California Public Utilities Commission

Introduction to the Net Energy Metering Cost Effectiveness Evaluation

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Prepared by
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Energy Division
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Technical Report by
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Introduction to Net Energy Metering (NEM) Cost-Effectiveness Evaluation

The California Public Utilities Commission (CPUC) hired Energy and Environmental Economics, Inc. (E3) to perform an analysis of the costs and benefits of net-energy metering (NEM) in compliance with Public Utility (PU) Code 2827 (c)(4), which requires the CPUC to "submit a report to the Governor and the Legislature on the costs and benefits of net energy metering." The *NEM Cost Effectiveness Evaluation* attached to this **Introduction to the Net Energy Metering Cost Effectiveness Evaluation** was prepared by E3, under the direction of the CPUC's Energy Division to fulfill this statutory mandate.

NEM is an electricity tariff billing mechanism, and its principal benefit is that it facilitates customers installing distributed generation (DG). Without NEM, some customers could be hesitant to install DG since a facility would receive no compensation for generation that may be exported to the grid at times when there is no simultaneous energy demand to utilize the DG generation onsite. For small customers, particularly residential customers, this could occur with some frequency. Another benefit of NEM is that it allows DG systems to be sized efficiently. Without NEM, customers are compelled to undersize DG systems relative to their total electrical load or their electrical bill to ensure they always use the DG output and to avoid any uncompensated electricity export. NEM provides customers a tremendous 'peace of mind' knowing that exports either will offset their consumption at other times or produce a bill credit that can be applied in the next billing cycle. NEM allows an intermittent DG resource, such as wind or solar, to be sized larger than "minimum load" so that annual generation can be matched to total annual electrical demand at the site, optimizing the economic value of the DG investment. For clarity, Appendix A attached to this Introduction presents a sample NEM bill with a detailed explanation of the elements as it appears on PG&E's website. This illustration graphically depicts the complexity involved in NEM billing.

While NEM clearly facilitates the development of DG resources in California, the attached *NEM Cost Effectiveness Evaluation* does not attempt to quantify the value of the DG resources overall. This report focuses on the quantifiable incremental costs and benefits associated with the NEM mechanism: (1) The costs are quantified in terms of bill credits calculated based on each customer generator's retail rate and the incremental billing costs associated with NEM; and (2) The benefits are quantified as the avoided costs of energy and capacity procurement.

The report does not compare the world "with NEM" to the world "without NEM," nor does it attribute to NEM as a benefit the role of the NEM tariffs in bringing DG resources online. Later this year, the CPUC will release two reports on the costs and benefits of DG overall: one focusing on solar and the other focusing on other ratepayer-funded DG technologies. These more comprehensive reports will include the NEM cost and benefit analysis as one consideration, but they will also take a broader view of the cost-effectiveness of the wide range of policies and programs that support DG.

Summary of Key Highlights

The key highlights of the report are summarized below, with more detailed descriptions following:

1. The report provides a measure of the total net costs to ratepayers from solar customers participating in the solar NEM tariffs, which until this point had not been estimated. This analysis also does not measure the overall cost-effectiveness of solar photovoltaics (PV) as an energy resource, but consistent with PU Code 2827 (c)(4), isolates and evaluates simply the direct costs and benefits of NEM.
2. The report estimates that on a lifecycle basis, all PV generation on NEM tariffs (386 megawatts (MW) installed through 2008) will result in a net present value cost to ratepayers of approximately $230 million over the next 20 years, or approximately $20 million per year on an annualized basis. The total net cost of NEM is less than one-tenth of one percent of total utility revenue. NEM as a policy is one small part of the utility's demand side efforts, which overall represent 7 percent of the average residential bill and provide a net savings to ratepayers.
3. The report estimates that the average net cost of NEM is $0.12 per kilowatt-hour (kWh)-exported, which is relatively high on a cents per kWh basis; however, NEM is not designed as an energy procurement program. Rather, it is a billing mechanism to facilitate customer generation. Further, the volume of energy exported to the utilities is small compared to the total solar generation and it is *de minimus* compared to the total energy procured by the utilities.
4. From the perspective of a customer who has invested in solar, the report demonstrates that NEM represents an ongoing and additional incentive equivalent to approximately $0.88 per watt (on average, and on a net present value basis) in addition to any rebates or incentives received under the California Solar Initiative (CSI).
5. The report includes several sensitivity analyses that indicate potential areas for further policy study, including the costs associated with NEM billing and NEM interconnection.
6. The report uses a robust methodology for estimating the costs and benefits of the NEM mechanism.
7. The report highlights a number of research and policy issues that merit further study and possible Commission action.

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. The Energy Division initiated the contract process in the fall of 2008, but the contracting process was delayed for several months in the spring of 2009 due to overall state budget conditions. E3 was selected based on a competitive bidding process and commenced work in the summer of 2009. The initial work was to finalize the project methodology and issue data requests to the utilities for key project data.

In November 2009, the Energy Division hosted a well-attended workshop where E3 consultants previewed the methodology and scope of the attached report. While the schedule did not allow for parties to comment formally on a draft of the report, the Energy Division plans to work with the Assigned Commissioner's office and Administrative Law Judge to invite parties to provide comments on this report as part of the ongoing Measurement and Evaluation program for the CPUC's CSI and DG programs. This analysis may be refined and repeated in future study years, and this study would particularly benefit from additional data (especially solar system performance data) that might become available as the result of other ongoing solar program evaluation efforts.

The Energy Division prepared an earlier NEM report in March 2005.[1] The current report is a more comprehensive effort to quantify the costs and benefits of NEM to utility ratepayers. The report includes general information and background on NEM, as well as a detailed analysis of the value of the energy exported to the grid by these systems. This report does not attempt to quantify the benefits to society of NEM as part of the comprehensive offerings of policies and programs that support clean distributed energy resources like solar PV, although significant environmental, public health and other non-energy benefits may accrue from solar generation associated with NEM.

Solar is Primary Focus of the Report

The report focuses exclusively on the NEM billing mechanism, which had enrolled over 40,000 utility customers installing 386 MW of distributed generation by the end of 2008. This generation represents a significant contribution to California's energy portfolio, as well as enabling progress towards the state's long-term renewable energy and GHG-emission reduction goals. The vast majority of customers on NEM tariffs (99 percent) had solar PV installed. Customers with fuel cells, biogas, wind, and hybrid technologies make up the remaining 1 percent. This NEM report focuses exclusively on the NEM solar customers since they comprise the bulk of the program, and are the systems for which the most generation and load data is currently available. The report estimates total 2008 gross generation at 580 GWh, including 250 GWh from residential NEM customer sites and

[1] See CPUC, March 2005, "Update on Determining the Costs and Benefits of California's Net Metering Program as Required by Assembly Bill 58". http://docs.cpuc.ca.gov/WORD_PDF/REPORT/45133.PDF.

more than 320 GWh from commercial sites.[2]

Solar PV installations not on NEM tariffs are excluded from this report. The CPUC staff recently reported that as of September 2009, 245 solar PV installations in IOU services areas representing over 43 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]

Key Highlights

The following highlights and key issues arise from the review of this report:

1. **The report provides a measure of the total net costs to ratepayers from solar customers participating in the solar NEM tariffs, which until this point had not been estimated. This analysis also does not measure the overall cost-effectiveness of solar photovoltaics (PV) as an energy resource, but consistent with PU Code 2827 (c)(4), isolates and evaluates the direct costs and benefits of NEM.**

The NEM analysis focuses exclusively on the costs and benefits to ratepayers from the existence of NEM as a billing mechanism. The NEM solar customers receive bill credits (at a cost to ratepayers), the utility incurs billing costs associated with NEM (at a cost to ratepayers), and the utility receives exported NEM generation (which is a benefit to ratepayers in that it allows the utility to avoid the cost of otherwise procuring that generation). The NEM analysis does not consider the costs and benefits associated with non-exported solar generation that is used to offset the customer's onsite coincident load because those costs and benefits would exist even in the absence of the NEM tariffs.

The NEM analysis presented herein is one step in the larger context of CPUC's DG cost-effectiveness evaluations. The NEM cost-effectiveness study is a more narrow undertaking than the forthcoming cost-effectiveness evaluations. As part of the California Solar Initiative (CSI) and Self Generation Incentive Program (SGIP) Measurement and Evaluation programs, the CPUC is overseeing the preparation of additional reports on the overall cost-effectiveness of the solar and non-solar DG incentive programs. The forthcoming reports will follow the cost-benefit methodology for the evaluation of DG adopted by the CPUC in Decision (D.) 09-08-026. Solar PV generation has many additional costs (e.g. upfront incentives, system purchase, installation, and maintenance costs) and benefits (e.g. market transformation effects, *avoided cost* benefits for the energy that is *not* exported but rather directly offsets loads) that are not a direct effect of the NEM tariff billing mechanism and therefore are not measured by this cost-benefit analysis.

2. **The report estimates that on a lifecycle basis, all PV generation on NEM tariffs (386 megawatts (MW) installed through 2008) will result in a net present value cost to**

[2] E3's energy generation estimate is based on application of generation capacity factors to the weighted average 2008 capacity for each generation technology. See Table 10, Page 16 of the report for details.

[3] CPUC October 2009 Staff Progress Report, Table 7, page 15. http://www.cpuc.ca.gov/PUC/energy/Solar/091021_staffprogressreport.htm

ratepayers of approximately $230 million over the next 20 years, or approximately $20 million per year on an annualized basis. The total net cost of NEM is less than one-tenth of one percent of total utility revenue. NEM as a policy is one small part of the utility's demand side efforts, which overall represent 7 percent of the average residential bill and provide a net savings to ratepayers.

The NEM report demonstrates that the net total cost to ratepayers is approximately $20 million per year. The NEM analysis considers the total cost of all solar PV generation installed through 2008 on a net present value basis (i.e. all of the costs that will ever be incurred over the next 20 years as a result of the cumulative total generation that was installed through 2008 were captured in this report). Of all the bill impacts from bill credits provided for exported generation modeled in the report, about 1 percent of the total bill impacts would result from estimated compensation from the future implementation of AB 920 (Huffman, 2009), which modified PU Code 2827 to allow customer generation in excess of total annual load to be credited and rolled over into subsequent years.[4]

Net NEM costs for installations through 2008 total approximately 0.08 percent of total utility revenues on an annual basis. Given an overall average rate of $0.144 per kWh, this implies an average rate impact of $0.00011 per kWh is necessary to cover NEM costs.[5] Figure 1 shows the Energy Division's analysis of the average monthly residential bill for each of California's large utilities, including the portion to cover NEM. All of the demand side programs collectively account for 7 percent of the average customer's residential bill. NEM is included in the chart but represents such a small percentage of the bill (less than one-tenth of 1 percent of the total bill) that it is not clearly visible. Figure 2 shows the total cost and associated savings of just the demand side programs. When shown relative to just the other demand side program costs, NEM is more visible, but provides a small fraction of the total costs of the demand side programs. Overall, the demand side programs provide a net benefit to ratepayers.

While the cost of NEM is currently a small part of total bill and a small part of the overall cost of demand side programs, the absolute cost of NEM will continue to grow as the number of customers on NEM tariffs continues to grow. If the total installed capacity of NEM solar generation reached 2,550 MW of solar capacity by 2017 to reach the CSI related goals within the areas of the investor-owned utilities, the total cost of the program would be approximately $137 million per year (in 2008 dollars). This total cost would be approximately 0.38 percent of projected IOU revenues in 2020, which would imply an average rate impact of $0.00395 per kWh in 2020.[6]

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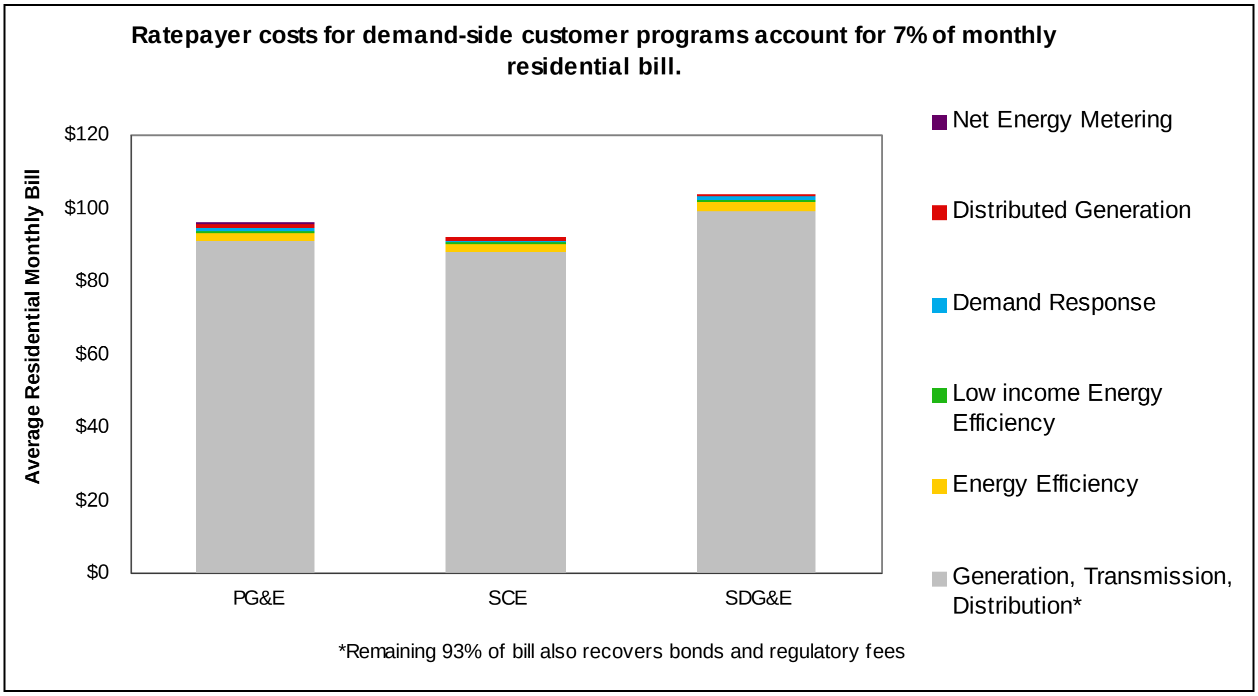
[4] AB 920 is not yet implemented at the CPUC, but for the sake of the report, this analysis assumes that the CPUC sets the Net Surplus Compensation rate at the "avoided cost." The CPUC will set the actual compensation rate in a ratemaking proceeding.

[5] The total revenue and average rate figures are taken from the Reference Case from the GHG Modeling, released November 13, 2009. The GHG Modeling Report and GHG Calculator are available at http://www.ethree.com/CPUC_GHG_Model.html.

[6] This calculation multiplies the 2008 NEM costs by the ratio of NEM solar generation when CSI is fully subscribed (2,550 MW) to current NEM solar generation (365 MW, see Table 12). The 2020 estimate of 2,550 MW is made up of 2,300 MW from CPUC CSI goals as well as California Energy Commission's New Solar Homes Partnership goals for investor-owned utilities, plus approximately 250 MW of solar PV installed in investor-owned utility

The report demonstrates that residential customers comprise the bulk of costs under the NEM mechanism. However, this result is partially an artifact of the fact that residential customers pay higher rates than commercial customers. In addition, there is a wide distribution of NEM costs on a per customer basis. Not every residential or commercial NEM customer represents a net cost (some are actually a net benefit), but there are a few customers that represent high costs. The majority of NEM customers represent net NEM costs of less than $277 per NEM customer per year. A small number of customers drive up the average NEM cost per customer to more than $508 per NEM customer per year.

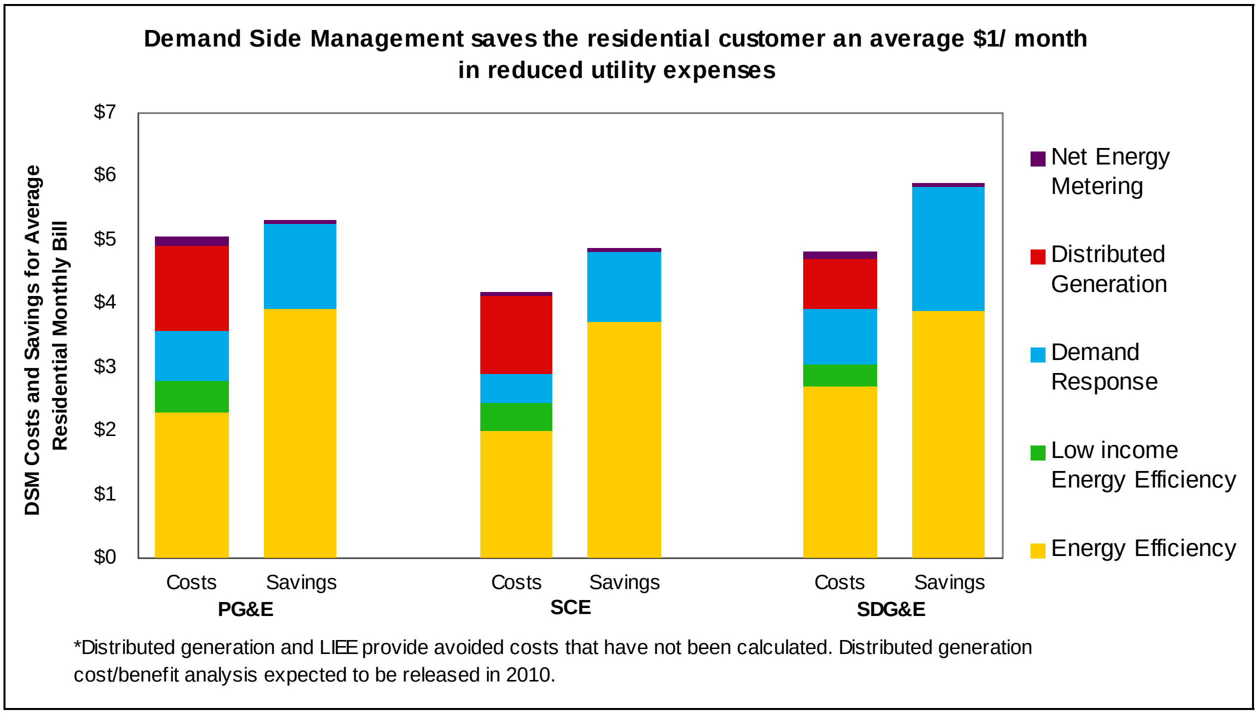
Figure 1. Demand Side Programs as a Percentage of Average Residential Bill



Source: CPUC Energy Division

territories prior to the CSI program that qualify for NEM. The remainder of the overall 3,000 MW goal from Senate Bill (SB) 1 (Murray, 2006) is made up of targets for the publically owned utility portions of the program.

Figure 2. Demand Side Program Costs and Savings for Average Residential Monthly Bill



Source: CPUC Energy Division

3. **The report estimates that the average net cost of NEM is $0.12 per kilowatt-hour (kWh)-exported, which is relatively high on a cents per kWh basis; however, NEM is not designed as an energy procurement program. Rather, it is a billing mechanism to facilitate customer generation. Further, the volume of energy exported to the utilities is small compared to the total solar generation and it is *de minimus* compared to the total energy procured by the utilities.**

The levelized net total cost of NEM is the net cost over the life of the program on a $ per kWh exported basis, and only reflects the energy exported and not the energy consumed onsite by the customer. The levelized net total cost of the program is approximately $0.12 per kWh-exported. However, NEM customers only export a minority of electricity generation; NEM customers receive 75 percent of their benefits from direct offset of their on-site energy use and just 25 percent of their benefits from NEM related bill credits.

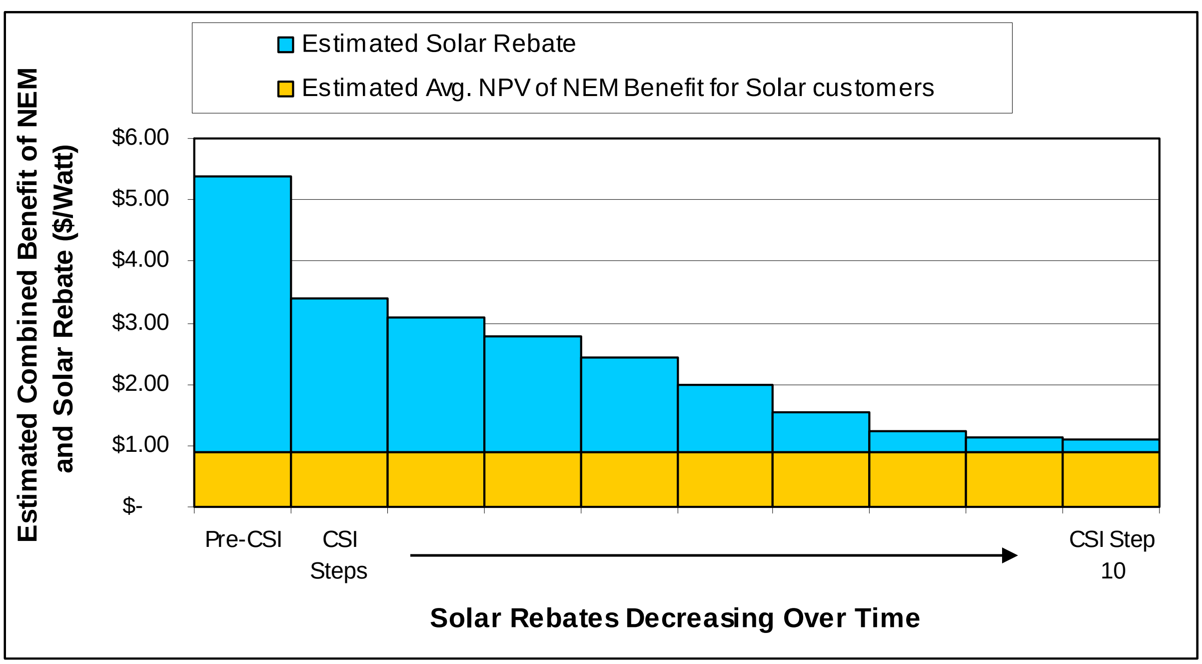
Further, the total volume of kilowatt-hours exported under NEM is small. On the other hand, NEM is a critical mechanism to facilitate the installation of onsite generation designed primarily to offset a customer's own load, allowing a customer to size their generation in an economically-optimal manner. NEM may stimulate the installation of more solar PV (as well as other forms of DG) than would be the case if the exported energy were uncompensated or compensated at a lower rate. The report does not attempt to measure this effect.

Finally, while the total net cost of NEM is $0.12 per kWh-exported, the report demonstrates that there is a distribution of $ per kWh-exported, with some small amount of exports representing a net benefit. Under NEM, more than 50 percent of electricity exported under the program has a cost of $0.08 per kWh-exported. The distribution of costs on a $ per kWh basis is wider across residential customers than across commercial customers because residential rate structures have a wider distribution.

4. **From the perspective of a customer who has invested in solar, the report demonstrates that NEM represents an ongoing and additional incentive equivalent to approximately $0.88 per watt (on average, and on a net present value basis) in addition to any rebates or incentives received under the California Solar Initiative (CSI).**

In June 2009, the CPUC staff estimated the total solar PV project costs before incentives ranged between $8.14 per watt for large commercial installations and $9.41 per watt for residential and small commercial installations. CSI incentives currently range from $1.10 per watt to $2.30 per watt on an installed capacity basis, depending on the type of the installation. The report estimates that the total benefits paid to a customer over the lifetime of the installation would be equivalent to approximately $0.88 per watt (on a net present value basis). Figure 3 illustrates the estimated combined value of the declining solar rebates and the upfront equivalent of the NEM benefit. The figure shows that NEM is a small portion of the total incentive for systems that installed in the early CSI steps, but it becomes increasingly significant as the rebates decline towards zero. Although shown on a net present value (NPV) basis, the figure is only hypothetical because while the solar rebate is essentially paid upfront, the NEM benefit is paid over the whole lifetime of the system.

Figure 3. Estimated Combined Benefit of Solar Program Rebates and NEM



Note: Pre-CSI – Prior to 1/1/2007, incentive levels varied, but peaked at $4.50/Watt under the CEC's Emerging Renewables Program.

Ratepayers receive some value for the energy exported under NEM, so the total net cost of NEM to ratepayers is slightly less than $0.88 per watt – approximately $0.54 per watt once the billing costs and avoided cost values are factored into account. Although it is useful to compare the cumulative NEM benefit to an upfront incentive, the fact that NEM provides the benefits over time is a key component of the program. By providing customers billing benefits over time, NEM builds in a customer incentive to maximize their potential NEM benefits by maintaining their solar systems, making investments in energy efficiency, and practicing energy conservation.

5. The report includes several sensitivity analyses that indicate potential areas for further policy study, including the costs associated with NEM billing and NEM interconnection.

While the base case approximates the annualized cost of NEM to be $20 million per year, the sensitivity analysis present "lowest" to "highest" scenarios that range from approximately $14 to $27 million in annualized costs.

- The incremental billing costs represented 27 percent of the overall net costs of NEM. If incremental billing costs were eliminated, the total costs of NEM would be 27 percent less. PG&E's incremental billing costs were approximately $18.31/customer per month, and these were significantly higher than either SDG&E or SCE because of legacy billing systems.
- The report did not have high quality data on the cost of interconnection, but the cost of interconnection (if properly accounted) might raise the cost of NEM by as much as 10 percent.
- The report analyzes the net cost of NEM if transmission and distribution (T&D) deferral were not considered part of the avoided cost calculation. This particular component of the avoided cost calculation is considered controversial by some utilities, and therefore the report notes that the costs of NEM would be 12 percent higher if T&D were not included.
- NEM customers are currently exempt from standby charges and this "cost" is not considered in the base case to be a result of NEM. If NEM was attributed with the cost of the lost standby charge revenue, the cost of NEM would be 13 percent higher.

Examination of the sensitivity analyses conducted in the report further support the need to consider this NEM cost-effectiveness analysis as just a one small part of the overall DG program cost-effectiveness analysis. In D.09-08-026, the Commission gave specific methodology direction for the consideration of factors (including T&D deferral, standby charges, interconnection costs, etc.) to be considered in the forthcoming overall cost-effectiveness of DG programs evaluations.

6. The report uses a robust methodology for estimating the costs and benefits of the NEM mechanism.

The NEM report uses the most rigorous and quantitative methodology ever conducted on the NEM mechanism. This analysis relies heavily on the methodology endorsed by the Commission in D. 09-08-026, which is designed to evaluate DG programs overall, not just one aspect like NEM billing arrangements. Some of the key aspects of the analysis work conducted for this report include:

- Development of a framework for the overall estimation of the benefits and costs of the NEM billing mechanism. The billing credits provided to customers and the increased billing costs associated with NEM accounts are both costs to the program. The avoided costs of energy procurement associated with the exported energy are a benefit of the program.
- Estimation of the amount and timing of energy exported by every NEM customer.
    - Each customer on a NEM tariff was assigned a representative load profile.
    - Each customer was assigned an estimate of PV generation on an hourly basis, using metered data, simulated data, or a combination thereof.
    - The customer load was netted against their PV generation and then run through a billing calculator to determine the bill credits associated with each account.
    - The results of the analysis were benchmarked against billing data provided to the utility.
- Estimation of the increased billing costs based on figures provided by the utilities.
- Estimation of the avoided costs based on a comprehensive avoided cost methodology that includes energy generation, losses, ancillary services, system capacity, T&D capacity, environmental benefits, and an RPS adder.
- Development of four sensitivity analyses that demonstrate the changes in total program costs if certain items are removed or added to the program cost analysis, including billing program cost, interconnection, T&D deferral, and standby charges.

7. The report highlights a number of research and policy issues that merit further study and possible Commission action.

- The report reveals a lack of consistency between the utility interconnection department data on solar PV, the utility billing department data on solar PV, and the rebate program data on installed solar PV.
- The report demonstrates that there is a lack of available solar PV production data that can be used to accurately analyze actual solar PV generation. To overcome this issue, this report uses a combination of metered and estimated solar generation data and then benchmarks the results (with a high degree of accuracy).

