the month (i.e., all hours of the months), (b) 75% of the highest measured demand determined the same way in the preceding 11 monthly billing periods, or (c) 75% of the contract capacity based on the customer's maximum load. This means that a 75% demand ratchet applies to the Base Demand Charge. A higher ratchet was implemented for the Base Demand Charge because the charge was designed to recover transmission and distribution demand-related costs which must be adequately sized to meet the customer's maximum demand whenever the demand occurs.

Q. What changes is LG&E proposing to the rate structure?

A. LG&E proposes to keep the same basic rate structure but to increase the demand ratchet for the Base Demand Charge to 100%. The Company is not proposing to change the demand ratchets for the Peak and Intermediate Charges at this time.

Q. Why is LG&E proposing this change?

A. The modification to the demand ratchets for the large customer rates is being proposed in conjunction with the elimination of the Company's standard rider for Supplemental or Standby Service (Rider SS). The Company has concluded that Rider SS is not adequate in light of fundamental changes that are taking place in the electric utility industry. Rider SS is available to customers who are regularly supplied with electric energy from generating facilities (distributed generation) owned by the customer and who desire to contract with LG&E for reserve, breakdown, supplemental or standby service. Fundamental changes are taking place in the electric utility industry whereby more customers are installing distributed generation to meet their power needs and falling back on the utility to supply power when their facilities are not operating. In some jurisdictions, there has been a surge in the installation of customer-owned renewable distributed generation such as solar generation or wind generation. In general, utilities are supportive of these initiatives as long as the utility's other customers are not subsidizing customers that install distributed generation facilities. Therefore, it is important for utilities to have a rate structure that prevents the subsidization of distributed generation by customers who have chosen not to install distributed generation.

It is also important for a utility to implement rates that allow the utility to recover the appropriate amount of fixed costs associated with serving customers who have installed distributed generation facilities but who want to rely on the utility to provide generation, transmission and distribution service when the distributed generation facilities are not operating. But LG&E also wants to offer a rate design that provides reasonable cost recovery while not discriminating against customers who install distributed generation and that isn't excessively harsh or onerous to customers who install distributed generation but want backup service.

Q. Why is the current standby rate inadequate?

A. In addition to the administrative problems with the rider that are addressed in the Direct Testimony of Robert M. Conroy, there has generally been an unwillingness on the part of customers with distributed generation to sign up under the rider because it is viewed as "too harsh" or "too onerous". Rider SS, which is a rider that would generally be applicable to customers served under Rates PS, TODS, TODP, RTS, or FLS, requires a standby customer to establish a contract demand for its entire load. The customer would then be billed a minimum demand charge that is the greater of (1) the customer's total demand charge billed under the customer's primary rate schedule (PS, TODS, TODP, RTS, or FLS), or (2) the demand charge calculated by applying the demand charges set forth in Rider SS to the customer's contact demand. Currently, the demand charges set forth in Rider SS are as follows:

Secondary Voltage:	$13.57 per kW (or kVA) per month
Primary Voltage:	$12.30 per kW (or kVA) per month
Transmission Voltage:	$10.83 per kW (or kVA) per month

These charges were designed to provide full recovery of all production, transmission, and distribution fixed costs. Therefore, for a customer who has installed its own distributed generation facilities, the customer will have paid for its own generation facilities plus the full fixed costs per kW (or kVA) of LG&E's generation facilities on a monthly basis. From the customer's perspective, under this arrangement the customer will view this as paying for the cost of generation assets twice.

Q. But if the utility is standing ready to provide generation backup service to customers who have installed their own generation, then shouldn't the customer pay a portion of the fixed costs?

A. Yes, they should. The challenge, though, is determining the appropriate level of fixed costs that the customer should pay. The amount that a distributed generator should pay largely depends on the operating characteristics of the distributed generation facilities that are installed. In all cases, a standby customer should pay for all of the transmission and distribution plant installed to serve the customer's maximum demand. As discussed earlier in the portion of my testimony addressing the demand ratchet for Rate PS, sufficient transmission and distribution capacity needs to be installed to deliver power to the customer whenever the customer needs it. For a customer who has installed distributed generation facilities, the utility must have transmission and distribution capacity to deliver sufficient power to meet the customer's load requirements whenever the customer's distributed generation facilities aren't operating. But for generation capacity, the cost of backing up the customer depends on the operating characteristics of the customer's generating facilities. For example, if the customer has installed solar generation, then the utility would be called upon to provide backup power whenever there isn't sufficient sunlight to energize the solar panels, which is likely to occur during periods when the utility is experiencing peak load conditions, such as during a winter system peak which typically occurs during nighttime hours. Likewise, if the customer has installed wind generation, then the utility would be called upon to provide backup power whenever the wind isn't blowing, which is also likely to occur during summer and winter system peak load conditions. Therefore, for these types of distributed generation facilities, it is highly likely that the utility would be called upon to provide backup power during time periods when the utility is experiencing peak load conditions. On the other hand, if the customer has installed a coal- or gas-fired generating facility that operates basically continuously at a low forced outage rate, then it is less likely that the utility would be called upon to provide generation backup power during peak load conditions. Therefore, it would, in general, be less costly to provide generation backup service to a customer who has a generating facility that is operated 24 hours per day, seven days per week, but with a random forced outage rate than to provide generation backup service to a customer whose generating facility is subject to wind conditions and available sunlight.

Q. How will the costs of providing backup service be addressed if Rider SS is eliminated?

A. Under LG&E's proposal, a customer with distributed generation facilities who relies on LG&E to provide backup service to its generating facilities would be served on the same rate as any other customer. Therefore, the Company will not discriminate between a customer who has distributed generation facilities and any other customer with similar fluctuating load requirements. If a customer with distributed generation meets the load requirements for one of the Company's standard rate schedules, then the customer will be served under that rate schedule. However, this policy necessitates a change in the demand ratchet for Rates TODS, TODP, RTS, and FLS.

Q. Please explain how serving standby customers under TODS, TODP, RTS, and FLS and changing the ratchet will help provide proper recovery of fixed generation, transmission, and distribution demand-related costs.

A. As explained earlier, generation fixed costs are essentially recovered through the Peak and Intermediate Demand Charges. A 50% demand ratchet is applied in determining the billing demand for these rate components. Importantly, the billing demands are based on measured demands during the Peak and Intermediate Billing Periods. Therefore, if a standby or other customer has a demand that occurs during the peak and intermediate hours (and most customers do), then the Peak and Intermediate Demand Charges will apply to those demands. But if the customer's demand occurs outside of the Peak and Intermediate Billing Periods, then there will be no measured demands during those periods and the Peak and Intermediate Demand Charges will not apply.

Furthermore, the 50% ratchet will be applied based on the maximum demands that have occurred during the preceding 11 months. ***LG&E is not proposing to change the ratchet percentages applicable to the Peak and Intermediate Demand Charges at this time.*** The structure for determining the billing demand allows the Company to recover at least 50% of a maximum demand that occurred during the peak and intermediate periods for the current and preceding 11 months. This demand ratchet therefore provides recovery of at least 50% of the annual fixed generation costs that the Company has incurred to supply generation capacity to the customer. At this point, the Company believes that the 50% demand ratchet, along with the change to the proposed ratchet for the Base Demand Charge, strikes a reasonable balance *between* (i) providing a pricing structure for recovering a reasonable portion of the annual fixed generation costs incurred to provide service to standby customers and to customers with intermittent loads that fluctuate from month to month *and* (ii) offering a pricing structure that isn't unduly harsh or onerous to standby or customers with intermittent loads. It should be kept in mind that the two components that provide recovery of generation fixed costs – the Peak and Intermediate Demand Charges – represent most of the total demand charges billed under Rates TODS, TODP, RTS, and FLS. Under LG&E's current rates, the peak and intermediate demand charges represent from approximately 71% to 78% of the total demand charges. (For example, by calculating a simple percentage of the peak and intermediate demand charges to the total of the peak, intermediate and base demand charges for Rate TODP, the percentage to the total is 71% [($5.26 + $3.91) ÷ ($5.26 + $3.91 + $3.75) = 71%]. For Rate FLS, the percentage is 78% [($3.42 + $2.37) ÷ ($3.42 + $2.37 + $1.62) = 78%].) Therefore, peak and intermediate demand charges, which represent most of the demand charges for these rate schedules, will be unaffected by the proposed change in the ratchet.

