California Public Utilities Commission

California Net Energy Metering Ratepayer Impacts Evaluation

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Introduction to the California Net Energy Metering Ratepayer Impacts Evaluation

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Technical Report by
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Introduction to the California Net Energy Metering Ratepayer Impacts Evaluation

The California Public Utilities Commission (CPUC) has contracted with Energy and Environmental Economics, Inc. (E3) to provide an evaluation of the costs and benefits of the net energy metering (NEM) program in California. This study fulfills the requirements of Assembly Bill (AB) 2514 (Bradford, 2012) and Commission Decision (D.) 12-05-036, to study "who benefits, and who bears the economic burden, if any, of the net energy metering program." This study also serves as an update to the CPUC's 2010 NEM Cost-Effectiveness Evaluation.[1]

NEM is an electricity tariff billing mechanism designed to facilitate the installation of renewable customer distributed generation (DG). Under NEM tariffs, customers receive a bill credit for generation that is exported to the electric grid during times when it is not serving onsite load. Bill credits for the excess generation are applied to a customer's bill at the same retail rate (including generation, distribution, and transmission components) that the customer would have paid for energy consumption, according to their otherwise applicable rate schedule. This study also provides a separate evaluation of the NEM fuel cell program, which credits the generation only component of the rate for participating fuel cells that achieve targeted reductions in greenhouse gas emissions.

Role of the CPUC's Energy Division in the Evaluation

The CPUC's Energy Division was responsible for contracting with E3 and overseeing the development of this report. Energy Division initiated the contract process in the spring of 2012, and E3 was selected following a competitive bidding process.

In October 2012, Energy Division hosted a well-attended workshop where E3 consultants previewed the methodology and scope of the cost-benefit analysis, avoided public purpose charges, and income distribution sections of the attached report. Informal comments were solicited from interested parties on November 5, 2012, and reply comments were received on November 15, 2012. E3 provided responses to comments in the December study scope of work. Unfortunately, due to delays in processing the funding needed to conduct the full cost of service analysis, the methodology for the NEM full cost of service calculation was not available for public comment. Utility costs of service were emulated from the methodology filed by each utility in its most recent General Rate Case (GRC).

In September 2013, E3 consultants presented the results of the draft NEM report. The CPUC solicited informal comments from interested parties on 'calculation errors' contained in the draft report, and comments were received by eight parties on October 10, 2013. Based on

[1] http://www.cpuc.ca.gov/NR/rdonlyres/0F42385A-FDBE-4B76-9AB3-E6AD522DB862/0/nem_combined.pdf

these comments, E3 made several modifications to the analysis, clarified several issues in the final report, and responded under separate cover to all of the substantive comments.

The final spreadsheet analysis tools, methodology workshop presentation materials, draft and final scope of work, stakeholder comments on the methodology and draft report, and E3's reply comments are available on the CPUC's NEM study webpage.[2]

Scope of the Evaluation

When the CPUC's Energy Division initiated the contract process for an evaluation of NEM in the spring of 2012, the primary focus of the evaluation was to incorporate an updated and more robust data set to the prior methodologies used in the 2010 NEM Cost-Effectiveness Evaluation. At the time, the analysis was limited to the costs and benefits of generation exports to the electric grid. Following the request for proposals (RFP) for the study, however, two mandates were adopted – Commission D. 12-05-036 in May 2012, and AB 2514 in September 2012 – which added significant breadth and scope to the study. These additional tasks include:

(1) A cost-benefit study of NEM at the capacity needed to reach the solar photovoltaic goals of the California Solar Initiative and the 5% net energy metering program cap. The costs and benefits of NEM should be evaluated relative to energy that is exported to the grid and energy consumed onsite.

(2) An evaluation of the extent to which NEM customers pay their share of utility costs.

(3) An estimate of the reduction in public purpose charges avoided by NEM customer-generators.

(4) An income demographic assessment for residential customers with NEM generation.

Unfortunately, the inclusion of multifaceted analytical approaches, at different penetration levels, precludes a single, simplified answer to the underlying question that we are trying to address: That is, who benefits from, and who bears the economic burden, if any, of the net energy metering program? However, when taken together, the various analyses included in the attached NEM Ratepayer Impacts Evaluation shed new light on the impacts of the NEM program in California, provided that the results are interpreted alongside the metrics used in the evaluation and in the context of current DG policies and utility operations. Two of the more relevant issues included in the report are discussed in more detail below.

Lastly, it is important to note that the attached NEM Report is focused exclusively on the utility ratepayer impacts of NEM, and does not include the overall societal benefits from the deployment of clean energy resources, although significant environmental, public health and other non-energy benefits occur. The importance of the environmental benefits that result from of the deployment of renewable generation is well established within the California

[2] http://www.cpuc.ca.gov/PUC/energy/Solar/nem_cost_effectiveness_evaluation.htm

Energy Action Plan, and is reflected in a number of the state's DG policies, including the Go Solar California campaign, the Commission's Self-Generation Incentive Program, as well as the NEM program.

NEM Cost-Benefit Analysis vs. Cost of Service Analysis

At its most basic level, the attached study employs two separate ratepayer impact measures: A cost-benefit analysis of the NEM program using the traditional California Standard Practices Manual (SPM) Ratepayer Impact (RIM) test, which estimates the net benefits (or costs) of a demand-side resource or program from the perspective of non-participating customers, and a full cost of service assessment, which compares the utility cost of serving NEM customers with their actual bill payments.

In the cost-benefit analysis, E3 evaluates the *change* in utility costs associated with the *change* in usage due to the installation of DG. If the customer bill savings resulting from NEM are greater than the corresponding reduction in utility costs, NEM will create a cost shift from NEM customers to other non-participating customers as utilities adjust their rates to compensate for the shortfall. Alternatively, if the reductions in customer bill savings are less than the reduction in utility costs, non-participating customers experience a net benefit. Note that this approach does not address or reflect any pre-existing cost shift onto NEM customers prior to their installation of customer generation.

In the full cost of service analysis, E3 evaluates the *total cost* to serve the remaining energy usage after accounting for the change in usage due to the installation of DG. The cost of service assessment compares the actual bills that NEM customers pay to the utility costs (including fixed costs) needed to serve the customer. This study evaluates whether customers who install NEM eligible systems pay more or less than the cost of providing them electricity service before and after they install a NEM eligible system. Utility costs of service are emulated from the methodology that each utility used in their most recent GRC.

Despite the use of different metrics, a central driver in both the cost-benefit and cost of service analyses is current retail rate designs. For residential NEM customers, tiered rates (for which a customer's marginal electricity rate increases with cumulative usage) and tiered time-of-use rates are the most commonly subscribed. As described in more detail below, changes to the tiered rates would have a significant impact on the study results. Similarly, differences in retail rates should be an important consideration for policymakers outside of California that are using this study.

Export Only vs. All NEM Generation

One of the key drivers of the magnitude of any cost impacts is what generation is measured. Pursuant to AB 2514, the cost-benefit analysis included in this study considers all NEM generation as well as only the generation that is exported to the grid.

The most explicit impact of NEM is associated with energy exports to the grid; both NEM and non-NEM DG receive bill reductions during hours when generation is offsetting onsite load, but only NEM customers receive bill credit for generation that is exported to the grid.

To the extent that NEM compensation allows a project to be viable, the entire NEM generation is a useful metric. In this instance, an exact measure of the effect of NEM on ratepayers would compare the state of the world with NEM to that without NEM, and calculate the ratepayer costs under both. Unfortunately, the state of the world *in the absence of NEM* is a theoretical and unknown condition, which is further confounded by other incentive programs designed to facilitate the deployment of DG (such as the Federal Income Tax Credit, California Solar Initiative, and Self-Generation Incentive Program). Because it is uncertain how much renewable DG would be installed in California without NEM, or how customers might choose to size DG or change their electricity usage to better align with the DG output, the all generation scenario included in the attached report likely overestimates the costs that are directly associated with NEM.

Solar is Primary Focus of the Report

The attached report focuses exclusively on the NEM program within the territories of the three large investor-owned utilities (IOUs), which had enrolled over 150,000 customers totaling 1,300 MW through the end of 2012. Collectively, these systems generated about 2,400 GWh of annual electricity. The vast majority of customers on NEM tariffs had installed solar PV (99% of accounts, and 96% of capacity). Customers with wind and bioenergy generation make up the remaining 1 percent. A separate evaluation of fuel cell NEM, which provides credits at the generation only component of the rate for fuel cells, including those that are fueled by natural gas, is also included in the report.

Customer-sited solar PV installations that are not enrolled on a NEM tariff are excluded from this report. As of June 2013, 492 installations in IOU service areas representing over 110 MW of generating capacity opted to not take NEM tariffs, presumably because their solar generation was not expected to exceed load at any time, and thus no benefits would be accrued from NEM.[3]

Impact of Possible NEM Policy Modifications and Rate Reform

This report evaluates the ratepayer impacts of the NEM program as it was outlined in 2012, assuming current rate structures. Under its open proceeding on future residential rate designs (R.12-06-013) and its process to implement AB 327 (Perea, 2013), the CPUC is required by statute to adopt a number of changes to the NEM rule and rate design, including modifying the NEM cap and considering reformation of residential rate designs to make rates more accurately

[3] Source: Energy Division Second Quarter 2013 Interconnection Data Request

reflect the true cost of utility service. To the extent that changes are made to the NEM policy and rate designs, the actual impacts of NEM will differ from those estimated in this study. By presenting a picture of the ratepayer impacts under the current NEM policy, this study provides a foundation for this future work and enables well-reasoned changes to NEM and rate design within the CPUC stakeholder process.

A large portion of the cost impacts associated with residential NEM that are identified in this report are the result of the current rate designs. The analysis in this report shows that, on average, residential NEM customers would have paid utility bills that are 54% greater than the utility's cost of providing service if they had not installed a NEM-eligible DG system. This high cost is due to the fact that most residential NEM customers are in the higher tiers. These customers stand to benefit the most by installing NEM eligible DG systems, but as discussed in section 4.5.1 of the report, the higher cost tiers also drive most of the residential cost impacts identified in the report's cost-benefit analysis.

While forecasting the impact of specific changes to the current rate design is beyond the scope of this study, the impact of the larger residential customers on the overall cost-benefit analysis make it clear that changes in the current tiered rate structures will also dramatically improve the cost-benefit results of NEM.

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1 Executive Summary

1.1 Net Energy Metering (NEM) Overview

This study evaluates the ratepayer impacts of the California net energy metering (NEM) program and fulfills the requirements of Assembly Bill (AB) 2514 (Bradford, 2012)[1] and Commission Decision (D.) 12-05-036 to determine "who benefits, and who bears the economic burden, if any, of the net energy metering program."[2]

NEM is an electricity tariff that facilitates the deployment of on-site renewable distributed generation (DG).[3] Under NEM tariffs, customers receive a bill credit for energy that they generate and export to the grid. In this study we evaluate two types of NEM: Renewable NEM, which provides credits at the full retail rate for solar PV, wind, and bioenergy generation; and fuel cell NEM, which provides credits at the generation only component of the rate for fuel cells, including those fueled by natural gas.

The vast majority of NEM customers in California are solar PV (99% of accounts, and 96% of capacity). At the end of 2012, California's three largest investor-

[1] See Appendix G for further information about AB 2514
[2] This study will also serve as an update to the CPUC's 2010 NEM Cost Effectiveness Evaluation (2010 NEM Study) http://www.cpuc.ca.gov/NR/rdonlyres/0F42385A-FDBE-4B76-9AB3-E6AD522DB862/0/nem_combined.pdf
[3] Public Utilities Code 2827 (b) (4)

owned utilities (IOUs)[4] had approximately 150,000 customers enrolled in NEM, totaling 1,300 MW of installed capacity. Collectively, these systems generated about 2,400 GWh of electricity during 2012.

1.2 Scope of Evaluation

We did four principle analyses in this study to characterize "who benefits from, and who bears the economic burden, if any, of, the net energy metering program"[5] as required in statute:

(1) Cost-benefit analysis of NEM to estimate any cost impacts from NEM customers to other customers,

(2) Cost of service evaluation to estimate the degree NEM customers pay their share of utility costs,

(3) Public purpose charge savings to estimate the reduction in payments of NEM customers toward public purpose programs, and

(4) Income demographic assessment to learn more about the household incomes of residential customers with NEM generation.

The study is based on the current NEM policy in California that is defined by a number of rules, including the 5% NEM cap established by D. 12-05-036, the net surplus compensation rate under AB 920 (Huffman, 2009), and the existing

[4] The IOUs are Pacific Gas and Electric, Southern California Edison, and San Diego Gas and Electric.
[5] All quotes in this section are from AB 2514, the full text of which is provided in Appendix G.

retail tariff designs at each utility. Changes to the structure of the NEM policy, or to the retail rate structures, would change the results of this study.

1.2.1 NEM COST-BENEFIT ANALYSIS

In the cost-benefit analysis, we compare the reduction in NEM customer bills to the reduction in utility costs. To the extent that the NEM customer's bill reduction is greater than offsetting utility savings, NEM will create a cost shift from NEM customers to other customers as utilities adjust their rates to compensate for the shortfall. The results of the analysis are disaggregated by a number of dimensions, including by "utility, and customer class," and for "household income groups within the residential class."

One of the key drivers of the magnitude of any cost impact is what generation is measured; all of the NEM generation, or only the electricity generated that is exported to the grid. We recognize that this issue is controversial, and therefore measure the net cost both ways. The net cost of the specific mechanism enabled by NEM, namely the ability to 'export' electricity to the utility at the retail rate, is measured by the 'export only' case in this study. This approach disregards NEM generation consumed on the customer premise. We also calculate the net cost of the entire NEM generator output. To the extent NEM compensation enables the whole DG project to be viable, and the total output of the project results in a cost to non-NEM customers, the entire NEM generation is the appropriate scope to measure the impact on non-NEM customers.

We analyze the costs and benefits of NEM at three different levels of installed capacity: A forecast from the actual installed capacity at the end of 2012 ('2012 Snapshot' case), totaling approximately 1,305 MW; the capacity needed to reach the goals of the California Solar Initiative (CSI) ('Full CSI Subscription'), totaling 2,916MW[6]; and the capacity needed to reach the 5% net metering cap as defined by D. 12-05-036 ('Full NEM Subscription'), forecast to be reached in 2020 at approximately 5,573 MW.

Other key input assumptions for which there is uncertainty, such as future natural gas prices, CO2 prices, retail rate escalation, cost of interconnecting and integrating NEM generation, and avoidance of transmission and distribution system capacity costs, are considered through sensitivity analyses.

1.2.2 COST OF SERVICE OF NEM

In addition to the cost-benefit analysis, we evaluate "the extent to which each class of ratepayers and each region of the state receiving service under the net energy metering program is paying the full cost of the services provided to them by electrical corporations." In the cost of service assessment we compare the resulting bills of NEM customers to their full cost of service. Full cost of service is a regulated utility term that includes all utility costs, including an appropriate share of utility fixed costs to serve the customer. We emulate the methodology each utility used in their most recent General Rate Case (GRC) cost of service allocations. The cost of service analysis is an indicator of whether NEM customers paid bills equal to their estimated share of the total utility cost of

[6] Includes solar, wind, and other NEM generation

service prior to installing a NEM eligible system and what impact installing a NEM eligible system has on whether they pay their estimated share of their cost of service after installing the system.

1.2.3 PUBLIC PURPOSE CHARGES

We disaggregate the NEM customer bill savings to estimate their savings in public purpose charges. In addition to public purpose charges, we decompose the bill savings into all of the other subcomponents of the NEM customer bill.

1.2.4 INCOME DISTRIBUTION OF NEM CUSTOMERS

We estimate the distribution of the household income of residential NEM customers based on the median household income by census tract and census block group using 2010 data provided by the IOUs. The current methodology for the publicly reported household income information is based on zip code, which is less granular than census tract and census block group levels. We believe the much smaller geographic areas and more homogenous demographics in census tract provide much better accuracy.

1.3 Summary of Cost-Benefit Analysis Results

1.3.1 NET ENERGY METERING COST-BENEFIT ANALYSIS

We evaluate the costs and benefits of NEM using two metrics: Our primary metric is a '2020 snapshot' of the cost impact from NEM generators to all ratepayers in the year 2020. We chose 2020 because it is the year our forecast of NEM generation reaches the 5% NEM cap. Calculating the annual cost shift does not require a forecast of avoided costs and bills beyond 2020, so it involves less uncertainty. In addition to the net cost in 2020, we evaluate the lifecycle costs and benefits of NEM generators installed in 2012 over an assumed 20-year economic life (2012 to 2031). The lifecycle analysis estimates the costs and benefits over the life of NEM generation systems in a single metric. We use the lifecycle results to estimate per unit costs, benefits, and net costs ($/kWh and $/watt installed) over the life of the generator.

Table 1 shows the net cost of NEM exports to the grid by residential and non-residential customers for each of the three penetration levels. In 2020, with a complete build out of systems to the existing NEM cap, the costs associated with NEM electricity exported to the grid under the current NEM tariffs are approximately $370 million per year, or 1.1% of the utility revenue requirement.

Table 1: Net Cost of NEM Generation Exports in 2020 (Millions $2012/year)

	2012 Snapshot	Full CSI Subscription	Full NEM Subscription
Residential	$61	$85	$291
Non-Residential	$18	$41	$79
Total	$79	$126	$370
% of Revenue Requirement	0.23%	0.36%	1.06%

Table 2 shows the net cost of all NEM generation by residential and non-residential customers for each of the three penetration levels. The costs associated with all NEM generation are forecast to be approximately $1.1 billion per year in 2020 (in $2012). This is approximately 3.1% of the forecasted utility revenue requirement.

Table 2: Net Cost of All NEM Generation in 2020 (Millions $2012/year)

	2012 Snapshot	Full CSI Subscription	Full NEM Subscription
Residential	$182	$250	$794
Non-Residential	$70	$170	$299
Total	$252	$420	$1,093
% of Revenue Requirement	0.72%	1.20%	3.13%

Approximately 2/3 of the net transfer is from residential NEM systems, with 1/3 of the net transfer from non-residential NEM systems. This is despite non-residential systems accounting for 56% of the installed NEM capacity.

The bill savings for NEM customers are entirely a function of the retail rate designs for each customer class and utility. In particular, there are significant differences between residential and commercial customer rates. For the mix of systems installed in 2012, the cost impact from residential NEM systems is significantly greater (levelized net cost of $0.20/kWh generated) in the All Generation case than the cost impact from non-residential systems (levelized net cost of $0.08/kWh generated) due to the residential inclining block rate design. Relative to the residential rates, the commercial rates generally include lower energy charges as well as demand charges related to the customer peak load. Because NEM systems tend to reduce net energy consumption by a greater percentage than they reduce peak demand, residential NEM customers tend to experience greater bill savings than commercial customers.

Table 3 and Table 4 show the levelized net cost of residential customers broken out by customer size. The larger customers are generally customers in the higher inclining block tiers. These results indicate that possible changes to the residential rate structure could have significant impacts on the costs associated with residential NEM generation.

Table 3: Levelized Cost of NEM for Residential Customers by Usage Bin - Export Only (Levelized $/kWh)

Customer Usage	PG&E	SCE	SDG&E	All IOUs	No. of Customers
< 5 MWh	0.01	0.03	0.05	0.03	12,370
5 to 10 MWh	0.08	0.08	0.10	0.09	45,170
10 to 25 MWh	0.21	0.15	0.17	0.17	70,462
25 to 50 MWh	0.29	0.22	0.24	0.25	7,995
50 to 100 MWh	0.27	0.25	-	0.26	354
100 to 500 MWh	0.31	-	-	0.31	18
Average	0.17	0.14	0.14	0.15	-

Table 4: Levelized Cost of NEM for Residential Customers by Usage Bin - All Generation (Levelized $/kWh)

Customer Usage	PG&E	SCE	SDG&E	All IOUs	No. of Customers
< 5 MWh	0.02	0.03	0.05	0.04	12,370
5 to 10 MWh	0.14	0.11	0.15	0.13	45,170
10 to 25 MWh	0.29	0.18	0.23	0.23	70,462
25 to 50 MWh	0.35	0.23	0.26	0.28	7,995
50 to 100 MWh	0.33	0.25	-	0.28	354
100 to 500 MWh	0.35	-	-	0.35	18
Average	0.26	0.17	0.19	0.20	-

In the remainder of the report we provide significantly more detail and disaggregation of the results for each of the respective analyses, as well as results of sensitivities. In addition, a spreadsheet tool of calculations and results has been made available to enable further disaggregation and testing of additional sensitivities.

