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Kentucky Conservation Committee

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Public Service Commission
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Frankfort, KY 40602-0615
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October 14, 2019

To: Public Service Commission
Reference case # 2019-00256

I am submitting comments on behalf of the Kentucky Conservation Committee, a statewide conservation nonprofit, representing approximately 600 members throughout the Commonwealth. Our organization works in partnership with other nonprofits to provide legislative assistance on environmental and conservation issues. The valuation of solar through net metering is an issue of great interest to many of the organizations we work with and represent.

In the order establishing the case, it was stated that the PSC would use these comments to develop a record that will be incorporated into the initial rate proceedings filed by utilities. The final order in this case will include a report summarizing the information received. We understand that each utility's new net metering rate will be established based on its particular circumstances.

Kentucky established its net metering rules in 20044, with the intent of spurring investment in what was, at that time, an emerging market, with a built-in "cap" once the market reaches 1% penetration. Reaching this 1% we believe would provide a bare minimum of data in order to fairly assess the impact of distributed solar.

Net metering provides an easy to understand set of rules that allows customers to make investments on their property to control their energy costs, just as they do when investing in energy efficiency retrofits to their homes. Investing in distributed solar gives consumers the freedom to reduce their own energy liability, benefiting customers at all income levels, particularly those on fixed incomes who are trying to stabilize their energy costs. We find that the new law creates a confusing set of rules that undermines customer choice as they consider ownership of solar power. It replaces an easy to understand system with a complicated one that we believe will depress consumer adoption of distributed solar. It is now up to the PSC to provide guidance that is fair to customers, without depressing an important market or creating limits on consumer choice to invest in their own ability to regulate their personal power costs.

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Comparative Studies:

We wish to provide the following studies from other states that have wrestled with this same question. We advise the PSC to consider the range of both costs and benefits considered in these studies:

Arkansas

Beach, R., and P. McGuire. 2017. *The Benefits and Costs of Net Metering Solar Distributed Generation on the System of Entergy Arkansas, Inc.* Crossborder Energy. Available at https://drive.google.com/file/d/0BzTHARzy2TINbHViTmRsM2VCQUU/view.

This study concluded that the benefits of distributed solar equal or exceed the costs of total resources, program administrator costs, and societal costs, and that Distributed Generation does not create a burden on other ratepayers.

Mississippi

Stanton, E.; J. Daniel; T. Vitolo; P. Knight; D. White; and G. Keith. 2014. *Net Metering in Mississippi: Costs, Benefits, and Policy Considerations.* Cambridge, MA: Synapse Energy Economics, Inc. Available at https://www.synapse-energy.com/sites/default/files/Net%20Metering%20in%20Mississippi.pdf.

The report concludes "net metering provides net benefits under almost all of the scenarios and sensitivities analyzed."

Nevada

Price, S.; Z. Ming; A. Ong; and S. Grant. 2016. *Nevada Net Energy Metering Impacts Evaluation 2016 Update.* San Francisco, CA: Energy and Environmental Economics, Inc. Available at http://pucweb1.state.nv.us/PDF/AxImages/DOCKETS_2015_THRU_PRESENT/2016-8/14264.pdf.

South Carolina

Patel, K.; Z. Ming; D. Allen; K. Chawla; and L. Lavin. 2015. *South Carolina Act 236: Cost Shift and Cost of Service Analysis.* San Francisco, CA: Energy and Economics, Inc. Available at https://regulatorystaff.sc.gov/sites/default/files/Documents/Regulatory/electricNaturalGas/Electricity/Act%20236%20Cost%20Shifting%20Report.pdf

This report primarily focused on the question of "cost shifting" using several different scenarios and concluded that NEM-related cost –shifting was de minimus due to the low number of participants.

Vermont

Vermont Public Service Department (PSD). 2014. *Evaluation of Net Metering in Vermont Conducted Pursuant to Act 99 of 2014.* Available at http://publicservice.vermont.gov/sites/dps/files/documents/Renewable_Energy/Net_Metering/Act%2099%20NM%20Study%20FINAL.pdf.

Respectfully submitted,

Lane E. Boldman

Lane E. Boldman,
Kentucky Conservation Committee Executive Director

Net Metering in Mississippi

Costs, Benefits, and Policy Considerations

Prepared for the Public Service Commission of Mississippi

September 19, 2014

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CONTENTS

1. EXECUTIVE SUMMARY

At its December 7, 2010 Open Meeting, the Mississippi Public Service Commission voted to open docket 2011-AD-2 in order to investigate establishing and implementing net metering and interconnection standards for Mississippi. Mississippi is one of only a few states that do not have some sort of net metering policy for their distribution companies.[1] In this report we describe a potential net metering policy for Mississippi and the issues surrounding it, focusing on residential and commercial rooftop solar.

Two vertically integrated investor-owned utilities serve customers in Mississippi: Entergy Mississippi and Mississippi Power. The Tennessee Valley Authority, a not-for-profit corporation owned by the United States government, owns generation and transmission assets within the state. Many Mississippi customers are served by electric power associations, including South Mississippi Electric Power Association, a generation and transmission cooperative, and the 25 distribution co-ops. These entities rely primarily on three resources for electric generation: natural gas, coal, and nuclear power. About 3 percent of generation is attributable to wood and wood-derived fuels. Less than 0.01 percent of Mississippians participated in distributed generation in 2013. We modeled and analyzed the impacts of installing rooftop solar in Mississippi equivalent to 0.5 percent of the state's peak historical demand with the goal of estimating the potential benefits and potential costs of a hypothetical net metering program.

Highlights of analysis and findings:

- Generation from rooftop solar panels in Mississippi will most likely displace generation from the state's peaking resources—oil and natural gas combustion turbines.
- Distributed solar is expected to avoid costs associated with energy generation costs, future capacity investments, line losses over the transmission and distribution system, future investments in the transmission and distribution system, environmental compliance costs, and costs associated with risk.
- Distributed solar will also impose new costs, including the costs associated with buying and installing rooftop solar (borne by the host of the solar panels) and the costs associated with managing and administering a net metering program.
- Of the three cost-effectiveness tests used for energy efficiency in Mississippi—the Total Resource Cost (TRC) test, the Rate Impact Measure, and the Utility Cost Test—the TRC test best reflects and accounts for the benefits associated with distributed generation.
- Net metering provides net benefits (benefit-cost ratio above 1.0) under almost all of the scenarios and sensitivities analyzed, as shown in ES Table 1.

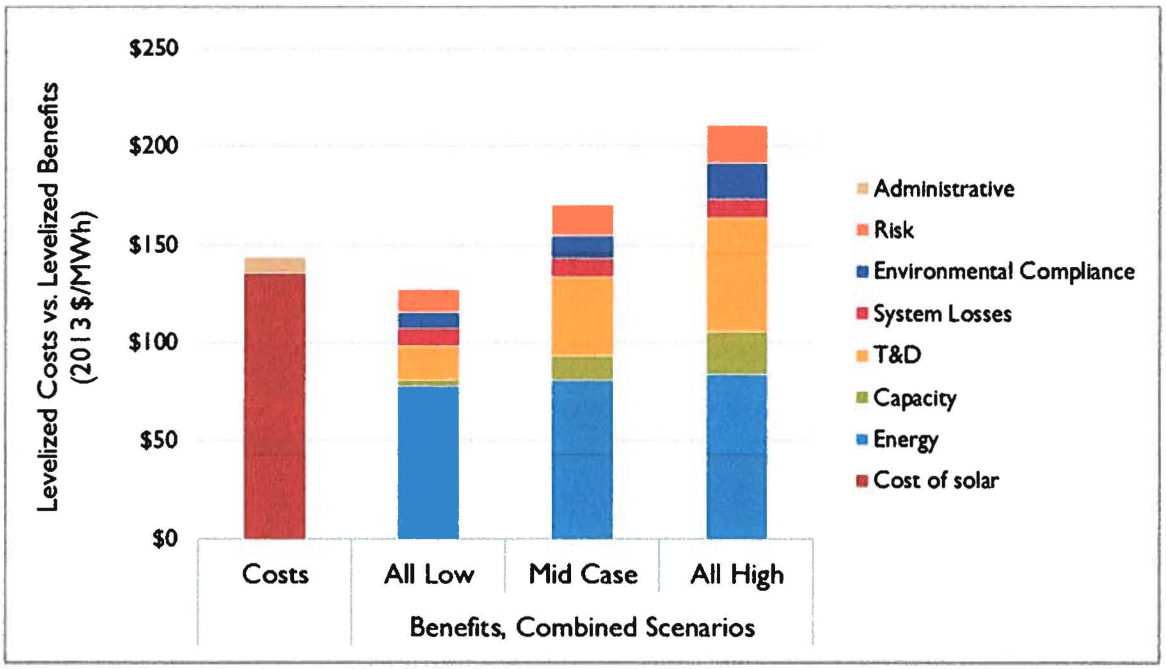
[1] Other states that do not have a net metering policy: Idaho, South Dakota, Texas, Alabama, and Tennessee.

ES Table 1. Summation of TRC Test benefit/cost ratios under various sensitivities

	Low	Mid	High
Fuel Price Scenario	1.17	1.19	1.21
Capacity Value Sensitivities	1.11	1.19	1.26
Avoided T&D Sensitivities	1.01	1.19	1.32
CO_2 Price Sensitivities	1.16	1.19	1.24
Combined Scenarios	0.89	1.19	1.47

- To determine the widest range of possible benefits, our analysis included combined scenarios in which all of the inputs were selected to yield the highest possible benefits (in the All High scenario) and the lowest possible benefits (All Low); the All Low scenario was the only scenario or sensitivity that did not pass the TRC test (see ES Figure 1).

ES Figure 1. Results of scenario testing under combined scenarios



- Distributed solar has the potential to result in a downward pressure on rates.
- Distributed solar provides benefits to hosts in the form of reduced energy bills; however, the host pays for the panels and if the reduced energy bills do not offset these costs, it is unlikely that distributed solar will achieve significant adoption within the state.
- If net metered customers are compensated at the variable retail rate in Mississippi, it is unlikely they will be able to finance rooftop solar installations.

2. BACKGROUND CONTEXT

2.1. What is Net Metering?

Net metering is a financial incentive to owners or leasers of distributed energy resources. Customers develop their own energy generation resources and receive a payment or an energy credit from their distribution company for doing so. Mississippi is one of only a few states that do not have some sort of net metering policy for their distribution companies (voluntary or otherwise).[2] In addition to presenting results of a cost-benefit analysis of net metering in Mississippi, this report describes some of the key issues that may be contested in the development of a net metering policy for Mississippi.

In our description of net metering and the issues surrounding it, we focus on residential and commercial rooftop solar.

Why Net Metering?

Net metering provides customers with a payment for electricity generation from their distributed generation resources. Distributed generation provides benefits to its host and to all ratepayers. Valuation of these benefits, however, has proven contentious. This section discusses issues in calculating costs avoided by distributed generation, as well as some additional difficult-to-monetize benefits: freedom of energy choice, grid resiliency, risk mitigation, and fuel diversity.

Avoided Costs

The term "avoided costs" refers to costs that would be borne by the distribution company and passed on to ratepayers were it not for distributed generation or energy efficiency (or other alternative resources). Avoiding these costs is a benefit to both ratepayers and distribution companies. Under the Public Utility Regulatory Policy Act (PURPA), utilities and commissions already go through the process of calculating avoided costs associated with generation from qualified facilities. As a result, the incremental costs associated with calculating avoided costs for net metering facilities is small. We provide a review of the avoided cost and screening tests already used in Mississippi below.

A variety of methods have been used to calculate avoided costs. Estimation of system benefits can be difficult and costly, and small changes in assumptions can sometimes dominate benefit-cost results. Avoided cost estimation methods range from:

- Adoption of the simple assumptions that (a) a single type of power plant is on the margin in all hours of the day and (b) distributed generation has no potential for offsetting or postponing capital expenses; to

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[2] Other states that do not have a net metering policy: Idaho, South Dakota, Texas, Alabama, and Tennessee.