For transmission and distribution costs, it is important to increase the ratchet percentage to provide assurance that the fixed costs of the transmission and distribution facilities installed to deliver power to customers any time they need the power are appropriately recovered from standby customers and from customers with large month-to-month fluctuations in their loads. As explained in the portion of my testimony dealing with the demand ratchets for Rate PS, transmission and distribution facilities must be sized to deliver the maximum load that the customer creates on the system. Unlike generation facilities, transmission and distribution facilities are designed to meet localized demands placed on the system by customers. The

Company is therefore proposing to implement a 100% ratchet for the component of the demand charge that provides for recovery of transmission and distribution fixed costs. The 100% ratchet will only apply to the Base Demand Charge which currently represents between 22% and 29% of the total demand charges (based on the above calculations).

Q. What is the effective *overall* demand ratchet if you consider all three rate components?

A. As I explained, for TODS, TODP, RTS, and FLS, the 100% ratchet would only apply to the Base Demand Charge and the current 50% ratchet would continue to apply to the Peak and Intermediate Demand Charges. Based on a simple analysis, since the 50% ratchet would apply to the demand charge components (Peak and Intermediate Demand Charge) that represent between 71% to 78% of the demand charges, whereas the 100% ratchet would apply to the demand charge component (Base Demand Charge) that represents between 22% and 29% of the cost, the simple weighted effect of both ratchets works out to be equivalent to a demand ratchet of 61% to 65%. [78% x 50% + 22% x 100% = 61% and 71% x 50% + 29% x 100% = 65%.] These effective ratchet percentages are not out of line with demand ratchet percentages typically included in rates applicable to large commercial and industrial customers.

Q. Will changing the demand ratchet for the Base Demand Charge have a large impact on customer's bills?

A. Because the impact will be factored into the determination of the revenue requirement for the rate classes, the change will not result in any more or any less revenue calculated for the class. Specifically, the revenues calculated at the proposed rates are determined by applying the proposed Base Demand Charges for TODS, TODP, RTS and FLS to billing demands for the test year that are reflective of the revised ratchet. In other words, in determining the proposed revenue for the Base Demand Charges the charges are multiplied by billing demands that are higher than what would otherwise be billed during the forecasted test year. Therefore, from the Company's perspective, the change is revenue neutral. The Company is not expected to collect any more revenue from customers as a result of making this change. While the proposed demand ratchet may protect against revenue erosion if customers install distributed generation, it is not anticipated that the Company will collect additional revenues coming out of the rate case as a result of this change. However, on an individual customer basis, the change will affect some customers more than others. Specifically, the change will result in larger increases to customers with large fluctuations in their monthly demands and in smaller increases to customers with steady demands that don't fluctuate from month to month. A number of manufacturing customers on LG&E and KU's system will benefit from the change, particularly high-load-factor manufacturing or commercial customers with relatively constant demands from month to month. Of course, customers with intermittent loads will see a larger increase.

Q. Do you have any other comments about the proposed change in the demand ratchet?

A. Yes. It is important to note that this proposal will create a level playing field for customers who install distributed generation and rely on LG&E for backup service and customers with large fluctuations in their monthly demands. From the utility's perspective there is not much difference between serving either type of customer. Therefore, the proposed rate structure represents a non-discriminatory approach to serving both types of customers while helping to ensure that the utility's other customers are not subsidizing standby customers or customers with large swings in their monthly demands.

G. CURTAILABLE SERVICE RIDER (CSR)

Q. Please describe the proposed changes to CSR.

A. The Curtailable Service Rider is a rider that provides a credit to industrial or commercial customers that will interrupt a portion of their load when called upon by LG&E. Curtailable customers receive a discount in the form of a credit to their demand charges in exchange for their willingness to receive curtailable service on a designated portion of their load. A customer taking service under CSR is subject to a maximum of 375 hours of curtailment (or interruption) during a 12-month period. LG&E is proposing to lower the CSR credit from $6.40 to $3.56 per kVA of curtailable billing demand for transmission voltage service and from $6.50 to $3.67 per kVA for primary voltage service. As also discussed in Mr. Conroy's testimony, the Company is proposing to restrict the rider so that it will only be available to customers served under the schedule as of the date new rates go into effect as a result of this proceeding.

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PUBLIC SERVICE
COMMISSION

SETTLEMENT AGREEMENT, STIPULATION, AND RECOMMENDATION

This Settlement Agreement, Stipulation, and Recommendation ("Settlement Agreement") is entered into this 12th day of January 2009, by and between Louisville Gas and Electric Company ("LG&E"); Kentucky Utilities Company ("KU") (LG&E and KU are hereafter collectively referenced as "the Utilities"); Commonwealth of Kentucky, ex. rel. Jack Conway, Attorney General, by and through the Office of Rate Intervention ("AG"); Kentucky Industrial Utility Customers, Inc. ("KIUC"); The Kroger Company ("Kroger"); Lexington-Fayette Urban County Government ("LFUCG"); Community Action Kentucky, Inc. ("CAK"); Community Action Council for Lexington-Fayette, Bourbon, Harrison and Nicholas Counties, Inc. ("CAC"); Association of Community Ministries ("ACM"); and, People Organized and Working for Energy Reform ("POWER") in the proceedings involving LG&E and KU which are the subject of this Settlement Agreement, as set forth below.

WITNESSETH:

WHEREAS, KU filed on July 29, 2008 with the Kentucky Public Service Commission ("Commission")its Application for Authority to Adjust Rates, *In the Matter of: An Application of Kentucky Utilities Company for an Adjustment of Base Rates*, and the Commission has established Case No. 2008-00251 to review KU's base rate application;

WHEREAS, LG&E filed on July 29, 2008 with the Commission its Application for Authority to Adjust Rates, *In the Matter of: An Application of Louisville Gas and Electric Company for an Adjustment of Its Electric and Gas Base Rates*, and the Commission has established Case No. 2008-00252 to review LG&E's base rate application (Case Nos. 2008-00251 and 2008-00252 are hereafter collectively referenced as the "rate proceedings");

WHEREAS, the AG, KIUC, Kroger, and CAK have been granted intervention by the Commission in both of the rate proceedings; LFUCG and CAC have been granted intervention by the Commission in Case No. 2008-00251 only; and ACM and POWER have been granted intervention by the Commission in Case No. 2008-00252 only;

WHEREAS, on August 22, 2008, the Commission granted consolidation of Case No. 2008-00251 with the case captioned *In the Matter of: Application of Kentucky Utilities Company to File Depreciation Study*, Case No. 2007-00565, and Case No. 2008-00252 with the case captioned *In the Matter of: Application of Louisville Gas and Electric Company to File Depreciation Study*, Case No. 2007-00564;