1.4 Summary of Cost of Service Results

The full cost of service analysis looks at the degree to which NEM customers pay bills commensurate with their estimated share of the total utility cost of service. In the full cost of service analysis we find that both the residential and non-residential customers look significantly different than typical customers. Residential NEM customers who install renewable DG are larger than the average residential customer. Because of the utility tiered rate structures, residential NEM customer bills were 54% greater than their cost of service, on average, before the installation of NEM generation. Non-residential NEM accounts had bills that exceeded their full cost of service by 22%. In the residential class, the differences were largely explained by the customer size and tiered rates. In the non-residential class, the reasons are linked more to an account's usage pattern, rather than total usage.

After the installation of NEM generation, the aggregate gap between bills and the full cost of service shrinks dramatically. Whereas total annual bills were $175 million in excess of the full cost of service before DG, the difference is only $12 million after DG. The relative changes to bills and full cost of service, however, are not uniform across all utilities and customer sectors. Table 5 shows that, with renewable DG, NEM residential customers pay 81% of their full cost of service compared to 154% before DG, and non-residential NEM customers pay 112%, compared to 122% before DG. Overall, based on limited information for a single year, the NEM accounts appear to be paying slightly more than their full cost of service.

Table 5: Percent Cost of Service Recovery from NEM Customers in 2011 With and Without DG Systems (% of Full Cost of Service)

	PG&E		SCE		SDG&E		All IOUs	
	Without DG	With DG	Without DG	With DG	Without DG	With DG	Without DG	With DG
Residential	171%	88%	152%	86%	101%	54%	154%	81%
Non-Residential	128%	106%	110%	105%	124%	122%	122%	112%
Total	146%	99%	122%	100%	119%	111%	133%	103%

1.5 Public Purpose Charges

In 2020, with a complete deployment of systems to the NEM cap, NEM customers avoid approximately $142 million in public purpose charges, or about 6.3% of the total estimated 2020 public purpose funding.

Table 6: Bill Savings in Public Purpose Charges from NEM in 2020 ($2012 Million/year)

	2012 Snapshot	Full CSI Subscription	Full NEM Subscription
Residential	$15	$21	$66
Non-Residential	$17	$48	$76
Total	$32	$69	$142
Total as % of Total Public Purpose Charges	1.4%	3.1%	6.3%

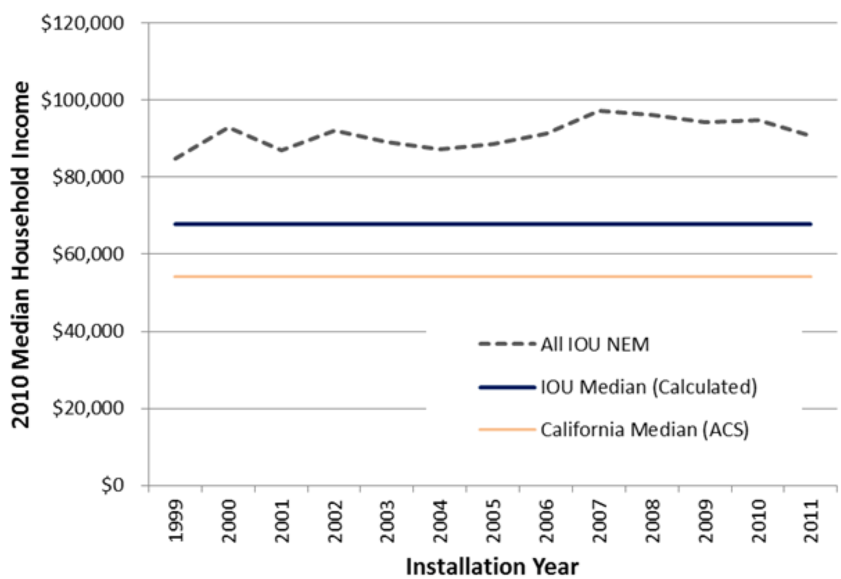
1.6 Income Distribution of NEM Participants

Within the residential sector, we find that the customers installing NEM systems since 1999 have an average median household income (based on IOU-provided data at the census tract level[7]) of $91,210, compared to the median income in California of $54,283 and in the IOU service territories of $67,821. Figure 1 shows the 2010 household income in the census tract of the customers that installed NEM generation since 1999 and the IOU and California median household incomes overall. The median household income of NEM customers

[7] Some data was provided at the more granular census block group level.

has been relatively consistent since 1999, but peaked in 2007 and has been declining moderately since.

Figure 1: NEM 2010 Household Income by Installation Year Compared to IOU and California Median Income



2 Introduction

2.1 Net Energy Metering (NEM) Program Overview

Under NEM tariffs,[8] customers with DG receive a bill credit for energy generated in excess of electric load that is exported to the grid. In this study we evaluate both renewable NEM, which provides credits at the full retail rate (including generation, transmission, and distribution rate components) for solar, wind, and technologies using bioenergy, as well as the separate fuel cell NEM program, which provides credits at the generation only component of the rate for fuel cells, including those that operate on natural gas. Bill credits are applied each month against charges for hours when the customer's load exceeds the customer's generation. Any excess bill credits remaining in a billing month are carried forward for up to one year. Eligible customer generators who produce electricity in excess of on-site load over a 12-month period may elect to receive net surplus compensation, or apply the net surplus electricity as a credit toward future consumption.

[8] See Appendix G for P.U. Code 2827 (b) (5)

2.1.1 CALIFORNIA NEM POLICY AND COORDINATED PROGRAMS

There are a number of rules and decisions that affect the overall compensation under California's NEM policy. This section outlines the key rules and decisions that are accounted for in the analysis.

2.1.1.1 Incentive Programs

Any customer meeting the eligibility requirements may convert to a NEM electric rate. NEM participants may have generation installed through an incentive program, such as the Self-Generation Incentive Program (SGIP) or California Solar Initiative (CSI), or of their own accord.

2.1.1.2 AB 920 and Net Surplus Compensation

In 2009, AB 920 (Huffman) amended the law to allow customers, beginning in January 2011, to receive compensation for annual net excess generation. For any net excess energy exported to the grid at the end of the year, compensation is based on each utility's default load aggregation point (DLAP) price on a 12-month rolling average plus a Renewable Energy Credit (REC) premium (applicable to customers that are in compliance with the Renewables Portfolio Standard (RPS) Guidebook).[9] The DLAP compensation rate fluctuates with market prices, and is currently about $0.04/kWh for net surplus generation.

[9] See Decision (D.) 11-06-016 at **http://docs.cpuc.ca.gov/PUBLISHED/FINAL_DECISION/137431.htm**

2.1.1.3 Free Interconnection

Pursuant to Commission D.02-03-057, NEM customers are exempt from interconnection application fees, study costs, and distribution upgrade costs.

2.1.1.4 Standby Charge Exemption

California Public Utilities (PU) Code Section 2827 states that eligible customer-generators cannot be assessed standby charges on the electrical generating capacity or the kilowatt-hour production of a renewable electrical generation facility.

2.1.1.5 Non-bypassable Charge Exemption

Pursuant to Commission D.03-04-030, NEM customer generation that is under 1 MW in size and eligible to participate in NEM is exempt from certain non-bypassable charges.

2.1.1.6 Renewable Energy Credits

NEM customers own the renewable energy credits for the generation on their facilities. In practice, most 3rd party solar installers 'purchase' these RECs as part of the contract to install solar. However, due to the relatively high costs associated with tracking and verifying RECs, the ultimate market for these credits associated with NEM generation is uncertain. Therefore, in this study we assume RECs will eventually be retired without transfer, and that renewable NEM generation does not directly reduce the utility RPS obligation through the generation of renewable energy.

2.2 Analysis Framework

This study evaluates the cost impacts of NEM using two approaches. The first approach compares the bill savings of customers who install NEM systems to the reduction in utility costs attributable to having the NEM system. Throughout the report we refer to this as the NEM 'cost-benefit analysis'. The cost-benefit analysis is based on the change in NEM customers' bills due to NEM generation compared to the associated change in utility costs. If the bill savings of NEM customers are greater than utility avoided costs, this will ultimately result in a cost increase to other utility customers since the utility is allowed to pass those costs on.

This study is the third study by the CPUC to investigate the impacts associated with net energy metering since 2005. The most recent study was completed in 2010 as part of the overall evaluation of the California Solar Initiative.[10] The 2010 study quantified the cost impacts associated with exports from NEM for solar PV systems. The CPUC also conducted a study in 2005.[11]

This study is designed similarly to the 2010 study, but includes a broader scope based on the requirements of AB 2514 and Commission D. 12-05-036. In particular, this study includes an estimate of the cost impacts of all of the output from NEM generation, as well as the proportion attributable to exported energy, for all NEM technology types.

[10] http://www.cpuc.ca.gov/NR/rdonlyres/0F42385A-FDBE-4B76-9AB3-E6AD522DB862/0/nem_combined.pdf
[11] http://docs.cpuc.ca.gov/WORD_PDF/REPORT/45133.PDF

In the second approach, called ‘full cost of service,’ we evaluate whether NEM customers are paying their full cost of service as defined by the investor-owned utilities (IOUs). To do this, we compare the actual customer bill with NEM to the full cost of service as calculated by each utility in their General Rate Case (GRC). We are not aware of a prior CPUC analysis (outside of the GRC process) to estimate the full cost of service, so there are some caveats. For example, there are differences in each utility’s approach to estimate full cost of service so the results are not perfectly comparable. In addition, it is difficult to exactly replicate the cost of service analysis for a sub-set of customers participating in NEM since the utilities evaluate cost of service at the customer class level.

Figure 2 illustrates the cost-benefit analysis approach. We calculate the NEM bill with and without the NEM generation to estimate savings, then calculate the utility avoided cost. The net cost is the change in customer bills less the utility avoided cost. If the bill savings are greater than the avoided cost then there will be a cost shift to other customers to make up for the shortfall.

Figure 2: Illustration of the Cost-Benefit Calculation

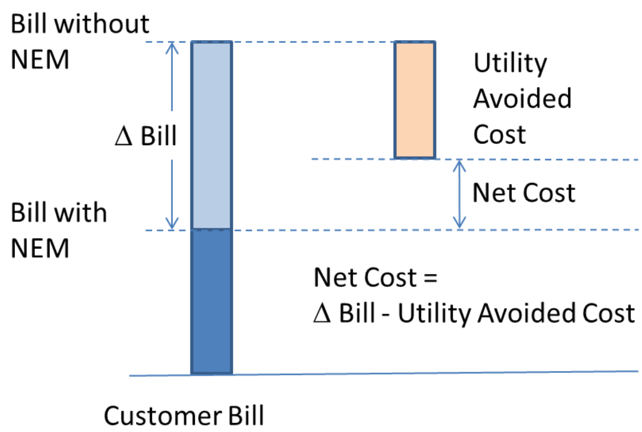
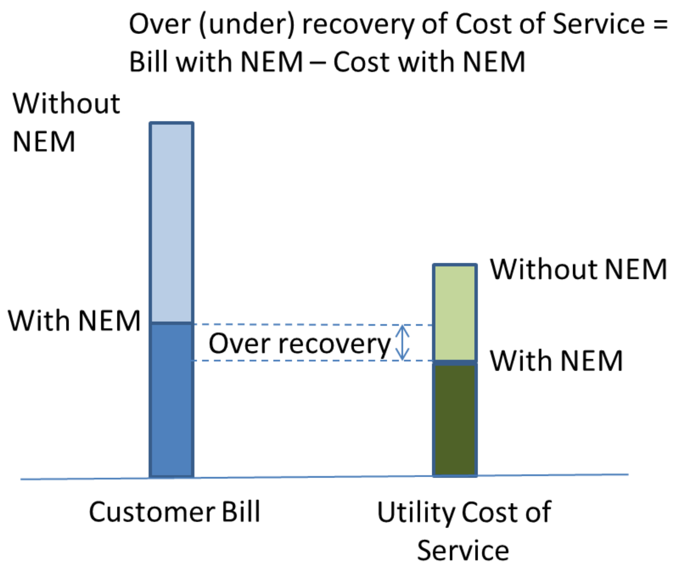


Figure 3, below, illustrates the cost of service approach for NEM customers. First, we compare the bills and the full cost of service of NEM customers without the NEM generation. This provides a customer characterization of the customers who choose to install NEM generation. Then, we compare the customer bills with the NEM generation to the full cost of service with the NEM generation. This comparison shows the contributions of NEM customers to their full cost of service after the installation of NEM generation.

Figure 3: Illustration of the Cost of Service Approach



2.3 Terminology Employed

In this report, descriptions and results are often labeled as pertaining to a certain "sensitivity," "penetration level," or "case. These names are standardized as follows:

2.3.1 SENSITIVITY

In the cost-benefit analysis, we present base case results that reflect our best estimate of the cost and benefits of NEM. The key sensitivity variables are described in Table 7, below.

Table 7: Sensitivities

Sensitivity	Description
T&D Avoided Costs	This sensitivity calculates results without transmission and distribution (T&D) avoided capacity value.
Natural Gas Prices	We test both high and low alternative natural gas price forecasts as sensitivities. These are based respectively on the Long Term Procurement Plan (LTPP) high gas case and flat real prices. These forecasts use the methodology developed in the CPUC's Market Price Referent (MPR) decisions[12].
CO2 Price	We calculate a low and a high sensitivity with the CO2 price at the CO2 allowance price floor and soft ceiling. Both of these extremes grow at 5% plus inflation through 2030.
Resource Balance Year	We evaluate a sensitivity whereby NEM generation receives the full generation capacity throughout the study horizon rather than a future resource balance year.
Solar Effective Load Carrying Capability	We evaluate a sensitivity whereby the Effective Load Carrying Capability (ELCC) is tied to the vintage of the installation. So, for example, a solar NEM customer installed in 2013 receives the ELCC for 2013 throughout its operating life.
Retail Rate Escalation	We develop high and low electricity retail rate escalation forecasts using the CPUC LTPP model. These forecasts are based on the high and low gas and CO2 price forecasts.
Standby Charges	NEM customers are exempt from standby charges, but we conduct a sensitivity in which non-residential customers would be required to pay standby charges in the absence of NEM.
Metering and Set-up Cost	NEM metering and set-up costs, incremental to standard customer metering and set-up costs, have historically been diminishing each year. We run a low sensitivity wherein these incremental costs are set to zero.
Interconnection Cost	Only limited interconnection cost data on non-reimbursed ratepayer costs were available. We test a range around the data available.
Integration Cost	It is possible that higher penetrations of DG will require higher costs to integrate with the grid. We run a high and low sensitivity of NEM generation integration costs.

[12] See http://www.cpuc.ca.gov/PUC/energy/Renewables/mpr

To organize all of these sensitivities, we group two opposing sets of decisions across all of these variables that represent a case where NEM is less cost-effective from a ratepayer perspective, or “Low Case,” and a more cost-effective case, or “High Case.” These cases aim to represent the reasonable bookends that one may consider in the cost-benefit analysis. The assumptions for each of these cases, and for the “Base Case” used in our analysis, are listed in Table 8.

Table 8: Definition of Sensitivities

Component	Base Case	NEM LESS Cost-Effective ‘Low Case’	NEM MORE Cost-Effective ‘High Case’
T&D Avoided Costs	Included	Excluded	Included
Natural Gas Prices	MPR forecast	Flat in real terms	LTPP high case
CO2 Price	MPR forecast	Cap-and-trade floor price	Cap-and-trade soft ceiling price
Resource Balance Year	2017	2025	2007
Solar Effective Load Carrying Capability	Based on analysis year; 2013 to 2020	Based on analysis year; 2013 to 2020	All systems awarded 2013 ELCC value
Retail Rate Escalation	2.61% average annual increase from 2011 to 2030	2.50% average annual increase from 2011 to 2030	3.02% average annual increase from 2011 to 2030
Standby Charges	Excluded from bill savings	Included in bill savings	Excluded from bill savings
Metering and Set-up Cost	Equal to 2011 values	Equal to 2011 values	No incremental cost assessed to NEM
Interconnection Cost	Equal to 2011 values	150% of 2011 values	50% of 2011 values
Integration Cost	$2.50/MWh	$5.00/MWh	None

We use “sensitivity” to refer to the Base Case, Low Case, or High Case set of assumptions being used to determine the values of various avoided cost, bill calculation, and program cost parameters.

2.3.2 PENETRATION LEVEL

In this study we investigate the cost-shifting associated with NEM at three penetration levels. The penetration level refers to the total amount of installed NEM generation. The three penetration levels evaluated in this study are: (1) the amount of NEM generation installed at the end of 2012 (1,905 MW), (2) the amount installed at the end of the CSI program for each utility and customer class (2,916 MW), and (3) the amount installed at the 5% NEM cap (5,573 MW).

2.3.3 GENERATION CASES: EXPORT ONLY VS. ALL GENERATION

In this study, we calculate all results considering two generation ‘cases.’ In the first case, we estimate the cost impact that is attributable to energy that is exported to the grid. This approach disregards NEM generation produced and consumed on the customer premise and captures the specific mechanism that is enabled by NEM. In the second case, we calculate any cost impact attributable to the entire output of the NEM generator, including output that serves load at the NEM customer site and is not exported to the grid. To the extent NEM compensation enables the whole DG project to be viable, and the total output of the project results in a cost to non-NEM customers, the entire NEM generation is the appropriate scope to measure the impact on non-NEM customers. These cases are referred to as either “Export Only,’ which includes only the electricity exported to the grid, or ‘All Generation,’ which includes all of the generation from the NEM generator.

2.3.4 COST UNITS AND LEVELIZATION

The cost units of this study are primarily dollars per year in 2020 (using $2012). The reason we choose a 'snapshot' in time is that the result is much less dependent on a number of uncertain input assumptions, such as retail rate escalation and the discount rate. In addition, we report two lifecycle values as $/watt installed and levelized $/kWh based on a 20-year economic life from 2012 to 2031.

2.3.4.1 Metric and Unit Definitions

$/year: These units are the cost, benefit, or net cost in a given year in nominal dollars. The majority of the results presented in $/year are the cost, benefit, or net cost in 2020 (in $2012). This metric is used as a primary result because it is much less sensitive to the assumptions on retail rate escalation, and the discount rate.

Levelized $/kWh: The levelized $/kWh is calculated on a nominal levelized basis over a 20-year life. The majority of levelized results are based on the installations in 2012. For example, $0.10/kWh levelized means that the value stream is equivalent to a constant $0.10/kWh every year from 2012 to 2031.

Lifecycle $/W: The lifecycle $/W metric measures the 20-year Net Present Value (NPV) of benefits, costs, or net benefits per installed watt of NEM generation. Again, these metrics are reported for installations in 2012.

3 Customer Characterization

3.1 Installed NEM Capacity

The vast majority of NEM customers in California are solar PV (99% of accounts, and 96% of capacity). In this study, we used NEM customer information through 2011 to forecast future NEM installation rates and profiles. At the end of 2011, more than 122,000 customer accounts from California's three large IOUs under CPUC jurisdiction were enrolled in NEM. These accounts had approximately 1,110 MW of installed generation and generated about 2,200 GWh of electricity.

For the purposes of our analysis we disaggregated the NEM customers in 2011 by customer class and technology type using lists of NEM customers from each utility, their associated system characteristics (size, technology, orientation of solar, and output), and the associated billing data for each customer. The breakdown of the resulting NEM customers installed through 2011 - including solar, wind, and fuel cells - is shown in Table 9. There were also approximately 20 bioenergy generators installed in California by the end of 2011 and a few NEM generators with unidentified technology type, however, the necessary billing data and customer information was insufficient to characterize them in our analysis.

