Incentivizing Solar Energy:

An In-Depth Analysis of U.S. Solar Incentives

Report prepared by:
Borlick Associates, LLC

CONSUMER **ENERGY** ALLIANCE
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Consumer Energy Alliance (CEA) brings together consumers, producers and manufacturers to engage in a meaningful dialogue about America's energy future. With more than 400,000 members nationwide, our mission is to help ensure stable prices for consumers and energy security. We believe energy development is something that touches everyone in our nation, and thus it is necessary for all consumers to actively engage in the conversation about how we develop and diversify our energy resources and energy's importance to the economy. CEA promotes a thoughtful dialogue to help produce our abundant energy supply, and balance our energy needs with our nation's environmental and conservation goals. Learn more at ConsumerEnergyAlliance.org.

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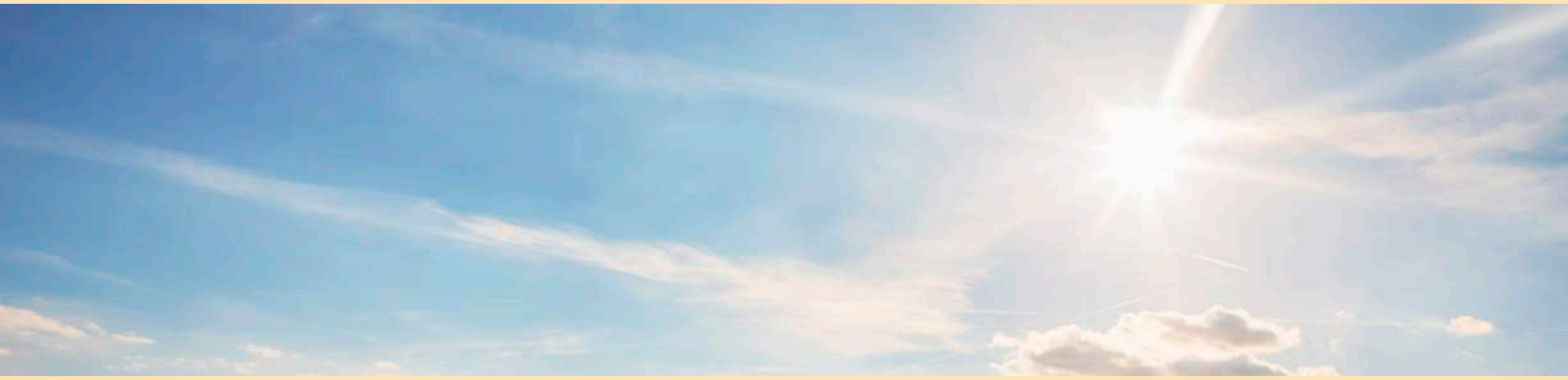
Pro-Solar. Pro-Grid. Pro-Consumer.

Solar energy technology has the power to dramatically change the face of modern electricity generation. From rooftop, to community, to utility-scale projects, consumers across the country are realizing the awesome potential that solar brings to them in the form of clean, affordable, and reliable energy. To ensure that solar energy technology thrives, and that consumers are able to access it, federal, state, county, and even local governments have created incentives that make solar technology make sense.

Accordingly, Consumer Energy Alliance (CEA) commissioned Borlick Associates to provide a report that describes and quantifies the amount of incentives that consumers have access to in various states across the country. From California to Massachusetts, and from Maine to Arizona, this comprehensive view of solar incentives should help lawmakers, policymakers, regulators, utilities, and consumers at the federal, state, and local level make informed policy, legal, and investment decisions based on the most current information available. Understanding the results of this report should yield solar policies that ensure the proliferation of solar technology, the continued efficiency of a robust electric grid, and increased access to clean, affordable, and reliable energy sources for all American consumers.

EXECUTIVE SUMMARY



To stimulate renewable energy development, governments at the local, state and federal level have provided a myriad of incentives for residential electricity customers who install solar panels on their roofs, some of which overlap. The combined effect of these incentives is quite substantial – particularly in light of the dramatic decline in the cost of solar panels that has recently occurred.

This report aims to inform policymakers by quantifying the total incentives as a percentage of the installed cost of a typical residential solar facility located in each of 15 states, including: Arizona, California, Connecticut, Florida, Georgia, Illinois, Louisiana, Maine, Massachusetts, Michigan, Minnesota, New Hampshire, New Jersey, Nevada, and North Carolina. These states were selected to capture diversity in location, state-level incentive policies, retail tariff designs, and wholesale electricity prices. Accordingly, this report focuses on the following:

NATURE OF THE INCENTIVES

While a number of financial incentives exist for rooftop residential solar PV users, this report explores the four most prominent and substantial types of incentives:

- Incentives provided to residential customers who own solar PV facilities, through tax credits and monetary payments from federal and state governmental entities and electric utilities,
- Incentives provided through state "net energy metering" (NEM) policies,
- Incentives provided to third party owners (TPOs) of residential rooftop solar PV facilities that either lease them or sell the energy they produce to their residential customers through long-term contracts,
- Incentives provided through Renewable Energy Certificates (RECs) that can be sold.

Direct Incentives

All residential customers that own solar PV receive the Residential Energy Efficiency Property Credit (REEPC), which is a federal tax credit equal to 30 percent of the solar PV facility's installed cost. In addition to the REEPC, many customers receive one or more of the following incentives:

- State income tax credits and/or deductions,
- State and/or local sales and/or property tax exemptions,
- State renewable energy payments,
- State Public Utility Commission (PUC)-approved incentives provided by the utilities they regulate.

In some states, owners of residential solar PV also receive incentives from their local governmental entities. To simplify the analyses, this report excludes these incentives.

Net Energy Metering (NEM) Incentives

In 44 states and the District of Columbia residential customers with solar PV can participate in NEM programs offered by their respective electric utilities. These programs bill the customer for the net amount of electricity consumed, i.e., what the customer consumes less the amount the customer produces onsite. Any excess energy produced flows back to the utility and the customer receives a bill credit that is applied to future bills. In effect, the utility purchases all of the customer's solar energy at the energy prices in the customer's retail tariff, which almost always exceed the utility's avoided costs. This report defines the NEM incentive as the present value of the customer's bill savings derived from the NEM program, less the present value of the costs the utility avoids due to the customer's onsite generation, over the 25-year expected economic life of the solar facility.

Third Party Ownership Incentives

Recently, a new business model has emerged — the third party ownership model — where a business entity owns the solar PV system installed on a homeowners' rooftop and either leases the system to the homeowner or sells the energy it produces to the homeowner through a long-term contract. This arrangement creates additional incentives because the third party owner (TPO) depreciates the solar facility as a business asset over just 5 years. In addition, the TPO bases the depreciation deductions and the federal ITC on the facility's fair market value (FMV), which is higher than the installed cost.

Renewable Energy Certificates

A renewable energy certificate (REC) is a property right created for the owner of a renewable resource when it produces one MWh of energy that is certified and reported to one of nine regional tracking systems. RECs created by solar facilities are a special subset often referred to as "Solar Renewable Energy Certificates (SRECs)." RECs have monetary value primarily because the electricity suppliers serving retail customers in 29 states and the District of Columbia must acquire them in order to comply with the renewable portfolio standards (RPS) adopted by these political jurisdictions. Owners of rooftop solar facilities can sell their RECs into one or more regional markets at the prevailing market prices. In addition, in some states the owners can sell their RECs directly to their host utilities through PUC-mandated programs that pay above-market prices.

ESTIMATES OF INCENTIVE VALUES

Figure 1 illustrates the installed cost and incentives available by a typical 3.9 kW-dc residential solar PV facility. The incentives shown are simple averages of the 15 state-specific results obtained for residential customers served under their respective utilities' standard tariffs. For comparison, it also presents the installed cost and incentives available by a third party-owned 3.9 kW-dc residential solar PV facility and by an equivalent amount of capacity from a typical, utility-scale fixed-tilt solar PV facility.

As Figure 1 shows, the installed cost of an equivalent amount of utility-scale solar PV capacity (also reported by SEIA for Q1-2015) is about half that of the residential solar PV facility. It also reveals that utility-scale solar PV facilities receive incentives (all from the federal government) equal to only about 58 percent of installed cost. Because a solar PV facility's initial investment essentially determines the resource cost of the electricity it produces, utility-scale solar PV produces electricity at a much lower resource cost than residential solar PV.

Figures 2 and 2A present the state-by-state incentive estimates for customer-owned residential solar PV in each of the 15 selected states. The incentives to customer-owned residential solar PV in 8 of the 15 states cover more than the customer's cost of installing the facilities. An additional 7 states provide incentives that cover more than three-quarters of the installed cost of the solar PV facilities.

CONCLUSIONS

Based on the various incentives and certificates at the federal, state, and local levels offered to solar PV rooftop users, this report will demonstrate the following conclusions to provide a foundation and context for policymakers to make well-reasoned and informed decisions regarding solar policy within their jurisdiction.

EXISTING INCENTIVES FOR RESIDENTIAL SOLAR PV ARE SUBSTANTIAL

The combined effect of the incentives in many states collectively exceeds the total cost of installing a solar

PV facility – particularly for third party-owned facilities.

INCENTIVES ARE EVEN MORE SIGNIFICANT FOR THIRD PARTY-OWNED SOLAR PV FACILITIES

When a customer leases a solar PV facility or purchases its energy output through a long-term contract, the TPO receives the federal ITC and 5-year accelerated depreciation, significantly enhanced by basing them on the fair market value of the facility, rather than its installed cost.

EXISTING INCENTIVES MAY CHANGE THE ECONOMICS OF FUTURE INVESTMENTS IN SOLAR

The non-incentivized cost of producing a kWh of energy with residential solar PV is much higher than the non-incentivized cost of producing a kWh of energy with a large-scale solar PV; consequently, incentivizing residential solar PV may not be the economically efficient way to increase solar penetration.

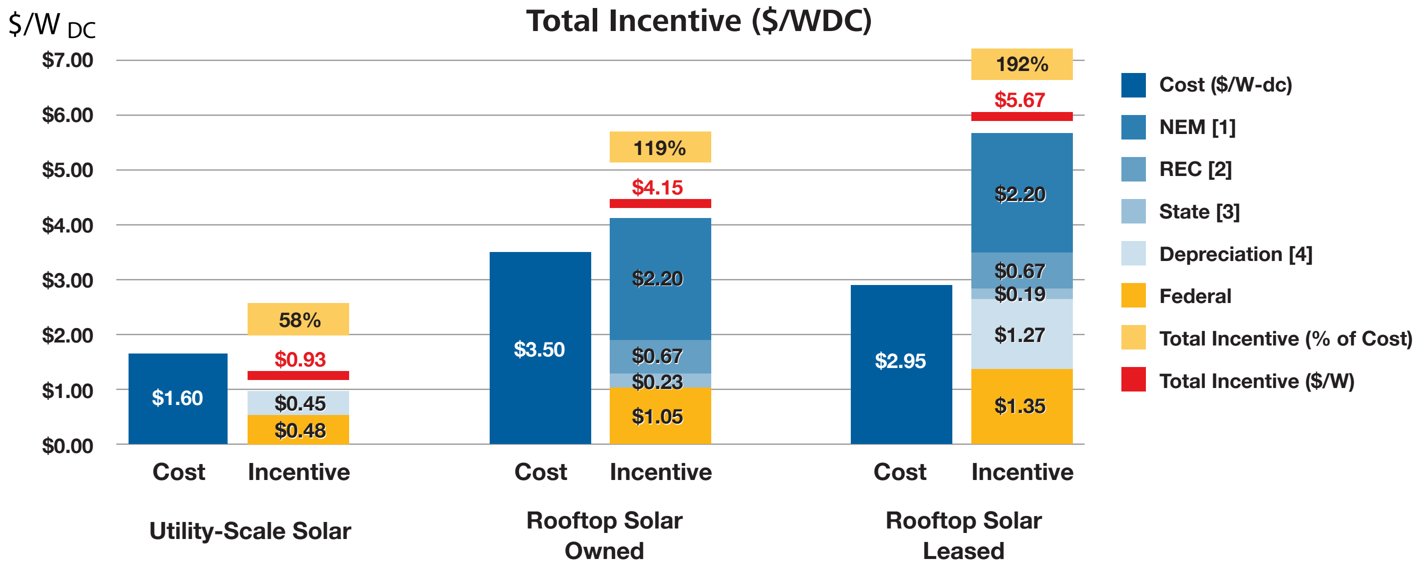
THE NEM INCENTIVE SHIFTS COSTS ONTO LESS AFFLUENT CUSTOMERS.

Net metering programs, which pay residential PV solar customers high rates for their excess electricity production, shift fixed utility infrastructure costs onto non-solar customers, who a number of reports show are typically less affluent than customers with solar PV.

INCENTIVES FOR RESIDENTIAL SOLAR PV VARY WIDELY AMONG THE STATES.

The total incentives for customer-owned residential solar PV facilities vary substantially among the states. Four factors create these disparities: (1) different state direct and REC incentives for residential solar energy, (2) different residential retail tariff designs, (3) different avoided utility costs and, (4) (for third party-owned facilities) different contract pricing strategies. Still, on a dollar per-kW basis, even the smallest package of total incentives far exceeds the incentives provided to utility-scale solar PV projects.

Figure 1. Total Incentives Available for a 3.9 kW-dc Customer-Owned and -Leased Solar PV Facilities and an Equivalent Amount of Utility-scale Solar PV Capacity ($/W-dc)



1. NEM incentive is the difference between the present values of the customer's bill savings and the utility's avoided costs over the facility's life. For the Rooftop Leased, the incentive flows to the homeowner and is largely passed through to the Third-Party Owner as a lease or PPA payment.
2. Renewable Energy Certificates / Credits are incentives available through applicable programs.
3. Incentives mandated by state legislatures are upfront and/or performance-based compensation, often through the state tax code.
4. Depreciation is based on renewable-specific 5-year MACRS

Figure 2. Incentives Available for Customer-Owned Residential Solar PV in Selected States, as a Percentage of Installed Cost (3.9kW)

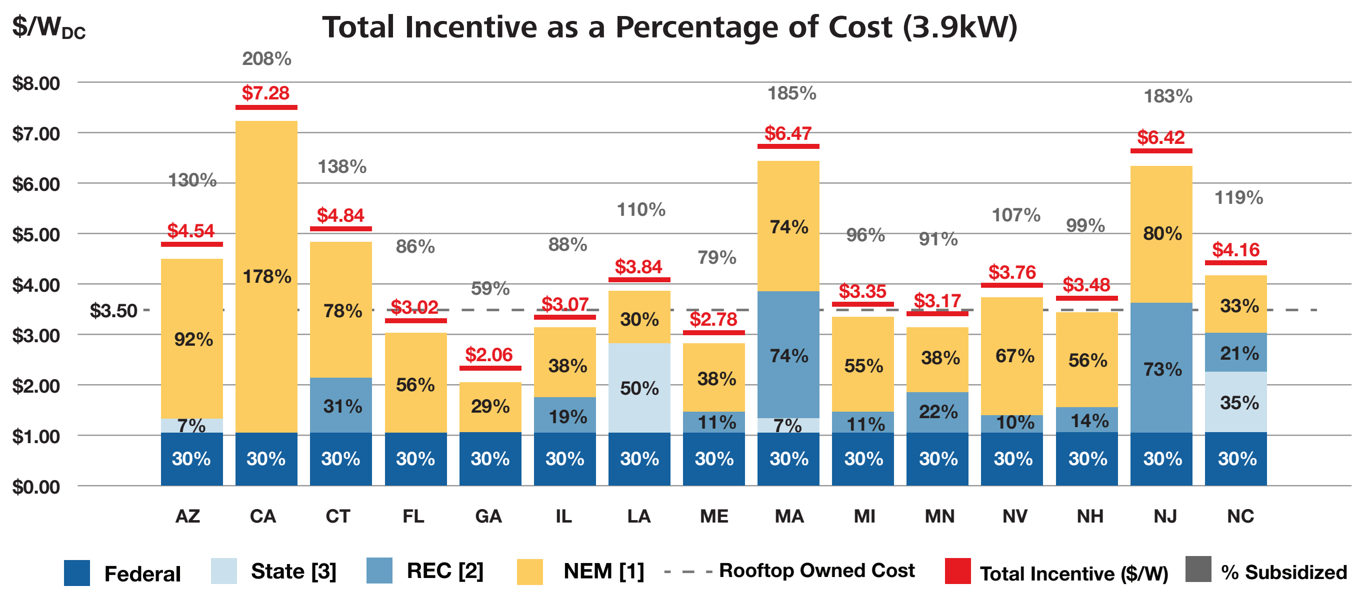


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Figure 2A. Incentives Available by Customer-Owned Residential Solar PV in Selected States, as a Percentage of Installed Cost (6.0kW)

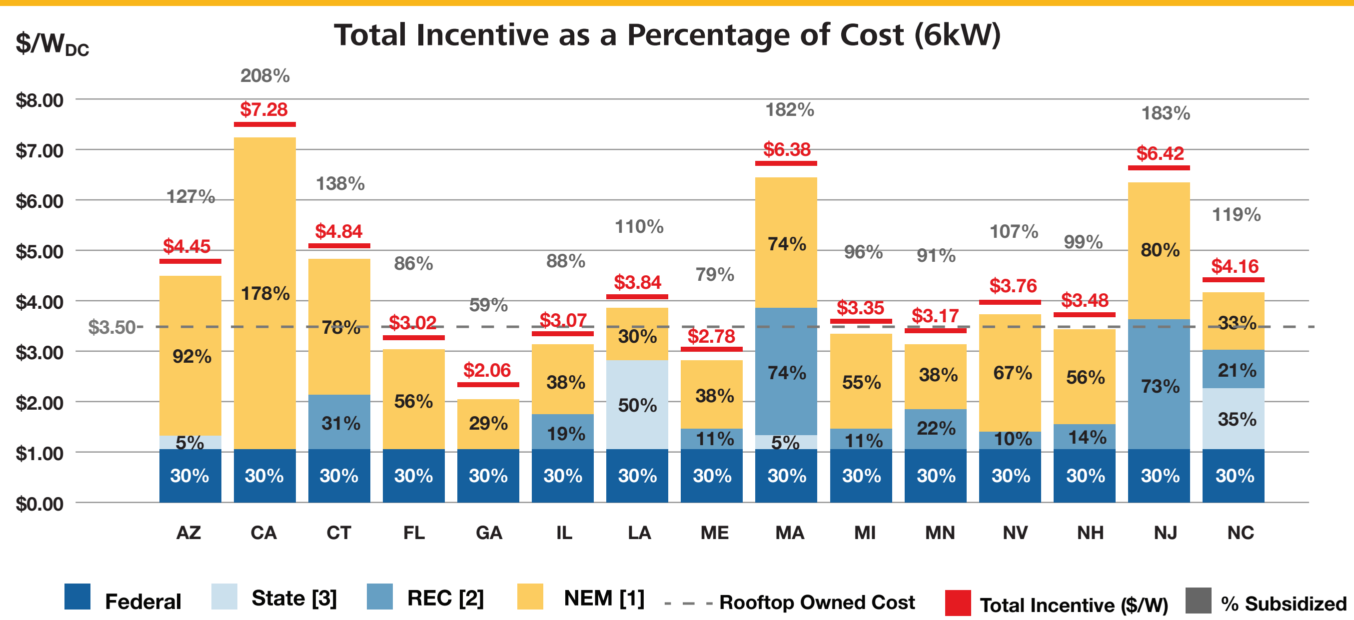


Figure 3. Total Incentive ($) for Typical Rooftop Owned System (3.9kW)

