Literature review summary for Vermont Act 125 evaluation of net metering

Public Service Department
September 17, 2012

A number of states have attempted to look at the question of rate impacts of net metering, specifically whether a subsidy or "cost shift" from non-participants to those participating in net metering is occurring. A 2009 qualitative study by the National Renewable Energy Laboratory (NREL), performed for the State of Minnesota as that state was considering raising its net metering cap, did not uncover any examples where state analysis had revealed a measurable net metering cross subsidy[1]. However, at that time, none of the states NREL interviewed had conducted a full cost-benefit analysis of their net metering policies, citing limited ratepayer impacts in other states.

Since then, relevant statewide studies have been performed in New York (as part of a broader review of the benefits and costs to New York ratepayers of increasing in-state solar capacity to 5,000 MW by 2025), Pennsylvania/New Jersey, and California. Additionally, utility-specific studies have been conducted in several states, most notably Texas (Austin Energy) and Arizona (Arizona Public Service).The methodologies used in – and results of – these studies are presented below, as is a generalized methodology for use in evaluating the costs and benefits of net metering recommended by the Solar America Board for Codes and Standards.

New York[2]

In January 2012, the New York State Energy Research and Development Authority (NYSERDA) published a broad analysis of the costs and benefits of meeting their 5,000 MW of solar by 2025 goal. The impact of net metering policy was only a small piece of the analysis, which also explored job and environmental impacts of meeting this goal (impacts are evaluated through 2049, to account for the lifetime of systems installed up until 2025) as well as various policy options for most cost effectively achieving the goal.

NYSERDA modeled lifetime average energy costs of residential, small commercial, large commercial, and MW-scale solar generation (modeled through PVWatts) for base-, low-, and high-cost scenarios using NREL's Cost of Renewable Energy Spreadsheet Tool (CREST). Administrative costs of developing and operating the state's solar incentive program were also included.

Benefits were evaluated using the Integrated Planning Model (IPM) and included: wholesale energy market value, wholesale capacity market value, avoided line losses, price suppression, avoided distribution costs, avoided RPS compliance costs, and monetized carbon values. Macroeconomic /jobs impacts where measured using the REMI PI+ model. The study did not address the potential for physical

[1] Doris, E., Busche, S., & Hockett, S. (2009). *Net Metering Policy Development in Minnesota: Overview of Trends in Nationwide Policy Development and Implications of Increasing the Eligible System Size Cap*. (NREL/TP-6A2-46670). Golden, CO: National Renewable Energy Laboratory.

[2] *New York Solar Study: An Analysis of the Benefits and Costs of Increasing Generation from Photovoltaic Devices in New York* (2012). Albany, NY: New York State Energy Research and Development Authority.

value of certain applications of solar on the grid, including localized reliability impacts, nor did it evaluate solar's potential as a fuel price hedge or for its role in grid security.

A summary of the study's broad policy objects is included from the report, below:

Table ES-1. Policy Objectives

Category	Policy Objectives
Environmental	• Minimize greenhouse gas emissions • Minimize criteria pollutant, mercury and other air pollution emissions • Reduce impacts related to water use in thermal electric generation (thermal, quality, quantity) • Preserve land from fuel cycle impacts (mining, drilling, etc.) • Minimize use of land with higher value alternative uses • Reduce reliance on finite fossil fuels
Energy Security and Independence	• Increase fuel diversity • Increase energy security and supply reliability • Increase domestic energy production
Reliability	• Reduce electric delivery disruption risk • Minimize negative grid planning and operating reserve impacts • Minimize distribution system negative reliability impacts (avoiding degradation of system loss of load probability)
Economic Development	• Maximize net in-state job creation • Maximize gross state product (GSP) growth • Support existing clean technology industries • Minimize out-of-state capital flows • Create stable business planning environment (for supply chain investment)
Energy Cost	• Reduce distribution system upgrades and minimize additional upgrades caused by PV • Reduce wholesale prices (energy and capacity impacts) • Minimize direct cost of policy to ratepayers • Minimize total cost of policy (exclusive of monetizing environmental, public health or other impacts) • Integrate well with competitive retail market structure in NY • Integrate well with competitive wholesale market structure in NY
Technology Policy	• Create a self-sustaining solar market • Assist emerging technologies in becoming commercial technologies • Foster technology innovation and development
Societal	• Ensure geographic distributional equity/ effectiveness at aligning benefits with those who bear the costs • Maximize benefits to environmental justice communities

The NYSERDA modeling showed that, of the benefits evaluated, price suppression and avoided electricity production costs were the greatest drivers of benefits. On the cost side, the future cost of solar and federal incentive levels were the primary drivers. Overall, the base case yielded a $2.2 billion net cost to New Yorkers – or 1% of total electricity bills – which could be driven downward by targeted geographic deployment of solar in downstate locations or by higher future natural gas prices.

The "cross subsidy" presented by the ability to net meter is acknowledged and "taken into account" by NYSERDA, in terms of the shift in fixed grid maintenance costs from net metering participants to other ratepayers, with the total transfer amount peaking coincident with the peak year for energy production from all systems then deployed:

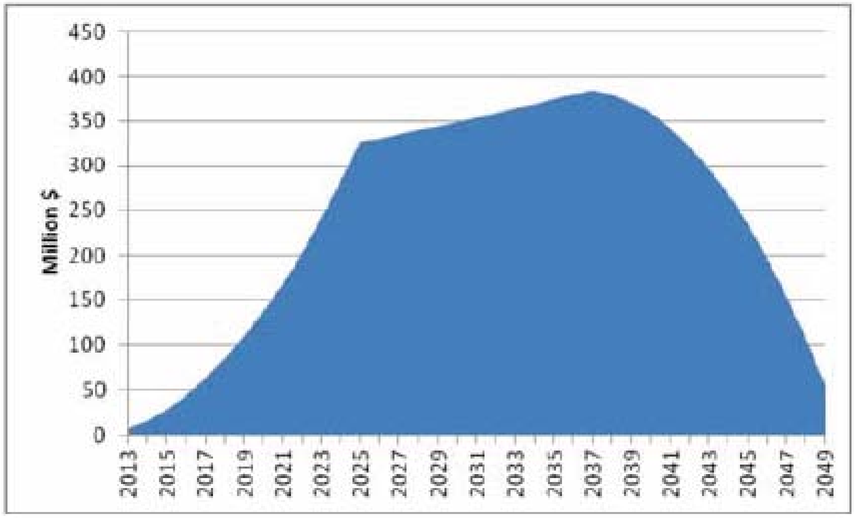


Figure 46. Net Metering Rate Impact, 2013-2049

The calculation of net metering rate impacts is included as part of the broader "net rate impacts" figures, which also include direct rate impacts and wholesale price suppression impacts:

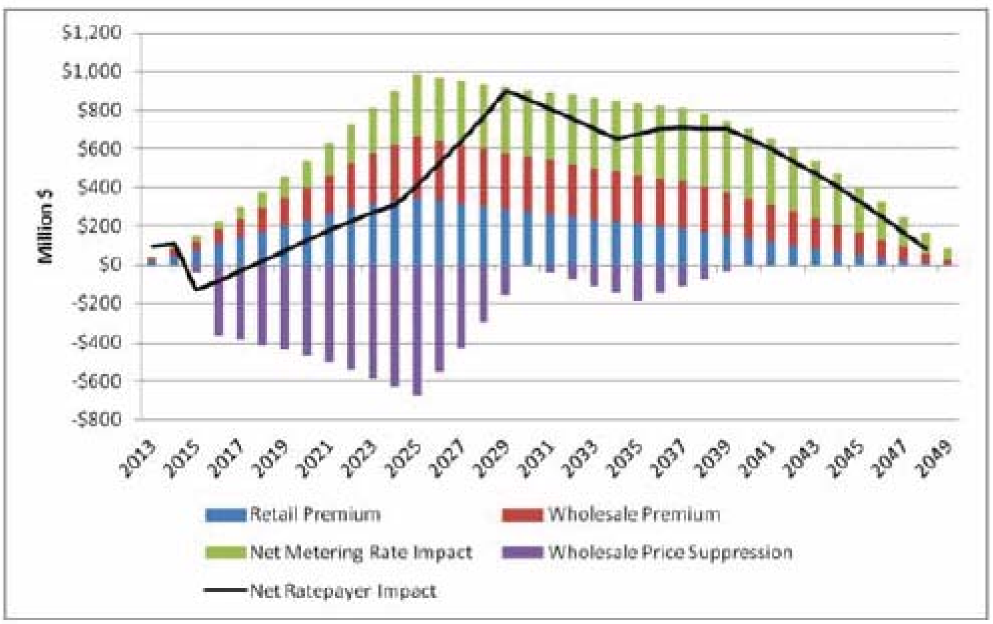


Figure 47. Net Rate Impact Components, Base PV Policy, 2013-2049 (nominal $)

Finally, in the section of the report dedicated to evaluating policy options for scaling up solar deployment, NYSERDA performed a quantitative analysis of net metering and utility ownership of solar. The pros of net metering identified were that it enables customers to offset their retail load, and the cons were that it decreases revenue for distribution companies and shifts costs to non-participants. To scale up the market, NYSERDA identifies a need to remove the program cap for net metering in each utility's service area; and the major constraint to scale-up is that to reach the 5,000 MW goal, the loss in utility revenue from net metering ratepayers' loads could require "significant cross subsidies."

California

Four California studies take a much more targeted approach than NYSERDA's, since they look at the narrow question of the cross subsidy occasioned by the existence of the net metering mechanism. The first study, published in 2010 and undertaken by Energy and Environmental Economics, Inc. (E3), reviewed the cost effectiveness of net metering in California as a first step in a broader review of the cost effectiveness of the entire California Solar Initiative; the second, performed by Lawrence Berkeley national Laboratory in 2010, examined the impact of retail rate design on hypothetical net metering bill savings for a sample of residential customers in two utility territories, PG&E and SCE; and the third and fourth, both published in 2012 by Crossborder Energy, revisited the E3 and LBNL studies with updated data.

E3[3]

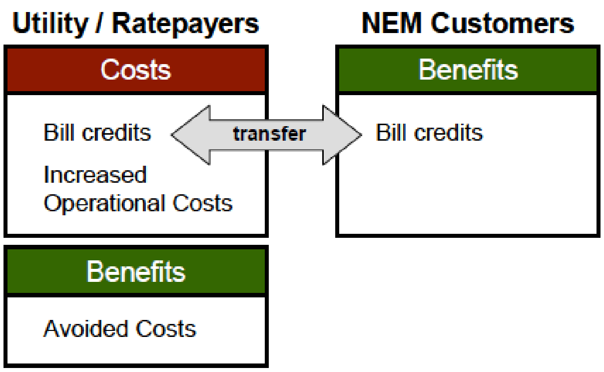
The 2010 E3 study, commissioned by the California Public Utilities Commission (CPUC), specifically looks at the quantifiable, incremental costs and benefits of net metering – specifically solar, the technology employed by 99% of net metering customers – and treats the costs as: (a) bill credits based on a customer's retail rate and (b) incremental billing costs to the utility. The benefits are calculated as utility avoided costs of energy and capacity procurement.

The report doesn't examine the broader benefit of net metering policy as a mechanism to encourage greater deployment of distributed renewables, or the economic, environmental, and societal benefits of those renewables. E3 only examines ratepayer costs (and benefits) that accrue due to the existence of the net metering billing mechanism; therefore, **only exported energy is examined**, since costs and benefits associated with energy consumed on-site would still exist without the ability to net meter.

The CPUC calls the E3 report methodology, "the most rigorous and quantitative methodology ever conducted on the NEM mechanism." The costs and benefits are evaluated for both participants in net metering as well as other, non-participating ratepayers and utilities. The conceptual framework of net-metering-attributable costs, benefits, and flows between entities is displayed in Figure 2 of E3's final report to the CPUC, below:

[3] Energy and Environmental Economics, Inc. (2010). *Net energy metering (NEM) cost effectiveness evaluation (E3 study)*. Available at http://www.cpuc.ca.gov/PUC/energy/DistGen/nem_eval.htm

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



Specifically, E3 measured the total benefits and costs of the fleet of California net metering generators over a 20-year period, expressing the results in terms of net present value (NPV), annualized value, and levelized value in 2008 dollars. NPV and annualized values will vary with enrollment in net metering, but the levelized value – that is, the net cost of net metering to ratepayers over 20 years on a $/kWh exported basis – is expected to remain the same absent changes in the underlying factors. The authors tested the sensitivity of their assumptions to: elimination of incremental billing costs; elimination of T&D deferral as a factor in the avoided cost calculation; inclusion of lost standby charge revenue; and inclusion of interconnection costs.