Table 9: NEM Customer Information Through 2011

Utility	PG&E		SCE		SDG&E		Total
	Res	Non-Res	Res	Non-Res	Res	Non-Res	All
Solar							
Number of Systems	69,269	4,159	24,080	4,959	17,228	1,895	121,590
MW Installed	289	361	105	233	61	54	1,104
Estimated GWh	544	679	198	439	115	101	2,075
Wind							
Number of Systems	96	53	217	32	30	4	432
MW Installed	1	1	2	0	0	0	4
Estimated GWh	1	2	3.1	0.32	0	0	7
Fuel Cell							
Number of Systems	15	25	19	12	0	5	76
MW Installed	0	8	0	5	0	1	15
Estimated GWh	0.54	58	1	33	0	9	100
All NEM Generators							
Number of Systems	69,380	4,237	24,316	5,004	17,257	1,903	122,098
MW Installed	290	371	107	238	62	55	1,123
Estimated GWh	545	739	202	472	116	110	2,183

3.2 Forecasted Penetration Levels

We developed a base forecast through 2020 of installed NEM generation based on the historical installation rates by technology type and utility territory through 2011. We then used the historical data and imposed two temporally-dependent capacity limits on the forecast to create three 'penetration levels' of NEM adoption:

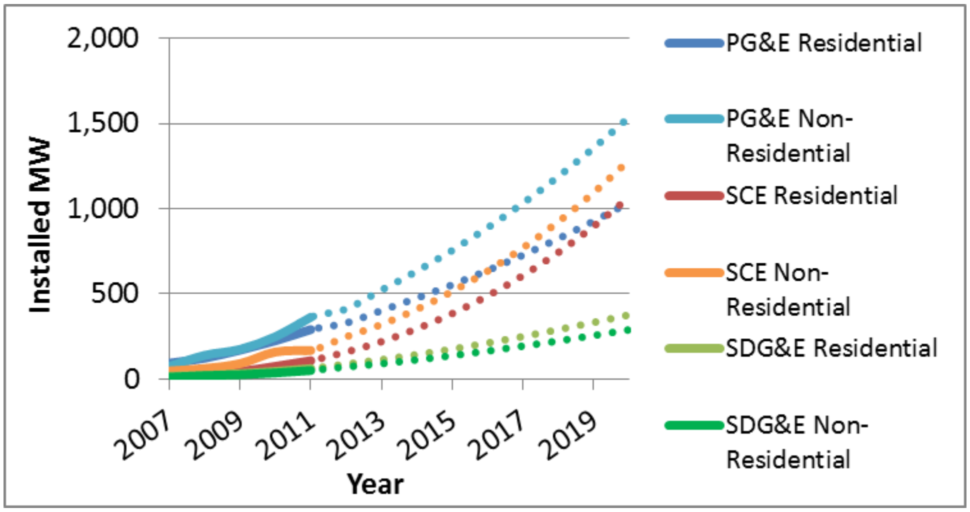
1) The installed capacity at the end of 2012 ("2012 Snapshot")

2) The installed NEM capacity when the CSI goals are met ("Full CSI Subscription"), and

3) The capacity needed to reach the 5% net metering cap as defined by D. 12-05-036 (Full NEM Subscription).

The forecasts of future NEM installations used to determine customer distributions for the full CSI and full NEM subscription levels are based on regressions using installation data from 2007 through 2011. Figure 4, below, shows the historical adoption rate from 2007 through 2011 (solid line) and the forecast of each class through 2020. The accuracy of this forecast is not critical for the 2012 'Snapshot' case, for obvious reasons, nor is it critical for the 2020 5% NEM adoption case, since this total is based on the 5% NEM limit. This forecast does affect the Full CSI case to a greater degree. Overall, however, the results in 2020 are not sensitive to the growth forecast so long as the 5% NEM cap is reached by 2020.

Figure 4: Forecast of NEM Adoption by Utility and Customer Class



Based on this forecast, the CSI tiers are exhausted for each utility and customer class between 2013 and 2019. Table 10, below, shows the year in which the total capacity would be subscribed for each utility and customer class. To develop the penetration level for the Full CSI Subscription scenario we use the installed NEM generation at the end of the year when the last Tier is exhausted for each utility and customer class. In addition to CSI installations, this penetration level also includes all other NEM-eligible technologies, for which we use the total installed generation at the end of the year, even if the tier is reached mid-year.

Table 10: Projection for Fully Subscribing CSI Tiers

	PG&E		SCE		SDG&E		All IOUs
	Res	Non-Res	Res	Non-Res	Res	Non-Res	Total
Forecast Year CSI Goal Reached	2013	2015	2014	2019	2013	2019	2019
Total CSI MW (At CSI Goal)	252	512	266	539	59	121	1,750
Total Installed NEM MW (At CSI Goal)	402	755	295	1095	113	256	2,916

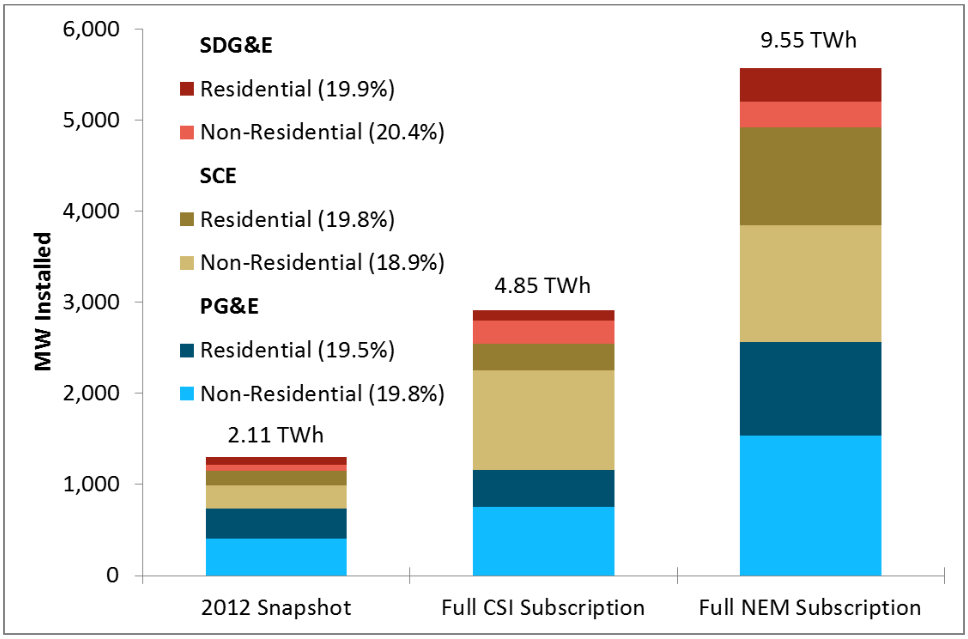
Based on this forecast, the 5% NEM cap as defined by D. 12-05-036 will be reached in approximately 2020. We calculate the 5% non-coincident cap, defined by the CPUC as a 4-year historical average of non-coincident peak loads, by multiplying the prior four years of historical coincident peak loads by factors developed by the IOUs that reflect diversity of customer loads. The resulting statewide NEM cap in 2020 is approximately 5,573 MW. The load forecast is from the mid-case 2012 California Energy Commission IEPR load forecast[13] and the diversity factors are from utility filings.[14]

Figure 5 displays the total MW of DG installed under each penetration level by customer class and IOU. The number at the top of each bar gives the total terra-watt-hours (TWh) generated by the installed systems, and the parenthetical values in the legend are the average capacity factors of the installed DG.

[13] http://www.energy.ca.gov/2012_energypolicy/documents/demand-forecast/mid_case/

[14] See diversity factors from PUC workshop presentation (http://www.cpuc.ca.gov/NR/rdonlyres/C89C6BF8-9A37-4DF8-BF2E-2A9C8FDD1B8D/0/CPUC_NEM_Workshop_062512C.PPTX)

Figure 5: Installed DG Capacity by IOU and Customer Class at Each Penetration Level



3.3 Data and Methodology for Estimating NEM Customer Profiles

In order to develop an accurate assessment of any of our four analyses, we need a detailed view of the consumption and generation characteristics of NEM customers. With this data, it is possible to calculate the *amount* and *timing* of generation serving onsite load and being exported to the grid and, thereby, the associated costs and benefits to the utility and to its customers. Because most of the available data for this study did not provide a precise enough measure of the amount and timing of energy generated and energy consumed onsite, we used metered generation data to simulate missing generation and used representative customer usage shapes to convert actual billing data to a more granular level. We then clustered customers into homogenous "groups" and developed representative customer "bins" based on these groups. These customer bins facilitate manageable computations and transparent display of data. They are used throughout the analysis to estimate the costs and benefits of NEM. This section discusses the data we received, our methodology for estimating sub-hourly customer generation and usage data, and the process used to create representative customer profiles.

3.3.1 DATA AVAILABILITY AND ISSUES

To measure the costs and benefits of NEM, as we define them in subsequent chapters, the following data is needed for each customer:

- Hourly or sub-hourly gross consumption (total energy consumed from the grid and from the DG system) for each hour of the year being evaluated
- Hourly or sub-hourly gross generation (total output of the DG system) for each hour of the year being evaluated

E3 requested several large data sets from the utilities that were used to compile a list of all NEM customers, and to create load and generation shapes for them. These data sets include:

1. NEM customer lists
2. Billing data for NEM customers
3. Metered DG output and bidirectional meter data
4. Load research data

The NEM customer lists provide the installation details of 100,550 NEM systems installed through the end of 2011, representing over 1,040 MW of installed capacity. In addition to providing a nearly comprehensive list of NEM accounts, these data are linked to the billing data to provide DG system size, utility rate and heating code, location, and several other details.

The billing data for NEM customers covered over 85,000 customers during 2011, and provides the annual consumption totals for all NEM customers that we model.

Sub-hourly DG output or bidirectional meter data are available for 6,251 NEM customers. In addition to being used directly in the analysis, these data are utilized to improve simulation of DG output for systems with missing generation data.

The load research data set is comprised of sample sub-hourly usage data of IOU customers. These data are used, along with billing and generation data, to estimate gross usage shaped of NEM customers.

We also received 2011 SolarAnywhere weather data from Clean Power Research to enable us to do simulation of sub-hourly generation for NEM systems for which we did not have metered generation data.

As described in the next section and in Appendix A, we combine all of these data sets to estimate sub-hourly generation and usage for actual NEM customers. We then use these customers to create representative NEM customer profiles (‘bins’).

3.3.2 METHODOLOGY FOR ESTIMATING SUB-HOURLY NEM GENERATION AND CONSUMPTION FOR REPRESENTATIVE CUSTOMERS

We use the available data to estimate sub-hourly generation and consumption for actual NEM customers and create representative customer 'bins' by means of the following process:

1. Assign 2011 sub-hourly gross generation (total output of the DG system) shapes for each customer

2. Calculate 2011 annual gross consumption for each customer by adding the customer's assigned DG output to the customer's actual billed monthly net load

3. Estimate 2011 sub-hourly gross consumption (total energy consumed onsite from the grid and the DG system) shapes for each customer using load research data

4. Obtain a 2011 sub-hourly net consumption shape for each customer by subtracting assigned DG output from estimated gross consumption

5. Create 'bins' of representative NEM customer profiles, each with one sub-hourly generation and one sub-hourly consumption shape

6. Convert 2011 representative customer generation and usage profiles into typical metrological year (TMY) profiles

Each of the main steps is described in more detail in the subsequent sections.

3.3.2.1 Sub-Hourly Gross Generation Estimates

We used a combination of actual and simulated generation data to estimate sub-hourly gross generation (total output of the DG system) shapes for each NEM customer over the course of 2011. Metered DG output data provided actual half-hourly DG output for over 7,000 systems over the course of 2011. With the DG system specs contained in the NEM customer lists, and information from the CSI PowerClerk database, we were able to simulate DG output using 2011 SolarAnywhere weather data from Clean Power Research to fill in any gaps in the metered data, and for any systems not contained in the set of metered data.

3.3.2.2 Sub-Hourly Gross Consumption Estimates

Estimating sub-hourly gross consumption profiles for individual NEM customers entailed a two-step process.

First, we developed *annual* gross consumption profiles. Annual *net* consumption (total consumption minus the output of the DG system that served onsite load) for all customers in our analysis was provided by the utility billing data. To estimate annual *gross* consumption, we simply added the estimated annual gross generation to the measured annual net consumption.

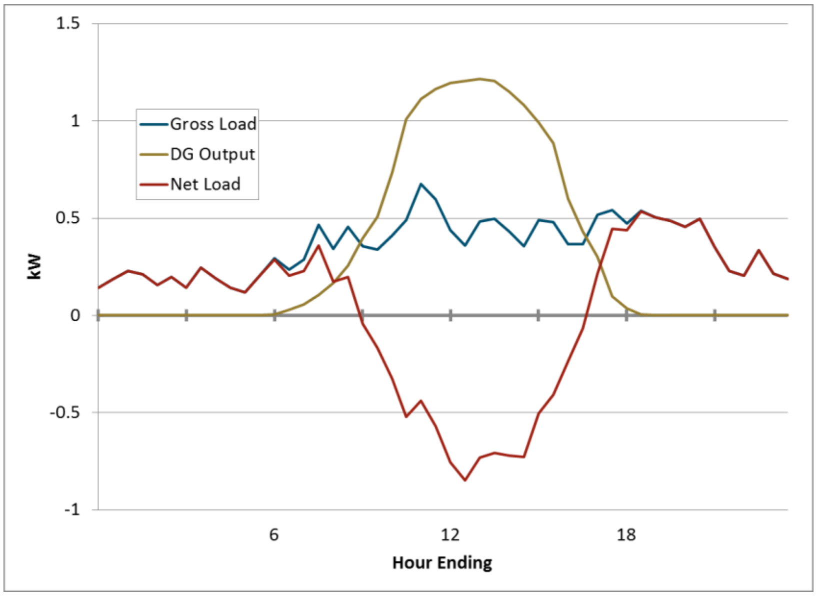
In order to get from *annual* gross customer consumption to *sub-hourly* customer consumption estimates, we then scaled load research data, or sub-hourly usage data for non-NEM customers, to match the correct annual gross load of the customer it is being used to represent. Each customer received one load research match based on location, rate, and usage profile, with the exception of customers for whom no good match could be found (difference in annual consumption of the two profiles was greater than 20%).

3.3.2.3 Sub-Hourly Net Consumption Estimates

Subtracting the metered or simulated DG output for the NEM customer profiles from the gross customer load profiles yields half-hourly net load profiles for individual NEM customers.

Combined, this approach provides estimates of gross load, net load, and generation for any given NEM customer. The net load profile for an example customer on a summer day is shown in Figure 6.

Figure 6: Load and DG Generation for an Example Residential Customer



3.3.2.4 Representative NEM Customer Bins

To reduce computational requirements, and make the analysis possible to display in the public NEM Summary Tool, we create 'bins' of representative NEM customers. Each bin is depicted by one gross consumption shape, one gross generation shape, and a number of other customer characteristics. These consumption profiles, generation profiles, and customer characteristics are treated in the analysis as the consumption, generation, and customer characteristics of every single NEM customer represented by the bin. The number of NEM customers represented by each bin is scaled up and down according to capacity forecasts, but per-customer generation and usage remain constant throughout the analysis. In all, there are 9,458 bins of representative customers with wind or solar generation and 31 fuel cell bins.

Creating bins involved a two-step process:

1. We divided actual NEM customers into 'groups' that are relatively homogenous in terms of customer characteristics and usage.

2. We created 1-4 customer bins for each customer group. Each bin was assigned a generation and consumption profile of one of the customers in the original group, and then these profiles were scaled to the mean annual generation, annual consumption, and NEM generator capacity of all customers in the group.

In the first step, we grouped customers based on the following customer characteristics:

- **Utility**: Customers receiving service from each of the three IOUs were grouped separately.

- **Customer class**: The customer classes used were residential, agricultural, and commercial/industrial.

- **Utility territory**: Twenty-three territories across the three IOUs were used to establish customer baselines. Classification by territory captures much of the variation in climate and other geographically-driven customer and building characteristics. Some territories were combined based on geographical proximity and rate baseline similarity.

- **DG technology**: Customers were further divided by generation type; customers with PV and wind generation were grouped separately from customers with only one generation type.

- **Retail rate**: All customers in each group are on the same utility retail rate.

- **Rate baseline**: Customers with electric heating and medical baseline allowances were grouped separately from those without these additional baseline allowances. In a few cases where there were no customers with load research matches on a medical baseline in a given group, customers were grouped with customers that shared every other customer characteristic, as we believe that this was more accurate than excluding these customers from the analysis. This is relevant for tiered rate structures only.

- **Voltage level**: This field denotes the voltage level at which customers receive electricity. Voltage levels comprise basic, primary, secondary, and transmission.

- **Gross annual consumption**: Customers were grouped roughly based on their annual consumption, as calculated from the billing data.

- **Ratio of PV generation to annual gross consumption:** This ratio was calculated for each customer using billing data and actual or simulated generation profiles. Customers were grouped based on rough categories of this ratio.

3.3.2.5 Conversion of Customer Profiles to Match Typical Meteorological Year (TMY)

Finally, because these profiles will be used to forecast through the year 2020, we convert from 2011 to a Typical Meteorological Year (TMY) weather profile. This TMY weather is based on the weather files adopted by the California Energy Commission for the Title 24 building standards and represents long-term average weather conditions in California.

4 Cost-Benefit Analysis

4.1 Cost-Benefit Analysis Approach

In order to evaluate "who benefits from, and who bears the economic burden, if any, of, the net energy metering program"[15] as required in statute we evaluate the costs and benefits of NEM from the perspective of NEM customers (participants) and ratepayers overall. The cost-benefit analysis measures any cost impact of NEM. To the extent that the bill reductions attributed to NEM exceed offsetting benefits, there is a cost shifting from NEM customers to other utility ratepayers. Therefore, the net cost of NEM to ratepayers is the sum of ratepayer costs (bill savings, incremental billing costs, and integration costs) less ratepayer benefits (avoided costs).

This comparison is made considering (1) the exported portion of NEM generation, and (2) the entirety of NEM generation. The calculations for these two generation cases for an example customer on a summer day are shown are shown in Figure 7 and Figure 8.

[15] Quote is from AB 2514, the full text of which is provided in Appendix G.

Figure 7: Calculation of "Export Only Generation" for an Example Customer and Day

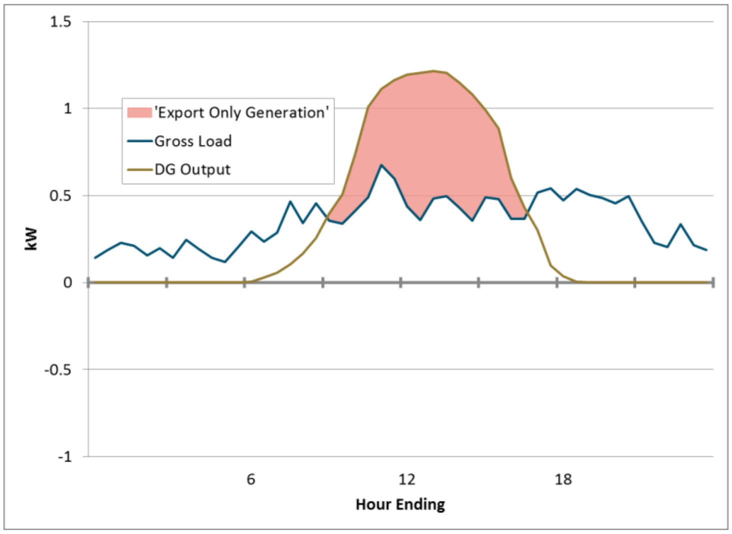
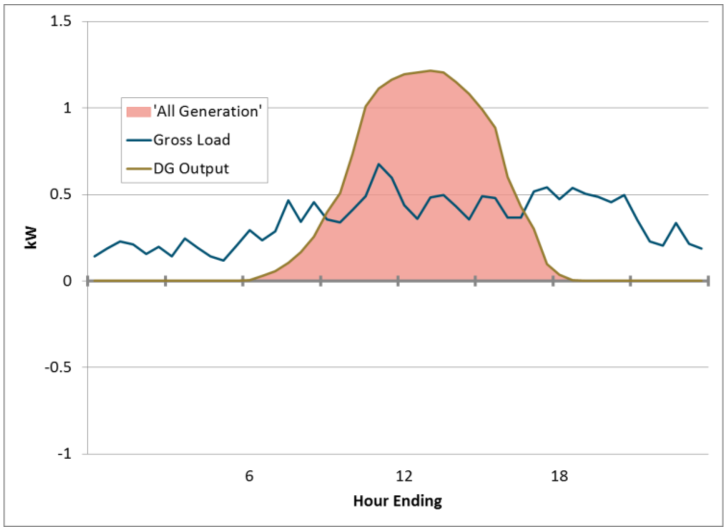


Figure 8: Calculation of "All Generation" for an Example Customer and Day



In this study, total generation and exported generation is measured on a half-hourly basis. Total monthly exported generation is computed as the sum of each of the half-hourly estimates.