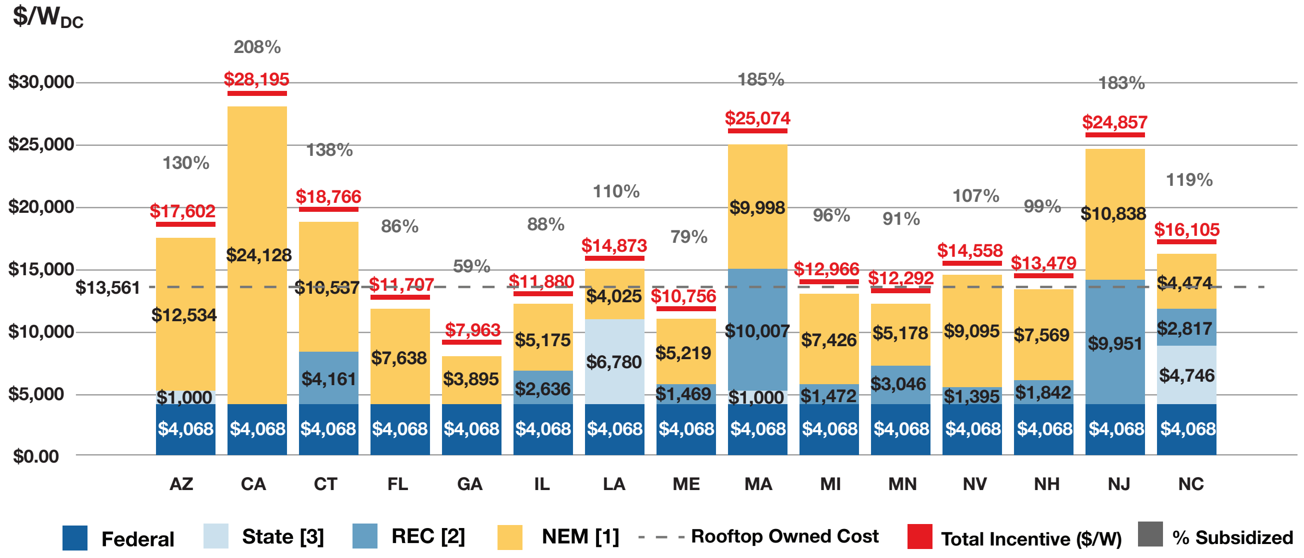
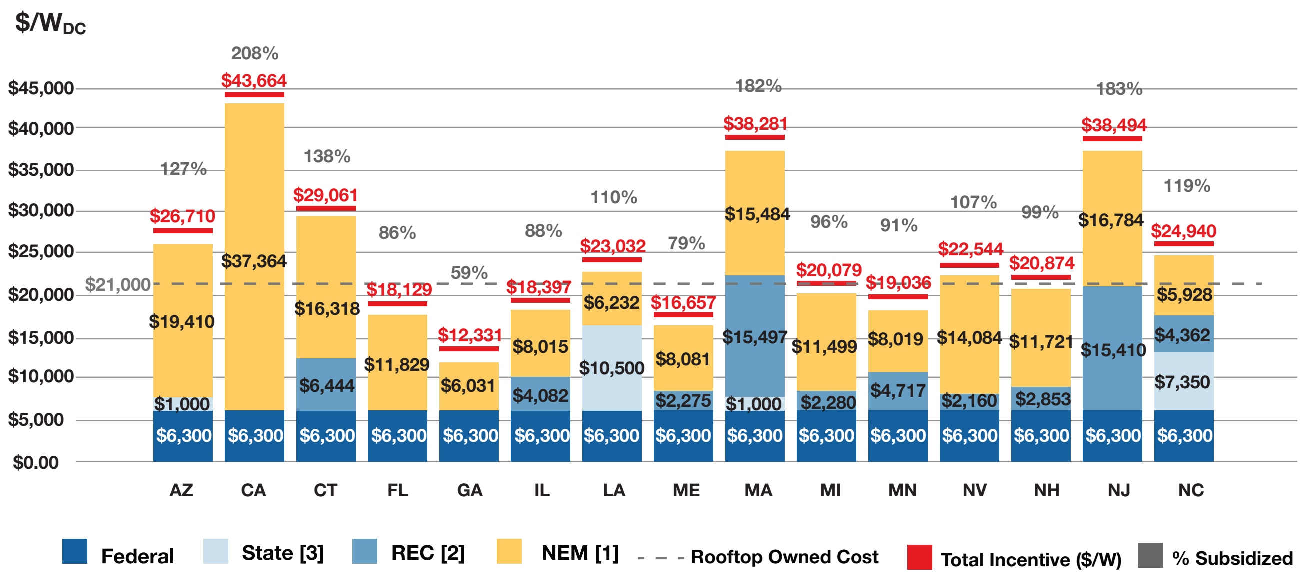


Figure 3A. Total Incentive ($) for Typical Rooftop Owned System (6.0kW)



INTRODUCTION

The cost of solar energy technology has been steadily declining for many years. While consumers are currently benefitting from utility-scale solar projects, community solar installations, and residential rooftop solar electric generating facilities (solar PV), this report focuses on residential solar PV and its recent growth and decline in costs. The reported median cost of residential rooftop solar PV installed in 2007 was about $9 per watt-dc.[1] By 2013, the reported median cost had declined to less than $5 per watt-dc. The Solar Energy Industries Association (SEIA) recently reported that in the first quarter of 2015 the nationwide average installed costs of residential solar PV, utility-scale fixed-tilt solar PV and utility-scale one-axis tracking solar PV were $3.46 per watt-dc, $1.58 per watt-dc and $1.80 per watt-dc, respectively.[2] [3]

Lower costs and state mandates have promoted the adoption of solar PV in many parts of the country. Solar PV is currently the fastest-growing segment of the U.S. renewable energy market, achieving annual growth rates exceeding 40 percent over the period 2011 through 2015.[4] By the second quarter, 2016, there were 27.5 GW-dc of installed solar PV capacity, most of which is utility-scale solar.[5]

Today, federal, state and local governmental incentives, combined with those offered by many electric utilities, have reduced residential customers' net, out-of-pocket costs for installing solar PV systems to very low levels – indeed, in many states the total incentives exceed the facility's total cost. In light of these dramatic cost reductions, many states are now reviewing the need for such generous incentives and considering incentive regimes that rely more on the competitive marketplace to provide the incentives needed to bring about economically optimal levels of solar PV adoption.

One of the key drivers in the assessments that many states are making is cost of energy produced by residential solar PV installations compared with the much lower cost of energy produced by utility-scale solar projects.[6] Given that solar energy delivers essentially the same societal benefits, in terms of carbon and emissions reductions, independent of how it is produced, some states have begun to look for economic efficiencies in their solar regimes.[7]

To help inform policy makers considering changes to their solar incentives regimes, this report quantifies the costs for a typical facility located in each of 15 states: Arizona, California, Connecticut, Florida, Georgia, Illinois, Louisiana, Maine, Massachusetts, Michigan, Minnesota, New Hampshire, New Jersey, Nevada, and North Carolina. These states were selected to capture diversity in state-level incentive policies, retail tariff designs, wholesale electricity prices, and solar insolation.

1. Feldman, David, et al., U.S. Department of Energy, Photovoltaic System Pricing Trends, Historical, Recent, and Near-Term Projections 2014 Edition, September 22, 2014. See: http://www.nrel.gov/docs/fy14osti/62558.pdf.
2. SEIA, Solar Market Insight Report, 2015 Q1 (Executive Summary), p. 11-13.
3. SEIA, Solar Market Insight Report, 2015 Q2 (Executive Summary), pp. 13-14.
4. SEIA, Solar Market Insight Report, 2015 Year in Review (Executive Summary), pp. 15.
5. Id., p.5.
6. The cost of electricity produced by a utility-scale solar PV facility is almost entirely determined by the recovery of its capital investment. As the SEIA data show, the average installed cost of a utility-scale facility is about half the average installed cost of a rooftop residential solar PV facility.
7. When combined with battery storage, residential solar PV can provide backup power during times of transmission or distribution system outages. However, this benefit is almost entirely captured by the solar PV customer so there is no compelling justification for socializing the cost of this localized reliability benefit.

NATURE OF THE INCENTIVES

A number of financial incentives exist for rooftop residential solar PV. This report explores the four most substantial types of incentives:

- Incentives provided to residential customers who own their solar PV facilities, through tax credits and monetary payments from the federal and state governmental entities and electric utilities,
- Incentives provided through state "net energy metering" (NEM) policies,
- Incentives provided to third party owners (TPOs) of residential rooftop solar PV facilities that either lease them or sell the energy they produce to their residential customers through long-term contracts,
- Incentives provided through Renewable Energy Certificates (RECs).

DIRECT INCENTIVES

All residential customers that own solar PV receive the Residential Energy Efficiency Property Credit (REEPC), which is a federal tax credit equal to 30 percent of the solar PV facility's installed cost. Although this credit is numerically equal to the Investment Tax Credit (ITC) that businesses receive on their investments in solar facilities, it is authorized under a different section of the IRS code. The REEPC was scheduled to end in 2015 but was extended in December 2015 and scheduled for phase-out by 2022. The 30 percent ITC was also extended and is scheduled to step-down to 10 percent by 2022.

In addition to the REEPC, many customers receive one or more of the following incentives:

- State income tax credits and/or deductions,
- State and/or local sales tax exemptions,
- State and/or local property tax exemptions,
- State renewable energy payments,
- State Public Utility Commission (PUC)-approved incentives, such as rebates, provided by the utilities they regulate.

Table 1 summarizes the direct incentives to residential solar PV offered in the selected states.

In some states, owners of residential solar PV receive incentives from their local governmental entities.[8] To simplify the analyses, this report excludes these incentives; consequently, the report results are conservative lower-bound estimates of the total incentives that residential customers with solar PV receive. A comprehensive description of all federal, state and local incentives, including those offered by electric utilities is available at www.dsireusa.org.

NET ENERGY METERING (NEM) INCENTIVES

In 44 states and the District of Columbia, residential customers with solar PV can participate in NEM programs offered by their respective electric utilities.[9] These programs bill the customer for the net amount of electricity consumed, which is equal to what the customer actually consumes less the amount the customer produces onsite. In billing periods, when the solar PV facility produces more energy than the customer consumes, the excess energy flows back to the utility and the customer receives a bill credit (expressed either in kWhs or dollars) that is carried forward and applied to future bills.[10] The values of these bill credits are equivalent to the utility purchasing all of the customer's solar energy (including that consumed onsite by the customer) at the energy prices in the customer's retail tariff, which almost always exceed the utility's avoided costs, for reasons described next.

Residential retail energy rates are typically designed to recover the utility's variable energy cost and some

8. For example, Montgomery County, Maryland grants residential customers with renewable energy facilities, including solar PV, up to $5,000 in property tax credits.
9. Stanton, Tom, State and Utility Solar Energy programs: Recommended Approaches for Growing Markets, National Regulatory Research Institute, Report No. 13-07, July 2013.
10. Most state NEM programs only allow bill credits to be carried forward for 12 months, at which time the credits expire or the utility buys them at a price that approximates the utility's avoided cost of wholesale energy. The buyback price is generally much lower than the energy prices in the customer's retail tariff, which discourages customers from oversizing their solar PV facilities.

NATURE OF THE INCENTIVES

Table 1. Direct Incentives for Resident-Owned Solar PV, by Selected State

State	Federal Income Tax Credit[1] (Percent)	State Payments		Commission Approved Utility Payments[2]			Primary Market for Renewable Energy Certificates (Revenue Sources)[3]
		State Income Tax Credit (Percent)	Cap ($)	Initial ($/Watt-dc)	Annual ($/kWh-dc)	Cap ($)	
Arizona	30	25	$1,000				WECC
California	30						WECC
Connecticut	30			$0.80[4]			15-year contracts with host utilities[4]
Florida	30			$2.00[6]		$20,000[6]	NC
Georgia	30						NC
Illinois	30			Greater of $1.50 or 25% of project cost.		$10,000	Illinois Power Agency for three years, then sold into MI Mkt
Louisiana	30	50	$12,500				NC
Maine	30						ISO-NE[5]
Massachusetts	30	15	$1,000				MA
Michigan	30			$0.20/Watt-dc System limited to 20 kW-dc but cannot exceed 100% estimated annual usage.[7]	$0.03[7]		MI[7] or OH Mkt
Minnesota	30				$0.08 (for 10 years) System limited to 20 kW-dc; cannot exceed 120% estimated annual usage.[8]		RECs transferred to Xcel –MN as part of its Solar*Currents program
Nevada	30			$0.40/Watt-ac System limited to 25 kW-dc; not to exceed 100% of estimated annual usage.[9]			RECs transferred to NV Energy
New Hampshire	30						NH
New Jersey	30						NJ
North Carolina	30	35[10]	$10,500[10]	$2.50[11]	$0.0045 / W[11]		RECs transferred to Duke Energy Progress

1. The Federal REEPC is scheduled for gradual phase-out by 2022.
2. Payments from the utility are for the purchase of RECs to meet state goals.
3. The markets shown are those most likely to maximize revenues from REC sales.
4. Rooftop solar may either sell their RECs to the utility via a utility payment or may sell their RECs to an aggregator.
5. This REC incentive was no longer available after the end of 2015 although is included in analysis.
6. This utility incentive payment ended on December 31, 2015 and is not included in the analysis because its expiration was specified in advance
7. Payments made through DTE's SolarCurrents program, which was fully subscribed and not available to new customers in 2015. Participating customers transfer REC ownership to the utility without further compensation.
8. Payments made through Xcel –MN's Solar*Rewards program, which was not fully subscribed in 2015. Participating customers transfer REC ownership to the utility without further compensation.
9. Payments made through NV Energy's SolarGenerations program. Participating customers transfer REC ownership to the utility without further compensation.
10. The North Carolina State Income Tax credit ended on December 31, 2015.
11. Duke Energy Progress SunSense Residential PV participants receive an initial cash payment is $2.50 per watt-ac and a monthly credit of 4.50 per kW-ac. The monthly credits are initially contracted for five years with the ability to renew for one year terms.

Source: www.dsireusa.org, utility websites, state government and public utility commission websites.

of its fixed infrastructure costs incurred in providing service to residential consumers. When rooftop residential solar PV owners receive the retail rate for their solar energy, they are credited not just for the energy the utility avoids producing (or procuring) but also for some of the infrastructure costs, which are not avoided. Despite not paying these infrastructure costs, customers with rooftop solar PV still rely on the distribution grid to serve their peak demands and to provide backup power when the sun does not shine. In addition, they utilize the grid to sell back to the utility any excess energy they produce.

Historically, retail rates were designed to recover fixed costs through volumetric energy charges – in part, because meters capable of recording peak energy usage within a billing period were too expensive to be deployed for small customers. Although advances in meter technology have since eliminated the need for this practice, it continues today for other reasons espoused by utility regulators, such as retaining simple tariff structures, encouraging energy conservation and subsidizing low-usage customers (who may or may not be low-income households).[11]

NEM programs, which compensate residential solar PV customers at the full retail rate, exploit the typical tariff designs to subsidize distributed generation by enabling customers with solar to avoid paying their appropriate share of the utility's fixed costs. When initiated in 1982, NEM was intended to help promote the development of fledgling distributed generation technologies, including solar PV. The negative side of NEM is that it divorced the energy prices that owners of onsite generation received for their energy production from the actual value of that energy to the utility, thereby creating a cost shift impacting the residential customers that lacked onsite generation. Although the costs imposed on utility customers who did not utilize solar PV were insignificant when distributed generation represented a negligible share of retail electricity sales, that is no longer true in light of today's rapid expansion of residential solar PV.

The customer's retail tariff rate structure largely determines the magnitude of the NEM incentive. If residential retail tariffs accurately recovered the underlying cost of serving each customer, all customers' bill savings would closely match the utility's associated avoided costs and essentially no NEM incentive would exist.[12] That is not the case today.[13]

Most residential retail tariffs employ one of two basic rate designs: those with energy prices that remain the same in all hours of the monthly (or bimonthly) billing period and those that assign different prices to different time periods within the monthly billing period, i.e., time-of-use (TOU) pricing. Both tariff designs can charge different prices in the summer and winter seasons to reflect cost differences that are seasonal in nature. Also, both tariff designs can contain tiered prices that vary with the customer's total monthly consumption (although it is unusual to have tiered pricing in a TOU tariff). In addition, both tariff designs generally include a fixed monthly customer charge

11. The existence of residential solar PV has negated this rationale; high-income customers that use rooftop solar PV transform themselves into "low-usage" customers.
12. Commonwealth Edison Company's Residential Real-Time Pricing (RRTP) is one particularly notable example of a cost-reflective tariff in that it charges the customer an energy price in each hour that is indexed to PJM's Day-Ahead Market, i.e., the price that ComEd pays for the energy it withdraws from the wholesale market. A common misunderstanding is that the homeowner incurs no upfront cost because the solar leasing company owns the facility. This is not so; under third party ownership the homeowner effectively rents the facility, or purchases its electrical output, through a long-term contract. Such a contract is a debt-equivalent obligation, similar to a mortgage, and it imposes an upfront cost on the homeowner by his/her reducing borrowing capacity and reducing his/her credit rating.
13. Many utilities have adopted, or are in the process of constructing, separate retail tariffs to serve customers with solar PV, in order to reduce or totally eliminate the NEM incentive. This is a 'second-best" solution. The better alternative is to get all of the retail tariffs right.IRS Publication 551 defines Fair Market Value (FMV) as: "FMV is the price at which property would change hands between a buyer and a seller, neither having to buy or sell, and both having reasonable knowledge of all necessary facts. Sales of similar property on or about the same date may be helpful in figuring the property's FMV."

to cover at least some of the billing, metering, and other costs that do not vary with the customer's level of energy consumption. Some residential retail tariffs contain demand charges that are determined by the customer's maximum average usage in pre-defined intervals (e.g., 30-minute or 1-hour) within each billing period. Lastly, a few residential tariffs dynamically index energy prices to wholesale energy market prices. Two examples of such dynamic tariffs are the Variable Peak Pricing (VPP) tariff offered by Connecticut Light and Power Company and the Residential Real-Time Pricing Program (RRTPP) tariff offered by Commonwealth Edison Company.

The above discussion generally addresses the retail tariffs of utilities that supply energy and deliver it to the customer. However, many states (i.e., "retail choice states") allow customers to choose their energy suppliers from a set of competing vendors, which generally includes the utility as the provider of last resort. In these states the utility may only deliver the energy supplied by others to some (or all) of their customers through tariffs that only charge for the delivery service. However, the typical delivery service tariff also recovers some of the utility's fixed costs through volumetric charges; consequently, it also subsidizes residential customers with solar PV just as full service tariffs do.

THIRD PARTY OWNERSHIP INCENTIVES

As the popularity of rooftop residential solar PV has increased, a new business model has emerged – the third party ownership model – wherein a business entity owns and maintains the solar PV system installed on a homeowners' rooftop and either leases the system to the homeowner or sells the energy it produces to the homeowner through a long-term contract.[14] This alternative ownership arrangement creates additional incentives for residential solar PV because the third party owner (TPO) is allowed to depreciate the solar facility as a business asset over just 5 years.[15] In addition, the TPO bases the value of the depreciation deductions, as well as the federal ITC, on the facility's fair market value (FMV), which is typically higher than its actual installed cost.[16] A TPO generally determines a solar facility's FMV by calculating the present value of the expected stream of net cash flows the TPO will receive over the life of the facility's long-term contract.[17] Thus, the more value the TPO can extract from its customers through higher contract prices, the greater the incentive it receives from Federal taxpayers.

RENEWABLE ENERGY CERTIFICATES

A renewable energy certificate (REC) is a property right created for the owner of a renewable resource when that resource produces one MWh of energy that is certified and reported to one of nine regional tracking systems.[18] RECs created by solar facilities are a special subset often referred to as "Solar Renewable Energy Certificates (SRECs)." Also, among the states there are slight variations on terminology and definitions. For example, Connecticut defines LRECs and ZRECs, which respectively stand for Low Emission and Zero Emission Renewable Energy Credits.

RECs have monetary value primarily because electric

14. A common misunderstanding is that the homeowner incurs no upfront cost because the solar leasing company owns the facility. This is not so; under third party ownership the homeowner effectively rents the facility, or purchases its electrical output, through a long-term contract. Such a contract is a debt-equivalent obligation, similar to a mortgage, and it imposes an upfront cost on the homeowner by reducing his/her borrowing capacity and reducing his/her credit rating.
15. Utilities that own solar facilities also get the benefit of 5-year accelerated depreciation but only based on the facility's actual installed cost – not on its fair market value.
16. IRS Publication 551 defines Fair Market Value (FMV) as: "FMV is the price at which property would change hands between a buyer and a seller, neither having to buy or sell, and both having reasonable knowledge of all necessary facts. Sales of similar property on or about the same date may be helpful in figuring the property's FMV."
17. Estimating the FMV of a solar facility, or a portfolio of such facilities, is a complex task involving a myriad of assumptions regarding investors' cost of capital, contract default rates, future market prices for SRECs and other uncertain factors. See: "Valuation of Solar Generation Assets," available at www.SEIA.org.
18. See: http://www3.epa.gov/greenpower/gpmarket/tracking.htm. A tenth tracking system is being developed for New York State.

utilities serving retail customers in 29 states and the District of Columbia are required to own them in order to comply with the renewable portfolio standards (RPS) adopted by these political jurisdictions.[19] In theory, the market price for RECs in a region should equal the difference between the marginal cost of producing renewable energy and the marginal cost of producing or procuring contemporaneous energy from nonrenewable resources. However, some states (e.g., New Jersey and New Hampshire) impose restrictions on the types and/or amounts of RECs that their jurisdictional utilities can utilize, which create barriers preventing the free trading of RECs across the country, thereby causing widely diverging REC prices.

Most RPS states allow a utility to satisfy its RPS obligation, either by directly procuring renewable energy and the associated RECs (i.e., bundled RECs) or by just procuring RECs (i.e., unbundled RECs). However, some states require the utility to satisfy some minimum share of its obligation by purchasing RECs or SRECs produced by distributed generation.[20] Other states place restrictions on the use of RECs produced by out-of-state resources, thereby inflating REC prices within the state.[21] In contrast, California limits utilization of unbundled RECs to a small fraction of its utilities' RPS obligations, thereby depressing REC prices within the state and throughout the entire Western region.

REC prices can be viewed as a proxy for the environmental value of renewable resources. This would be plausible if the individual state RPS targets were arrived at through rigorous analyses that were consistent across the country – but this is not the case. RPS targets vary widely and are the product of a political process reflecting disparate objectives not necessarily related to environmental benefits (e.g., local job creation). For this reason this report treats the market value of RECs as pure incentives and leaves to the readers the task of subtracting out whatever values they wish to assign to emissions avoided through the use of residential solar PV.[22]

Owners of rooftop solar facilities can sell their RECs into one or more regional markets at the prevailing market prices. In addition, in some states the owners can sell their REC directly to their host utilities through PUC-mandated programs that pay above-market prices. This report estimates the higher monetary value of REC sales in both of these situations for each state examined. For those states that offer solar customers contracts for their REC sales, the report calculated the present value of the stream of contract sales revenues through the life of the contract. For those states where the RECs must be sold into a state or regional market, the report calculated the present value of the sales revenues at the forecasted spot market prices but only for the first 10 years of the facility's life.