WHEREAS, pursuant to the terms of the Utilities' Small Time-of-Day ("STOD") pilot tariffs, the Utilities performed studies of their STOD rates after the three-year pilot period, which studies the Utilities filed in these proceedings pursuant to the Commission's August 15, 2008 Orders in these proceedings;

WHEREAS, a prehearing informal conference for the purpose of discussing settlement, attended in person by representatives of the AG, KIUC, Kroger, LFUCG, CAK, CAC, ACM and POWER, the Commission Staff and the Utilities, took place on January 6, 7, and 9, 2009 at the offices of the Commission during which a number of procedural and substantive issues were discussed, including potential settlement of all issues pending before the Commission in the above-referenced proceedings;

WHEREAS, all of the Parties hereto unanimously desire to settle all the issues pending before the Commission in the above-referenced proceedings;

WHEREAS, the adoption of this Agreement will eliminate the need for the Commission and the parties to expend significant resources litigating these proceedings, and eliminate the possibility of, and any need for, rehearing or appeals of the Commission's final order herein;

WHEREAS, it is understood by all Parties hereto that this Settlement Agreement is subject to the approval of the Commission, insofar as it constitutes an agreement by all parties to the rate proceedings for settlement, and, absent express agreement stated herein, does not represent agreement on any specific claim, methodology or theory supporting the appropriateness of any proposed or recommended adjustments to the Utilities' rates, terms, and conditions;

WHEREAS, the Parties have spent many hours, over several days, in order to reach the stipulations and agreements which form the basis of this Settlement Agreement;

WHEREAS, all of the Parties, who represent diverse interests and divergent viewpoints, agree that this Settlement Agreement, viewed in its entirety, is a fair, just, and reasonable resolution of all the issues in the above-referenced proceedings; and

WHEREAS, it is the position of the Parties hereto that this Settlement Agreement is supported by sufficient and adequate data and information, and should be approved by the Commission.

NOW, THEREFORE, for and in consideration of the premises and conditions set forth herein, the Parties hereby stipulate and agree as follows:

ARTICLE I. Revenue Requirement.

Section 1.1. The Parties hereto stipulate that the following decreases in annual revenues for LG&E electric and KU operations, for purposes of determining the base electric rates of LG&E and KU in the rate proceedings, are fair, just, and reasonable for the Parties and for all customers of LG&E and KU:

Section 1.1.1. LG&E Electric Operations: $13,157,000;

Section 1.1.2. KU Operations: $8,851,000.

The Parties hereto agree that these decreases in annual revenues for LG&E electric operations and for KU operations will be effective for service rendered on and after February 6, 2009.

Section 1.2. The Parties hereto agree that, effective for service rendered on and after February 6, 2009, an increase in annual revenues for LG&E gas operations of $22,000,000, for purposes of determining the base rates of LG&E gas operations in the rate proceedings, is fair, just, and reasonable for the Parties and for all gas customers of LG&E.

ARTICLE II. Allocation of Revenue.

Section 2.1. The Parties hereto agree that the allocations of the decreases in annual revenues for KU and LG&E electric operations, and that the allocation of the increase in annual revenue for LG&E gas operations, as set forth on the allocation schedules designated Exhibit 1 (KU), Exhibit 2 (LG&E electric), and Exhibit 3 (LG&E gas) hereto, are fair, just, and reasonable for the Parties and for all customers of LG&E and KU.

Section 2.2. The Parties hereto agree that, effective February 6, 2009, the Utilities shall implement the electric and gas rates set forth on the tariff sheets in Exhibit 4 (KU), Exhibit 5 (LG&E electric), and Exhibit 6 (LG&E gas), attached hereto, which rates the Parties unanimously stipulate are fair, just, and reasonable and should be approved by the Commission.

ARTICLE III. Treatment of Certain Specific Issues.

Section 3.1. The Parties agree that LG&E and KU may amortize their actual rate case expenses in these proceedings over a three year period. The amortization shall begin in the month after which the Commission approves this Settlement Agreement.

Section 3.2. The Parties agree that the depreciation rates attached hereto as Exhibit 7 (KU) and Exhibit 8 (LG&E electric and gas), which include the depreciation of the cost of the

Utilities' new Customer Care System software over ten years, are based on the Average Service Life methodology and the service lives as filed in the respective applications, and shall be effective for the Utilities' accounting and ratemaking purposes upon the approval of this Settlement Agreement.

Section 3.3. The Parties hereto agree that, effective as of the first expense month after which the Commission approves this Settlement Agreement, the return on equity that shall apply to the Utilities' recovery under their environmental cost recovery ("ECR") mechanism is 10.63%.

Section 3.4. The Parties hereto agree that the Commission should grant the Utilities' requests, as stated in their Applications, to establish and amortize over five years a regulatory asset for each of the Utilities for the costs associated with the transmission depancaking settlement agreement in Federal Energy Regulatory Commission Docket No. ER06-1458-000 between the Utilities and East Kentucky Power Cooperative, Inc. The amortization shall begin in the month after which the Commission approves this Settlement Agreement.

Section 3.5. The Parties hereto agree that the Commission should grant the Utilities' requests that revenues related to MISO Schedule 10 expenses deferred between the end of the test year and February 6, 2009, as well as any future adjustments to the MISO exit fee, be deferred as regulatory liabilities until the amounts can be amortized in future base rate cases. The amortization of the amounts related to MISO Schedule 10 expenses and the MISO exit fee already deferred as of the end of the test year shall begin in the month after which the Commission approves this Settlement Agreement.

Section 3.6. The Parties hereto agree that the Utilities' currently approved customer charges shall remain unchanged in the new rates, terms, and conditions proposed by this

Settlement Agreement, with the exception of LG&E's gas residential customer charge, which shall increase by $1.00 per month to $9.50 per month.

Section 3.7. The Parties hereto agree that the Utilities' merger surcredits will terminate February 6, 2009, and the total distribution of the merger surcredits will be prorated to that date.

Section 3.8. The Parties hereto agree that the following residential customer deposit amounts shall be implemented: $135 for LG&E electric; $160 for LG&E gas; $295 for LG&E electric and gas combined; and $135 for KU. All other customer deposit amounts will be as filed by the Utilities in these proceedings.

Section 3.9. The Parties hereto agree that, if a residential customer indicates an inability to pay or difficulty in paying a required customer deposit, the appropriate Utility shall offer the customer the option to pay all or a portion of the required deposit in installments over a period not to exceed the first four normal billing periods.

Section 3.10. The Parties hereto agree to the following changes to the following Curtailable Service Riders for LG&E electric and KU: the CSR1 credit will increase from the currently approved level by $2.00 per kW; CSR1 customers will be interruptible for no more than 200 hours annually, and no more than two interruptions per day; the CSR2 credit will increase from the currently approved level by $1.50 per kW; CSR2 customers will be interruptible for no more than 425 hours annually, and no more than two interruptions per day. The amount of load that can be eligible for the CSR2 rider shall be limited to an aggregate of 100 MW per Utility.

Section 3.11. The Utilities agree to work with interested parties to study the feasibility of measuring demand for generation service to multi-site customers based on conjunctive demand, where "conjunctive demand" herein refers to the measured demand at a meter at the time that the total demand of a multi-site customer's loads, measured over a coinciding time period, has reached its peak during the billing period.