- The report did not conduct a sensitivity analysis of the cost of the NEM bill credits being set at the generation component of rates instead of full retail rates. Such an analysis might be appropriate for a future study.
- The report did not conduct any sensitivity analyses around different AB 920 implementation options. Such analysis might be appropriate for future study.
- The report highlights that the utilities have different billing costs associated with managing the NEM billing mechanism.
- The report highlights that the utilities do not have readily available information about the costs of interconnection resulting from solar PV interconnections.
- The report preparation process highlights that there is a need for significant stakeholder review and input for the forthcoming more comprehensive program cost-effectiveness evaluations.

APPENDIX A: SAMPLE NEM BILL FROM PG&E SERVICE TERRITORY

The following pages are taken from the PG&E website explaining the NEM bill to customers. Similar pages are available for each utility, and the selection of PG&E's example was purely one of convenience. For reference:

PG&E:
http://www.pge.com/includes/docs/pdfs/b2b/newgenerator/understandingyourbill_residential.pdf

SCE: **http://www.sce.com/solarleadership/gosolar/california-solar-initiative/NEM/**

SDG&E: **http://www.sdge.com/nem/**

Pacific Gas and Electric Company®

Net Energy Metering
Understanding Your Bill

Thank you for making the choice to promote renewable energy.

PG&E supports customers who make smarter energy choices. Customers like you are playing an increasingly important role by adding renewable generation to the electrical grid. In order to ensure the success of the Net Energy Metering Program (NEM), PG&E is committed to helping our customers understand the billing process so they can best leverage their investment.

Understanding Your NEM Rate Schedule

Otherwise Applicable Rate Schedule (OAS)

On your interconnection agreement, you selected an Otherwise Applicable Rate Schedule (OAS) that will be used to bill your NEM account. Your OAS is important because it determines not only how you will be charged for net usage, but also in part, it determines how you will be credited for net-generation—which is the excess energy your system exports back to PG&E. If you have any questions about your OAS, please call us at 1-800-468-4743.

NEM Rate Schedule Options for Residential / Small Commercial

Standard Rate Schedule
For customers who chose the standard residential rate schedule (E-1), or the standard small-commercial rate schedule (A-1), the cost per kilowatt hour (kWh) will not vary by time of day. The net energy meter will collect data on a cumulative basis.

Time-of-Use Rate Schedule
For customers who chose a time-of-use (TOU) rate schedule the cost per kWh varies by season and time of day. A net energy meter on a time-of-use rate schedule collects data for each time-of-use period. TOU rates are higher when the demand for energy is highest. Peak hours are midday and early evening.

California Solar Initiative
Customers receiving rebates through the California Solar Initiative are required to choose service under an applicable existing TOU rate starting in 2007, provided there is an applicable TOU rate for your customer class. For residential customers PG&E offers two TOU rate options: E-6 and E-7**. For commercial and industrial: A-6, A-10, E-19, and E-20.

TOU Example: The chart below is graphical representation of a PG&E residential TOU rate (E-6):

SUMMER	Sunday	Monday	Tuesday	Wednesday	Thursday	Friday	Saturday
Midnight – 6 a.m.	Off-peak						
6 a.m. – 10 a.m.	Off-peak						
10 a.m. – 1 p.m.	Off-peak	Part-Peak					Off-peak
1 p.m. – 7 p.m.	*Part-peak 5 p.m. – 8 p.m.	Peak					*Part-peak 5 p.m. – 8 p.m.
7 p.m. – 9 p.m.		Part-Peak					
9 p.m. – Midnight	Off-peak						

**The summer season is May 1 through October 31. In addition to the part-peak periods from 10 a.m. - 1 p.m. and 7 p.m. - 9 p.m. on weekdays, there is a part-peak period from 5 p.m. - 8 p.m. on weekends. All the hours on tariff designated Holidays are considered off-peak.*

*** New NEM solar residential customers taking service after January 1, 2007 may select E-7 as their OAS until either 5,000 new NEM solar customers have been interconnected or until the final 2007 General Rate Case decision has been made regarding revisions to E-6, whichever is sooner. Customers taking service on E-7 may remain on E-7 until they decide to make a change in their OAS.*

WINTER	Sunday	Monday	Tuesday	Wednesday	Thursday	Friday	Saturday
Midnight – 6 a.m.	Off-peak						
6 a.m. – 10 a.m.	Off-peak						
10 a.m. – 1 p.m.	Off-peak						
1 p.m. – 7 p.m.	Off-peak	*Part-peak 5 p.m. – 8 p.m.					Off-peak
7p.m. – 9 p.m.							
9p.m. – Midnight	Off-peak						

**The winter season is November 1 through April 30. A part-peak period exists from 5 p.m. - 8 p.m. on weekdays. All the hours on tariff designated Holidays are considered off-peak.*

Understanding Net-Generation Credits

Your renewable energy generation production can help you reduce your energy bill in three unique ways:

1. Your generator can send energy directly to your home appliances, offsetting any PG&E supplied energy directly. This is as if you are effectively receiving the equivalent of a full retail rate credit for your generation.

2. Your generator may export energy to the PG&E grid. When you are not using energy while your generator is running, the energy that is produced is sent to PG&E's grid, causing your PG&E meter's net kWh reading to decrease. At night when your generator is not producing energy and you require power for lighting and appliances, your PG&E meter reading will increase. The offset caused by sending your excess energy to the grid and making your PG&E meter "spin backward", and using the energy when you need it will result in a full retail rate credit for any net-generation.

3. Each month PG&E reads its meter at your house. By subtracting the monthly reading from the previous month, PG&E determines the net amount of energy you either used or sent to PG&E's grid during the month. If you used energy, PG&E will calculate that month's usage as a charge, in the same way it would if you did not have a generator and were just taking service on your OAS alone. If you sent more energy to PG&E's grid than you used, it is valued as a credit. The valuation of that credit is based on the full retail energy charge provided in your OAS. That credit is carried forward on your NEM account and can be used to offset energy charges throughout the duration of your true-up period.

Understanding Net-Consumption Charges

Net-consumption charges are dependent on a number of factors:

Net kilowatt hour usage (kWh) represents the total amount of energy supplied by PG&E that your household consumes. This amount, in concert with the TOU period and baseline tier in which the energy was used, will determine what you will pay for energy.

The Baseline quantity is the maximum amount of kWh usage that can be billed at the lowest price of your chosen OAS. Residential customer rates are tiered; meaning usage over baseline allowance is calculated at a higher rate (depending on the rate schedule). Baseline quantities vary by season, climate zone and the customer's heat source.

Keeping usage below or near your baseline quantity is a great way to lower your bill.

These quantities are intended to represent the electricity necessary to supply a significant portion of the reasonable energy needs for an average residential customer. Customers enrolled in the California Alternate Rates for Energy (CARE) program who receive discounts on their energy rates and customers with medical baselines receive additional amounts of baseline usage.

If applicable, TOU periods, in concert with baseline tiers, determine the charges for the kWh that you consume. Customers using energy during peak periods are charged at the applicable peak rate, taking into account the customer's usage in relation to their baseline quantity. Likewise, net kilowatt-hours produced by you and exported to PG&E's grid are valued at the same price per kilowatt-hour that PG&E would charge during that same time of use period.

Pacific Gas and Electric Company

- SAMPLE BILL -

PACIFIC GAS AND ELECTRIC COMPANY
NET ENERGY METERING ELECTRIC STATEMENT
THIS IS NOT A BILL 1
Service Dates: December 29, 2005 to January 30, 2006 2
True-up Period from March, 2005 to February, 2006 3

CUSTOMER NAME — Rate Schedule: E A6TB 4
SERVICE ADDRESS — Account ID: xxxxxxxxxx 5
SERVICE ADDRESS — Service ID: xxxxxxxxxx 6

TOTAL CURRENT MONTH'S BILLED AMOUNT **$11.74*** 7

*This amount is the minimum you must pay this month and is reflected on your regular monthly blue bill, in addition to the energy charges that you may pay monthly or at the end of the true-up period showed above. It includes the following components: Transmission $0.41, Distribution $10.77, Public Purpose Programs $0.09, Nuclear Decommissioning $0.01, Generation $0.46.

ENERGY CHARGES/CREDITS:

Current Month Energy Charge/Credit (-): **$107.99** 8

Cumulative Energy Charges/Credits (-) for the current true-up period: **$432.10** 9
This Cumulative Energy Charges does not reflect any payment you may have made.

You have the option to pay your energy charges either monthly or at the end of your true-up period. 10

ANY UNPAID ENERGY CHARGES WILL BE DUE AT THE END OF YOUR TRUE-UP PERIOD (Feb 2006)

CURRENT MONTH METER INFORMATION:

METER BADGE ID	SEASON 11	TOU PERIOD 12	PRIOR READ	CURRENT READ	DIFFERENCE 13	METER CONSTANT	ENERGY
126M98	Winter	Peak	49,227	49,227	0	1	0
126M98	Winter	Part	47,383	47,763	380	1	380
126M98	Winter	Off	70,666	71,098	432	1	432
TOTAL(S)							812

CURRENT MONTH BASELINE QUANTITY INFORMATION: 14

SEASON	RATE EFFECTIVE DATE	RATE DAYS	DAILY BASELINE QUANTITY	MONTHLY BASELINE QUANTITY
Winter	10/01/05	2	10.20	20.400
Winter	01/01/06	30	10.20	306.000
TOTAL(S)				326.400

Question Regarding This Bill Can Be Directed To: BUSINESS CUSTOMER CENTER (800) 468-4743 15

DATE BILLED: 02/01/06 — Billing Point ID: xxxxxxxxxx

Pacific Gas and Electric Company

- SAMPLE BILL -

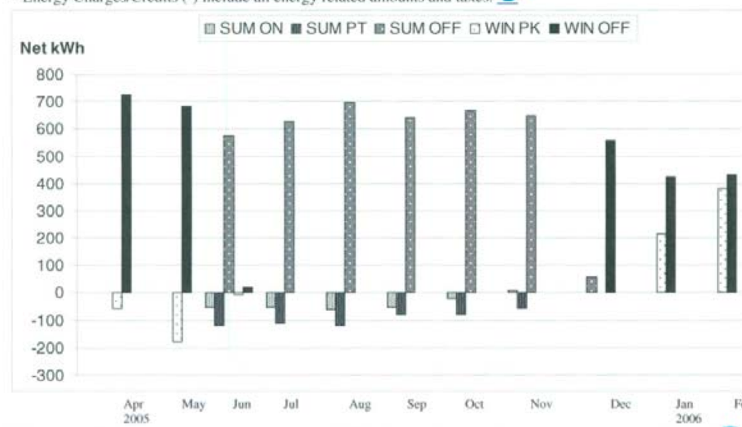
PACIFIC GAS AND ELECTRIC COMPANY
NET ENERGY METERING ELECTRIC STATEMENT
THIS IS NOT A BILL 1
Service Dates: December 29, 2005 to January 30, 2006 2
True-up Period from March, 2005 to February, 2006 3

CUSTOMER NAME — Rate Schedule: E A6TB 4
SERVICE ADDRESS — Account ID: xxxxxxxxxx 5
SERVICE ADDRESS — Service ID: xxxxxxxxxx 6

ENERGY TRUE-UP HISTORY:

BILLING MONTH	BILL TO DATE	SUMMER ON	SUMMER PART	SUMMER OFF	WINTER PART	WINTER OFF	TOTAL ENERGY	ENERGY CHARGES / CREDITS
Feb 2006	**01/30/06**				**380**	**432**	**812**	**$107.99**
Jan 2006	12/29/05				215	426	641	$61.54
Dec 2005	11/30/05	2	0	56	1	557	616	$45.06
Nov 2005	10/28/05	8	-59	649			598	$52.07
Oct 2005	09/29/05	-20	-78	666			568	$40.93
Sep 2005	08/29/05	-53	-78	641			510	$16.55
Aug 2005	07/29/05	-60	-120	698			518	$14.24
Jul 2005	06/29/05	-52	-114	626			460	$11.05
Jun 2005	05/31/05	-52	-121	577	-4	19	419	$5.01
May 2005	04/29/05				-179	683	504	$26.57
Apr 2005	03/31/05				-56	726	670	$51.09
TOTALS							6,316	$432.10

**Energy Charges/Credits (-) include all energy related amounts and taxes. 16



This graph reflects your net energy charge and credit (-). The total output of your generator may be different. 17

Question Regarding This Bill Can Be Directed To: BUSINESS CUSTOMER CENTER (800) 468-4743 15

DATE BILLED: 02/01/06 — Billing Point ID: xxxxxxxxxx

Additional Information

1 **This is not a bill:** The Net Energy Metering Electric Statement is not a bill; it is a statement that details the net-generation and net-consumption related to your NEM account. This statement is sent on a monthly basis and is intended to provide you with details about your net-energy usage and the charges/credits that you have accrued so you can keep track of your total charges/credits throughout the true-up period.

2 **Service Dates:** The dates used to calculate a bill exclusive of the "Bill From" date and including the "Bill To" date.

3 **True-up Period:** The "true up" is the annual reconciliation of all charges and/or credits accrued at the end of your 12-month billing cycle. This period normally represents the anniversary date of your interconnection.

4 **Rate Schedule:** When you applied for Net Energy Metering, you selected an Otherwise Applicable Rate Schedule (OAS). Your OAS is important because it determines not only how you will be charged for net usage, but also how you will be credited for the net-generation that you export to PG&E's grid from your generating facility.

5 **Account ID:** When you have questions or need service, giving PG&E this unique account identifier will help us serve you more quickly.

6 **Service ID:** A *new* 10-digit number that uniquely identifies your service agreement and your account information. The service agreement makes use of rates, billing days, metering information, and other factors in order to calculate applicable charges.

7 **Total Current Month Billed Amount:** This amount reflects the monthly minimum charges due.

8 **Current Month Energy Charges/Credits:** The current month energy charge/credit reflects the kWh charges/credits accrued by you in the current billing period. Residential and Commercial customers on A1 or A6 have the option to pay their energy charges either monthly or annually. Such customers whose generator credits will not offset most of their usage charges or who are accruing a large Cumulative Energy Charge (see 9 below) may want to pay their energy charges monthly to avoid a large year end true-up bill. All other customers are required to pay their energy charges on a monthly basis.

9 **Cumulative Energy Charges/Credits:** The cumulative energy charges/credits for the current true-up period is an aggregated total of the kWh charges that you have accrued throughout the true-up period. If not paid or offset by energy credits, this amount will be payable upon receipt of your true-up statement.

10 **Option to Pay Monthly or Annually:** Pursuant to California Public Utility Code, residential customers, customers on a non-demand rate schedule (A1 or A6) and commercial customers with demand less than 20 kW have the option to pay energy charges on either a monthly or an annual basis.

11 **Seasonal Effects on your Rate:** Depending on the season, your rates will vary and your baseline quantities will change. The summer season represents the dates from May 1 through October 31 and the winter season from November 1 through April 30. During the winter season, baseline allowances will generally increase, while they generally decrease during the summer season. During billing periods that crossover between seasons, you will see separate entries for your usage in each seasonal period.

Additional Information (Continued)

12 **TOU Period:** Time-of-Use (TOU) rates are higher during peak hours when the demand for energy is highest. Peak hours occur during midday and early evening. Part-peak hours (if applicable) are generally in the morning and evening hours and off-peak periods are generally during the overnight and weekend periods. Please check your specific rate schedule to determine the exact timing of your TOU periods.

13 **Meter Difference:** The monthly meter difference is the difference in two consecutive meter reads of your PG&E meter and represents the kWh used from the beginning to the end of a specific billing period. This meter difference, multiplied by the meter constant (usually 1 for residential customers) determines the net kWh that you have used during a billing period.

14 **Baseline Quantity:** The baseline quantity is a designated amount of kilowatt-hours (kWh) of energy that PG&E customers can buy at a predetermined rate. The baseline quantity designated for each customer depends on the season, whether or not the customer has permanently installed electric heating and the geographic zone in which the customer lives. Baseline quantity is important as it is a component of how you are charged/credited for usage and generation exported to the grid.

15 **Business Customer Center (BCC):** PG&E's BCC is a group of business customer specialists within the Account Services department that provide assistance to solar customers.

16 **Energy Charges/Credits:** Following the completion of a true-up period, any credits for excess generation that you earn will be applied to electricity charges within this 12-month reconciliation period. If you produce more energy than you use, please note that you will not be paid for any excess energy production at the end of the annual reconciliation period, nor will any excess energy credits be applied to your next true-up period.

17 **Net Usage Graph:** This graph provides a visual measure of your net usage/generation by TOU and seasonal period.

For more information visit pge.com

- *Understanding Your Bill*
- *Energy Efficiency Rebates*
- *Financial Assistance*
- *Pay Your PG&E Regular Bill*

Net Energy Metering (NEM)

Cost-Effectiveness Evaluation

Prepared for:

California Public Utilities Commission

505 Van Ness Avenue

San Francisco, CA 94102

January, 2010

Energy and Environmental Economics, Inc.

Table of Contents

1. Executive Summary

The California Public Utilities Commission (CPUC) hired Energy and Environmental Economics, Inc. (E3) to perform an analysis of the costs and benefits of net-energy metering (NEM) in compliance with Public Utility Code 2827, which requires the CPUC to "…submit a report to the Governor and the Legislature on the costs and benefits of net energy metering…"[1] The analysis follows the cost-benefit methodology for the evaluation of distributed generation (DG) adopted by the CPUC in Decision (D.) 09-08-026. The NEM analysis is one step in the larger context of DG cost-effectiveness evaluation.

Net Energy Metering (NEM) allows customers from Pacific Gas and Electric (PG&E), Southern California Edison (SCE), and San Diego Gas & Electric (SDG&E)[2] with certain types of on-site generation[3] to receive bill credits for any energy generation in excess of electric load that is exported from the customer premises to the electric grid. 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 over and applied against the following month's bill. Currently, any bill credits remaining at the end of each 12-month period expire. Assembly Bill (AB) 920 (Huffman, 2009) amended the law to allow customers, beginning in January 2011, to either continue to roll-over the bill credits indefinitely or receive compensation for the net-excess generation.

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

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[1] P.U. Code 2827 (c) (4)

[2] P.U. Code 2827 covers more utilities than PG&E, SCE, and SDG&E, but this analysis is limited solely to NEM in the territories of those three utilities.

[3] Solar, wind, biogas, and fuel cells with a capacity of not more than 1 megawatt (MW).

As shown in Table 1, at the end of 2008 more than 40,000 customer accounts from California's three large investor-owned utilities (IOUs) under CPUC jurisdiction were enrolled in NEM. These accounts had nearly 400 MW of installed generation, and generated nearly 600,000 MWh of electricity. The vast majority of NEM generators (99%) were solar PV.

Table 1: PG&E, SCE, and SDG&E NEM accounts, generation capacity, and electric generation as of 12/31/2008

	PG&E	SCE	SDG&E	Total
Number of Accounts	**27,030**	**8,882**	**5,745**	**41,657**
Residential	*25,250*	*8,128*	*5,347*	*38,725*
Non-Residential	*1,780*	*754*	*398*	*2,932*
Generation Capacity (CEC-AC kW)[4]	**216,654**	**118,576**	**51,331**	**386,561**
Residential	*104,034*	*40,556*	*20,002*	*164,592*
Non-Residential	*112,620*	*78,020*	*31,329*	*221,969*
2008 Generation (MWh)	**322,176**	**171,940**	**85,718**	**579,834**
Residential	*166,070*	*60,295*	*33,426*	*259,791*
Non-Residential	*156,106*	*111,645*	*52,292*	*320,043*

PG&E data are from a September 2009 response to a CPUC data request. SCE and SDG&E data were provided in conjunction with the CPUC's data request related to E3's CSI and NEM evaluations.

1.1. NEM Cost-Effectiveness Evaluation

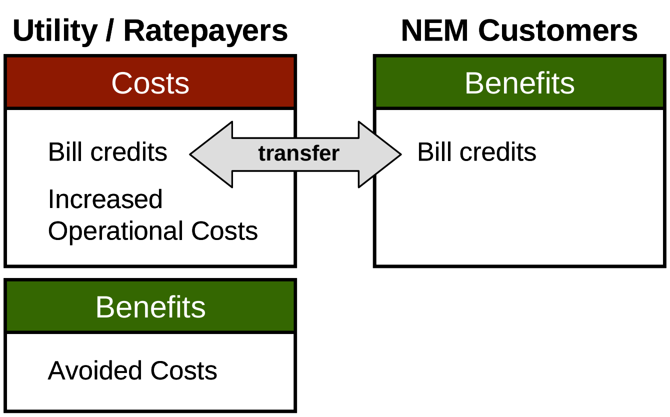
Analysis of the costs and benefits of NEM is one component of an overall cost-effectiveness evaluation of CSI, SGIP, and other DG programs. (E3's contract with the CPUC includes separate evaluations of CSI and other DG programs to be completed in 2010). NEM cost-effectiveness analysis in the present report is limited to distributed solar PV generation, which currently comprises the vast majority of NEM generators and NEM generation (see Table 11 through Table 13 in Chapter 2). This evaluation is focused on the costs and benefits of NEM billing practice and policy. This report does not attempt to quantify the overall benefits to society of a NEM program that supports clean energy resources like solar PV, although significant environmental, public health, and other non-energy benefits may accrue from solar generation associated with NEM.

[4] The CEC-AC capacity de-rates the nameplate DC capacity of solar PV to account for panel and inverter losses and correct for azimuth and tilt.

Figure 1 shows the conceptual flow of NEM costs and benefits between participants and non-participants. NEM customers (participants) receive benefits in the form of bill credits (we use the term bill credits in this figure and throughout the report to include both the credits applied to the customer's bill and any compensation from AB 920 implementation).

Every dollar of benefit received by NEM customers is a direct reduction in utility revenues. Since the utility must continue to meet its revenue requirement, this revenue reduction must be made up by ratepayers. The bill credits are thus a direct cost to ratepayers. Likewise, any additional operational costs resulting from NEM, such as incremental billing administration costs, must be covered by the utility, and therefore by ratepayers. In return, the utility (and therefore ratepayers) receive the benefit of the energy exported by NEM customers to the grid; the utility avoids the cost of having to procure and deliver this energy through other means.

Figure 1: Illustration of NEM costs and benefits



The customer generation under NEM has additional utility and ratepayer costs (such as upfront incentive payments) and benefits (such as market transformation effects), but these additional costs and benefits are not, strictly speaking, a function of NEM.

It is also true that NEM customers incur other costs and receive other benefits from their solar PV production (including bill reductions in hours when electric load exceeds generation and the customer is *not* exporting energy). These additional benefits are not a function of NEM, however, as the customer would receive these benefits even in the absence of NEM. We will consider the full array of costs and benefits associated with solar PV and other forms of DG in our 2010 analyses.

Additional detail on our methodology for evaluating benefits and costs of NEM are provided in Chapter 3 and Chapter 5.

1.2. Results

Our analysis measures the costs and benefits of utilities “purchasing” exported energy from customer-generators with solar PV by giving the customer a bill credit based, in the case of solar PV, on the customer’s retail rate. Because retail rates are in most cases higher than the utility’s marginal cost of delivering energy, NEM results in a cost to utilities, and therefore to ratepayers.

1.2.1. Description of measurements

We represent the net cost of NEM in three ways: Net Present Value (NPV) of total costs; Annualized Costs; and Levelized ($/kWh-exported) costs, as described in Table 2.

Table 2: Methods of expressing benefit/cost results

NPV. To calculate the net present value (NPV), we estimate the annual benefits and costs of NEM for each year of the 20-year analysis period and take the present value of the stream of net costs using, as the discount rate, the utilities’ average weighted average cost of capital (WACC). These values are expressed in 2008 dollars.
Annualized Value. The annualized cost value calculates the uniform annual stream of costs that would result in the same NPV. This differs from our estimated annual values in that the estimated annual values may vary from year-to-year (for example, declining due to degradation in solar PV system output) whereas the annualized value is uniform. All annualized values are expressed as real annualized values in 2008 dollars, assuming 2% inflation throughout the analysis period.
Levelized Value. The levelized value represents the net cost over the life of the program on a $/kWh-exported basis. It is expressed in real 2008 dollars, assuming 2% inflation.

In each case, our analysis considers NEM generation installed through the end of 2008 on a lifecycle basis. That is, we look at the 2008 generation base over a 20-year analysis period and consider the total benefits and costs incurred over the full analysis period. Thus the levelized $/kWh-exported cost is not an expression of NEM program costs in 2008; rather it is an expression of the 20-year costs and benefits of NEM generation installed through 2008, levelized over the total kWh exported, in 2008 dollars. Nor should the levelized cost per kWh-exported be thought of as the cost of buying a kWh of solar PV production through NEM. Rather, it is a measure of the net costs (net of *avoided cost* benefits) to ratepayers of NEM, considered over all the kWh "purchased" by the utility through NEM.

While the NPV and annualized values will vary with the number of accounts enrolled in NEM, the levelized value will remain the same as the program grows to the extent underlying factors (rates, consumption and generation profiles, etc.) remain constant.

Our methodology and underlying assumptions are further described in Chapter 5.

1.2.2. Results

All results are presented in real 2008 dollars and pertain to the NEM program within the scope of our study; that is, the fleet of solar PV generation enrolled in NEM through the end of 2008.

Table 3 shows the benefits (costs) of NEM by utility and customer class for all NEM PV systems installed through the end of 2008. We estimate that on a lifecycle basis, generation installed through 2008 will result in NPV costs to ratepayers of approximately $230 million, or approximately $20 million/year on an annualized basis. NEM costs on a levelized basis per kWh exported to the grid total approximately $0.12/kWh-exported.[5] The levelized cost for residential customers ($0.19/kWh-exported) is substantially higher than for non-residential ($0.03) mainly because of residential customers' higher energy rates and inclining block rate structure.

[5] This cost is unrelated to and does not include any CSI incentives, which step-down, as program penetration increases, from $0.39/kWh to $0.03/kWh for Performance-Based Incentives.

Table 3: Net NEM benefits (costs) to non-participants for generation installed through 2008, expressed in NPV ($000s), Annualized Value ($000s), and Levelized Value ($/kWh-exported)

	Residential	Non-Residential	Total
PG&E			
20-year NPV ($000s)	($144,452)	($24,066)	($168,519)
20-year Annualized ($000s)	($12,327)	($2,054)	($14,380)
Levelized ($/kWh-exported)	($0.22)	($0.07)	($0.17)
SCE			
20-year NPV ($000s)	($41,871)	($2,011)	($43,882)
20-year Annualized ($000s)	($3,573)	($172)	($3,745)
Levelized ($/kWh-exported)	($0.14)	($0.01)	($0.06)
SDG&E			
20-year NPV ($000s)	($15,296)	($2,937)	($18,232)
20-year Annualized ($000s)	($1,305)	($251)	($1,556)
Levelized ($/kWh-exported)	($0.14)	($0.03)	($0.08)
All Utilities			
20-year NPV ($000s)	($201,619)	($29,013)	($230,632)
20-year Annualized ($000s)	($17,205)	($2,476)	($19,681)
Levelized ($/kWh-exported)	($0.19)	($0.03)	($0.12)

As shown in Table 4, net NEM costs total less than one-tenth of one percent of utility revenue.

Table 4: NEM cost as a percent of total utility revenue

	Net NEM Cost (Annualized $000s)	Total Revenue ($000s)	Percent	Implied Rate Increase ($/kWh)
PG&E	$14,380	$11,373,950	0.13%	0.00018
SCE	$3,745	$12,107,743	0.03%	0.00005
SDG&E	$1,556	$2,534,874	0.06%	0.00009
Total	**$19,681**	**$26,016,568**	**0.08%**	**0.00011**

Given an overall average rate of $0.144/kWh, this 0.08% increase in costs implies that an average rate increase of $0.00011/kWh is necessary to cover NEM costs.[6]

[6] The total revenue and average rate figures used in Table 4 and Table 5 and the surrounding discussion are taken from the Reference Case from the GHG Modeling, released November 13, 2009. The GHG Modeling Report and GHG Calculator are available at http://www.ethree.com/CPUC_GHG_Model.html.