- The rigorous modeling of production costs using hourly dispatch of all units in a region and capacity expansion over long time horizons. This method requires development of distributive generation load shapes (patterns of generation over the day and year) for present and future years, energy and capacity demands for the region, expected environmental regulations and their respective compliance costs, and projections for commodity prices such as natural gas and coal.

Table 1 provides a list of avoided costs from distributed generation facilities that have been analyzed in other studies. The appropriate avoided costs to include in a benefit-cost analysis depend on state- and distribution-company-specific factors.

Table 1. List of potential costs avoided by distributed generation

Avoided Costs	Description
Avoided Energy	All fuel, variable operation and maintenance emission allowance costs and any wheeling charges associated with the marginal unit
Avoided Capacity	Contribution of distributed generation to deferring the addition of capacity resources, including those resources needed to maintain capacity reserve requirements
Avoided Transmission and Distribution Capacity	Contribution to deferring the addition of transmission and distribution resources needs to serve load pockets, far reaching resources, or elsewhere
Avoided System Losses	Preventing energy lost over the transmission and distribution lines to get from centralized generation resources to load
Avoided RPS Compliance	Reduced payments to comply with state renewable energy portfolio standards
Avoided Environmental Compliance Costs	Avoided costs associated with marginal unit complying with various existing and commonly expected environmental regulations, including pending CO_2 regulations
Market Price Suppression Effects	Price effect caused by the introduction of new supply on energy and capacity markets
Avoided Risk (e.g., reduced price volatility)	Reduction in risk associated with price volatility and/or project development risk
Avoided Grid Support Services	Contribution to reduced or deferred costs associated with grid support (aka ancillary) services including voltage control and reactive supply
Avoided Outages Costs	Estimated cost of power interruptions that may be avoided by distributed generation systems that are still able to operate during outages
Non-Energy Benefits	Includes a wide range of benefits not associated with energy delivery, may include increased customer satisfaction and fewer service complaints

Distributed energy avoids costs related to energy generation and future capital additions, as well as transmission and distribution load losses and future capital expenditures, especially in pockets of concentrated load. Net metering may also result in some additional transmission and distribution expenses where the excess generation is significant enough to require upgrades. Because distributed generation occurs at the load source, a share of transmission and distribution line losses also may be avoided. In states with Renewable Portfolio Standard (RPS) goals set as a percent of retail sales, distributed generation reduces the RPS requirement and associated costs.

Generation from distributed energy resources also results in price suppression effects in the energy and capacity markets (where applicable). As a recent addition to MISO, Entergy will participate in future MISO capacity and energy markets and may therefore experience a price suppression effect from net metering.

In 2013, Mississippi's electricity generation was 60 percent natural gas, 21 percent nuclear, 16 percent coal, and 3 percent biomass and others.[3] Maintaining a diverse mix of generation resources protects ratepayers against a variety of risks including fuel price volatility, change in average fuel prices over time, uncertainties in resource construction costs, and the costs of complying with new environmental regulations. In Mississippi, increased electric generation from solar, wind, or waste-to-energy projects would represent an improvement in resource diversity, thereby lowering these potentially costly risks.

Other costs that may be avoided by integrating distributed generation onto the grid have not been as rigorously studied or quantified. For example, distributed generation may contribute to reduced or deferred costs associated with ancillary services, including voltage control and reactive supply. It may also reduce lost load hours during power interruptions and costs associated with restoring power after outages, including the administrative costs of handling complaints. Allowing for and assisting in the adoption of distributed generation may increase customer satisfaction and result in fewer service complaints, both of which are in energy providers' best interest.

Additional Benefits

Grid resiliency

Grid resiliency reduces the amount of time customers go without power due to unplanned outages. Resiliency may be achieved with: major generation, transmission, and distribution upgrades; load reductions from distributed generation and energy efficiency; and new technologies, such as smart meters that allow for real-time data to be relayed back to grid operators. Distributed generation may also improve grid resiliency to the extent that it is installed in conjunction with "micro-grids" that have the capacity to "island."[4] Valuing grid resiliency as a benefit is sometimes done using a "value of lost

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[3] U.S. Energy Information Administration (EIA). 2013. *Form 923*.

[4] A micro-grid is a group of interconnected loads and distributed energy resources within clearly defined electrical boundaries that act as a single controllable entity with respect to the grid. A micro-grid can connect and disconnect from the grid to enable it to operate fully connected to the grid or to separate a portion of load and generation from the rest of the grid system. To learn more about the micro-grid, Synapse recommends these documents as primers:
http://energy.gov/sites/prod/files/2012%20Microgrid%20Workshop%20Report%2009102012.pdf
http://energy.pace.edu/sites/default/files/publications/Community%20Microgrids%20Report%20(2).pdf
http://nyssmartgrid.com/wp-content/uploads/Microgrid_Primer_v18-09-06-2013.pdf

load" to determine how much customers would be willing to pay to avoid disruption to their electric service (discussed later in this report).

Freedom of energy choice

The "right to self-generate" or the freedom to reduce energy use, choose energy sources, and connect to the grid is sometimes cited as a benefit of distributed generation. Some supporters of freedom of energy choice assert that any barrier to self-generation is an infringement of rights. Others take the position that customers have no right to self-generate unless they are disconnected from the grid.

Implementing a Net Metering Policy

States have made a variety of choices regarding several technical net metering issues that may have important impacts on costs to ratepayers. The technical issues discussed in this section are metering, treatment of "behind-the-meter" generation, treatment of net excess generation, third-party ownership, limits to installation sizes, caps to net metering penetration, "neighborhood" or "community" net metering, virtual net metering, distribution company revenue recovery, and the value of solar tariff.

Metering

Distributed generation resources are metered in one of three ways, depending on state requirements:

1. For customers with an electric meter that can "roll" forwards or backwards (measuring both electricity taken from the grid and electricity exported to the grid), distribution companies track only net consumption or generation of energy in a given billing cycle. Excess generation in some hours offsets consumption in other hours. If generation exceeds consumption within a billing cycle, the customer is a net energy producer. Because generation from some net metered facilities (particularly renewables) is subject to variability on hourly, monthly, and annual time scales, generation may exceed consumption in some months but be less than consumption in others. Distribution companies' data on net consumption or production are limited by the frequency at which meters are monitored.

2. More advanced "smart" meters log moment-by-moment net consumption or generation at each customer site. With this type of meter, distribution companies may pay customers for excess generation using different rates for different hours.

3. Net metering facilities may also be installed with two separate meters: one for total electricity generation and one for total electricity consumption. Metered generation may be bought at a pre-determined tariff rate while consumption is billed at the retail rate. It is also common to have a second meter installed for tracking solar generation for Solar Renewable Energy Credit (REC) tracking.

Treatment of "Behind-the-Meter" Generation

Net metered systems are typically attached to a host site, which has a load (and meter) associated with it. During daylight hours on a net metered solar system:

1. The host site's load may exceed or be exactly equal to generation. In these hours, solar generation is entirely "behind the meter." From the distribution company's perspective, the effect of this generation is a reduction in retail sales (see Figure 1).

2. Generation may exceed the host site's load. In these hours, solar generation is exported onto the grid. From the distribution company's perspective, the effect of this generation is both a reduction in retail sales and an addition to generation resources (see Figure 2).

Figure 1. Illustrative example of net metered facility with demand greater than generation

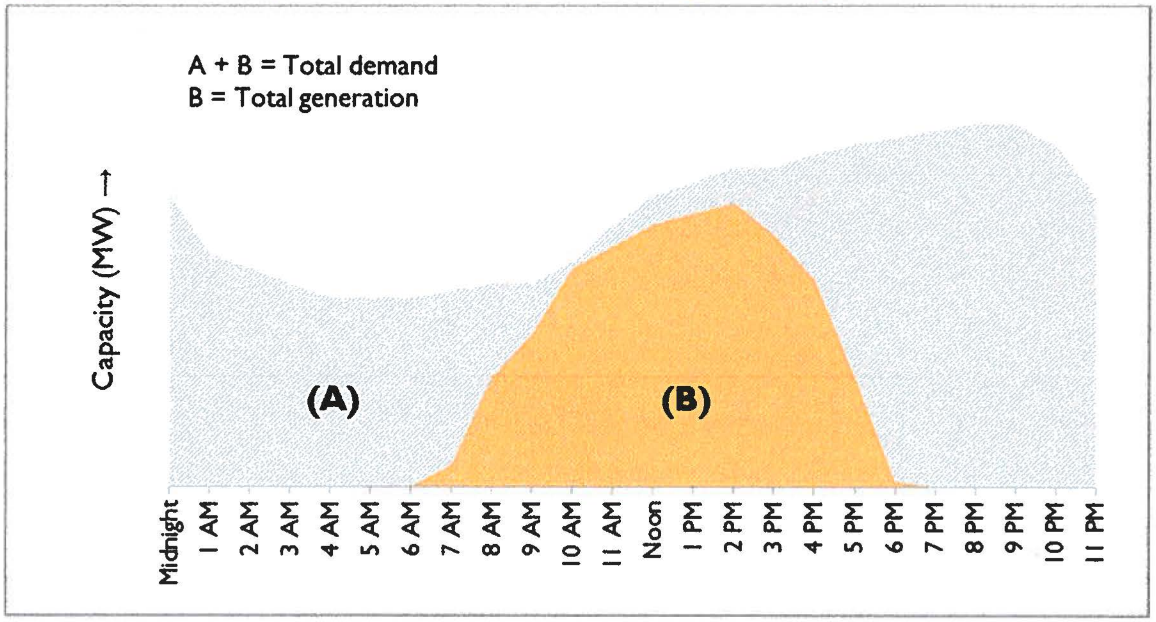
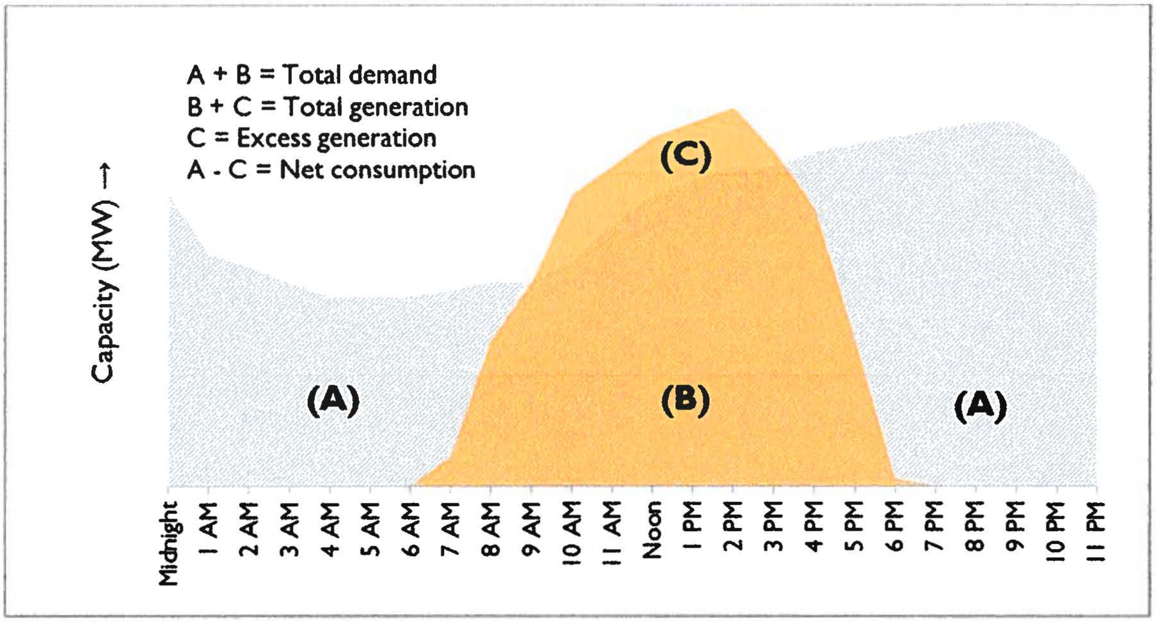


Figure 2. Illustrative example of net metered facility with excess generation



Typically, generation is considered behind the meter up to the point where a host load is exactly equal to generation when summed over a typical billing period. Systems that are designed to accomplish this are called Zero Net Energy Systems. While these systems, summed over the billing cycle, do not produce any net excess generation, they do produce excess generation during some hours of the day and do, therefore, utilize the grid.