Section 3.12. The Parties hereto agree that payment for a customer's bill shall be due to the appropriate Utility twelve days after the date on which the Utility issues the bill, though there will be no adverse credit impact on the customer's payment and credit record, including credit scoring, both internally and externally, and the account will not be considered delinquent for any purpose if the Utility receives the customer's payment within fifteen days after the date on which the Utility issues the customer's bill. If the appropriate Utility does not receive the customer's payment within fifteen days after the date on which the Utility issues the customer's bill, the Utility may assess a late payment charge as set out in the Utility's proposed tariffs in these proceedings. The Parties acknowledge and agree that LG&E and KU will not be able to implement the change in the due date of customers' bills and that KU will not be able to implement its late payment charge until the first billing cycle following the full operation of its new Customer Care System.

Section 3.13. The Parties hereto agree that the Utilities, CAK, and ACM/POWER will consult with each other concerning the design of a plan regarding the identification of late payment charges for low income customers associated with utility assistance payments. Specifically, they shall discuss the implementation of a plan by which CAK, ACM/POWER, their member agencies, and other Utility-approved emergency energy assistance agencies ("Assistance Agencies") would annually pre-certify recipients of certain utility payment assistance, conceptually similar to the pre-certification program currently in place in the Commonwealth of Virginia, which would allow the Utilities' Kentucky operations to waive the late payment charges for such pre-certified customers during the months of December through

March each year Participation in such a pre-certification program would be optional to any or all of the Assistance Agencies.

Section 3.14. The Parties hereto agree that the Utilities shall increase the currently approved monthly residential meter charge (for gas and electric meters) for the Home Energy Assistance ("HEA") program from $0.10 to $0.15 per meter. For a period of two years following the implementation of the rates proposed in this Settlement Agreement or until rates take effect in the Utilities' next base rate proceedings, whichever is longer, the Utilities shall make a dollar-for-dollar contribution from shareholder funds to the HEA program to match HEA funds collected from customers (up to $300,000 per year on a combined-Utilities basis).

Section 3.15. The Parties hereto agree that, except as modified in this Settlement Agreement and the exhibits attached hereto, the rates, terms, and conditions proposed by the Utilities in the rate proceedings shall be approved as filed. Approval of this Settlement Agreement shall not be construed to approve or deny the adjustments to LG&E's and KU's electric revenues and expenses associated with the normalization of weather.

ARTICLE IV. Miscellaneous Provisions.

Section 4.1. Except as specifically stated otherwise in this Settlement Agreement, the Parties agree that making this Settlement Agreement shall not be deemed in any respect to constitute an admission by any party hereto that any computation, formula, allegation, assertion or contention made by any other party in these proceedings is true or valid.

Section 4.2. The Parties hereto agree that the foregoing stipulations and agreements represent a fair, just, and reasonable resolution of the issues addressed herein and request the Commission to approve the Settlement Agreement.

Section 4.3. The Parties hereto agree that, following the execution of this Settlement Agreement, the Parties shall cause the Settlement Agreement to be filed with the Commission by January 12, 2009 together with a request to the Commission for consideration and approval of this Settlement Agreement for rates to become effective on February 6, 2009.

Section 4.4. Each party waives all cross-examination of the other parties' witnesses unless the Commission disapproves this Agreement, and each party further stipulates and recommends that the Notice of Intent, Notice, Application, testimony, pleadings, and responses to data requests filed in this proceeding be admitted into the record. The Parties stipulate that after the date of this Settlement Agreement they will not otherwise contest the Utilities' proposals, as modified by this Settlement Agreement, in the hearing of the above-referenced proceedings regarding the subject matter of the Settlement Agreement, and that they will refrain from cross-examination of the Utilities' witnesses during the hearing, except insofar as such cross-examination is in support of the Settlement Agreement.

Section 4.5. The Parties hereto agree that this Settlement Agreement is subject to the acceptance of and approval by the Commission. The Parties hereto further agree to act in good faith and to use their best efforts to recommend to the Commission that this Settlement Agreement be accepted and approved.

Section 4.6. If the Commission issues an order adopting this Settlement Agreement in its entirety, each of the parties agrees that it shall file neither an application for rehearing with the Commission, nor an appeal to the Franklin Circuit Court with respect to such order.

Section 4.7. The Parties hereto agree that, if the Commission does not accept and approve this Settlement Agreement in its entirety, then: (a) this Settlement Agreement shall be void and withdrawn by the parties hereto from further consideration by the Commission and none of the parties shall be bound by any of the provisions herein, provided that no party is precluded from advocating any position contained in this Settlement Agreement; and (b) neither the terms of this Settlement Agreement nor any matters raised during the settlement negotiations shall be binding on any of the Parties to this Settlement Agreement or be construed against any of the Parties.

Section 4.8. The Parties hereto agree that, should the Settlement Agreement be voided or vacated for any reason after the Commission has approved the Settlement Agreement, then the parties shall be returned to the *status quo* existing at the time immediately prior to the execution of this agreement.

Section 4.9. The Parties hereto agree that this Settlement Agreement shall in no way be deemed to divest the Commission of jurisdiction under Chapter 278 of the Kentucky Revised Statutes.

Section 4.10. The Parties hereto agree that this Settlement Agreement shall inure to the benefit of and be binding upon the parties hereto, their successors and assigns.

Section 4.11. The Parties hereto agree that this Settlement Agreement constitutes the complete agreement and understanding among the parties hereto, and any and all oral statements, representations or agreements made prior hereto or contained contemporaneously herewith shall be null and void and shall be deemed to have been merged into this Settlement Agreement.

Section 4.12. The Parties hereto agree that, for the purpose of this Settlement Agreement only, the terms are based upon the independent analysis of the parties to reflect a fair, just, and reasonable resolution of the issues herein and are the product of compromise and negotiation.

Section 4.13. The Parties hereto agree that neither the Settlement Agreement nor any of the terms shall be admissible in any court or commission except insofar as such court or commission is addressing litigation arising out of the implementation of the terms herein or the approval of this Settlement Agreement. *This Settlement Agreement shall not have any precedential value in this or any other jurisdiction.*

Section 4.14. The signatories hereto warrant that they have appropriately informed, advised, and consulted their respective Parties in regard to the contents and significance of this Settlement Agreement and based upon the foregoing are authorized to execute this Settlement Agreement on behalf of their respective Parties.

Section 4.15. The Parties hereto agree that this Settlement Agreement is a product of negotiation among all parties hereto, and no provision of this Settlement Agreement shall be strictly construed in favor of or against any party. Notwithstanding anything contained in the Settlement Agreement, the parties recognize and agree that the effects, if any, of any future events upon the operating income of the Utilities are unknown and this Settlement Agreement shall be implemented as written.

Section 4.16. The Parties hereto agree that this Settlement Agreement may be executed in multiple counterparts.

IN WITNESS WHEREOF, the parties have hereunto affixed their signatures:

Louisville Gas and Electric Company
and Kentucky Utilities Company

HAVE SEEN AND AGREED:

By: Kendrick R Riggs
Kendrick R. Riggs, Counsel

-and-

By: Allyson K Sturgeon
Allyson K. Sturgeon, Counsel

400001 129265/557255 1

Commonwealth of Kentucky, ex. rel. Jack Conway, Attorney General, by and through the Office of Rate Intervention

HAVE SEEN AND AGREED:

By:____________________________________
Dennis G. Howard II, Counsel

Kentucky Industrial Utility Customers, Inc.

HAVE SEEN AND AGREED:

By: Michael L. Kurtz
Michael L. Kurtz, Counsel

The Kroger Company

HAVE SEEN AND AGREED:

By: ______________________
David C. Brown, Counsel

Lexington-Fayette Urban County Government

HAVE SEEN AND AGREED:

By: Willis L. Wilson
Willis L. Wilson, Counsel
Pending approval of the Fayette Urban County Council

Community Action Kentucky, Inc.