The cost of NEM – and rate increase necessary to recover the cost – will grow as the amount of generation under NEM increases. To measure this effect, we forecasted the values in Table 4 under the assumption that by 2020, the CSI program will fully achieve its goals.[7] Table 5 shows the results.

Table 5: Forecast of NEM solar PV cost as a percent of total utility revenue in 2020, assuming achievement of CSI program goals (2008 dollars)

	Net NEM Cost (Annualized $000s)	Total Revenue ($000s)	Percent	Implied Rate Increase ($/kWh)
PG&E	$100,463	$15,921,596	0.63%	0.00106
SCE	$26, 164	$16,763,730	0.16%	0.00026
SDG&E	$10,871	$3,603,089	0.30%	0.00051
Total	**$137,497**	**$36,288,415**	**0.38%**	**0.00064**

Given a projected average 2020 rate of $0.168/kWh (in 2008 dollars), this 0.38% increase in costs from solar NEM implies an average rate increase of $0.00064/kWh.

Table 6 shows the breakdown of benefits and costs in greater detail. The largest portion of cost derives from the bill credit itself; incremental billing costs are responsible for less than 15% of total program costs ($0.03/($0.19+$0.03) in the lower right cell of Table 6).

[7] This calculation multiplies the 2008 NEM costs in Table 4 by the ratio of NEM solar generation when CSI is fully subscribed (2,550 MW) to current NEM solar generation (365 MW, see Table 12). The 2020 estimate of 2,550 MW is made up of 2,300 MW from CPUC CSI goals for investor-owned utilities, plus approximately 250 MW of solar PV installed prior to the CSI program that qualify for NEM.

Table 6: 20-Year Levelized Non-Participant Benefits and Costs of NEM by Utility ($/kWh-exported)

	Residential	Non-Residential	Total
PG&E			
Bill Impacts	($0.26)	($0.15)	($0.22)
Incremental Billing Cost	($0.08)	($0.01)	($0.05)
Avoided Cost (benefit)	$0.12	$0.09	$0.11
Total, PG&E	($0.22)	($0.07)	($0.17)
SCE			
Bill Impacts	($0.23)	($0.11)	($0.16)
Incremental Billing Cost	($0.01)	($0.00)	($0.00)
Avoided Cost (benefit)	$0.10	$0.10	$0.10
Total, SCE	($0.14)	($0.01)	($0.06)
SDG&E			
Bill Impacts	($0.23)	($0.13)	($0.18)
Incremental Billing Cost	($0.03)	($0.01)	($0.02)
Avoided Cost (benefit)	$0.12	$0.11	$0.12
Total, SDG&E	($0.14)	($0.03)	($0.08)
All Utilities			
Bill Impacts	($0.25)	($0.13)	($0.19)
Incremental Billing Cost	($0.05)	($0.01)	($0.03)
Avoided Cost (benefit)	$0.11	$0.10	$0.11
Total, All Utilities	($0.19)	($0.03)	($0.12)

Note: values may not sum due to rounding

The bill impacts in Table 6 represent only a portion of the total bill impacts from the generation installed by NEM customers. Customers also receive direct offsets to their energy use, and hence their bills, during times when the customer's load exceeds generation output. This direct bill offset is not a part of NEM or our NEM cost-benefit analysis, but we calculated it for reference. Overall, we estimate 25% of total bill impacts from NEM solar generation to be a result of NEM bill credits (including AB 920 effects), and 75% a result of direct offset to energy consumption. In other words, the bill effects from NEM are one-third as large as the bill effects that would result even if there were no NEM. The AB 920 effects are only about one percent of the total NEM bill credit costs in our analysis.

1.2.3. Sensitivities

We tested the sensitivity of our results to several variables to better understand drivers of the results and to evaluate results under alternative assumptions. Sensitivity cases include:

- **No incremental billing costs.** This answers the question, "what would the results be if utilities achieved billing efficiencies in NEM billing and could eliminate incremental billing costs?" While it is not realistic to assume that such efficiencies could be instantly achieved, the calculated result places an upper bound on the value of billing efficiencies.

- **No T&D deferral.** This answers the question, "what would the results be if transmission and distribution (T&D) deferral were not considered part of the avoided cost calculation?" (See Section 5.2 for a discussion of avoided costs). This sensitivity provides a measure of the importance of T&D avoided costs to overall cost-effectiveness.

- **Inclusion of lost standby charge revenue.** This answers the question, "what would the results be if NEM customers had to pay standby charges?" NEM customers are, by law, exempt from standby charges. Loss of standby charge revenue is, therefore, a cost if one assumes the customer would have been assessed standby charges for solar in the absence of NEM. Our base case assumes customers would not be assessed standby charges in any case; this sensitivity tests the alternative.

- **Inclusion of interconnection costs.** This answers the question "what would the results be if NEM customers paid interconnection costs?" NEM customers are, by law, exempt from interconnection costs. While the lost revenue from the foregone interconnection charges is a real cost to the utility, only limited data were available on interconnection costs. We therefore exclude interconnection costs from the base case and use this sensitivity to test inclusion of interconnection costs based on the limited available data.

Table 7 shows the results of our sensitivity testing on a levelized $/kWh-exported basis. With the exception of incremental billing costs, the tested sensitivities raise overall NEM costs by approximately 10-15% each. Eliminating incremental billing costs would result in an overall reduction in NEM costs of approximately 27%.

Table 7: Sensitivity analysis results (Levelized $/kWh) and Percent Change from Base Case

	Base Case	No Incremental Billing Cost	No T&D deferral in Avoided Cost	Standby Charges	Inter-connection Costs
Bill Impacts	($0.193)	($0.193)	($0.193)	($0.209)	($0.193)
Incremental Billing Cost	($0.032)	-	($0.032)	($0.032)	($0.032)
Interconnection Cost	-	-	-	-	($0.012)
Avoided Cost	$0.106	$0.106	$0.092	$0.106	$0.106
Net Cost of NEM *	**($0.119)**	**($0.087)**	**($0.133)**	**($0.135)**	**($0.132)**
(% Change from Base Case)		**(-27%)**	**(+12%)**	**(+13%)**	**(+10%)**

* Net cost value may not equal the sum of components due to rounding

From Table 7, one may construct a range of lowest to highest cost estimates from our analysis. The lowest cost estimate holds all sensitivities at the base case with the exception of the incremental billing costs, which are set to zero. The highest cost estimate keeps the incremental billing costs, removes T&D deferral, and includes interconnection costs and loss of standby charge revenue. These “lowest” to “highest” scenarios are compared to the Base Case in Table 43 showing a range of approximately $14-27 million in annualized costs.

Table 8: “Lowest” and “Highest” sensitivity combinations compared to Base Case

	Base Case	“Lowest” Cost	“Highest” Cost
20-year NPV ($000s)	($230,632)	($168,812)	($311,285)
20-year Annualized ($000s)	($19,681)	($14,405)	($26,563)
Levelized ($/kWh-exported)	($0.12)	($0.09)	($0.16)

Overall, NEM is a cost to ratepayers, as are other incentives for clean generation such as CSI incentives. We estimate this cost at about $20 million/year on a 20-year annualized basis for the fleet of solar PV installed through the end of 2008; under our "highest" cost scenario this estimate is about 35% higher at roughly $27 million/year.

The NEM incentive is significantly larger on a per-kWh-exported basis for residential customers than for non-residential ($0.19 and $0.03, respectively). This results from residential customers' higher rates and inclining block rate structure that provides very high credits for the highest tiers of energy exported.

Total bill impacts from NEM, however, are only one-third as large as the bill impact resulting from direct offset of consumption that would occur with or without NEM. And the amount of energy exported to the grid through NEM is limited by the existing restrictions on PV sizing relative to load. These restrictions help limit total costs to ratepayers. Net NEM costs for the fleet of solar PV installed through 2008 total less one-tenth of one percent of total utility revenue.

The equivalent upfront payment (Table 9) is the lifecycle value of the bill credits for the exported energy. This represents the average upfront payment to NEM participants that would be necessary to make them indifferent between the upfront payment versus the monthly and annual NEM bill credits.

Table 9: Lifecycle value to system owners of NEM credits expressed as Equivalent Upfront Payment ($/W installed)

	Residential	Non-Residential	Total
PG&E	$1.41	$0.44	$0.92
SCE	$1.53	$0.50	$0.87
SDG&E	$1.09	$0.40	$0.69
Total	$1.40	$0.46	$0.88

The lifecycle value of NEM credits can be compared to CSI upfront incentives, which step down from $2.50/Watt to $0.20/Watt over the ten-year program.[8]

[8] Solar systems on NEM that were installed prior to CSI may have received incentives as high as $4.50/watt.

This comparison reveals that the NEM credit is a significant component of ratepayer cost related to solar PV distributed generation, especially for the residential sector.

Table 10 shows the “equivalent net cost” to ratepayers, which is the lifecycle net cost per Watt of PV installed.

Table 10: Lifecycle Equivalent Net Cost of NEM to ratepayers ($/W installed)

	Residential	Non-Residential	Total
PG&E	($1.19)	($0.20)	($0.70)
SCE	($0.92)	($0.02)	($0.34)
SDG&E	($0.65)	($0.09)	($0.32)
Total	($1.06)	($0.12)	($0.54)

Overall, the cost of the NEM subsidy is approximately $0.54/Watt installed, or about 20% of the initial CSI incentive of $2.50/Watt. This compares to an average 2008 and 2009 total project cost (before rebates) for CSI projects of $8.14/Watt installed for large commercial customers and $9.41/Watt installed for residential and small commercial customers.[9]

The ratepayer impact (Table 10) is smaller than the participant payment (Table 9) because ratepayers receive the avoided cost benefit, offsetting a portion of the bill credit payments.

Results are discussed in greater detail in Chapter 6 of this report.

[9] CPUC, *California Solar Initiative Annual Program Assessment*, June 2009, p.22.

2. NEM Program Overview

California's net-energy metering (NEM) law, which took effect in 1996, requires the state's investor-owned utilities – PG&E, SCE, and SDG&E – to offer NEM tariffs to customers with wind, solar, biogas, or fuel cell generation up to 1 MW in size.[10] Under the statute, utilities must make NEM available to customers until the total NEM rated generating capacity exceeds 2.5 percent of the utility's aggregate customer peak demand. PG&E voluntarily extended the cap to 3.5 percent in 2009.[11]

Under NEM, customers receive bill credits for excess generation (generation exceeding electric load) that is exported to the grid. Any excess bill credits at the end of a billing month may be applied against the following month's bill. Under the original law, any net-excess generation remaining at the end of each 12-month period was granted to the utility. In 2009, AB 920 amended the law to allow PV customers, beginning in January 2011, to either roll-over the credit indefinitely or receive compensation for the net excess generation (at a to-be-determined valuation).[12]

Through 2008, nearly 40,000 residential and 3,000 non-residential accounts from California's three large IOUs enrolled in NEM, as shown in Table 11.[13] The vast majority of customers with NEM (99%) had solar PV installed. Fuel cells, biogas, wind, and hybrid technologies make up the remaining one percent.

It should be noted that not all solar PV accounts are on NEM tariffs. The CPUC staff recently reported that as of September 2009, 245 solar PV accounts representing 43 MW of generating capacity opted to not take NEM tariffs, presumably because their solar generation was not expected to exceed load at

[10] California Public Utilities Code 2827. The original law applied only to solar and wind generation. It was later amended to included biogas and fuel cells. . The law also applies to all other utilities, except Los Angeles Department of Water and Power.
[11] Advice Letter 3555-E, effective December 7, 2009.
[12] For the purposes of our analysis, we assume AB 920 compensation is set to match avoided costs.
[13] Table 11 and Table 12 are derived from: PG&E data from a September, 2009 response to a CPUC data request; SCE and SDG&E data provided in conjunction with the CPUC's data request related to E3's CSI and NEM evaluations.

any time, and thus no benefits would be accrued from NEM.[14] Non-NEM solar PV customers are excluded from the analysis described in this report.

Table 11: Number of NEM accounts through 2008 by utility and generation technology

	PG&E	SCE	SDG&E	Total	(%)
Fuel Cell	**3**	**2**	**4**	**9**	**(0%)**
Residential	-	-	-	-	
Non-Residential	*3*	*2*	*4*	*9*	
Hybrid[15]	17	**-**	**-**	**17**	**(0%)**
Residential	-	-	-	-	
Non-Residential	*17*	-	-	*17*	
Solar PV	**26,864**	**8,659**	**5,721**	**41,244**	**(99%)**
Residential	*25,124*	*7,926*	*5,330*	*38,380*	
Non-Residential	*1,740*	*733*	*391*	*2,864*	
Wind / Solar	**76**	**-**	**7**	**83**	**(0%)**
Residential	*71*	-	*7*	*78*	
Non-Residential	*5*	-	-	*5*	
Wind	**69**	**217**	**12**	**298**	**(1%)**
Residential	*55*	*202*	*10*	*267*	
Non-Residential	*14*	*15*	*2*	*31*	
Biogas	**1**	**4**	**1**	**6**	**(0%)**
Residential	-	-	-	-	
Non-Residential	*1*	*4*	*1*	*6*	
Total	***27,030***	***8,882***	***5,745***	***41,657***	***(100%)***
Residential	*25,250*	*8,128*	*5,347*	*38,725*	
Non-Residential	*1,780*	*754*	*398*	*2,932*	

Installed capacity under NEM totaled more than 164 MW residential and more than 221 MW non-residential by the end of 2008, as shown in Table 12.

[14] CPUC October 2009 Staff Progress Report, Table 7, page 15.
http://www.cpuc.ca.gov/PUC/energy/Solar/091021_staffprogressreport.htm
[15] Hybrid technologies include fuel cells and PV combined with some other form of generation, such as "Photovoltaic Panels & Microturbine (< 250kw) Natural Gas/propane Fueled." While not all generation included in each hybrid category is necessarily NEM eligible, we do not concern ourselves with the distinction here because it is incidental to our analysis and conclusions.

Table 12: Installed generation capacity under NEM by the end of 2008 (CEC-AC kW)

	PG&E	SCE	SDG&E	Total	(%)
Fuel Cell	**1,491**	**1,475**	**2,250**	**5,216**	**(1%)**
Residential	-	-	-	-	
Non-Residential	*1,491*	*1,475*	*2,250*	*5,216*	
Hybrid	**7,304**	**-**	**-**	**7,304**	**(2%)**
Residential	-	-	-	-	
Non-Residential	*7,304*	-	-	*7,304*	
Solar PV	**206,128**	**110,491**	**48,876**	**365,495**	**(95%)**
Residential	*103,255*	*38,903*	*19,931*	*162,089*	
Non-Residential	*102,873*	*71,588*	*28,945*	*203,406*	
Wind / Solar	**430**	**-**	**52**	**482**	**(0%)**
Residential	*353*	-	*52*	*405*	
Non-Residential	*77*	-	-	*77*	
Wind	**600**	**4,121**	**23**	**4,744**	**(1%)**
Residential	*426*	*1,654*	*19*	*2,098*	
Non-Residential	*175*	*2,467*	*4*	*2,646*	
Biogas	**700**	**2,490**	**130**	**3,320**	**(1%)**
Residential	-	-	-	-	
Non-Residential	*700*	*2,490*	*130*	*3,320*	
Total	***216,653***	***118,576***	***51,331***	***386,561***	***(100%)***
Residential	*104,034*	*40,556*	*20,002*	*164,592*	
Non-Residential	*112,620*	*78,020*	*31,329*	*221,969*	

We estimate total 2008 generation from residential NEM customer sites at more than 250 GWh and more than 320 GWh from commercial sites.[16] This figure represents gross generation; in other words, it includes both the exported energy that is the focus of this report and the on-site use during hours when customer load exceeded generation output.

Because of their larger size, non-PV generation technologies make up a larger portion of total generation than of the total number of installations. Even so,

[16] Our energy generation estimate is based on application of generation capacity factors to the weighted average 2008 capacity for each generation technology. The weighted average is used rather than the end-of-year capacity from Table 12 because some of the generation was installed in 2008 and therefore generated energy for only a portion of the year. The capacity factors used were based on: for fuel cells, internal combustion, microturbines, and solar PV – Itron's 2008 SGIP Impact Report, *CPUC Self-Generation Incentive Program Eighth-Year Impact Evaluation*, July 2009; for wind and biogas – Renewable Energy Transmission Initiative (RETI) data, http://www.energy.ca.gov/reti/index.html; and for wind/solar combined – internal estimate.

solar PV generation still accounts for the majority of energy produced by NEM generators, as shown in Table 13.

Table 13: 2008 total (gross) NEM generation (MWh) by utility and generation technology

	PG&E	SCE	SDG&E	Total	(%)
Fuel Cell	**6,239**	**6,595**	**13,795**	**26,629**	**(5%)**
Residential	-	-	-	-	
Non-Residential	*6,239*	*6,595*	*13,795*	*26,629*	
Hybrid	**5,773**	**-**	**-**	**5,773**	**(1%)**
Residential	-	-	-	-	
Non-Residential	*5,773*	-	-	*5,773*	
Solar PV	**303,072**	**136,181**	**70,847**	**510,101**	**(88%)**
Residential	*164,362*	*55,757*	*33,273*	*253,392*	
Non-Residential	*138,710*	*80,424*	*37,574*	*256,709*	
Wind / Solar	**918**	**-**	**115**	**1,033**	**(0%)**
Residential	*749*	-	*115*	*864*	
Non-Residential	*169*	-	-	*169*	
Wind	**1,319**	**11,666**	**48**	**13,032**	**(2%)**
Residential	*959*	*4,538*	*39*	*5,535*	
Non-Residential	*360*	*7,128*	*9*	*7,497*	
Biogas	**4,919**	**17,498**	**914**	**23,330**	**(4%)**
Residential	-	-	-	-	
Non-Residential	*4,919*	*17,498*	*914*	*23,330*	
Total	***322,240***	***171,940***	***85,718***	***579,898***	***(100%)***
Residential	*166,070*	*60,295*	*33,426*	*259,791*	
Non-Residential	*156,170*	*111,645*	*52,292*	*320,107*	

Because solar PV makes up the vast majority of installations (99%), capacity (95%), and energy generated (88%) under NEM, the focus of this report is limited to the costs and benefits of PV installations under NEM. Other NEM generation sources, such as Fuel Cells, Wind, and Biogas, will be considered in overall DG cost-effectiveness evaluations to be conducted in 2010.

3. NEM Benefits and Costs

Standard practice for quantifying the costs and benefits of a program (or policy), is to measure costs and benefits with the program in place and compare to outcomes that would have been expected in the program's absence. Understanding NEM benefits and costs, therefore, begins with a clear understanding of the NEM mechanism, and a clear set of assumptions of what would happen in the absence of NEM. Sensitivity analysis is used to explore alternative assumptions.

3.1. Understanding the NEM program for benefit-cost calculation

We evaluate the costs and benefits of NEM from the perspective of NEM customers (participants) and all other ratepayers (non-participants). Figure 2 illustrates the framework for consideration of NEM costs and benefits used throughout this report. The net cost of NEM to ratepayers is the sum of ratepayer costs (bill credits and incremental billing costs) and ratepayer benefits (avoided costs).

Bill credits are a cost to ratepayers. NEM customer-generators receive benefits in the form of bill credits, which in our analysis are calculated to include any compensation arising from AB 920 implementation. Every dollar of benefit received by NEM customers is a direct reduction in utility revenues. Since the utility must continue to meet its revenue requirement, this revenue reduction must be made up by ratepayers. The bill credits 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, must be covered by the utility, and therefore by ratepayers.

Avoided costs are a benefit to ratepayers. Utilities, and therefore ratepayers, receive the benefit of the energy exported by NEM customers to the grid; utilities avoid the cost of having to procure and deliver this energy through other means.

Figure 2: Framework for evaluating the costs and benefits of NEM

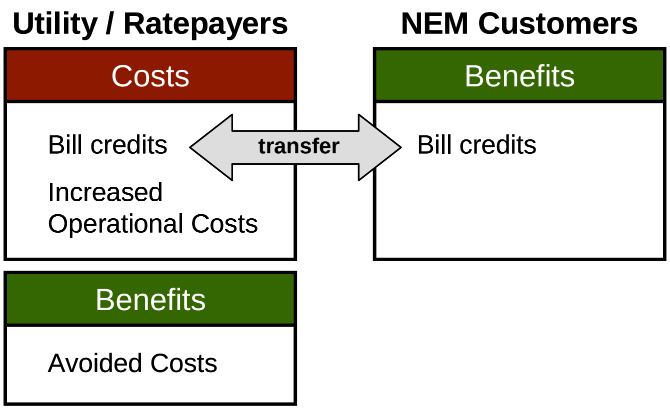
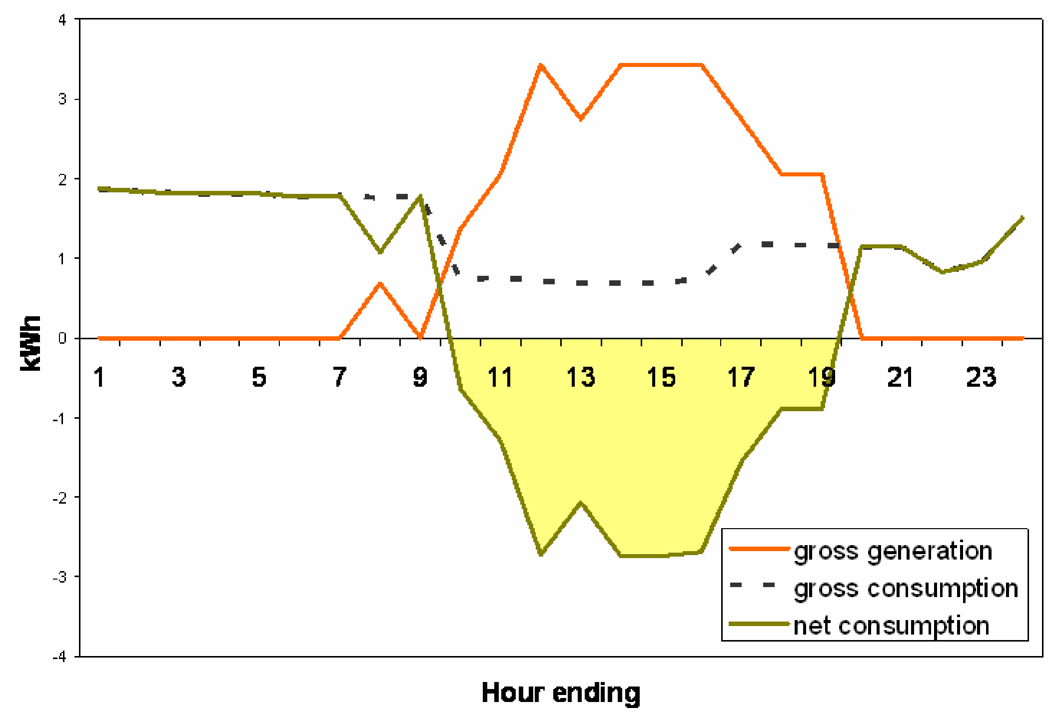


Figure 3 helps illustrate NEM costs and benefits for a residential customer with solar PV. The figure shows, for a 24-hour period, the gross consumption the customer would have had without the PV, PV output, and net consumption.

Figure 3: PV production and net load for a sample residential NEM customer



From 8 pm until 7 am, the customer's solar PV does not generate energy. Net consumption, therefore, is equal to gross consumption during those hours. The solar PV generates energy from 8 am until 7 pm; during these hours the customer's net consumption declines by the amount of generation. From 10 am until 7 pm, generation exceeds consumption and the customer's net consumption is negative, indicating that the customer is exporting power to the grid. The shaded area of the chart represents the energy exported to the grid.

Under NEM, the customer receives bill credits for exported generation, effectively "spinning the meter backwards" during periods when generation is greater than consumption. The bill credit is calculated based on the applicable rate.[17] If, at the end of the month, bill credits for exported energy are greater than the bill cost for imported energy, the remaining credit is carried over to the following month.

For a customer on a time-of-use (TOU) rate, the net consumption is computed by time period, and the bill credit is based on the full retail rate at the time the energy is exported. Since TOU rates are higher during the peak period, it is possible for TOU customers to have bill credits that more than offset their bill even when they consume more energy in a month than they produce. Essentially, this customer sells back energy at a high rate, and buys energy at a low rate.

Currently, the amount of excess generation credited by the utility is bounded. At the end of a 12-month billing period any remaining credit for net-excess generation is forfeited to the utility, and the customer begins the new 12-month billing period with a zero balance. This provision of the law reduces any incentive for the customer to oversize generation with respect to load.

With the enactment of AB 920, beginning in 2011[18] customers may carry forward indefinitely their bill credit for any net-excess generation, or receive Net

[17] Under P.U. Code 2827 solar NEM customers receive compensation at the full retail rate; other rules apply to biogas, fuel cells, and wind NEM customers.
[18] Customers may sign-up for Net Surplus Compensation beginning in January 2010; they will not receive compensation until 2011, at the end of the 12-month period that would otherwise expire.

Surplus Compensation for the excess generation at a rate to be determined by the CPUC.

3.1.1. NEM Costs

A cost of the NEM program to the utility and, by extension, to ratepayers, is the "purchase" price paid to the customer for any excess generation. The sum of these individual "purchases" makes up one cost component of NEM. Currently, the utility purchases excess generation monthly at the full retail rate[19], providing customers with bill credits. However, the bill credits currently expire if not used to offset other purchases (i.e. consumption from the grid) within a 12-month customer-specific true-up period. Beginning in 2011, customers may continue to carry over bill credits beyond the 12-month true-up period, or receive payment for the excess generation balance. This payment or carryover represents an additional cost to ratepayers.

To administer the NEM program, utilities also incur additional overhead costs. We consider the incremental billing costs of NEM in our base case analysis. Since the NEM statute prohibits utilities from charging customers for interconnection, interconnection costs born by the utility are another cost of NEM. Because we had only limited data on interconnection costs associated with NEM, we evaluate this cost in a sensitivity test.

3.1.2. NEM Benefits

The energy obtained from NEM exports does not need to be purchased elsewhere and delivered by the utility to customers. Therefore, the benefit of NEM is the sum of the costs that the utility avoids as a result of customer generation exported to the grid. The avoided costs considered in our analysis include: energy purchases; generation capacity or resource adequacy; line losses; transmission and distribution capacity; air pollution permits and offsets including

[19] This is true for NEM solar customers, which are the focus of this report. Other types of generation (e.g. biogas, fuel cells) receive less than the full retail for some or all of their bill credits. All customers receive the full retail rate value for the portion of their generation that is used to directly offset load, but only *exported* generation is relevant to the this study.

CO_2; ancillary services; and renewable energy purchases. The value of each of these elements is forecasted by hour and location for a 20-year period. This approach is largely the same as that used for evaluation of CPUC energy efficiency programs. Avoided costs are discussed in greater detail in Chapter 5 and in Appendix A to this report.

3.1.3. Sensitivity Analysis

We conduct four sensitivity analyses:

1. **Billing Costs**. NEM billing results in additional administrative cost -- for example, to upload and validate metered data. The utilities have an increased cost on a per bill basis (over and above a non-NEM customer) to process each NEM bill. For the purposes of our base case, we assume that the incremental NEM billing costs remain constant in nominal dollars through the analysis period. To test the effect of potential future billing efficiencies, sensitivity analysis tests the case where there are no incremental billing costs of NEM. While it is not realistic that incremental billing cost could drop to zero immediately, this sensitivity provides a bound for savings that are possible through greater billing efficiencies.