In order to specifically calculate costs and benefits, E3 needed to gather detailed data on the amount and timing of excess generation from net metering customers' systems, in addition to procuring those customers' billing rates. By gathering each net metering customer's hourly gross consumption and hourly gross PV generation for each hour of 2008, the authors were able to calculate the amount, timing, and cost to the utility of exported generation. E3 gathered various forms of net metering system capacity, consumption, and generation data from the utilities and were able to successfully link records of customer system PV capacity with customer combined generation-plus-consumption data for over 31,000 customers; however, detailed, hourly gross generation data was only available for a little over 600 of the systems.

Therefore, E3 had to develop a methodology to estimate amount and timing of exported energy from the other net metered systems, by "binning" like customers into categories and creating representative generation and consumption profiles (or shapes) for each bin. They then benchmarked their results both by comparing their estimates of the number of customers who had a year-end net export balance with the actual number of customers identified by utility data as having a year-end net export balance, as well as by comparing modeled and actual year-end net export balances. They suggest a third benchmark using modeled vs. actual year-end dollar value credits, but this field was either missing or incomplete in the utility-provided data.

After calculating the amount and timing of excess generation, E3 then used the information – along with customer billing data – to determine net metering participant costs. They crunched annual numbers for two sets of bills using the representative load profiles, with one set assigned a zero dollar-value for hours of net energy export, and the second assigned a flat or time-of-use (TOU) rate – as appropriate to the customer – for hours of net energy export. The difference between the two bills gave a non-participant cost (aka a *participant* benefit). That difference was then extrapolated out over 20 years (with PV system degradation and rate increases factored in), calculated as a NPV for each net metering customer, and multiplied by the number of customers in the representative bin; then the various bins were summed.

E3 also needed to calculate additional operational costs to the utility of net metering, which would theoretically include both incremental interconnection and billing costs; however, only data for billing costs were available. The various utilities each used different billing categories, so E3 calculated a weighted average incremental billing cost by customer class for a year.

To calculate benefits to the non-participants – the utility and the non-net-metering ratepayers – E3 first calculated avoided costs to the utility as a result of net metering, using a methodology E3 developed for the CPUC to us in evaluating the benefits of energy efficiency programs. The methodology has been adopted by both the CPUC and the California Energy Commission and is available for public review online[4]. The methodology estimates the hourly marginal cost to the utility of delivering electricity in each of California's 16 climate zones using: energy generation hourly wholesale values, line losses, ancillary services, system capacity costs, T&D capacity costs, environmental externality costs, and the additional costs incurred as the result of a Renewable Portfolio Standard. The avoided costs, forecast for each hour and year of the analysis, were then applied to individual net-metered system net export shapes to calculate its total avoided costs.

The E3 analysis base case found that the 386 MW of solar net metered in California as of 2008 would result in a net present value cost to ratepayers of $230 million over the next 20 years ($373M in bill impacts plus $61.8M in incremental billing costs minus $205M in avoided cost benefits), or $20 million per year on an annualized basis, or approximately $0.12/kWh exported on a levelized basis. The implied average rate increase required to cover the costs of net metering is estimated at $0.00011/kWh. That cost is one tenth of one percent of total utility revenue and represents a small fraction of utilities' demand side efforts, which account for seven percent of the annual residential customer bill and provide an overall net savings to ratepayers. Extrapolated out to the California Solar Initiative goal of 2,550 MW of installed solar by 2020, the net present value cost would rise to $137 million per year (in 2008 dollars), or 0.38 percent of 2020 projected IOU revenues, or an implied average rate increase of $0.00064/kWh.

The authors' analysis reveals that the largest cost driver is bill credits – as opposed to incremental billing costs to the utility (bill credits include full-rate credits allocated within a year and cash-out of excess credits at the end of a one-year period at the avoided cost rate, as enabled by impending implementation of AB 920). And, even though it wasn't part of the analysis – since it is not a direct consequence of the net metering mechanism – the authors also calculated the value of a net metering system directly offsetting a customer's energy use when their load exceeds the system's output, and

[4] http://www.ethree.com/public_projects/cpuc.php

determined that value actually accounts for about 75% of bill impacts, as opposed to 25% from bill credits. “In other words,” they say, “the bill effects from NEM are one-third as large as the bill effects that would result even if there were no NEM.”

The sensitivity analyses revealed that all assumptions except incremental billing costs raised overall costs of net metering by 10-15% each (though eliminating billing costs reduced overall costs of net metering by 27%). Taking the sensitivities into account, the lowest- and highest-cost scenarios produced a range of $14-$27 million in annualized costs – but even the lowest-cost scenario revealed some cost to ratepayers.

When the authors calculated annualized net costs per customer, they found that costs increased with the size of the customer (larger customers tend to install larger systems). But, at the very highest end of the size scale, net metering benefits actually flowed back to ratepayers, highlighting those systems’ relatively large avoided cost value compared with their incurred bill credits and incremental billing costs.

E3 also calculated two additional metrics: equivalent upfront payment (upfront payment required to make net metering customers indifferent between it vs. the bill credits over the 20-year analysis period) and equivalent net cost (net cost to ratepayers of the 20 years’ worth of credits per watt of installed PV). The average equivalent upfront value to net metering participants is $0.88/watt of installed PV capacity, while the average equivalent net cost to ratepayers is $0.54/watt. The authors attribute the difference to the avoided cost benefit to ratepayers offsetting some of the bill credit payments.

LBNL[5]

The LBNL study did not examine the value of net metering of solar to non-participating ratepayers; instead, the authors reviewed the impact of retail rate design on hypothetical net metering bill savings for a sample of residential customers in two utility territories, PG&E and SCE; they then compared the value of those bill savings under the current net metering compensation scheme with the potential for bill savings under three alternative compensation schemes: a market price referent (MPR)-based feed-in tariff, MRP hourly netting, and MPR monthly netting.

To determine the value of net metering under the extant rate structures in PG&E and SCE, the LBNL researchers pulled a sample of 215 single-family residences in those utility territories, gathered one year’s worth of 15-minute load data for those homes, and matched that load data with simulated hourly solar system production for that same year for three different solar system orientations. They then compared what customer utility bills would be with and without the solar systems (expressed as annual dollars saved per annual kWh generated), assuming each customer would choose the most beneficial rate structure for the given scenario.