Treatment of Net Excess Generation

Net excess generation is the portion of generation that exceeds the host's load in a given billing period. Some distributed resources (such as solar panels) will have net excess generation in some billing periods but require net electricity sales from the distribution company in other periods. Host sites receive payment for their net excess generation, but the value placed on this generation differs from state to state. Participants are compensated for net excess generation in various ways. Examples of ways in which participants are compensated include:

- receiving the full retail rate as a credit on their monthly bill; these credits can roll over to future bills indefinitely
- receiving the full retail rate as a credit on their monthly bill; these credits can roll over to future bills but for some finite period (typically one year) at which point they expire
- receiving the full retail rate as a credit on their monthly bill; these credits can roll over to future bills indefinitely or the customer can choose to be paid out at the avoided cost rate

- receiving a pre-determined rate (typically the avoided cost rate) as a credit on their monthly bill; these credits can roll over to future bills for a finite period (typically one year) at which point they expire
- receiving a pre-determined rate as a credit on their monthly bill, but with no set guarantee for how long they can roll over
- receiving no payment at all

Third-Party Ownership

Third-party financing is the practice by which the host of the distributed energy system does not pay the upfront costs to install the system and instead enters into a contract with a third party who owns the system.[5] Often structured through a power purchase agreement (PPA) or lease, third-party financing may increase access to distributed generation for households without access to other financing, or to public entities that want to offset their electric bills with solar but cannot benefit from state or federal tax incentives. With a PPA, the distributed generation is installed on the customer's property by the developer at no cost to the customer. The customer and the developer enter into an agreement in which the customer purchases the energy generated by the solar panels at a fixed rate, typically below the local retail rate. The distribution company experiences a reduction in retail sales but is not otherwise involved. (Note that some municipal owned generators ("munis") and electric co-ops do not allow net metering to be structured under a PPA with a third party.) With a solar lease, the customer enters into a long-term contract to lease the solar panels themselves, offsetting energy purchases and receiving payment from the distribution company for excess net generation.

Contract language to address issues such as responsibility for maintenance, ownership of renewable energy credits (RECs), and the risk for legislative or utility commission disallowance has been an area of concern in some states. In the PPA structure, the developer takes on some of the responsibilities of a provider and may need to be regulated by a public commission.

Limits to Installation Sizes

Most states have imposed limits on the size of installations eligible for net metering, often with different limits for different customer classes, or for private versus public installations. Limits may be set in absolute terms (a specific kW capacity limit) or as a percentage of historical peak load of the host site. In some states, the *de facto* limit is actually smaller than the official limit because the size of the installation is determined by policies other than net metering. For example, in Louisiana the legal limit to

[5] The National Renewable Energy Laboratory put together an extensive report outlining third-party PPAs and leasing: http://www.nrel.gov/docs/fy10osti/46723.pdf.

installations is 25 kW, but most installations are smaller than 6 kW due to a 50 percent tax rebate on solar installations 6 kW or smaller.[6]

Caps to Net Metering Penetration

In most states, there are limits to how much net metered generation is allowed on the grid. Net metering caps are commonly calculated as a share of each distribution company's peak capacity. Munis and co-ops may or may not be subject to the same caps as utilities. To the extent that new investments in transmission and distribution may be necessary with large-scale penetration of distributed generation, net metering caps keep the actual installation of distributed resources in line with the planned roll out.

"Neighborhood" or "Community" Net Metering

Where neighborhood or community net metering is permitted, groups of residential customers pool their resources to invest in a distributed generation system and jointly receive benefits from the system. The system may be installed in a nearby parcel of land or on private property within the neighborhood development. Multiple customers each invest a portion of the costs of installing the net metered facility and each receive a proportional amount of the energy credits based on their respective investment. Neighborhood net metering may make it possible for lower-income communities or renters to invest in renewable technologies that would otherwise be cost prohibitive.

Virtual Net Metering

Virtual net metering allows development of a net metered facility that is not on a piece of land contiguous to the host's historical load. The legal definition of virtual net metering differs from state to state. The energy generated at the remote site is then "netted" against the customers' monthly bill. Virtual net metering may permit customers to take advantage of economies of scale, but there is disagreement regarding how to differentiate a virtual net metering arrangement from a PURPA-regulated generator.

Distribution Company Revenue Recovery

Only one state, Hawaii, currently has solar capacity in excess of 5 percent of total capacity. In Hawaii, solar represents 6.7 percent of total capacity; in New Jersey, 4.7 percent; in California, 2.7 percent; and in Massachusetts, 2.3 percent. All other states have significantly less solar capacity as a share of total capacity.[7] Nonetheless, stakeholders in a number of states have begun drafting proposed legislation for special monthly fixed charges, rate classes, and/or tariffs for solar net metered projects. Supporters of

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[6] Owens, D. 2014. "One Regulated Utility's Perspective on Distributed Generation." Presented at the 2014 Southeast Power Summit, March 18, 2014.

[7] National Renewable Energy Laboratory. "The Open PV Project." Accessed June 3, 2014. Available at: openpv.nrel.gov. Supplemented with Synapse research (see Table 4 of this report).

the solar-specific fixed charges and rate classes argue that these policies help prevent shifting costs from those participating in net metering to those not participating. Special charges and rates may have the effect of discouraging solar net metered development by increasing the cost and complexity of net metering arrangements.

Value of Solar Tariff

A feed-in tariff or a value-of-solar tariff is subtly different from net metering. Feed-in tariffs are fixed rate payments made to solar generators. The tariff amount is predetermined in dollars per kilowatt-hour and is typically valid for a fixed length of time. In states that have a solar feed-in tariff (such as Minnesota and Tennessee), solar generation is metered separately from the host's demand. The host gets paid for all electricity generated by the solar panels at the tariff rate and pays for all the electricity consumed at the retail rate. Concerns raised regarding feed-in tariffs for distributed generation include the host's tax liability and the need for periodic changes to the value of solar. Tariffs have the potential to create stability in the financial forecasts for resource technologies, thereby lowering costs.

Rate Design Issues

Net metering raises several rate design issues related to cost sharing. In this section, we discuss cross-subsidization and fairness to distribution companies.

Cross-Subsidization

Situations in which one group of people pays more for a good or service while a different group of people pays less (or gets paid) for some related good or service are referred to as "cross-subsidization." In situations of regressive cross-subsidization, a lower income group pays more per unit of service and a higher income group pays less per unit of service. Utility rate design and implementation are fraught with opportunities for cross-subsidization. There are three main ways that net metering can potentially act as a cross-subsidy: credit for compliance with renewable energy goals; federal tax subsidies; and cost shifting in rate making.

Compliance with renewable energy goals

Most U.S. states have renewable energy goals or incentives. To meet their renewable energy goals, energy providers pay renewable credits or certificates in addition to the wholesale price of energy. Where net metered renewable facilities are eligible for these payments, there is a possibility of cross-subsidization. Since Mississippi does not have an RPS, tariff payments for renewables, or state tax incentives for renewable energy, renewable energy incentives are not a likely pathway for cross-subsidization in the state.

Federal tax subsidies

The federal government currently offers investment tax credits (ITC) for wind, solar, and other renewable energy resources. A small share of Mississippians' federal income taxes, therefore, subsidizes renewable energy generation. Given the relative lack of renewable energy development within the state, it is unlikely that the state is receiving its full share of federal funds for renewable energy development, and possible that Mississippians are cross-subsidizing renewable energy generation (at a very small scale) in California, New Jersey, Massachusetts, and other states with relatively more renewable energy development.

Cost shifting in rate making

Distributed generation reduces distribution companies' total energy sales. With lower sales, distribution companies' fixed costs are spread across fewer kilowatt-hours. The effect is a higher price charged for each kilowatt-hour sold. These costs are offset—at least in part—by the benefits that distributed generation provides to the grid and to other ratepayers (as discussed above in the Avoided Costs section of this memo). If all avoided costs are accurately and appropriately accounted for and the consumers are paid an avoided cost rate, then there is no cost shifting because the costs to non-participants (those customers without distributed generation) are equal to the benefits to non-participants. From a social equity standpoint, this is important because net metering customers may have higher than average incomes.[8] Net metering customers should be paid for the value of their distributed generation, but non-participants should not bear an undue burden as a consequence of net metering. One strategy to help mitigate the impact of cost shifting is to create opportunities for all income classes to participate in net metering; this is sometimes achieved through community solar projects.

Fairness to Distribution Companies

Mississippi's distribution companies reliably provide electricity to customers and are entitled to recover a return on their investments. Policies that undermine their financial solvency have the potential to put reliable electric generation and distribution at risk.

Reducing distribution company revenues

Distributed generation resources are sometimes viewed as being in competition with providers because they reduce retail sales and, therefore, reduce distribution companies' revenues. Reduced sales will eventually cause providers to apply for rate increases so that they can recoup their expenses over the new (lower) projected sales forecast. Higher electric rates make distributed energy and energy efficiency a better investment, and may lead to deeper penetration of these resources, further reducing retail sales. This feedback scenario has become known as the "utility death spiral." Arguments are made both that net metering (together with energy efficiency) may put providers out of business, and that the effect of net metering on providers' revenues is actually negligible. Distributed generation's share of

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[8] Langheim, R., et. al. 2014. "Energy Efficiency Motivations and Actions of California Solar Homeowners." Presented at the ACEE 2014 Sumer Study on Energy Efficiency in Buildings. August 17-22, 2014. Available at: http://energycenter.org/sites/default/files/docs/nav/policy/research-and-reports/Energy%20Efficiency%20Motivations%20and%20Actions%20of%20California%20Solar%20Homeowners.pdf. See also: Hernandez, M. 2013. "Solar Power to the People: The Rise of Rooftop Solar Among the Middle Class." Center for American Progress. October 21, 2013. Available at: http://www.americanprogress.org/issues/green/report/2013/10/21/76013/solar-power-to-the-people-the-rise-of-rooftop-solar-among-the-middle-class/

total generation is a key factor in understanding these impacts. Mississippi had less than 0.01 percent of its customers participate in distributed generation in 2013.[9]

Increasing distribution company costs

Distributed generation also has the potential to reduce distribution companies' revenues by increasing costs. The argument that net metered facilities impose costs when providers are forced to plan for and manage excess generation, again, depends on the share of distributed generation resources out of total generation or the concentration of distributed resources in small, local areas. The share of distributed generation necessary to impose additional costs on a provider likely depends on a number of factors including (but not limited to) transmission and distribution infrastructure, the aggregate and individual capacity of solar installations, local energy demand, and the demand load shape over the day and the year.

Another potential cost issue for providers is the safety risk that rooftop solar panels may pose to utility line workers. This is primarily a design and permitting issue: in the absence of the proper controls, a utility worker could get electrocuted by excess generated from the solar panels.