2. **T&D Avoided Costs**. For the purposes of our base case, we calculate T&D avoided costs in a similar manner to that used for the evaluation of energy efficiency programs (see Section 5.2). Sensitivity analysis tests the case where T&D avoided costs are not included.

3. **Standby Charges**. For the purposes of our base case, we assume that customers would not be assessed standby charges in the absence of NEM, just as they are not under NEM. Sensitivity analysis tests the case where customers *would* be assessed standby charges in the absence of NEM.

4. **Interconnection Costs**. Because only one of the three utilities provided interconnection costs in response to our data request, the base case does not include interconnection costs. In the sensitivity analysis, we apply available interconnection cost data to all three utilities.

4. Data and Methodology for Estimating Hourly NEM Export

As discussed in Chapter 3, calculation of NEM costs and benefits hinges on the amount and timing of excess generation exported to the grid by NEM customers (and the rates under which these customers are billed). However, as discussed below, available data do not provide a precise measure of the amount and timing of energy exported by every NEM customer. This chapter discusses the limitations of available data and our methodology for overcoming them.

4.1. Data Availability and Issues

4.1.1. Data Need

To precisely measure the costs and benefits of NEM as we have defined them in Chapter 3, the following data would be needed for each NEM customer:

- Hourly gross consumption for each hour of the year being evaluated (2008 in our analysis)
- Hourly gross PV generation (output) for each hour of the year being evaluated

With the above data, we can calculate the amount and timing of excess generation exported to the grid (the shaded area in Figure 3 from Chapter 3), and thereby calculate the cost to the utility (and benefit to customers) of compensating customers for this generation export at the customers' respective retail rates.

4.1.2. Available Data

Our analysis draws on several sources of data pertaining to NEM customers with solar PV, shown in Table 14.

Table 14: Data sources for NEM analysis

	Data Source	Number of Records			
		PG&E	**SCE**	**SDG&E**	**Total**
1	**Generation capacity for NEM customer Solar PV**[20]	**26,864**	**8,659**	**5,721**	**41,244**
2	Installed PV generation capacity and other PV system characteristics from the PowerClerk database[21]	18,555	7,180	3,702	29,437
3	NEM customer billing data from the utilities, which provides monthly consumption net of PV generation[22]	25,537	5,768	6,685	37,990
4	Itron SGIP hourly metered 2008 PV generation	303	177	77	557
5	Hourly metered 2008 PV generation from CSI PMRS providers[23]	39	20	10	69
6	***Billing data successfully linked to PV capacity data (Row 3 linked to Row 1 or Row 2)***	***19,310***	***5,247***	***6,679***	***31,236***

Based on data provided by the utilities (Row 1), there were a total of 41,244 accounts with solar PV generation on NEM at the end of 2008. Rows 1 and 2 provide capacity (kW) information, but do not provide a measure of energy generated (kWh) for any period.

Monthly net consumption data (billing data) for NEM customers with solar PV were available for 37,990 accounts (Row 3). This data shows the net of consumption plus PV generation but does not provide a measure of solar generation (kWh) for any period.

Using unique identifiers such as Account ID or Application ID, we were able to link 31,236 of the billing records to PV capacity data in order to couple at least minimal information on generation with the billing data (Row 6).

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[20] PG&E data are from a September, 2009 response to a CPUC data request. SCE and SDG&E data were provided in conjunction with the CPUC's data request related to E3's CSI and NEM evaluations.
[21] Projects that were cancelled or withdrawn are excluded. The PowerClerk database includes only projects that were initiated after 1/1/07; NEM customers with earlier installation dates are therefore not included.
[22] Includes all accounts that had a full year of 2008 billing data. SDG&E and SCE's billing data included nameplate capacity of PV system for some accounts.
[23] PMRS = Performance Monitoring and Reporting Service. The numbers represent systems for which the data was at least 90% complete (less than 10% of interval data values were missing).

As noted in Section 4.1.1, hourly generation and consumption data are needed to directly estimate NEM costs and benefits. The 31,236 records that link monthly net consumption and PV capacity are thus insufficient for direct estimation of benefits and costs. Hourly gross generation data, in fact, is available for only a small portion of the total systems (Rows 4 and 5; 557 + 69 = 626 out of 31,236, or 2%).

Because we do not have anything approaching a complete measure of the amount and timing of exported energy under NEM, we must develop a methodology to estimate it. We do this on a representative basis, by "binning" customers into categories of similar customers, as described in the next section. This analysis uses the 31,236 records with net consumption and solar PV system capacity data. We then adjust the results of our calculations to account for the remaining solar PV NEM accounts we were not able to use (the difference between Rows 6 and 1).

4.2. Methodology for Estimating Hourly NEM Export

To estimate hourly exported energy under NEM, we develop "bins" of customers with similar characteristics. For each bin, we create representative generation and consumption profiles, which we use to calculate customer bills with and without NEM. Our process to develop customer bins and representative generation and consumption profiles entails the following steps:

1. Develop annual gross generation estimates for all customers
2. Develop annual gross consumption estimates for all customers
3. Sort customers into bins of similar customers
4. Estimate representative *hourly* generation and consumption profiles for each bin

Each step is described in detail below.

4.2.1. Annual Gross Generation Estimates

As described in Section 4.1.2, metered generation data is available for only a small portion of NEM customers. For the remaining customers, we must estimate annual gross generation. Our method for doing this is to estimate a capacity factor for various system types and apply this capacity factor to the nameplate rating.[24]

To estimate a capacity factor, we group systems for which we have hourly generation data into groups with similar characteristics. The characteristics we use to create these groups are:

- Utility (as PV system characteristics and other factors such as geography and weather may vary from one utility to another)
- Customer class – residential and non-residential (as different types of systems are used by different types of customers)
- Climate zone (the local climate at the location of the PV has a direct impact on PV output)
- System age (we account for the degradation of PV output over time)[25]

The above categorization creates 32 groups; each group contained 1 to 68 output profiles, in accordance with available data, which we used to estimate an average capacity factor for the group. Average capacity factors for each group are shown in Table 15.

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[24] Where we had only CEC-AC capacity, we applied an average scale factor to increase the CEC-AC rating to nameplate capacity.

[25] To account for age where directly metered data is insufficient, we calculate an average capacity factor and average age for all available metered profiles in the group (Table 15), which we then degrade by 1.25 percent annually to estimate a capacity factor for each system from the billing data. For example, if the average age is 2 and the system in the billing data is 5 years old, we degrade the capacity factor by 3 years.

Table 15: Estimated Solar PV Capacity Factors by Utility, Climate Zone, and Customer Class (average for all system ages)

Utility	Climate Zone	Customer Class	
		Residential	Non-Residential
PG&E	Coast	15.4%	15.3%
	Desert/Mountain	16.1%	16.6%
	Hills	14.8%	16.7%
	Valley	15.7%	17.9%
SCE	CEC Zone 6	14.7%	16.8%
	CEC Zone 8	17.3%	16.2%
	CEC Zone 9	17.8%	19.6%
	CEC Zone 10	19.8%	16.1%
	CEC Zone 13	16.8%	17.0%
	CEC Zone 14	20.6%	17.7%
	CEC Zone 15	19.6%	20.7%
	CEC Zone 16	19.5%	18.5%
SDG&E	Coastal	18.0%	16.0%
	Mountains	17.9%	20.1%
	Desert	21.0%	20.4%
	Inland	17.4%	20.2%

We apply the calculated capacity factors to the nameplate capacity rating of each customer in the group in order to calculate estimated annual gross generation for every NEM solar PV customer in our analysis.

4.2.2. Annual Gross Consumption Estimates

Annual *net* consumption for all customers in our analysis was provided by utilities from billing data. To estimate annual *gross* consumption, we simply add the estimated annual gross generation to the measured annual net consumption.

4.2.3. Binning

We bin customers based on factors that are likely to result in relative homogeneity in generation and consumption profiles. We first divide customers into various groups, based on the following factors:

- Utility (as consumption and PV system characteristics may vary from one utility to another)

- Customer class – residential and non-residential (as different customer classes tend to have different load profiles and are also likely to use different types of PV systems)

- Climate zone (the location of the PV has a direct impact on both load and PV output)

- Retail rate (this provides a finer cut on customer type and is also necessary for the ultimate bill calculation)

This creates a total of 86 customer groups, representing possible combinations of the above factors. For each of these groups, we further distinguish customers by:

- Gross annual consumption (this ensures customers of a similar size are analyzed together)

- Ratio of annual PV generation to annual gross consumption (this ensures that customers are grouped into bins with similar net-export ratios)

The delineations used for gross annual consumption and PV generation to consumption ratio are shown in Table 16.

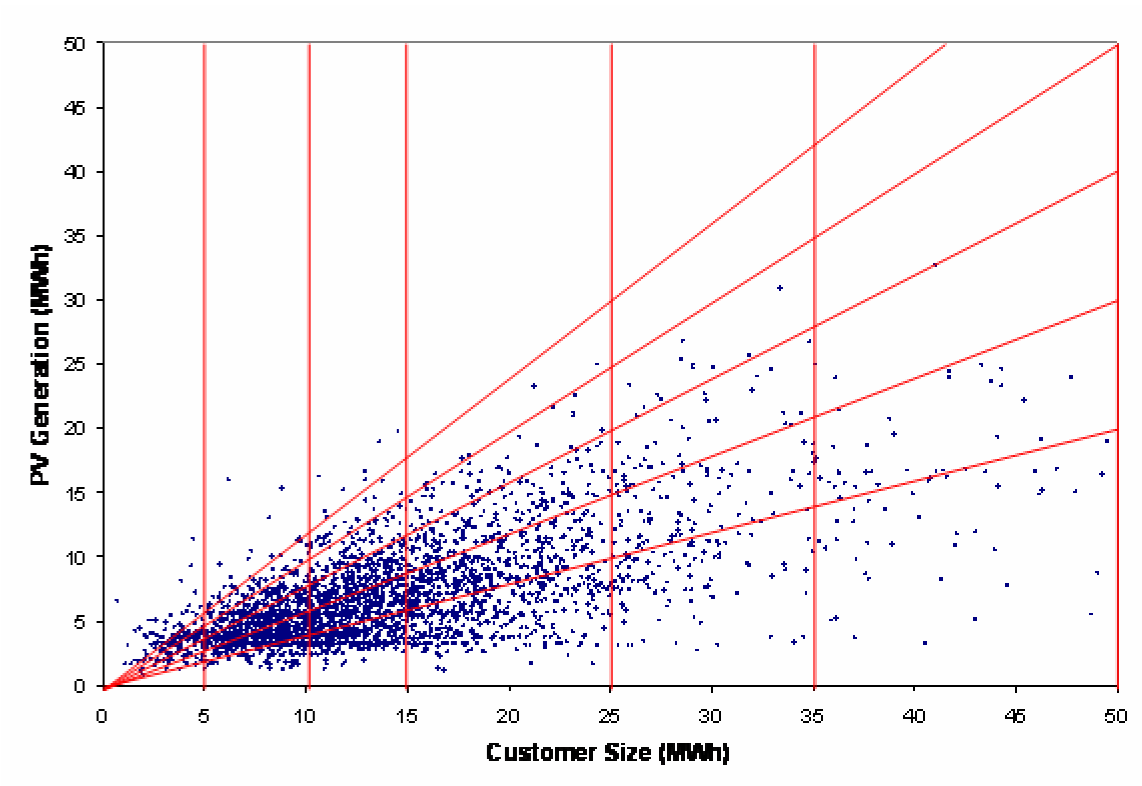
Table 16: Delineations of gross annual consumption and generation/consumption ratio for purposes of binning

Ratio of annual PV generation to gross annual consumption	Gross annual consumption
0 to .4	0 to 5 MWh
.4 to .6	5 to 10 MWh
.6 to .8	10 to 15 MWh
.8 to 1	15 to 25 MWh
1 to 1.2	25 to 35 MWh
Over 1.2	35 to 50 MWh
	50 to 100 MWh
	100 to 500 MWh
	Over 500 MWh

Figure 4 shows the binning profile for an example group of customers (PG&E, Residential, “Valley” climate zone, rate “E1”). The generation-to-consumption ratio delineations from Table 16 are defined by the diagonal lines in Figure 4. Customers (represented by dots) below the lowest diagonal have estimated generation less than 40% of consumption. Customers above the second from top diagonal line have a generation to consumption ratio of greater than 1.0, indicating that they generate more energy than they consume.

The gross annual consumption delineations from Table 16 are defined by the vertical lines in Figure 4.

Figure 4: "Bins" for Residential NEM customers of PG&E, "Valley" climate zone, rate "E1"

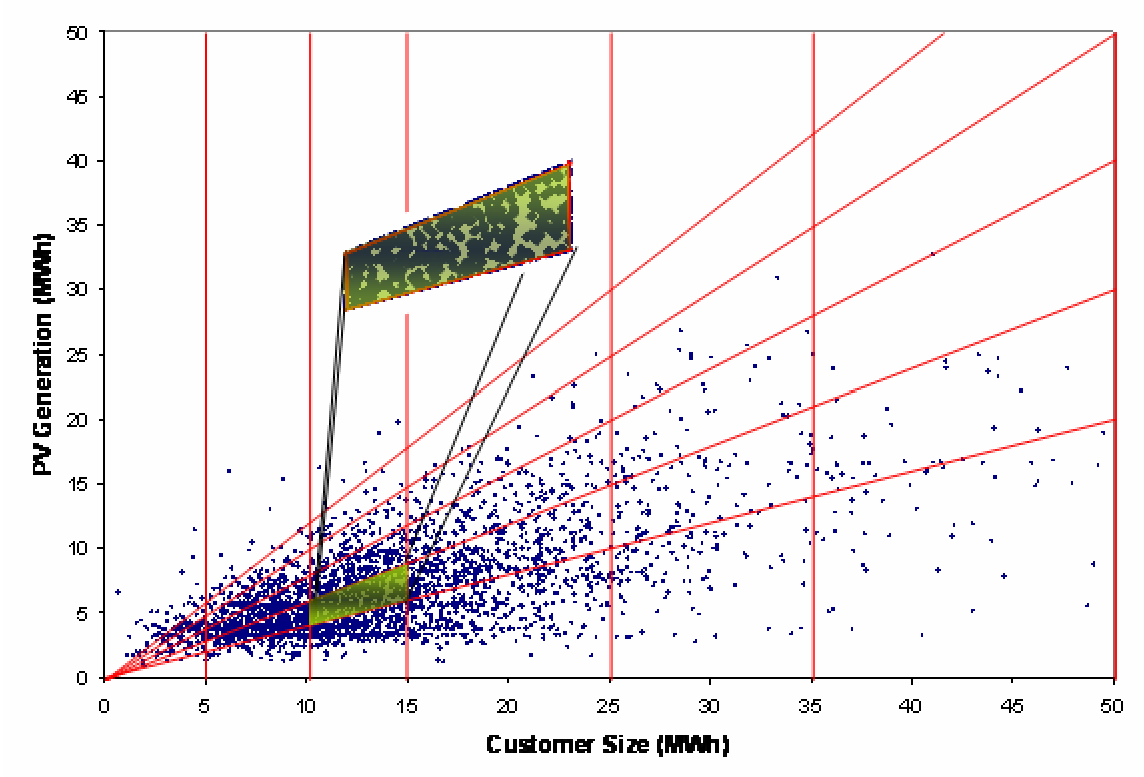


Each cell defined by red borders in Figure 4 represents a bin of customers that are likely to exhibit similar load and PV generation profiles. We perform similar binning for each of the 86 groups of customers, resulting in 1,387 bins containing at least one account. We discard bins for which we have no hourly generation or consumption data. These discarded bins number 134 in all, and, with an average of just over 6 accounts in each bin, do not represent very many customers. Thus, the final number of bins included in our analysis is 1,253. We "gross-up" final results to account for the discarded bins.

4.2.4. Representative *hourly* generation and consumption profiles

As described above, each bin (see Figure 5) contains a set of customers that are likely to exhibit similar generation and load profile shapes.

Figure 5: Callout showing customer bin for Residential NEM customers of PG&E, "Valley" climate zone, rate "E1" with gross consumption from 10-15 MWh and a generation/consumption ratio of 0.4- 0.6.



The specific hourly load and generation profiles for each customer in the bin are unknown, as this data was not available. For each bin, we develop representative load and generation profiles as described below.

Representative Hourly Gross Consumption Profiles

Creation of representative gross consumption profiles entails the following steps:

1. For each bin, calculate average gross annual consumption across all the customers in the bin.

2. Sort all available gross customer load shapes that apply to the bin by load factor. This step uses actual metered load data from utility load research profiles or metered customer data for customers with PV, where available.

3. Pick two load shapes to represent the bin based on the 33% and 67% percentile of the load factors. Scale these load shapes so that the annual gross consumption matches the average for the bin.

Representative Hourly Gross Generation Shapes

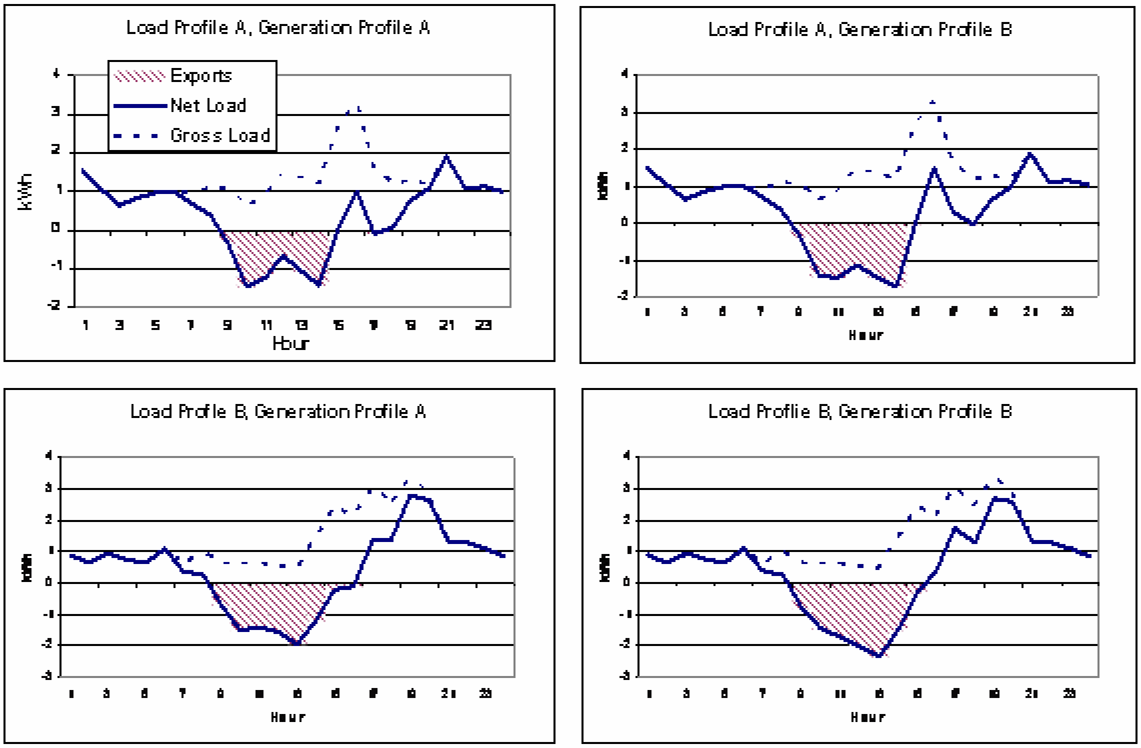
We developed 624 representative PV output shapes to represent the generation characteristics of PV systems in each bin (many of the output shapes were applicable to more than one bin). Of these 624, metered data were available for all hours in 2008 in a small number of cases. For much of the remainder, we augmented available data with simulation by statistically comparing simulated data to metered data and calculating an “adjustment factor” which we used to adjust the simulated data. The advantage of this approach is that the adjustment is able to account for conditions, such as system shading, that the simulation is not able to predict. Overall, the average adjustment factor between the simulated and metered data was 0.82. In 294 of the 624 cases, we used purely simulated data. This was necessary to adequately represent the spectrum of generation in the bins.

To create representative hourly gross generation profiles we randomly select two PV output profiles from among available PV interval data in the bin.

Representative Net Consumption Shapes

We combine each representative hourly generation profile with each representative gross hourly load profile to arrive at four representative *net* load profiles. Figure 6 shows our calculated representative net load profiles for the same customer bin discussed earlier (PG&E, Residential, “Valley” climate zone, rate “E1”, 10-15 MWh, generation/consumption ratio of 0.4-0.6). While Figure 6 shows only a single day for illustration, we calculate the generation and load profile for the full year, 2008.

Figure 6: Representative net consumption shapes for a single example day for the bin shown in Figure 5



As can be seen in Figure 6, each representative generation and load profile combination produces a different estimate of the amount and timing of power exported to the grid. Annual energy export and percent of total generation exported are shown in Table 17.

Table 17: 2008 Exported Energy (kWh) and Percent of Generation Exported under four representative net load shapes from a sample bin

	Load Profile A	Load Profile B
Generation Profile A	2,284 (37%)	2,514 (41%)
Generation Profile B	2,383 (38%)	2,505 (40%)

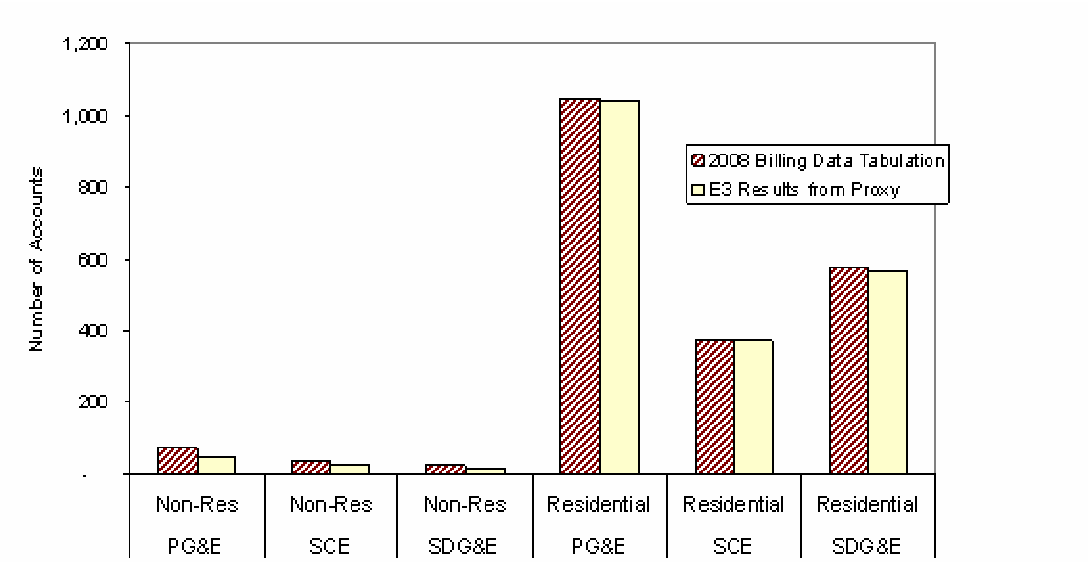
The hourly net load profiles give us the data we need to calculate bill effects. For each net consumption profile, we calculate the annual customer bill with and without NEM. We then apply this bill differential to the customers in each bin to arrive at total costs and benefits from bill credits for the bin. This process is described in detail in Chapter 5.

4.3. Benchmarking calculated results

We performed benchmarking to check the accuracy of our representative net consumption shapes. From the billing data provided by utilities, we tabulated the number of customers who have a net-export balance at the end of the year (the number of customers whose generation exceeds consumption over the year) and the associated kWh. If our method of converting monthly utility billing data into hourly net consumption profiles is accurate, our calculated values for number of customers with net-export balance and kWh exported should be closely aligned with a direct tabulation of the utility billing data. As can be seen in Figure 7 and Figure 8, this is indeed the case, providing confidence that our method for estimating net load shapes provides reasonable results. The data for these figures are shown in Table 18 and Table 19.

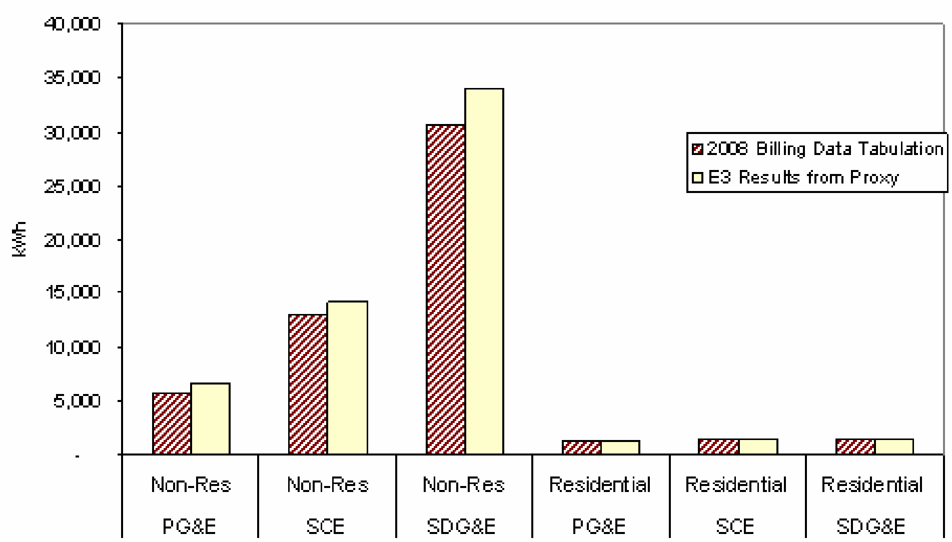
A possible third benchmark would compare the dollar value credit remaining at the end of the 12-month period in the billing data to our calculated value. However, data provided by the utilities either did not include this field or the field was included but had mostly missing data. Therefore, we were unable to perform this third benchmarking test.

Figure 7: Benchmarking of E3 calculation for number of accounts with net-export balance at end of 12-month period



Note: The number of accounts with net-export balance (shown here) is a subset of the total number of NEM accounts shown in Table 14.

Figure 8: Benchmarking of E3 calculation for kWh net-export balance at end of 12-month period (average among those with net-export balance)[26]



[26] SDG&E's larger kWh net-export balance for non-residential customers results in part from the fact that a higher proportion of SDG&E customers with net-excess generation were large customers (44% for SDG&E were larger than 50 MWh, compared to 20% for SCE and 23% for PG&E).

Table 18: Number of accounts with net-export balance at end of 12-month period and comparison to total number of accounts

		(A) 2008 Billing Data Tabulation	(B) E3 Results from Proxy	(C) Total Number of Accounts from Utility Data	(D) Difference as % of Total (A-B)/C
Non-Residential	PG&E	72	49	1,740	1.3%
	SCE	35	27	733	1.1%
	SDG&E	25	17	391	2.0%
Residential	PG&E	1,051	1,041	25,124	0.0%
	SCE	375	371	7,926	0.1%
	SDG&E	577	566	5,330	0.2%

For reference, Table 18 also shows the total number of accounts in each category. Column D shows that, compared to the total number of accounts, the difference between the utility billing tabulation and the E3 proxy calculation is small; 2% or less in every case.

Table 19: Net-export balance in total kWh remaining at end of 12-month period, billing data compared to E3 calculation (average of those with net-export balance)

		2008 Billing Data Tabulation	E3 Results from Proxy
Non-Residential	PG&E	5,727	6,596
	SCE	13,063	14,300
	SDG&E	30,624	34,027
Residential	PG&E	1,233	1,224
	SCE	1,378	1,388
	SDG&E	1,340	1,331

5. Cost/Benefit Evaluation Methodology

We calculate costs and benefits on a Net Present Value (NPV), annualized, and levelized (per-kWh-exported) cost basis for a 20-year window from 2008-2027. Throughout, real annualized and real levelized values are calculated in 2008 dollars. Annualized and levelized values, while intuitively comparable to rates and value today, should not be confused with program costs in a single (2008) year; rather, they represent effects of NEM over the entire 20-year period.