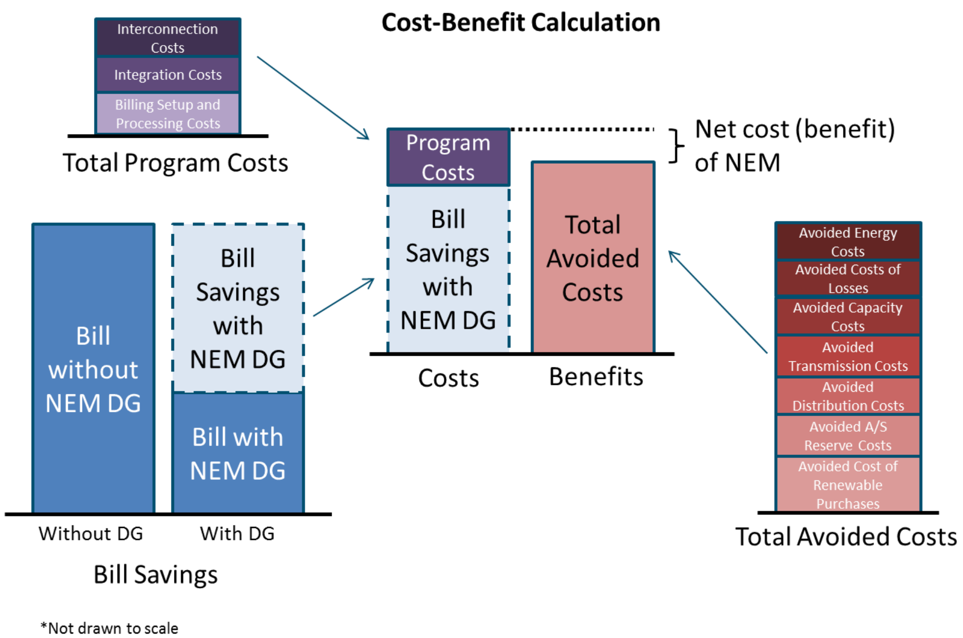
The summary the cost-benefit calculation of each approach is as follows:

1. Export Only Net Cost (Benefit) = Bill Savings of Export Only + Program Costs - Avoided Cost of Export Only

2. All Generation Net Cost (Benefit) = Bill Savings of All Generation + Program Costs - Avoided Cost of All Generation

Figure 9 shows the formulation of the cost-benefit analysis, including the derivations of each of the key calculation components: Bill Savings, Program Costs, and Avoided Costs.

Figure 9: Formulation of the Cost-Benefit Calculation



Bill savings are a cost to ratepayers. NEM customer-generators receive benefits in the form of bill savings, which in our analysis are calculated to include any reduction in bills from exported energy, or arising from AB 920 implementation. Every dollar of bill savings received by NEM customers is a direct reduction in utility revenues. Since rates are adjusted over time such that utilities meet their revenue requirement, this revenue reduction will be made up by ratepayers. The bill savings are thus a direct cost to ratepayers.

Increased operational costs are a cost to ratepayers. Any additional operational costs resulting from NEM, such as incremental billing administration costs, or integration costs, must be covered by the utility, and therefore by ratepayers.

Avoided costs are a benefit to ratepayers. The energy delivered by the NEM generators offsets purchases of energy and capacity, and other avoided costs. These savings are evaluated consistently with a long history of avoided cost estimates at the CPUC. In addition, sensitivity analysis is used to define high and low ranges of avoided costs.

The remainder of this chapter of the report describes the calculation of the NEM customer bill savings, avoided costs, and program costs and then presents the cost-benefit results. These results are also benchmarked against the CPUC's 2010 NEM study.

4.2 Bill Savings

Bill savings are the difference between what a NEM customer's bill would be without the NEM generation compared to what the bill is with the NEM generation. To calculate bills, we parse the half-hourly load profiles developed for each customer bin into billing determinants. These determinants are then input into the E3 Utility Bill Calculator, which outputs the annual bills for each customer bin based on 2011 rates. The details of this tool are provided in Appendix B.

Three sets of bills are created using the E3 Utility Bill Calculator: A set based on gross load billing determinants, a set based on net load billing determinants, and a set based on positive net load billing determinants (in which all exports are set to zero). To calculate the bill savings of the Export Only case, we subtract the net load bill from the positive net load bill. To calculate the bill savings of the All Generation case, we subtract the net load bill from the gross load bill.

The results in this section reflect the aggregate bill savings of all NEM customers across various rates, calculated separately for each penetration level. Figure 10 and Figure 11 show the number of customers on each of the top 10 residential and commercial NEM rates calculated for the 2012 Snapshot case. A total of 75 NEM customer rates are included in this analysis.

Figure 10: Number of Customers on the Top 10 Residential NEM Rates

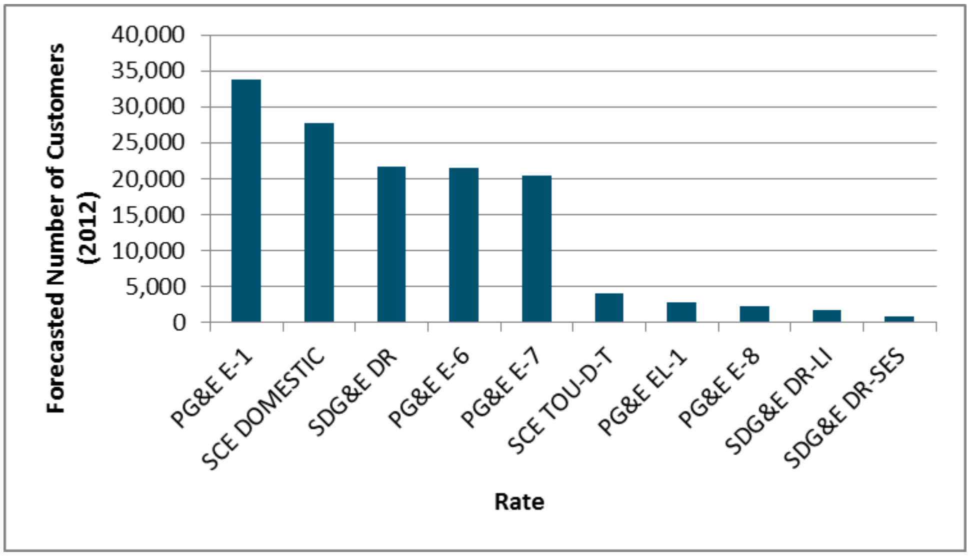
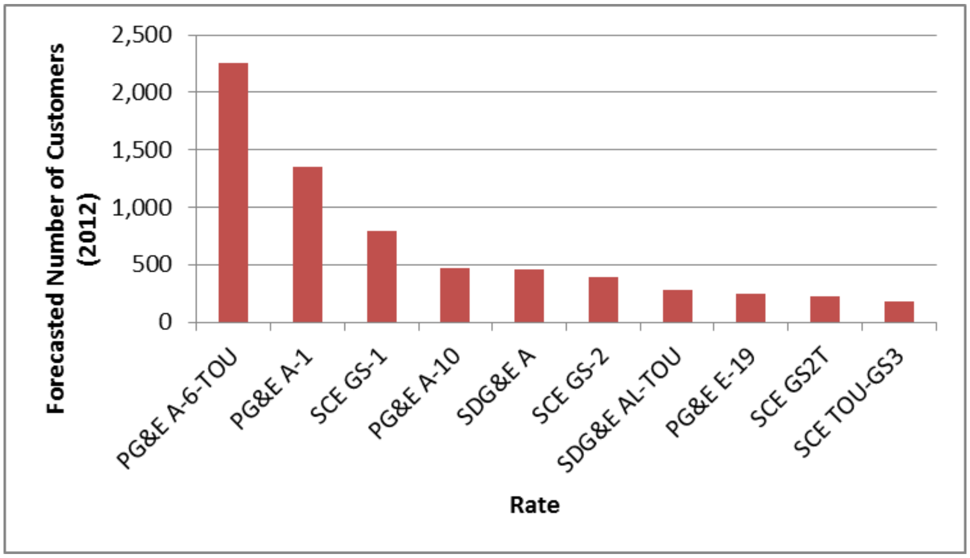


Figure 11: Number of Customers on the Top 10 Commercial NEM Rates



The bill savings for NEM customers are entirely a function of the retail rate designs for each customer class and utility. In particular, there are significant differences between residential and commercial customer rates. The default residential rates and the rates that most NEM customers are on include inclining block rate designs. Under inclining block rate designs, a customer's marginal electricity rate increases with cumulative usage within each billing period. In California, the rate structure is divided into 2-5 tiers where each successive block has a higher rate per kWh of electricity. The commercial rates include generally lower energy charges as well as demand charges related to the customer peak load. Some of the residential and commercial rates vary by time of year and time of day, although more temporal dependency can be found in commercial rates.

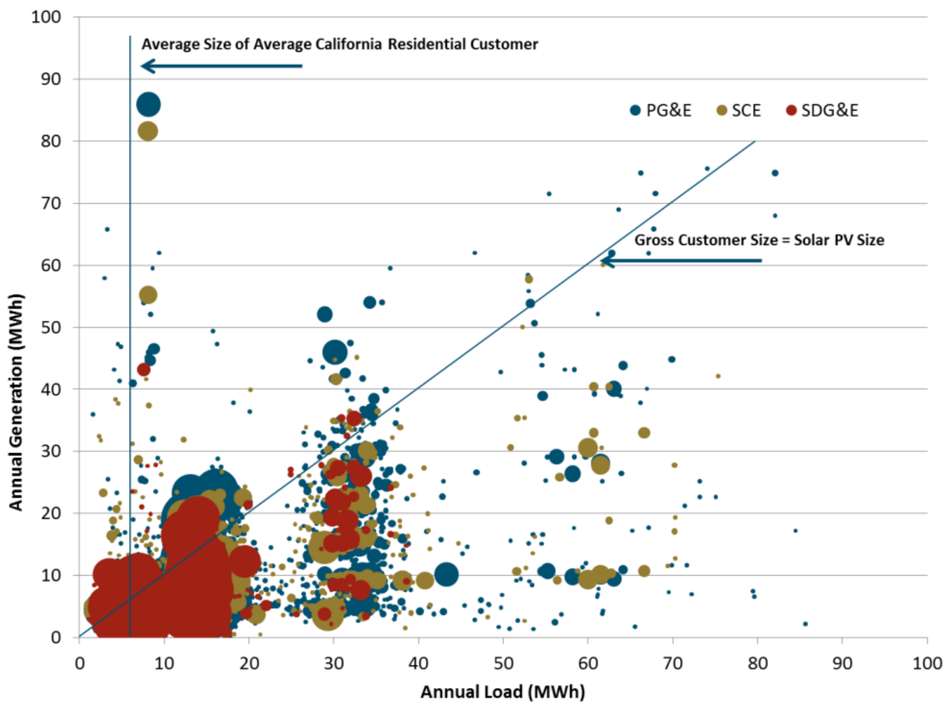
NEM participants are not paid directly for excess generation; instead, they earn credits which can be applied to offset their electricity bills. These credits can be applied only to the energy charge portion of the customers' utility bills. Other charges, including meter charges, demand charges, phase charges, and any other non-energy charges cannot be offset by excess generation credits. However, all charges are calculated based on the customers' net energy usage, so the demand charge portion of the bill can be reduced significantly through NEM participation independent of the value of excess generation. Based on our load research, NEM DG reduces customer billing demand by a substantially smaller percentage amount (approx. 3% of nameplate capacity) than the amount by which it reduces total energy consumption (approx. 20% of nameplate capacity).[16] Therefore, NEM customers on rates with only energy charges experience greater bill reductions, and impose greater costs to their utilities, than customers on rates with demand charges.

Since all of the utilities have tiered residential rates, the amount of consumption relative to generation from residential NEM customers is of critical importance. Figure 12, below, shows the distribution of estimated gross consumption of the residential customers on NEM compared to estimated annual output of the NEM generation. The size of each dot is proportional to the number of customers. A diagonal line is drawn where NEM production equals gross consumption. All customers above this line are net annual exporters. A vertical line is drawn at the approximate average residential consumption in California

[16] Percentage reductions based on 2011 representative customer data. The demand reduction calculation only included representative customers on rates with demand charges.

of 6.8MWh per year.[17] This figure shows that the majority of residential NEM customers have greater than average consumption.

Figure 12: Comparison of Gross Residential Load and NEM Generation Size



4.2.1 BILL SAVINGS FROM NEM

Table 11 shows the NEM customer bill savings associated with exports in millions of dollars in the year 2020. These are the savings directly attributable to the NEM incentive mechanism. Because full CSI subscription caps the non-residential class at a higher proportion to total installations than currently

[17] See US EIA **http://www.eia.gov/tools/faqs/faq.cfm?id=97&t=3.** Note that this includes multifamily consumption, and therefore is approximate. The US average annual electricity consumption is approximately 11MWh.

exists, the share of bills savings are weighted more heavily towards the non-residential sector. The relatively high share of residential bill savings is a result of residential inclining block rate design and that residential customers export an average of 49% of their total generation, while non-residential customers export an average of 30% of their total generation (based on penetration levels for Full NEM subscription).

Table 11: Total Bill Savings in 2020 by Penetration Level - Export Only (Millions $2012/year)

	2012 Snapshot	Full CSI Subscription	Full NEM Subscription
Residential	$108	$153	$489
Non-Residential	$54	$145	$242
Total	$161	$298	$731

Table 12 shows the bill savings of All Generation in millions of dollars in the year 2020. The higher energy charges present in residential rate structures results in larger total residential bill savings between customer classes, despite 57% of all DG generation coming from non-residential systems.

Table 12: Total Bill Savings in 2020 by Penetration Level - All Generation (Millions $2012/year)

	2012 Snapshot	Full CSI Subscription	Full NEM Subscription
Residential	$299	$416	$1,289
Non-Residential	$218	$607	$949
Total	$517	$1,023	$2,238

4.2.2 LEVELIZED BILL SAVINGS

Table 13 displays the levelized bill savings of exports for 2012 DG installations by customer class and utility over the life of the generator. The $/W figure represents the bill savings resulting from exported energy seen by a NEM customer over the DG system's lifetime per watt installed. In a sense, these values can be viewed as the equivalent upfront payment for the exported NEM generation.

Table 13: Total Levelized Bill Savings for Systems Installed in 2012 by Utility - Export Only ($/W; $/kWh)

	PG&E		SCE		SDG&E		All IOUs	
	$/W	$/kWh	$/W	$/kWh	$/W	$/kWh	$/W	$/kWh
Residential	$2.6	$0.29	$2.3	$0.23	$2.1	$0.23	$2.3	$0.25
Non-Residential	$1.2	$0.19	$0.6	$0.13	$0.7	$0.13	$1.0	$0.17
Average	$1.9	$0.24	$1.9	$0.22	$1.5	$0.20	$1.8	$0.22

Table 14 displays the levelized bill savings for 2012 DG installations by customer class and utility over the life of the generator. The higher energy rates of residential customers are evidenced by the higher $/kWh values. Additionally, the higher PV capacity factors of Southern California are reflected by the higher $/W values relative to the $/kWh value. In the All Generation case, the $/W figure represents the bill savings resulting from all energy seen by a NEM customer over the DG system's lifetime per watt installed.

Table 14: Total Levelized Bill Savings for Systems Installed in 2012 by Utility - All Generation ($/W; $/kWh)

	PG&E		SCE		SDG&E		All IOUs	
	$/W	$/kWh	$/W	$/kWh	$/W	$/kWh	$/W	$/kWh
Residential	$7.4	$0.39	$5.6	$0.29	$6.0	$0.31	$6.3	$0.33
Non-Residential	$4.4	$0.23	$2.9	$0.16	$4.1	$0.21	$4.1	$0.21
Average	$5.7	$0.30	$5.0	$0.27	$5.3	$0.27	$5.4	$0.28

4.2.3 LEVELIZED RESIDENTIAL BILL SAVINGS BY CUSTOMER SIZE

Table 15 shows the levelized bill savings by customer size for the residential class for exported energy. Here, we see the rate of bill savings increasing steadily as customers are larger. This effect is due to the higher usage tiers associated with inclining block rate structures. Note that these are 'levelized' values assuming escalation of rates over a 20-year period, and are not directly comparable to current rates.[18]

[18] Because there are very few residential NEM customers with load greater than 100 MWh, the data in that row is incongruous due to small sample size.

Table 15: Residential Levelized Bill Savings for Systems Installed in 2012 by Customer Size and Utility - Export Only ($/W; $/kWh)

Annual Gross Load	PG&E		SCE		SDG&E		All IOUs	
	$/W	$/kWh	$/W	$/kWh	$/W	$/kWh	$/W	$/kWh
< 5 MWh	$1.8	$0.13	$1.9	$0.14	$2.0	$0.15	$1.9	$0.14
5 to 10 MWh	$2.1	$0.19	$2.0	$0.18	$2.1	$0.20	$2.1	$0.19
10 to 25 MWh	$2.7	$0.32	$2.3	$0.25	$2.0	$0.26	$2.4	$0.27
25 to 50 MWh	$3.4	$0.40	$2.5	$0.31	$2.4	$0.32	$2.8	$0.35
50 to 100 MWh	$3.4	$0.39	$1.8	$0.32	-	-	$2.4	$0.35
100 to 500 MWh	$1.8	$0.40	-	-	-	-	$1.8	$0.40
Average	$2.6	$0.29	$2.3	$0.23	$2.1	$0.23	$2.3	$0.25

Table 16 shows the levelized bill savings by gross customer size for the residential class for the All Generation case. The results are similar to those of Table 15 in showing larger customers avoiding the higher tiers of residential inclining block rates. The levelized bill savings are greater in the All Generation case compared to the Export Only case due to the tier structure and because much of the NEM generation is consumed on site before it is exported.

Table 16: Residential Levelized Bill Savings for Systems Installed in 2012 by Customer Size and Utility - All Generation ($/W; $/kWh)

Annual Gross Load	PG&E		SCE		SDG&E		All IOUs	
	$/W	$/kWh	$/W	$/kWh	$/W	$/kWh	$/W	$/kWh
< 5 MWh	$2.9	$0.15	$2.9	$0.15	$3.3	$0.17	$3.0	$0.16
5 to 10 MWh	$5.2	$0.27	$4.3	$0.23	$5.1	$0.27	$4.9	$0.25
10 to 25 MWh	$8.1	$0.43	$5.9	$0.31	$6.7	$0.35	$6.8	$0.36
25 to 50 MWh	$9.2	$0.48	$6.8	$0.36	$7.4	$0.38	$7.8	$0.41
50 to 100 MWh	$8.6	$0.47	$7.2	$0.38	-	-	$7.7	$0.41
100 to 500 MWh	$9.3	$0.48	-	-	-	-	$9.3	$0.48
Average	$7.4	$0.39	$5.6	$0.29	$6.0	$0.31	$6.3	$0.33

These levelized bill savings assume continuation of the current retail rate structures. Actual levelized bill savings could be dramatically different if future rate structures differ from the current structures.

4.2.4 SENSITIVITIES

We calculate bill savings with a low sensitivity, in which retail rate escalation follows a lower trajectory than that of the Base Case, and a high sensitivity, in which retail rate escalation follows a higher trajectory than the Base Case. Table 17 shows the results of these sensitivities for the Export Only case and each penetration scenario in millions of dollars in the year 2020. These savings are calculated as the difference of the estimated customer bill with and without credit for exports to the grid from the NEM customer.

Table 17: Total Bill Savings in 2020 by Penetration Level - Export Only Sensitivities ($2012/year)

	2012 Snapshot		Full CSI Subscription		Full NEM Subscription	
	High	Low	High	Low	High	Low
Residential	$113	$108	$160	$153	$514	$489
Non-Residential	$56	$54	$153	$146	$254	$242
Total	$170	$161	$313	$298	$768	$731

Table 18, below, shows the bill savings in the All Generation case. In the All Generation case, the bill savings is the difference in the customer bill with and without the NEM generation. Note that since NEM customers are exempt from standby charges, this bill savings is not reduced by a standby charge in the base case and high cases. In the low case sensitivity, we reduce the bill savings for non-residential customers for the standby charges that would be assessed without the exemption.

Table 18: Total Bill Savings in 2020 by Penetration Level - All Generation Sensitivities ($2012/year)

	2012 Snapshot		Full CSI Subscription		Full NEM Subscription	
	High	Low	High	Low	High	Low
Residential	$315	$299	$438	$417	$1,355	$1,290
Non-Residential	$229	$218	$638	$607	$998	$949
Total	$544	$518	$1,075	$1,023	$2,353	$2,239

4.3 Avoided Costs

Avoided costs are a representation of the value that a resource provides to the electrical system. In the case of NEM, the avoided costs are an estimate of the costs that the IOUs would otherwise have to pay in the absence of NEM generation. We use the avoided cost framework that has been developed in numerous proceedings at the CPUC since it was adopted in 2004. This approach provides a transparent method to value net energy production from distributed generation on a time-differentiated cost-basis. Appendix C describes the avoided cost calculation in detail, and there is a publically available Avoided Cost Model that is used to develop the avoided costs.