Forecasting future spot market REC prices is very difficult given the diverse and fragmented nature of the REC markets, the likely future increases in RPS targets, and the uncertainties shrouding future natural gas prices and the future (declining) costs of solar facilities. In order to produce conservative, lower-bound monetary estimates the report assumed that REC market prices will remain the same (in real dollars) for 10 years as they were at the start of 2015 and thereafter will drop to zero.

19. Although state RPS mandates create most of the demand for RECs, non-utility buyers include companies and individuals that want to promote the use of "green" energy. For example, Whole Foods voluntarily purchases RECs to cover 100 percent of the electricity consumed in its US and Canadian stores.
20. About 95 percent of the energy produced with distributed generation comes from solar PV facilities.
21. For example, the District of Columbia, which disallows RECs created outside its boundaries except for those created by renewable resources in Maryland that directly connect to distribution system feeders delivering energy to DC. Thus, REC prices paid by retail suppliers serving DC are the highest in the US.
22. A recent study sponsored by the State of Minnesota estimated the value of CO_2 and non-CO_2 emissions avoided due to residential solar PV energy at about $.019 per kWh (in 2015 dollars) This translates into a total social benefit of approximately $0.27 per Watt-dc for solar PV capacity located in Minneapolis. This will vary somewhat from state-to-state, depending on the composition of the fuel mix of the generation fleet and the amount of energy produced by the average residential solar PV facility.

NATURE OF THE INCENTIVES

Table 2 summarizes the results of these calculations.

While several states may not have viable REC markets, the utilities in those states may still have programs established to purchase RECs from rooftop owners. For example, Florida has no state RPS requirement but had a program that required its investor-owned utilities to purchase RECs from their rooftop solar customers. While it is included in this report because it applied to the reference solar facility entering service on January 1, 2015, Florida's solar rebate program sunset on December 31, 2015. Similarly, the REC for Maine was no longer available in 2016 although it is included because it was available to systems at the time of the analysis.

Table 2. Incentives Provided for Residential Solar PV Through REC Prices

State	Regional Market determining REC Prices	Program Prices or Spot Market Prices	Contract Length (Years)	Present Value of Annual REC Revenues ($2015 per Watt-dc)
Arizona	WECC	Spot		< $0.01
California	WECC	Spot		< $0.01
Connecticut	State Auction	Program	15	$1.07
Florida	NC	Spot		< $0.01
Georgia	NC	Spot		< $0.01
Illinois	ISPP	Spot		$0.68
Louisiana	NC	Spot		< $0.01
Maine[1]	ISO-NE	Spot		$0.38[2]
Massachusetts	MA	Spot		$2.58
Michigan	MI or OH	Spot		$0.38
Minnesota	Utility[3]	Program	10	$0.79
Nevada	Utility[3]	Program		$0.36
New Hampshire[1]	NH	Spot		$0.48
New Jersey	NJ	Spot		$2.57
North Carolina	Utility[3]	Contract	5+	$0.73

1. Customers participating in these REC markets rely on the broader REC market, not those focused on the solar-specific carve-outs (e.g. SREC markets).
2. This REC incentive was no longer available after the end of 2015 but was included in the analysis of an average theoretical system installed January 1, 2015.
3. Customers participating in utility solar programs in these states transfer their RECs to the utility without further compensation.

QUANTIFYING THE NEM INCENTIVE

This report quantifies the NEM incentive for a major metropolitan area in each of the 15 selected states. The metropolitan areas were chosen primarily based on population. Table 3 lists these metropolitan areas and the major electric utilities that serve them.

DEFINITION OF THE NEM INCENTIVE

This report defines the NEM incentive as the present value of the customer's bill savings derived from the NEM program, less the present value of the costs the utility avoids due to the customer's onsite generation, over the 25-year expected economic life of the solar facility. Stated another way, the difference between what these customers save on their bills and what the utility avoids in costs is the NEM incentive.

The NEM incentive is mostly paid for by the utility's residential customers that do not have solar.[23] This cost shift necessarily occurs because the utility is generally permitted to recover its costs that have been deemed prudent by its Public Utility Commission; consequently, it will typically reallocate the fixed costs it did not recover from residential solar PV customers in any given billing period, to all residential customers (most of whom do not self-supply) in future billing periods. These reallocations generally occur through subsequent increases in base energy rates or through automatic (decoupling) energy rate adjustments. Because these rate increases are not well understood by the general public, the NEM incentive is generally hidden from both policymakers and the public.

A number of studies have shown that the average residential customer with solar PV is substantially

Table 3. Metropolitan Areas Selected For Analysis

State	Metropolitan Area	Electric Utility
Arizona	Phoenix	Arizona Public Service Company
California	Los Angeles	Southern California Edison Company
Connecticut	Hartford	Connecticut Light and Power Company
Florida	Miami	Florida Power and Light Company
Georgia	Atlanta	Georgia Power Company
Illinois	Chicago	Commonwealth Edison Company
Louisiana	Baton Rouge	Entergy Gulf States Louisiana
Maine	Portland	Central Maine Power Company
Massachusetts	Boston	NSTAR Electric Company
Michigan	Detroit	DTE Electric Company
Minnesota	Minneapolis	Northern States Power Company
Nevada	Las Vegas	Nevada Power Company
New Hampshire	Manchester	Public Service Company of New Hampshire
New Jersey	Newark	Public Service Electric and Gas Company
North Carolina	Charlotte	Duke Energy Carolinas

23. The cost shift produced by residential solar PV is largely confined to the residential customer class because the ratemaking process generally first allocates a utility's total costs to each of the various customer classes. It then designs the retail tariffs for each class to further allocate these costs to the individual customers within the class. However, other customer classes may be indirectly affected with increased adoption of solar PV, because the solar generation will significantly alter the time of the system peak load, and therefore the relative amounts of generation capacity costs allocated to each customer class.

more affluent than the average residential customer without solar PV.[24] This remains true for third party-owned solar PV facilities because the customers must have relatively high credit ratings to be eligible to enter into the long-term contracts.[25] Consequently, these incentives mostly represent a transfer of disposable income from residential customers without solar to residential customers with solar, the latter generally being wealthier and having stronger credit scores.

Customer Bill Savings

The combination of a rooftop residential solar PV customer's energy production and the energy prices in its retail tariff determine the customer's bill savings. Energy produced onsite displaces energy that the customer would have otherwise purchased from the utility at the marginal energy price in its retail tariff; consequently, a residential solar PV customer exposed to a high marginal energy price saves more than one exposed to a lower one. For example, one utility in this report offers a tariff containing tiered energy prices ranging from 12 to 21 cents per kWh, while another utility offers a tariff with tiered energy prices that are all less than 10 cents per kWh. The NEM incentive produced by the former tariff is more than three times larger than that produced by the latter.[26] Lastly, retail tariffs that include tiered prices that increase with consumption produce larger bill savings for higher-usage customers than for lower-usage customers.

Utility Avoided Costs

A utility's avoided cost theoretically consists of the costs of not having to produce or procure:

- energy needed to serve the customer,
- generation plus demand response (i.e., interruptible load) capacity needed to satisfy the utility's resource adequacy obligation, to the extent peak load is reduced,
- transmission and distribution system assets needed to maintain reliable service, if applicable,
- voltage support, frequency control and other technical services needed to maintain the quality, safety, and reliability of electric service (i.e., "ancillary services"), if applicable,
- renewable energy certificates (RECs) and (in a few states) carbon credits.

Not all of these costs will be avoided by any given utility. While acknowledging this reality, it was necessary to develop a generic methodology that could be uniformly applied to all of the utilities in the report sample. Each utility must adopt a methodology that best addresses the costs it is likely to avoid due to solar PV generation, and some of these methodologies may substantially deviate from the generic one employed in this report.

External costs, such as greenhouse gas emissions, are not treated as utility avoided costs because in most states the utilities are not yet legally obligated to pay such costs and consequently are not allowed to charge their customers for them. However, to the extent that these external costs have been made part of the utility's obligations (i.e., internalized), they become a component of the utility's avoided energy. California and nine East Coast states that participate in the Regional Greenhouse Gas Initiative (RGGI)

24. Energy+Environmental Economics, Inc., California Net Energy Metering Ratepayer Impacts Evaluation, October 28, 2013, p. 11. The E3 study found that the average median household income of residential customers who installed distributed generation like solar PV since 1999 was $91,210, compared with an average median income of $54,283 for all residential customers in California.
Navigant Consulting Inc., California Solar Initiative Market Transformation Study (Task 2), Final Report, March 27, 2014, p. 52. This more recent study corroborated the E3 results. Navigant found that participants in the California Solar Initiative are more affluent than the population of California homeowners and 60 percent have annual household incomes of $100,000 or more.
25. For example, SolarCity's creditworthiness policy requires a residential customer to have a FICO score of at least 680 in order to qualify for a lease or PPA. However, this is the minimum requirement; the portfolio of residential solar PV contracts that SolarCity securitized in 2013 represented customers whose FICO scores averaged 762. See: Standard & Poors, Rating Services, Ratings Direct, Presale: SolarCity LMC Series I LLC (Series 2013-1), pp. 6, 8.
26. However, a customer's bill saving is not the sole determinant of the NEM incentive because the utility's avoided costs must also be accounted for.

have internalized the cost of utility greenhouse gas emissions through cap-and-trade programs, which create carbon allowances.[27]

This report did not attempt to quantify the avoided costs associated with deferred investments in transmission and distribution assets or ancillary services, primarily because their contributions to total avoided costs are relatively modest, as a number of other studies have consistently concluded.[28] For example, a recent report completed for Arizona Public Service Company concludes that the utility avoids essentially no distribution investment due to solar PV production because "Most of the feeders reviewed were residential feeders that typically peak close to sunset when solar PV production is greatly reduced."[29] For many utilities, the relationship between solar energy production and the timing of the distribution system peak load is similar to that of Arizona Public Service's.

There are also situations where solar energy production imposes additional costs on the utility. A recent MIT study concluded that the cost of accommodating two-way energy flows within a utility's distribution system increases with increased residential solar PV penetration and, at some point, totally offsets any savings from reduced distribution system investment and reduced distribution energy losses.[30] Another cost imposed by solar production is that of accommodating the "Duck Curve" observed by the California Independent System Operator (CAISO).[31] As solar production falls off rapidly at sunset, the power system must compensate for these changes by employing fast-ramping resources to meet the late afternoon residential demand peak and maintain the supply-demand balance. This fast ramping capability is an ancillary service whose increased cost is ultimately borne by electricity consumers.[32]

CALCULATING THE NEM INCENTIVE

Appendix A describes in detail how the NEM incentives were calculated using a computer model specifically developed for this report and also describes all of the underlying report assumptions, input data, and data sources. The computer model performs all of the calculations needed to estimate the 25-year annual streams of incentives and avoided costs, and then discounts them to obtain their respective present values on January 1, 2015. First the model calculates the hourly bill savings and avoided utility energy costs, then aggregates them up to the annual level. The model also calculates the annual avoided cost of generation capacity.

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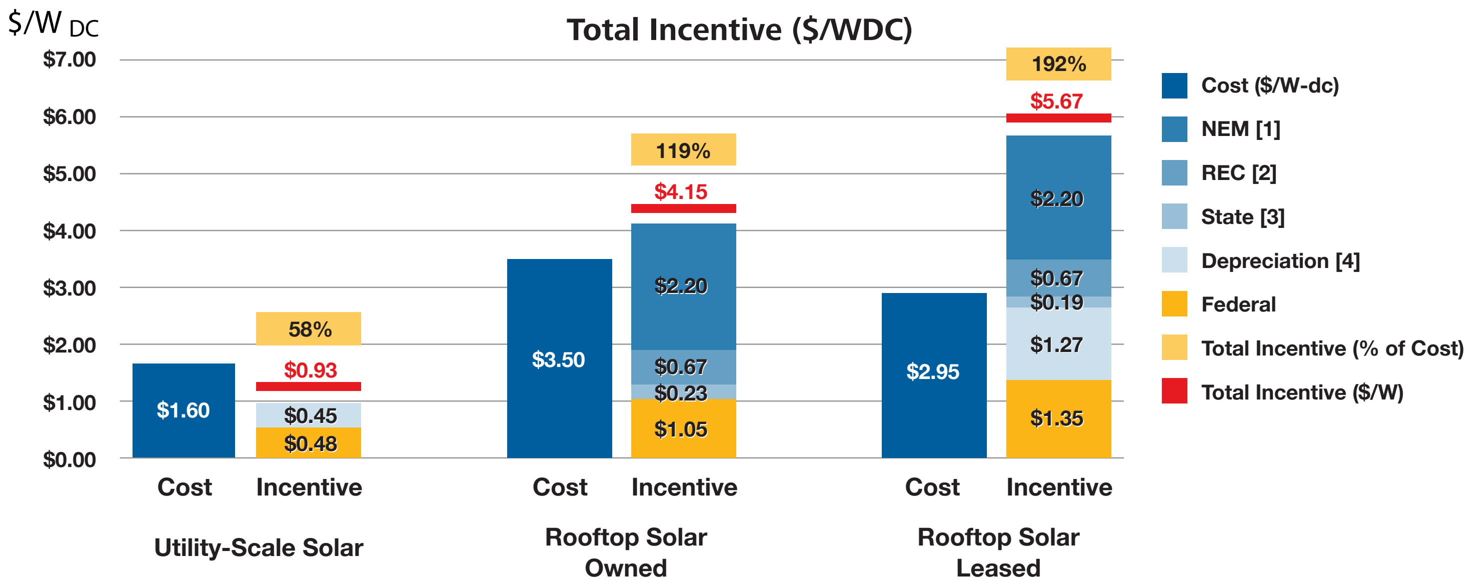
27. California's cap-and-trade program went into effect in 2013. It covers electric power plants and large industrial boilers that emit greenhouse gases equivalent to, or greater than, 25,000 metric tons of CO_2 per year. Owners of these emissions sources must possess emissions allowances to cover their annual greenhouse emissions. These allowances are tradable, thus have monetary value. Through its cap-and-trade program California has already internalized the social cost of the greenhouse gas emissions associated with generating electricity; therefore, it is part of the utilities' avoided energy costs. See: http://www.arb.ca.gov/cc/capandtrade/capandtrade.htm.
28. Rocky Mountain Institute, SUMMARY OF DPV BENEFITS AND COSTS, 2nd Edition, September 2013, pp. 22-23.
29. Science Applications International Corporation (SAIC), 2013 Updated solar PV Value Report, Prepared for Arizona Public Service, May 2013, pp. 2-11.
30. Massachusetts Institute of Technology, The Future of Solar Energy, 2015, p. xviii.
31. http://www.caiso.com/Documents/FlexibleResourcesHelpRenewables_FastFacts.pdf
32. Currently the costs of ancillary services are directly allocated to wholesale electricity buyers, rather than to the resources causing the need for the service. A more rational approach would be to allocate the costs associated with the "Duck Curve" to the solar facilities that contribute to it.

ESTIMATES OF INCENTIVE VALUES

Figure 1 illustrates the installed cost and incentives available for a typical 3.9 kW-dc residential solar PV facility.[33] The incentives shown are simple averages of the 15 state-specific results obtained for residential customers served under their respective utilities' standard tariffs.[34] For comparison, it also presents the installed cost and incentives available for a third party-owned 3.9 kW-dc residential solar PV facility and by an equivalent amount of capacity from a typical, utility-scale fixed-tilt solar PV facility.

Figure 1. Total Incentives Available for a 3.9 kW-dc Customer-Owned and -Leased Solar PV Facilities and an Equivalent Amount of Utility-scale Solar PV Capacity ($/W-dc)



The installed cost of the typical customer-owned residential facility is assumed to be $3.50 per Watt-dc, consistent with that reported by SEIA.[35] The customer receives direct incentives from the federal and state governments amounting to $1.28 per Watt-dc. The NEM incentives add another $2.20 per Watt-dc. Lastly, the REC incentives add $0.67 per Watt-dc. Thus, the total incentive sums to $4.15 per Watt-dc, which is 119 percent of the facility's installed cost.

The total incentive for a third party-owned residential solar PV facility is about 35 percent higher than for an identical customer-owned facility, even though its installed cost is about 16 percent lower.[36] The report estimated this additional incentive by applying an assumed FMV of $4.50/Watt-dc, which was taken from public disclosures of prominent TPOs.[37] Using this value the report calculated the January 2015 present value of the federal ITC and the 5-year depreciation deductions that the facility would

33. Because solar panels are manufactured in standard sizes the facility's actual installed capacity is 3.8745 kW-dc.
34. The NEM incentives shown in Figure 1 are based on the assumption that most residential solar PV customers choose the utility's standard, (i.e., non-TOU) retail tariff that excludes any optional discounts for space heating, senior citizens, load controls, monthly demand charges, etc. Appendix B presents the incentives produced by each utility's TOU tariffs.
35. SEIA, 2015, Fig 2.5.
36. TPOs typically install residential solar facilities at a lower cost per watt because of the economies of scale and scope achievable through high volume installations. SolarCity reported an installed cost of $2.95 per Watt-dc for residential solar PV. See: SolarCity, Investor Presentation, May 2015, pp. 20, 23.
37. UBS Global Research, US Solar & Alterative Energy, The Real Risk of Rising Rates on Renewables, 20 July 2015, p.9.

produce for the TPO.

As Figure 1 shows, the installed cost of an equivalent amount of utility-scale solar PV capacity is about half that of the residential solar PV facility. It also shows that utility-scale solar PV facilities receive incentives (all from the federal government) equal to only about 58 percent of installed cost. Because a solar PV facility's initial investment essentially determines the resource cost of the electricity it produces, utility-scale solar PV produces electricity at a much lower resource cost than residential solar PV.[38]

Figure 1 demonstrates the average values of the incentives for residential solar PV, but does not reveal the substantial differences that exist among the states. Figure 2 presents the state-by-state incentive estimates for customer-owned residential solar PV in each of the 15 selected states.[39]

Figures 2 and 2A reveal that the incentives to customer-owned residential solar PV in 8 of the 15 states cover more than the customer's cost of installing the facilities. An additional 7 states provide incentives that cover more than three-quarters of the installed cost of the solar PV facilities.[40]

The total incentive varies substantially across the states, partly because different states offer different direct incentives, and partly because the NEM incentive varies among the utilities. The 30 percent federal tax credit is the same in all states, so it does not contribute to the variance. Again, these results only apply to customer-owned facilities. For TPO facilities the variance will be even higher due to differences in TPO contract pricing strategies.

DIRECT INCENTIVES

In all states residential customers that own solar PV receive a 30 percent federal tax credit. In addition, (as shown earlier in Table 1) 12 of the 15 states also offer direct incentives.

REC INCENTIVES

Because market prices for RECs are generally depressed in most of the country, only eight states in our sample significantly benefit from REC sales, i.e., Connecticut, Illinois, Maine, Massachusetts, Michigan, Minnesota, New Hampshire and New Jersey. Some of these states provide premium compensation for SRECs created by in-state resources or by resources in a few adjoining states. SREC values created by residential customers in Minnesota and Nevada are unknown because the customers must transfer them to Xcel Energy and NV Energy, respectively, if they participate in the direct incentive programs administered by these utilities. As Figure 2 shows, REC incentives in New Jersey are an outlier. This state relies solely on high REC prices and the NEM incentive to support rooftop solar PV.

UTILITY AVOIDED COST COMPONENTS

To better understand the nature of the NEM incentives, Figure 3 disaggregates the utility avoided

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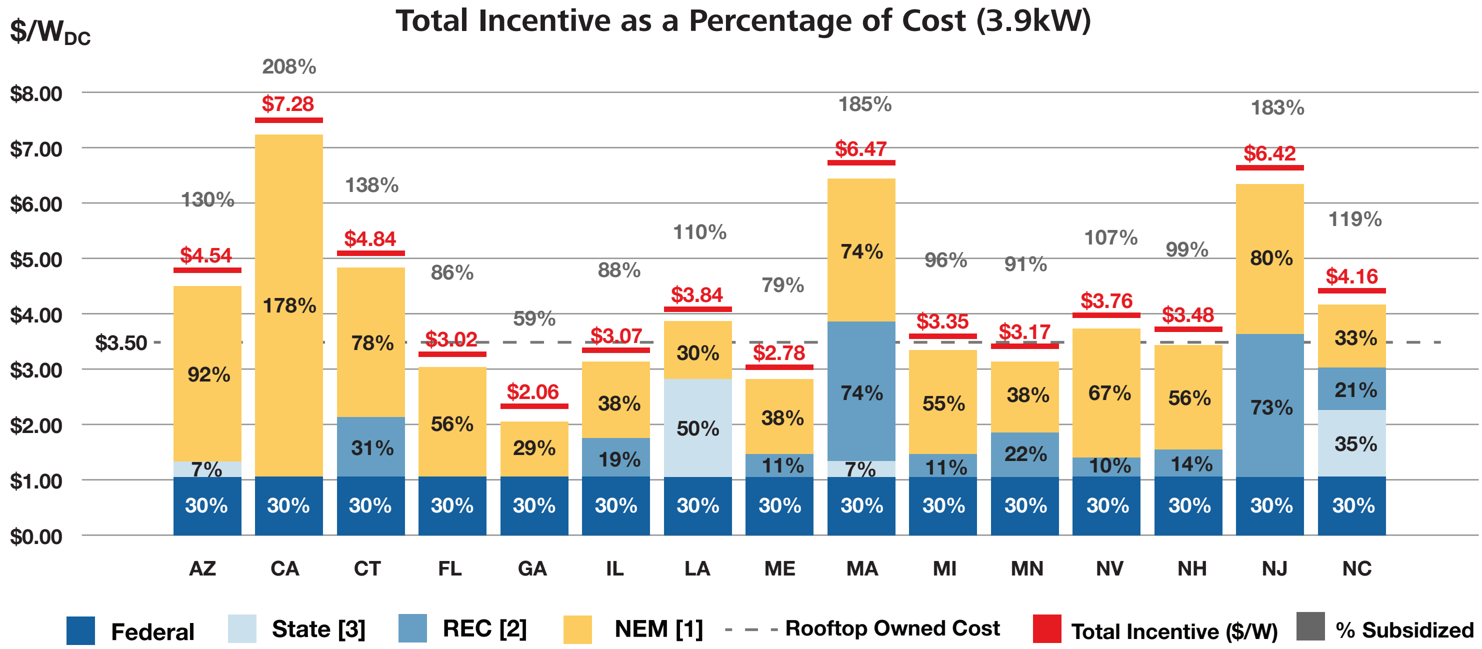
38. Incentives do not reduce the basic cost of the resources consumed to produce a good or service (including electricity) – they only shift the costs to other parties, such as taxpayers and non-solar electricity consumers.
39. It was not possible to calculate state-by-state incentives for a TPO facility because FMVs used to determine the ITC and accelerated depreciation deductions depend on specific contract prices, which are not publicly available.
40. The fact that a total incentive covers less than the full installed cost of a solar facility does not mean the facility is an unattractive investment. The customer's return on investment is the stream of annual bill savings resulting from that customer's solar energy production. To estimate this return the utility's avoided costs (which are subtracted from the customer's bill savings to determine the NEM incentive) must be added to the incentive. Doing so reveals that the typical residential solar PV facility produces a substantial positive net present value in all of the states examined in this report.