Though the value of bill savings for the customers examined varied widely, because primarily of the steep time-of-use pricing tier structure then employed in PG&E (and to a lesser extent SCE), customer

[5] Barbose, Galen, Naïm Darghouth, and Ryan Wiser (2010). *The Impact of Rate Design and Net Metering on the Bill Savings from Distributed PV for Residential Customers in California*. Berkeley, CA: Ernest Orlando Lawrence Berkeley National Laboratory

savings generally fell with larger system sizes, rose with increased consumption, were unaffected by panel orientation, and were exhausted (over a year) with systems sized to meet less than 100% of load.

When LBNL looked at alternative compensation schemes for net metering system owners, they found dramatically reduced savings under an MPR-based feed-in tariff. Monthly MPR netting yielded some loss of savings, while hourly netting (also the method employed by the E3 study) yielded the fewest losses in comparison with current net metering compensation; for both hourly and monthly netting, savings were greater with increasing net excess generation.

When the authors looked at imposing an adder for utility system benefits of net metering to the MPR-based compensation schemes ($0.01/kWh for avoided T&D, a 110% multiplier for reduced line losses), the gap between these schemes and the current net metering compensation scheme narrowed even further; indeed, for hourly netting with adders, the cost of residential net metering was $0.01 per kWh of system production, or less than $0.02 to $0.05 per kWh of exported power. Overall, they concluded that if a feed-in tariff were to be employed to compensate net metering customers rather than rate-based compensation, the prices would need to be well above the current MPR to continue to drive solar market growth.

Crossborder[6]

In January 2012, R. Thomas Beach and Patrick G. McGuire of Crossborder Energy revisited the E3 and LBNL studies and updated the prior analyses with new information. Crossborder looked only at the PG&E utility territory, which originates more than two-thirds of the net costs of net metering for non-participants as well as for all ratepayers across the state of California.

The authors were compelled to perform the updated analyses because, since the 2010 E3 and LBNL studies, the CPUC significantly restructured PG&E residential rates: high-usage customers' rates were lowered substantially, lowering net metering credit amounts commensurately and thus reducing the rate impacts of those customers to non-participants. Beach and McGuire also incorporated new avoided cost modeling that accrues greater benefits to net metering as a new source of renewable generation.

Beach and McGuire were interested in, first, exploring the differing philosophical approaches taken by the E3 and LBNL study authors. They note:

> Although the E3 and LBNL studies used similar approaches to evaluating the economics of [net metering], their conclusions present different perspectives. The E3 NEM study cites a cost of NEM of $137 million per year once the CSI is fully built-out, in 2017. This is not an insignificant amount of money, even if it is small in the context of the IOUs' entire revenue requirement. Similarly, E3 calculates that residential NEM customers impose a net cost of $0.19 per kWh of power exported to the grid, which appears to be significant given that the average IOU residential rate is in the range of $0.17 to $0.19 per kWh, even though only a fraction of PV output is exported. On the other hand, the LBNL study suggests that NEM is only slightly more expensive than if the power exported to the grid were priced at an avoided cost rate (the MPR) plus avoided line losses and T&D costs – as noted above, less than $0.02 to $0.05 per kWh of

[6] Beach, Thomas R. and Patrick G. McGuire (2012). *Re-evaluating the Cost-Effectiveness of Net Energy Metering in California*. Berkeley, CA: Crossborder Energy.

> power exported. The LBNL work thus can be read as suggesting there is not a significant problem with NEM for residential customers.
>
> Which perspective is correct? One key point on which both studies agree is that, in the final analysis, any “cost shift” resulting from NEM is a function of rate design. The largest contributors to the NEM “cost shift” are large residential customers who install smaller systems that move them out of the expensive upper rate tiers, but which preserve their benefits from the low Tier 1 and 2 rates for their remaining usage. This is an artifact of the design of California’s residential rates, not of NEM. Thus, as California’s rate structures change over time, so will the economics of NEM. (P. 7)

Because they found residential rate structures presented a common driving force of net metering cost shift in both prior studies, and because PG&E’s rate structure had been substantially revised since the publication of those studies (with the elimination of the highest tier and the reduction of the next-highest tier), Beach and McGuire were compelled to perform an updated analysis. Changes to other assumptions of the two previous studies, based upon updated information, underscored the need for re-evaluation. These included new (lower) assumptions of retail rate escalations based on historical data and recent CPUC dockets; using an alternative benchmark to the MPR (one based on the avoidance of central station renewables, as opposed to market/fossil resources), as the legislature directed the CPUC to do in their legislation enabling a 33% Renewable Portfolio Standard; and use of a new avoided cost model that captures full avoided RPS compliance costs to the utility due to net metering.

Beach and McGuire used an hourly approach – the same as used in the E3 and LBNL studies – though they used a modeling approach rather than analyzing individual billing records (due to lack of access to the latter). They first simulated a net metering customer’s savings under standard net metering, and then ran the same load profile with excess production priced at avoided costs (updated as described above). In cases where the second calculation figures were less than under the standard net metering calculation, they assumed a cost to non-participants.

The authors found that the net cost to non-participating ratepayers in the PG&E residential market is $0.02/kWh of net metering exports to the grid – one-seventh the figure arrived at for the PG&E residential customers in the E3 study ($0.14/kWh, or $0.12/kWh when Beach and McGuire ran E3’s study assumptions through their own modeling tool), indicating a move toward increased cost effectiveness of net metering in California. They also note that if the other California utilities’ net metering programs are run through a similar, updated lens, the results might show net cost effectiveness over the combined territories of all of the utilities. The authors also parsed their analysis and looked at the differences in net metering cost-effectiveness between residential and large commercial customers, finding overall cost-effectiveness for the latter, which comprise over half of the net metering capacity in the state.

Beach and McGuire also take pains to point out that this type of test – a Ratepayer Impact Test (RIM) – is rarely used as a sole measure for analyzing the state’s demand side programs (indeed, such programs rarely pass RIM test). Instead, programs such as energy efficiency and demand response are usually subject to passing a broader, societal cost-benefit test; thusly would it be appropriate to similarly view net metering and other distributed generation programs, as California has done with their 2010 California Solar Initiative program review (of which the E3 net metering study was only one piece).