We estimate avoided costs in the six component categories described in Table 19. Each of the avoided cost components is a direct cost that would otherwise be borne by the utility or utility customers through their electricity bills in the absence of NEM generation.

Table 19: Components of Marginal Energy Cost

Component	Description
Generation Energy	Estimate of hourly marginal wholesale value of energy adjusted for losses between the point of the wholesale transaction and the point of delivery
System Capacity	The marginal cost of procuring Resource Adequacy resources in the near term. In the longer term, the additional payments (above energy and ancillary service market revenues) that a generation owner would require to build new generation capacity to meet system peak loads
Ancillary Services	The marginal cost of providing system operations and reserves for electricity grid reliability
T&D Capacity	The costs of expanding transmission and distribution capacity to meet customer peak loads
CO2 Emissions	The cost of carbon dioxide emissions (CO2) associated with the marginal generating resource
Avoided RPS	The cost reductions from being able to procure a lesser amount of renewable resources while meeting the Renewable Portfolio Standard (percentage of retail electricity usage).

We forecast each of the six avoided cost components at the hourly level through the year 2050, although only forecasts through 2031 are used in this analysis. The 2020 avoided costs are used for the 2020 snapshot analysis, and the 2012-2031 avoided costs are used to calculate levelized system benefits. The Commission adopted the use of hourly avoided costs in 2004. In that original application, the hourly costs were developed for use with the predictable load reduction profiles of energy efficiency measures. In the intervening years, E3 has worked with parties to enhance the methodology for distributed generation and other distributed energy resources.

We develop the hourly forecasts using a two-step process, whereby annual avoided costs are first forecast for each component through 2050. E3 then disaggregates, or shapes, the annual values to encompass hourly variations and peak timing. Table 20 summarizes the methodology applied to each component to develop the annual and hourly forecasts.

Table 20: Summary of Methodology for Avoided Cost Component Forecasts

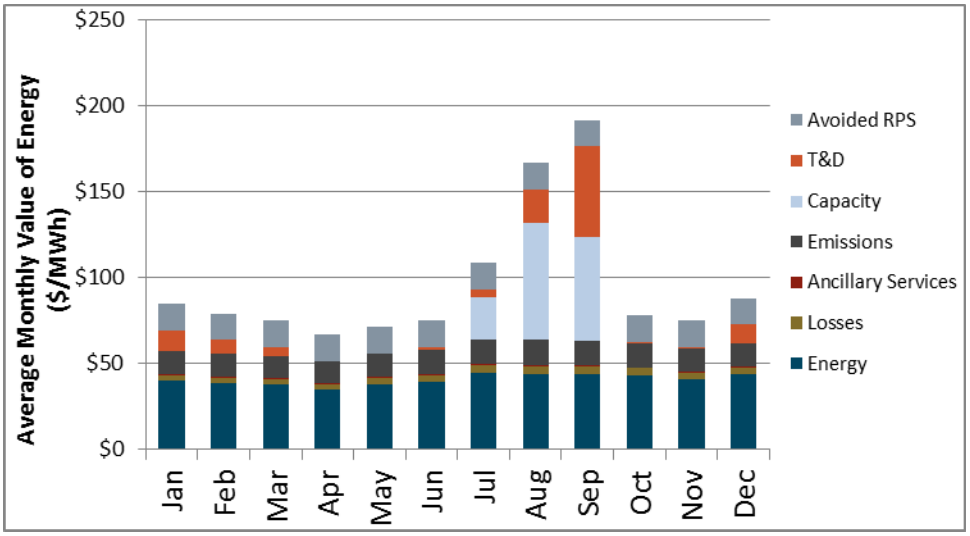
Component	Basis of Annual Forecast	Basis of Hourly Shape
Generation Energy	Forward heat rate projections from 2010 CPUC Long Term Procurement Plan and monthly fuel cost projections	Historical hourly day-ahead market price shapes from MRTU OASIS aligned to a typical meteorological year based on daily system loads
System Capacity	Lower of the residual capacity value a new simple-cycle combustion turbine or combined cycle gas turbine	Hourly allocation factors calculated as a proxy for LOLP based on system loads
Ancillary Services	Percentage of generation energy value	Directly linked with energy shape
T&D Capacity	Marginal transmission and distribution costs from utility ratemaking filings.	Hourly allocation factors calculated using hourly TMY temperature data as a proxy for local area load
Environment	CARB 2013 auction results; 2011 Market Price Referent (MPR)[19]	Directly linked with energy shape with bounds on the maximum and minimum hourly value
Avoided RPS	Cost of a marginal renewable resource less the energy and capacity value associated with that resource	Flat across all hours

Figure 13 shows average monthly value of load reductions, revealing the seasonal characteristics of the avoided costs. The energy component dips in the spring, reflecting increased hydro supplies and imports from the Northwest, and peaks in

[19] http://www.ethree.com/documents/2011_MPR_E4442_CPUC_Final_Resolution.pdf

the summer months when demand for electricity is highest. The value of capacity—both generation and T&D—is concentrated in the summer months and results in significantly more value on average during these months.

Figure 13: Average Monthly Avoided Cost (Levelized Value Over 30-yr Horizon)

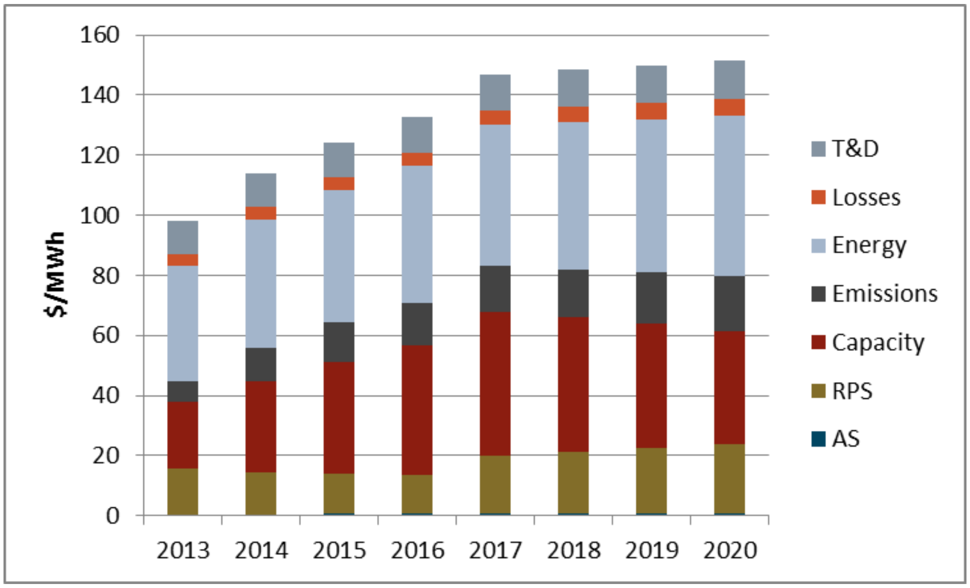


In order to calculate the total avoided costs, we multiply the half-hourly DG generation profiles (kWh) developed for each customer bin by hourly avoided cost values ($/kWh), which are the output of the Avoided Cost Model. These values are then summed to provide total annual avoided cost results.

When considering the Export Only case, only DG production that is exported onto the grid (negative net load) is valued. When considering the All Generation case, the entire DG generation profile of each customer bin is valued using the avoided costs.

Figure 14, below, shows the value of each component of avoided cost over time for the combined NEM output shape in the Base Case assumptions. Note the evolving relative importance of each component of the avoided costs over time.

Figure 14: Average NEM Avoided Costs by Component



4.3.1 TOTAL AVOIDED COST

Table 21 shows the total avoided cost of the Export Only case in millions of 2012 dollars in the year 2020. As with bill savings, the higher percentage of exported DG generation for the residential class is evident in the class's larger share of total avoided costs relative to the All Generation case.

Table 21: Total Avoided Cost in 2020 by Penetration Level - Export Only (Millions $2012/year)

	2012 Snapshot	Full CSI Subscription	Full NEM Subscription
Residential	$50	$72	$239
Non-Residential	$37	$108	$173
Total	$87	$180	$412

Table 22 shows the avoided cost of All Generation in millions of 2012 dollars in the year 2020. The share of avoided costs between residential and non-residential is almost identical to the split of GWh generated by each customer class in 2020.

Table 22: Total Avoided Cost in 2020 by Penetration Level - All Generation (Millions $2012/year)

	2012 Snapshot	Full CSI Subscription	Full NEM Subscription
Residential	$121	$172	$541
Non-Residential	$151	$445	$668
Total	$272	$617	$1,209

4.3.2 LEVELIZED AVOIDED COST

Table 23 displays the levelized avoided cost for 2012 DG installations by customer class and utility over the life of the generator for the Exports Only case.

Table 23: Total Levelized Avoided Cost for Systems Installed in 2012 by Utility - Export Only ($/W; $/kWh)

	PG&E		SCE		SDG&E		All IOUs	
	$/W	$/kWh	$/W	$/kWh	$/W	$/kWh	$/W	$/kWh
Residential	$1.2	$0.13	$1.1	$0.12	$1.0	$0.11	$1.1	$0.12
Non-Residential	$0.8	$0.12	$0.5	$0.11	$0.6	$0.10	$0.7	$0.11
Average	$0.9	$0.12	$1.0	$0.12	$0.8	$0.11	$0.9	$0.12

Table 24 displays the levelized avoided cost for 2012 DG installations by customer class and utility over the life of the generator for the All Generation case. The consistent $/kWh values suggest similar avoided costs across the three IOUs.

Table 24: Total Levelized Avoided Cost for Systems Installed in 2012 by Utility - All Generation ($/W; $/kWh)

	PG&E		SCE		SDG&E		All IOUs	
	$/W	$/kWh	$/W	$/kWh	$/W	$/kWh	$/W	$/kWh
Residential	$2.7	$0.14	$2.6	$0.14	$2.5	$0.13	$2.6	$0.14
Non-Residential	$2.6	$0.14	$2.5	$0.14	$2.6	$0.13	$2.6	$0.13
Average	$2.7	$0.14	$2.6	$0.14	$2.5	$0.13	$2.6	$0.14

4.3.3 SENSITIVITY ANALYSIS RESULTS

We calculate a high and low sensitivity for avoided costs by grouping assumptions together that increase or decrease the avoided costs as described previously. The low avoided cost sensitivity assumes a lower gas price forecast, a lower CO2 price forecast, no avoided T&D value, and a later resource balance year relative to the Base Case. The high avoided cost sensitivity assumes a higher gas price forecast and a higher CO2 price forecast relative to the Base Case, along with a resource balance year that gives full capacity value in every year and a 2013 vintage ELCC.[20] Table 25 shows the results of these sensitivities for each penetration scenario for the Export Only case in millions of dollars in the year 2020.

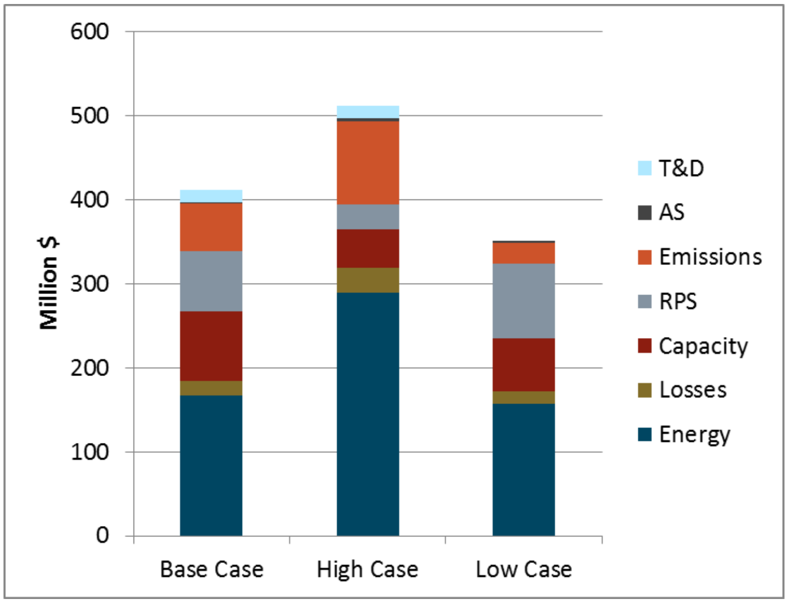
Table 25: Total Avoided Cost in 2020 by Penetration Level - Export Only (Millions $2012/year)

	2012 Snapshot		Full CSI Subscription		Full NEM Subscription	
	High	Low	High	Low	High	Low
Residential	$61	$42	$89	$61	$296	$203
Non-Residential	$46	$32	$137	$93	$216	$148
Total	$108	$74	$225	$153	$512	$351

Figure 15 shows the breakdown by component of avoided costs in millions of dollars in the year 2020 for each Export Only case sensitivity. Bear in mind that the Low and High sensitivities are named for their effects on total NEM cost-effectiveness from a utility perspective, and not their effects on individual components of the calculation.

[20] Because the high gas price forecast used in the high avoided cost sensitivity results in higher energy market prices, the capacity value in the high avoided cost case is lower than in the base avoided cost case. See Appendix C for a detailed explanation of the relationship between market prices and capacity value.

Figure 15: Total Avoided Costs by Component of Export Only in 2020 for Full NEM Cap (Millions $2012/year)



Subject to the same sensitivities, Table 26 shows the high and low avoided cost ranges for the All Generation case at each penetration level.

Table 26: Total Avoided Cost in 2020 by Penetration Level - All Generation (Millions $2012/year)

	2012 Snapshot		Full CSI Subscription		Full NEM Subscription	
	High	Low	High	Low	High	Low
Residential	$144	$100	$205	$142	$649	$448
Non-Residential	$181	$125	$537	$368	$803	$553
Total	$325	$225	$742	$510	$1,452	$1,001

4.4 Program Costs

Program costs are the costs to the IOUs associated with maintaining the NEM tariff. These include one-time initial set up costs associated with setting up the NEM billing account, recurring incremental metering costs due to the complexity of NEM customers, one time interconnection costs, and recurring integration costs associated with balancing the intermittent DG resources on the system.

Initial set-up costs, metering costs, and interconnection costs are incurred during system installation and do not change based on a customer's usage or DG production profile. Therefore, there are no real differences in program costs between the All Generation and Export Only cases. However, when integration costs are assessed as $/MWh, the denominator used in the Export Only case is equal to only exported MWh, while the denominator used in the All Generation case comprises all generated MWh.

4.4.1 PROGRAM COST DATA

PG&E and SCE provided program cost data for the year 2011 to E3 in a series of data requests. The following tables present the data that was received, which form the basis for the calculations of program costs presented below. Since no data was received from SDG&E, their program costs are assumed to be an average of the costs of the other IOUs.

Table 27 provides the reported interconnection costs. Our understanding is that this data reflects the costs associated with the application review and site inspection for new DG systems. By NEM statute, these costs are not passed to NEM customers. Estimates of distribution system upgrade costs, if any, were not available from the utilities, and therefore are not included in these estimates.

Table 27: Interconnection Costs ($/customer)

Customer Description	Cost
PG&E	$209
SCE (DG ≤10 kW)	$105
SCE (DG >10 kW)	$524

Table 28, below, provides the reported incremental billing costs of NEM customers. These are the costs above and beyond the regular cost of billing for non-NEM customers. Note that the incremental billing costs, particularly the auto billing costs, are significantly improved from the 2010 NEM Evaluation. For PG&E, these decreased costs are also a reflection of the availability of more granular billing data.

Table 28: Incremental Billing Cost ($/customer-month)

Customer Description	Cost
PG&E (Auto billing)	$1.35
PG&E (Manual billing)	$4.66
SCE (Auto billing)	$0.69
SCE (Manual billing)	$19.06

Table 29, below, provides the NEM customer setup services. These are the one-time costs to include a customer in the billing system. From the data requests it is clear that PG&E and SCE use different cost attribution for billing and setup of NEM customers. In addition to different formats, there may also be different costs accounted for in the estimates of initial set-up costs provided by the utilities.

Table 29: Initial Set-up Cost ($/customer)

Utility	Cost Component	Cost
PG&E	All	$39.41
SCE	Application Processing	$84.63
SCE	Account Billing Setup	$6.37
SCE	Metering Services Setup (Load 4-6 kW)	$396.22
SCE	Metering Services Setup (Load <20 kW)	$441.59
SCE	Metering Services Setup (Load 130-165 kW)	$1,174.73

4.4.2 PROGRAM COSTS

Using the costs provided above, Table 30 displays the levelized program cost for 2012 DG installations by customer class and utility over the life of the generator. These costs are based on the Export Only case, and are therefore shown per kWh exported to the grid. The program costs are higher for residential customers because there are proportionally higher setup costs relative to the amount of energy generated. Overall, however, the magnitude of these costs is insignificant relative to the bill savings and avoided costs.

Table 30: Total Levelized Program Cost for Systems Installed in 2012 by Utility - Export Only ($/W; $/kWh)

	PG&E		SCE		SDG&E		All IOUs	
	$/W	$/kWh	$/W	$/kWh	$/W	$/kWh	$/W	$/kWh
Residential	$0.1	$0.01	$0.2	$0.02	$0.2	$0.02	$0.2	$0.02
Non-Residential	$0.0	$0.00	$0.0	$0.01	$0.1	$0.01	$0.0	$0.01
Average	$0.1	$0.01	$0.2	$0.02	$0.1	$0.02	$0.1	$0.01

The program costs in the All Generation case are lower per kWh. Table 31 displays the levelized program cost for 2012 DG installations by customer class and utility over the life of the generator. Many numbers are unchanged due to rounding from the prior table.

Table 31: Total Levelized Program Cost for Systems Installed in 2012 by Utility - All Generation ($/W; $/kWh)

	PG&E		SCE		SDG&E		All IOUs	
	$/W	$/kWh	$/W	$/kWh	$/W	$/kWh	$/W	$/kWh
Residential	$0.2	$0.01	$0.2	$0.01	$0.2	$0.01	$0.2	$0.01
Non-Residential	$0.1	$0.00	$0.1	$0.00	$0.1	$0.00	$0.1	$0.00
Average	$0.1	$0.01	$0.2	$0.01	$0.2	$0.01	$0.1	$0.01

4.4.3 SENSITIVITY ANALYSIS

Although small, we do include a sensitivity analysis in which lower metering costs, set-up costs, and interconnection costs are used relative to the Base Case. Similarly, we evaluate a high sensitivity in which higher interconnection and integration costs are used relative to the Base Case. These sensitivities have a relatively small impact on the analysis. Table 32 and Table 33 show levelized program costs for the sensitivity ranges for the Export Only and All Generation cases, respectfully.

Table 32: Levelized Program Cost for Systems Installed in 2012 by Utility - Export Only ($/kWh)

	PG&E		SCE		SDG&E		All IOUs	
	Low	High	Low	High	Low	High	Low	High
Residential	$0.00	$0.02	$0.00	$0.02	$0.00	$0.03	$0.00	$0.02
Non-Residential	$0.00	$0.01	$0.00	$0.01	$0.00	$0.01	$0.00	$0.01
Average	$0.00	$0.01	$0.00	$0.02	$0.00	$0.02	$0.00	$0.02

Table 33: Levelized Program Cost for Systems Installed in 2012 by Utility - All Generation ($/kWh)

	PG&E		SCE		SDG&E		All IOUs	
	Low	High	Low	High	Low	High	Low	High
Residential	$0.0	$0.01	$0.0	$0.01	$0.0	$0.01	$0.0	$0.01
Non-Residential	$0.0	$0.01	$0.0	$0.01	$0.0	$0.01	$0.0	$0.01
Average	$0.0	$0.01	$0.0	$0.01	$0.0	$0.01	$0.0	$0.01

4.5 Cost-Benefit Analysis Results

The tables and figures within this section present the total NEM cost-benefit analysis results. Results are given first for the Export Only case, and then for the All Generation case. An additional subsection provides the results unique to fuel cell customers, whose differentiated NEM tariff requires them to be analyzed separately.

4.5.1 NEM COST-BENEFIT ANALYSIS

Table 34 shows the total net cost of NEM in millions of dollars in the year 2020 for the Export Only case. Recall that we defined net cost such that a positive value indicates a cost shift from NEM participants to other ratepayers. The total net cost of NEM exports, at full subscription in the year 2020, will be in the range of $370 million dollars per year. This is approximately 1.1% of the combined IOU revenue requirement in that year. The revenue requirement forecast is formed by escalating current IOU revenue requirements at the modeled retail rate escalation.