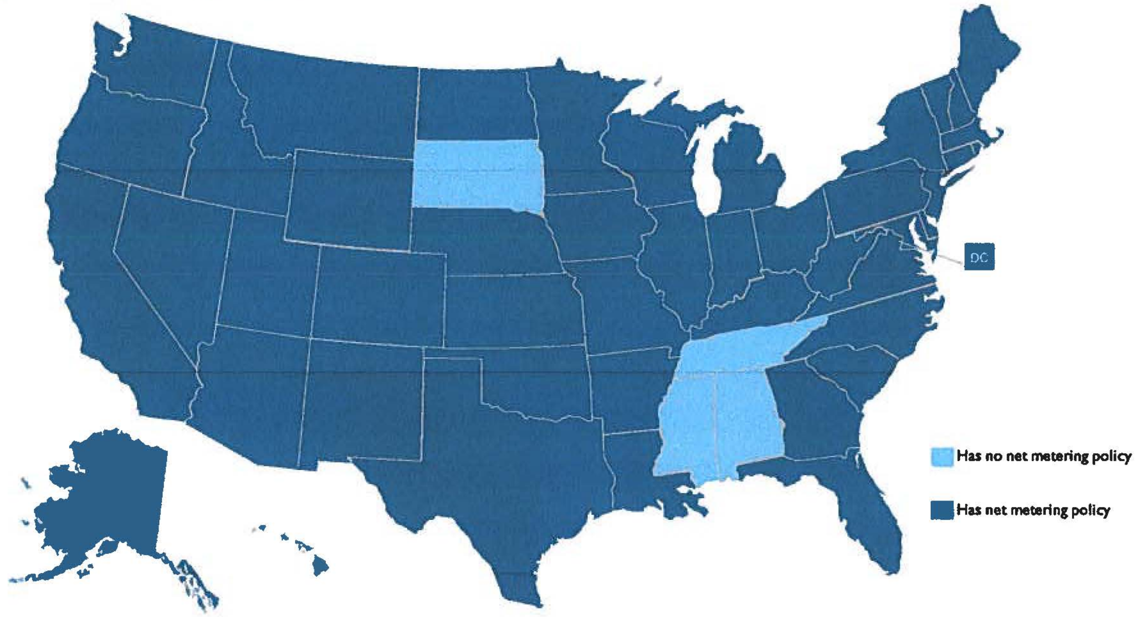
2.2. Regional Context

Net Metering in the Region

As shown in Figure 3, as of July 2013 net metering policies had been implemented in 46 states and the District of Columbia. Mississippi is one of four states that does not currently have any net metering policies in place. The active docket to investigate establishing and implementing net metering and interconnection standards for Mississippi is discussed below. Of those states immediately bordering Mississippi, Louisiana and Arkansas have net metering policies, while Tennessee and Alabama do not.

[9] Wesoff, E. 2014. "How Much Solar Can HECO and Oahu's Grid Really Handle?" *Greentech Media*. Available at: http://www.greentechmedia.com/articles/read/How-Much-Solar-Can-HECO-and-Oahus-Grid-Really-Handle

Figure 3. Net metering policy by state



Source: IREC and Vote Solar "Freeing the Grid" (2013, www.freeingthegrid.com)

The net metering policies of Louisiana and Arkansas are very similar: both states feature a 300 kW maximum capacity for non-residential customers and a 25 kW maximum for residential customers. There is a 0.5 percent aggregate capacity limit in Louisiana,[10] and net metered generators are compensated at the retail rate with excess carried over indefinitely. There is no policy in Louisiana regarding ownership of RECs sold to other states. Arkansas' net metering customers face no aggregate capacity limit, and while excess generation can be carried over indefinitely, only a limited quantity of carry-over is allowed. Arkansas' net metering payments are at the retail rate, and the customer retains ownership of any RECs generated by the net metered facility.

Mississippi Docket 2011-AD-2

At its December 7, 2010 Open Meeting, the Mississippi Public Service Commission voted to open docket 2011-AD-2 in order to investigate establishing and implementing net metering and interconnection standards for Mississippi. The Commission has called for a three-phase proceeding:

1. Identify specific issues that should be addressed in the rule and what procedures should be used to solicit input from interested parties;
2. If the Commission chooses to proceed, develop a Proposed Rule; and finally,
3. Use traditional rulemaking procedures to establish net metering process, eligibility, and rates.

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[10] Entergy New Orleans has no aggregate capacity limit.

All three phases allow for interveners.

Renewable Energy Policies in the Region

States pursue a variety of channels to encourage increased renewable energy generation. Perhaps the most commonly discussed state-level renewable energy policy is the RPS, a policy that requires distribution companies within the state to procure an increasing number of RECs, inducing a demand for renewably generated energy. While 29 states, 2 territories, and the District of Columbia have binding RPS policies in place and an additional 7 states have formal, non-binding RPS goals, neither Mississippi nor any of its 4 surrounding states have such a policy. Louisiana has implemented a Renewable Energy Pilot Program to study whether a RPS is suitable for Louisiana.

The Tennessee Valley Authority (TVA), operating in nearly all of Tennessee and smaller portions of Mississippi, Alabama, Georgia, North Carolina, and Kentucky, does not have an RPS policy but does have a number of policies to encourage the procurement of renewably generated electricity, including TVA Green Power Providers, a feed-in tariff 20-year contract that pays generators an above-market price for energy. TVA's Green Power Providers program offers customers of TVA and participating munis and co-ops within the TVA corporation's territory the opportunity to enter into a 20-year purchase agreement for distributed, small-scale renewably generated electricity. Eligible residential and non-residential customers can install solar, wind, biomass, or hydro generators sized between 0.5 kW and 50 kW, subject to the additional size constraint that the expected annual generation does not exceed the expected demand of the customer at that site. TVA will pay the customer's retail rate for the generated electricity, plus an additional 3-4 cents per kWh for the first 10 years of the contract.[11] There are 18 distributor participants in Alabama, 14 in Georgia, 18 in Mississippi, 3 in North Carolina, 78 in Tennessee, and 1 in Virginia.[12]

There are a number of tax benefits available for renewable generation installations in the region, including both corporate and personal tax credits and property tax incentives in Louisiana for solar installations; property and sales tax incentives for installing wind, solar, biomass, and geothermal generators in Tennessee; and tax subsidies for switching from gas or electric to wood-fueled space heating in Alabama. Large tax incentives and government loans exist for the siting of substantial renewable generator manufacturing facilities in Mississippi, Arkansas, and Tennessee.

Subsidized loans are another common renewable policy mechanism, allowing for favorable lending conditions for the purchase and installation of renewable generation. Louisiana lends money to residential customers, and Alabama and Mississippi lend to commercial, industrial, and institutional customers. Alabama also lends to local municipalities, and Arkansas lends to a variety of customers.

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[11] Tennessee Valley Authority. 2014. "2014 Green Power Providers (GPP) Update." Available at: http://www.tva.com/greenpowerswitch/providers/.

[12] Tennessee Valley Authority. 2014. "Green Power Providers Participating Power Companies." Available at: http://www.tva.com/greenpowerswitch/providers/distributors.htm.

Table 2 summarizes the region's renewable energy policies.

Table 2. Renewable policies by state

Policy	LA	AR	TN	AL	MS
Renewable Portfolio Standard					
Feed-In Tariff			✓	✓ TVA	✓ TVA
Tax Incentives	✓		✓		✓
Incentives for Manufacturing		✓	✓		✓
Subsidized Loans	✓	✓		✓	✓

Solar Installations by State

Tracking all solar photovoltaic installations by state is not a simple exercise, though a variety of sources attempt to measure capacity installed. This report relies on *U.S. Solar Market Trends 2012*,[13] with the results detailed in Table 3. According to this source, in 2012, Mississippi installed 0.1 MW of solar photovoltaic capacity, which brought total capacity installed to 0.7 MW.

Table 3. Installed solar photovoltaic capacity by state

	Incremental Installed Capacity, 2012 (MW)	Cumulative Capacity Installed through 2012 (MW)
Louisiana	11.9	18.2
Arkansas	0.6	1.5
Tennessee	23.0	45.0
Alabama	0.6	1.1
Mississippi	0.1	0.7

2.3. Avoided Cost and Screening Tests Used in Mississippi

There is a precedent in Mississippi for using particular avoided cost and screening tests that may be relevant to the quantification of the state's avoided costs of net metering. The July 2013 Final Order from Mississippi Docket No. 2010-AD-2 added Rule 29 to the Public Utility Rules of Practice and Procedure related to Conservation and Energy Efficiency Programs, the purpose of which "is to promote the *efficient* use of electricity and natural gas by implementing energy efficiency programs and

[13] Sherwood, L. 2013. *U.S. Solar Market Trends 2012*. Interstate Renewable Energy Council. Appendix C.

standards in Mississippi."[14] Section 105 of Rule 29 specifies the cost-benefit tests to be used when assessing all energy efficiency programs. There are four tests used within the context of Rule 29.[15]

- The Total Resource Cost (TRC) test determines if the total costs of energy in the utility service territory will decrease. In addition to including all the costs and benefits of the Program Administrator Cost (PAC) test (described below), it also includes the benefits and costs to the participant. One advantage of the TRC test is that the full incremental cost of the efficiency measure is included, because both the portion paid by the utility and the portion paid by the consumer is included.

- The Program Administrator Cost (PAC) test, also known as the Utility Cost Test (UCT), determines if the cost to the utility administrator will increase. This test includes all the energy efficiency program implementation costs incurred by the utility as well as all the benefits associated with avoided generation, transmission, and distribution costs. Because the test is limited to costs and benefits incurred by the utility, the impacts measures are limited to those that would eventually be charged to all customers through the revenue requirements. These impacts include the costs to implement the efficiency programs borne by ratepayers and the benefits of avoided supply-side costs, both included in retail rates. This test provides an indication of the direct impact of energy efficiency programs on average customer rates.

- The Rate Impact Measure (RIM) determines if utility rates will increase. All tests express results using net present value, and each provides analysis from a different viewpoint. The RIM includes all costs and benefits associated with the PAC test, but also includes lost revenue as a cost. The lost revenue, equal to displaced sales times average retail rate, is typically significant.

- The Participant Cost Test (PCT) measures the benefits to the participants over the measure life. This test measures a program's economic attractiveness by comparing bill savings against the incremental cost of the efficiency equipment, and can be used to set rebate levels and forecast participation.

2.4. Mississippi Electricity Utilities and Fuel Mix

Just over 1.2 million Mississippi residents are served by Entergy in the west or Mississippi Power in the southeast. The electricity delivered to northeastern Mississippians is almost entirely generated by the Tennessee Valley Authority (TVA) and delivered by one of the 14 municipal entities or 14 cooperatives in the region.[16] Throughout the state are 26 not-for-profit cooperatives that collectively serve 1.8 million

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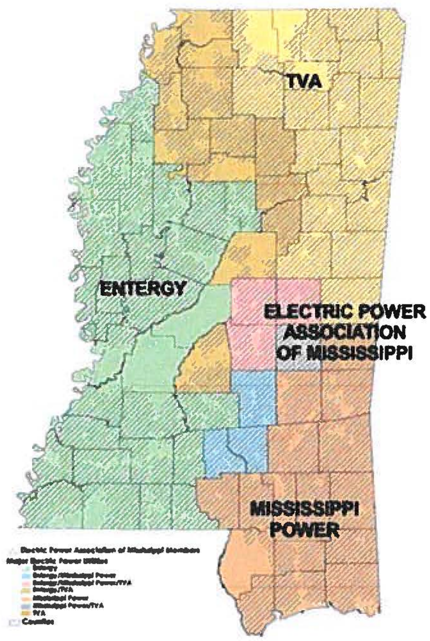
[14] Mississippi Public Service Commission, Final Order Adopting Rule, Docket No. 2010-AD-2. July 11, 2013. Original emphasis.

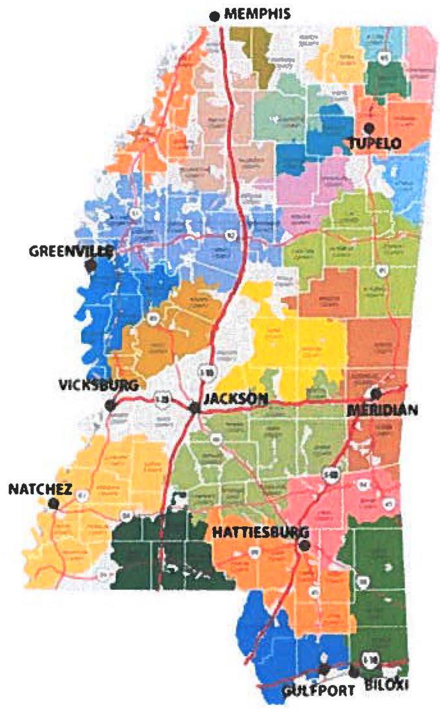
[15] Descriptions of the four tests come from Malone et al. 2013. "Energy Efficiency Cost-Effectiveness Tests (Appendix D)." *Readying Michigan to Make Good Energy Decisions: Energy Efficiency.* Available at: http://michigan.gov/documents/energy/ee_report_441094_7.pdf.