Crossborder 2[7]

In October, 2012, Crossborder Energy conducted an update to their study (using the same methodology) on behalf of The Vote Solar Initiative. For this update, the authors broadened their analysis beyond the PG&E territory and considered instead the validity of concerns about cost-shifts from solar to non-solar customers – particularly residential customers – across all three major utility service territories in California.

Though they again found a very small cost shift for residential net metering in PG&E territory ($0.019/kWh exported), it is more than offset by the net benefits calculated for the other utilities' residential markets ($0.015/kWh exported for SCE and $0.025/kWh exported for SDG&E), resulting in an overall net benefit to ratepayers. The difference is mainly attributable to PG&E's relatively higher-value upper tier block rates and relatively lower values figures for costs avoided due to net metering.

Extrapolating the results out to the buildout of the California Solar Initiative yields a net benefit to non-participants of $1.7 million per year; extrapolating out to the 5% net metering cap (recently reinterpreted by the California Public Utilities Commission) yields a net benefit of $3 million. The authors point out the diminutive nature of the numbers in comparison to the utilities' annual electric revenues of about $25 billion and – as with their earlier study – emphasize that any cost impacts of net metering on non-participants is a function of the underlying electric rate design and not of net metering as a concept in and of itself (as evidenced by the reduction in rate impacts between the publication of the E3 study and the original Crossborder study, during which time rates were significantly redesigned).

Austin Energy, Arizona Public Service, Perez, and Clean Power Research

Four other studies have attempted to quantify the value (but not costs) of distributed solar photovoltaics in geographically diverse areas, each of which is summarized briefly below.

Austin Energy[8]

In 2006, Clean Power Research, LLC, performed an analysis of the **value** of distributed solar photovoltaics to Austin Energy and the City of Austin (i.e., to the utility and to ratepayers), to support the municipal utility's plan to install 100 MW of solar by 2020 (the study was updated in 2012[9]). The authors considered and documented methodologies to determine the values of: energy production; generation capacity; T&D deferrals; reduced transformer and line losses; environmental benefits; and

[7] Beach, Thomas R. and Patrick G. McGuire (2012). *Evaluating the Benefits and Costs of Net Energy Metering for Residential Customers in California*. Berkeley, CA: Crossborder Energy.
[8] Braun, Jerry, Thomas E. Hoff, Michael Kuhn, Benjamin Norris, and Richard Perez (2006). *The Value of Distributed Photovoltaics to Austin Energy and the City of Austin.* Napa, CA: Clean Power Research, LLC.
[9] Harvey, Tim, Thomas E. Hoff, Leslie Libby, Benjamin L. Norris, and Karl R. Rabago (2012): *Designing Austin Energy's Solar Tariff Using a Distributed PV Value Calculator*. Austin, TX and Napa, CA: Austin Energy and Clean Power Research.

natural gas price hedge. Clean Power also sought to consider the value of distributed solar in reactive power control, retail price hedge, managing load uncertainty, and blackout prevention/disaster recovery, but the authors ultimately opted to forgo inclusion of those values in the final study for various reasons, explained below. They examined each benefit for 15 MW of photovoltaics in various orientations and configurations.

The basic methodologies employed to evaluate each benefit are:

Energy production: Used satellite-based measured weather data corresponding to the time period of the study (due to lack of measured system performance data or even measured global horizontal and direct irradiance data for the study period), which the authors ran through the program that powers PVWatts in order to generate hourly output simulations for each year load data were analyzed.

Generation capacity: Calculated the economic value of an ideal resource – a natural gas turbine – adjusted (using the Effective Load Carrying Capacity method) to reflect solar's actual peak load reduction value to Austin Energy; developed method that captures technology synergies that firm solar generation (such as storage and power controls), enabling additional capacity benefits.

T&D deferrals: Calculated the economic value of an ideal T&D resource and then adjusted based on effective capacity provided by solar, using utility-supplied estimates of deferrable investments by distribution area and year.

Reduced transformer and line losses: Determined benefit-specific loss savings percentage (i.e. the percentage of another benefit, such as energy production, increased as a result of loss savings) and the corresponding benefit value. Demonstrated loss savings should be calculated on a marginal instead of an average basis.

Environmental benefits: Used market data on voluntary green power purchasing programs.

Natural gas price hedge: Used 5-year natural gas futures prices and then Austin Energy's forecast of natural gas prices for the next 25 years; applied risk-neutral valuation methodology employed in financial economics.

Reactive power control: This hypothetical value (would require inverter modifications) was found to be minimal and was not included in the results. That is likely to change with pending updates to the international technical standard for interconnection of inverters, and as utilities become more familiar with emerging data on the value of photovoltaics for reducing voltage variability.

Disaster recovery: Developed preliminary, first-of-its-kind method to quantify disaster recovery benefit, but due to the uncertainties of quantification, values were not included in the final results; however, inclusion of the preliminary figures would have nearly doubled the overall value of photovoltaics to the utility.

The authors found a solar net present value of $1,983 - $2,938/kW or, on a levelized basis, $0.109 - $0.118/kWh – higher than electricity rates at the time – and that the highest value occurred with oneaxis tracking systems oriented 30 degrees west of south to coincide with utility peak demand. Over two-thirds of the value came from the energy generated by the solar panels.

Interestingly, this study has ultimately resulted in Austin Energy introducing (on October 1, 2012) a new structure for net metering systems up to 20 kW – regardless of when the system was installed – whereby customers pay for their gross energy consumption at the applicable residential electricity rate and are then credited for their gross solar generation at a separate, "Value of Solar" rate that is recalculated annually; this is called "Gross Metering" and is similar in nature to a feed-in tariff. Austin Energy says that, "The new rate structure is intended to improve the incentive for customer investment in solar [photovoltaics] and more fairly reward solar system operators for the energy they produce" and that "this ensures that solar [photovoltaic] customers retain the incentive to conserve energy and invest in making energy efficiency improvements."[10]

The Value of Solar credit calculation was originally developed for the 2006 study and considers all of the benefits that were included in the study's final solar value calculation. The current value is $0.128/kWh; under the new 5-tier pricing scheme for residential rates, a customer using <500 kWh/month would pay a $10 customer charge each billing cycle and then $0.018/kWh for electricity from October-May and then $0.033/kWh electricity June-September (rates scale up for higher electricity usage, but even the highest residential rates - $0.114/kWh, for residences using >2,501 kWh/month and in summer – are less than the solar value).[11]

Arizona Public Service[12]

In 2008, Arizona Public Service (APS) commissioned a study, led by R.W. Beck, to assess the **values** to the utility of various penetration scenarios (0.5%, 6.4%, and 14% by 2025) of distributed solar photovoltaics, solar hot water systems, and commercial daylighting systems. The authors sought to establish a boundary of expected solar values to use as a benchmark for further studies and analyses, and also brought in numerous stakeholders to assist with developing inputs and methodologies. The study did not look at costs to the utility or ratepayers of solar, distributed generation, or the net metering mechanism.