Table 34: Net Cost of NEM Generation Exports in 2020 (Millions $2012/year)

	2012 Snapshot	Full CSI Subscription	Full NEM Subscription
Residential	$61	$85	$291
Non-Residential	$18	$41	$79
Total	$79	$126	$370
% of Revenue Requirement	0.23%	0.36%	1.06%

Table 35 shows the total net cost in millions of dollars in the year 2020 for all NEM generation. The total net cost of the NEM program, at full subscription in the year 2020, will be in the range of $1,093 million dollars per year. For perspective, this is projected to be about 3.1% of the combined IOU revenue requirement. As we are considering all NEM generation, including generation that meets onsite load and that is exported to the grid, the cost of the NEM program more than doubles that of the Export Only case.

Table 35: Net Cost of All NEM Generation in 2020 (Millions $2012/year)

	2012 Snapshot	Full CSI Subscription	Full NEM Subscription
Residential	$182	$250	$794
Non-Residential	$70	$170	$299
Total	$252	$420	$1,093
% of Revenue Requirement	0.72%	1.20%	3.13%

Table 36 displays the per unit cost impact for the exported energy on a levelized $/kWh and lifecycle $/watt basis for 2012 DG installations by customer class and utility. We find that NEM generation exports have a net cost of 12 ¢/kWh, or a lifecycle net cost of 1.0 $/W installed on average. The residential costs per watt installed are significantly higher than the non-residential costs because more energy is exported, and because the retail rate credit for residential customers is greater.

Table 36: Levelized Net Cost ($/kWh) and Lifecycle Cost ($/W) of NEM for Systems Installed in 2012 by Utility - Exports Only

	PG&E		SCE		SDG&E		All IOUs	
	$/W	$/kWh	$/W	$/kWh	$/W	$/kWh	$/W	$/kWh
Residential	$1.6	$0.17	$1.3	$0.14	$1.2	$0.14	$1.4	$0.15
Non-Residential	$0.5	$0.07	$0.1	$0.03	$0.2	$0.03	$0.4	$0.06
Average	$1.0	$0.13	$1.1	$0.12	$0.8	$0.11	$1.0	$0.12

Table 37 displays the levelized total net cost of all NEM generation for 2012 installations by customer class and utility over the life of the generator per watt installed and per kWh generated. We find that NEM generation creates a levelized cost impact of 15 ¢/kWh generated, or 3.1 $/W installed on average. These numbers are significantly higher for residential customers, who incur bill savings at higher retail rates.

Table 37: Levelized Net Cost ($/kWh) and Lifecycle Cost ($/W) of NEM for Systems Installed in 2012 by Utility - All Generation

	PG&E		SCE		SDG&E		All IOUs	
	$/W	$/kWh	$/W	$/kWh	$/W	$/kWh	$/W	$/kWh
Residential	$4.9	$0.26	$3.2	$0.17	$3.7	$0.19	$3.9	$0.20
Non-Residential	$1.8	$0.09	$0.5	$0.03	$1.7	$0.08	$1.5	$0.08
Average	$3.2	$0.17	$2.6	$0.14	$2.9	$0.15	$2.9	$0.15

Figure 16 shows the costs and benefits of exports on a levelized $/kWh exported basis side-by-side for each utility. The difference in height between the cost bars and the benefit bars is the net cost shown in Table 37, above. These levelized net costs are per kWh exported. Note that the bill savings are the dominant driver of the results of this analysis. The program costs are a relatively small component.

Figure 16: Levelized Costs and Benefits of NEM for Systems Installed in 2012, Export Only (Levelized $/kWh)

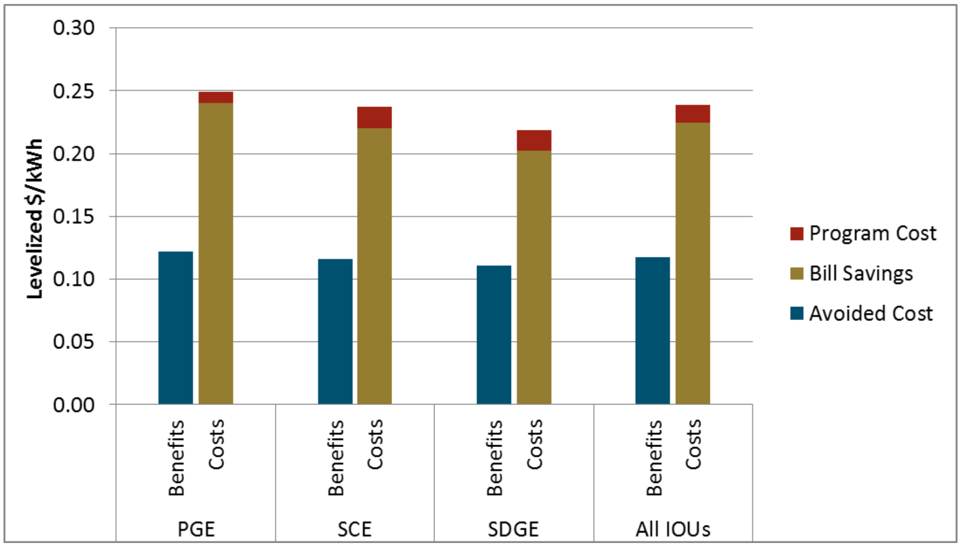


Figure 17 shows the All Generation costs and benefits on a levelized $/kWh basis side-by-side for each utility. Compared to the Export Only case, program costs play a smaller role here. Program costs are relatively equivalent in the two cases, but they are distributed over fewer kWh in the Export Only case.

Figure 17: Levelized Costs and Benefits of NEM for Systems Installed in 2012 - All Generation (Levelized $/kWh)

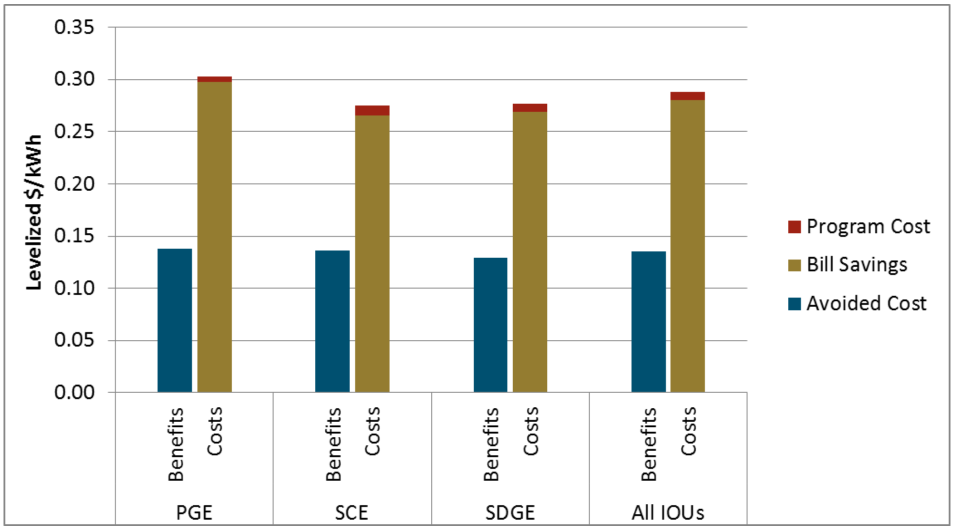


Table 38 shows the levelized net cost of exports from residential NEM systems by customer size. The table shows that larger residential NEM customer impose higher per-kWh costs on the system than smaller customers. This is primarily due to the inclining block residential rate structures. Changes in the current inclining block rate structures would likely impact the overall levelized cost of NEM substantially. Since over half of the customers using NEM have DG systems that produce more than 10 MWh and because larger customers have significantly higher levelized costs than smaller customers, these cost results are especially sensitive to changes in the rates of the higher inclining blocks, with lower rates resulting in lower levelized costs.

Table 38: Levelized Cost of NEM for Residential Customers by Usage Bin - Export Only (Levelized $/kWh)

Customer Usage	PG&E	SCE	SDG&E	All IOUs	Number of Customers
< 5 MWh	0.01	0.03	0.05	0.03	12,370
5 to 10 MWh	0.08	0.08	0.10	0.09	45,170
10 to 25 MWh	0.21	0.15	0.17	0.17	70.462
25 to 50 MWh	0.29	0.22	0.24	0.25	7,995
50 to 100 MWh	0.27	0.25	-	0.26	354
100 to 500 MWh	0.31	-	-	0.31	18
Average	0.18	0.14	0.14	0.15	136,549

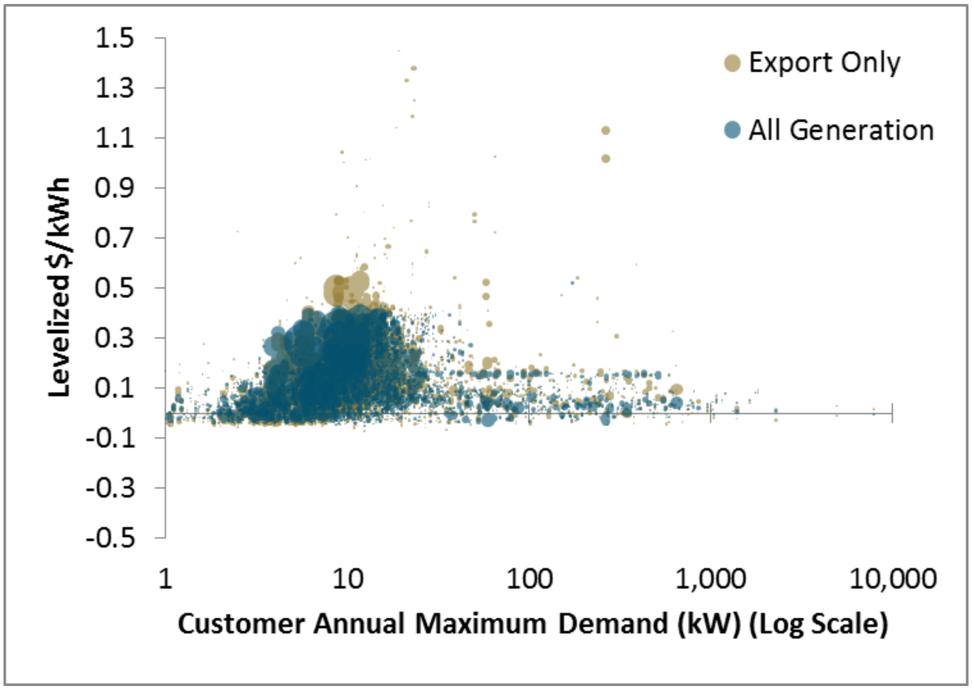
Table 39 displays the levelized net cost of all generation from residential NEM systems by customer size. The per-kWh cost disparity between small and large residential customers is even larger in this case than in the Export Only case. Again, any change in the current inclining block rate structures would affect the overall levelized cost of NEM, with rate decreases for higher tiers reducing the overall net cost shift of NEM.

Table 39: Levelized Cost of NEM for Residential Customers by Usage Bin - All Generation (Levelized $/kWh)

Customer Usage	PG&E	SCE	SDG&E	All IOUs	Number of Customers
< 5 MWh	0.02	0.03	0.05	0.04	12,370
5 to 10 MWh	0.14	0.11	0.15	0.13	45,170
10 to 25 MWh	0.29	0.18	0.23	0.23	70.462
25 to 50 MWh	0.35	0.23	0.26	0.28	7,995
50 to 100 MWh	0.33	0.25	-	0.28	354
100 to 500 MWh	0.35	-	-	0.35	18
Average	0.26	0.17	0.19	0.20	136,549

While average metrics are useful for understanding the costs and benefits of NEM, there is a significant diversity across different customers. Figure 18 shows the total net cost of NEM of each customer bin modeled for both the Export Only case and the All Generation case. The total net cost is expressed in levelized $/kWh over the lifetime of DG systems installed in 2012 and is plotted as a function of customer size, expressed in annual gross demand (plotted on a log scale). The size of each bubble is proportional to the number of customers represented by each customer bin. As demonstrated in this chart, there is a wide range of cost effectiveness of individual customers and a large number that provide net benefits (customers that provide more benefits than costs to the system), as expressed by the points located below the y-axis.

Figure 18: Scatter Plot of Net Levelized Costs and Maximum Demand for NEM Customers by Bin



Note that some points may be excluded due to scale of axes
Size of bubble corresponds to number of customers represented by each point

4.5.2 SENSITIVITY ANALYSIS

Figure 19 shows the range of export net costs in millions of dollars in the year 2020 based on our high and low sensitivities for each penetration level. The range of sensitivity is relatively symmetric above (high case) or below (low case) from the Base Case and is +/- approximately 20%. The non-residential cost-shifting is a relatively larger contributor to the total cost impact in the CSI case because there is relatively more non-residential capacity installed as the non-residential tiers become fully subscribed.

Figure 19: Sensitivity Results of Net Cost of NEM Exports in 2020 (Millions $2012/year)

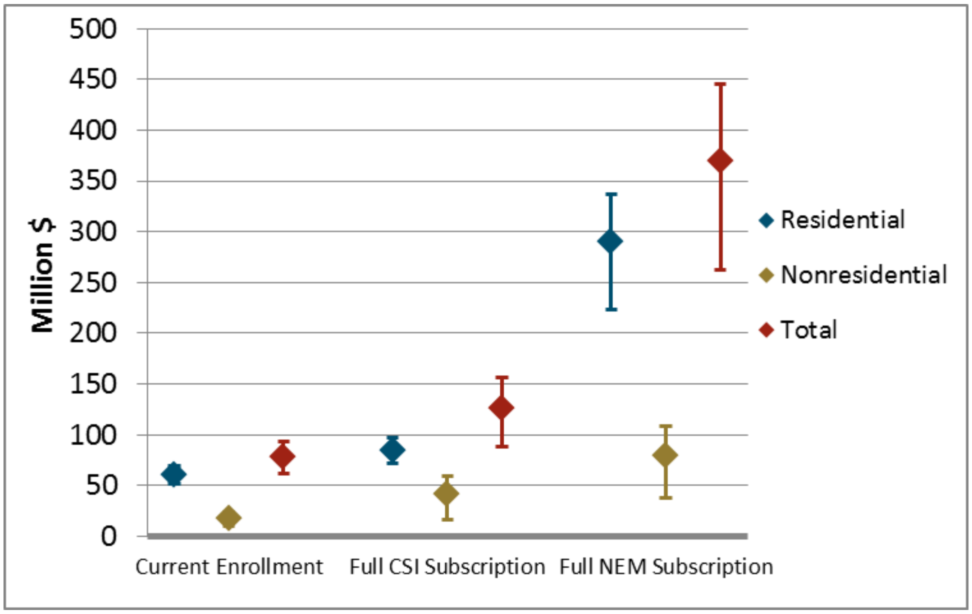
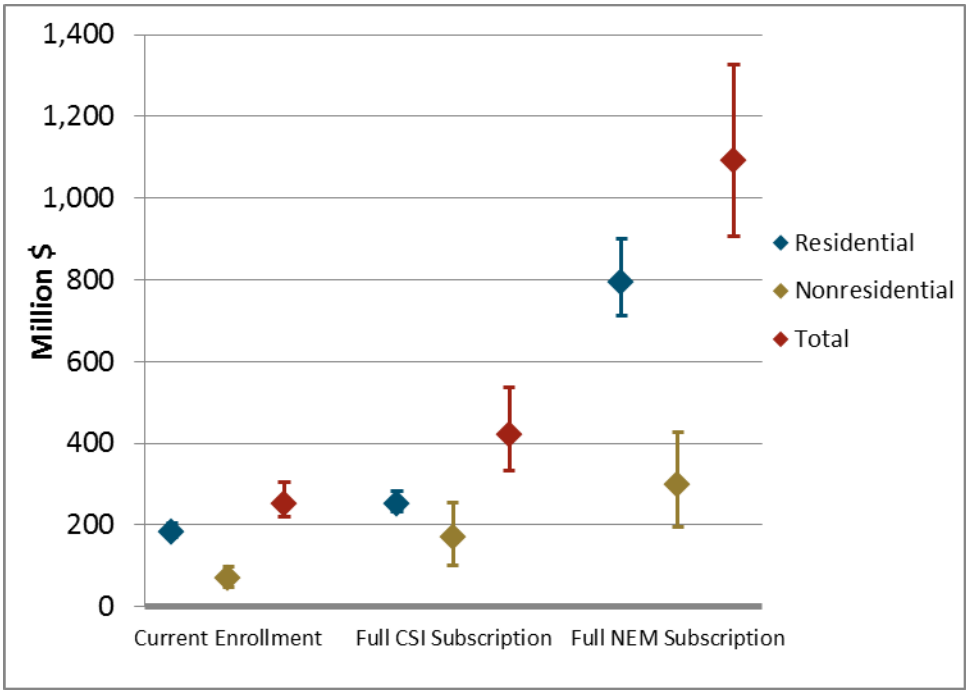


Figure 20 shows the range of All Generation net cost of NEM in millions of dollars in the year 2020 based on the high and low sensitivities for each penetration level. Though the scale of the numbers changes, the relative results are nearly identical to the Export Only case.

Figure 20: Sensitivity Results of Net Cost of NEM Generation in 2020 (Millions $2012/year)



4.6 Benchmarking to 2010 Study

This study can be readily compared to the prior CPUC analysis of NEM costs and benefits released in 2010.[21] The 2010 study employed a similar methodology, with a few notable exceptions. One difference is that the 2010 study only evaluated the exports associated with NEM. Also, the analysis only included solar

[21] http://www.cpuc.ca.gov/PUC/energy/DistGen/nem_eval.htm

PV systems that were NEM, and did not include wind or fuel cells. Lastly, the analysis only included systems installed through 2008, and we 'scaled' these systems to estimate 2020 impacts after full CSI implementation at the IOUs. The metrics reported in that study were based on a 20-year NPV and an annualized impact.

Table 40, below, shows the comparison of the lifecycle net cost between the 2010 study and the results of this study on a lifecycle and annualized value basis. To make the comparison, the comparable NPV lifecycle values from this study were calculated. Based on this comparison, the overall net cost per kWh exported is lower, despite the larger overall MW of NEM due to the inclusion of wind and fuel cell generation. This lower net cost is primarily due to retail rate escalation rates being lower than they were forecast to be in 2010. The equivalent upfront incentive of exports is higher now because of a lower discount rate, and an assumption of lower PV system degradation.

Table 40: Lifecycle Analysis Comparison: Method from 2010 Study (2008 dollars)

Study	Year	Net Cost NPV $MM	Annualized Net Cost $MM/Year	MW Installed	Net Cost Levelized $/kWh Exported	Net Cost NPV $/W
2010 Study	2008	$ 230.6	$ 19.7	365	0.12	1.02
2013 Study	2008	$ 323.6	$ 28.5	391	0.11	1.49
2010 Study	2012	$ 769.6	$ 65.7	1,218	0.12	1.02
2013 Study	2012	$ 1,017.1	$ 89.5	1,305	0.11	1.62
2010 Study	2020	$ 1,611.3	$ 137.5	2,550	0.12	1.02
2013 Study	2020 Full CSI	$ 1,418.5	$ 124.8	2,916	0.07	1.53

In the current study we evaluate different metrics than were previously evaluated in the 2010 study. Rather than lifecycle NPV values, we assess the net cost in specific years. The reason is that the lifecycle results are highly dependent upon the retail rate escalation over the next 20 years, which is uncertain, and the discount rate assumption. Table 41, below, shows the comparison on an annual basis for the key metrics for 2008. All results have been normalized to 2008 dollars for comparison.

Table 41: Snapshot Analysis Comparison for 2008: Method from 2013 Study ($)

Year	Net Cost $MM/Yr	MW Installed	GWh Generated	GWh Exported	$/kWh Bill Savings	$/kWh Avoided Cost
2010 Study, 2008	$ 11.0	365	625	197	$0.16	$0.11
2013 Study, 2008	$ 12.9	391	700	271	$0.17	$0.12

Comparing the 2008 results of the two studies, there are more MW installed in the current study through the inclusion of wind and fuel cell NEM. There is also more exported electricity per GWh generated. These factors contribute to the net cost estimate being a little higher for 2008 than in the prior study.

4.7 NEMFC Results

NEM customers with fuel cells may be placed on a unique version of the NEM tariff referred to as NEMFC. NEMFC participants receive a credit only for the generation component of their energy exports to the grid, while traditional NEM participants earn credits at their full retail electricity rate. Due to the fact that, through 2012, fewer than 80 fuel cell customers have joined NEMFC, the contribution of NEMFC to the overall NEM costs and benefits is de minimis.

While the NEMFC bill calculations differ from those of other NEM customers, the avoided costs of energy generated or exported are the same, and are estimated using the same methodologies outlined in sections 4.3 and 4.4.