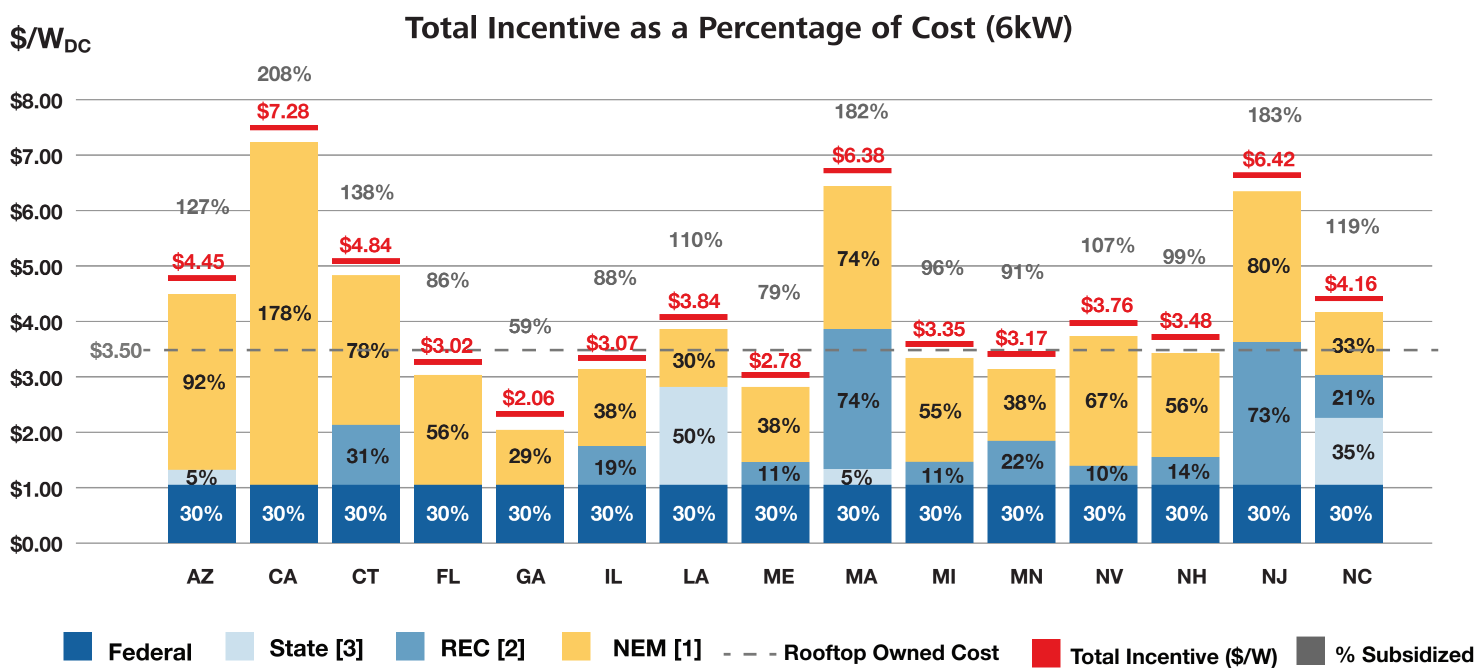
ESTIMATES OF INCENTIVE VALUES

Figure 2. Incentives Available by Customer-Owned Residential Solar PV in Selected States, as a Percentage of Installed Cost (3.9kW)



1. NEM incentive is the difference between the present values of the customer's bill savings and the utility's avoided costs over the facility's life. For the Typical Lease, the incentive flows to the homeowner and is largely passed through to the Third-Party Owner as a lease or PPA payment.
2. Renewable Energy Certificates are incentives available through applicable programs.
3. Incentives mandated by state legislatures are upfront and/or performance-based compensation, often through the state tax code.

Figure 2A. Incentives Available by Customer-Owned Residential Solar PV in Selected States, as a Percentage of Installed Cost (6.0kW)



ESTIMATES OF INCENTIVE VALUES

Figure 3. Total Incentive ($) for Typical Rooftop Owned System (3.9kW)

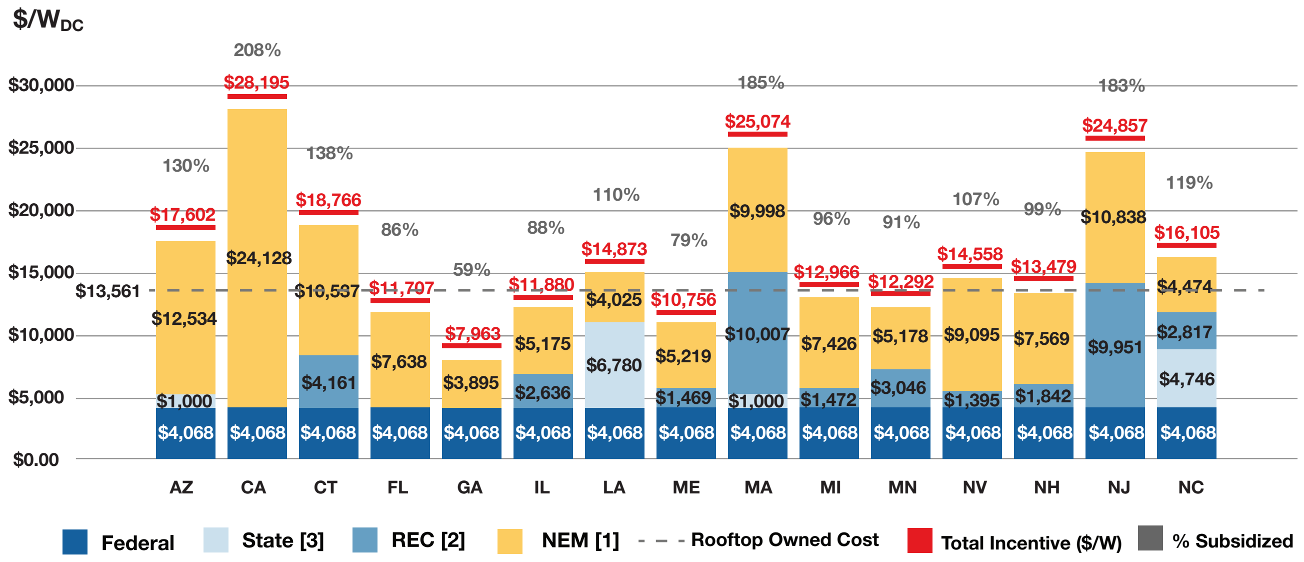
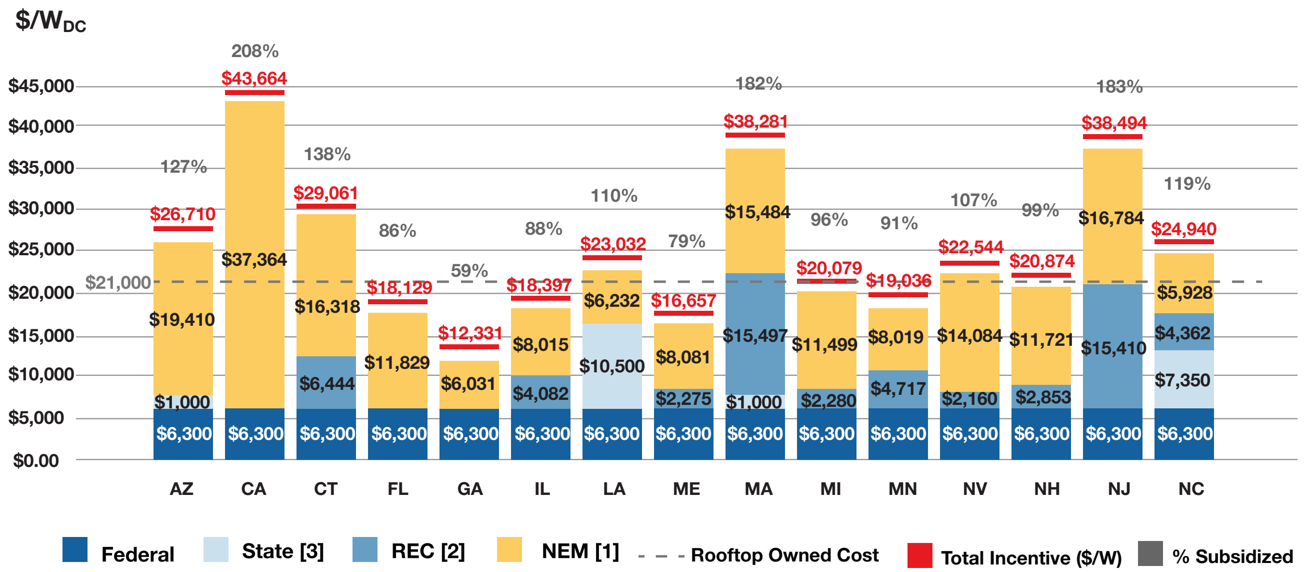


Figure 3A. Total Incentive ($) for Typical Rooftop Owned System (6.0kW)



costs into the three components: avoided retail energy, avoided distribution losses and avoided generating capacity costs.

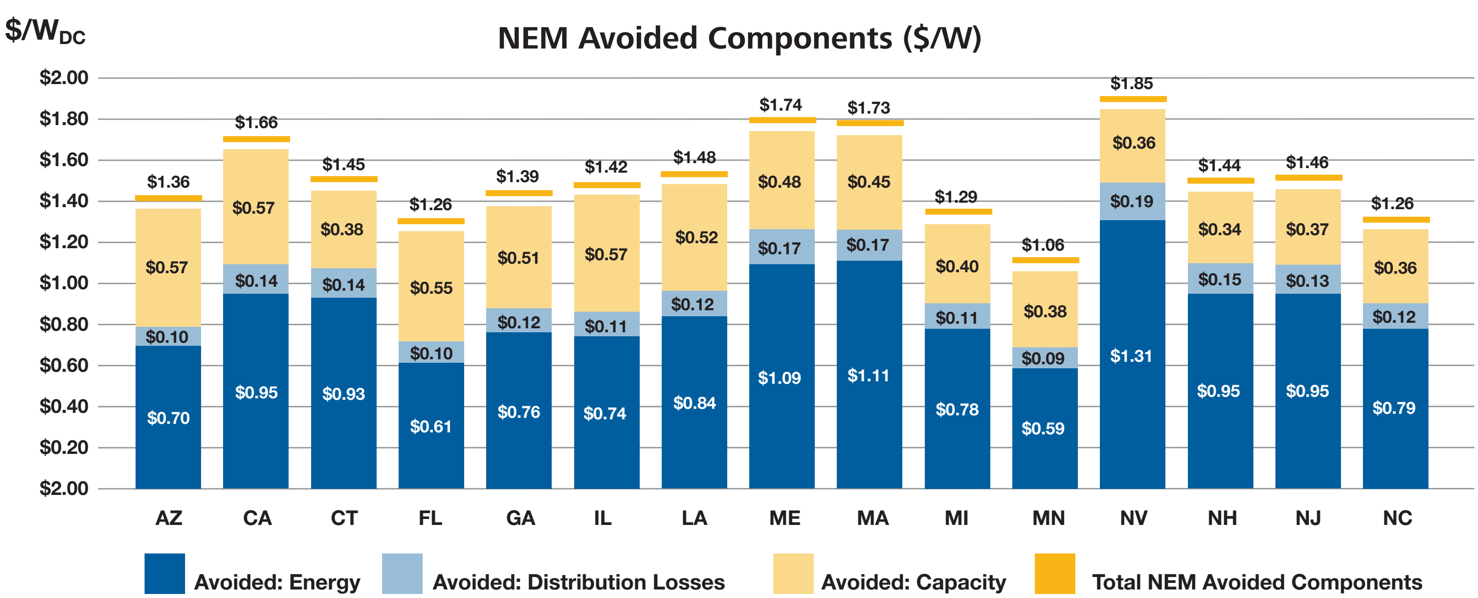
As Figure 4 shows, the utilities' avoided retail energy and generating capacity costs are the dominant components while the costs of avoided distribution system losses are relatively small.[41] In Figure 3 the cost of avoided capacity, measured in $ per Watt-dc of installed solar capacity, does not vary appreciably among the states, but this finding is largely an artifact of the methodology used to produce these estimates, as discussed in the next section. In contrast, the cost of avoided retail energy varies widely, primarily because of regional differences in wholesale energy prices.

Avoided Capacity Cost Estimates Are Overstated

The avoided costs of generation capacity are overstated in this report for three reasons. Firstly, the report estimated the capacity value of solar PV production for a low level of solar PV penetration. As penetration increases, solar energy production will shift power systems' peak loads further into the late afternoon hours when solar production rapidly falls off, or even from the summer season to the winter season when the peak may occur in the morning on a cold day. When that occurs, the capacity value of solar PV will approach zero.

Secondly, the report estimated the avoided cost of capacity based on the assumption that all 15 metropolitan areas are located in reliability planning regions that currently have, and will maintain, the minimum installed capacity needed to satisfy their respective mandated resource adequacy requirements. But, as Table 4 shows, all of the metropolitan areas are in North American Electric Reliability Corporation (NERC) regions that currently have substantial amounts of excess generating capacity.[42] To be conservative the report did not adjust downward its avoided capacity costs to account for these capacity surpluses. On the other hand, the Table 4 data do not account for recent

Figure 4. Avoided Cost Components of the NEM Incentive, by State



41. Although Figure 3 separates out the cost of distribution losses, they are actually part of the utility's total avoided energy cost as measured at the wholesale (transmission voltage) level.
42. North American Electric Reliability Corporation, 2014 Long-Term Reliability Assessment, November 2014. The NERC assessment suggests that excess generation capacity will continue for about a decade; however, NERC did not adjust for the plant retirements likely to occur in response to EPA's Clean Power Plan or the early retirements of nuclear plants.

Table 4. NERC Long-Term Reliability Assessment of Bulk Power System, by State

State	NERC Region	2015 Reference Reserve Margin (Percent)	2015 Prospective Reserve Margin (Percent)	2024 Reference Reserve Margin (Percent)	2024 Prospective Reserve Margin (Percent)
Arizona	WECC-SRSG	14.06	33.83	14.06	14.21
California	WECC-CA/MX	15.02	15.31	15.02	20.77
Connecticut	NPCC – NE	15.70	23.75	14.30	18.32
Florida	FRCC	15.00[1]	27.40	15.00	29.38
Georgia	SERC – SE	15.00	33.56	15.00	22.82
Illinois	PJM	15.70	25.93	15.70	21.70
Louisiana	MISO	14.80	17.01	14.80	14.67
Maine	NPCC- New England	15.70	23.77	14.30	18.32
Massachusetts	NPCC- New England	15.70	23.77	14.30	18.32
Michigan	MISO	14.80	17.01	14.80	14.67
Minnesota	MISO	14.80	17.01	14.80	14.67
Nevada	WECC–NWPP	11.00	16.82	11.00	16.86
New Hampshire	NPCC- New England	15.70	23.77	14.30	18.32
New Jersey	PJM	15.70	28.42	15.70	21.70
North Carolina	SERC – North	15.00	19.24	15.00	24.33

1. NERC used a reference reserve margin equal to 15 percent for FRCC; however, the Florida investor-owned utilities are required to carry 20 percent reserve margins.

Source: North American Electric Reliability Corporation, 2014 Long-Term Reliability Assessment, November 2014.

announcements of early nuclear plant retirements. The Table 4 data imply that capacity prices in all of the relevant NERC regions are currently below equilibrium levels. PJM's recent capacity auction partially confirms this; PJM's capacity price for its "Rest of RTO" region (which includes Commonwealth Edison Company) cleared at $120 per MW-Day (i.e., $43,800 per MW-Yr.) in the 2016-17 Base Residual Auction (BRA).[43] This is far below the cost of new entry ($117,100 per MW-Yr.) that the Brattle Group estimated in a recent report conducted for PJM.[44]

Thirdly, the report assumes that future regional capacity prices will be set by the cost of a new, state-of-the-art, gas-fired combustion turbine and that this plant will continue to be the marginal capacity resource throughout the 25-year economic life of the solar PV facilities. Although this is an accepted industry approach, most likely technological progress will produce a cheaper form of peaking capacity before 2039.

43. See: www.pjm.com/markets-and-operations/rpm.aspx.
44. The Brattle Group and Sargent & Lundy, Cost of New Entry Estimates for Combustion Turbine and Combined Cycle Plants in PJM With June 1, 2018 Online Date, May 15, 2014.
Brattle's CONE estimate is expressed in mid-2018 dollars, whereas PJM's 2016-2017 Base Residual Auction (BRA) price is expressed in mid-2016 dollars. But after adjusting Brattle's estimate downward to account for two years of cost escalation (approximately 6 percent) the estimate is still far above the BRA price.

ESTIMATES OF INCENTIVE VALUES

NEM Incentives Produced by Optional TOU Tariffs

The NEM incentives shown in Figures 1 through 3 were calculated using the marginal energy prices in each utility's "standard" (i.e., non-TOU) residential tariff based on the assumption that most residential solar PV customers will choose these tariffs even though many utilities offer optional tariffs to their residential customers. In addition to TOU tariffs, some utilities offer price discounts for senior citizens and for customers with electric space heating, utility-controllable water heating and/or air conditioning loads, or plug-in electric vehicles. Also, three utilities offer tariffs that include monthly peak demand charges combined with lower marginal energy prices.

Although residential solar PV customers are free to choose any of these specialized tariffs, most have chosen either the standard tariff or (if offered) the TOU tariff with the highest on-peak prices in order to maximize their bill savings. Because these two tariff designs produce different NEM incentives, the report calculated both. Appendix Tables A-2 and B-1 present the NEM incentives that both tariff designs produced along with the marginal energy prices in the tariffs that were used to calculate them.

CONCLUSIONS

The quantitative results of this report lead to the following conclusions.

EXISTING INCENTIVES FOR RESIDENTIAL SOLAR PV ARE SIGNIFICANT

The combined effect of the direct and NEM incentives in many states collectively exceeds the total cost of installing a solar PV facility – particularly for third party-owned facilities. Although the federal tax credit (REEPC) constitutes a substantial incentive for customer-owned residential solar PV in all of the states, it is less than the sum of the other incentives in all but one state – Georgia.

INCENTIVES ARE EVEN MORE SIGNIFICANT FOR THIRD PARTY-OWNED SOLAR PV FACILITIES

When a customer leases a solar PV facility, or purchases its energy output through a long-term contract, the TPO receives the federal ITC and 5-year accelerated depreciation. Both of these tax benefits are further enhanced by basing them on the fair market value of the facility, not on its installed cost. The fair market value is higher than the asset's installed cost because the TPO charges the customer contract prices that recoup substantially more than the asset's installed cost.

EXISTING INCENTIVES MAY CHANGE THE ECONOMICS OF FUTURE INVESTMENTS IN SOLAR

Given that the non-incentivized cost of producing a kWh of energy with residential solar PV is much higher than the non-incentivized cost of producing a kWh of energy with a utility-scale solar PV, the federal, state and local incentives for residential solar PV may not be the most economically efficient means for a government entity to increase solar penetration. With all solar energy (residential and utility-scale) delivering essentially the same societal benefits in terms of carbon and other emissions reductions, we expect policy makers to examine whether their solar incentive regimes should favor distributed solar PV over utility-scale solar PV.

NEM INCENTIVES SHIFT COSTS ONTO LESS AFFLUENT CUSTOMERS

Net metering programs, which pay residential PV solar customers a higher rate for excess electricity, shift variable energy costs and fixed infrastructure costs completely onto non-solar customers, who a number of reports show are typically less affluent than customers with solar PV.