The R.W. Beck team approached their study in three phases. The first phase involved characterizing solar generation from the three technologies by reviewing existing distributed solar installation in APS territory, depicting the three study technologies, forecasting future solar deployments, and calculating future solar energy production.

The second phase involved developing a value approach for what was ultimately a subset of the values incorporated into the Austin Energy study: reduction in T&D line losses, deferment of T&D capacity upgrades and additions, reduction in the size of equipment needed within the distribution system, avoided capacity and fixed operating costs, and avoided energy and fuel purchases (environmental

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[10] http://www.austinenergy.com/energy%20efficiency/Programs/Rebates/Solar%20Rebates/proposedValueSolarRate.pdf
[11] http://www.austinenergy.com/About%20Us/Newsroom/Press%20Releases/2012/councilApprovesRates.html
[12] *Distributed Renewable Energy Operating Impacts and Valuation Study* (2009). Seattle, WA: R.W. Beck.

benefits and natural gas price hedge were excluded). The team looked at targeted deployment opportunities, calculated values for all scenarios, and assessed issues and impediment to deployment.

The final phase involved assembling the results and compiling an integrated value assessment – or business case – that quantified methodologies for calculating values, explored qualitative issues, and considered strategies for APS to meet its renewable mandates in the near term.

The study authors describe their methodology as being consistent with the revenue requirement approach for capital investment economic evaluations developed by the Electric Power Research Institute (EPRI), which recognizes all of the utility costs of providing service (both energy components and capacity components); the solar value calculations result in deductions from those energy and capacity costs. However, the authors identified virtually no distinct capacity benefits prior to 2025, both because capacity pricing is rolled into energy pricing (and thus ends up being reflected partially in the energy valuation) and because of the assumption that incremental solar additions will not defer need for new generation until those additions cumulatively equal the capacity of an entire utility generator.

The additive avoided T&D, O&M, capacity, and energy cost values ranged from $0.0791 to $0.1411/kWh in 2008 dollars (for reference, current customers under the Standard rate plan pay $0.09417/kWh November-April and $0.09687-$0.17257/kWh – depending on usage – from May to October). Most of the value comes from avoided energy purchases, followed by O&M, capacity, and then T&D savings. Interestingly, the study also found that peak solar production (mid-day) is not coincident with APS customer peak (late in the day), thereby limiting capacity savings, though the authors did not examine scenarios that encouraged southwest-facing arrays (as the Austin Energy study had done).

Perez[13]

In 2011, Richard Perez, Ken Zweibel, and Thomas E. Hoff attempted to describe the combined **value** that solar delivers to utilities' ratepayers (energy, capacity) and society's taxpayers (environmental, fuel price mitigation, outage risk protection, and long-term economic growth), specifically in the New York City area. Perez et al. assess the following costs and values for solar in New York (costs are described as the stream of revenues/incentives needed for a solar developer to break even – $0.20-$0.30/kWh – plus up to $0.05/kWh in infrastructure and operational costs to manage non-controllable solar costs and continue to reliably meet demand, based on previous research by Perez and others[14]):

[13] Hoff, Thomas E., Richard Perez, and Ken Zweibel (2011). *Solar Power Generation in the US: Too Expensive, or a Bargain?* Albany, NY: Clean Power Research, LLC.
[14] Hoff, Thomas E., Marc Perez, and Richard Perez (2010). *Quantifying the Cost of High PV Penetration*. Proc. Of ASES National Conference, Phoenix, AZ.

TABLE 1

	Developer/Investor	Utility/Ratepayer	Society/Taxpayer
Distributed solar* system Cost	20-30 ¢/kWh		
Transmission Energy Value		6 to 11 ¢/kWh	
Transmission Capacity Value		0 to 5 ¢/kWh	
Distribution Energy Value		0 to 1 ¢/kWh	
Distribution Capacity Value		0 to 3 ¢/kWh	
Fuel Price Mitigation		3 to 5 ¢/kWh	
Solar Penetration Cost		0 to 5 ¢/kWh	
Grid Security Enhancement Value			2 to 3 ¢/kWh
Environment/health Value			3 to 6 ¢/kWh
Long-term Societal Value			3 to 4 ¢/kWh
Economic Growth Value			3+ ¢/kWh
TOTAL COST / VALUE	**20-30 ¢/kWh**	**15 to 41 ¢/kWh**	

***** *Centralized solar has achievd a cost of 15-20 cents per kWh today. However less of the above value items would apply. The distribution value items would not apply. Transmission capacity, and grid security items would generally be towards the bottom of the above ranges, while penetration cost would be towards the top of the ranges because of the burden placed on transmission and the possible need for new transmission lines -- nevertheless, a value of 14-30 cents per kWh could be claimed.*

Regarding the table above, the authors note:

> Table 1 summarizes the costs and values accruing to/against the solar developer, the utility/ratepayer, and the society at large represented by its tax payers. The combined value of distributed solar generation to New York's rate and tax payers is estimated to be in the range of 15-41 cents per kWh. The upper bound of the range applies to solar systems located in the New York metro/Long Island area and the lower bound applies to very high solar penetration for systems in non-summer peaking areas of upstate New York. In effect, Table 1 shows that grid parity already exists in parts of New York – and by extension in other parts of the country – since the value delivered by solar generation exceeds its costs. This observation justifies the existence of (or requests for) incentives as a means to transfer value from those who benefit to those who invest. (P. 9)

Perez et al. stress that it is important to consider the values that accrue to both the ratepayer and the taxpayer when evaluating the costs vs. benefits of solar, because they are each two sides of the same coin and should be considered holistically – even though the values that stream to each (not to mention the subsidies provided by each) are different. However, the study does not specifically call out net metering or break out the components of the costs to ratepayers and tax payers, so it is impossible to understand how net metering credits, billing costs, etc. are being considered in the analysis.