[16] TVA has seven directly served customers to which 4.5 billion kWh were sold in 2013. Available at: http://www.tva.com/news/state/mississippi.htm.

Mississippians. The service territories of Entergy, Mississippi Power, and the munis supplied by TVA are shown on the map on the left in Figure 4; the service territories of all 26 cooperatives are shown on the map on the right.

Figure 4. Mississippi electric utility maps





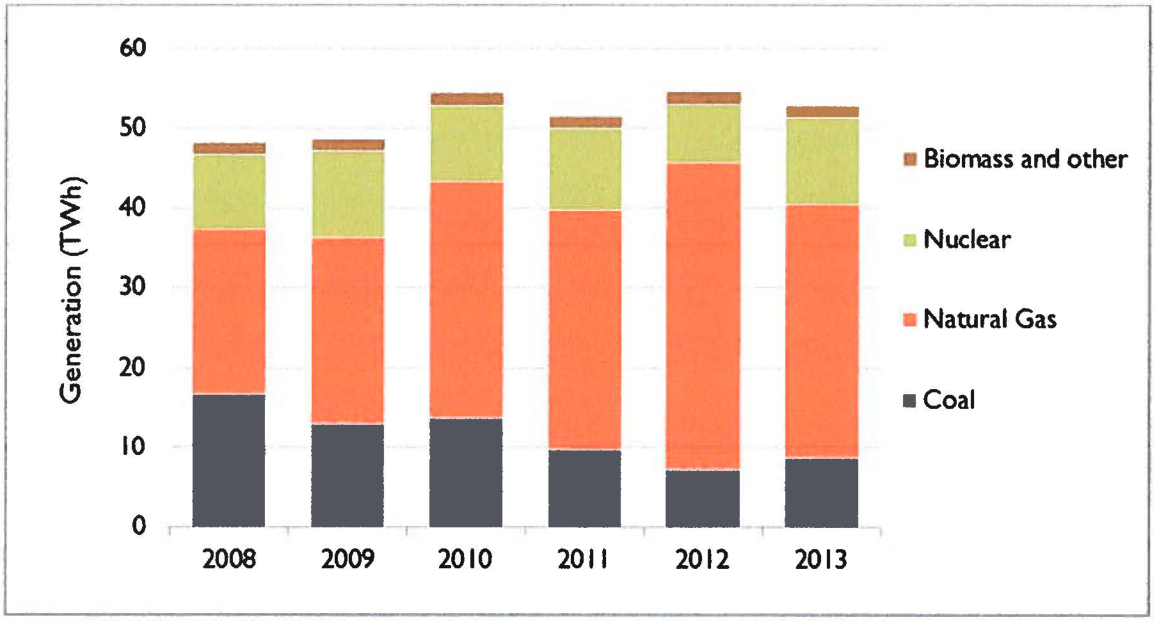
Source: Mississippi Development Authority, Electric Power Associations of Mississippi

Entergy and Mississippi Power are vertically integrated investor-owned utilities. TVA is a generation and transmission not-for-profit corporation owned by the United States government. While South Mississippi Electric Power Association is a generation and transmission co-op, the remaining 25 cooperatives are distribution electric power associations.

The primary fuel used for generating electricity in Mississippi is natural gas, accounting for approximately half of electricity generated (see Figure 5). Coal and nuclear power make up the vast majority of remaining generation, with about 3 percent attributable to wood and wood-derived fuels. In

2013, Mississippi withdrew 1.5 percent of the natural gas extracted in the United States[17] and mined 0.4 percent of the short tons of coal extracted from U.S. soil.[18]

Figure 5. Mississippi electric generation fuel sources



Source: EIA Form 923 2008-2012.
Note: "Other" includes generation from oil, municipal solid waste, and other miscellaneous sources.

2.5. Growth of Solar in the United States

Though not the case in Mississippi, solar resources have gained prevalence in other parts of the United States in recent years. U.S. solar installations have been growing rapidly over the past five years (see Figure 6). State data on solar and net metered generation is scattered and often under-reported. The National Renewable Energy Laboratory (NREL) runs the OpenPV project, which attempts to track solar projects of all sizes in all states. California, Hawaii, New Jersey, and Massachusetts have some of the most developed net metering programs and some of the most aggressive state goals for distributed solar. Based on NREL's OpenPV project, these states have installed solar capacity equivalent to between 0.9 and 4.7 percent of their state's generation capacity. Recognizing the lag in reporting, Synapse has conducted additional research in Hawaii and in Massachusetts. Based on this research, solar penetration in these states ranges from 2.3 and 6.7 percent (see Table 4).

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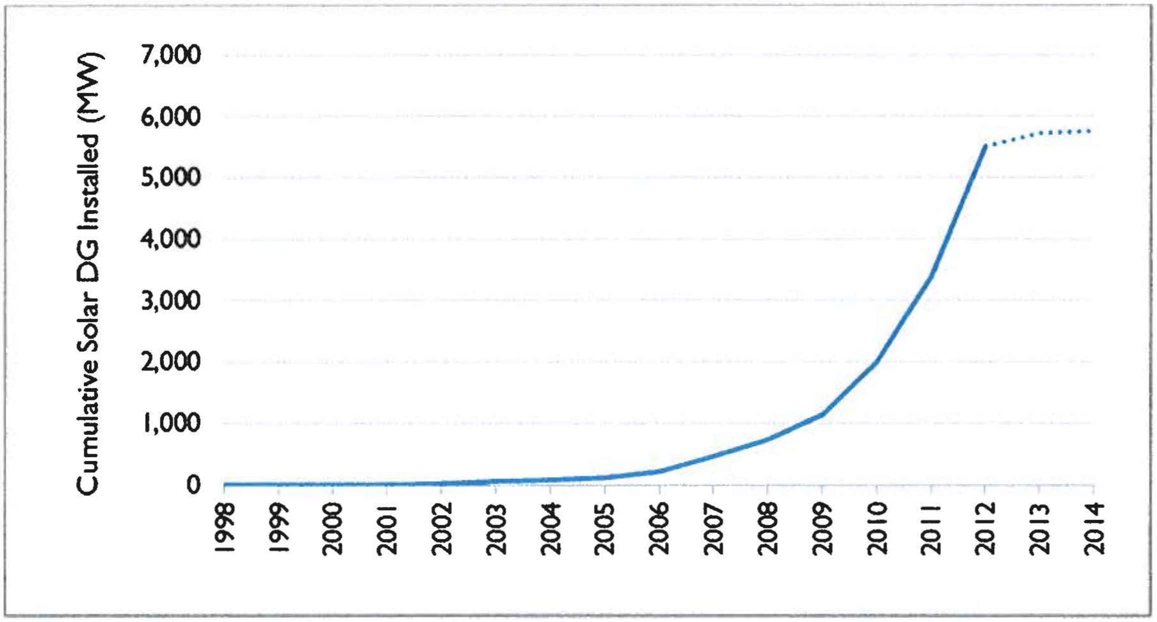
17 Energy Information Administration. 2014. "Natural Gas Gross Withdrawals and Production." Available at: http://www.eia.gov/dnav/ng/ng_prod_sum_dcu_NUS_m.htm.

18 Energy Information Administration. June 30, 2014. *Quarterly Coal Report*. Table 2: Coal Production by State. Available at: http://www.eia.gov/coal/production/quarterly/pdf/t2p01p1.pdf.

Figure 6. U.S. cumulative solar distributed generation (MW)



Source: NREL's OpenPV project (openpv.nrel.gov); 2013 and 2014 reporting is as yet incomplete

Table 4. NREL solar capacity for selected states, with and without Synapse corrections

	Capacity (MW)		% of State Capacity	
	Per NREL OpenPV Project 2014	With Synapse Supplemental Research	Per NREL OpenPV Project 2014	With Synapse Supplemental Research
MS	1	1	0.0%	0.0%
CA	2,055	2,055	2.7%	2.7%
HI	27	200	0.9%	6.7%
NJ	979	979	4.7%	4.7%
MA	244	350	1.6%	2.3%

Source: NREL's OpenPV project (openpv.nrel.gov) and Synapse research

3. MODELING

Net metered generating facilities result in both benefits (primarily avoided costs) and costs, including lost revenues to distribution companies and the expense of distributed generation equipment. Our quantitative analysis of a net metering policy for Mississippi provides benefit and cost estimates at the state level to provide policy guidance for Mississippi decision-makers and to help establish a protocol for measuring the benefits and costs of net metering for use in distribution company compliance. The costs and benefits outlined in this report provide a framework for that discussion.

In the event that a net metering policy is adopted, distribution companies will likely be required to use their detailed, often proprietary data along with the long-term production cost models that they have at their disposal to measure benefits and costs specific to each company. Such modeling requires detailed forecasts of energy fuel prices, capacity, transmission, and distribution needs, as well as the expected costs of compliance with environmental regulations.

3.1. Modeling Assumptions

Our benefit and cost analysis is limited along the following dimensions:

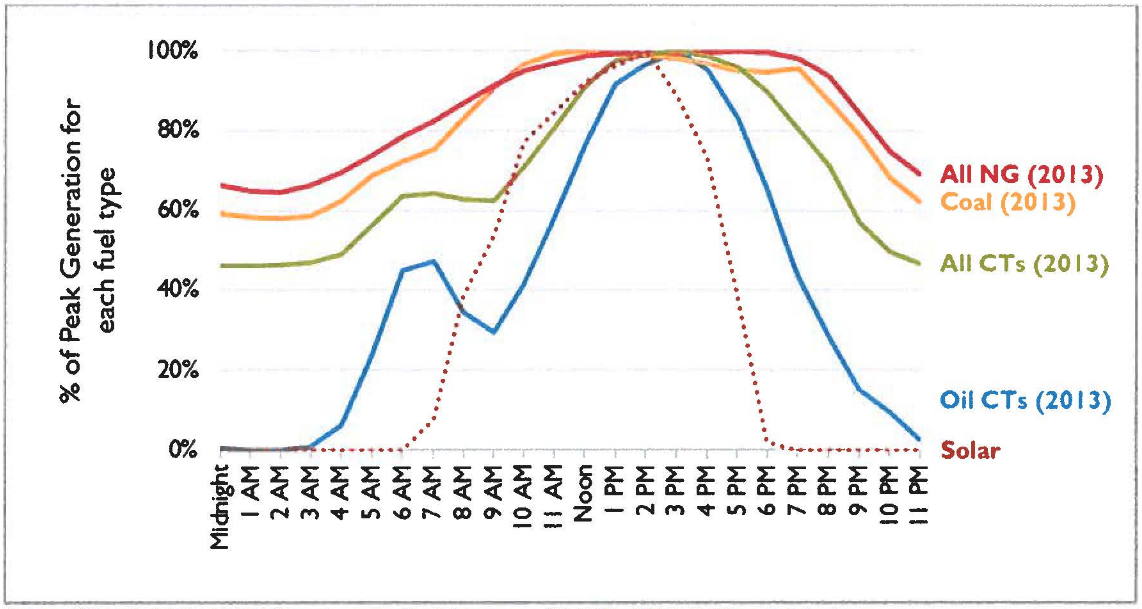
- **Modeling years:** One-year time steps from 2015 to 2039, with results provided both on an annual and a 25-year levelized basis. A 25-year analysis was chosen to reflect typical effective lifespans of solar panels.
- **Technology used for net metering:** Solar rooftop only.
- **Geographic resolution of analysis:** The state of Mississippi on an aggregate basis; we do not address specific costs and benefits for Tennessee Valley Authority, Entergy Mississippi, Mississippi Power, SMEPA, or the co-ops.
- **Source of generation:** Energy demand within the state is assumed to be met by resources within the state with energy balancing at the state level.[19]
- **Rate of net metering penetration:** Net metering installations equivalent to 0.5 percent of historical peak load in 2015, which holds constant over the entire study period.
- **Data sources:** We supplement Mississippi average and utility-specific data with regional and national information regarding load growth, commodity prices, performance characteristics of existing power plants in Mississippi, and costs of generation equipment.
- **Marginal unit:** Mississippi's 2013 generation capacity includes 508 MW of natural gas- and petroleum oil-based combustion turbines (CT).[20] While these oil units do not contribute a significant portion of Mississippi's total energy generation, they do contribute to the state's peaking capabilities. On aggregate, these peaking resources operated 335 days in 2013—most frequently during daylight hours—and had a similar aggregate load shape to potential solar resources (see Figure 7). Our benefit and cost analysis follows the assumption that gas and oil CT peaking resources will be on the margin when solar resources are available and, therefore, that solar net metered facilities will displace the use of these peaking resources. At the level of solar penetration explored in our analysis (0.5 percent), it is unlikely that solar resources will

[19] It should be noted that this is a simplifying assumption, and that in reality each of the generation companies in Mississippi is free to buy or sell electricity and capacity to other states. The three largest owners of generation capacity in the state—Entergy Mississippi, TVA, and MPC—are all part of entities that operate in other states.