NEM will only produce equitable outcomes if all utility customers (both solar and non-solar) are served through tariffs which closely reflect the costs that each customer imposes on the utility. Such tariffs would, most likely, include demand charges that fairly allocate fixed infrastructure costs and energy prices that dynamically reflect the hourly cost of energy provided to the customer or avoided through self-generation. Given the cost shift between non-solar PV customers and solar PV customers, we expect that policymakers will contemplate reductions in the NEM incentives through retail tariff modifications which better match each solar customer's payments with the costs that customer imposes on the utility.

INCENTIVES FOR RESIDENTIAL SOLAR PV VARY WIDELY AMONG THE STATES

The report findings reveal a substantial state-by-state variation in the total incentives for customer-owned residential solar PV facilities. Because of contract pricing differences it is likely that the variation is even greater for third party-owned facilities. Four factors create these disparities: (1) different state direct and REC incentives for residential solar energy, (2) different residential retail tariff designs, (3) different avoided utility costs and, (4) (for third party-owned facilities) different contract pricing strategies. Still, on a dollar per-kW basis, even the smallest of these incentives far exceeds the incentives provided to utility-scale solar PV projects.

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NEM INCENTIVE METHODOLOGY AND REQUIRED DATA INPUTS

This appendix describes in detail the methodology, model and data inputs used to estimate the indirect incentives produced by state-sponsored net energy metering (NEM) programs. It also identifies the sources utilized to obtain the data.

DEFINING THE NEM INCENTIVE

In this report the incentive produced through customer participation in an NEM program is defined as the present value of the customer's bill savings, less the present value of the associated costs the utility avoids, over the 25-year economic life of the residential solar PV facility.[45]

THE NEM INCENTIVE MODEL (NIM)

This analysis employed the NEM Incentive Model (NIM), a computer model implemented in EXCEL, to calculate the present values of bill savings and utility avoided costs for each retail tariff. The NIM performs all of the calculations needed to estimate the 25-year annual streams of incentives and avoided costs, then discounts them to obtain their respective present values on January 1, 2015. The model begins by calculating the hourly bill savings and avoided utility energy costs, then aggregates them up to the annual level. The model also calculates the annual avoided cost of generation capacity.

ESTIMATING CUSTOMER BILL SAVINGS

Customer bill savings are entirely determined by the production profile of the customer's solar PV facility and the marginal energy price in the customer's retail tariff.

SOLAR ENERGY PRODUCTION

The report used the System Advisory Model (SAM) developed by the National Renewable Energy Laboratory (NREL) to simulate a full year of hour-by-hour energy production for a typical 3.9 kW-dc rooftop solar PV facility located in each of 15 selected metropolitan areas. Key inputs to SAM include the latitude and longitude of the solar facility's location, the prevailing weather at that location, and the solar panel and inverter equipment. The typical residential solar PV facility assumed in the report employs the default equipment configuration provided in SAM, as described in Table A-1.[46]

Table A-1. Equipment Configuration of the Reference Solar PV Facility in NREL's System Advisory Model

Functional Component	Manufacturer and Equipment	Rating (kW-dc)	Quantity
Solar Panel	Sunpower: SPR-210-BLK –U	0.215	18
Inverter	SMA America: SB 4000US 240V	4.000	1
	Maximum Facility Output (kW-dc):	***3.8745***	

45. Consistent with the performance warrantees of solar panel manufacturers, the report assumed a 25-year economic life for rooftop solar PV facilities. See: http://global.sunpower.com/products/solar-panels/warranty/.
46. National Renewable Energy Laboratory, System Advisory Model, Version 2014.11.24.

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Table A-2 summarizes the annual energy production of the reference solar PV facility in its first year of operation for each of the 15 selected locations. The NIM reduces solar energy production by 0.5 percent per annum to account for solar panel degradation.[47]

Table A-2. First Year Energy Output of the Reference Solar PV Facility in NREL's System Advisory Model

Facility Location	Annual Solar Output (kWh-ac)	Annual Capacity Factor (Percent)
Phoenix, AZ	6,857	20.2%
Los Angeles, CA	6,155	18.1%
Hartford, CT	4,603	13.6%
Miami, FL	5,580	16.4%
Atlanta, GA	4,775	14.1%
Chicago, IL	4,881	14.4%
Baton Rouge, LA	5,159	15.2%
Portland, ME	5,136	15.2%
Boston, MA	5,032	14.8%
Detroit, MI	4,477	13.2%
Minneapolis, MN	4,291	12.6%
Las Vegas, NV	6,813	20.1%
Manchester, NH	4,508	13.3%
Newark, NJ	4,967	14.6%
Charlotte, NC	5,497	16.2%

47. This is a standard industry assumption and is consistent with the performance guarantees offered by most solar panel manufacturers. See: http://global.sunpower.com/products/solar-panels/warranty/

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RETAIL TARIFFS

This report assumes that each solar PV facility entered service on January 1, 2015. The residential retail tariffs of the utilities serving the 15 selected metropolitan areas that were in effect on that date were obtained from the respective utilities' websites. The marginal energy rates in these tariffs are key inputs to the analysis. For tariffs with inclining block energy prices the report chose (with two exceptions) the highest block price based on the assumption that customers would optimally size their solar facilities to avoid these high prices most of the time. Arizona Public Service Company, which offers a standard tariff consisting of four price tiers with the top two applying to customers consuming more than 800 kWh per month. Knowing that the average residential solar facility in Arizona is about 7 kW-dc and produces about 12,000 kWh per year, it was assumed that customers with solar would reduce their net consumption down to the top of the first tier price.

This assumption is conservative and almost certainly underestimates the customers' bill savings and also the utility's NEM incentive. Southern California Edison Company's standard tariff also consisted of four price tiers. It was assumed that customers with solar would reduce its consumption down to the top of the second tier price.

Most utilities offered more than one tariff to NEM customers; however, most customers with solar are likely to choose either the standard tariff or the TOU tariff containing the highest prices in order to maximize their bill savings. The NEM incentive was calculated for both of these tariffs.

Table A-3 summarizes the marginal energy rates used to calculate the NEM incentives for each of the 15 states. These rates include all of the rider surcharges, sales taxes, and franchise taxes that are added to the published base tariff rates.

Table A-3. Marginal Energy Rates Used to Calculate the NEM Incentives for Each State

Utility Residential Tariffs[1]	Standard Tariff (Cent per kWh)		TOU Tariff (Cents per kWh)			
	Summer	Winter	Summer		Winter	
			Peak	Off-Peak	Peak	Off-Peak
Arizona Public Service						
Standard	17.0	11.9				
Time-of-Use			29.3	8.1	23.93	8.1
Central Maine Power						
Standard	12.8	12.8				
Time-of-Use			18.0	10.0	23.5	15.5
Commonwealth Edison						
Standard	12.3	12.1				
Time-of-Use			None	None	None	None
Connecticut L & P						
Standard	19.4	19.4				
Time-of-Use			21.7	18.2	21.7	18.2

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DTE Electric						
Standard (No Space Heat)	15.5	15.5				
Time-of-Use			21.4	12.4	19.3	12.3
Duke Energy Carolinas						
Standard	10.0	10.0				
Time-of-Use			7.5	6.2	7.5	6.2
Entergy Gulf States Louisiana						
Standard	10.0	9.9				
Time-of-Use			None	None	None	None
Florida P & L						
Standard	12.9	12.9				
Time-of-Use			14.3	12.3	14.3	12.3
Georgia Power						
Standard	15.6	9.0				
Time-of-Use			16.9	4.7	16.9	4.7
Nevada Power						
Standard (Large Customer)	13.0	13.0				
Time-of-Use A (ORS)			39.4	7.4	5.9	5.9
Northern States Power – MN						
Standard	14.1	12.5				
Time-of-Use			26.8	7.0	22.8	7.0
NSTAR						
Standard	18.3	18.3				
Time-of-Use			2015 rates unknown – See End Note 2			
Public Service Company of New Hampshire						
Standard	16.8	15.5				
Time-of-Use[2]			2015 rates unknown – See End Note 2			
Public Service Electric and Gas Company						
Standard	19.5	18.0				
Time-of-Use			None	None	None	None
Southern California Edison						
Standard[3]	29.5	29.5				
Time-of-Use[4]			47.0	30.2	36.9	26.2

1. All marginal energy rates include rider adjustments and taxes.
2. Although NSTAR and PSNH offer TOU delivery tariffs, they must be combined with the TOU energy rates offered by the customers' retail electricity suppliers, which were not available.
3. The marginal energy rates shown for SCE are a 50-50 blend of the top two tiered rates.
4. The SCE TOU tariff includes a Super Off-Peak rate which does not affect PV Solar bill savings.

Arizona Public Service Company imposes a monthly solar connection charge of $0.70 per kW-dc (plus taxes and regulatory fees) on its residential solar PV customers. To account for this charge the customers' monthly NEM bill savings were adjusted downward by that amount multiplied by 3.875 kW-dc. The NIM also made downward adjustments to the bill savings of residential solar PV customers served by Northern States Power Company – Minnesota. In that state residential customers with solar PV are charged $3.50 per month for the bidirectional meter required to support NEM.

CALCULATING ANNUAL BILL SAVINGS

The NIM calculates the customer's bill savings by multiplying the solar energy produced in each hour of the year by the marginal energy price in the customer's retail tariff applicable to that same hour. The NIM then sums the hourly bill savings to forecast the total bill savings for the starting year, 2015. The NIM escalates the retail tariff energy prices at rates derived from EIA's price forecasts in its 2014 Annual Energy Outlook. Table A-4 summarizes these escalation rates.

Table A-4 also summarizes EIA's annual escalation rates for the prices of natural gas delivered to the electric utility sector. The NIM used these natural gas escalation rates to forecast utility avoided energy costs, as described below.

ESTIMATING UTILITY AVOIDED COSTS

The avoided costs associated with solar PV energy production consist of the following five components:

- energy needed to serve the customer,
- generation plus demand response (i.e., interruptible load) capacity needed to satisfy the utility's resource adequacy obligation, to the extent peak load is reduced,
- transmission and distribution system assets needed to maintain reliable service, if applicable,
- voltage support, frequency control and other technical services needed to maintain the quality, safety and reliability of electric service (i.e., "ancillary services"), if applicable,
- renewable energy certificates (RECs) and in a few states carbon credits.

Table A-4.	EIA Forecasts of Real Escalation Rates for Residential Electricity Tariffs and Prices of Natural Gas Delivered to Electric Utilities

Region	Average Annual Real Escalation Rates (Percent)	
	Residential Tariff Prices	Prices of Natural Gas Delivered to Electric Utilities
New England	0.63	2.47
Middle Atlantic	0.47	2.66
South Atlantic	0.24	2.01
East North Central	0.53	2.01
East South Central	0.01	2.35
West North Central	0.42	2.68
West South Central	1.06	2.50
Mountain	0.69	2.43
Pacific	-0.08	2.30

Escalation rates were calculated from price forecasts in EIA's 2014 Annual Energy Outlook. EIA did not include in its forecasts of tariff escalation rates the potential impact of EPA's Clean Power Plan so the rates for regions heavily dependent on coal-fired generation may be systematically understated.

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This report only quantifies the avoided energy and generation capacity costs described in the first two bullet points, primarily because the magnitudes of the other costs are relatively small compared to the avoided energy and generation capacity costs, as asserted by a number of comprehensive studies.[48]

Avoided energy costs (the first bullet point) can be further subdivided into retail energy and distribution system losses. Retail energy refers to the energy delivered to the retail customer's meter, which is less than the amount of energy the utility must procure at the wholesale level because energy is lost while flowing through the distribution system. Both categories of energy were accounted for when calculating a utility's avoided energy cost.

AVOIDED RETAIL ENERGY COST

Assuming the customer's consumption behavior is unchanged by the amount of solar production, the avoided retail energy in any hour equals the amount of solar energy produced in that hour.[49] The cost avoided due to the solar production is therefore the amount of energy not delivered to the customer in each hour multiplied by the utility's hourly marginal energy cost, i.e., its "system lambda." Balancing Authorities are required to report their hourly system lambdas to the FERC on Form 714. These data are good proxies for the marginal energy costs of a utility that is served by that Balancing Authority. For a utility that is a member of an ISO, the hourly wholesale prices of energy at the commercial pricing node (CPnode) where the utility withdraws energy from the transmission system, i.e., the locational marginal prices (LMPs) at that point, are better proxies for the utility's marginal energy cost. These LMPs are readily available on the ISO websites for historical years. The Form 714 data and the ISO LMPs were the two data sources of the hourly marginal energy prices that the NIM utilized.[50]

Because energy prices and costs are necessarily historical, the data had to be adjusted to produce forecasts of hourly prices for 2015 and beyond. The NIM escalated these historical prices using future real escalation rates based on the historical and forecasted prices of natural gas delivered to electric utilities, as published in EIA's 2014 Annual Energy Outlook and its most recent 2015 Short Term Energy Outlook.[51]

The rationale for applying natural gas price escalation rates to hourly wholesale electricity prices is that during the hours of significant solar energy production the wholesale generating plants operating at the margin will almost certainly be those fueled by natural gas; consequently, the price of natural gas delivered to those plants will directly determine their dispatch prices. During off-peak hours this may not be true but in those hours there will be little or no solar energy produced so the NIM calculations will not be adversely affected. Furthermore, to the extent that the marginal energy costs are not set by natural gas prices in some hours, the NIM calculations will overstate the avoided costs and thereby conservatively understate the NEM incentive.

48. Rocky Mountain Institute, Id.
49. This invariance assumption is not strictly true. A price elasticity effect does exist, similar to the "snapback" effect observed with respect to energy efficiency measures. We assume this effect is small enough to ignore.
50. It was not necessary to download LMPs from PJM's website for Commonwealth Edison Company because the utility published the day-ahead LMPs that it used to set the 2014 hourly prices in its Residential Real-Time Pricing (RRTP) tariff.
51. Monthly prices for natural gas delivered to electric utilities in 2013 and 2014, along with forecasted monthly prices for 2015, were taken from EIA's Short Term Energy Outlook, February 2015. Average annual forecasted prices were taken from EIA's 2014 Annual Energy Outlook – Natural Gas Prices to the Electricity Utility Sector.

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AVOIDED DISTRIBUTION SYSTEM LOSSES

The other component of avoided energy cost is the energy lost in the distribution system. The energy loss in any hour is equal to the energy flow multiplied by the marginal distribution loss rate in that hour. Because distribution losses increase in proportion to the square of the power flow, the marginal loss rate increases in direct proportion to the power flow.[52] The NIM estimates a marginal distribution loss rate for each hour of the year and applies that rate to the hourly reductions in retail energy produced by solar energy production in order to estimate the associated hourly reductions in distribution system energy losses.

Energy lost in the distribution system must be made up by injecting equal amounts of energy at the wholesale level. Thus, the avoided cost associated with distribution losses in any hour is equal to retail energy flow, multiplied by the marginal distribution loss rate, and multiplied again by the marginal wholesale energy price for that hour. The NIM does these hour-by-hour calculations as described in the following equations:

1. Annual Total Loss = K1*Annual Total Load^2 where Annual Total Load equals MWhs of energy delivered to retail customers.
2. Annual Total Loss = Annual No-Load Loss + Annual Variable Loss
3. Annual Variable Loss = K2 * Annual Total Loss
4. Annual Variable Loss = $\sum_{\text{all hours}}$ (Hourly Variable Loss)
5. Hourly Variable Loss = K3*Hourly Load^2
6. Annual Variable Loss = $\sum_{\text{all hours}}$ K3*(Hourly Load^2) where K3 is constant in all hours of the year.
7. K3 = Annual Variable Loss/$\sum_{\text{all hours}}$ (Hourly Load^2)
8. K3 = K2*Annual Total Loss/$\sum_{\text{all hours}}$ (Hourly Load^2)
9. K3 = K2*K1*Annual Total Load2/$\sum_{\text{all hours}}$ (Hourly Load^2)
10. Hourly Marginal Loss Rate = d(Hourly Variable Loss)/d(Hourly Retail Load)
11. Hourly Marginal Loss Rate = 2*K3*Hourly Load.

The report assumes that for each utility examined the annual distribution system losses equal approximately 7 percent of the energy delivered to that utility's retail loads (i.e., K1 = .07). It also assumes that the no-load losses are about 25 percent of the annual distribution losses (i.e., the K2 = .75). These assumptions are based on analyses done by the Regulatory Assistance Project (RAP) and by SAIC.[53]

The NIM calculations of distribution system marginal losses are admittedly crude. The only way to accurately estimate distribution losses is to reconstruct the hourly power flows throughout the distribution system down to the individual feeder circuits. Calculation of this was well beyond the report scope.

Although the NIM estimates of hourly marginal losses are rough approximations, they err on the side of systematically overestimating the total cost of distribution losses avoided by the solar PV production. This is because the marginal distribution loss rates are estimated using the hourly loads of each Balancing Authority, which include not just residential loads but also industrial and commercial (C&I) loads. Because the power flows dedicated to serving just C&I loads

52. Distribution system losses consist of the "no load" loss, which is invariant with respect to power flow, and the other losses, which vary with the power flow. Because the no-load loss does not contribute to the hourly marginal losses the NIM ignores these losses when calculating hourly marginal loss rates.
53. Lazar, Jim, and Baldwin, Xavier, Valuing the Contribution of Energy Efficiency to Avoided Marginal Line Losses and Reserve Requirements, Regulatory Assistance Project, August, 2011, p 3. Available at: raponline.org/document/download/id/4537.
 SAIC, Id. SAIC conducted the study for Arizona Public Service in 2013 and reported an average annual distribution system energy loss rate of seven percent, which increased to 11.7 percent in the hour of peak system demand.

are little affected by changes in the residential loads the losses in these high voltage distribution circuits do not contribute to the marginal losses measured at residential customers' meters; consequently, they do not contribute to the losses avoided as a result of residential rooftop solar PV production. However, the NIM calculations do not exclude these C&I power flows from the marginal loss calculations. The resulting overestimation of marginal losses conservatively underestimates the NEM incentive.

AVOIDED GENERATION CAPACITY COST

The amount of generation capacity (or demand response resources) that a utility must procure in order to satisfy its resource adequacy obligation is determined by the utility's load at the time of its Balancing Authority's peak load. If solar energy produced by the utility's customers reduces this coincident peak load it also reduces the utility's resource adequacy obligation and therefore has capacity value. Generally energy production from a residential solar facility does not peak when the Balancing Authority's load peaks because the solar panels are typically oriented southward in order to maximize the annual energy output; however, the facility will still have some capacity value if it produces some energy in the hour when the total system load peaks.

For all of the metropolitan areas examined in this report some solar energy is produced at the time of the utilities' coincident system peak loads; therefore, residential solar PV facilities are likely to have some capacity value. To accurately estimate the capacity value of an intermittent resource (including solar PV) requires application of complex probabilistic models, which was beyond the report scope. Fortunately NREL has developed and benchmarked some simple methods for approximating these capacity values, as described below. [54]

ELCC of Solar PV

This report estimates the Effective Load-Carrying Capability (ELCC) of a solar PV resource, which is defined as the amount of additional load a power system can serve, with the same ex ante level of reliability, after the resource is added to the system.[55] It uses a simple technique for approximating an intermittent resource's ELCC, i.e., calculating the average capacity factor of the resource over a subset of the power system's highest hourly loads. Milligan and Parsons have shown that the capacity factor of an intermittent resource calculated over the highest 30 percent of the load hours produces a reasonable close estimate of the resource's ELCC.[56] However, to err on the side of overstating the solar facility's ELCC, the report calculated the capacity factor over just the 1,000 highest load hours.

The hourly loads used to approximate the resource's ELCC are not those of the distribution utility, but rather those of the utility's Balancing Authority that is responsible for the collective sharing of its members' capacity resources. Examples of such Balancing Authorities are PJM, ISO-New England and the Midcontinent ISO. Some utilities (e.g., Arizona Public Service) serve as their own Balancing Authorities. All Balancing Authorities are required to report their hourly loads on FERC Form 714.

Using FERC Form 714 data and the hourly solar production simulated by NREL's SAM model, the NIM calculated the solar resource's capacity factor over the top 1,000 load hours to approximate a typical residential solar PV facility's ELCC located in each of the 15 selected metropolitan areas. NREL's SAM model simulates solar PV energy production as measured on the AC output side of the facility's inverters. To determine an ELCC for the solar PV facility that is equivalent to that of a wholesale generator, the facility's AC electricity production was

54. Madaeni, Seyed Hossein et al, Comparison of Capacity Value Methods for Photovoltaics in the Western United States, NREL Technical Report, NREL/TP-6A20-54704, July 2012.
55. The ex-ante level of reliability is that level that existed before the new resource is added to the power system. The standard industry measure of reliability is Loss of Load Expectation (LOLE).
56. Milligan, Michael and Parsons, Brian, A Comparison and Case Study of Capacity Credit Algorithms for intermittent Generators, Presented at Solar '97, Washington, DC, April 27-30, 1997, March 1997.

"grossed up" to account for the marginal distribution losses that are avoided because the solar production occurs at a terminal point on the distribution system. The "grossed up" ELCC was then directly compared with the ELCC of a reference wholesale generator connected to the transmission system.

Table A-5 presents the results of these calculations for the 15 selected metropolitan areas.