Results pertain to the fleet of solar PV generation under NEM through the end of 2008.

5.1. Non-participant costs

As described in Chapter 3, NEM costs from the utility/ratepayer perspective include bill credits to NEM customers and any additional utility operational costs.

5.1.1. Bill credit computation

Chapter 4 describes the process by which we developed representative 2008 hourly net load profiles for customers in each of 1,253 bins of similar customers (see Section 4.2.4). To calculate the cost of NEM bill credits, we compute and compare two bills using these representative net load profiles. The first bill computation assigns a zero value to any hours where the customer is a net energy exporter. In other words, the customer receives no credit for energy exported to the grid.

The second bill computation tracks energy export by TOU period and applies energy generation from hours when the customer is a net-exporter against energy consumption from hours when the customer is a net-consumer. To the extent generation exceeds consumption in any TOU period over the course of the month, the customer receives a bill credit for the net-excess generation based on the TOU rate. (If the customer is not on a TOU rate, then the calculation is not differentiated by time period).

For customers on tiered rates, the carryover credit is calculated as baseline quantity multiplied by baseline price, plus tier-2 quantity multiplied by tier-2 price, etc., up to the total quantity of kWh carried over.

Bills are calculated under the first and second method for a full year. Bill credits remaining under the second method at the end of the 12-month period are lost. The difference between the annual bill total for the first and second method provides the utility/ratepayer cost (and participant benefit) of NEM in 2008. To estimate annual bill savings for the 20-year analysis period, we adjust the annual bill savings to reflect degradation over time in PV output and rate increases. Assumptions are shown in Table 20.

Table 20: Assumptions for calculating 20-year stream and NPV of bill impacts

Annual degradation in PV Output[27]	1.25%
Rate increase in nominal dollars[28]	4.47%
Discount rate (average utility WACC)[29]	8.65%

Beginning in 2011, to reflect the effects of AB 920, any kWh credits remaining at the end of the 12-month billing period are assumed to be compensated at a value equivalent to avoided costs.[30]

From the 20-year stream of bill impacts, we compute a NPV of bill impacts for each representative customer profile for which a bill calculation was performed. We then multiply the result by the number of customers represented by the

[27] Based on information in Itron's 2008 SGIP Impact Report, *CPUC Self-Generation Incentive Program Eighth-Year Impact Evaluation*, July 2009.

[28] The retail rate escalation is from the 33% RPS Implementation Analysis "Low Load" sensitivity, http://www.cpuc.ca.gov/PUC/energy/Renewables/hot/33implementation.htm. It is based on projections of natural gas prices, renewables costs, and load forecast including efficiency and on-site generation levels. Alternative E3 nominal retail rate increase estimates range from 4.32% to 5.07%.

[29] Utility Weighted Average Cost of Capital (WACC) is based on utility average WACCs used in the E3 Energy Efficiency Avoided Cost Calculator, which are in turn derived from utility cost of capital filings as provided by CPUC Energy Division staff.

[30] The CPUC is required under AB 920 to establish a compensation value for remaining kWh credits and will do so in a 2010 rate proceeding. In the absence of a CPUC determined value, E3 uses a value equivalent to avoided costs since the law specifies that "all other ratepayers will be held indifferent" which implies a value along the lines of avoided cost.

profile to arrive at a total NPV of bill impacts for customers in the bin. Bins are then summed to provide the program total.

Table 21 shows the total number of accounts and nameplate kW in our analysis by rate.

Table 21: Number of accounts and total nameplate kW of NEM customers under various rates

Utility	Rate	# of Accounts	Total Nameplate kW
PG&E	A1	504	9,314
	A10_TOU-S	3	491
	A10S	289	31,737
	E1	15,143	74,677
	E19S	47	17,289
	E1M	142	847
	E20PF	7	5,219
	E7	1,920	9,738
	E8	933	7,931
	Other	322	11,751
SCE	D	4,759	29,326
	GS1	164	2,162
	SG2	178	11,606
	Other	146	14,301
SDG&E	A	156	1,933
	A6	173	23,639
	DR	6,271	28,633
	Other	79	3,706
Total		*31,236*	*284,299*

The rates with the largest number of NEM accounts and generation capacity are “E1” at PG&E, “D” at SCE, and “DR” at SDG&E. These three residential rates have tiered structures, such that rates increase with consumption above a baseline, as shown in Table 22.[31]

[31] Rates are available for each utility online at the following urls:
PG&E - http://www.pge.com/tariffs/ERS.SHTML#ERS;
SCE - http://www.sce.com/AboutSCE/Regulatory/tariffbooks/ratespricing/;
SDG&E - http://www.sdge.com/regulatory/currentEffectiveTariffs.shtml.

Table 22: Tiered rates at PG&E, SCE and SDG&E, December, 2009

Energy Usage	PG&E Rate "E1"	SCE Rate "D"	SDG&E rate "DR"	
			Summer	Winter
Baseline	0.11531	0.10933	0.11579	0.11784
101-130 %	0.13109	0.13634	0.13596	0.13801
131-200 %	0.26078	0.27040	0.29767	0.28348
201-300 %	0.38066	0.31931	0.31767	0.30348
Over 300%	0.44348	0.36823		

5.1.2. Additional utility operational costs

NEM increases utility operational costs in two ways. Under NEM, utilities may not charge customers for interconnection costs associated with the customer's generation; therefore, these non-recovered interconnection costs are a cost of NEM. Utilities also incur incremental billing administration costs as a result of NEM. Due to a lack of available data, only the latter cost is considered in our base case analysis.

In response to a CPUC data request, utilities estimated incremental billing costs as shown in Table 23, Table 24, and Table 25. These costs arise from special procedures required to complete the NEM billing. For example, PG&E notes that NEM billing cost "includes initial set-up of the NEM service agreement plus monthly system validations, uploads to CC&B, and routine account maintenance (i.e. meter changes, rate changes, change of parties)."[32]

Table 23: Monthly incremental cost of billing each NEM customer, PG&E

Billing Method	PG&E
Automatic NEM billing	$15.55
Manual NEM billing	$29.34

According to the data request response, 80% of PG&E NEM customers are automatically billed.

[32] PG&E, Rulemaking 08-03-008 Data Response, Oct. 21, 2009.

Table 24: Monthly incremental cost of billing each NEM customer, SCE

Customer Type	SCE
Residential	$3.02
Non-Residential	
< 20 kW	$2.95
20 – 200 kW	$2.97
TOUs < 200 kW	$2.34
TOUs > 200 kW	$0.00

Table 25: Monthly incremental cost of billing each NEM customer, SDG&E

Billing Method	SDG&E
Residential	$5.96
Non-Residential	$17.44

As can be seen in the tables above, the utilities provided billing cost data by varying categories. For computational simplicity, we calculated a weighted average incremental billing cost by customer class, shown in Table 26.

Table 26: Weighted average monthly incremental NEM billing cost per-customer

Customer Type	PG&E	SCE	SDG&E
Residential	$18.31	$3.02	$5.96
Non-Residential	$18.31	$2.55	$17.44

To calculate the annual incremental billing cost associated with NEM, we multiply the monthly cost per customer shown in Table 26 by 12 and then by the total number of customers in each category. This gives us the total incremental billing costs for 2008. We assume this value remains constant in nominal dollars over the 20-year analysis period for purposes of calculating the NPV of incremental billing costs over the 20-year period. This assumption is consistent with a modest incremental billing cost decline over time in real terms as a result of business-as-usual efficiency gains; however, no explicit estimate of billing cost efficiencies was made.

5.2. Non-participant benefits

5.2.1. Utility avoided costs

Every kWh of electricity exported to the grid by customer-generators is a kWh the utility does not have to procure and deliver through other means. These avoided procurement and delivery costs are known as *avoided costs*.

Avoided costs have a history of being used in California to evaluate the cost-effectiveness of conservation and demand-side management programs; E3's time-and-area-specific methodology for estimating the avoided costs of energy efficiency programs was adopted by the CPUC in D.05-04-024 (later updated in D.06-06-063). A similar approach has also been adopted by the California Energy Commission for the Title 24 Building Standards. D.09-08-026 orders that cost-effectiveness evaluation of distributed generation (including NEM cost-benefit analysis) should use an avoided cost methodology that is consistent with the one used in earlier proceedings.[33]

E3's avoided cost model is available for public review and may be downloaded from the E3 web site.[34] For each of 16 climate zones,[35] the avoided cost methodology estimates the total hourly marginal cost of delivering electricity as a sum of seven components shown in Table 27.

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[33] "The DG cost-benefit tests should use the avoided cost methodology developed by Energy and Environmental Economics Inc. (E3) and adopted in Decision (D.) 05-04-024, and later updated in D.06-06-063. The inputs to this E3 avoided cost methodology should be consistent with those used in Commission directed evaluation of energy efficiency programs. Any modifications to adapt these avoided costs to DG facilities shall be thoroughly documented and justified by the entity performing the cost-benefit analysis" D.09-08-026, p. 3.

[34] http://www.ethree.com/CPUC_CSI.html

[35] The 16 climate zones are those specified by the California Energy Commission for Title 24 energy efficiency standards

Table 27: Components of total hourly marginal cost of delivered electricity

Component	Description
Energy Generation	Hourly wholesale value of energy at the point of the wholesale energy transaction, based on actual 2008 data
Losses	Losses between the delivery location and the point of the wholesale energy transaction
Ancillary Services	The costs of providing system operations and reserves for electricity grid reliability
System Capacity	The costs of building new generation capacity to meet system peak loads
T&D Capacity	The costs of expanding transmission and distribution capacity to meet peak loads
Environment	The cost of CO2, NOx, and particulates (PM10) associated with electricity generation
RPS Adder	The additional cost of purchasing renewable resources to meet an RPS

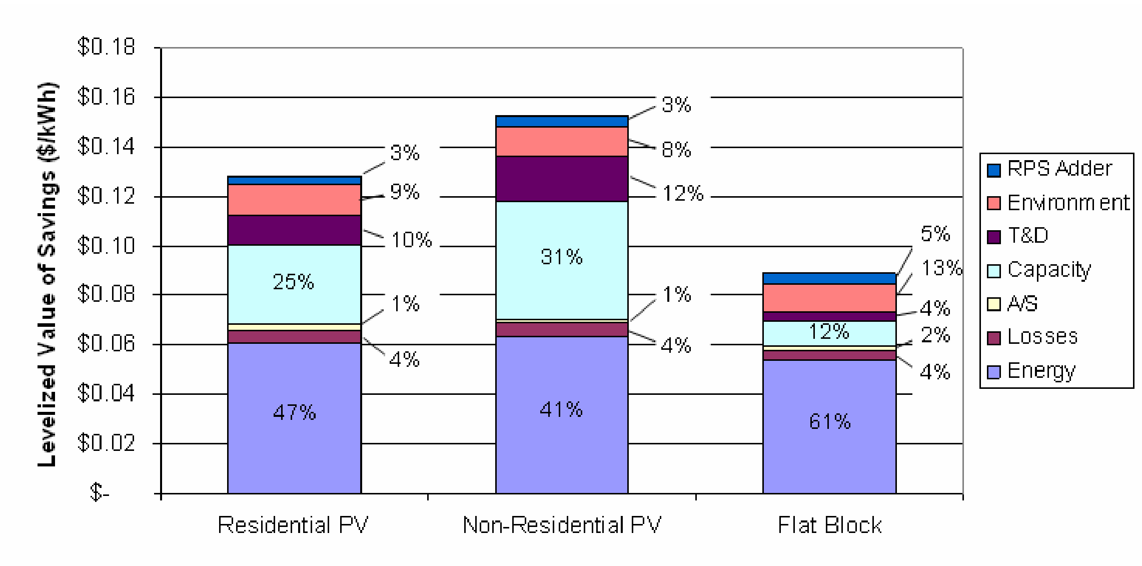
Each component is estimated for each hour in a typical year, and forecasted into the future for 30 years. The hourly level of granularity captures the diversity of avoided costs that vary by time-of-day and that are markedly higher in the top 300 or so hours of the year, when high loads drive the need for generation, transmission, and distribution capacity.

The result is a set of hourly avoided costs for each climate zone for each year of the analysis. The avoided costs may then be applied to corresponding individual net-export shapes to calculate total avoided costs for each shape.

For illustration, Figure 9 presents the levelized avoided cost benefits for three sample generation shapes: a randomly selected residential PV output shape, a randomly selected non-residential PV output shape, and flat (24x7) production shape. The levelized benefits in Figure 9 are for the full PV generation profile rather than just energy exported.

The flat block comparison illustrates the fact that levelized avoided costs (per kWh of generation) are higher for generation that coincides with system peak than for steady output, since the output profile is highly correlated with peak times on the system. This is illustrated by the higher share of capacity costs and T&D for PV as compared to the flat generation shape.

Figure 9: Levelized savings from avoided costs for two sample solar PV generation shapes compared to a flat block



The two PV output shapes underlying Figure 9 were randomly selected from the data used in our analysis. There is variation in avoided costs between PV output shapes because weather, system specifications, and other factors affect both the timing and amount of generation and the local value of the generation. For example, the non-residential PV output shape underlying Figure 9 may have resulted from a PV system with a better orientation to the sun the residential PV system.

5.2.2. Differences from avoided costs used for energy efficiency

There are three differences between the avoided costs currently used for energy efficiency at the CPUC and those used in the NEM analysis.

Data updates

The first difference is that all key inputs – such as natural gas prices, electricity prices, and 2008 temperature profiles by climate zone – have been updated. Thus, the metered hourly generation and consumption data from 2008 on which our analysis is based can be compared to actual loads and market prices by hour for 2008.

Generation capacity cost

The second difference is a change to the approach used to allocate generation capacity costs to hours. The existing energy efficiency avoided costs simply use an average annual market price forecast that has been “shaped” by the hourly market prices that were observed in the California Power Exchange (PX) from 1998 to 1999. During this “functional” period of the PX, with plenty of generation capacity, these prices are relatively flat over time even though the market included the total payment to generators including energy and capacity. This data series has long been observed to undercount capacity during the peak periods and has led to the need for “adjustment factors” applied to peak reducing energy efficiency programs such as air conditioning upgrades.

The prior allocation methodology has been replaced with a new approach that approximates the current market structure in California which has two components. The first component is a wholesale energy market (MRTU) and the second is a bilateral Resource Adequacy (RA) market. The new approach adds consideration of the RA capacity market to the avoided cost formulation. The RA price in 2008 is set at the average observed RA cost and trended toward the long-run total cost in the resource balance year. These annual costs are then allocated to the top 250 load hours observed in 2008. This approach approximates the value of generation capacity that NEM exports and other DG resources will provide the system.

Avoided RPS costs

The third difference is the addition of a new component of avoided cost that values the avoided renewable portfolio standard (RPS) purchases. RPS goals require 33% of retail sales to be met with renewable generation by 2020.[36] Lower total electrical load reduces the quantity of generation purchased, including renewable generation – as load declines, the quantity of renewable power needed to make up 33% of load declines correspondingly. The value of

[36] Although a 33% RPS has not yet been adopted by the legislature, Executive Order S-14-08 sets a 33% RPS target by 2020 and the eventual passage of corresponding legislation is, in our view, a likely outcome and therefore the best way to model this future condition. A 20% RPS assumption would result in a negligible change to the results.

this component is small because California currently purchases significantly less renewable energy than the 33% goal. For the purposes of this analysis we assume that California will continue to bring online as much renewable energy as is practicable until the 33% goal is achieved in 2020 and only then does the "netting" effect change the RPS purchase requirements. This results in a relatively small adjustment of less than \$5/MWh (or \$0.005/kWh).

The avoided cost methodology is described in detail in Appendix A.

6. Results

6.1. Benefits and costs of NEM – Base Case

Our NEM analysis included a base case and a number of sensitivities. The base case analysis calculates total NEM program costs under the following assumptions:

1. In January, 2011, customer-generators begin receiving compensation for remaining bill credits at the end of the year at a rate that reflects utility avoided costs

2. Incremental billing costs of NEM remain at the current nominal levels specified by the utilities in their response to our data request

3. Avoided costs are based on the methodology described in Section 5.2 and include deferral of avoided T&D investment[37]

4. Loss of standby charge revenue is not included as a cost of NEM under the assumption that standby charges would not apply in the absence of NEM

5. Interconnection costs are not included as only one utility provided us with interconnection costs in response to our data request

Sensitivity analyses test the alternate cases for assumptions 2-5, namely: no incremental billing costs; no inclusion of transmission and distribution investment deferral in the avoided cost calculation; inclusion of lost standby charge revenue; and inclusion of interconnection costs for all utilities based on limited available data.

All results are presented in real 2008 dollars and pertain to the NEM program within the scope of our study; that is, the fleet of solar PV generation enrolled in

[37] This is consistent with the conclusion D.09-08-026 that, "DG cost-benefit tests [should use] the avoided cost methodology adopted in D.05-04-024," (p. 64), which includes T&D avoided costs, and with Attachment A to the decision which specifies inclusion of T&D avoided costs.

NEM through the end of 2008. We use the terminology "bill impacts" to encompass both intra-year bill credits that are offered at the full-retail rate and compensation for any outstanding bill credits at the end of each 12-month period in accordance with AB 920 (assuming compensation at the avoided cost rate). Bill impacts do not include the value of generation that directly offsets load and therefore is not a part of NEM.

Table 28 presents the base case benefits and costs of solar NEM on a net present value (NPV) basis for the 20-year analysis period from the perspective of ratepayers (utility costs and benefits). We estimate that on a lifecycle basis, generation installed through 2008 will result in NPV costs to ratepayers of approximately $230 million.

Table 28: 20-Year NPV Total Benefits and Costs of solar NEM, by Utility ($000s)

	Residential	Non-Residential	Total
PG&E			
Bill Impacts	($170,150)	($52,727)	($222,877)
Incremental Billing Cost	($51,301)	($3,262)	($54,563)
Avoided Cost (benefit)	$76,998	$31,923	$108,921
Total, PG&E	($144,452)	($24,066)	($168,519)
SCE			
Bill Impacts	($69,626)	($41,904)	($111,531)
Incremental Billing Cost	($2,830)	($632)	($3,462)
Avoided Cost (benefit)	$30,585	$40,526	$71,111
Total, SCE	($41,871)	($2,011)	($43,882)
SDG&E			
Bill Impacts	($25,834)	($13,668)	($39,503)
Incremental Billing Cost	($3,113)	($683)	($3,796)
Avoided Cost (benefit)	$13,652	$11,414	$25,066
Total, SDG&E	($15,296)	($2,937)	($18,232)
All Utilities			
Bill Impacts	($265,610)	($108,300)	($373,910)
Incremental Billing Cost	($57,244)	($4,577)	($61,821)
Avoided Cost (benefit)	$121,235	$83,864	$205,099
Total, All Utilities	($201,619)	($29,013)	($230,632)

The NEM bill impacts in Table 28 are only a portion of the bill savings that customers realize from their solar generation. Customers also receive the benefit of direct offsets to their energy use, and hence their bills, at times when the customer's electric load exceeds generation output. Though this direct bill offset is not a part of NEM or our NEM cost-benefit analysis, we calculated the value for reference.

Table 29: Direct consumption offset compared to NEM bill impacts, NPV ($000s)

	Total – All Utilities	**Percent**
Direct Offset	$1,119,309	75%
NEM Bill Impacts (including AB 920 effects)	$373,910	25%
Total Bill Effects	*$1,493,219*	*100%*

Table 29 shows that direct offsets to consumption make up 75% of the total bill savings resulting from solar PV generation installed by NEM customers and the NEM bill credit effects that are the subject of this study are responsible for 25% of customers' total bill savings. In other words, the bill effects from NEM are one-third as large as the bill effects that would result even if there were no NEM.

Table 30 shows two additional ways of looking at total program costs: the annualized and levelized values. For reference the NPV value from Table 28 is also included.

Table 30: Net Costs of solar NEM expressed in NPV ($000s), Annualized Value ($000s), and Levelized Value ($/kWh-exported)

	Residential	Non-Residential	Total
PG&E			
20-year NPV ($000s)	($144,452)	($24,066)	($168,519)
20-year Annualized ($000s)	($12,327)	($2,054)	($14,380)
Levelized ($/kWh-exported)	($0.22)	($0.07)	($0.17)
SCE			
20-year NPV ($000s)	($41,871)	($2,011)	($43,882)
20-year Annualized ($000s)	($3,573)	($172)	($3,745)
Levelized ($/kWh-exported)	($0.14)	($0.01)	($0.06)
SDG&E			
20-year NPV ($000s)	($15,296)	($2,937)	($18,232)
20-year Annualized ($000s)	($1,305)	($251)	($1,556)
Levelized ($/kWh-exported)	($0.14)	($0.03)	($0.08)
All Utilities			
20-year NPV ($000s)	($201,619)	($29,013)	($230,632)
20-year Annualized ($000s)	($17,205)	($2,476)	($19,681)
Levelized ($/kWh-exported)	($0.19)	($0.03)	($0.12)

On an annualized basis, we estimate NEM costs for the solar fleet as of 2008 at approximately $20 million/year. NEM costs on a levelized basis per kWh exported to the grid total approximately $0.12/kWh-exported.[38] The levelized cost for residential customers ($0.19/kWh-exported) is substantially higher than for non-residential ($0.03) mainly because of residential customers' higher energy rates.

While the NPV and annualized values will vary with the number of accounts enrolled in NEM, the levelized value will remain constant in real dollars to the extent underlying factors (rates, consumption and generation profiles, etc.) remain constant.

The levelized $/kWh-exported cost is not an expression of NEM program costs in 2008, nor of the cost to "purchase" a kWh of solar generation through NEM. Rather, it is a measure of the net costs (net of *avoided cost* benefits) to

[38] This cost is unrelated to and does not include any CSI incentives, which step-down, as program penetration increases, from $0.39/kWh to $0.03/kWh for Performance-Based Incentives.

ratepayers of NEM, considered over all the kWh “purchased” by the utility through NEM.

6.1.1. Base Case results by customer size

Table 31 shows how the net costs of solar NEM vary by customer size.

Table 31: 20-year Net solar NEM costs by customer size and utility (NPV $000s)

	Customer Size	PG&E	SCE	SDG&E	Total
Residential	0 to 5 MWh	($4,212)	($165)	($269)	($4,646)
	5 to 10 MWh	($19,485)	($2,679)	($1,757)	($23,921)
	10 to 15 MWh	($30,711)	($5,732)	($3,333)	($39,775)
	15 to 25 MWh	($40,055)	($14,882)	($4,431)	($59,368)
	25 to 35 MWh	($18,436)	($8,434)	($2,629)	($29,499)
	35 to 50 MWh	($10,397)	($5,078)	($1,152)	($16,627)
	50 to 100 MWh	($6,439)	($3,227)	($775)	($10,441)
	100 to 500 MWh	($6,728)	($1,674)	($948)	($9,350)
	Over 500 MWh	($7,990)		($1)	($7,991)
	Sub Total	($144,452)	($41,871)	($15,296)	($201,619)
Non-Residential	0 to 5 MWh	($97)	($92)	($14)	($204)
	5 to 10 MWh	($383)	($168)	($26)	($577)
	10 to 15 MWh	($463)	($246)	($5)	($715)
	15 to 25 MWh	($950)	($623)	($89)	($1,662)
	25 to 35 MWh	($873)	($220)	($79)	($1,172)
	35 to 50 MWh	($975)	($532)	($138)	($1,645)
	50 to 100 MWh	($2,242)	($1,013)	($534)	($3,789)
	100 to 500 MWh	($6,926)	($225)	($900)	($8,051)
	Over 500 MWh	($11,157)	$1,109	($1,152)	($11,199)
	Sub Total	($24,066)	($2,011)	($2,937)	($29,013)
Total		($168,519)	($43,882)	($18,232)	($230,632)

For reference, Table 32 shows the number of customers in each of the defined categories. The 31,236 accounts in Table 32 represent accounts for which we were able to match billing and PV capacity data. As discussed in Chapter 4, we scaled up from this number based on capacity to account for NEM PV generation that we were not able to match to billing data. The results presented throughout this report are based on the scaled-up values.

Table 32: Number of Customers by customer size and utility

	Customer Size	PG&E	SCE	SDG&E	Total
Residential	0 to 5 MWh	1,932	271	722	2,925
	5 to 10 MWh	5,819	1,068	1,976	8,863
	10 to 15 MWh	4,663	1,196	1,537	7,396
	15 to 25 MWh	4,133	1,520	1,468	7,121
	25 to 35 MWh	1,080	502	412	1,994
	35 to 50 MWh	396	187	145	728
	50 to 100 MWh	145	69	70	284
	100 to 500 MWh	32	21	10	63
	Over 500 MWh	5	0	4	9
	Sub Total	18,205	4,834	6,344	29,383
Non-Residential	0 to 5 MWh	25	10	9	44
	5 to 10 MWh	78	18	10	106
	10 to 15 MWh	76	27	19	122
	15 to 25 MWh	131	45	29	205
	25 to 35 MWh	91	37	18	146
	35 to 50 MWh	92	42	19	153
	50 to 100 MWh	163	58	53	274
	100 to 500 MWh	292	111	93	496
	Over 500 MWh	157	65	85	307
	Sub Total	1,105	413	335	1,853
Total		19,310	5,247	6,679	31,236

Residential customers tend to fall into the smaller size divisions, while non-residential tend to fall into the larger size divisions. This is reflected in the total cost by category from Table 31.

Table 33 presents another way to look at the results. Here, the net costs of solar NEM are shown in annualized dollars *per customer*. Not surprisingly, costs on a per-customer basis tend to increase with the size of the customer, reflecting the larger PV systems installed by larger customers. For the largest customers at SCE, however, NEM provides net benefits to ratepayers. This is an indication that the avoided costs from the energy provided by these customers exceed the bill credit received and any incremental billing costs.

Table 33: 20-year net solar NEM costs by customer size and utility (Annualized $/Customer)

	Customer Size	PG&E	SCE	SDG&E	Wtd Average
Residential	0 to 5 MWh	**($147)**	($33)	**($47)**	**($118)**
	5 to 10 MWh	($226)	($135)	($112)	($197)
	10 to 15 MWh	($446)	($258)	($273)	($385)
	15 to 25 MWh	($656)	($526)	($383)	($588)
	25 to 35 MWh	($1,158)	($899)	($810)	($1,034)
	35 to 50 MWh	($1,802)	($1,460)	($1,015)	($1,601)
	50 to 100 MWh	($3,144)	($2,474)	($1,552)	($2,711)
	100 to 500 MWh	($15,002)	($4,217)	($16,821)	($10,368)
	Over 500 MWh	($133,608)		($62)	($95,187)
	Average	($537)	($465)	($305)	($493)
Non-Residential	0 to 5 MWh	($297)	($156)	($198)	($205)
	5 to 10 MWh	($354)	($206)	($346)	($292)
	10 to 15 MWh	($391)	($139)	**($47)**	($233)
	15 to 25 MWh	($511)	($221)	($552)	($343)
	25 to 35 MWh	($578)	($96)	($466)	($295)
	35 to 50 MWh	($809)	($194)	($726)	($397)
	50 to 100 MWh	($989)	($255)	($826)	($551)
	100 to 500 MWh	($1,401)	($32)	($763)	($613)
	Over 500 MWh	($4,091)	**$623**	($989)	($1,975)
	Average	($1,407)	($84)	($781)	($650)
Average		($589)	($386)	($338)	($508)

For a few other categories, (shown in bold and highlighted) avoided costs exceed the bill credits and it is only the incremental billing costs that push the customer group into negative territory. If it were possible to incur no incremental NEM billing costs to serve these customers, NEM would provide ratepayers with net benefits rather than net costs for these groups of customers.

Table 34 shows the net costs of solar NEM on the basis of levelized dollars per kWh-exported.