[20] EPA. 2012. Air Markets Program (AMP) Dataset.

displace base load units. Our analysis includes an estimate of how much net metered solar generation is necessary to displace base load units.

Figure 7: Normalized average load shapes by fuel type, including estimated shape of solar



Source: (1) EPA. 2012. Air Markets Program (AMP) Dataset. (2) NREL. 2014. PVWatts® Calculator.

- **Size of installations:** We assume that all solar net metered facilities will be designed to generate no excess generation in the course of a year. Because we are modeling on a state-level basis for each year, annual solar generation from net metered facilities is equivalent to the behind-the-meter load reduction.

- **Solar capacity contribution:** The amount solar panels will contribute to reducing peak load was determined by using a state-specific effective load carrying capacity (ELCC). In 2006, NREL updated its study on the effective load carrying capability of photovoltaics in the United States. The analysis was done by using load data from various U.S. utilities and "time-coincident output of photovoltaic installations simulated from high resolution, time/site-specific satellite data."[21] The report provides the ELCC for several types of solar panels and at varying degrees of solar penetration. Synapse used the values corresponding to 2 percent solar penetration (the lowest value provided in the report) and the average of three types of panels (horizontal, south-facing, and southwest-facing). The resulting assumed solar capacity contribution is 58 percent.

- **Solar hourly data and capacity factor:** NREL's Renewable Resource Data Center developed the PVWatts® Calculator as a way to estimate electricity generation and

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[21] Perez, R., R. Margolis, M. Kmiecik, M. Schwab, M. Perez. 2006. *Update: Effective Load-Carrying Capability of Photovoltaics in the United States.* Prepared for the National Renewable Energy Laboratory. Available at: http://www.nrel.gov/docs/fy06osti/40068.pdf.

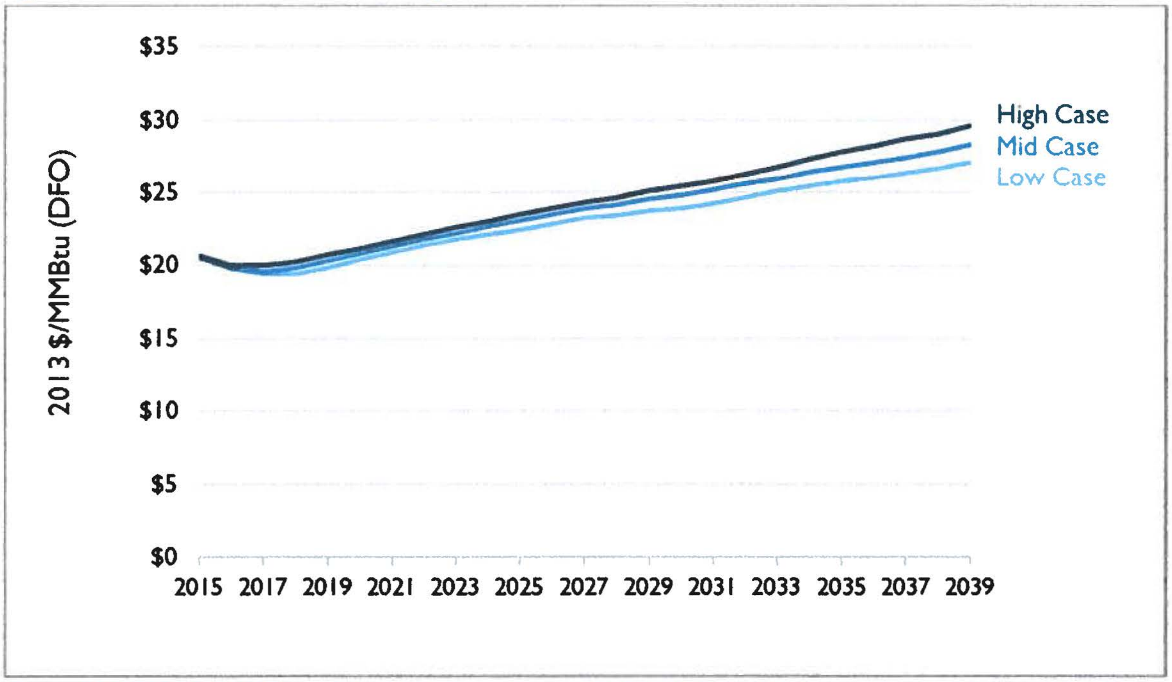
performance of roof- or ground-mounted solar facilities. The calculator, which uses geographically specific data, provides hour-by-hour data including irradiance, DC output, and AC output. PVWatts® only had one location in Mississippi—Meridian—and this was used as a sample for our hourly data and to calculate a capacity factor. The calculated capacity factor, used in all of the calculations in this analysis, is 14.5 percent.

3.2. Model Inputs: General

Fuel Price Forecast

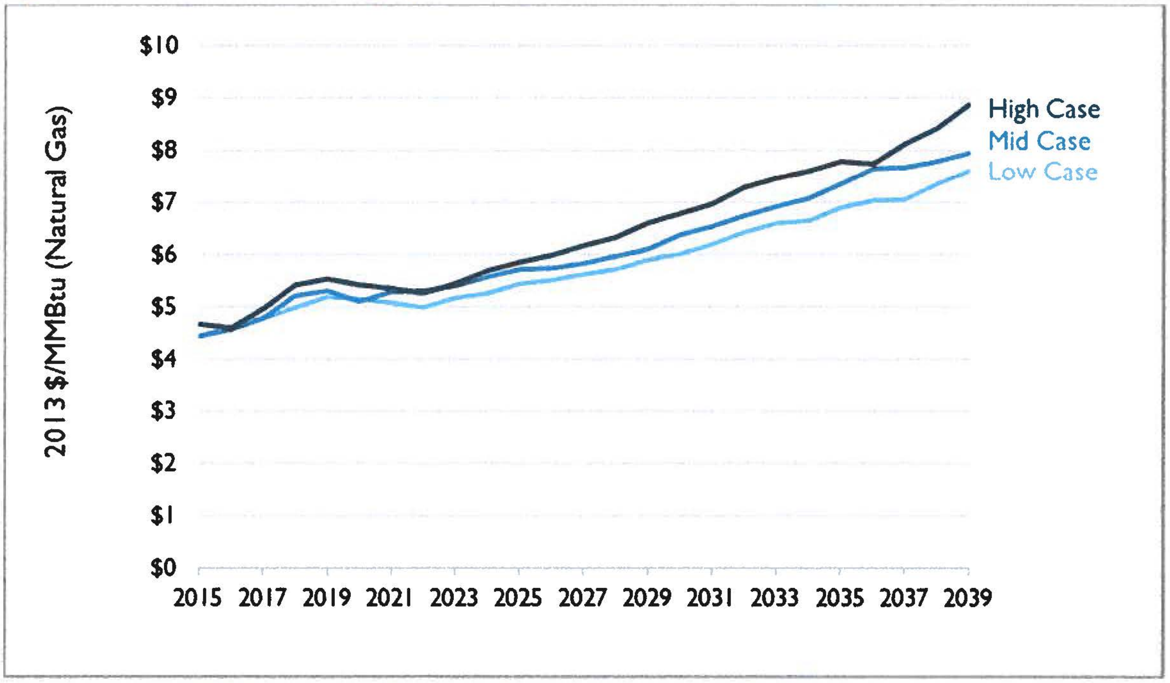
Our model assumes that net metered solar rooftop generation displaces oil- and natural gas-fired units. Consequently, fuel cost forecasts are a critical driver of avoided energy costs. The model uses fuel data price forecasts from AEO 2014 specific to the East South Central region (see Figure 8 and Figure 9). Our Mid case is the AEO Reference case, and our Low and High case values are the AEO 2014 High Economic Growth and Low Economic Growth cases, respectively.

Figure 8. East South Central diesel fuel oil price forecasts



Source: AEO 2014 Table 3.6. Energy Prices by Sector and Source - East South Central; Reference Case, High Economic Growth Case, and Low Economic Growth Case

Figure 9. East South Central natural gas price forecasts



Source: AEO 2014 Table 3.6. Energy Prices by Sector and Source - East South Central; Reference Case, High Economic Growth Case, and Low Economic Growth Case

Capacity Value Forecast

Mississippi's in-state energy resources comprised 17,542 MW of capacity in 2012,[22] serving an in-state peak demand of 9,400 MW along with significant out-of-state demand.[23] Even with the 582 MW Kemper IGCC plant scheduled to come online in 2015, additional capacity may still have a positive value in the future as Mississippi and its neighbors respond to expected environmental regulations. For example, in its 2012 planning document, Entergy identified a system-wide need for up to 3.3 GW of capacity in its reference load forecast.[24] Incremental capacity has the potential to serve other states in the service territories of distribution companies operating in Mississippi

The value of capacity is the opportunity cost of selling it to another entity that needs additional capacity for reliability purposes. For companies participating in capacity markets (such as MISO, PJM, and ISO New England), the value of capacity is determined by the clearing price. The most recent MISO South Reliability Pricing Model (RPM) Base Residual Auction (BRA) capacity market cleared at $16 per MW-day.

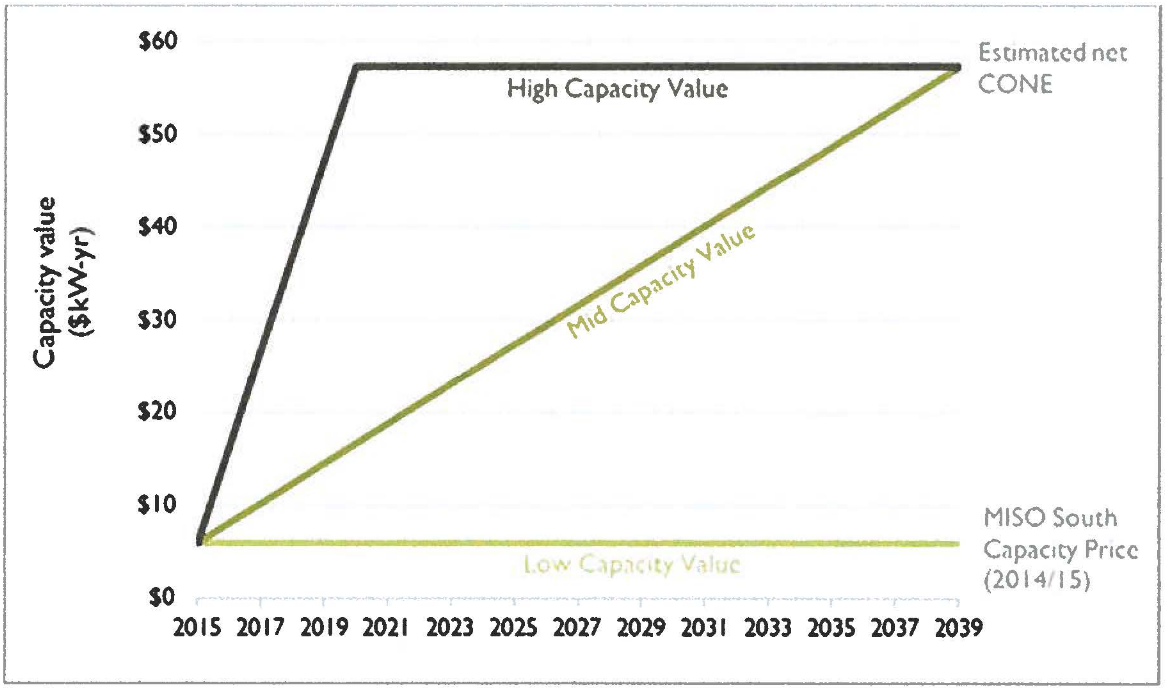
[22] EIA. 2012. EIA 860 2012. Available at: http://www.eia.gov/electricity/data/eia860/xls/eia8602012.zip.