Clean Power Research[15]

In 2012, Richard Perez teamed up again with Thomas E. Hoff as well as with Benjamin L. Norris in order to study the **values** that a fleet of distributed solar systems in various configurations (fixed horizontal, south-facing 30-degree tilt, west-facing 30-degree tilt, and 1-axis tracking at 30-degree tilt) delivers to

[15] Hoff, Thomas E., Benjamin L. Norris, and Richard Perez (2012). *The Value of Distributed Solar Electric Generation to New Jersey and Pennsylvania.* Albany, NY: Clean Power Research, LLC.

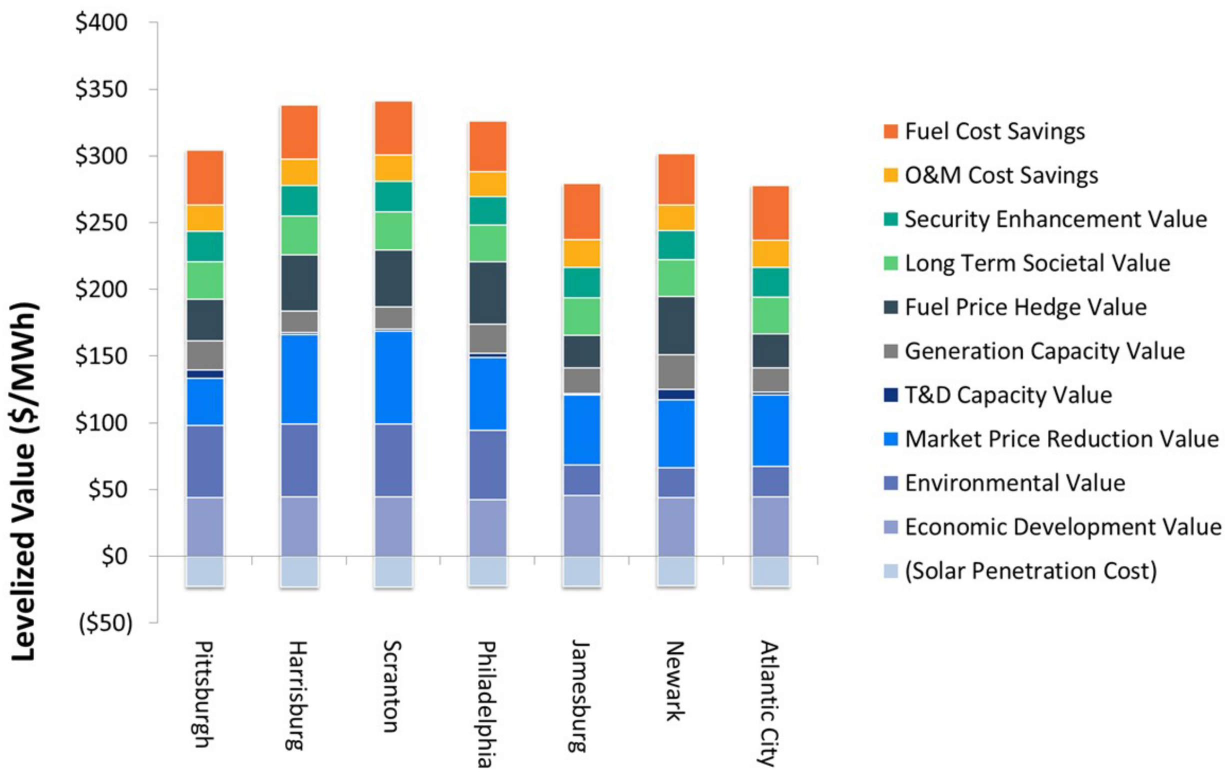
utilities, ratepayers, and taxpayers in Pennsylvania and New Jersey. The Clean Power Research team assessed the following costs and values for solar in each of seven different locations across the two states:

Table ES- 1. Value component definitions.

Value Component	Basis
Fuel Cost Savings	Cost of natural gas fuel that would have to be purchased for a gas turbine (CCGT) plant operating on the margin to meet electric loads and T&D losses.
O&M Cost Savings	Operations and maintenance costs for the CCGT plant.
Security Enhancement Value	Avoided economic impacts of outages associated due to grid reliability of distributed generation.
Long Term Societal Value	Potential value (defined by all other components) if the life of PV is 40 years instead of the assumed 30 years.
Fuel Price Hedge Value	Cost to eliminate natural gas fuel price uncertainty.
Generation Capacity Value	Cost to build CCGT generation capacity.
T&D Capacity Value	Financial savings resulting from deferring T&D capacity additions.
Market Price Reduction	Wholesale market costs incurred by all ratepayers associated with a shift in demand.
Environmental Value	Future cost of mitigating environmental impacts of coal, natural gas, nuclear, and other generation.
Economic Development Value	Enhanced tax revenues associated with net job creation for solar versus conventional power generation.
(Solar Penetration Cost)	Additional cost incurred to accept variable solar generation onto the grid.

The Clean Power Research team computed the following levelized values for a fleet of 30-degree-south-tilted distributed solar arrays (which yielded the highest values of all the different configurations) in seven different locations across the two states:

Figure ES- 1. Levelized value ($/MWh), by location (South-30).



The sum of all values ranges from $256/MWh to $318/MWh in the various locations studied. Of all the values assessed, the authors note that Market Price Reduction and Economic Development Value provide the most benefit; the former (average $55/MWh) attributable to coincidence between locational marginal price and solar output, and the latter (average $44/MWh) reflecting the tax revenue enhancement of local jobs created – even under the conservative assumption that 80% of the related manufacturing jobs would remain out of state.

The cumulative values found are in line with the previous Perez study, and again reflect only the value (as opposed to the cost) to utilities and ratepayers and society of solar – not the net cost of value of a policy mechanism like net metering.

Solar ABCs[16]

In January 2012, the Solar America Board for Codes and Standards (Solar ABCs) published *A Generalized Approach to Assessing the Rate Impacts of Net Energy Metering*, written by Jason Keyes and Joseph Wiedman of the Interstate Renewable Energy Council (IREC). This "study of studies" attempts to provide a consistent methodology for analyzing the potential rate impacts of net metering.