Table 34: 20-year net solar NEM costs by customer size and utility (Levelized $/kWh-exported)

	Customer Size	PG&E	SCE	SDG&E	Wtd Average
Residential	0 to 5 MWh	($0.08)	($0.02)	($0.03)	($0.06)
	5 to 10 MWh	($0.11)	($0.06)	($0.06)	($0.10)
	10 to 15 MWh	($0.21)	($0.10)	($0.13)	($0.18)
	15 to 25 MWh	($0.27)	($0.15)	($0.21)	($0.22)
	25 to 35 MWh	($0.33)	($0.20)	($0.25)	($0.27)
	35 to 50 MWh	($0.37)	($0.20)	($0.25)	($0.29)
	50 to 100 MWh	($0.37)	($0.23)	($0.24)	($0.30)
	100 to 500 MWh	($0.34)	($0.23)	($0.25)	($0.30)
	Over 500 MWh	($0.31)			($0.31)
	Average	($0.22)	($0.14)	($0.14)	($0.19)
Non-Residential	0 to 5 MWh	($0.13)	($0.07)	($0.03)	($0.08)
	5 to 10 MWh	($0.14)	($0.06)	($0.09)	($0.10)
	10 to 15 MWh	($0.13)	($0.03)	($0.01)	($0.06)
	15 to 25 MWh	($0.12)	($0.06)	($0.10)	($0.09)
	25 to 35 MWh	($0.15)	($0.02)	($0.06)	($0.06)
	35 to 50 MWh	($0.11)	($0.03)	($0.09)	($0.06)
	50 to 100 MWh	($0.10)	($0.02)	($0.07)	($0.05)
	100 to 500 MWh	($0.08)	($0.00)	($0.02)	($0.03)
	Over 500 MWh	($0.05)	$0.01	($0.03)	($0.03)
	Average	($0.07)	($0.01)	($0.03)	($0.03)
Average		($0.17)	($0.06)	($0.08)	($0.12)

Because tiered residential rates provide higher marginal credits for customers with larger amounts of export energy, the bill impacts of NEM on a per-kWh basis tend to grow with residential customer size. For non-residential customers, rates tend to decline as customer size increases; therefore on a per-kWh basis NEM costs also tend to decline as customer size increases.

6.1.2. Bill impacts by customer size

Table 31, Table 33, and Table 34 in the previous section present total net solar NEM costs by customer size. This total net cost is made up of bill impacts, incremental billing costs, and avoided costs. Table 35, Table 37, and Table 38 present bill impacts only (including AB 920 compensation), providing a direct indication of the benefit of solar NEM to *participants*.

Table 35: 20-year NEM bill impacts by customer size and utility (NPV $000s)

	Customer Size	PG&E	SCE	SDG&E	Total
Residential	0 to 5 MWh	$5,678	$1,218	$1,212	$8,108
	5 to 10 MWh	$24,664	$7,035	$4,902	$36,601
	10 to 15 MWh	$33,355	$10,703	$5,649	$49,707
	15 to 25 MWh	$43,980	$23,867	$6,144	$73,991
	25 to 35 MWh	$21,692	$12,200	$3,655	$37,548
	35 to 50 MWh	$12,368	$7,614	$1,666	$21,648
	50 to 100 MWh	$8,128	$4,612	$1,154	$13,894
	100 to 500 MWh	$9,055	$2,378	$1,452	$12,884
	Over 500 MWh	$11,230		$0	$11,230
	Sub Total	$170,150	$69,626	$25,834	$265,610
Non-Residential	0 to 5 MWh	$119	$231	$58	$408
	5 to 10 MWh	$478	$434	$49	$961
	10 to 15 MWh	$610	$996	$75	$1,681
	15 to 25 MWh	$1,458	$1,546	$179	$3,182
	25 to 35 MWh	$1,093	$1,319	$186	$2,599
	35 to 50 MWh	$1,538	$2,364	$265	$4,167
	50 to 100 MWh	$4,029	$4,886	$1,290	$10,205
	100 to 500 MWh	$14,461	$17,600	$5,899	$37,960
	Over 500 MWh	$28,942	$12,527	$5,668	$47,137
	Sub Total	$52,727	$41,904	$13,668	$108,300
Total		$222,877	$111,531	$39,503	$373,910

For reference, Table 36 shows the average capacity of PV systems installed in each customer category. As one would expect, PV system capacity increases with customer size. For the very largest customers, PV system size is orders of magnitude higher than for smaller customers, consistent with the much higher per-customer bill impacts for larger customers shown in Table 37.

Table 36: Average capacity of solar PV by customer size and utility (nameplate kW)

	Customer Size	PG&E	SCE	SDG&E	Wtd Average
Residential	0 to 5 MWh	2.5	2.7	5.8	3.3
	5 to 10 MWh	3.5	3.6	4.2	3.7
	10 to 15 MWh	4.9	4.7	5.1	4.9
	15 to 25 MWh	6.5	6.5	5.5	6.3
	25 to 35 MWh	8.9	9.1	8.0	8.8
	35 to 50 MWh	11.0	11.2	9.3	10.7
	50 to 100 MWh	17.9	17.3	14.8	17.0
	100 to 500 MWh	75.6	31.4	113.5	64.1
	Over 500 MWh	685.9		6.6	394.8
	Average	5.3	5.9	5.5	5.4
Non-Residential	0 to 5 MWh	2.9	2.7	4.9	3.2
	5 to 10 MWh	3.9	4.5	4.2	4.0
	10 to 15 MWh	5.9	6.6	8.4	6.3
	15 to 25 MWh	8.0	7.3	8.4	7.8
	25 to 35 MWh	10.8	10.1	12.8	10.8
	35 to 50 MWh	17.7	11.5	16.7	15.5
	50 to 100 MWh	27.0	24.5	21.8	25.2
	100 to 500 MWh	63.7	62.7	85.1	67.7
	Over 500 MWh	354.4	194.6	235.0	297.8
	Average	82.3	41.0	105.4	77.2
Average		8.7	8.1	9.5	8.8

Table 37: 20-year NEM bill impacts by customer size and utility (Annualized $/Customer)

	Customer Size	PG&E	SCE	SDG&E	Wtd Average
Residential	0 to 5 MWh	$198	$241	$210	$205
	5 to 10 MWh	$286	$355	$314	$301
	10 to 15 MWh	$484	$481	$462	$481
	15 to 25 MWh	$721	$843	$531	$733
	25 to 35 MWh	$1,363	$1,301	$1,127	$1,316
	35 to 50 MWh	$2,143	$2,189	$1,468	$2,085
	50 to 100 MWh	$3,969	$3,535	$2,313	$3,607
	100 to 500 MWh	$20,189	$5,989	$25,765	$14,287
	Over 500 MWh	$187,794		$0	$133,765
	Average	$632	$774	$515	$649
Non-Residential	0 to 5 MWh	$363	$390	$811	$411
	5 to 10 MWh	$442	$532	$648	$487
	10 to 15 MWh	$515	$560	$744	$548
	15 to 25 MWh	$784	$549	$1,105	$658
	25 to 35 MWh	$723	$574	$1,104	$653
	35 to 50 MWh	$1,276	$862	$1,390	$1,007
	50 to 100 MWh	$1,777	$1,232	$1,994	$1,483
	100 to 500 MWh	$2,925	$2,512	$5,005	$2,891
	Over 500 MWh	$10,613	$7,040	$4,869	$8,312
	Average	$3,082	$1,761	$3,637	$2,425
Average		$779	$980	$733	$824

Table 38: 20-year NEM bill impacts by customer size and utility (Levelized $/kWh-exported)

	Customer Size	PG&E	SCE	SDG&E	Wtd Average
Residential	0 to 5 MWh	$0.11	$0.12	$0.12	$0.11
	5 to 10 MWh	$0.14	$0.15	$0.16	$0.15
	10 to 15 MWh	$0.23	$0.19	$0.22	$0.22
	15 to 25 MWh	$0.29	$0.24	$0.29	$0.28
	25 to 35 MWh	$0.39	$0.28	$0.34	$0.34
	35 to 50 MWh	$0.44	$0.31	$0.36	$0.38
	50 to 100 MWh	$0.46	$0.33	$0.36	$0.40
	100 to 500 MWh	$0.46	$0.33	$0.38	$0.42
	Over 500 MWh	$0.44			$0.44
	Average	$0.26	$0.23	$0.23	$0.25
Non-Residential	0 to 5 MWh	$0.16	$0.19	$0.13	$0.17
	5 to 10 MWh	$0.18	$0.17	$0.17	$0.17
	10 to 15 MWh	$0.17	$0.14	$0.12	$0.15
	15 to 25 MWh	$0.19	$0.16	$0.19	$0.17
	25 to 35 MWh	$0.19	$0.12	$0.15	$0.14
	35 to 50 MWh	$0.18	$0.13	$0.17	$0.15
	50 to 100 MWh	$0.18	$0.12	$0.18	$0.14
	100 to 500 MWh	$0.16	$0.10	$0.13	$0.12
	Over 500 MWh	$0.14	$0.09	$0.12	$0.12
	Average	$0.15	$0.11	$0.13	$0.13
Average		$0.22	$0.16	$0.18	$0.19

6.1.3. Relative Importance of AB 920 to bill impacts

Table 35, Table 37, and Table 38 in the previous section present bill impacts by customer size. A portion of this value results from our estimation of the effects of AB 920, which allows customer-generators to begin in 2011 to receive compensation for any net-excess generation remaining at the end of the 12-month period (any such net-excess is currently zeroed out at the end of each 12-month period). Customers will receive AB 920 compensation at a rate to-be-determined by the CPUC; for the purposes of our analysis, we set the payment equal to avoided costs. Table 39 shows the relative portion of total bill impacts that result from customers receiving the AB 920 compensation.

Table 39: Proportion of bill impacts resulting from AB 920 (%)

	Customer Size	PG&E	SCE	SDG&E	Total
Residential	0 to 5 MWh	11.42%	14.45%	12.68%	12.07%
	5 to 10 MWh	0.96%	1.56%	1.97%	1.21%
	10 to 15 MWh	0.19%	0.50%	0.74%	0.32%
	15 to 25 MWh	0.05%	0.09%	0.19%	0.07%
	25 to 35 MWh	0.13%	0.01%	0.12%	0.09%
	35 to 50 MWh	0.10%	0.10%	0.05%	0.10%
	50 to 100 MWh	0.00%	0.00%	0.13%	0.01%
	100 to 500 MWh	0.00%	0.00%	0.00%	0.00%
	Over 500 MWh	0.00%			0.00%
	Sub Total	0.60%	0.53%	1.20%	0.64%
Non-Residential	0 to 5 MWh	23.84%	10.70%	50.27%	20.18%
	5 to 10 MWh	7.67%	9.32%	5.24%	8.29%
	10 to 15 MWh	11.85%	30.45%	14.64%	23.00%
	15 to 25 MWh	2.03%	1.75%	0.00%	1.78%
	25 to 35 MWh	0.20%	9.81%	14.86%	6.13%
	35 to 50 MWh	2.72%	19.23%	5.62%	12.27%
	50 to 100 MWh	1.12%	0.00%	9.37%	1.63%
	100 to 500 MWh	0.21%	2.23%	0.83%	1.25%
	Over 500 MWh	0.00%	0.02%	3.94%	0.48%
	Sub Total	0.54%	3.28%	3.50%	1.98%
Total		0.58%	1.56%	2.00%	1.03%

The proportion of bill impacts resulting from AB 920 is small – approximately one percent. The remaining 99% of bill impacts result from intra-year bill credits provided at the full retail rate that are consumed by the customer prior to the end of the 12-month period.

Our results show that smaller customers tend to have a larger proportion of their 20-year NEM bill impacts from the estimated AB 920 effects. This is because these smaller customers are more likely to have oversized their PV systems relative to load. Customers with the highest loads may be less able to oversize their PV systems due to space limitations.

These results reflect currently installed systems that were sized with NEM rules that limit carryover of excess bill credits. If customers respond to AB 920 by further increasing PV system size relative to load, the portion of bill impacts resulting from AB 920 will increase. Likewise, the total cost of NEM will increase.[39]

6.1.4. Equivalent Upfront Metrics

Two additional metrics for measuring NEM costs have been calculated: "equivalent upfront payment" and "equivalent net cost" – both in dollars per Watt installed.

The equivalent upfront payment (Table 40) is the lifecycle value of the bill credits for the exported energy. This represents the average upfront payment to NEM participants that would be necessary to make them indifferent between the upfront payment versus the monthly and annual NEM bill credits.

Table 40: Lifecycle value to system owners of NEM credits expressed as Equivalent Upfront Payment ($/W installed)

	Residential	Non-Residential	Total
PG&E	$1.41	$0.44	$0.92
SCE	$1.53	$0.50	$0.87
SDG&E	$1.09	$0.40	$0.69
Total	$1.40	$0.46	$0.88

The lifecycle value of NEM credits can be compared to CSI upfront incentives, which step down from $2.50/Watt to $0.20/Watt over the ten-year program.[40] This comparison reveals that the NEM credit is a significant component of ratepayer cost related to solar PV distributed generation, especially for the residential sector.

Table 41 shows the "equivalent net cost" to ratepayers, which is the lifecycle net cost per Watt of PV installed.

[39] Oversizing relative to load may be limited by the definition of eligible generation as "intended primarily to offset part or all of the customer's own electrical requirements." (P.U. Code 2827 (b) (4)).
[40] Solar systems on NEM that were installed prior to CSI may have received incentives as high as $4.50/watt.

Table 41: Lifecycle Equivalent Net Cost of NEM to ratepayers ($/W installed)

	Residential	Non-Residential	Total
PG&E	($1.19)	($0.20)	($0.70)
SCE	($0.92)	($0.02)	($0.34)
SDG&E	($0.65)	($0.09)	($0.32)
Total	($1.06)	($0.12)	($0.54)

Overall, the cost of the NEM subsidy is approximately $0.54/Watt installed, or about 20% of the initial CSI incentive of $2.50/Watt. This compares to an average 2008 and 2009 total project cost (before rebates) for CSI projects of $8.14/Watt installed for large commercial customers and $9.41/Watt installed for residential and small commercial customers.[41]

The ratepayer impact (Table 41) is smaller than the participant payment (Table 40) because ratepayers receive the avoided cost benefit, offsetting a portion of the bill credit payments.

6.2. Sensitivities

Table 42 shows the sensitivity of total net program costs to several changes. With the exception of incremental billing costs, the tested sensitivities raise overall NEM costs by 10-15% each. Eliminating incremental billing costs would result in an overall reduction in NEM costs of approximately 27%.

[41] CPUC, *California Solar Initiative Annual Program Assessment*, June 2009, p.22.

Table 42: Sensitivity analysis results (Levelized $/kWh) and Percent Change from Base Case

	Base Case	No Incremental Billing Cost	No T&D deferral in Avoided Cost	Standby Charges	Inter-connection Costs
Bill Impacts	($0.193)	($0.193)	($0.193)	($0.209)	($0.193)
Incremental Billing Cost	($0.032)	-	($0.032)	($0.032)	($0.032)
Interconnection Cost	-	-	-	-	($0.012)
Avoided Cost	$0.106	$0.106	$0.092	$0.106	$0.106
Net Cost of NEM *	**($0.119)**	**($0.087)**	**($0.133)**	**($0.135)**	**($0.132)**
(% Change from Base Case)		**(-27%)**	**(+12%)**	**(+13%)**	**(+10%)**

* Net cost value may not equal the sum of components due to rounding

Table 42 implies a range of lowest to highest cost estimates from our analysis. The lowest cost estimate holds all sensitivities at the base case with the exception of the incremental billing costs, which are set to zero. The highest cost estimate keeps the incremental billing costs, removes T&D deferral, and includes interconnection costs and loss of standby charge revenue. These "lowest" to "highest" scenarios are compared to the Base Case in Table 43 showing a range of approximately $14-27 million in annualized costs.

Table 43: "Lowest" and "Highest" sensitivity combinations compared to Base Case

	Base Case	"Lowest" Cost	"Highest" Cost
20-year NPV ($000s)	($230,632)	($168,812)	($311,285)
20-year Annualized ($000s)	($19,681)	($14,405)	($26,563)
Levelized ($/kWh-exported)	($0.12)	($0.09)	($0.16)

Table 44, Table 45, and Table 46 show the sensitivity results on an individual utility basis. For PG&E the "No Incremental Billing Cost" sensitivity results in relatively larger savings since incremental billing costs are significantly higher at PG&E.

Table 44: Sensitivity analysis results (Levelized $/kWh) and Percent Change from Base Case – PG&E

	Base Case	No Incremental Billing Cost	No T&D Avoided Cost	Standby Charges	Inter-connection Costs
Bill Impacts	($0.218)	($0.218)	($0.218)	($0.227)	($0.218)
Incremental Billing Cost	($0.053)	-	($0.053)	($0.053)	($0.053)
Interconnection Cost	-	-	-	-	($0.015)
Avoided Cost	$0.107	$0.107	$0.094	$0.107	$0.107
Net Cost of NEM	**($0.165)**	**($0.112)**	**($0.178)**	**($0.174)**	**($0.180)**
(% Change from Base Case)		**(-32%)**	**(+8%)**	**(+5%)**	**(+9%)**

The “No T&D Avoided Cost”, “Standby Charge”, and “Interconnection Cost” sensitivities have a proportionally larger effect at SDG&E and SCE, in part because of the overall lower NEM costs at those utilities.

Table 45: Sensitivity analysis results (Levelized $/kWh) and Percent Change from Base Case – SCE

	Base Case	No Incremental Billing Cost	No T&D Avoided Cost	Standby Charges	Inter-connection Costs
Bill Impacts	($0.160)	($0.160)	($0.160)	($0.177)	($0.160)
Incremental Billing Cost	($0.005)	-	($0.005)	($0.005)	($0.005)
Interconnection Cost	-	-	-	-	($0.009)
Avoided Cost	$0.102	$0.102	$0.089	$0.102	$0.102
Net Cost of NEM	**($0.063)**	**($0.058)**	**($0.076)**	**($0.079)**	**($0.072)**
(% Change from Base Case)		**(-8%)**	**(+20%)**	**(+26%)**	**(+14%)**

Table 46: Sensitivity analysis results (Levelized $/kWh) and Percent Change from Base Case – SDG&E

	Base Case	No Incremental Billing Cost	No T&D Avoided Cost	Standby Charges	Inter-connection Costs
Bill Impacts	($0.184)	($0.184)	($0.184)	($0.227)	($0.184)
Incremental Billing Cost	($0.018)	-	($0.018)	($0.018)	($0.018)
Interconnection Cost	-	-	-	-	($0.013)
Avoided Cost	$0.117	$0.117	$0.092	$0.117	$0.117
Net Cost of NEM	**($0.085)**	**($0.067)**	**($0.109)**	**($0.128)**	**($0.098)**
(% Change from Base Case)		**(-21%)**	**(+29%)**	**(+51%)**	**(+16%)**

APPENDIX A:

AVOIDED COSTS

Appendix A: Methodology for Determining Utility Avoided Cost

Overview

Every kWh of electricity exported to the grid by customer-generators is a kWh the utility does not have to procure and deliver through other means. These avoided procurement and delivery costs are known as *avoided costs*.

The avoided cost methodology described below provides a transparent method to value net energy production from distributed generation using a time-differentiated cost-basis. This appendix provides the background and methodology underlying the conclusions in the costs and benefits of net energy metering. The utility avoided costs represent the benefit of the net energy metering program.

The electricity produced by distributed generation has significantly different avoided cost value depending on the time (and location) of delivery to the grid. The value of electricity production varies considerably day to night, and season to season. Furthermore, because of the regional differences in weather and overall energy usage patterns, the relative value of producing energy at different times varies for different regions of California. The time and location based avoided cost methodology reflects this complexity.

Approach

By using a cost-based approach, valuation of net energy production will reflect the underlying marginal utility costs. The avoided costs evaluate the total hourly marginal cost of delivering electricity to the grid by adding together the individual components that contribute to cost. The cost components include Generation Energy, Losses, Ancillary Services, System (Generation) Capacity, T&D Capacity, Environmental costs, and Avoided

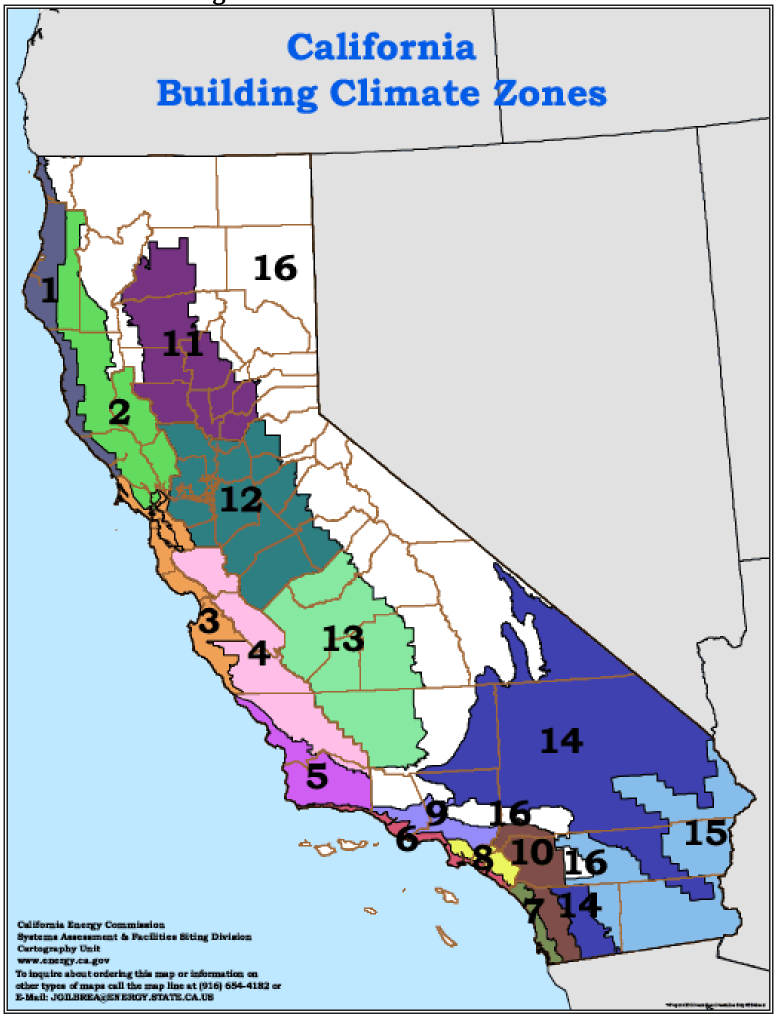
Renewable Purchases. The utility avoided cost value is calculated as the sum in each hour of the seven individual components.

Methodology

Climate Zones

To define climate zones in California we adopt the 16 climate zones used for the Title 24 energy efficiency standards. These climate zones group together areas with similar climates, temperature profiles, and energy use patterns in order to differentiate regions in a manner that captures the effects of weather on energy use. Figure 1 is a map of the climate zones in California.

Figure 1: California Climate Zones



Each climate zone has a single representative city, which is specified by the California Energy Commission. These cities are listed in Table 1. A set of hourly avoided costs are calculated for each climate zone.

Table 1: Representative cities for California Climate Zones

Climate Zone	Utility Territory	Representative City
CEC Zone 1	PG&E	Arcata
CEC Zone 2	PG&E	Santa Rosa
CEC Zone 3	PG&E	Oakland
CEC Zone 4	PG&E	Sunnyvale
CEC Zone 5	PG&E/SCE	Santa Maria
CEC Zone 6	SCE	Los Angeles
CEC Zone 7	SDG&E	San Diego
CEC Zone 8	SCE	El Toro
CEC Zone 9	SCE	Pasadena
CEC Zone 10	SCE/SDG&E	Riverside
CEC Zone 11	PG&E	Red Bluff
CEC Zone 12	PG&E	Sacramento
CEC Zone 13	PG&E	Fresno
CEC Zone 14	SCE/SDG&E	China Lake
CEC Zone 15	SCE/SDG&E	El Centro
CEC Zone 16	PG&E/SCE	Mount Shasta

Resource Balance Year

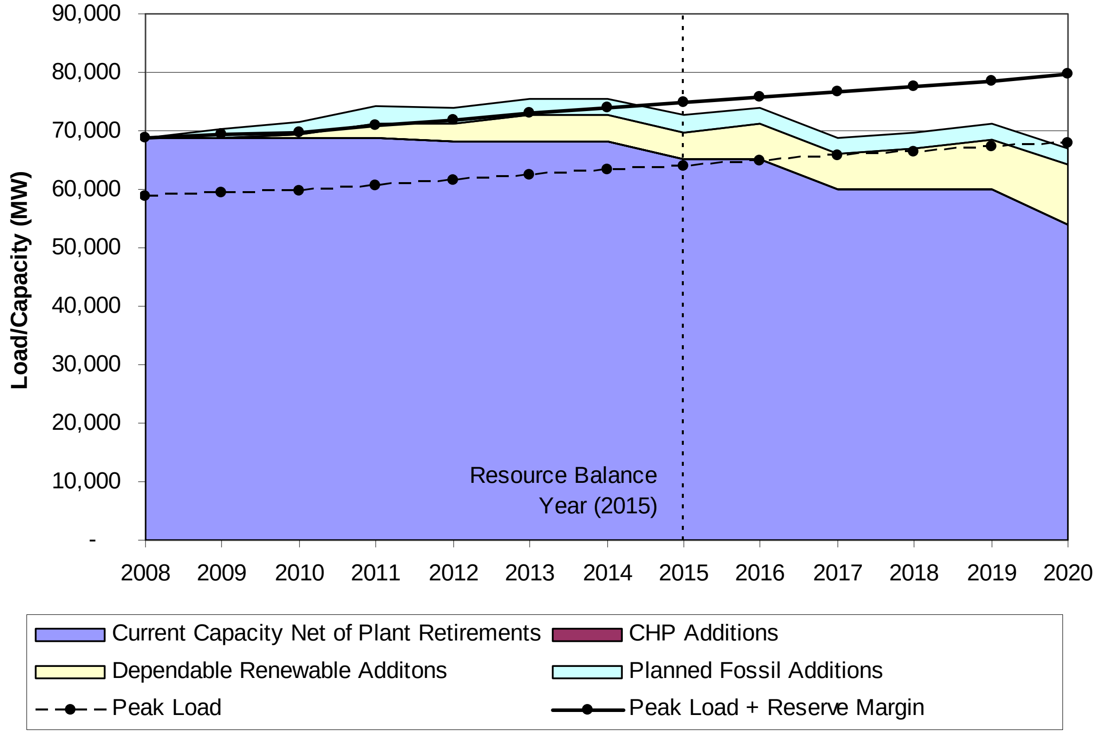
California utilities must maintain sufficient generation to meet peak load and provide a reserve margin for reliability purposes. Currently, the state enjoys excess reserve, beyond reserve margin requirements. At some point, new generation will need to avoid falling below the peak load plus reserve margin requirement. The resource balance year represents this moment; the first year in which system capacity would be insufficient to meet peak period demand plus the reserve margin. In the evaluation of the avoided cost of electricity, the determination of the resource balance year represents the point at which the forecasts for energy and capacity value transition from short-run to long-run time scales; after this point, the energy and capacity values should capture the all-in costs of a combined-cycle turbine and a combustion turbine. The cost after the resource balance year is the long run marginal avoided cost.

The resource balance year is evaluated by comparing the CEC's forecast of peak loads in California[1] with California's expected committed capacity resources. The forecast for expected capacity includes several components: 1) existing system capacity as of 2008, net of expected plant retirements; 2) fossil plants included in the CEC's list of planned projects with statuses of "Operational," "Partially Operational," or " Under Construction"; and 3) a forecast of renewable capacity additions to the system that would be necessary to achieve California's 33% Renewable Portfolio Standard by 2020 based on E3's 33% Model developed in support of the CPUC's 33% RPS Implementation Analysis published in June, 2009.

The load-resource balance is shown in Figure 2 below; based on this analysis, the resource balance year for California was set at 2015. This represents the first year in which committed capacity resources would be insufficient to meet the expected peak system demand and required reserve margin.