HAVE SEEN AND AGREED:

By:______________________
Joe F. Childers, Counsel

Community Action Counsel for
Lexington-Fayette, Bourbon, Harrison
and Nicholas Counties, Inc.

HAVE SEEN AND AGREED:

By: ______________________
Iris G. Skidmore, Counsel

Association of Community Ministries

HAVE SEEN AND AGREED:

By: ______________________
Lisa Kilkelly, Counsel

People Organized and Working for
Energy Reform

HAVE SEEN AND AGREED:

By: ______
Lisa Kilkelly, Counsel

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In re the Matter of:

APPLICATION OF KENTUCKY	)	
UTILITIES COMPANY FOR AN	)	**CASE NO. 2009-00548**
ADJUSTMENT OF BASE RATES	)	

TESTIMONY OF WILLIAM STEVEN SEELYE PRINCIPAL & SENIOR CONSULTANT THE PRIME GROUP, LLC

Filed: January 29, 2010

volatile manner. In other words, KU will be providing customers served under this rate, which currently only includes the Arc Furnace, with an inducement to manage spikes in their demands.

Q. Why is the Company adopting the time-of-day structure in Rate TOD for Fluctuating Load Service?

A. As mentioned earlier, KU and LG&E are adopting a uniform time-day-structure for all demand-billed rates, which separates the current peak time period into two time periods to provide customers with greater opportunity to reduce or shift their Peak and Intermediate period demands.

Q. Was the fluctuating nature of the Arc Furnace's load taken into account in the cost of service study?

A. No. All demand allocators in the cost of service study were measured on an hourly basis. Using hourly demands in the cost of service study likely understates the costs allocated to the Arc Furnace and thus overstates the rate of return for the Arc Furnace. Furthermore, the cost of service study did not identify any incremental load-following or regulation costs associated with serving the Arc Furnace. This is another area where the cost of service study likely understates the cost of serving the Arc Furnace.

G. CONJUNCTIVE DEMAND

Q. Was there a provision in the Settlement Agreement in KU and LG&E's last general rate cases to study Conjunctive Demand?

A. Yes. Section 3.11 of the Settlement Agreement, Stipulation, and Recommendation ("Settlement Agreement") stated that KU and LG&E "agree to work with interested parties to study the feasibility of measuring demand for generation service to multi--site customers based on conjunctive demand, where 'conjunctive demand' herein refers to the measured demand at a meter at the time that the total demand of a multi-site customer's load, measured over a coinciding time period, has reached its peak during the billing period."

Q. Please explain what this means.

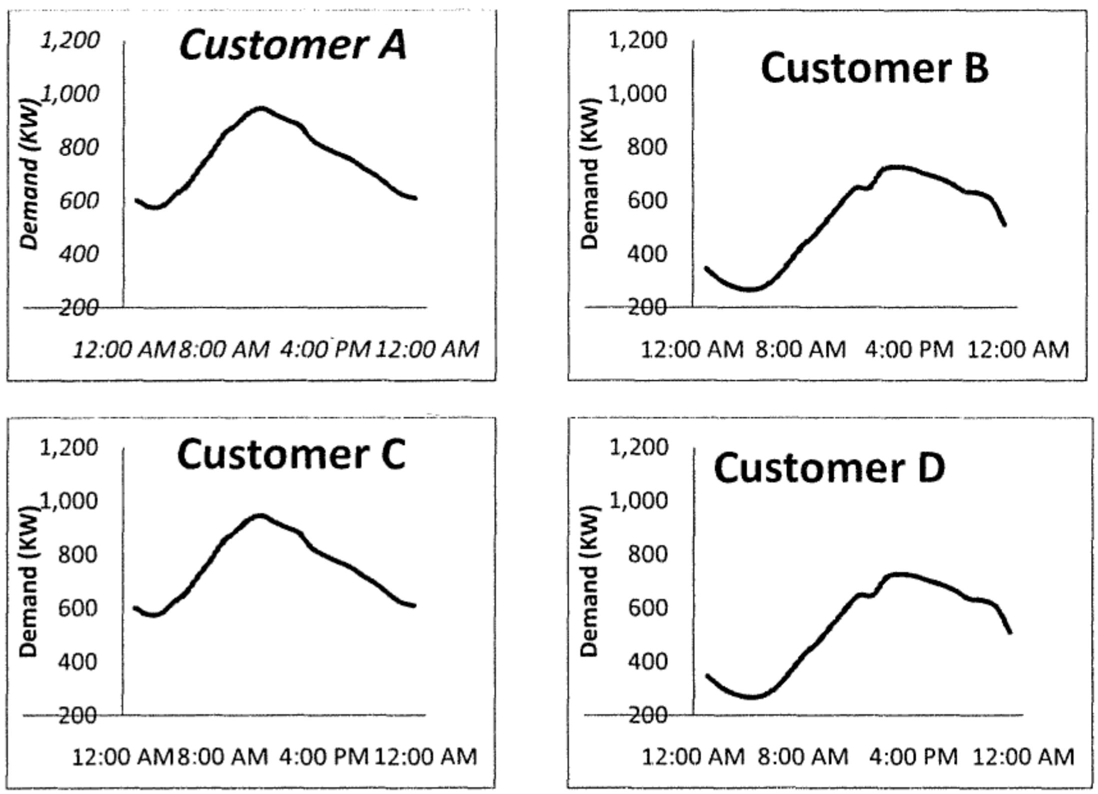
A. Conjunctive demand is a form of aggregated billing, where the loads for a customer with multi-site accounts, such as a group of grocery stores or retail stores owned by a single corporate entity, are aggregated for purposes of billing a component of the utility's demand charge.

Q. Is aggregated billing allowed under the Commission's regulations?

A. No. Section 9(2) of 807 KAR 5:041 states that, "The utility shall regard each point of delivery as an independent customer and meter the power delivered at each point. Combined meter readings shall not be taken at separate points, nor shall energy used by more than one (1) residence or place of business on one (1) meter be measured to obtain a lower rate." Thus any sort of aggregated billing would require a deviation that could only be authorized by a Commission Order upon a showing of good cause. Certainly, under 807 KAR 5:041, Section 22, the Companies and interested parties could request a deviation from this provision in order to allow for a form of conjunctive demand that is consistent with cost of service and ratemaking principles, provided there is good cause for such deviation.

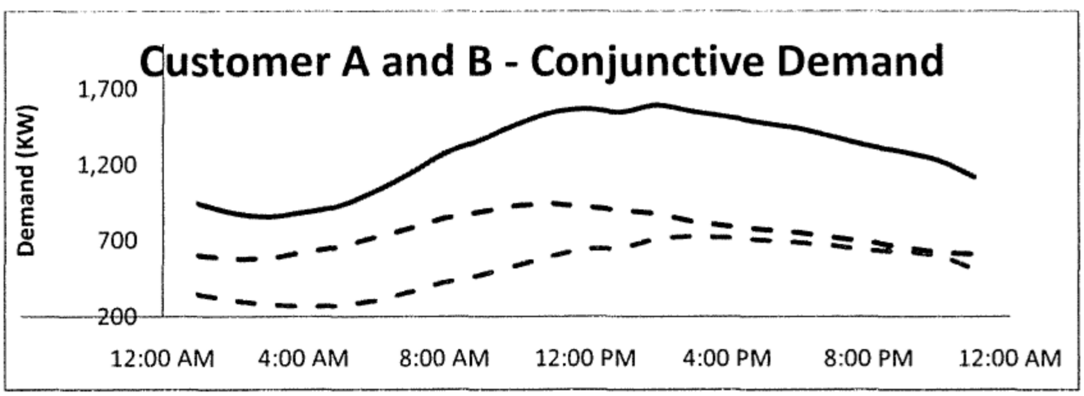
Q. Explain how Conjunctive Demand would be billed?