[16] Keyes, Jason B. and Joseph F. Wiedman (2012). *A Generalized Approach to Assessing the Rate Impacts of Net Energy Metering*. Solar America Board for Codes and Standards, http://www.google.com/url?sa=t&rct=j&q=&esrc=s&frm=1&source=web&cd=1&cad=rja&ved=0CB8QFjAA&url=http%3A%2F%2Fwww.solarabcs.org%2Fabout%2Fpublications%2Freports%2Frateimpact%2Fpdfs%2Frateimpact_full.pdf&ei=GetQUKubIqXz0gHgoIDADg&usg=AFQjCNFrShDiNmbD3WepxF4g5W7DRzGExQ.

Keyes and Wiedman review and synthesize three net metering studies performed for major utilities over the past decade (Austin Energy, Arizona Public Service, and E3, as described above) and then – based upon the methodology employed by each of those studies – lay out a general approach any state or utility might ostensibly use to analyze rate impacts of net metering within their borders. The focus of the methodology is on solar, which is the predominant type of facility participating in most state net metering programs. In addition, the authors address only the rate implications to customers not participating in net metering; they don't look at impacts to net metering participants nor do they address broader environmental or economic questions.

The study suggests the following costs and benefits be considered as part of a net metering rate impact evaluation based upon the literature:

TABLE 2
Necessary Costs and Benefits Inputs in a Methodology for Evaluating the Rate Impacts of Net Energy Metering

Benefits to the Utility	Costs to the Utility
Avoided Energy Purchases	NEM Bill Credits
Avoided T&D Line Losses	Program Administration
Avoided Capacity Purchases	
Avoided T&D Investments and O&M	
Environmental Benefits—NO_x, SO_x, PM, & CO_2	
Natural Gas Market Price Impacts	
Avoided RPS Generation Purchases	
Reliability Benefits	

The E3 study is the only one of the three examined by Keyes and Wiedman that attempts to assess the **costs** to the utility and ratepayer of net metering, those being bill credits and program administration. The authors urge caution in calculating bill credits, especially in avoiding double-counting. For instance, they point out:

> If [net metering] bill credits are determined by comparison of estimated bills before and after renewable resources are installed, "revenue losses" related to T&D charges and non-fuel generation revenues are already included. Moreover, customers who face demand charges based on maximum demand during the billing period could see little or no change in their demand charges, and thus would still be paying the T&D and non-fuel generation costs. For these reasons, inclusion of an additional input

> to measure T&D and non-fuel generation charges not collected by the utility due to NEM of solar and wind facilities is almost certainly double counting of this potential "lost revenue." (Pp. 16-17)

Similarly, they urge caution against double counting of T&D charges in calculations of potential lost revenues from standby charge exemptions, as well as in scrutinizing self-reported utility administrative billing cost data – especially in the case where (as in California) one utility's costs were nearly five times the costs of the other utilities, with no explanation as to the variation, and no study assumptions regarding the decrease in these costs as utilities update billing software and implement smart grid measures over time.

The general set of benefits inputs recommended by Keyes and Wiedman are: avoided energy purchases, avoided T&D line losses, avoided capacity purchases, avoided T&D investments and O&M, environmental benefits (NOx, SOx, PM & CO2), natural gas market price impacts, avoided RPS generation purchases, and reliability benefits. The first four are consistent across the studies reviewed, and should be "relatively noncontroversial," according to the authors, "given their consistent identification as benefits of customer investment in renewable energy resources." However, they urge caution in evaluating T&D investment deferrals to ensure the calculus includes both the deferral of the capacity investment as well as reductions in need for/frequency of O&M; they also recommend capacity benefits are modeled under a long-term framework to ensure the value of net metered solar in deferring capacity investments under a long-term planning framework is property evaluated.

Environmental benefits were recognized in two of the studies reviewed – Austin Energy and E3 – and Keyes and Wiedman emphasize their importance in the general evaluation approach. However, the framework for evaluation will look different in each state as a result of that state's environmental regulatory frameworks (as would be the case for evaluating many of the costs and benefits).

In terms of natural gas market price impacts, though the Austin Energy study found a negligible impact, Keyes & Wiedman point out that a literature review conducted by Lawrence Berkeley National Laboratory (LBNL) in 2005 found that natural gas price hedge impacts from renewables range from $10/MWh to $65/MWh across the U.S. – a significant value that should be examined in any cost-benefit evaluation, especially given the increasing prevalence of natural-gas-fired generation in many utilities' portfolios as of late[17].

Additionally, each state/utility evaluation will need to consider whether net metered systems will reduce utilities' need to purchase renewable energy to meet Renewable Portfolio Standards.

Finally, Keyes and Wiedman argue that reliability benefits should be carefully considered, especially as inverters and associated technical standards are improved to allow net metered systems to proactively respond to grid voltage fluctuations, and as smart grid and other system improvements (such as energy storage) are implemented that allow for backup power for grid outages, especially at critical needs facilities.

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[17] Bolinger, Mark, Matt St. Clair, and Ryan Wiser. *Easing the Natural Gas Crisis: Reducing Natural Gas Prices through Increased Deployment of Renewable Energy and Energy Efficiency* (2005). Berkeley, CA: Lawrence Berkeley National Laboratory.

Keyes and Wiedman also point out that only accounting for the costs and benefits of exported power – as the E3 study does – might be an oversimplification, since it assumes that in the absence of net metering, the amount of installed solar would remain the same, given other available incentives. However, in practice, customers without net metering available to them might undersize systems to avoid exporting minimal-value excess energy to the grid, or they might choose to make investments in storage technologies. Unfortunately, determining how much generation might be installed in the absence of net metering would be a very difficult, and very academic, proposition. Therefore – and given the relatively small percentage of generation that is actually net metered – Keyes and Wiedman resolve that the oversimplification is not unreasonable, and ultimately recommend that any net metering cost-benefit methodology look at only exported energy.

In conclusion, Keyes and Wiedman make note of the high cost of net metering studies in relation to any net costs or benefits, and advise, “The results discussed in this report should give regulators confidence that rate impacts at the earliest stages [of net metering deployment] will be negligible and need not be a concern that leads to a restrictive [net metering] policy.”