[1] California Energy Commission, *California Energy Demand 2010-2020 Adopted Forecast*, December, 2009.

Figure 2: Evaluation of the resource balance year in California



Overview of Avoided Cost Components

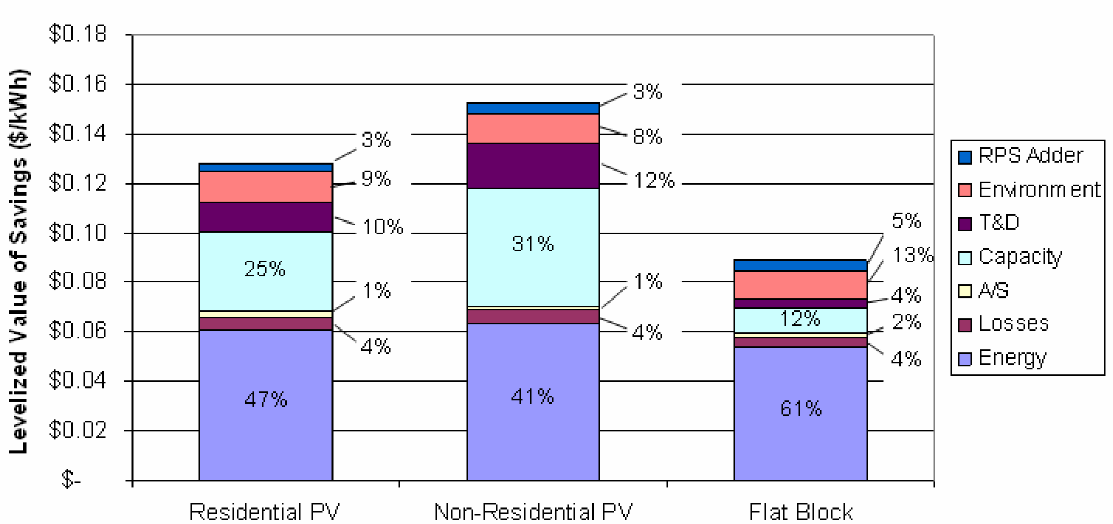
For each of the climate zones, we estimate the total hourly marginal cost of delivering electricity as a sum of individual components. The cost components include Generation Energy, Losses, Ancillary Services, System (Generation) Capacity, T&D Capacity, Environmental costs, and Avoided Renewable Purchases. The value is calculated as the sum in each hour of the seven individual components. A more detailed description of each of the components is provided in Table 2.

Table 2: Components of marginal energy cost

Component	Description
Generation Energy	Estimate of hourly wholesale value of energy measured at the point of wholesale energy transaction
Losses	Losses between the delivery location and the point of wholesale energy transaction
Ancillary Services	The costs of providing system operations and reserves for electricity grid reliability
System Capacity	The costs of building new generation capacity to meet system peak loads
T&D Capacity	The costs of expanding transmission and distribution capacity to meet peak loads
Environment	The cost of CO2 associated with electricity generation
RPS Adder	The cost of purchasing renewable resources to meet an RPS Portfolio that is a percentage of total retail sales

The resulting avoided costs for two example PV output shapes are summarized in Figure 3, with avoided cost of flat production shape provided for comparison. There is variation in avoided costs between PV output shapes because weather, system specifications, and other factors affect both the timing and amount of generation and the local value of the generation.

Figure 3: Levelized value of avoided cost for two example PV output shapes and a flat production shape



Compared to a flat block, the avoided cost of PV output is greater because the output profile is highly correlated with peak times on the system. This is most clearly illustrated by the higher share of capacity costs for PV as compared to a flat generation shape.

In the value calculation, each of these components is estimated for each hour in a typical year, and forecasted into the future for 30 years. The hourly level of granularity is important to capture the value of electricity savings during the top 300 to 400 hours of the year. The hourly granularity also aligns with the output of the common energy simulation tools such as DOE-2, which can also use the same TMY3 weather files as this analysis.

Figure 4, below, shows an example of the components of Time-Dependent Valuation (TDV) for a week in the summer in CZ13. As shown, the cost of providing an additional amount of electricity is significantly higher in the summer afternoons than in the very early morning hours. This chart also shows the relative magnitude of different components in this region in the summer for these days. The highest peaks of total cost shown in Figure 4 of almost $1,000/MWh or more are driven by higher energy market costs, higher losses, and allocation of the capacity costs of generation, transmission and distribution to the highest load hours.

Figure 4: Three-day snapshot of energy values in CZ13

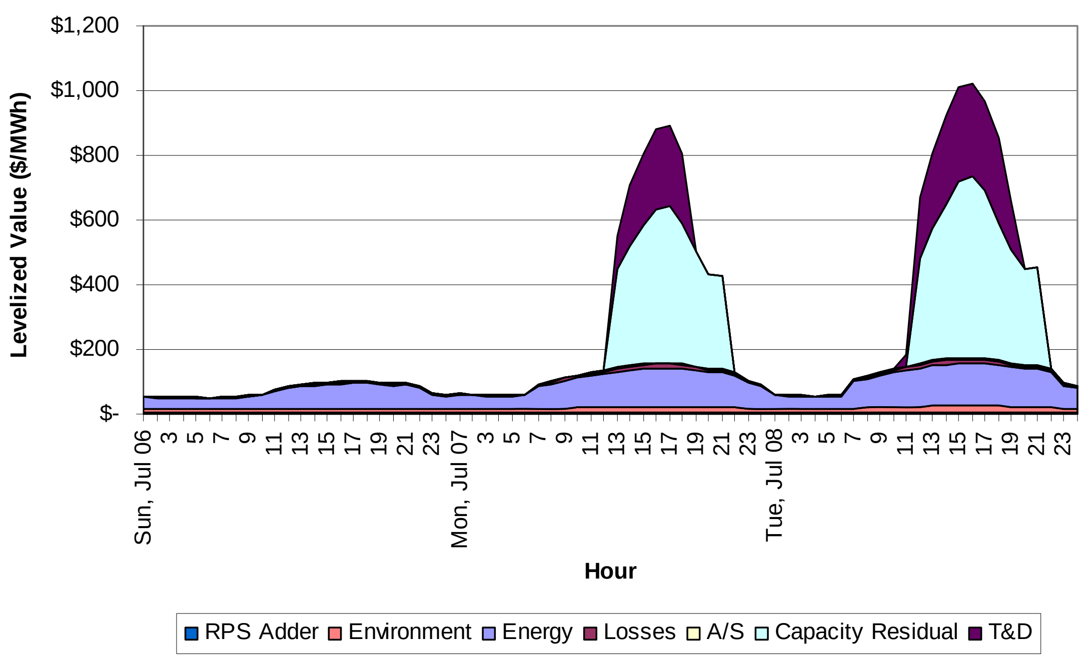


Figure 5 shows the annual chronological set of estimated values for CZ13 for an entire year. There are a few high spikes driven by hours with the highest load, and seasonal increases and decreases over the course of the year. The spikes are caused by the costs of adding capacity to deliver electricity in the few highest load hours. The generation capacity value is known as a "capacity residual" because the payments necessary to spur the development of peaking generation units are assigned residually to the highest load hours.

Figure 5: Annual levelized energy values for CZ13

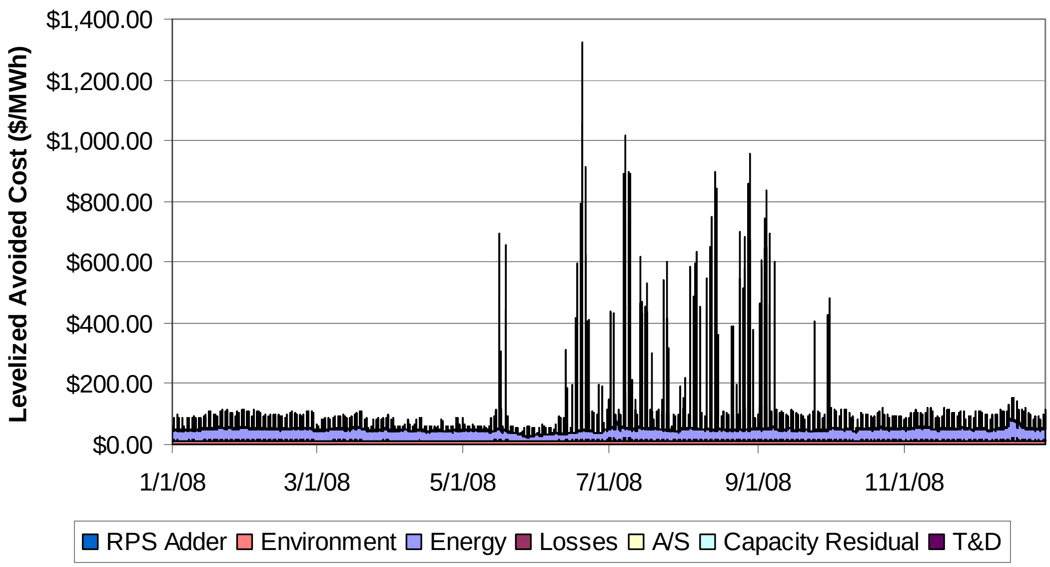
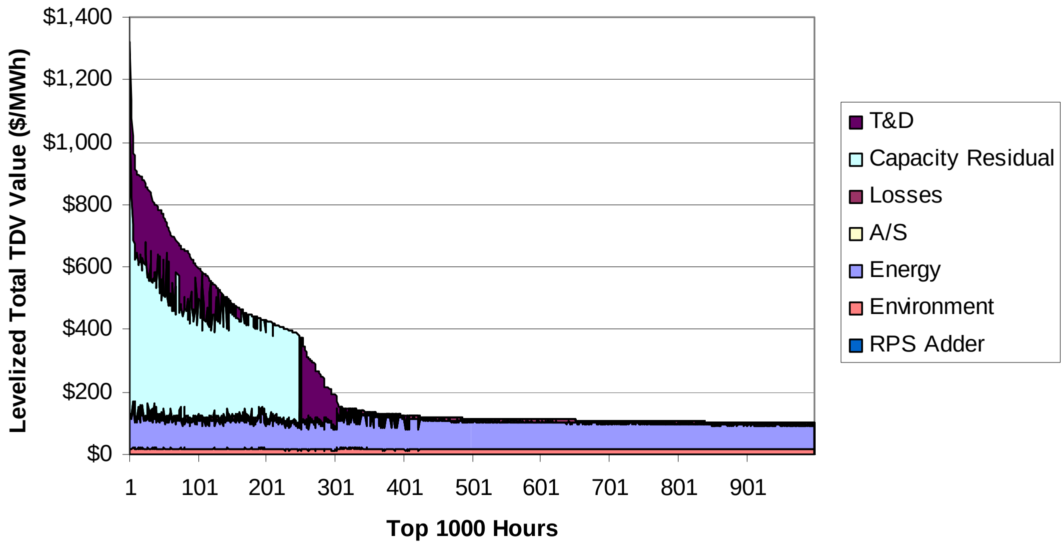


Figure 6 shows the components of value for the highest value hours in sorted order of cost. This chart shows the relative contribution to the highest hours of the year by component. Note that most of the high cost hours occur in approximately the top 200 to 400 hours. This is true in all regions in California evaluated because of the capacity costs, though the timing and magnitude vary by location.

Figure 6: Price duration curve showing top 1000 hours for CZ13

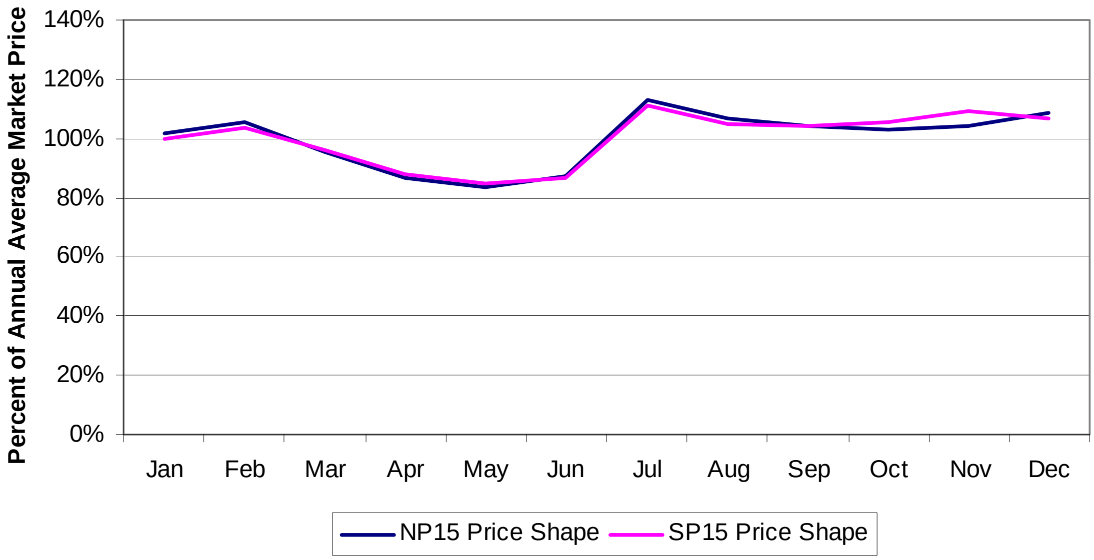


Energy Generation

The energy component is evaluated in two parts. The first is the development of an hourly market price shape. This hourly market shape represents the expected relative value of energy in wholesale markets during each hour of the year. Because the hourly avoided costs are being matched against actual PV output data and both are highly weather-correlated, the hourly price shape should maintain the daily and hourly variability of actual historical wholesale markets during the periods for which PV data is available.

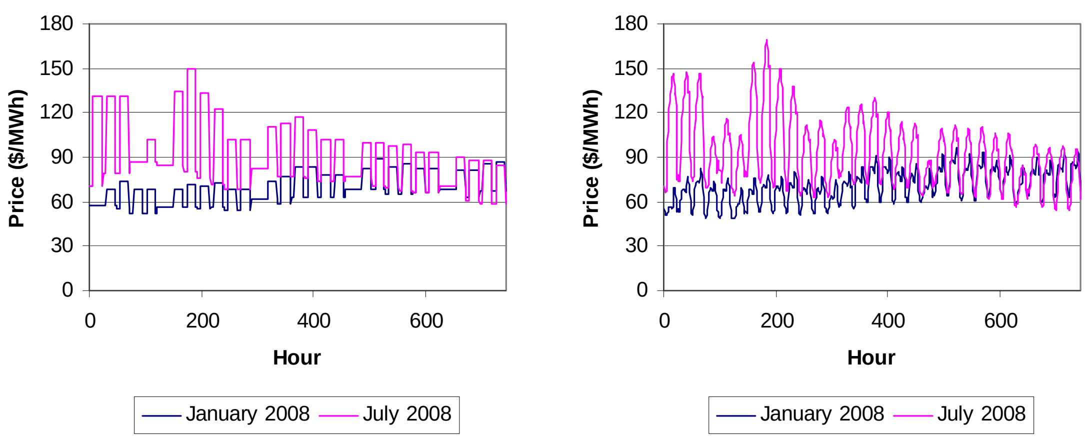
A three-step process is used to develop an hourly price shape that mimics daily and hourly patterns of actual markets while conforming to an annual shape that accounts for historical (and expected future) monthly trends. The first step in this process involves determining the average monthly price of electricity as a percentage of the annual average. For each month, the average market heat rate over the period 2003-2008 is calculated based upon spot market prices at NP15 and SP15. By adjusting the market heat rate by a monthly natural gas price shape based on Henry Hub natural gas forwards, the average monthly price shape for the NP15 and SP15 electricity markets shown in Figure 7 below is calculated.

Figure 7: Monthly market price shape based on historical electricity and gas prices (2003-2008)



The next step is to develop an hourly price shape for each month based on actual market data from January 2008 to June of 2009. Ideally, the hourly market price shapes would be based on CAISO's MRTU Locational Marginal Prices, but because this data is only available beginning in April 2009, this data cannot be used directly for the avoided costs. However, by scaling peak and off-peak spot prices by hourly system loads, an hourly price curve can be developed. This scaling process is shown in Figure 8 for two sample months.

Figure 8: Diagram of scaling process used to convert daily peak and off-peak prices to hourly prices based on load



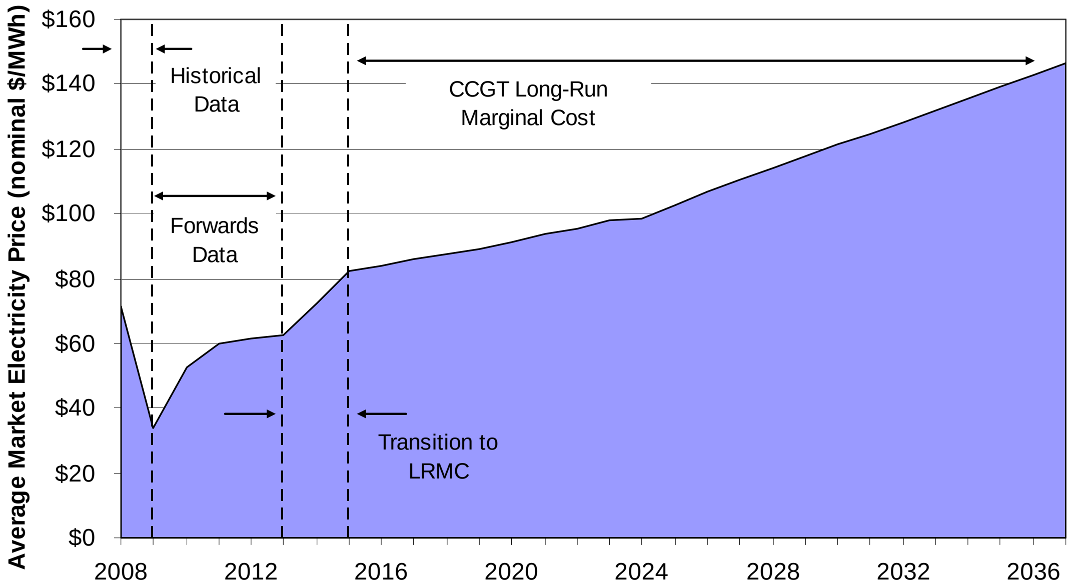
This methodology has been benchmarked against the MRTU LMPs during months when both data sources were available, and it results in a relatively close approximation of the actual hourly trends in wholesale markets (The benchmarking section later in this appendix contains benchmarking charts that compare the two prices series). It is worth noting that many of the spikes in the MRTU LMP series are not reproduced in the scaled market prices; nonetheless, because general trends are reproduced in the scaled curves and a better data source is not currently available, the scaled curves are used for the hourly shapes by month.

The final step in the development of the hourly price series is to combine the average monthly prices with the hourly price shapes for each month. The price in each hour is the product of the hourly price as a percent of the monthly average and the monthly price as a percent of the annual average. This process is repeated for each month between January and December of 2008.

The second part to forecasting energy cost is a forecast of average annual market prices in California. The forecast includes both a short-run and a long-run component, with the transition between the two occurring in the resource balance year. The short-run forecast is based upon historical market spot prices (2008-2009) and forwards prices (2010-2013) for NP15 and SP15. The long-run forecast, which begins in 2015, is based upon the 'all-in' cost of a combined cycle gas power plant. With the market price at the all-in cost, the revenues from operating a combined cycle plant will just offset the fixed CCGT costs; thus, using this value as the average market price captures the full value of the installed CCGT. The inputs necessary to compute the long-run marginal cost are taken from the CPUC 2009 Market Price Referent (MPR).[2] These include the forecast of natural gas prices and the cost and performance of a combined cycle gas turbine provided at the end of the appendix. The forecast of market prices resulting from these combined sources is shown in Figure 9.

[2] The 2009 MPR was adopted by Resolution E-4298 on December 17, 2009. The Resolution and 2009 MPR model are available at: http://www.cpuc.ca.gov/PUC/energy/Renewables/mpr. The MPR is a benchmark representation of the market price of electricity and is used to assess the above-market costs of RPS contracts.

Figure 9: Forecast of average market electricity prices



Losses

The value of both energy and capacity are increased to account for losses. Table 3 shows the loss factor assumptions used in the energy cost value. In the case of energy, the loss factors are differentiated by time of use period broken down into two seasonal categories (May-September and October-March) and three hourly periods (peak, shoulder, and off-peak). The losses for energy are measured from the customer to the wholesale market hub. For capacity costs, the loss factors are estimates of the losses during the highest load hours, and are measured from the customer to either the distribution substation, or the high voltage transmission system (Table 4). Since the capacity loss factors are the losses only between the customer and the lower voltage parts of the system, they are not as high as energy losses, even though they measure the losses during the highest load period.

Table 3: Marginal energy loss factors by utility and time period[3]

Time Period	PG&E	SCE	SDG&E
Summer Peak	1.109	1.084	1.081
Summer Shoulder	1.073	1.080	1.077
Summer Off-Peak	1.057	1.073	1.068
Winter Peak	-	-	1.083
Winter Shoulder	1.090	1.077	1.076
Winter Off-Peak	1.061	1.070	1.068

Table 4: Loss factors during peak period for capacity costs

	PG&E	SCE	SDG&E
Distribution	1.006	1.022	1.014
Transmission	1.038	1.059	1.039

Ancillary Services (A/S)

Ancillary services are the products that the California ISO must purchase to maintain reliable service. These include spinning reserve, non-spinning reserve, regulation, and other services. In general, the cost of this bundle of reliability services is proportional to the load. In the value calculation, ancillary services are included as a percentage of energy cost in each hour. This results in higher A/S costs during higher priced hours. The assumption for A/S costs is set equal to 2.84% of the energy price in each hour based on an analysis correlating energy and ancillary service spending in California.

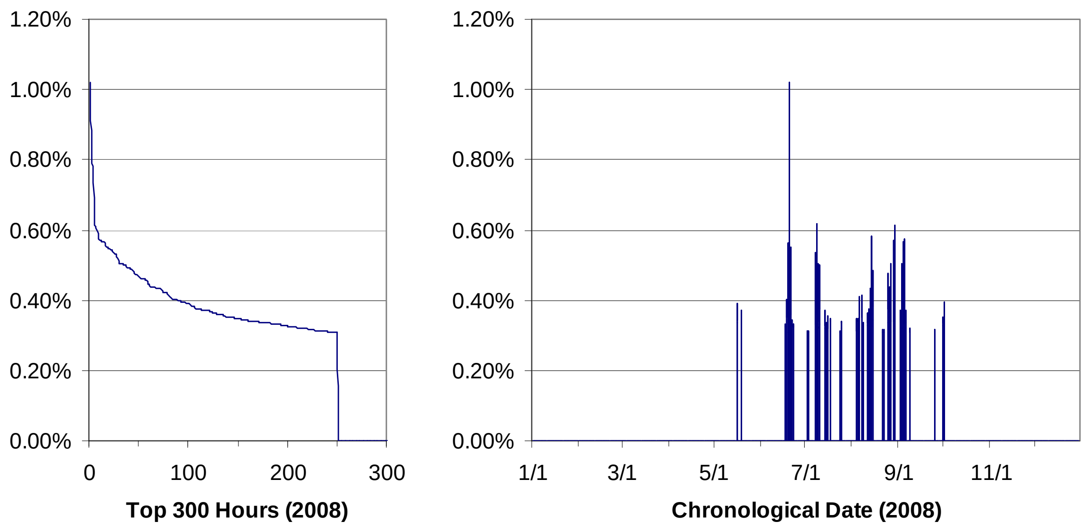
System Capacity

The system capacity costs are evaluated in two parts. In the first part, the correlated system load profile, along with assumptions on operating reserve of 7%, is used to develop capacity allocation factors. The capacity allocation factors are a simplified proxy for relative loss of load probabilities (rLOLP) sometimes used to allocate generation capacity costs. These hourly allocation

[3] Loss factors indicate the additional energy that needs to be supplied to the grid to compensate for line losses. For example, a factor of 1.073 indicates that 7.3% more energy is supplied to the grid than is ultimately delivered to end-users.

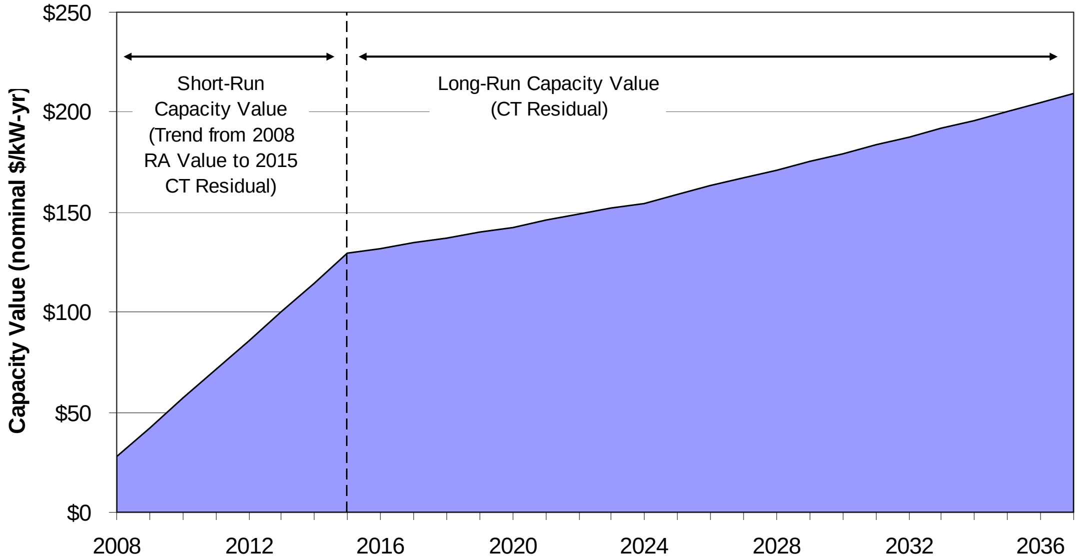
factors allocate generation capacity value to the top 250 hours of each year based on system load. Figure 10, below, shows the generation capacity cost allocation factors for CZ13. The formulation of the generation capacity cost allocators is provided at the end of this document.

Figure 10: Allocation of generation capacity costs (CZ13)



In the second part, the generation capacity cost is calculated and then allocated to hours of the year using the allocation factors. As with energy value, the forecast for capacity value has both a short- and long-run component. In the long run, generation capacity value is equal to the annual carrying cost of a combustion turbine (CT) less the net revenue the generator can earn in the energy market, or 'contribution to fixed costs'. The contribution to fixed cost is calculated as the sum over the hours when it is economic to operate the CT and is equal to the energy market price less the fuel and variable O&M costs given the heat rate assumption of the CT as shown in Figure 11. Short-run capacity value is based upon a linear interpolation between a 2008 resource-adequacy value of $28/kW-yr and the long-run capacity residual of $141/kW-yr in 2015 (the resource balance year, see Figure 11).