[23] EIA. 2013. Air Markets Program Dataset, hourly 2013 for Mississippi. Available at: http://ampd.epa.gov/ampd.

[24] Entergy. 2012. *2012 Integrated Resource Plan: Entergy System.* Available at: https://spofossil.entergy.com/ENTRFP/SEND/2012Rfp/Documents/2012%20System%20IRP%20Report%20-%20Final%2002Oct2012.pdf.

To approximate the value of capacity in Mississippi, Synapse formulated three capacity value projections (see Figure 10). In these projections, gross cost of new entry (CONE) was calculated as the 25-year levelized cost of a new NGCC, and net CONE was calculated based on the ratio of net CONE to gross CONE observed in PJM reliability calculations (0.84).[25] In the Low case, the capacity value stays at the 2014/2015 MISO South BRA clearing price of $6 per kW-year. For the Mid case, the capacity value escalates linearly to a net CONE of $57 per kW-year by 2030. In the High case, the capacity value rises to the estimated net CONE value of $57 per kW-year by 2020, where it remains for the rest of the study period. These projections do not represent Synapse estimates of future MISO South BRA clearing prices[26]; rather, they approximate values suitable for estimating benefits and performing sensitivity analyses.

Figure 10. Inputs for avoided capacity cost sensitivities



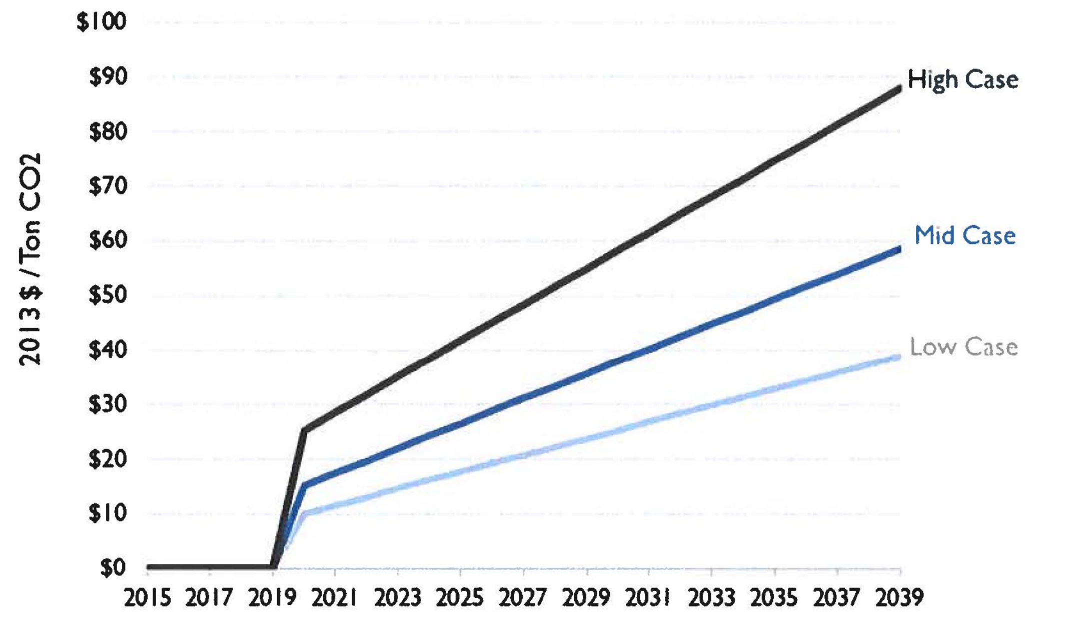
[25] PJM Planning Period Parameters 2017-2018. Available at: http://pjm.com/~/media/markets-ops/rpm/rpm-auction-info/2017-2018-planning-period-parameters.ashx. MISO calculates gross CONE but not net CONE.

[26] "MISO Clears 136,912 MW in Annual Capacity Auction" Electric Light & Power, April 15, 2014. http://www.elp.com/articles/2014/04/miso-clears-136-912-mw-in-annual-capacity-auction.html

CO_2 Price Forecast

Synapse has developed a carbon dioxide (CO_2) price forecast specifically for use in utility planning.[27] The Synapse CO_2 forecast is developed through analysis and consideration of the latest information on federal and state policymaking and the cost of pollution abatement.[28] Because there is inherent uncertainty in those regulations, the Synapse forecast is provided as High, Mid and Low cases, as illustrated in Figure 11. In this analysis, the Synapse Mid case was used for the policy reference case while the High and Low cases were used in sensitivity analyses.

Figure 11. Synapse high, mid, and low CO_2 price forecasts.



3.3. Model Inputs: Benefits of Net Metering

Generation from rooftop solar panels in Mississippi will displace generation from the state's CT peaking resources, thereby avoiding: these resources' future operating costs, the cost of compliance with certain environmental regulations, and the need for additional capacity resources.

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[27] Luckow, P., E. A Stanton, B. Biewald, J. Fisher, F. Ackerman, E. Hausman. 2013. *2013 Synapse Carbon Dioxide Price Forecast*. Synapse Energy Economics. Available at: http://synapse-energy.com/project/synapse-carbon-dioxide-price-forecast.

[28] Luckow, P., J. Daniel, S. Fields, E. A. Stanton, B. Biewald. 2014. "CO2 Price Forecast." *EM Magazine*. Available at: http://www.synapse-energy.com/Downloads/SynapsePaper.2014-06.0.EM-Price-Forecast.A0040.pdf.

Avoided Energy Costs

The avoided energy costs include all fuel, variable operation and maintenance, emission allowances, and wheeling charges associated with the marginal unit (in our analysis, a blend of oil and gas combustion turbines).

Because fuel is a driving factor in the value of avoided energy costs, we made distinct short- and long-run assumptions regarding the fuel mix of peaking resources. We assumed the 2013 mix in year 2015 (approximately 25 percent oil and 75 percent natural gas), and a linear transition to 100 percent natural gas use in peaking units by 2020.

Avoided energy costs are estimated by multiplying the per MWh variable operating and fuel costs of the marginal resource by the projected MWh of solar generation in each modeled year.[29] AEO's 2014 Electric Market Module reports that the variable operation and maintenance for an oil CT is $15.67 per MWh, and for a NGCT it is $10.52 per MWh.[30] For fuel costs, we used the AEO 2014 data to project costs on an MMBtu basis and unit heat rates to convert to fuel costs on a dollars per MWh basis. Our analysis calculated the heat rates of fossil fuel units in Mississippi using data available from EPA's Air Markets Program. From this dataset, we calculated that the average in-state oil-fired unit (both steam and combustion turbines) had an 11.89 MMBtu per MWh heat rate and that the average natural gas-fired combustion turbine was 10.41 MMBtu per MWh.

Capacity Value Benefits

In this analysis, capacity value benefits were calculated as the contribution of solar net metering projects to increasing capacity availability within the state. For each year of the study period, we calculated the total amount of installed solar capacity (in this analysis, 88 MW) and then calculated the number of megawatts that contribute to peak load reduction by using the calculated Effective Load-Carrying Capability (ELCC) of 58 percent (88 MW × 58% = 51 MW of capacity contribution).[31] We then multiplied the capacity contribution by the capacity value in each year, and divided the total by the solar generation of that year to yield a dollar per MWh value.

Avoided Transmission and Distribution Capital Costs

The avoided capital costs associated with transmission and distribution (T&D) are the contribution of a distributed generation resource to deferring the addition of T&D resources. T&D investments are based on load growth and general maintenance. Growth of both the system's peak demand and energy

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[29] U.S. Energy Information Administration. 2014. *Annual Energy Outlook 2014 (AEO 2014)*. Available at: www.eia.gov/forecasts/aeo.

[30] U.S. Energy Information Administration. 2014. *AEO 2014 Electric Market Module*. Table 8.2. Available at: http://www.eia.gov/forecasts/aeo/assumptions/pdf/electricity.pdf. Converted to 2013 dollars.

[31] Because distributed solar resources are a demand-side resource, they reduce the load and energy requirements that the distribution companies have to serve. The ELCC is used to translate how much the companies can expect peak load to be reduced as a result of distributed solar resources.

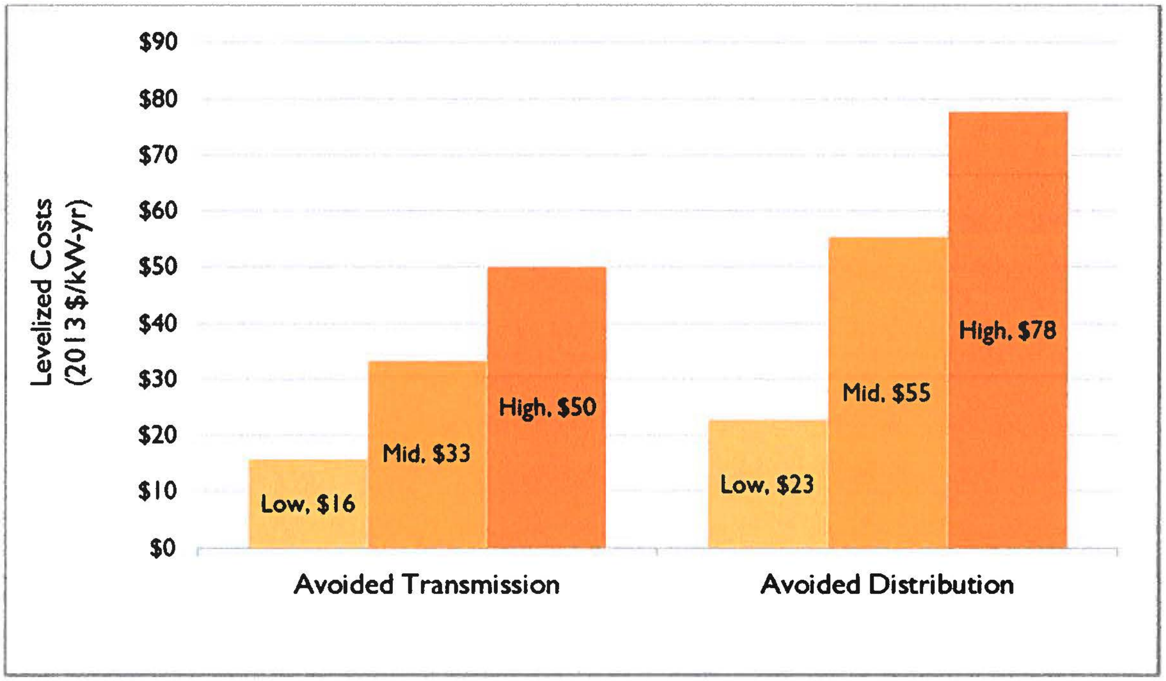
requirements are reduced by the customer-side generating resources (as it would be for other demand-side resources such as energy efficiency), and these costs can be avoided if the growth is counteracted by the solar resources. General maintenance costs are not entirely avoidable but can be reduced by distributed generation measures. For example, an aging 100-MW cable might be replaced with a slightly less expensive 85-MW cable. The same holds for distribution system costs. For example, costs associated with maintaining or building new transformers and distribution buses at substations will be lower if the peak demand at that substation is reduced.