Table A-5. Approximate ELCCs of Solar PV Facilities Located in Fifteen Metropolitan Areas

Metropolitan Area	Balancing Authority	Approximate Per-Unit Solar ELCC (Percent of Installed Solar AC Capacity)
Phoenix, AZ	Arizona Public Service	36.1
Los Angeles, CA	Southern California Edison	33.3
Hartford, CT	ISO-New England	21.5
Miami, FL	Florida Power & Light	38.6
Atlanta, GA	Georgia Power	35.7
Chicago, IL	PJM	30.0
Baton Rouge, LA	Entergy	33.5
Portland, ME	Central Maine Power	24.9
Boston, MA	NSTAR	26.2
Detroit, MI	Midwest ISO	21.6
Minneapolis, MN	Midwest ISO	20.1
Las Vegas, NV	Nevada Power	31.2
Manchester, NH	Public Service of New Hampshire	20.0
Newark, NJ	Public Service Electric and Gas	25.3
Charlotte, NC	Duke Power - Carolinas	29.7

The approximate ELCC shown for each solar PV facility is its average capacity factor calculated over the highest 1000 hourly loads of the Balancing Authority of the utility serving the solar customer. These capacity factors were then adjusted upward to account for avoided marginal distribution losses in each hour.

FERC Form 714 load data were used to identify the top 100 load hours of the Balancing Authority.

ELCC of the Wholesale Reference Peaking Plant

The ELCC of the reference plant is a new gas-fired simple cycle combustion turbine (GCT) because this technology is most likely to be the marginal new entrant setting the price of capacity.[57] The ELCC of a new GCT is approximately 95 percent of its summer capability.[58]

57. This is a standard industry assumption underlying the Cost of New Entry calculation. See Brattle Group, Id.
58. This ELCC is the result of the GCT having an equivalent forced outage rate (EFOR) of 0.05. Based on NERC GADS data this is a reasonable assumption.

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GCT Installed Cost

EIA employed an outside consultant (SAIC) to produce regional estimates of the overnight construction cost and operating costs of various utility-scale generation technologies, including an advanced technology (210 MW GE Frame F type) GCT.[59] SAIC developed these costs for a generic plant sited in a "…non-specific U.S. location with no unusual location impacts…."[60] SAIC also developed adjustment factors for application to the overnight cost of the generic GCT to account for regional differences in local labor rates, materials costs, plant elevation and summer temperatures. SAIC did not develop adjustments for application to the generic GCT's fixed operating costs. Table A-6 presents the EIA capital and fixed operating cost estimates for an advanced technology GCT sited within the regions that contain a metropolitan area analyzed in this report.

The EIA overnight construction costs are expressed in mid-2012 dollars so they had to be escalated to mid-2015. The NIM did this by using the producer price indices for labor and materials for years 2012 and 2015 and the assumption that the GCT's overnight construction costs consisted of 40 percent labor and 60 percent equipment and materials. The NIM applied these indices to the EIA overnight construction cost for each EMM region. Lastly, the NIM adjusted upward the resulting regional overnight construction to account for financing costs during construction by applying the developer's after-tax weighted average cost of capital (ATWACC) and assuming that the centroid of construction outlays occurred 7.5 months prior to the plant entering commercial service.

Table A-6. Regional Overnight Construction Cost and Annual Fixed Operating Cost of a Gas-Fired Simple-Cycle Combustion Turbine Plant

EMM Region	Description of Region	Overnight Construction Cost (2012 $/kW)	Fixed Operating Cost (2012 $/kW-Yr.)
FRCC	FL Peninsula	$659	$7.04
MROW	Midwest - Western WI, MN, ND, SD	$674	$7.04
NEWE	All of New England	$777	$7.04
RFCM	MI excluding UP	$674	$7.04
RFCW	Chicago, MI-UP, IN, Northern OH, KY	$715	$7.04
SRDA	MO, LA, AK	$670	$7.04
SRCE	GA, AR, MS	$654	$7.04
SRVC	VA, WV, NC, SC	$647	$7.04
AZNW	AZ & balance of NM	$803	$7.04
NWPP	WA, OR, NV, UT, ID, MT, Western WY	$728	$7.04

Source: Source: EIA, Electricity Market Module, Table 8.2 Cost and Performance Characteristics of New Central Station Electricity Generating Technologies, 2014, supplemented by data extracted from EIA's EMM database (provided by EIA Data Specialist, Jim Diefenderfer).

59. Energy Information Administration, Updated Capital Cost Estimates for Utility Scale Electricity Generating Plants, April 2013, p. 2-6.
60. Science Applications International Corporation (SAIC), EOP III TASK 1606, SUBTASK 3 – REVIEW OF POWER PLANT COST AND PERFORMANCE ASSUMPTIONS FOR NEMS, February 2013.

Annual Capacity Payment for a New GCT

The owner of a new generating plant must recover the project's invested capital and all of its operating costs and related income tax payments from the project's future after-tax cash flows over its expected life. The NIM calculated the present value of these future cash flows by discounting the time-stream of the ex-ante estimates of the expected values of the cash flows using an ATWACC that reflects the developer's view of the risk inherent in those cash flows.

The desired ATWACC can be estimated from financial market data. In a recent report conducted for PJM the Brattle Group estimated the ATWACC for merchant power plants to be approximately 8 percent in nominal terms.[61] This report adopts the Brattle estimate.[62]

A new project's cash flow in year t of the project's life is:

(12) $\mathbf{CF_t = Capacity\ Payment_t - Fixed\ O\&M_t - PropTax_t - Insurance_t - Income\ Tax_t}$

The income tax obligation in year t is:

(13) $\mathbf{Income\ Tax_t = (Capacity\ Payment_t – Installed\ Cost_0{*}Depn_t){*}TaxRate}$
$\mathbf{– (Fixed\ O\&M_t + PropTax_t + Insurance_t\ ){*}TaxRate}$

The subscript on Installed Cost indicates the year the project entered service.

Substituting (2) into (1):

(14) $\mathbf{CFt = Capacity\ Payment_t{*}(1-TaxRate) + Installed\ Cost_0{*}Depn_t{*}TaxRate}$
$\mathbf{– (Fixed\ O\&M_t + PropTax_t + Insurance_t\ ){*}(1-TaxRate)}$

The developer's assessment of the present value of these cash flows over the project's life must at least equal the project's installed cost or the project will not be undertaken. For the marginal project, which sets the market value of capacity in year t:

(15) $\mathbf{PV\{\sum CF_t\}= Installed\ Cost_0}$

where the notation, $PV\{X_t\}$, is a shorthand way to express $\sum_{t = 1 \text{ to } 20} X_t /(1+ATWACC)^t$.

Substituting (14) into (15) and solving for $PV\{Capacity\ Payment_t\}$:

(16) $\mathbf{PV\{Capacity\ Payment_t\} = Installed\ Cost_0{*}(1 – PV\{Depn_t\}{*}TaxRate)/(1-TaxRate)}$
$\mathbf{+ PV\{Fixed\ O\&M_t + PropTax_t + Insurance_t\}}$

61. The Brattle Group, Id.
62. Although the Brattle estimate appears to be reasonable, no effort was made to independently verify it. However, the choice of ATWACC does not greatly affect the report's incentive estimates because the utilities' future annual avoided generation capacity payments are discounted at a rate derived from the same ATWACC used to calculate those payments.

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Annual property tax and insurance charges are typically determined by respectively applying percentage rates to the market value and replacement cost of the plant, which we assume will be roughly proportional to its installed cost, i.e.,

(17) $\mathbf{PropTax_t = Installed\ Cost_0 * R_{ptax} * K2_t}$

(18) $\mathbf{Insurance_t = Installed\ Cost_0 * R_{ins} * K3_t}$

where $K2_t$ and $K3_t$ adjust the market values and replacement costs of the plant based on its age and on exogenous market factors, such as the existence of cheaper peaking resources employing more advanced technologies.

The NIM models the plant's market value as linearly declining with age.[63]
Substituting (17) and (18), into (16), and dividing by Installed $Cost_0$:

(19) $$PV\{Capacity\ Payment_t\}/Installed\ Cost_0 = (1 - PV\{Depn_t\}*TaxRate)/(1\text{-}TaxRate) + PV\{R_{ptax}*K2_t + R_{ins}*K3_t\} + PV\{Fixed\ O\&M_t\}/Installed\ Cost_0$$

Recognizing that the expected value of the capacity payment a developer will receive is likely to systematically change over time, the NIM models this by expressing Capacity $Payment_t$ in terms of Capacity $Payment_0$ and defining a nominal escalation rate, R_{cp}.

(20) $$Capacity\ Payment_t = Capacity\ Payment_0*(1+R_{cp})_t$$

Substituting (9) and (10) into (8):

(21) $$Capacity\ Payment_0*PV\{(1+R_{cp})_t\} = [(1\text{-}PV\{Depn_t\}*TaxRate)/(1\text{-}TaxRate) + PV\{R_{ptax}*K1_t + Rins*K2_t\}]*Installed\ Cost_0 + PV\{Fixed\ O\&M_t\}.$$

(22) $$Capacity\ Payment_0 = [(1\text{-}PV\{Depn_t\}*TaxRate)/(1\text{-}TaxRate)]/PV\{(1+Rcp)_t\} + R_{ptax}*PV\{K1_t\}*Installed\ Cost_0/PV\{(1+R_{cp})_t\} + R_{ins}*PV\{K2_t\}*Installed\ Cost_0/PV\{(1+R_{cp})_t\} + PV\{Fixed\ O\&M_t\}/PV\{(1+R_{cp})t\}$$

All of the present values that appear on the right side of equation (22) were calculated using the values of the input variables and assumptions described in Table A-7.
The NIM performed these calculations to solve for the first year capacity payment in each region. After the first

Table A-7. Fixed Costs Included in Calculation of GCC Annual Capacity Payments

Fixed Cost Item	Basis of Annual Cost Estimate
Fixed Operation & Maintenance Costs	$7.52 per kW of installed capacity (2015$)
Property Taxes	One percent of installed cost in first year; declines linearly to zero over the 20-year plant life.
Property Insurance	One-half percent of installed cost in first year; declines linearly to zero over the 20-year plant life.

63. Though rather simplistic, given the approximate nature of other report assumptions further refinement is not warranted.

year the nominal capacity payments increase at the nominal escalation rate, R_{cp}.

The capacity payment's escalation rate R_{cp} can be less than the general inflation rate, either because the "learning curve" reduces the cost of today's technology or because a cheaper technology emerges, such as some form of electricity storage. EIA projects that the real overnight construction cost of the advanced GCT plant will decline at least 10 percent by the year 2035.[64] This implies an average real cost escalation rate of about - 0.5 percent per year. This report adopted EIA's learning curve assumption. Because the plant's overnight construction cost is the primary determinant of the capacity payment the report also assumes that the avoided generation capacity payments decline at a real rate of 0.5 percent per year.

Solving equation (22) produces the first-year avoided capacity payment for a new GCT sited in each of the ten metropolitan areas. Table A-8 presents these capacity costs.

These calculations are based on the assumption that the Balancing Authority of each distribution utility has a minimum reserve margin requirement equal to the NERC reference reserve margin for the region and that the power system is in a compliance in 2015 and remains approximately so over the 25-year economic life of the rooftop solar PV facilities. This assumption is conservative, thus it overstates avoided capacity payments and understates the NEM incentive because all of the Balancing Authorities serving the 15 metropolitan areas currently have excess generating capacity installed.

Table A-8. First-Year Capacity Payments for New Gas-Fired Combustion Turbine Plants Sited in 15 Selected States.

State	EIA EMM Region	EIA Overnight Construction Cost ($/kW)		EIA Installed Cost[3]	First-Year Capacity Payment[5]
		Oct 2012 $	Jan 2015 $	2015 $/kW	2015 $/kW-Yr.
Arizona	AZNW	$803	$860	$907	$117
California	CAMX	$889	$952	$1,004	$129
Connecticut	NEWE	$777	$832	$878	$114
Florida	FRCC	$659	$706	$744	$97
Georgia	SRCE	$654	$700	$738	$97
Illinois	RFCW	$715	$766	$807	$105
Louisiana	SRDA	$670	$718	$757	$99
Maine	NEWE	$777	$832	$878	$114
Massachusetts	NEWE	$777	$832	$878	$114
Michigan	RFCM	$674	$722	$761	$99
Minnesota	MROW	$674	$722	$762	$100
Nevada	NWPP	$728	$780	$822	$107
New Hampshire	NEWE	$777	$832	$878	$114
New Jersey	RFCE	$870	$889	$938	$121
North Carolina	SRVC	$647	$693	$730	$96

64. U.S. EIA, AEO 2012 Electricity Market Module Assumptions Document, Table 8.3.

APPENDIX A

Capacity Value of Solar PV

The next step is to convert the first-year capacity payment of a GCT to the capacity value of the installed solar PV facility. The NIM did this by determining the amount of new GCT capacity that need not be constructed (or procured) for each kW-dc of solar PV capacity added and multiplying that quantity by the GCT's annual capacity payment. The amount of GCT capacity displaced depends solely on the ratio of the two resources' ELCCs, i.e.,

(23) Displaced New GCT capacity = $(ELCC_{SOLAR} \div ELCC_{GCT}) \times \text{Installed Capacity}_{Solar}$.

Table A-9 shows the results of these calculations.

Table A-9. Avoided Cost of Solar PV Capacity for Fifteen Metropolitan Areas

Metropolitan Area	First-Year GCT Capacity Payment (2015 $/kW-Yr.)	Solar ELCC (Percent)	GCT ELCC (Percent)	Annual Avoided Capacity Cost of Roof-top Solar PV[1] (2015 $/kW-dc)
Phoenix, AZ	$117	36.1	95.0	$53
Los Angeles, CA	$129	33.3	95.0	$53
Hartford, CT	$114	21.5	95.0	$35
Miami, FL	$97	38.6	95.0	$51
Atlanta, GA	$98	35.7	95.0	$48
Chicago, IL	$107	30.0	95.0	$53
Baton Rouge, LA	$100	33.5	95.0	$48
Portland, ME	$114	24.9	95.0	$45
Boston, MA	$114	26.2	95.0	$42
Detroit, MI	$99	21.6	95.0	$37
Minneapolis, MN	$101	20.1	95.0	$35
Las Vegas, NV	$104	31.2	95.0	$34
Manchester, NH	$114	20.0	95.0	$32
Newark, NJ	$121	25.3	95.0	$35
Charlotte, NC	$96	29.7	95.0	$34

1. The annual avoided capacity cost shown is not grossed up to include for the utility's reserve margin requirement.

CALCULATING PRESENT VALUES

The NIM calculated the present values of the 25-year time streams of annual bill savings (expressed in Start-of-Year 2015 dollars) using a real, risk-adjusted discount rate of 3.5 percent per annum. This discount rate accounts for the uncertainty shrouding the marginal energy prices in residential tariff rates.

The NIM separately discounted the utility's annual avoided energy and distribution losses at a real risk-adjusted rate of 4.5 percent per annum. The model also discounted the annual avoided generation capacity costs by a real risk-adjusted rate of 7.8 percent per annum.

APPENDIX A

Bill Savings Discount Rate

Annual bill savings are the product of solar PV generation and the marginal energy prices in the customer's retail tariff. The uncertainty associated with solar PV generation is almost entirely a function of weather, thus is essentially random and non-systematic; consequently, it contributes very little to the risk premium in the discount rate. In contrast, the marginal energy prices in retail tariffs partly reflect the utility's cost of producing or procuring electric energy, which introduces significant systematic risk that does contribute to the discount rate. However, some of that energy is generated with coal, nuclear and hydro, which the typical utility will procure at prices that are less uncertain than natural gas prices. In addition, these tariff prices generally recover some of the utility's fixed costs that were created from past capital investments, which are known with certainty. The net effect is that future retail tariff energy prices are less risky than future natural gas prices; therefore, the appropriate risk-adjusted discount rate for customers' bill savings will be lower than the risk-adjusted discount rate for natural gas prices. This report assumes that the differential risk justifies a discount rate that is 100 basis points lower than that for natural gas prices.

Avoided Energy Cost Discount Rate

As discussed earlier in the section entitled, "Avoided Retail Energy Costs," the risk associated with a utility's avoided energy costs is largely determined by the systematic risk associated with natural gas prices; therefore, the NIM discounted the stream of avoided energy costs, including that lost in the distribution system, at the discount rate for natural gas prices.

Avoided Capacity Cost Discount Rate

The ATWACC represents the developer's view of the financial risk associated with the stream of annual capacity payments over the life of the plant. The ATWACC also accounts for the developer's use of debt financing, which takes advantage of income tax savings, and reduces the project's cost of capital. Utilities procuring capacity in the wholesale markets pay those capacity payments so they are subject to the same market risk as the developer; however, they gain no income tax savings because the capacity payments are treated as expenses that are flowed through to their customers. For this reason it was necessary to deleverage the ATWACC in order to arrive at the appropriate rate for discounting the utilities' future avoided capacity costs. The Modigliani-Miller Proposition I provides the tool for doing this: [65]

(24) R = Rd*(D/V) + Re*(E/V)

where:

R is the cost of capital of an all-equity financed project, which only reflects the project's business risk,

Rd is the cost of debt (i.e., the interest rate on borrowed funds),

Re is the cost of equity capital, which reflects both the business risk and the financial risk associated with debt financing,

D is the market value of the borrowed funds,

E is the market value of the project equity funds,

V is the project's total market value (i.e., V = D + E).

The ATWACC is defined as:

(25) ATWACC = Rd*(D/V)*(1 – TaxRate) + Re*(E/V)

(26) ATWACC = R – Rd*(D/V)*TaxRate

Solving for R:

(27) R = ATWACC + Rd*(D/V)*TaxRate

65. Modigliani, F. and Miller, M.H., "The Cost of Capital, Corporate Finance and the Theory of Investment," American Economic Review, 48 (June 1958), pp. 261-297.

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To extract R from Brattle's estimate of ATWACC one need only substitute Brattle's assumed values for ATWACC, D/V and TaxRate into equation (27):

(28) R = 0.08 + 0.07*(.6)*(.42) = .098 (i.e., 9.8 percent in nominal terms)

To express the project cost of capital in real terms the expected 25-year average inflation rate must be subtracted from R. The expected 25-year average inflation rate was approximated by subtracting the yield-to-maturity of 30-year U.S. Treasury Inflation Protected Securities (0.76 percent per annum) from the yield-to-maturity of 30-year U.S. Treasury Bonds (2.69 percent per annum) to discover the implied inflation rate (1.93 percent per annum). Given the approximate nature this adjustment the inflation estimate was rounded up to 2 percent per annum.[66] This produced a real project cost of capital of 7.8 percent, which the NIM used to discount the avoided cost of generation capacity.

Natural Gas Price Discount Rate

Based on the Capital Asset Pricing Model (CAPM), the market-based required return on an investment in a natural gas futures contract is:

(31) $R = Rf + \sum *(Rm - Rf)$

where:

R is the required annual return on an investment

Rf is the risk-free interest rate over the investment period

Rm is the rate of return on an investment in the market

$\sum$ is the covariance of the investment return and the market return divided by the variance of the market return.

The risk-free interest rate for a 25-year investment is equal to the yield on a US Treasury Zero-Coupon Bond ("Strip") with a maturity date 25 years in the future. This interest rate is reasonably approximated by the yield on Strips that mature on February 15, 2039. On January 2, that yield was reported as being about 2.49 percent.[67] The market risk premium (Rm – Rf) is approximately 6.5 percent.[68] In a proprietary study done for a utility client the beta for investments in long-term natural gas contracts was estimated to be approximately 0.6.

Inserting the above values into equation (31) produces a nominal required return of about 6.4 percent per annum. Subtracting out the two percent expected inflation rate yields a real return of 4.4 percent per annum, which was rounded up to 4.5 percent. As stated earlier, the NIM used this rate to discount the avoided costs of retail energy and distribution losses.

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66. Federal Reserve, Economic Research & Data, Statistical Releases and Historical Data, Release Date: January 5, 2015. http://www.federalreserve.gov/releases/H15/data.htm.
67. The Wall Street Journal, Market Data Center, April 1, 2015.
68. Ibbotson, SBBI 2014 Valuation Yearbook, Chicago: Morningstar, 2014.

APPENDIX B

INCENTIVES PRODUCED BY STANDARD AND TOU RETAIL TARIFFS

Table B-1 presents the results of the incentive calculations the standard (i.e., non-TOU) and the TOU tariffs that residential customers with solar PV are most likely to choose.

Table B-1. Incentives Produced by Utilities' Standard and TOU Residential Tariffs

State Utility	Residential Tariff	Direct Incentives ($ per kW-dc)	NEM Incentive ($ per kW-dc)	Total Incentives ($ per kW-dc)
Arizona				
Arizona Public Service	Standard	$1,308	$3,235	$4,543
	Time-of-Use		$4,117	$5,425
California				
Southern California Edison	Standard	$1,050	$6,227	$7,277
	Time-of-Use		$6,714	$7,764
Connecticut				
Connecticut Light & Power	Standard	$2,124	$2,720	$4,844
	Time-of-Use		$2,565	$4,689
Florida				
Florida Power & Light	Standard	$1,050	$1,971	$3,021
	Time-of-Use		$1,840	$2,890
Georgia				
Georgia Power	Standard	$1,050	$1,005	$2,055
	Time-of-Use		-$86	$964
Illinois				
Commonwealth Edison	Standard	$1,730	$1,336	$3,066
	Time-of-Use		NA	NA
Louisiana				
Entergy Gulf States Louisiana	Standard	$2,800	$1,039	$3,839
	Time-of-Use		NA	NA
Maine				
Central Maine Power	Standard	$1,429	$1,347	$2,776
	Time-of-Use		-$1,743	-$313
Massachusetts				
NSTAR	Standard	$3,891	$2,581	$6,472
	Time-of-Use		NA	NA
Michigan				
DTE Electric	Standard	$1,430	$1,917	$3,346
	Time-of-Use		$2,193	$3,623
Minnesota				
Northern States Power	Standard	$1,836	$1,336	$3,173
	Time-of-Use		$2,420	$4,256
Nevada				
Nevada Power	Standard	$1,410	$2,347	$3,757
	Time-of-Use		$1,474	$2,884
New Hampshire				
Public Service of New Hampshire	Standard	$1,526	$1,953	$3,479
	Time-of-Use		NA	NA
New Jersey				
Public Service Electric and Gas	Standard	$3,618	$2,797	$6,416
	Time-of-Use		NA	NA
North Carolina				
Duke Energy Carolinas	Standard	$3,002	$1,155	$4,157
	Time of Use		$1,151	$4,153
NA: Not applicable because utility does not offer a TOU tariff or the 2015 rates were not known.				