Table 42 displays the levelized total net cost of NEMFC for DG installations through 2012 by customer class and utility over the life of the generator per watt installed and per kWh exported. Because most fuel cell customers are large users, the denominators of the levelized costs for the Export Only case are extremely small, making the results somewhat volatile. Overall, the Export Only case represents a very small benefit to ratepayers (1 ¢/kWh). This result is dominated by SDG&E's NEMFC participants: while the utility has a small number of NEMFC customers, they are relatively large exporters, so they have a significant impact on the average statewide Export Only net costs.

Table 42: Net Cost per Watt Installed and Levelized Cost of NEMFC for Systems Installed Through 2012 - Export Only ($/W; $/kWh)

	PG&E		SCE		SDG&E		All IOUs	
	$/W	$/kWh	$/W	$/kWh	$/W	$/kWh	$/W	$/kWh
Residential	$0.2	$0.02	$0.1	$0.01	-	-	$0.2	$0.01
Non-Residential	$0.0	$0.00	$0.0	$0.09	-$0.7	-$0.02	-$0.1	-$0.01
Average	$0.0	$0.00	$0.0	$0.03	-$0.7	-$0.02	-$0.1	-$0.01

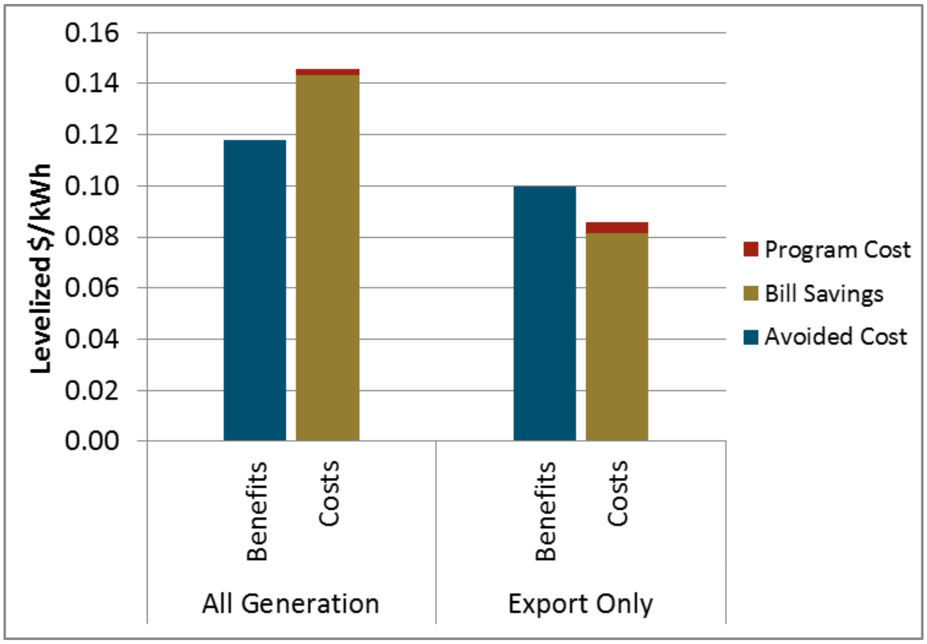
Table 43 displays the levelized total net cost of NEMFC for DG installations through 2012 by customer class and utility over the life of the generator and the cost per W installed. In the All Generation case, the NEMFC program represents an overall cost to ratepayers of 5 ¢/kWh or 3.3 $/W installed. The per-unit net cost to ratepayers is much higher for residential NEMFC generators than for non-residential NEMFC generators. However, because non-residential systems are much more common, the overall per-unit program cost is close to the non-residential unit cost and much lower than the residential unit cost. In comparison to the Export Only case results, the All Generation costs are higher because of the relatively low export credits awarded under the NEMFC program.

Table 43: Net Cost per Watt Installed and Levelized Cost of NEMFC for Systems Installed in 2012 - All Generation ($/W; $/kWh)

	PG&E		SCE		SDG&E		All IOUs	
	$/W	$/kWh	$/W	$/kWh	$/W	$/kWh	$/W	$/kWh
Residential	$24.6	$0.34	$11.8	$0.16	-	-	$17.6	$0.24
Non-Residential	$2.4	$0.03	$1.0	$0.01	$1.7	$0.02	$1.8	$0.03
Average	$2.6	$0.04	$1.2	$0.02	$1.7	$0.02	$2.0	$0.03

Figure 21 shows the total NEMFC costs and benefits on a levelized $/kWh basis side-by-side for the Export Only case and the All Generation case. It is worth noting that, in comparison to the avoided costs of renewable NEM, the avoided costs are lower per kWh generated due to the flat shape of fuel cell output relative to the load-coincident shape of PV output. Furthermore, the bill savings drop significantly due to the specialized rules of the tariff.

Figure 21: Levelized Cost of NEMFC for Systems Installed in 2012 (Levelized $/kWh)



5 Full Cost of Service

As required by AB 2514 (Bradford, 2012), we estimate the degree to which NEM customers pay their share of utility costs, or 'full cost of service.' To do this, the following analysis compares NEM customer bills to their share of utility costs as defined by an approximation of NEM customer full cost of service.

Net and gross NEM customer bills are calculated for each customer 'bin' using the E3 Utility Bill Calculator based on 2011 net and gross billing determinants, respectively.

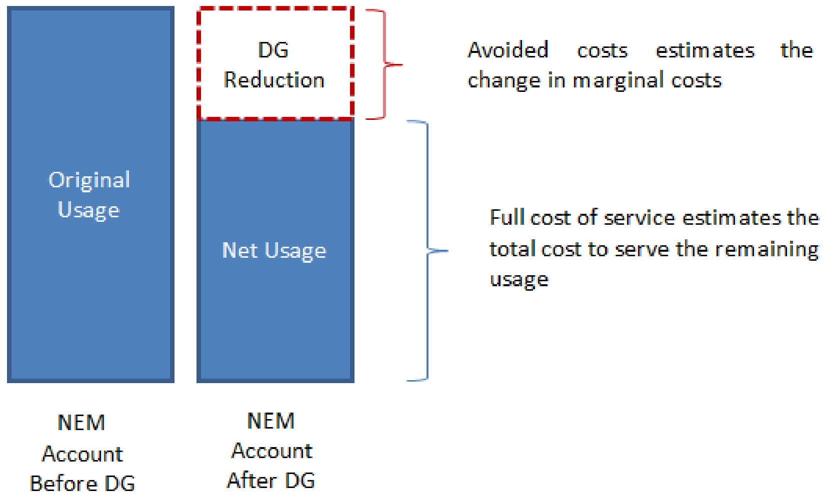
Full cost of service is a regulatory construct that refers to the total amount of revenue that a customer group would pay relative to other customer groups, based on how that group imposes costs on the utility. There are numerous steps in the ratemaking process that result in *all* customers, not just NEM customers, paying bills that differ from their actual full cost of service. Nevertheless, the utility GRC methods to calculate full cost of service method remain the most transparent and straightforward processes for developing an approximation of a customer's share of utility costs.

Full cost of service is generally not a metric that is evaluated when looking at resource options like demand response (DR). As such, it may be unfamiliar to readers and confusing when juxtaposed with the traditional avoided cost analysis presented earlier in this report. Despite *full cost of service* and *avoided cost* both having "cost" in their titles, they are actually very different metrics.

As illustrated in Figure 22, the avoided cost approach evaluates the marginal cost change associated with the change in usage due to DG, whereas the full cost approach evaluates the total cost to serve the remaining NEM account usage (net usage). Moreover the full cost of service considers all utility costs, including fixed and historical utility costs, rate surcharges, balancing and memorandum accounts, and costs that are directly attributable to a particular customer or customer group, whereas the avoided cost approach only considers marginal costs.[22]

[22] Another difference is that the NEM full cost of service analysis uses 2011 customer load data and 2011 DG output shapes. E3 uses the 2011 data to be consistent with the full cost of service information that was prepared by the IOUs based on 2011 data. This approach differs from the NEM avoided cost analysis, where E3 uses DG output shapes that are based on Typical Meteorological Year (TMY) data.

Figure 22: Avoided Cost versus Full Cost of Service Approaches



The avoided cost approach provides the cost information necessary to evaluate the impact of the DG resource. The full cost of service approach, on the other hand, is focused on the cost characteristics of the remaining NEM account usage. As such, the full cost of service analysis provides more of an indication of issues related to utility rate design, rather than issues related to the DG resource itself. While the DG facilitates the characteristics of the "after-DG" NEM accounts, any issues revealed in evaluating the full cost of service for those accounts would also exist for non-NEM accounts with similar usage characteristics.

5.1 Full Cost of Service Approach

The full cost of service is composed of three classes of costs:

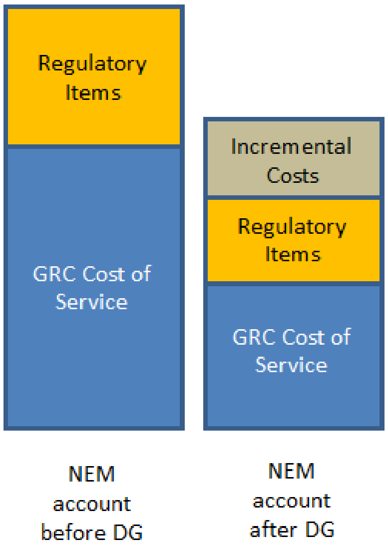
1. **GRC Cost of Service.** Generation, subtransmission, distribution, and customer costs are allocated to customers through utility GRC ratemaking proceedings and comprise the bulk of the full cost of service. SCE's FERC transmission is also allocated to customers via the GRC cost of service methods.

2. **Regulatory Items.** Costs or credits included in customer bills, but not assigned to customers in the GRC cost of service process. These regulatory cost items are generally assigned to customers on an equal cents per kWh basis, and we assume those tariff rates are equal to their cost of service. For PG&E and SDG&E, we also assume that their tariff rates for FERC transmission are equal to their cost of service.

3. **Incremental Costs.** Utility costs that are unique to NEM accounts and are not included in either the GRC Cost of Service or Regulatory Items. Such costs can include items such as interconnection costs, billing setup and processing costs, and integration costs. These costs are incurred because of the DG, and we add these incremental costs directly to the full cost of service for the NEM account.

The full cost of service components are illustrated in Figure 23. The stacked bars on the left represent the NEM account before the installation of DG. The full cost of service is comprised of the cost items assigned in the utility GRC proceedings (generation, transmission for SCE, subtransmission, distribution, and customer service) plus the regulatory amounts that are pass through based on the utility tariffs (rate surcharges, such as transmission for PG&E and SDG&E, etc.). The stacked bar on the right illustrates the full cost of service components after DG is installed. The GRC and regulatory items remain, but in smaller amounts, and there is the new incremental cost category associated with the addition of the DG.

Figure 23: Full Cost of Service Components



5.1.1 GRC COST OF SERVICE

GRC cost of service is the largest component of an account's full cost of service. To estimate the GRC cost of service, E3 estimates the cost that each account would be assigned if the account were treated as its own customer group in the utility GRC revenue allocation process.[23] The approach of treating each account as a customer class provides maximum flexibility for evaluating the full cost of service for NEM accounts. While this method is highly precise in calculating customer-specific full cost of service estimates, the estimates are only indicative of what an individual customer might have received in utility ratemaking proceeding.

The fact that these results are only indicative cannot be stressed enough. While the utility cost proposals and methods from their prior GRC proceedings represent the best information currently available, there are numerous caveats to viewing the GRC cost of service as the revenues that NEM accounts would pay. Some of these caveats are listed below.

+ Party settlements are often used to resolve ratemaking results. As such, there are disconnects between cost of service and the costs that are actually adopted for a customer group.
+ The actual determination of a definitive GRC cost of service study is not possible at this time due to the lack of adopted marginal costs and methods from the GRC proceedings.[24]
+ The GRC cost of service analysis is based on 2011 data, whereas utility filings use multiple years of data and perform weather normalizations.

[23] For PG&E and SDG&E, each account is analogous to its own customer class; for SCE, each customer group is analogous to its own rate sub-schedule within the larger SCE rate schedule. This subtle difference exists because the EPMC factors provided by SCE vary by rate schedule and function, whereas the EPMC factors provided by PG&E and SDG&E only vary by function.

[24] In settlement agreements parties often disagree on the unit of marginal costs and calculation methods used to determine the full cost of service. Where there is agreement on a number, such agreement is usually limited to use in the particular case, and its use does not carry any precedence.

+ The GRC cost of service estimates for an individual customer may be abnormally high or low due to vagaries in their 2011 usage. Utility GRC cost of service is conducted at a more aggregate level that may temper such variations.
+ The GRC cost of service analysis relies upon utility customer cost information, which is averaged at the class or rate schedule level and masks individual variations in customer costs. For residential sector, in particular, the predominance of single-family detached dwellings among NEM accounts (as opposed to apartments), likely results in an underestimate of the customer costs for the NEM accounts.
+ Utility ratemaking would likely result in more uniform cost of service within a customer class since utilities develop costs using aggregated loads.
+ SCE's distribution capacity cost allocators for this GRC cost of service analysis are, by necessity, a stylized version of the allocation factors that SCE uses in their ratemaking filings.

5.1.1.1 Relationship between Marginal Cost and GRC Cost of Service

The GRC cost of service assigned to each account starts with estimates of the marginal cost revenue responsibility (MCRR) of serving the account. MCRR is the product of the utility marginal costs multiplied by each account's costing determinants. Costing determinants include an account's hourly energy usage, its peak demand coincident with generation, transmission or distribution peaks, and its maximum demand. E3 worked with each utility to reproduce their GRC methods as closely as possible. Citations of utility data responses used for this analysis are contained in the full cost of service Appendix.

The larger the MCRR for an account, the larger the share of GRC costs that are assigned to the account, all other things being equal. This is why the costing scenarios discussed in the next section can affect the GRC cost of service and the full cost of service for each account.

The fact that MCRR is only used to determine shares of costs highlights another important caveat with this analysis. The scope of work and budget for the NEM full cost of service analysis only allowed for the data collection and estimation of full cost of service results specific to NEM accounts. To fully understand how NEM customers fit into the GRC revenue allocation process, it would be necessary to calculate the MCRR for all utility accounts, including non-NEM accounts. For this analysis, we are forced to assume that 2011 usage and the proxy methods used herein would have resulted in the exact same MCRR for all other non-NEM accounts.

5.1.1.2 Scenarios

As with the avoided cost analysis, we conducted scenario analyses for the full cost of service comparison to customer bills. Of particular uncertainly was whether certain cost components should reflect the account's gross load (prior to any load reduction from distribution generation) or net load (effective load that reflects lower utility purchases, or even negative usage due to distributed generation). For costs that are incurred when a quantity is used, the net load is appropriate. However, for costs that are incurred based on potential, and not necessarily based on actual usage, then gross loads may be appropriate.

At the one end of the spectrum, marginal energy costs are a function of the market prices in the aggregate California or wider western markets, and are incurred on an "as used" basis. E3 estimates marginal energy costs for NEM accounts using net loads.

Marginal generation costs are incurred at the aggregate utility net peak demand level. Utilities plan for aggregate net peak loads and E3 believes that the diversity of DG output is sufficient at the system level to warrant use of the net account load for generation capacity cost estimation.

At the other end of the spectrum, secondary distribution equipment is sized for the maximum demand that a customer *could* impose. E3 estimates marginal secondary costs using gross loads for each account.

For the other capacity components (transmission, subtransmission, distribution, primary, and primary-new business), the level of DG diversity and utility planning practices are less clear.

Therefore, we evaluate three cases. The base case reflects the assumptions made by the utilities in their respective GRCs and is therefore called the 'Utility' case. A low case which calculates the cost of service assuming more components full cost of service would be allocated on net consumption, and a high case which calculates the cost of service assuming more components are based on gross consumption. Note that the 'Utility' case is very similar to the high case in this analysis.

Table 44: Full Cost of Service Scenario use of Net or Gross Loads

Marginal Cost Category	No NEM DG Case	Low Case	Utility Case	High Case
Generation Energy	Gross	Net	Net	Net
Generation Capacity	Gross	Net	Net	Net
Transmission (SCE)	Gross	Net	Net	Gross
Transmission (PG&E and SDG&E)	Gross Bill Pass-Through	Net Bill Pass-Through	Net Bill Pass-Through	Net Bill Pass-Through
Subtransmission (SCE)	Gross	Net	Gross	Gross
Distribution (SCE and SDG&E)	Gross	Net	Gross	Gross
Primary Distribution (PG&E)	Gross	Net	Gross	Gross
Primary New Business (PG&E)	Gross	Net	Gross	Gross
Secondary Distribution (PG&E)	Gross	Gross	Gross	Gross
Customer Cost	Gross	N/A	N/A	N/A

Net load is the account's hourly usage after it has been reduced by the DG output. Gross load is the account's hourly usage absent the DG. Net Load = Gross Load - DG Output.

5.1.1.3 Truing-Up to Utility Revenue Requirements

The revenue allocation process must ultimately reconcile to the utility CPUC jurisdiction revenue requirement. The standard way to achieve that in California is through the use of an Equal Percentage of Marginal Cost (EPMC) multiplier. The EPMC multiplier equals the utility revenue requirement divided by the sum of the MCRRs for all customer groups for the utility.

Each utility has separate EPMC factors for (1) generation (generation energy and capacity), and (2) subtransmission distribution and customer-related costs. Transmission is addressed in separate FERC proceedings, so there is no EPMC factor for transmission. The full cost of service for each customer group starts with the sum of the product of the MCRRs for each customer group multiplied by the respective EPMC multiplier.

E3 then adds costs for the bill components that are incremental to the utility revenue allocation process, as well as incremental utility cost associated with providing service to customer with renewable distributed generation. The complete formula for the full cost of service for customer "c" is shown below. Note that not all cost components will apply to all utilities.

Full Cost of Service$_c$ = (Gen Energy MCRR$_c$ + Gen Capacity MCRR$_c$)*EPMC$_{Gen}$

+ Transmission (PG&E and SDG&E is in Regulatory Items)

+ (SubTran MCRR$_c$ + Dist MCRR$_c$ + Primary MCRR$_c$ + Primary New Business MCRR$_c$ + Customer MCRR$_c$) * EPMC$_{Dist}$

+ Regulatory Items$_c$

+ Incremental Utility Costs$_c$

5.1.2 REGULATORY ITEMS

The rates of each utility also include regulatory-related costs and fees that are not included in the revenue allocation process. The costs are calculated using the 2011 tariff rates and customer loads, and they vary slightly for each IOU. The full list of regulatory items added to the full cost of service is presented below.

Table 45: Regulatory Items Added to Full Cost of Service

Utility	Regulatory Items
PG&E	• Nuclear Decommissioning, • Public Purpose Programs • Competition Transition Charge • New System Generation Charge • Energy Cost Recovery Amount • Department of Water Resources Bond Charges • Transmission
SCE*	• Transmission non-bypassable • Distribution non-bypassable • New System Generation Charge • Nuclear Decommissioning Charge • Public Purpose Programs • Department of Water Resources Bond Charges • PUC reimbursement Fee
SDG&E	• Public Purpose Programs • Nuclear Decommissioning • Ongoing Competition Transition • Reliability Services • Total Rate Adjustment Component • Department of Water Resources Bond Charges • Transmission

** Some of the SCE items are not shown separately in the SCE tariffs. Those items can be found the full cost of service appendix.*

5.1.3 INCREMENTAL UTILITY COSTS

The installation of renewable generation imposes additional capital and ongoing costs onto the utility that are not paid for by the renewable generation owner. These additional costs are added to the full cost of service estimate for each account. See Section 4.4 for further discussion of these costs.

5.2 Full Cost of Service Results

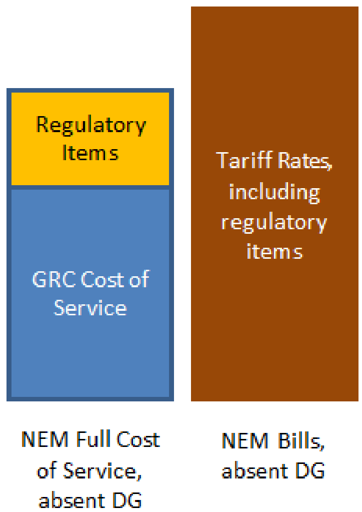
5.2.1 FULL COST OF SERVICE AND BILLS, ABSENT DG

Once the full cost of service is calculated for the NEM accounts, the next step is to compare those costs to the utility bills that customers would receive. In order to provide some perspective on the NEM account results, it is useful to first compare bills and full cost of service for those accounts ***absent the installation*** of DG (Gross usage). By examining the bill and full cost of service results of NEM account gross usage, we can identify the extent to which the accounts would have exhibited differences if the NEM system did not exist. Again, some of the differences will also be due to not being able to calibrate the full cost of service results for all customers using 2011 data.[25] Nevertheless, the starting differences, regardless of their cause, provide important reference points for the evaluation of NEM impacts.