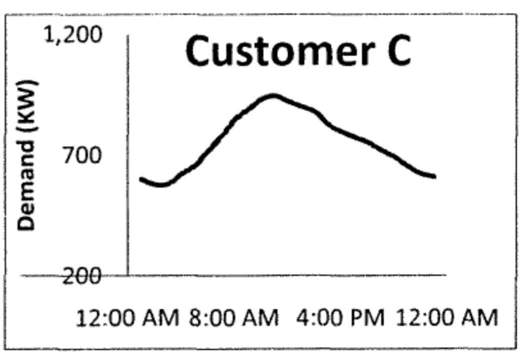
A. Perhaps an easy way to understand what the provision of the Settlement Agreement means is to consider four customers with two different demand profiles, referred to as Customer A, Customer B, Customer C and Customer D. In this example, Customer A and Customer C share the same load characteristics for the month (Load Profile 1). Customer B and Customer D also share the same load characteristics (Load Profile 2) which is different from Customer A and Customer C. As a further simplifying assumption, suppose that the maximum monthly demands for all four customers occur on the same day, which happens to be the same day during which the utility's monthly system peak occurs. The 15-minute peak-day loads for the four hypothetical customers are shown below:

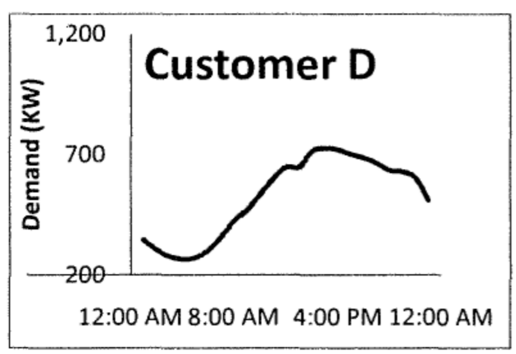


Now suppose that Customer A is a warehouse and Customer B is a retail store owned by the same corporate entity. Therefore, Customer A and Customer B represent a single "multi-site customer" according to Section 3.11 of the Settlement Agreement. Further, suppose that Customer C is also a warehouse and Customer D is a retail store, not owned by the same entity but separate individual entities.

Under Section 3.11 of the Settlement Agreement, the Conjunctive Demand for Customer A and Customer B would be determined by aggregating (or "conjoining") the 15-minute loads for the two customers and applying the generation component of the demand charge to the maximum 15-minute demand from the aggregated loads, whereas the billing demands for Customer C and Customer D would continue to be determined individually, as follows:







For the multi-site customers, in this example, the Conjunctive Demand applicable to the production demand component would be 1,593 kW, whereas the billing demand for the two non-multi-site customers would continue to be 1,750 kW, even though their loads are identical.

Q. Could you provide hypothetical demand charge calculations for these four hypothetical customers without using Conjunctive Demand.

A. Yes. Suppose that the utility's total monthly demand charge is $10 per kW as applied to each individual customer's maximum demand, which consists of a $6.50 per kW production demand component and a $3.50 per kW transmission and distribution demand component. With a standard non-coincident peak (NCP) rate applied to each individual customer's demand, the demand charge billing for Customer A would be the same as the demand charge billing for Customer C. Likewise, the demand charge billing for Customer B would be the same as the demand charge billing for Customer D, as follows:

Customer A (multi-site warehouse)

Demand Charges = 1,000 kW x $10.00/kW = $10,000

Customer C (non-multi-site warehouse)

Demand Charges = 1,000 kW x $10.00/kW = $10,000

Customer B (multi-retail retail store)

Demand Charges = 750 kW x $10.00/kW = $ 7,500

Customer D (non-multi-site retail store)

Demand Charges = 750 kW x $10.00/kW = $ 7,500

Under this example Customer A (the multi-site warehouse) and Customer B (the multi-site retail store), together, would be billed demand charges of $17,500 for the month. Customer C (the non-multi-site warehouse) and Customer D (the non-multi-site retail store owned by some other individual entity), together, would be billed $17,500, the same amount as the two-multi-site accounts.

Q. What happens with Conjunctive Demand?

A. With Conjunctive Demand, the 15-minute loads for the two multi-site customers would be aggregated and the production demand component would be applied to the maximum aggregated demand during the month, and transmission demand component would continue to be applied to the maximum demands for the individual accounts, as follows:

Customer A and Customer B (multi-site customers)

Production –	1,593 kW x $6.50/kW	= $10,354.50
Trans & Dist	1,750 kW x $3.50/kW	= $ 6,125.00
Total Customers A & B		= $16.479.50

Customer C and Customer D (non-multi-site customers)

Demand Charges =	1,000 kW x $10.00/kW	= $10,000.00
Demand Charges =	750 kW x $10.00/kW	= $ 7,500.00
Total Customers C and D		= $17,500.00

Therefore, under Conjunctive Billing, as defined in the Settlement Agreement, Customer A and Customer B, together, would pay $16,479.50 in demand charges, while Customer C and Customer D, together, with identical loads, would pay $17,500. Under the form of Conjunctive Billing as defined in the Settlement Agreement, the multi-site customers would realize a rate benefit (or rate disparity) of $1,020.50 without taking any action to modify their load patterns. In other words, the multi-site customers would receive a rate benefit through conjunctive billing of $1,020.50 compared to the two non-multi-site customers even though the cost of serving the multi-site customers is the same as the two non-multi-site customers.

Q. Do you believe that the type of Conjunctive Demand defined in the Settlement Agreement is consistent with sound cost of service and ratemaking principles?

A. No. In a regulatory context, the term "fair, just, and reasonable rates" has taken on the meaning that the rates are cost based and non-discriminatory. The cost of serving Customers A and C in the example above would be the same, and the cost of serving Customers B and D would be the same. As can be seen from the example above, there is clearly an advantage to aggregating the loads of Customers A and B before applying the rates whenever there is diversity among the load patterns. Allowing loads to be aggregated before the rates are applied results in a lower bill. Allowing such load aggregation for multi-site accounts yet denying it for non-multi-site accounts could easily be regarded as discriminatory treatment.

Q. Would a full-scale implementation of the type of Conjunctive Demand as defined in the Settlement Agreement result in even greater disparities than shown in your example?

A. Yes. As more accounts are added the total amount of the rate disparities would be larger.

Q. Are there other forms of conjunctive billing that are more consistent with cost of service and ratemaking principles?

A. Yes. Coincident peak CP demand billing can be viewed as a form of conjunctive billing, and can be applied on an aggregated basis so that it can be implemented as a full-fledged conjunctive billing approach. With CP demand rates, the production (and perhaps transmission) demand costs would be applied to the customer's demand at the time of the Company's system peak. CP demand rates are fully consistent with cost of service principles. An important consideration in the Companies' generation resource planning efforts is to plan the system so that it has adequate capacity to meet maximum system demands, which determine the time when CP demands are measured. In the Company's cost of service study, a significant portion of production and transmission demand-related costs are allocated on the basis of class contributions to CP demands. Therefore, conjunctive demands determined on the basis of multi-site customer's CP demands would be consistent with cost of service and ratemaking principles. However, because CP demands are additive (i.e., because they are determined for loads at a particular point in time) CP billing will result in the same demand charges regardless of whether they are applied conjunctively or individually.