APPENDIX C

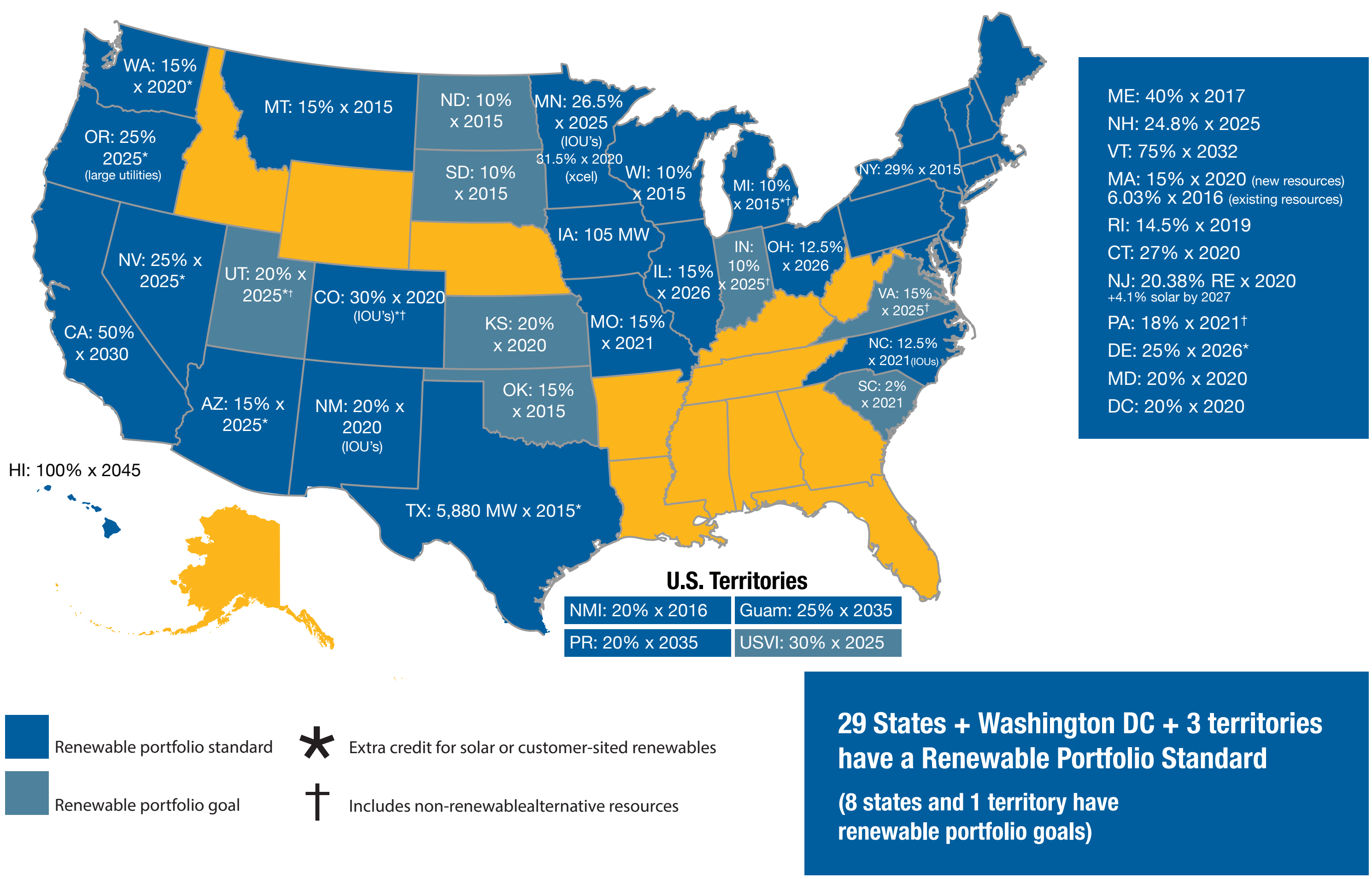
RENEWABLE ENERGY CERTIFICATES

This appendix describes how the value of renewable energy certificates (RECs) for residential rooftop solar facilities are quantified in this report.

BACKGROUND

Twenty nine states plus the District of Columbia have adopted renewable energy portfolio standards (RPS) which mandate that electric utilities serving retail customers (i.e., end-users) within the state must procure a minimum percentage share of the electric energy delivered to these customers within a given year to be produced from renewable resources. Figure C-1 identifies the states that have implemented energy portfolio standards.

Figure C-1. Renewable Portfolio Standard Policies

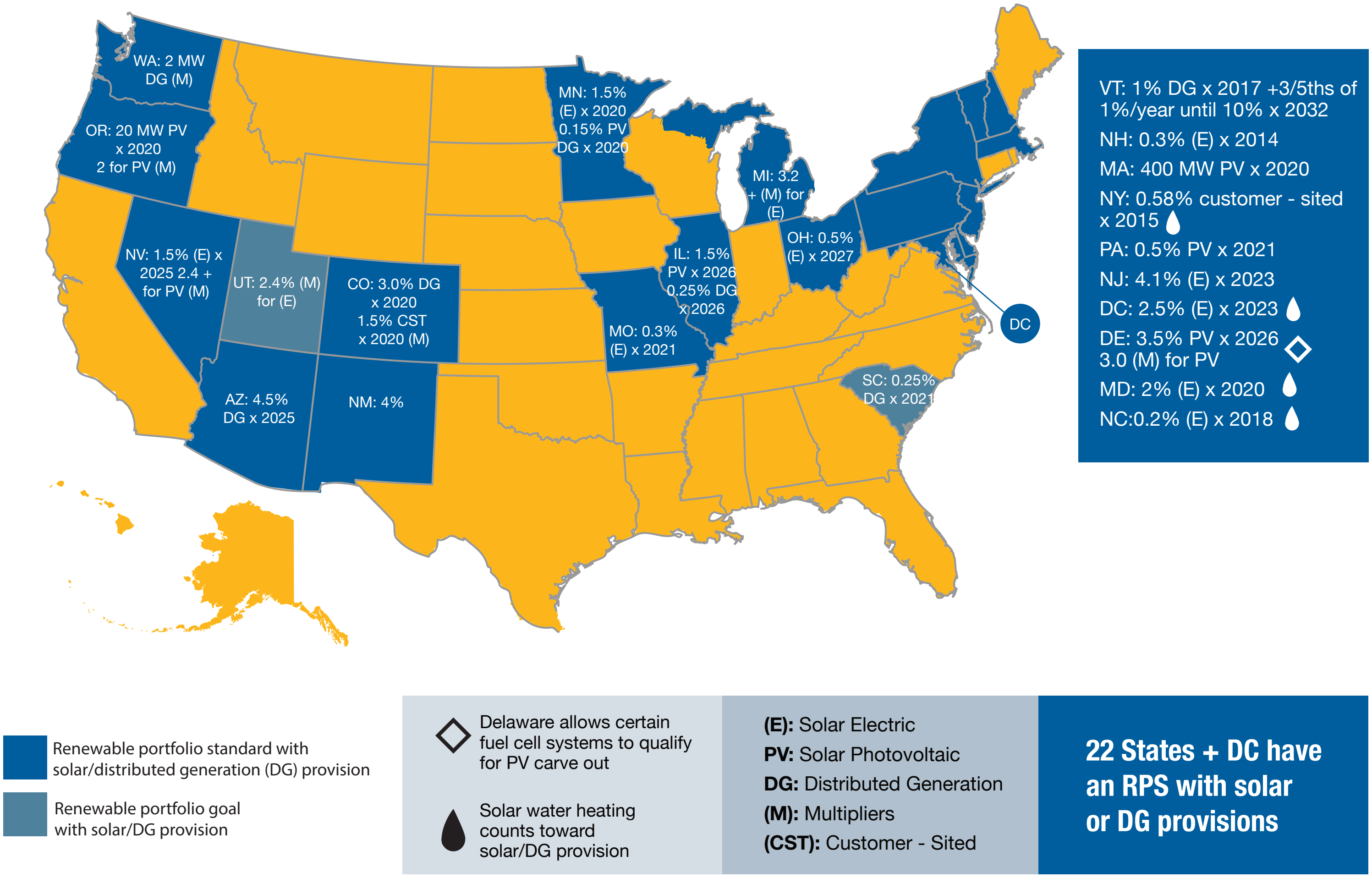


Source: www.dsireusa.org

APPENDIX C

In addition to having an RPS, 22 states plus the District of Columbia have established separate set-asides for solar or distributed energy resources, as illustrated in Figure C-2.

Figure C-2. Renewable Portfolio Standards with Solar/Distributed Generation Provisions



A renewable energy certificate (REC) is created when an eligible renewable resource produces one MWh of energy. A renewable resource is eligible if it is registered in one of the regional tracking systems. Table C-1 describes the geographic coverage of the nine U.S. tracking systems. A tenth system is being developed for New York State.

Generally a retail electricity supplier can satisfy its RPS obligation, either by procuring renewable energy and the associated RECs (i.e., bundled RECs) or by procuring RECs (i.e., unbundled RECs). However, in some states the retail electricity supplier must also satisfy a portion of its obligation by purchasing RECs produced by solar facilities (SRECs) or by distributed generation.[69] Thus, while all SRECs are RECs not all RECs are SRECs.

Although state RPS mandates create most of the demand for RECs and SRECs, other sources of demand are companies and individuals that want to promote the use of "green" energy. For example,

69. About 95 percent of the energy produced with distributed generation comes from solar PV facilities.

APPENDIX C

Table C-1. Renewable Energy Certificate Tracking Systems in the US

Tracking System	Region Covered
Texas Renewable Energy Credit Program (ERCOT)	TX
NEPOOL – Generation Information System (GIS)	CT, MA, ME, NH, RI, VT
PJM – Generation Attribute Tracking System (PJM-GATS)	DE, IL, IN, KY, MD, MI, NJ, NC, OH, PA, TN, VA, WV, DC
Western Renewable Energy Generation Energy Tracking System (WREGIS)	AB, AZ, BC, Baja CA, CA, CO, ID, MT, NB, NV, NM, OR, SD, TX, UT, WA, WY
Midwest Renewable Energy Tracking System (M-RETS)	AK, IL, IN, IA, LA, MB, MN, MS, MO, MT, ND, OH, KY, SD, TX, WI
North American Renewables Registry (NAR)	States/Provinces not covered by other markets
Michigan Renewable Energy Certification System (MIRECS)	MI
Nevada Tracks Renewable Energy Credits (NVTRECS)	NV
North Carolina Renewable Energy Tracking System (NC-RETS)	NC

Whole Foods has voluntarily purchased RECs to cover 100 percent of the electricity consumed in their U.S. and Canadian stores and other facilities.[70] Typically these "green energy" RECs are not counted toward satisfying a state's RPS.

ESTIMATING THE INCENTIVE VALUE OF FUTURE SREC SALES

Conceptually, estimating the incentive value of SRECs produced by a residential solar PV facility is straightforward: forecast the 25-year revenue stream of SREC sales from one Watt-dc of the facility's capacity and discount it at an appropriate risk-adjusted discount rate. However, forecasting future SREC prices is difficult for a number of reasons, e.g., the disjointed nature of the SREC markets, the likelihood of future increases in RPS targets, and the uncertainties shrouding future natural gas prices and the installed cost of solar PV facilities. To be conservative, the report only considered the economic value of REC sales in the first 10 years and ignored any further benefits flowing from sales in the following 15 years of the solar facility's life. In addition, it was assumed that SREC market prices would remain the same (in real dollars) over that time period. Market-based payments were discounted at the real discount rate used for natural gas prices, i.e., 3.8 percent, because the riskiness inherent in SREC prices is largely determined by natural gas prices, as discussed next.

Limiting the present value calculation to the first 10 years is consistent with two assumptions: (1) natural gas prices will rebound by 2025 (most likely sooner) and (2) the cost of installing utility-scale solar facilities will continue to decline. The combined effect of these two developments will bring about cost parity between energy produced by unsubsidized utility-scale solar PV facilities and energy produced by natural gas-fired generation. Once cost parity is achieved, the market-based premium for renewable energy will essentially vanish, thereby reducing REC prices to zero in the regional REC markets that do not constrain supply by limiting, or prohibiting, the utilization of RECs produced by out-of-state resources.

In states that do constrain the supply of SRECs (e.g., Connecticut, Illinois, Massachusetts, New Jersey) local SREC prices can deviate substantially from those

70. http://www.wholefoodsmarket.com/mission-values/environmental-stewardship/green-mission.

in the broader regional markets. Also, several states have established programs that allow residential customers to sell their SRECs to their utilities, or to state entities, through fixed-price contracts extending out as far as 15 years (e.g., Connecticut and Illinois). For those states the report calculated the present value of the known contract payments and added to it the present value of spot market sales that will occur following contract termination (but not beyond 2024). Because these contract payments are known with near certainty they were discounted at the riskless interest rate of 2.5 percent (i.e., the nominal interest rate on 10-Year U.S. Treasury Bonds).

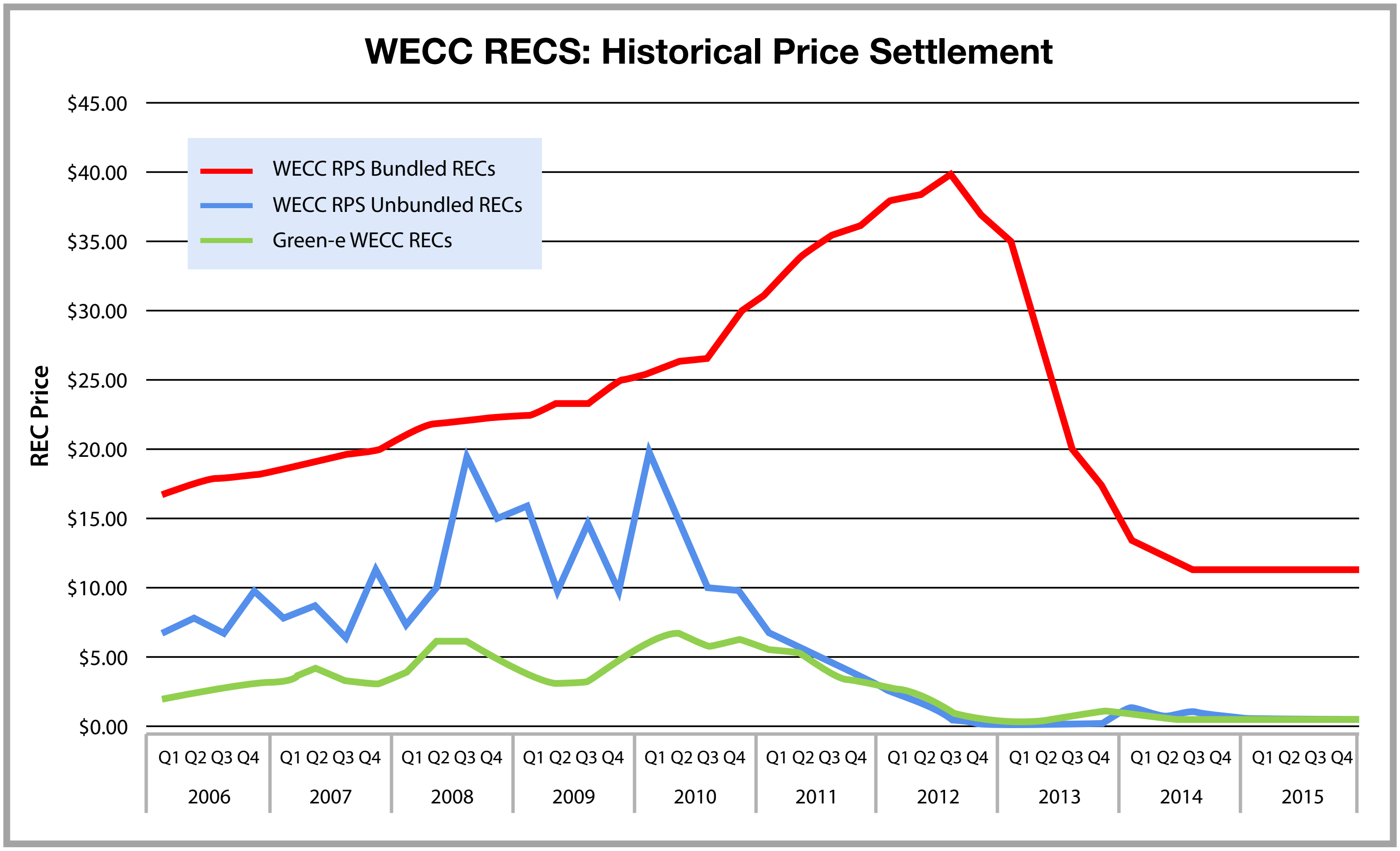
STATE-BY-STATE SREC SALES REVENUES

This section describes how SREC prices and sales revenues were estimated for residential solar PV facilities.

ARIZONA

Arizona has adopted an RPS of 15 percent to be attained by 2025. This includes a 4.5 percent carve-out (i.e., 30 percent of 15 percent) for distributed renewable generation, of which half must come from residential facilities. All of these requirements can be met through procurements of bundled RECs produced from resources located within the Western Electricity

Figure C-3. Market Prices for Bundled and Unbundled RECs in WECC



Source: Evolution Markets, Inc.[71]

71. Evolution Markets, West Renewable Energy Markets: The calm before the storm? Mid-C Seminar, July 22, 2015.

Coordinating Council (WECC). Figure C-3 presents the historical prices for both bundled and unbundled RECs in WECC.

WECC has a surplus of unbundled RECs, primarily because SRECs created by residential solar PV facilities in California cannot be fully utilized in that state (for reasons described below). Assuming that unbundled SREC prices remain at their current levels (in real terms) the present value of a 10-year stream of annual REC payments for a residential solar PV facility located in Phoenix is less than $1 per Watt-dc, which is insignificant.

CALIFORNIA

In October 2015, California adopted the country's second most aggressive RPS, i.e., 50 percent by 2030.[72] All retail electricity suppliers within the state must meet this standard, including those that are not investor-owned, by procuring three categories of renewable energy products.[73]

Category 1 products are RECs bundled with the associated energy that also have:

- a first point of interconnection with a California balancing authority,
- a first point of interconnection with distribution facilities used to serve end users within a California balancing authority area, or
- are scheduled from the eligible renewable energy resource into a California balancing authority without substituting electricity from another source.

Category 2 products as those that bundle RECs with the associated energy that are firmed and shaped by renewable energy resources and provide incremental electricity scheduled into a California balancing authority.

Category 3 products as those that are eligible renewable energy resource electricity products, or any fraction of the electricity generated, including unbundled renewable energy credits, that are not Category 1 or 2 products. This includes unbundled SRECs created by residential solar PV facilities for onsite consumption, as defined in the host utility's net metering tariff. However, SRECs created by residential solar PV facilities that exceeds onsite consumption within the customer's 12-month billing period (which the host utility then purchases) is a Category 1 product if the customer also transfers ownership of the SRECs to the host utility.[74]

Residential customers providing a Category 1 product are paid a Renewable Attribute Adder (RAA), which is a proxy for the average annual market value of bundled RECs within the Western Electricity Coordinating Council (WECC) footprint. The RAA is updated each October based on U.S. DOE data. On

Compliance Period	§399.16b(1) – Category 1	§399.16b(2) – Category 2	§399.16b(3) – Category 3
Jan 2011 - Dec 2013	At least 50 Percent	Residual (0 to 50 Percent)	No More Than 25 Percent
Jan 2014 - Dec 2016	At least 65 Percent	Residual (0 to 35 Percent)	No More Than 15 Percent
After 2016	At least 75 Percent	Residual (0 to 25 Percent)	No More Than 10 Percent

72. In June 2015, Vermont adopted an RPS of 75 percent to be achieved by 2032.
73. California Senate Bill 2(1X), Stats. 2011, ch.1, effective December 10, 2011.
74. The purchases of such solar excess energy are made at the utility's avoided cost because the solar facility is deemed to be a Qualified Facility (QF) under PURPA.

October 1, 2015 the RAA value was $0.01645 per kWh.

The effect of RAA payments is small because most residential solar facilities are purposely sized to produce little or no annual net energy production. Almost all of the SRECs associated with residential solar energy are Category 3 products.

The California Public Utilities Code limits the proportions of the REC products that utilities can use to satisfy their obligations in three successive time periods:
The constraint on Category 3 product utilization has caused an excess supply of this product, which has depressed market prices for unbundled RECs throughout WECC. Figure C-3 clearly illustrates this effect.

Residential customers in California can sell their RECs into the WECC market but the present value of those SREC sales is about the same as in Arizona - insignificant.