As shown in Figure 24, the full cost of service is composed of the GRC cost of service for the account, based on 2011 gross usage, plus the cost of regulatory items that are included in the tariffs but not allocated in the GRC cost of service process. The bill is simply the product of the tariff rates and the 2011 NEM account gross usage. Regulatory items are already included in the tariff rates, so there is no need to add them separately to the bill.

[25] Because a cost of service study involves the allocation of utility revenue requirements based on customer costs, it is necessary to estimate the costs for all customers (NEM and non-NEM customers) to provide the most accurate results. This type of analysis would have been extensive, and would have required more time and budget than allotted in this study.

Figure 24: Comparison of Full Cost of Service and Utility Bills (Gross Usage)



Because of the differences between the ways that cost are incurred and assigned in the GRC cost of service process, and the methods by which customers are billed (tiered rates, seasonal demand charges, facilities demand charges, customer charges, etc.), it would only be by coincidence that any account would have a bill that exactly matches its full cost of service.

Comparisons of full cost of service and bills for 2011 NEM account gross usage are shown in Table 46 and Table 47. A positive value in Table 46 indicates that the estimated bills are greater than the estimated full cost of service for that sector in aggregate. The table shows that, absent DG, all of the NEM account sectors would receive bills that exceed their full cost of service.

Table 46: Aggregate Bill Payments Above Full Cost of Service for NEM Customers– No DG Case (1,000$)

	PG&E	SCE	SDG&E	All IOUs
Residential	$75,368	$19,480	$170	$95,018
Non-Residential	$42,082	$9,358	$28,187	$79,626
Average	$117,449	$28,838	$28,357	$174,644

Table 47 shows the total bills divided by the total full cost of service for each sector. For example, a value of 110% indicates that the sector is estimated to have bills that are 10% greater than the sector's full cost of service. Again, the results indicate that all of the sectors have aggregate total bills in excess of the full cost of service for gross usage. In other words, before installing DG, the NEM participants in aggregate were likely[26] paying bills that exceeded their full cost of service.

Table 47: Percent of Cost of Service Recovery from NEM Customers – No DG Case

	PG&E	SCE	SDG&E	All IOUs
Residential	171%	152%	101%	154%
Non-Residential	128%	110%	124%	122%
Total	146%	122%	119%	133%

The difference between gross bills and full cost of service for SDG&E residential NEM accounts is partly explained by the difference in average rates between the gross NEM accounts and the average SDG&E residential account. Looking at schedule DR Domestic accounts, the gross NEM Accounts have 61% higher

[26] We qualify this statement because of the caveats discussed in section 5.1.1.

average usage, and a 3% higher average rate than the average SDG&E DR Domestic customer. The higher than average rate is due to the inclining tier residential rates.

Higher average usage also explains part of the PG&E and SCE residential gross NEM account results. For both the PG&E E-1 and SCE Domestic residential NEM account, gross usages are almost twice the schedule average. This higher than average usage translates to PG&E E-1 and SCE Domestic gross NEM account average rates that are 30% and 16% higher than the respective schedule averages.[27] Other differences between the gross bills and cost of service are due to variations between the participants and average customers on the other residential rate schedules, as well as the caveats for the full cost of service estimation process, as discussed in section 5.1.1.

Looking at the non-residential accounts, PG&E and SDG&E have gross bills substantially above the gross full cost of service. As with the residential accounts, some of the differences can be explained by differences between the NEM participants, even before any DG, and average customers. For example, SDG&E AL-TOU NEM accounts have gross usage that is far "peakier" than the average AL-TOU customer. Because there is a substantial non-coincident demand charge for this rate, the poor load factor of the NEM accounts results in average rates for gross usage that are far higher than the average AL-TOU account.

A less extreme example is PG&E's A-6 TOU schedule. Those customers are small commercial accounts that comprise a large portion of the non-residential NEM

[27] PG&E's gross NEM accounts have a higher deviation due to the 40.3 cent per kWh upper tier rate, compared to SCE's 30 cent per kWh upper tier rate.

population. The PG&E A-6 NEM participants have gross usage that is 11% higher than the schedule average during the most expensive summer peak and partial peak periods. The higher summer use may also result in somewhat higher cost of service, but the example does illustrate the differences between NEM participants and the average customer.

Ultimately, regardless of the reason for the difference between gross bills and gross full cost of service, it is important to keep those starting differences in mind when reviewing the full cost of service Utility Case results that are presented in the next section.

5.2.2 FULL COST OF SERVICE AND BILLS, UTILITY CASE RESULTS

The Utility Case analysis compares 2011 bills for the NEM accounts, net of the DG output (net usage), with the Utility Case full cost of service for the net usage of those accounts. As shown in Figure 25, the NEM account bill is based on the 2011 tariffs that include the regulatory items and NEM account net usage. The full cost of service is comprised of 1) the GRC cost of service, based on a combination of gross and net usage characteristics[28]; 2) the regulatory items based on net usage; and 3) incremental costs. The incremental costs are the additional costs imposed on the utilities to connect, integrate, and bill the NEM accounts.

[28] We refer to the base case as evaluating 2011 NEM account net usage. We use the term net usage (metered usage that is lower or negative because of DG self-generation) to distinguish the analysis from the evaluation of gross usage in the prior section. In performing the GRC cost of service analysis, however, some cost components are more correctly evaluated based on a customer's gross usage. Details on when gross usage and net usage are used in the GRC cost of service analysis are provided in Table 50 in Section 5.2.3 Sensitivity Analysis.

Figure 25: Comparison of Full Cost of Service and Utility Bills (Utility Case)

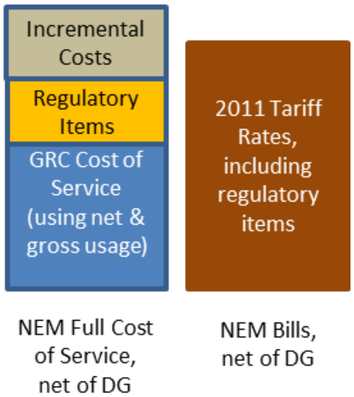


Table 48 shows the Utility Case results by utility and customer class. A positive result indicates that customers' bills are higher than their full cost of service. The full cost of service for PG&E and SDG&E NEM accounts is their estimated share of the total utility cost of service. The full cost of service for SCE NEM accounts is their estimated share of the corresponding class or rate schedule full cost of service.

Table 48: Aggregate Bill Payments above Full Cost of Service for NEM Customers - Utility Case (1,000$)

	PG&E	SCE	SDG&E	All IOUs
Residential	-$7,329	-$3,377	-$8,811	-$19,516
Non-Residential	$5,502	$3,468	$22,418	$31,389
Total	-$1,827	$92	$13,608	$11,872

The associated full cost of service recovery percentages are shown below. The percentages are aggregate annual customer bills in 2011, divided by the associated aggregate full cost of service.

Table 49: Percent of Cost of Service Recovery from NEM Customers - Utility Case

	PG&E	SCE	SDG&E	All IOUs
Residential	88%	86%	54%	81%
Non-Residential	106%	105%	122%	112%
Total	99%	100%	111%	103%

We find that, in aggregate, NEM customers pay amounts close to their full cost of service. In general, the non-residential accounts continue to see bills that substantially exceed their full cost of service. The percentage of exceedance remains relatively unchanged for SCE and SDG&E, while PG&E accounts see bills 22% closer to the full cost of service compared to the NEM accounts without DG.

The largest changes, however, occur within the residential sector. Just as the residential inclining tier rate structure resulted in NEM accounts paying bills that exceeded their full cost of service when they consumed more than the average residential customer, the same tier structure results in the NEM accounts paying less than their full cost of service when the NEM accounts consume less than the average residential customer. Table 50 summarizes the average monthly usage for the major residential rate schedules, and the corresponding gross and net usage of NEM accounts on those schedules. The table clearly demonstrates how the DG transforms the NEM accounts from larger-than-average to smaller-than-average customers. It should be noted that SCE residential accounts might also be paying less in aggregate than their full cost of service. Even though Table 49 shows that SCE residential NEM accounts are paying 102% of their full cost of service, because of all of the caveats discussed in section 5.1.1, the true number could easily be less than 100%.

Table 50: Residential Average Monthly Usage for Schedule Average and NEM Accounts (kWh/month)

	PG&E (E-1)	SCE (Domestic)	SDG&E (DR)
Schedule Average	538	522	545
NEM Gross Usage	1,068	1,111	876
NEM Net Usage	435	417	299

Finally, it is important to bear in mind that the comparison results are estimated based on 2011 bills and 2011 full cost of service. Over the life of the DG, however, weather patterns and utility cost causation factors (such as the timing of generation and transmission and distribution peaks, and the hourly pattern of energy prices) would change --- not to mention utility rate designs --- all of which would alter the results. Therefore, caution should be observed in extrapolating the snapshot 2011 results to conclusions regarding over or underpayment by NEM accounts over the lifecycle of the installed renewable distributed generation.

5.2.3 SENSITIVITY ANALYSIS

We perform a 'low case' and a 'high case' sensitivity analysis to capture a range of potential costs of service.

The "low case" sensitivity uses net distribution costs for cost of service calculation for all distribution cost components except for PG&E's secondary distribution cost component. The "high case" sensitivity considers more costs fixed, which increases the estimated cost of service of NEM customers. In the high cost sensitivity, we use the gross load profile to estimate the cost of service for transmission. This results in slightly higher full cost of service estimates for SCE.

Table 51: Aggregate Bill Payments Above Full Cost of Service for NEM Customers - Low Case (1,000$)

	PG&E	SCE	SDG&E	All IOUs
Residential	$1,108	-$3,192	-$8,156	-$10,240
Non-Residential	$15,191	$5,170	$25,242	$45,603
Total	$16,299	$1,978	$17,086	$35,363

Table 52: Percent of Cost of Service Recovery from NEM Customers - Low Case

	PG&E	SCE	SDG&E	All IOUs
Residential	102%	86%	56%	89%
Non-Residential	117%	108%	126%	118%
Total	111%	102%	115%	110%

Using this conservative cost of service specification, the SCE percent cost of service recovery increases by about 2 percentage points, SDG&E percent cost of service recovery increases by about 3 percentage points, and PG&E's increases by about 13 percentage points.

The results of the "high case" sensitivity are presented below. For the High Case, the only change in assumptions relative to the Utility Case is the use of gross transmission for determining SCE capacity costs.

Table 53: Aggregate Bill Payments Above Full Cost of Service for NEM Customers - High Case (1,000$)

	PG&E	SCE	SDG&E	All IOUs
Residential	-$7,329	-$5,198	-$8,811	-$21,337
Non-Residential	$5,502	$129	$22,418	$28,050
Total	-$1,827	-$5,068	$13,608	$6,712

Table 54: Percent of Cost of Service Recovery from NEM Customers - High Case

	PG&E	SCE	SDG&E	All IOUs
Residential	88%	79%	54%	80%
Non-Residential	106%	100%	122%	111%
Total	99%	94%	111%	102%

The change in the treatment of SCE transmission costs reduces the percent cost of service recovery by six percentage points. It is notable that the direction of whether NEM customers pay their full cost of service, on average, reverses with the slight change in the cost of service specification for SCE in the high case.

5.2.4 MEDIAN ANALYSIS

While the aggregate cost of service analysis estimates the mean total cost of service recovery from all NEM customers in 2011, it is important to note that these results may be disproportionately driven by a small number of customers with extreme discrepancies between bills and cost of service. This section explores the cost of service results for the median NEM customer. Combined with the aggregate analysis, the median results provide further insight into the distribution of cost of service recovery by NEM customers.

Absent NEM generation, the distribution of cost of service recovery is fairly symmetric. The bills of the median NEM customer are about 32% greater than the cost of serving that customer, while the bills of the average (mean) NEM customer are about 33% greater than cost of service. Without NEM generation, approximately 76% of NEM customers are overpaying their cost of service. Table 55 displays the breakdowns of mean and median percentage cost of service recovery by utility and customer class.

Table 55: Percent of Cost of Service Recovery from Mean and Median NEM Customers – No DG Case

	PG&E		SCE		SDG&E		All IOUs	
	Mean	Median	Mean	Median	Mean	Median	Mean	Median
Residential	171%	124%	152%	127%	101%	157%	154%	131%
Non-Residential	128%	141%	110%	141%	124%	124%	122%	138%
Total	146%	131%	122%	129%	119%	157%	133%	132%

With NEM generation, the distribution of full cost of service recovery from NEM customers differs significantly from the mean, with most customers not recovering their cost of service and a few customers grossly overpaying their cost of service. As shown in Table 56, the median NEM customer's annual bill is only 57% of the cost of serving that customer. Approximately 78% of NEM customers pay less than their cost of service. Nevertheless, as discussed in Section 5.2.2, NEM customers as a group pay their cost of service. This aggregate result is driven by a minority of large, non-residential NEM customers who significantly overpay their cost of service.

Table 56: Percent of Cost of Service Recovery from Mean and Median NEM Customers – Utility Case[29]

	PG&E		SCE		SDG&E		All IOUs	
	Mean	Median	Mean	Median	Mean	Median	Mean	Median
Residential	88%	57%	86%	57%	54%	53%	81%	57%
Non-Residential	106%	58%	105%	63%	122%	70%	112%	58%
Total	99%	57%	100%	58%	111%	56%	103%	57%

While the average percentage cost of service recovery varies considerably by utility and customer class, the median results remain fairly constant across utilities and customer classes. The median residential customers at the three IOUs pay between 53% and 57% of their cost of service, and the non-residential customers pay between 58% and 70% of their cost of service.

[29] With customers for whom both cost of service estimates and total annual bill estimates are negative, percent cost of service recovery is calculated as the ratio of cost of service to bills.

6 Avoided Public Purpose and Other Charges

6.1 Methodology

Pursuant to Commission D.03-04-030, NEM customer generation is exempt from certain non-bypassable public purpose charges. In order to calculate the avoided public purpose charges for NEM customers, we simply multiplied the change in customer consumption as a result of NEM generation by the applicable public purpose charge in each rate for all NEM customers. This bill saving is a portion of the total bill savings presented in the cost-benefit analysis section.

6.2 Results

We find that in 2020, with a complete deployment of systems to the NEM cap, NEM customers avoid approximately $142 million in public purpose charges. In comparison, the total public purpose charges for the three IOUs were approximately $2 billion in 2012.[30] Adjusting for escalation (assuming public

[30] SCE 2012 GRC $890 million, PG&E 2011 GRC $936 million, SDG&E 2008 GRC $129 million of public purpose charges.

purpose charges increase at the same rate as we forecast for retail rates),[31] the reduction in collected public purpose charges is forecast to be approximately 1.4% at current NEM subscription, growing to 6.3% of the total public purpose funding at full subscription to the NEM cap.

Table 57: Bill Savings in Public Purpose Charges from NEM in 2020 ($ Million/year) – All Generation

	2012 Snapshot	Full CSI Subscription	Full NEM Subscription
Residential	$15	$21	$66
Non-Residential	$17	$48	$76
Total	$32	$69	$142
Total as % of Total Public Purpose Charges	1.4%	3.1%	6.3%

Public Purpose Charges represent a share of the total bill savings. The following tables show the portion of total bill savings by component. Table 58 and Table 59 show the breakdown of bill savings by component for residential and non-residential customers. Both tables show these results for the All Generation case in millions of dollars in 2020.

[31] Public purpose charges forecast to be $2.65 billion in 2020.

Table 58: Residential Bill Savings in 2020 by Rate Component (M$/year)

	2012 Snapshot	Full CSI Subscription	Full NEM Subscription
Generation and Other Non-Specified Charges	$143	$202	$631
Transmission	$15	$20	$61
Distribution	$102	$140	$426
Public Purpose Charge	$15	$21	$66
Nuclear Decommissioning Fund	$1	$1	$2
Competitive Transaction Charge	$8	$11	$36
Energy Cost Recovery	$3	$4	$10
DWR Bond Charge	$5	$8	$24
CPUC Surcharge	$0	$0	$1
CEC Surcharge	$0	$0	$1
CARE Surcharge	$7	$9	$27
Net Surplus Compensation	$1	$1	$4
Total	$299	$416	$1,289

Table 59: Non-Residential Bill Savings in 2020 by Rate Component (Millions $/year)

	2012 Snapshot	Full CSI Subscription	Full NEM Subscription
Generation and Other Non-Specified Charges	$116	$365	$522
Transmission	$11	$28	$45
Distribution	$57	$159	$244
Public Purpose Charge	$18	$53	$80
Nuclear Decommissioning Fund	$1	$1	$2
Competitive Transaction Charge	$8	$23	$35
Energy Cost Recovery	$3	$6	$13
DWR Bond Charge	$7	$23	$34
CPUC Surcharge	$0	$1	$2
CEC Surcharge	$0	$1	$2
CARE Surcharge	$9	$23	$37
Net Surplus Compensation	$1	$4	$7
Total	$232	$688	$1,022

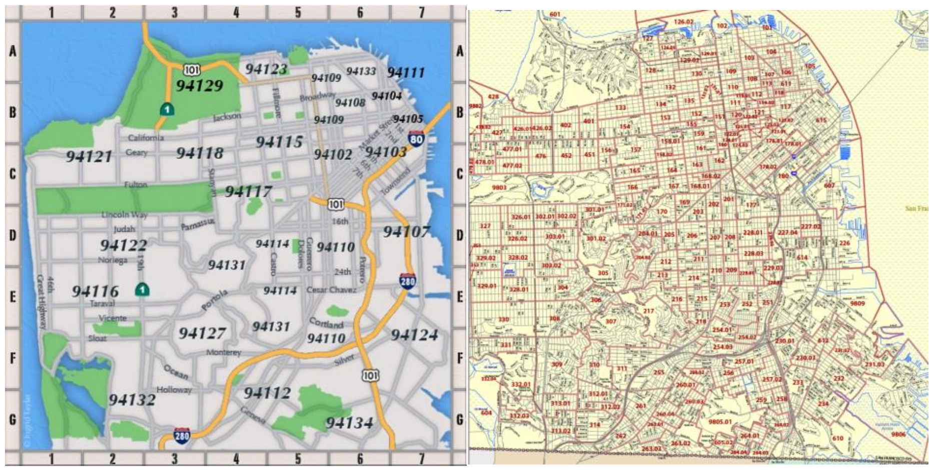
7 Household Income of NEM Customers

7.1 Methodology

In this analysis, we estimate the household incomes of NEM participants and compare them to non-NEM IOU customers and Californians overall. Income estimates of California Solar Initiative (CSI) participants, which are the vast majority of NEM customers, are currently reported on the Go Solar Website as well as in the California Solar Initiative Annual Report.[32] These estimates are computed using median household incomes by zip code. In this study, we make a significant update to the prior methodology by performing the analysis using census tract and more granular data from the 2010 US Census, rather than zip codes used in the current public reporting. The census tracts are much smaller geographic areas than those represented by zip code, and they are selected to have more homogenous demographics. Therefore, a census tract approach provides a more accurate estimate of NEM customer household income and has significantly different results.

[32] http://www.cpuc.ca.gov/NR/rdonlyres/0C43123F-5924-4DBE-9AD2-8F07710E3850/0/CASolarInitiativeCSIAnnualProgAssessmtJune2012FINAL.pdf

Figure 26: A Map of San Francisco Labeled at the Zip Code Level (left) and Census Tract Level (right)



7.2 Results

For residential sector NEM systems, we find that the customers installing NEM systems system since 1999 have an average household income based on 2010 census tract data of $91,210, compared to the median income in California and in the IOU service territories of $54,283 and $67,821, respectively. The median income of our population of NEM customers is about 68% greater than the median California household income and about 34% greater than the median household income of IOU customers. We find that the relative income gap between those customers that installed NEM generation to those that have not has remained consistent since approximately 2005.

Figure 27 shows the average of 2010 median household incomes for customers who installed NEM generation over time and compares to the median 2010 household income of all IOU customers and statewide. As is portrayed below, the average median household income of customers installing NEM systems was about 30% to 40% higher than that of the general IOU customer population in 1999. As the NEM program developed and the number of new customers rose, the household income differential income peaked at 43% in 2007, but has shown a gradual decline to around 34% in 2011.

Figure 27: NEM 2010 Household Income by Installation Year Compared to IOU and California Median Income