Q. Would the Company be willing to consider conjunctive billing if it is applied on a system CP basis?

A. Yes, as long as there are some restrictions. If the parties to this proceeding are interested in conjunctive demand based on the billing of production demand-related costs on the basis of system CP demands, the Company would be willing develop conjunctive rates along these lines for filing with the Commission as a pilot program. Any such pilot program would need to include some restrictions on the rate, such as minimum load-factor and minimum individual load thresholds, in order to limit the revenue impact on the Company. Of course, customers would be responsible for any additional metering, billing and administrative costs associated with providing this service by paying a higher basic service charge. Again, for a system CP-based conjunctive demand rate, it would not be necessary to aggregate the loads for individual accounts; therefore, it would not be necessary for the parties to request a deviation from Section 9(2) of 807 KAR 5:041.

H. OTHER RATES

Q. Is KU proposing any new lighting services in this proceeding?

A. Yes. The Company is proposing to offer a fixture-only option for Contemporary High Pressure Sodium installations where multiple fixtures can be installed on a single pole. The support for this new rate offering is included in Seelye Exhibit 4. In allocating the proposed revenue increase to street lights and outdoor lights, the same percentage increase was applied to each light with the exception of mercury vapor and incandescent lights. Because mercury vapor and incandescent lights have been restricted for a number of years and are not being replaced, the Company is not proposing to increase the charges for these lights.

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In re the Matter of:

APPLICATION OF LOUISVILLE GAS	)	
AND ELECTRIC COMPANY FOR AN	)	CASE NO. 2009-00549
ADJUSTMENT OF ITS ELECTRIC	)	
AND GAS BASE RATES	)	

TESTIMONY OF
WILLIAM STEVEN SEELYE
PRINCIPAL & SENIOR CONSULTANT
THE PRIME GROUP, LLC

Filed: January 29, 2010

volatile manner. In other words, LG&E will be providing customers served under this rate, which currently only includes the Arc Furnace, with an inducement to manage spikes in their demands.

Q. Why is the Company adopting the time-of-day structure in Rate TOD for Fluctuating Load Service?

A. As mentioned earlier, LG&E and KU are adopting a uniform time-day-structure for all demand-billed rates, which separates the current peak time period into two time periods to provide customers with greater opportunity to reduce or shift their Peak and Intermediate period demands.

Q. Was the fluctuating nature of the Arc Furnace's load taken into account in the cost of service study?

A. No. All demand allocators in the cost of service study were measured on an hourly basis, and since the Arc Furnace is a KU customer, its load is not included in LG&E's electric cost of service study. Nonetheless, using hourly demands in the cost of service study likely understates KU's costs allocated to the Arc Furnace and thus overstates the rate of return for the Arc Furnace. Furthermore, the cost of service study did not identify any incremental load-following or regulation costs associated with serving the Arc Furnace. This is another area where the cost of service study likely understates KU's cost of serving the Arc Furnace.

G. CONJUNCTIVE DEMAND

Q. Was there a provision in the Settlement Agreement in LG&E and KU's last general rate cases to study Conjunctive Demand?

A. Yes. Section 3.11 of the Settlement Agreement, Stipulation, and Recommendation ("Settlement Agreement") stated that LG&E and KU "agree to work with interested parties to study the feasibility of measuring demand for generation service to multi--site customers based on conjunctive demand, where 'conjunctive demand' herein refers to the measured demand at a meter at the time that the total demand of a multi-site customer's load, measured over a coinciding time period, has reached its peak during the billing period."

Q. Please explain what this means.

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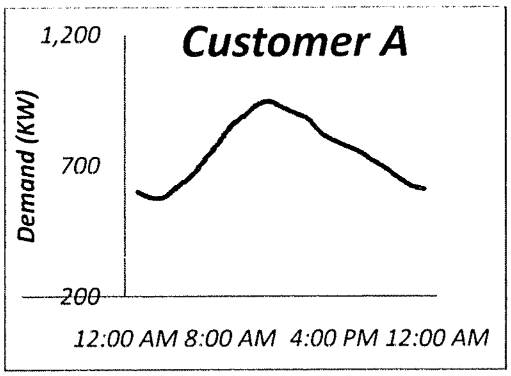
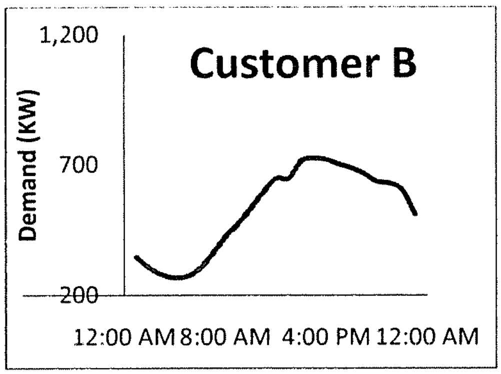
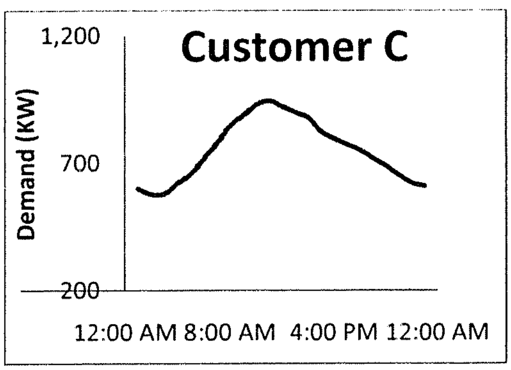
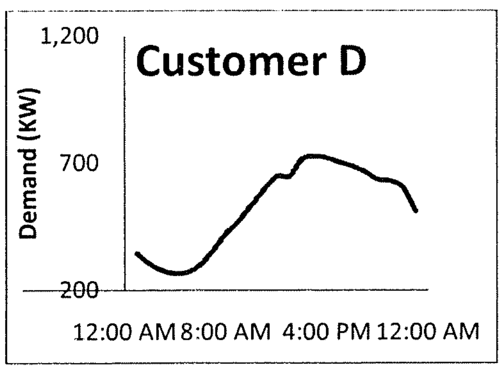
A. Perhaps an easy way to understand what the provision of the Settlement Agreement means is to consider four customers with two different demand profiles, referred to as Customer A, Customer B, Customer C and Customer D. In this example, Customer A and Customer C share the same load characteristics for the month (Load Profile 1). Customer B and Customer D also share the same load characteristics (Load Profile 2) which is different from Customer A and Customer C. As a further simplifying assumption, suppose that the maximum monthly demands for all four customers occur on the same day, which happens to be the same day during which the utility's monthly system peak occurs. The 15-minute peak-day loads for the four hypothetical customers are shown below:



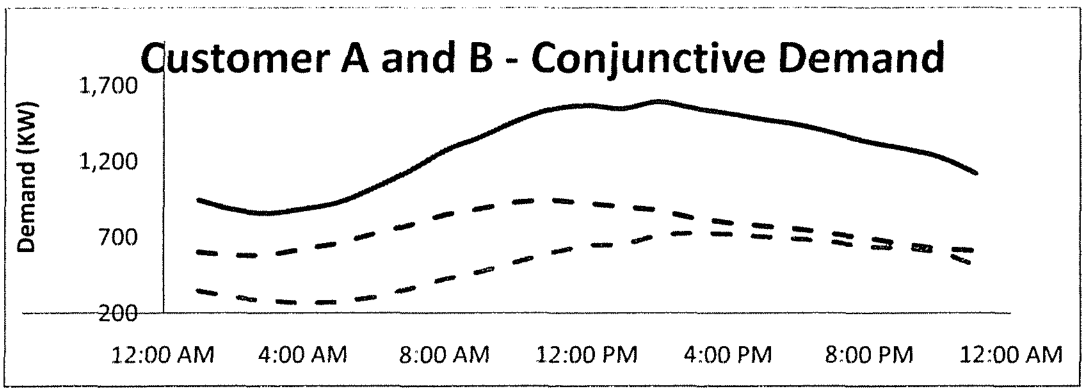


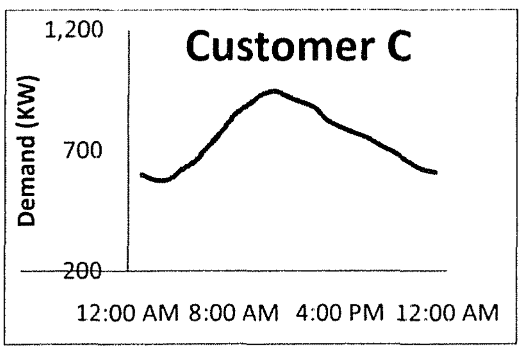


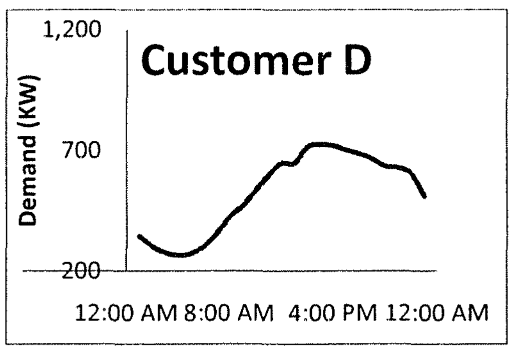


Now suppose that Customer A is a warehouse and Customer B is a retail store owned by the same corporate entity. Therefore, Customer A and Customer B represent a single "multi-site customer" according to Section 3.11 of the Settlement Agreement. Further, suppose that Customer C is also a warehouse and Customer D is a retail store, not owned by the same entity but separate individual entities.

Under Section 3.11 of the Settlement Agreement, the Conjunctive Demand for Customer A and Customer B would be determined by aggregating (or "conjoining") the 15-minute loads for the two customers and applying the generation component of the demand charge to the maximum 15-minute demand from the aggregated loads, whereas the billing demands for Customer C and Customer D would continue to be determined individually, as follows:







For the multi-site customers, in this example, the Conjunctive Demand applicable to the production demand component would be 1,593 kW, whereas the billing demand for the two non-multi-site customers would continue to be 1,750 kW, even though their loads are identical.

Q. Could you provide hypothetical demand charge calculations for these four hypothetical customers without using Conjunctive Demand.

A. Yes. Suppose that the utility's total monthly demand charge is $10 per kW as applied to each individual customer's maximum demand, which consists of a $6.50 per kW production demand component and a $3.50 per kW transmission and distribution demand component. With a standard non-coincident peak (NCP) rate applied to each individual customer's demand, the demand charge billing for Customer A would be the same as the demand charge billing for Customer C. Likewise, the demand charge billing for Customer B would be the same as the demand charge billing for Customer D, as follows:

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Demand Charges = 1,000 kW x $10.00/kW = $10,000

Customer C (non-multi-site warehouse)

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Customer B (multi-retail retail store)

Demand Charges = 750 kW x $10.00/kW = $ 7,500

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Under this example Customer A (the multi-site warehouse) and Customer B (the multi-site retail store), together, would be billed demand charges of $17,500 for the month. Customer C (the non-multi-site warehouse) and Customer D (the non-multi-site retail store owned by some other individual entity), together, would be billed $17,500, the same amount as the two-multi-site accounts.

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Total Customers A & B		= $16.479.50

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Demand Charges =	750 kW x $10.00/kW	= $ 7,500.00
Total Customers C and D		= $17,500.00

Therefore, under Conjunctive Billing, as defined in the Settlement Agreement, Customer A and Customer B, together, would pay $16,479.50 in demand charges, while Customer C and Customer D, together, with identical loads, would pay $17,500. Under the form of Conjunctive Billing as defined in the Settlement Agreement, the multi-site customers would realize a rate benefit (or rate disparity) of $1,020.50 without taking any action to modify their load patterns. In other words, the multi-site customers would receive a rate benefit through conjunctive billing of $1,020.50 compared to the two non-multi-site customers even though the cost of serving the multi-site customers is the same as the two non-multi-site customers.

Q. Do you believe that the type of Conjunctive Demand defined in the Settlement Agreement is consistent with sound cost of service and ratemaking principles?

A. No. In a regulatory context, the term "fair, just, and reasonable rates" has taken on the meaning that the rates are cost based and non-discriminatory. The cost of serving Customers A and C in the example above would be the same, and the cost of serving Customers B and D would be the same. As can be seen from the example above, there is clearly an advantage to aggregating the loads of Customers A and B before applying the rates whenever there is diversity among the load patterns. Allowing loads to be aggregated before the rates are applied results in a lower bill. Allowing such load aggregation for multi-site accounts yet denying it for non-multi-site accounts could easily be regarded as discriminatory treatment.

Q. Would a full-scale implementation of the type of Conjunctive Demand as defined in the Settlement Agreement result in even greater disparities than shown in your example?

A. Yes. As more accounts are added the total amount of the rate disparities would be larger.

Q. Are there other forms of conjunctive billing that are more consistent with cost of service and ratemaking principles?

A. Yes. Coincident peak CP demand billing can be viewed as a form of conjunctive billing, and can be applied on an aggregated basis so that it can be implemented as a full-fledged conjunctive billing approach. With CP demand rates, the production (and perhaps transmission) demand costs would be applied to the customer's demand at the time of the Company's system peak. CP demand rates are fully consistent with cost of service principles. An important consideration in the Companies' generation resource planning efforts is to plan the system so that it has adequate capacity to meet maximum system demands, which determine the time when CP demands are measured. In the Company's cost of service study, a significant portion of production and transmission demand-related costs are allocated on the basis of class contributions to CP demands. Therefore, conjunctive demands determined on the basis of multi-site customer's CP demands would be consistent with cost of service and ratemaking principles. However, because CP demands are additive (i.e., because they are determined for loads at a particular point in time) CP billing will result in the same demand charges regardless of whether they are applied conjunctively or individually.

Q. Would the Company be willing to consider conjunctive billing if it is applied on a system CP basis?

A. Yes, as long as there are some restrictions. If the parties to this proceeding are interested in conjunctive demand based on the billing of production demand-related costs on the basis of system CP demands, the Company would be willing to develop conjunctive rates along these lines for filing with the Commission as a pilot program. Any such pilot program would need to include some restrictions on the rate, such as minimum load-factor and minimum individual load thresholds, in order to limit the revenue impact on the Company. Of course, customers would be responsible for any additional metering, billing and administrative costs associated with providing this service by paying a higher basic service charge. Again, for a system CP-based conjunctive demand rate, it would not be necessary to aggregate the loads for individual accounts; therefore, it would not be necessary for the parties to request a deviation from Section 9(2) of 807 KAR 5:041.

H. OTHER RATES

Q. Is LG&E proposing any new lighting services in this proceeding?

A. Yes. The Company is proposing to offer a fixture-only option for Contemporary High Pressure Sodium installations where multiple fixtures can be installed on a single pole. The support for this new rate offering is included in Seelye Exhibit 4. In allocating the proposed revenue increase to street lights and outdoor lights the same percentage increase was applied to each light with the exception of mercury vapor and incandescent lights. Because mercury vapor and incandescent lights have been restricted for a number of years and are not being replaced, the Company is not proposing to increase the charges for these lights.