Figure 11: Forecast of capacity value for CZ13



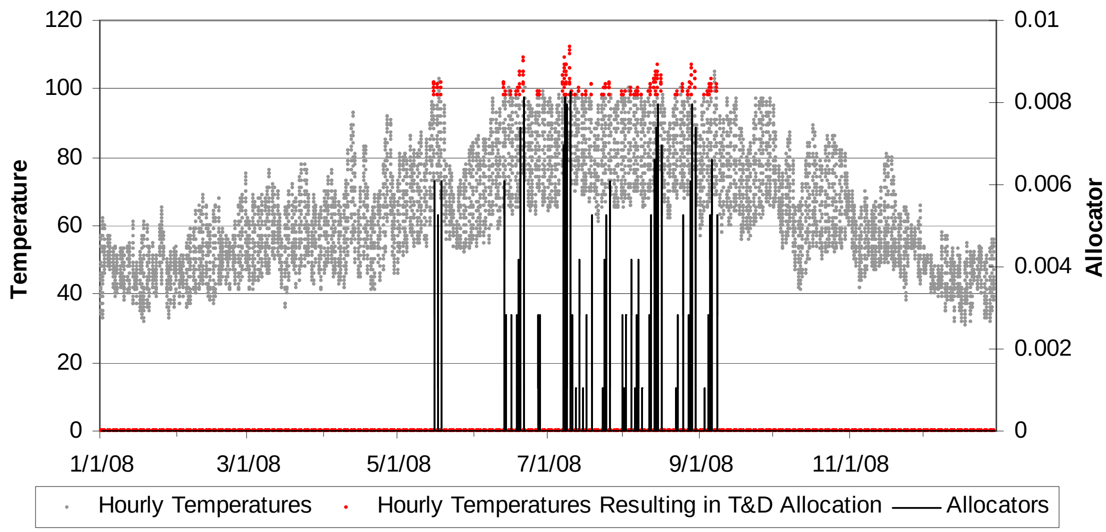
T&D Capacity

The cost of T&D capacity is evaluated in two parts. In the first part, allocators are developed to assign T&D capacity value to specific hours in the year. In the second part, estimates of the marginal transmission and distribution capacity costs are allocated to hours.

When calculating the energy generation component, the California ISO system load is used to develop allocation factors in proportion to the load level in a given hour. In this approach, the T&D capacity costs also distributed using an allocation factor equal to the percent of annual capacity costs to apply in a given hour. Ideally, the T&D allocators would be based upon local loads, and T&D costs would be allocated to the hours with the highest loads. Because such data is not readily available for the sixteen climate zones, hourly temperature data, which has a robust correlation with local loads, is used to determine the allocators for each climate zone. The T&D allocators are calculated using a triangular hour weighting algorithm that is described in further detail in the *Calculation of the T&D Capacity Allocators* Section at the end of this Appendix. Figure 12 shows the resulting allocators in chronological order as well as the hourly annual temperature profile from which they were derived for CZ13.

In the second part, a forecast of marginal T&D capacity costs is estimated and multiplied by the allocation factor in each year. The marginal distribution costs for each climate zone are based on a load-weighted average of the marginal distribution costs of all the utility divisions that fall within that zone. Marginal transmission costs are specific to each utility and are added to the marginal distribution costs to attain the marginal costs of T&D.

Figure 12: Development of T&D allocators for CZ13



Environment

The environmental component is an estimate of the value of the avoided CO_2 emissions. While there is not yet a CO_2 market established in the US, it is included in the forecast of the future. There is some probability that there will not be any cost of CO_2, however, it is looking increasingly likely that federal legislation establishing a cost of CO_2 will be included in the near future. Therefore, there is a high probability that CO_2 will be priced. Since a forecast should be based on expected value, our forecast includes the value of CO_2.

More challenging for CO_2 is estimating what the market price is likely to be, assuming a market for CO_2 allowances. The price of CO_2 will be affected by many factors including market rules, the stringency of the cap set on CO_2 allowances, and other elements. Therefore, the mid-point of a meta-analysis that surveyed many CO2 cost forecasts associated with the various proposed climate legislation is used in the for the environment component for the forecast value. Values in this forecast grow from approximately $18/ton in 2013 to approximately $78/ton in 2027 (nominal $).

Avoided Renewable Purchases

The avoided cost also includes the value of avoided renewable purchases. Because of California's commitment to reach a RPS portfolio of 33% of total retail sales by 2020, any reductions to total retail sales will reduce the required supply of renewable energy to remain compliant with the RPS target (as total sales decline, 33% of total sales also declines). This added benefit is captured in the avoided costs through the RPS Adder.

The calculation of benefits resulting from avoided purchases of renewables begins in 2020. Because of the large gap between existing renewable resources and the 33% target in 2020, the rate at which renewable resources come online during this period is unlikely to be affected by small changes to retail sales. However, after 2020, any reduction to retail sales will reduce requirements to obtain additional resources to continue compliance with the 33% case. As a result, the value of avoided renewable purchases is considered a benefit beyond 2020.

The RPS Adder is a function of the Renewable Premium, the incremental cost of the marginal renewable resource above the cost of conventional generation. The marginal renewable resource is based upon the Fairmont CREZ, the most expensive resource bundle that is included in the renewable portfolio in E3's 33% Model 33% Reference Case.[4] The Renewable Premium is calculated by subtracting the market energy and capacity value associated with this bundle, as well as the average CO2 emissions from a CCGT, from its levelized cost of energy as shown in Figure 13. The RPS Adder is calculated directly from the

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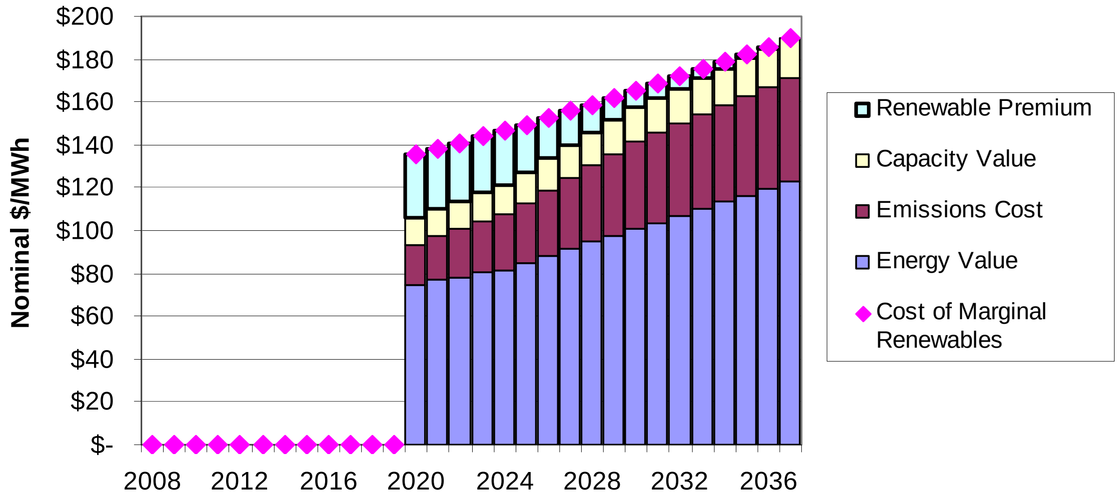
[4] 33% RPS Implementation Analysis, http://www.cpuc.ca.gov/PUC/energy/Renewables/hot/33implementation.htm

Renewable Premium by multiplying it by 33%, as, for each 1 kWh of avoided retail sales, 0.33 kWh of renewable purchases are avoided.

Figure 13: Evaluation of the Renewable Premium



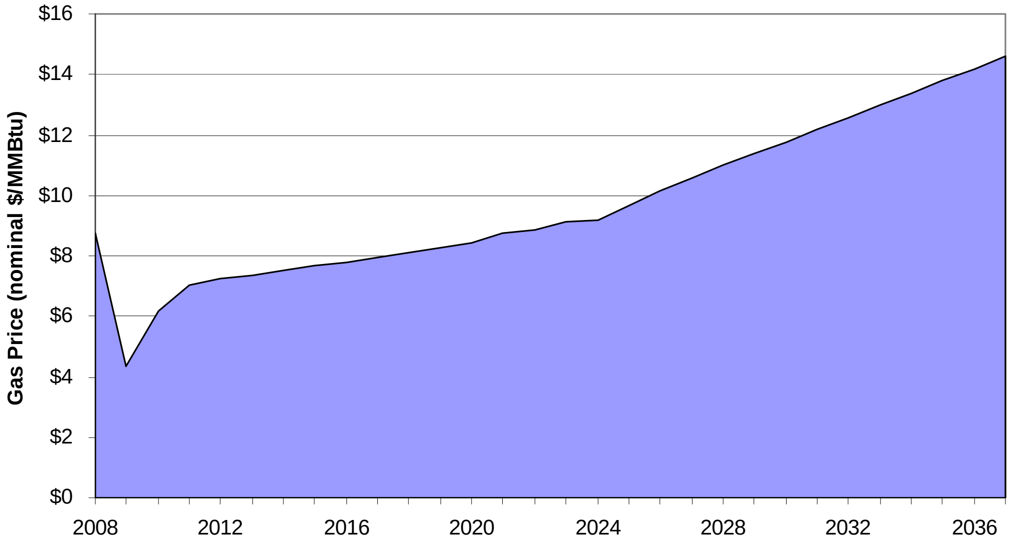
Key Data Sources and Specific Methodology

This section provides further discussion of data sources and methods used in the calculation of the hourly avoided costs.

Natural gas forecast

The natural gas price forecast, which is the basis for the calculation of the CCGT all-in cost, is taken from the CPUC MPR 2009 Update (historic data is used for 2008 and 2009). This forecast is based upon NYMEX Henry Hub futures, average basis differentials, and delivery charges to utilities. The forecast is shown in Figure 14.

Figure 14: Natural gas price forecast used in calculation of electricity value



Power plant cost assumptions

Cost assumptions as well as operating parameters for the CCGT plant are taken from the California PUC 2009 MPR Proceedings.[5]

Cost assumptions and operating parameters for the CT are based upon the California ISO 2008 Market Report's standard combustion turbine.

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

Figure 15: Power plant cost assumptions from avoided cost model

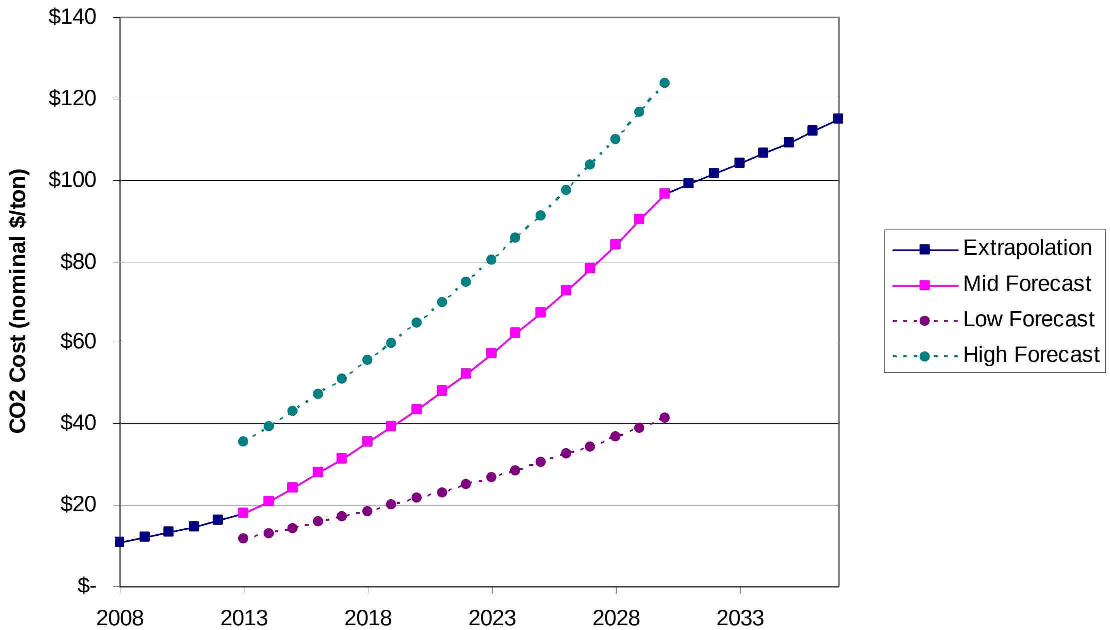
Central Station Plant Assumptions	**CCGT**	**CT**
Operating Data		
Heat rate (BTU/kWh)	6,924	9,300
Cap Factor	91.8%	9.4%
Lifetime (yrs)	20	
Plant Costs		
In-Service Cost ($/kW)	$ 1,098	
Fixed O&M ($/kW-yr.)	$ 10.20	$ 20.80
Property Tax (%)	1.20%	
Insurance (%)	0.60%	
Total Annualized Fixed Cost ($/kW-yr)		$ 162.10
Variable O&M ($/MWh)	$ 4.74	$ 10.90
Cost Basis Year for Plant Costs	2009	2008
Financing		
Debt-to-Equity	50%	
Debt Cost	7.7%	
Equity Cost	12.0%	
Marginal Tax Rate	40.7%	

Cost of CO2 Emissions

The CO2 cost projection is taken from a meta-analysis of CO2 price forecasts performed by Synapse Energy Economics, Inc. (the Synapse forecasts were also used in the 2009 MPR update). Figure 16 summarizes the Synapse price forecasts[6]; the mid-level forecast is used in the calculation of avoided costs.

[6] Synapse Energy Economics Inc., Synapse 2008 CO2 Price Forecasts, July 2008. http://www.synapse-energy.com/Downloads/SynapsePaper.2008-07.0.2008-Carbon-Paper.A0020.pdf.

Figure 16: The CO2 price series embedded in energy values



The emissions rates of natural gas plants are interpolated based on heat rate. Figure 17 shows the emissions factors at 6,240 and 14,000 heat rates. All heat rates in-between are interpolated.

Figure 17: Emissions rates of gas power plants

	Heat Rate (Btu/kWh)	CO2 (tons/MWh)
Low Efficiency Plant	14,000	0.8190
High Efficiency Plant	6,240	0.3650

Benchmarking of Load-Shaped Price Curve Against MRTU LMPs

The hourly market price curves resulting from scaling peak and off-peak prices in proportion to load during those periods were benchmarked against MRTU Locational Marginal Prices when both series were available (between April and June 2009). Figure 18 and Figure 19 show two ten-day snapshots that compare the two series. As earlier discussed, the load-shaped prices follow general trends that are similar to the LMPs but neglect to capture many of the hourly price spikes. Nonetheless, the load-shaped prices were chosen as the best available data for this analysis.

Figure 18: Benchmarking of load-shaped prices against LMPs, 4/1/09-4/10/09

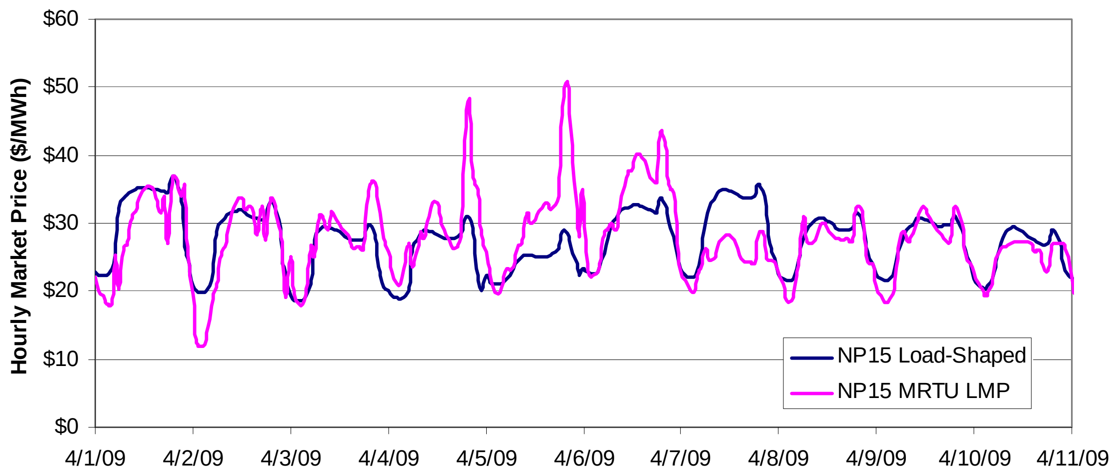
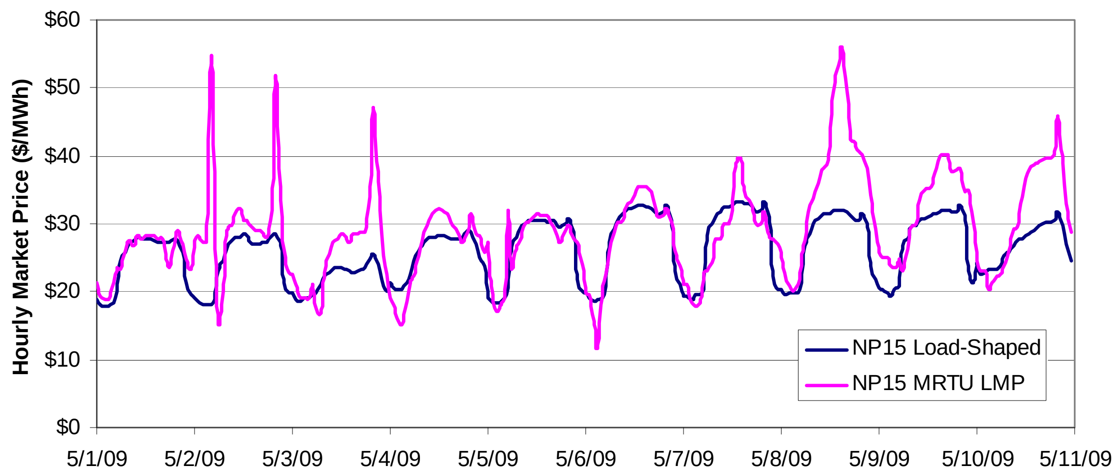


Figure 19: Benchmarking of load-shaped prices against LMPs, 5/1/09-5/10/09



Calculation of the System Capacity Allocators

The following calculation sequence is used to compute a capacity cost allocation factor in each of the top 100 system load hours. This methodology is applied in the calculation of the hourly avoided cost of electricity

- Compute the system capacity that provides 7% operating reserves = peak load * 1.07

- Compute a relative weight in each hour as 1 / the difference between the load in each of the top 100 hours and the planned system capacity

- Normalize the weights in each hour to sum to 100%

Calculation of the T&D Capacity Allocators

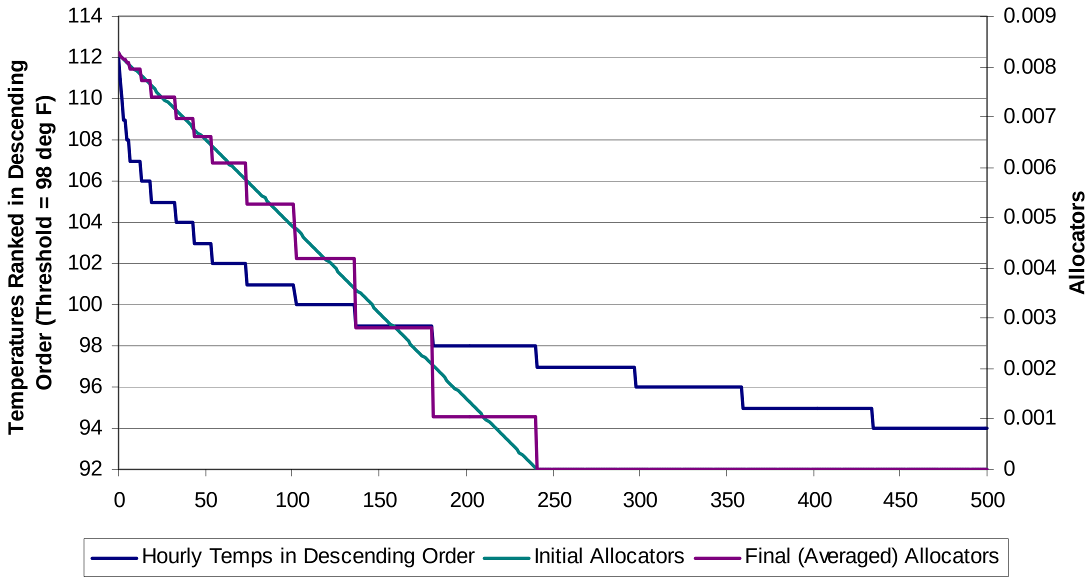
The following is a brief description of the algorithm used to allocated T&D capacity value. T&D capacity value is allocated to all hours with temperatures within 15ºF of the peak annual temperature.

- Select all hours with temperatures within 15ºF of the peak annual temperature (excluding hours on Sundays and holidays) and order them in descending order

- Assign each hour an initial weight using a triangular algorithm, such that the first hour (with the highest temperature) has a weight of 2/(n+1) and the weight assigned to each subsequent hour decreases by 2/[n*(n+1)], where n is the number of hours that have a temperature above the threshold established in the first step ("Initial Allocators" in Figure 20)

- Average the initial weights among all hours with identical temperatures so that hours with the same temperature receive the same weight ("Final Allocators in Figure 20)

Figure 20: Calculation of T&D allocators (example for CZ13)



APPENDIX B:

CLEAN POWER RESEARCH BILL CALCULATOR

Appendix B: Bill Calculation Methodology

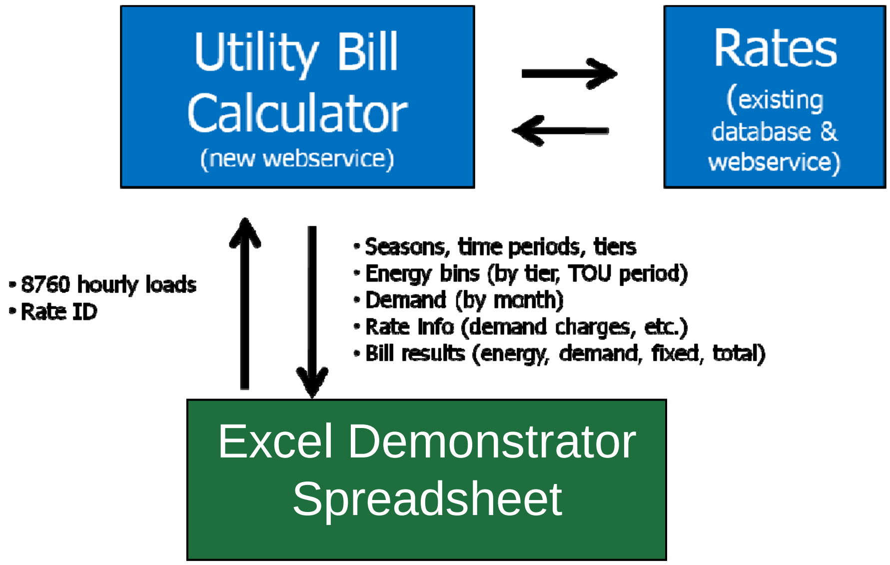
Overview

To support the analysis, CPR created a stand-alone web service, the "Utility Bill Calculator" (UBC), providing metered energy analysis and bill calculation results to client applications. Hourly metered energy data from customers with PV was supplied to the web service twice: first assuming standard metering, and second assuming net metering. The difference between results of these two cases was used to calculate the economic impact of net metering. The cases were run using data from all three IOUs, a range of geographical areas, and a number of rate schedules.

As shown in **Figure 1**, the UBC receives metered load values and a Rate ID (the example illustrates a full year of 8760 values; any number of interval readings may be used). It in turn calls CPR's Rates web service to get current rate structure and pricing information, calculate billing determinants, and return a range of data to the requesting client.

In this case, the "Excel Demonstrator Spreadsheet" is a client program. This spreadsheet is an example client that was created for transparency and validation purposes. The actual analysis used the same web service, but a database client application to facilitate large batch runs.

Figure 1. Utility Bill Calculator Schematic



The detailed spreadsheet output provides public transparency of the calculations for independent verification (duplicating UBC results). The individual hourly values can be independently binned in order to confirm the results of a given tier or TOU energy quantity in a given month. Maximum demand could be independently verified. The rates themselves can also be independently verified, as well as the resulting dollar values.

The UBC is a tool to calculate utility bills using raw, metered, hourly data. It covers the subtleties associated with rate structures, including fixed charges, minimum bills, sell back limitations, tiered usage charges, time-of-use (TOU) energy charges, and TOU demand charges.

Outputs are provided in Extensible Markup Language (XML) in a format that reflects the structure of the specified rate. For example, some rates have tier structures, and others do not. Some have TOU periods defined, and others do not.

The UBC determines the energy (kWh) and demand (kW) values when applicable. For example, in the PG&E rate E-1, the hourly input data is analyzed and the return results include the integrated energy values corresponding to each season and each tier (corresponding to each energy price). For the PG&E A-10 TOU-Secondary schedule, however, the return results include the energy binned into the Summer on-peak period, the Summer partial-peak period, and so on. Likewise, if the rate schedule called for a demand charge, the maximum monthly demand (kW) for each month is calculated and returned.

Finally, summary and detailed bill result values (in dollars) are returned. The details correspond to the rate structure. For example, the dollar amount corresponding to the energy consumed in the second tier during the month of April is provided. Likewise, the dollar amount corresponding to the demand charge during the month of September is provided. Dollar amounts are summarized by type (fixed, energy, and demand) and month. Finally, the total bill (the sum of all billing months) is also provided.

Inputs to the rate calculator are provided in Table 1.

Table 1: Rate Calculator Inputs

Rate ID	The ID corresponding to the rates database.
DemandTimeInterval	The normal interval between sequential values. Allowable values are: • **Hour**. Data is given every hour. • **30Min**. Data is given every 30 minutes. • **15min**. Data is given every 15 minutes.
DemandIntervalConvention	Defines the averaging interval. Allowable values are: **IntervalBegin**. Demand data reported represents an average over the following interval. For example, if the data is for 3:00 am, and DemandTimeInterval is **Hour**, then the demand data represents an average between 3 am and 4 am. **IntervalMidpoint**. Demand data represents an average over the preceding interval. For example, if the data is for 3:00 am, and DemandTimeInterval is **Hour**, then the demand data represents an average between 2:30 am and 3:30 am.

	IntervalEnd. Demand data represents an average over the preceding interval. For example, if the data is for 3:00 am, and DemandTimeInterval is **Hour**, then the demand data represents an average between 2 am and 3 am.
DemandUnit	Defines the unit of the demand data. Allowable values are: **KW**. Values are in KW. **KWH**. Values are in kWh.
DemandInterpolationMethod	This value identifies the method for interpreting missing data. Allowable values are: **Ignore**. Missing data should be ignored. Values are assumed to be zero for energy and demand calculations. **Average**. Missing data should be estimated by averaging the reported values on either side of the missing set. If the missing data occurs at the beginning or end of the set (i.e., unbounded), then the nearest data point is replicated for all adjacent intervals.
NEMCarryoverValue	The dollar value, if any, of the NEM carryover from the previous billing month.
BillingMonthID	Corresponds to a billing month, i.e., the time between meter reads. Energy and demand data should be separately apportioned into these months.
Demand	The metered value.
Interval	The time corresponding to the metered value, in the form YYYYMMDDHHNNSS where YYYY is the year (2008 or 2009), MM is the month number (01 to 12), DD is the day number (01 to 31), HH is the hour number (00 to 23), NN is the minute (00 to 59) and SS is the second (00 to 59). Time stamps should correspond to local standard time.

The web service accepts any number of rows of demand data (i.e., the file does not have a limit in length). The starting date and time may be any value. For example, the input data may cover June 16 at 2:00 pm to September 2 at 10:15 am.

Hourly values are net amount consumed. Positive values indicate power import from the utility, and negative values indicate export (e.g., a PV system or other generator is producing more energy than that consumed, and the excess is delivered to the utility).

APPENDIX C:

PV SIMULATION

Appendix C: PV Simulation

Hourly energy simulations were performed for 624 CSI PV systems for the year 2008. These simulations used the system components that had been entered into the PowerClerk database in the course of the program application process. The database included the following:

- PV module (make and model)
- Inverter (make and model)
- Orientation (azimuth and elevation of PV modules)

Shading information is also included in the database, but this was not required for the CSI program, so was not included. Also, adjustments were made to selective systems to establish consistent conventions for azimuth angle.

The analysis included, for every hour, a calculation of sun position and the incident solar radiation upon the module aperture. Hourly data for 2008 was taken from the SolarAnywhere satellite-based resource database corresponding to the latitude and longitude of each system. This data contains hourly irradiance data with a 10 km by 10 km resolution dating back 6 years. The data was processed by Dr. Richard Perez at SUNY and is provided by CPR as an online service.

Using this solar data, PV system energy calculations were performed using a simplified version of PV Form as implemented in the PVSimulator service.