CONNECTICUT

Connecticut's RPS is 27 percent by 2020. In addition, the state has a small "Zero-Emission Renewable Energy Credit" (ZREC) program that applies to small solar PV facilities (100 kW-ac or smaller) located within the state. Owners of these facilities can sell their ZRECs to their host utility through 15-year contracts at prices equal to 110 percent of the weighted-average bid prices received in the most recent state REC auction. The 2015 auction set the small ZREC contract price at $80.97.

The annual budget for this program is limited and participation is on a first-come, first-served basis. Assuming that the 2015 budget is sufficient to accommodate all (or most) of the applicants, the present value of a 15-year contract for a residential solar PV facility located in Hartford is $1.07 per Watt-dc, which is about 31 percent of the facility's unsubsidized installed cost.

FLORIDA

Florida has no RPS so it does not give rise to a REC market but residential customers in that state can sell their SRECs into the North Carolina market if they register in the NC-RETS tracking system. Because North Carolina currently has a surplus of RECs their market values are minimal. This surplus is likely to continue indefinitely because the state's utilities can utilize RECs produced by facilities located in any other state, including the WECC region. For this reason the present value of Florida SREC sales was assumed to be the same as for Arizona, i.e. insignificant.

GEORGIA

Like Florida, Georgia has no RPS. Also like Florida, residential customers in Georgia can sell their RECs into the North Carolina market. The present value of Georgia SREC sales is the same as in Florida, i.e. insignificant.

ILLINOIS

Illinois, a "retail choice state," requires all retail electricity suppliers to procure 25 percent of the electricity they deliver to Illinois from renewable resources by 2026. In addition, the state has established a carve-out that Commonwealth Edison and the Ameren utilities must meet with solar PV or distributed generation. By 2026 these utilities must procure 1.5 percent of their energy from solar PV and .25 percent from distributed resources if these goals can be fulfilled without driving retail electricity prices up beyond a capped limit, which is adjusted annually.

To further encourage solar energy development the legislature established the Illinois Supplemental PV Procurement Program (ISPP). This program will procure SRECs from residential and commercial solar PV facilities through three (or four) auctions held in 2015, 2016, and 2017. To be eligible a facility must be

Table C-1. Table C-2. ISPP Program SREG Procurements From Small Facilities in 2015

	June 2015 Auction Nameplate Capacity < 25 kW-dc		November 2015 Auction Nameplate Capacity < 25 kW-dc	
	Identified Systems	**Unidentified Systems**	**Identified Systems**	**Unidentified Systems**
SRECs Procured	2,296	16,245	4,934	11,135
Average Bid Price ($/MWh)	$172.74	$168.00	$185.63	$209.68
Average System Size (kW)	6.4	Unknown	8.16	Unknown
Source: Illinois Power Agency, Fall 2015 Procurement Events November 18, 2015				

located within the state, have a nameplate capacity not greater 2 MW-dc, and not have been energized before January 21, 2015.[75]

Illinois held two auctions in 2015 and included bids for prospective systems that had not yet been sited. Table C-2 presents the auction results for facilities smaller than 25 kW-dc. The winners will be paid their respective bid prices for the SRECs their facilities produce over the 3-year period for which the program is authorized.

Because these are "pay-as-bid auctions" there are no market clearing prices reported. For this reason the report used the average bid prices as proxies for the expected values of the prices that the successful bidders will receive for their SRECs.

To estimate the average incentive for a residential solar facility located in Chicago the report assumed an average contract price of $180 per SREC paid quarterly for 5 years. The present value of this revenue stream, discounted the nominal riskless interest rate, is $0.68 per Watt-dc, which amounts to about 19 percent of the solar PV facility's unsubsidized installed cost.

LOUISIANA

Louisiana has no RPS, therefore supports no REC market. While the states' residential customers can sell their SRECs into the North Carolina market, for reasons described earlier, the value of their SRECs is insignificant.

MAINE

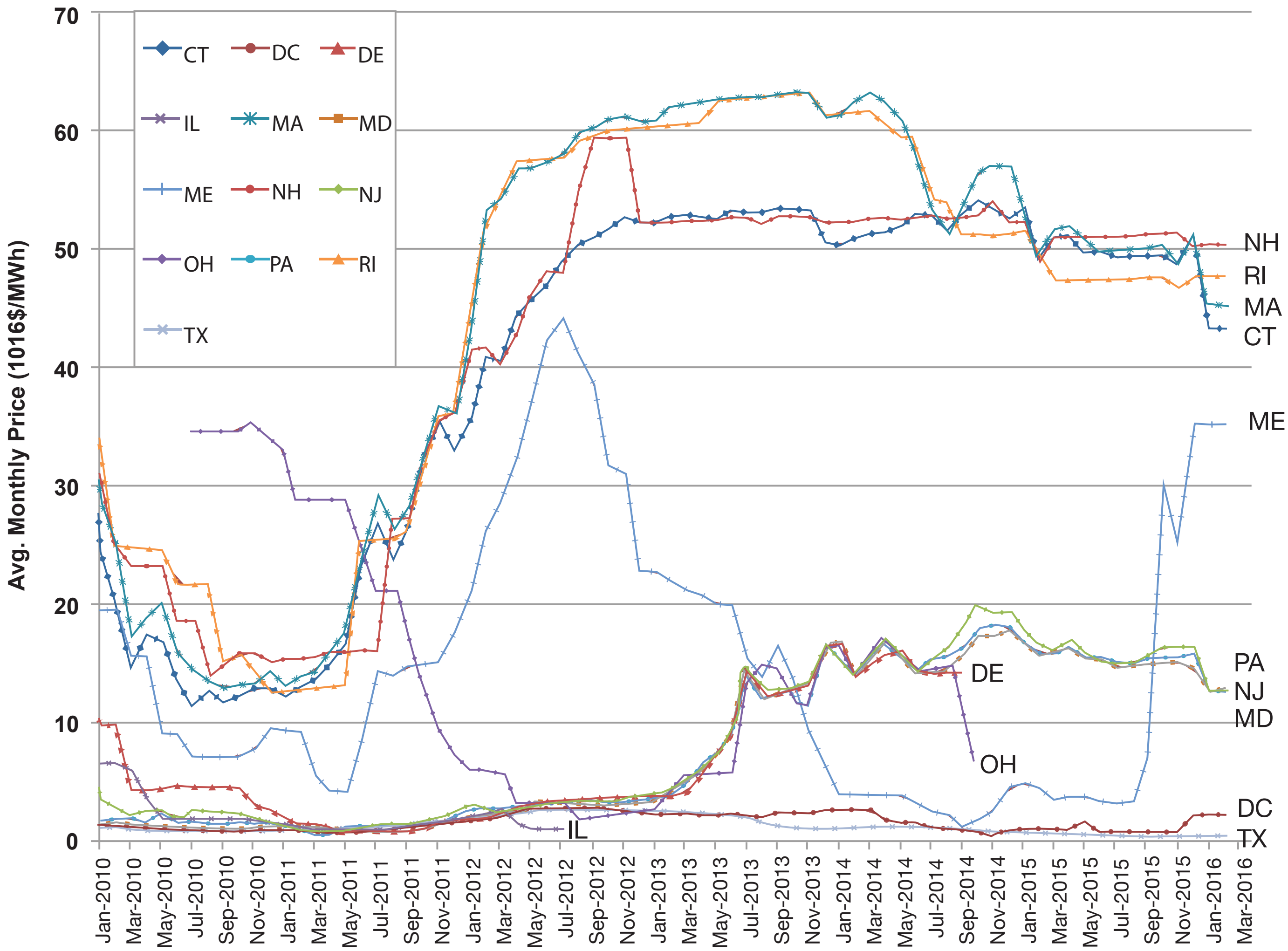
Maine has an RPS target of 40 percent by 2017, of which one-quarter must be met with resources that entered service after September 1, 2005 (Class I resources). The state has no carve-out for solar so SRECs are valued no differently than other RECs. Instead of purchasing RECs the retail electricity suppliers can pay the Alternate Compliance Price, which was $67.07 in 2015, and increases annually at the general inflation rate. Thus, the ACP caps future REC prices.

SRECs created in Maine can be sold into the REC markets of other New England states except for New Hampshire, which only recognizes RECs produced by in-state resources. Figure C-4 shows the historical REC prices for Maine and other states. In 2015 the REC prices in Connecticut, Massachusetts, New Hampshire, and Rhode Island averaged around $50 whereas Maine REC prices were significantly less.

Figure C-4 does not include Vermont REC prices. In 2015 the Vermont legislature established an aggressive RPS requirement - 75 percent by 2032

75. Although the report examines a generic 3.9 kW-dc facility that entered service on January 1, 2015, this condition was relaxed for Illinois to allow the inclusion of the incentives provided by the Illinois Supplemental PV Procurement (ISPP) program. Had this not been done the SREC incentive calculation would have used the market prices for RECs traded in Pennsylvania because customers served by ComEd can sell their SRECs into that market. Those prices ranged from about $15 to $55 through 2015 and would have produced incentives ranging between $0.078 and $0.287 per Watt-dc. The ISPP payments are substantially more lucrative.
See: http://www.srectrade.com/srec_markets/pennsylvania

Figure C-4. REC prices in Various States - January 2010 through March 2016



Trading Month, January 2010 to March 2016

Source: Marex Spectron (2016). Plotted values are the last trade (if available) or the mid-point of Bid and Offer prices, for the current or nearest future compliance year traded in each month.

with implementation starting on January 2017. Vermont RECs can be carried forward for up to three years so retail electricity suppliers in that state may be stockpiling RECs for future use. This may be the reason why Maine REC prices suddenly jumped when the Vermont RPS was enacted, rising from less than $5 to about $35. Over time one can expect the market price of Maine RECs to equilibrate with those of other New England states (excluding perhaps New Hampshire).

To be conservative the report calculated the present value of Maine REC sales using the current $35 price. The present value of the projected revenue stream, discounted at the real, risk-adjusted interest rate, is $0.38 per Watt-dc, which amounts or about 11 percent of the solar PV facility's unsubsidized installed cost. The Maine REC was no longer available in 2016 although is included because the theoretical system was analyzed based on the incentives and conditions existing as of January 1, 2015.

MASSACHUSETTS

Massachusetts adopted an RPS target of 15 percent by 2020, which includes a carve-out for solar energy.

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The initial carve-out was for just 400 MW (the SREC-I program), which was reached in 2013. In 2014 the target was extended to 1600 MW. Projects that qualify under either program are granted SREC credits for the first 40 quarters of their solar energy production.

The generic solar PV resource examined in this report is only eligible for SRECs through the SREC-II program. To qualify under SREC-II a solar PV project:

- must be 6 MW or smaller,
- must supply some energy to an onsite load,
- must directly connect to a distribution system in Massachusetts, and
- must commence operation after December 31, 2014.

During its 40-quarter production period an owner of a qualified facility can sell its SRECs into the spot SREC market or, by June 15th of each Compliance Year an owner can deposit some (or all) of its unsold SRECs that can be applied in that Compliance Year, into the state's Solar Credit Clearinghouse Auction Account. Deposited SRECS are offered to buyers at a fixed auction price, which is $300 per MWh for 2014 - 2016 and which declines thereafter as shown below.[76]

The Solar Credit Clearinghouse Auctions are held no later than July 31st. These are "quantity-only" auctions, i.e., buyers submit bids for the quantity of SRECs they wish to purchase at the fixed price. If the auction is oversubscribed, each bidder is awarded SRECs in proportion to its share of the total bid volume. If the auction is undersubscribed the shelf life of the SRECs is increased to three years (enhancing their market value), and the auction is repeated. If the auction is still undersubscribed, the Minimum Standard for that Compliance Year is adjusted upward by the MWh quantity of the unsold and the auction is

Forward Solar Carve-Out II ACP Rate Schedule		
Compliance Year	**Auction Bid Price ($/MWh)**	**Less 5 Percent Auction Fee ($/MWh)**
2014	$300	$285
2015	$300	$285
2016	$300	$285
2017	$285	$270.75
2018	$271	$257.45
2019	$257	$244.15
2020	$244	$231.80
2021	$232	$220.40
2022	$221	$209.95
2023	$210	$199.50
2024	$199	$189.05
2025	$189	$179.55
2026	$180	$171.00
2027 and after	Added no later than January 31, 2017	

76. Five percent of the proceeds are retained for fund administration of the auction and the remainder is paid to the owners that deposited the sold SRECs.

repeated. If this third round is still undersubscribed, the sold SRECs are allocated pro rata to the owners that the deposited SRECs and their unsold SRECs are returned to them. These SRECs are eligible for application to Massachusetts Solar Carve-Out Minimum Standard in each of the next three Compliance Years.

Because the 1600 MW limit will be reached in 2016 the Solar Credit Clearinghouse Auction for Compliance Year 2017 it is unclear that the $275 floor price can be maintained after 2016. The state is working on developing a successor to the SREC-II program but no definitive information is available at this time. In light of this uncertainty the report conservatively assumes that SRECs are sold at the $285 nominal auction price in 2015 and 2016 and at a real price reflecting current REC prices in most of New England, i.e., $50, for the next eight years. Prices for 2015 and 2016 are discounted at the riskless interest rate because they are known with certainty. The prices for 2017 and beyond are discounted at the real, risk-adjusted rate to account for market price uncertainty. The present value of the projected revenue stream is $2.58 per Watt-dc, which represents about 74 percent of the solar PV facility's unsubsidized installed cost.

MICHIGAN

The Michigan RPS is 10 percent by 2015. All retail electricity suppliers in Michigan have met their obligations, primarily by purchasing RECs from wind farms; SREC purchases constitute less than 2 percent of the total.[77] Furthermore, the suppliers have procured more RECs than the RPS requires and have banked them for future application.

As part of the state's RPS compliance plan DTE Energy established "Solar Currents," a program that pays residential customers for the energy output of their solar PV facilities; however, the program was fully subscribed at the start 2015. Residential customers in the state can sell their RECs into the Ohio SREC market (or into the Pennsylvania SREC market if they are served by an AEP utility). Using the 2015 Ohio prices produced a REC value of $0.38 per Watt-dc, which represents about 11 percent of the solar facility's unsubsidized installed cost.

MINNESOTA

Minnesota's RPS is 26.5 percent by 2025, which only applies to the state's investor-owned utilities. It also includes a 0.15 percent set-aside for distributed solar PV.

In 2014 the state implemented the Solar*Rewards program, which requires Northern States Power – Minnesota to buy the SRECs of its customers with solar PV facilities that are 20 kW-dc or less and produce no more than 120 percent of the customer's onsite annual energy consumption. The purchases take place through 10-year contracts at a fixed price of 8 cents per kWh of solar production. These contract prices produced a present value of $0.79 or about 22 percent of the solar facility's unsubsidized installed cost.

The Solar*Rewards program has an annual budget of $5 million and operates on a first-come, first-served basis – but it was not fully subscribed in 2015. The program is currently scheduled to continue through 2018.

Customers participating in the Solar*Rewards program transfer all of their SRECs to the utility without additional compensation, i.e., SREC values are already embedded in the program payments. Customers that do not participate can sell their RECs at the MIRECS prices (which will roughly equal prices in the Ohio REC market); however, this option is less remunerative than participating in the Solar*Rewards program.

NEW HAMPSHIRE

New Hampshire has an RPS target of 23.8 percent to be reached by 2025, which must be satisfied by resources located within the state. In addition, it has a separate target for solar energy, which is 0.3 percent

77. Report on the Implementation of the P.A. 295 Renewable Energy Standard ad the Cost-Effectiveness of the Energy Standards, Michigan Public Service Commission, February 13, 2015.

of the retail electric energy sold after 2013. The state's Alternate Compliance Price for solar resources entering service after 2005 (Class II resources) is $55.72 in 2016 and increases annually at the CPI rate. The ACP imposes a ceiling on SREC prices.

As Figure C-4 shows, New Hampshire REC prices averaged about $52 per MWh in 2015 and the first quarter of 2016, i.e., very close to the ACP. The Class II RPS target was reached in 2014 so one can expect the supply of, and demand for, PV solar to remain in rough balance through the life of the solar panels, i.e., through 2039. Any SRECs produced in excess of the 0.3 percent target will be sold as non-thermal Class I RECs, which are subject to the same ACP as the Class II RECs. Given the 2015-2016 price performance for New Hampshire RECs one would expect future prices for Class II RECs to remain at current levels thorough 2025, then fall off rapid thereafter once the supply of these RECs no longer needs to expand to meet the demand.

To calculate the value of SRECs in New Hampshire the report assumed that market prices will remain at January 2016 levels ($52/MWh in 2016 dollars) through 2024. Because these forecasted prices are uncertain they were discounted at the real, risk-adjusted rate, producing a present value of $0.48 per Watt-dc, which is about 14 percent solar facility's unsubsidized installed cost.

NEW JERSEY

New Jersey's RPS is 20.38 percent by 2020 which includes a carve-out for solar, requiring each of its Load Serving Entities (LSEs) to provide at least 4.1 percent of the electricity delivered from solar installations located within the state by 2028. New Jersey SREC prices are determined either by their market availability subject to the ceiling prices established by New Jersey's Solar Alternative Compliance Payment (SACP). The price cap is $331 for 2014-2015 and sequentially steps down to $239 for 2027-2028.

Table C-3. 2015 – 2018 Bid Ask Prices for SRECs in New Jersey

Year	SREC Bid Price	SREC Ask Price	Bid/Ask Average Price
2015	$272.50	$280.00	$276.25
2016	$280.00	$290.00	$285.00
2017	$280.00	$290.00	$285.00
2018	$245.00	$255.00	$250.00
All prices are in nominal dollars. Source: SRECTrade Pricing Sheet, December 29, 2015.			

Table C-3 shows the bid and ask prices for 2015 and for forward market prices for 2016-2018 New Jersey SRECs listed on the SRECTrade website.

To calculate the present value of SRECs in New Jersey the report assumed that market prices would equal the average of the 2015 bid and ask prices, in real terms, for ten years. These prices did not exceed the SACP caps in any of the years and they produced a present value of $2.57 per Watt-dc, which is about 73 percent of the solar facility's unsubsidized installed cost.

NEVADA

Nevada's RPS is 20 percent by 2015 and increases to 25 percent by 2025. The state's only investor-owned utility, NV Energy, can partly satisfy its RPS obligation by acquiring Portfolio Energy Credits (PECs). One PEC is created either by generating one kWh of renewable energy or by saving one kWh through an energy efficiency measure within the state. At least 5 percent of the RPS obligation must be met with PECs created by renewable energy.

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Solar PV facilities owned and maintained by residential customers and installed before December 31, 2015 are treated differently in that they earn 2.45 PECs for each kWh of energy they produce. At the start of 2015 NV Energy was offering to pay 2.5 cents per PEC. This is the equivalent to a SREC price of $61.25 for solar PV facilities owned and maintained by residential customers. Customers receiving these payments from NV Energy must transfer ownership of their SRECs to the utility without receiving any additional compensation. Alternatively, residential customers can sell their SRECs into the WECC REC market but this option is unattractive because of WECC's low REC prices.

The NV Energy payments produced a present value of $0.36 per Watt-dc, which is about 10 percent of the solar facility's unsubsidized installed cost.

NORTH CAROLINA

North Carolina has an RPS of 12.5 percent by 2021, which applies only to its investor-owned utilities. In addition, at least 0.2 percent of this obligation must be met with RECs created by solar generation. The state's utilities can utilize RECs from out-of-state renewable resources that are registered in NC-RETS, which has the effect of depressing the going price for RECs from all resources. REC prices within the state will not exceed the prices in WECC.

Solar PV facilities located in the Dominion-North Carolina Power territory within the state can register in PJM-GATS and sell their SRECs into Pennsylvania. Because the report modeled Duke-Carolinas, whose solar customers do not have this option, the present value of their SREC sales is insignificant. However, rooftop solar owners in Duke Energy Progress' service territory in North Carolina can participate in the SunSense Residential PV program that provides both upfront and ongoing incentives that transfer the RECs to the utility and provide an incentive to the owner at a present value of $0.73 per Watt-dc, which is about 21 percent of the solar facility's installed cost.

APPENDIX C

STATE-BY-STATE SUMMARY

Table C-4 summarizes the results of the state-by-state present value calculations.

Table C-4. Incentives Provided for Residential Solar PV Through SREC Prices

State	Regional Market determining SREC Prices	Contract Prices Or Spot Market Prices	Contract Length (Years)	Present Value of SREC Revenues ($2015 per Watt-dc)	Percentage of Un-subsidized Installed Cost (Percent)
Arizona	WECC	Spot Market		< $0.01	Insignificant
California	WECC	Spot Market		< $0.01	Insignificant
Connecticut	State Auction	Contract	15	$1.07	31
Florida	NC	Spot Market		< $0.01	Insignificant
Georgia	NC	Spot Market		< $0.01	Insignificant
Illinois	ISPP	State Auction		$0.68	19
Louisiana	NC	Spot Market		< $0.01	Insignificant
Maine	New England	Spot Market		$0.38[1]	11
Massachusetts	MA	Spot Market		$2.58	74
Michigan	MI or OH	Spot Market		$0.38	11
Minnesota	Utility[2]	Contract	10	$0.79	22
Nevada	Utility[2]	Contract		$0.36	10
New Hampshire	NH	Spot Market		$0.48	14
New Jersey	NJ	Spot Market		$2.57	73
North Carolina	Utility[2]	Contract	5+	$0.73	21

1. This REC incentive was no longer available after the end of 2015 but was included in the analysis of an average theoretical system installed January 1, 2015.

2. Customers participating in utility solar programs in these states transfer their RECs to the utility without further compensation.

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