In the absence of utility-specific values for avoidable T&D costs, we use our in-house database of avoided T&D costs calculated for distributed generation and energy efficiency programs to provide a reasonable estimate. The average avoided transmission value from this database is $33 per kW-year and the average avoided distribution value was $55 per kw-year, for a combined avoided T&D value of $88 per kW-year. This value is multiplied by the capacity contribution and divided by generation—the same way the capacity benefit was—to yield an avoided T&D cost in dollars per MWh.

Synapse is aware of no long-term avoided transmission and distribution (T&D) cost study that has been conducted for those entities that operate in Mississippi for use in this analysis. Synapse has assembled a clearinghouse of publicly available reports on avoided T&D costs. Our current database includes detailed studies on avoided costs of T&D for over 20 utilities and distribution companies that serve California, Connecticut, Oregon, Idaho, Massachusetts, New Hampshire, Maine, Rhode Island, Utah, Vermont, Washington, Wyoming, and Manitoba.[32] For our analysis, we developed a low, mid, and high estimate of avoided T&D costs by first separating transmission and distribution costs and then converting all costs to 2013$ values. The low value for each category (transmission and distribution) was calculated by taking the 25th percentile of reported values; the high value used the 75th percentile. The mid value was calculated as an average of the reported values for each category. The values for each category were then combined to develop an estimated avoided T&D cost.

[32] The values in this database are consistent with a 2013 review of avoided T&D costs of distributed solar in New York, New Jersey, Pennsylvania, Texas, Colorado, Arizona, and California. See: Hansen, L., V. Lacy, D. Glick. 2013. *A Review of Solar PV Benefit and Cost Studies, 2nd Edition*. Rocky Mountain Institute. Available at: www.rmi.org/elab_emPower.

Figure 12. Avoided transmission and distribution costs



Avoided System Losses

Avoided system losses are the reduction or elimination of costs associated with line losses that occur as energy from centralized generation resources is transmitted to load. Usually presented as a percent of kWh generated, these losses vary by section of the T&D system and by time of day. The greatest losses tend to occur on secondary distribution lines during peak hours, coincident with solar distribution generation.

To account for variation in line losses, our analysis estimates avoided system losses using a weighted average of line losses during daylight hours. This value was calculated by weighing daylight line losses of each Mississippi T&D system (Entergy Mississippi, Mississippi Power, and the rest of the state) in proportion to the load each system serves. Our analysis incorporates Entergy- and Mississippi Power-specific data for their T&D systems. For the remainder of the state, including SMEPA, our analysis uses national average T&D system losses adjusted to reflect losses during the hours when solar panels generate energy.[33]

Avoided system losses were calculated as the product of the weighted average system losses and the projected generation from solar panels in each year in kWh multiplied by the avoided dollars per kWh energy cost in that same year.

[33] U.S. Energy Information Administration. 2014. "How much electricity is lost in transmission and distribution in the United States?" *EIA Website: Frequently Asked Questions.* Available at: http://www.eia.gov/tools/faqs/faq.cfm?id=105&t=3. Updated May 7, 2014.

Avoided Environmental Compliance Costs

Avoided environmental compliance costs are the reduction or elimination of costs that the marginal unit would incur from various existing and reasonably expected environmental regulations. For oil and gas CTs, these avoided environmental compliance costs are primarily associated with avoided CO_2 emissions.[34]

Mississippi's distribution companies have used a price for CO_2 emissions in their planning for many years. For the Kemper IGCC project, analysts included the impacts of "existing, moderate, and significant" future carbon regulations in their economic justification for the project.[35] Entergy developed a system-wide Integrated Resource Plan (IRP) for all six Entergy operating companies, including Entergy Mississippi, which modeled a CO_2 price in its reference case.[36] Tennessee Valley Authority's most recent finalized IRP also incorporates a CO_2 price in seven of its eight scenarios developed for that IRP.[37] Our benefit and cost analysis uses the Synapse Mid case in our avoided environmental compliance estimation. The Synapse Mid case forecasts a carbon price that begins in 2020 at $15 per ton, and increases to $60 per ton in 2040.[38]

Avoided Risk

There are a number of risk reduction benefits of renewable generation (and energy efficiency) from both central stations and distributed sources. The difficulties in assigning a value to these benefits lie in (1) quantifying the risks, (2) identifying the risk reduction effects of the resources, and (3) quantifying those risk reduction benefits. Increased electric generation from distributed solar resources will reduce Mississippi ratepayers' overall risk exposure by reducing or eliminating risks associated with transmission costs, T&D losses, fuel prices, and other costs. Increasing distributed solar electricity's contribution to the state's energy portfolio also helps shift project cost risks away from the utility (and subsequently the ratepayers) and onto private-sector solar project developers.

The most common practical approach to risk-reduction-benefit estimation has been to apply some adder (adjustment factor) to avoided costs rather than to attempt a detailed technical analysis. There is, however, little consensus in the field as to what the value of that adder should be. Current heuristic practice would support a 10 percent adder to the avoided costs of renewables such as solar. There are

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34 For more information on this topic see: Wilson, R., Biewald, B. June 2013. *Best Practices in Electric Utility Integrated Resource Planning*. Synapse Energy Economics for the Regulatory Assistance Project. Available at: www.raponline.org/document/download/id/6608.

35 URS Corporation. March 7, 2014. IM Prudence Report, Mississippi Public Service Commission Kempler IGCC Project.

36 Entergy. 2012. *2012 Integrated Resource Plan, Entergy System*. Available at: https://spofossil.entergy.com/ENTRFP/SEND/2012Rfp/Documents/2012%20System%20IRP%20Report%20-%20Final%2002Oct2012.pdf.

37 Tennessee Valley Authority. 2011. *Integrated Resource Plan: TVA's Energy and Environmental Future*. Available at: http://www.tva.com/environment/reports/irp/archive/pdf/Final_IRP_Ch6.pdf.

38 Luckow, P., E.A. Stanton, B. Biewald, J. Fisher, F. Ackerman, E. Hausman. 2013. *2013 Carbon Dioxide Price Forecast*. Synapse Energy Economics. Available at: http://synapse-energy.com/project/synapse-carbon-dioxide-price-forecast.

both more avoided costs and risk reduction benefits associated with distribution generation; thus, one would expect greater absolute risk reduction benefits with distributed generation. Based on this, we applied a 10 percent avoided risk adder when calculating avoided costs in this analysis. For more information on the value of avoided risk and the literature review of current practices, see Appendix A of this report.

3.4. Model Inputs: Costs

Net metered solar facilities will also result in some costs: reduced revenue to distribution companies and administrative costs. We assume that net metered resources in Mississippi will both reduce retail sales with their behind-the-meter generation and be compensated for their net energy generation.

Customer Perspective Modeling

CREST Model

In order to model costs and benefits, our analysis required the assumption that some solar net metered projects would be developed. However, it is entirely possible that, depending on the net metering policy, net metering would not experience widespread adoption in Mississippi. In order to determine the likelihood of customers in Mississippi adopting rooftop solar, we estimated the financial impacts of installing rooftop solar in Mississippi using the Cost of Renewable Energy Spreadsheet Tool (CREST) model to estimate the cost of rooftop photovoltaic projects in Mississippi and estimate the subsidies required to allow them to earn a competitive rate of return.[39] Developed for the National Renewable Energy Laboratory, CREST is a cash-flow model designed to evaluate project-based economics and design cost-based incentives for renewable energy.

Model Assumptions and Inputs

Using the CREST model, we analyzed residential-scale photovoltaic projects (assumed to be 5 kW in size) and commercial projects (500 kW). We assumed that all projects are developed and owned by the building owner. Projects are assumed to be developed in 2015; therefore, the effects of the 30 percent federal Investment Tax Credit (ITC) are included. Table 5 reports the inputs used in our CREST analysis.

The installed cost of photovoltaic projects continues to fall rapidly across the country, and it is difficult to discern current average project costs. Carefully reviewed datasets tend to appear a year or two after the fact, and information in the press or released by project developers often focuses on selected data points that are not representative of industry averages. Our assumed project costs, shown in Table 5, are based on ongoing review of data from government agencies and energy labs, solar industry trade

[39] National Renewable Energy Laboratory. 2011. "CREST Cost of Energy Models." Retrieved August 1, 2014. Available at: https://financere.nrel.gov/finance/content/crest-cost-energy-models.

groups, our work in proceedings before utility commissions, and discussions with photovoltaic project developers.

Table 5. Inputs for photovoltaic costs analysis

	Residential Projects	Commercial Projects
Capital Costs ($/W$_{DC}$)	$4.00	$3.65
O&M ($/kW-yr)	$21.00	$20.00
Federal Tax Rate (%)	28%	34%
State Tax Rate (%)	5%	5%
Inflation rate	2%	2%
Insurance (% of capital costs)	0.3%	0.3%
Federal ITC (% of capital costs)	30%	30%
Debt (% of capital costs)	40%	40%
Debt Term (years)	15	15
Interest Rate (%)	4%	4%
After-Tax Equity IRR (%)	0%	0%

We use a 0 percent return on equity to represent a project that exactly breaks even. Therefore, the revenue requirement the model produces represents the lowest expected revenue that would cause a rational building owner to proceed with the project. The revenue would cover all costs, including debt service, by the end of the project's 25-year life. (The payback period would be 25 years.) We have modeled projects in this way for ease of comparison with retail electricity rates. That is, where levelized, forecasted rates are higher than the levelized costs, projects would expect to earn a return on equity and have a shorter payback period. Where forecasted retail rates are lower, projects would be expected to lose money. Table 6 shows the levelized cost of energy for each of the project types and the average of the two values.

Table 6. The estimated levelized cost of energy from rooftop photovoltaic panels in Mississippi

Project type	Levelized Cost ($/MWh)
Residential	142
Commercial	129
Average	135

Finally, note that the federal ITC is scheduled to fall to 10 percent in 2016. If this occurs, it is likely to cause an elevation in levelized costs lasting several years, even as cost reductions continue on their recent trajectory during this period.

As shown in Table 6, our analysis indicates that the expected cost of net metered rooftop solar in Mississippi is $129 per MWh for commercial customers and $142 per MWh for residential customers (see Table 6). From this we can reasonably expect that more capacity of solar will be installed by commercial customers than residential; however, without additional information it is difficult to predict the rate of adoption and the relative share of installations between these two sectors. As a simplifying assumption in the modeling presented in this report, we refer to the average of the commercial and residential levelized cost of solar: $135 per MWh.

Administrative Costs

Because Mississippi currently has no net metering program, it was necessary to assume costs for administering the program. We conducted research sampling data from other states with net metering programs. The incremental costs associated with managing a net metering program in most states are difficult to separate from other normal, everyday administrative costs. However, cost data is widely available for many states' energy efficiency programs. We estimate that the average utility spends between 6 percent and 9 percent of energy efficiency program costs on administrative tasks, with the average administrator spending 7.5 percent.[40] This value includes program administration, marketing, advertising, evaluation, and market research. Based on a limited dataset on estimated costs to manage the net metering programs in California and Vermont and a comparison of those state's respective energy efficiency programs, we find that administering net metering programs tends to be less costly than administering energy efficiency programs.

In 2012, Mississippi spent approximately $12 million on energy efficiency, of which approximately $0.9 million was spent on various administration costs like the ones discussed above. For our analysis, we assumed a value of $0.9 million per year for administrative costs associated with net metering. These costs would include front office administrative costs, handling permitting issues, and keeping track of net metering installations. While these costs may not prove to perfectly reflect the experience Mississippi may have, it represents a reasonable, first order approximation of those costs.

Reduced Revenue to Distribution Companies

Distribution companies' kilowatt-hour sales will be reduced by net metered generation. These reduced revenues were calculated as the amount of energy generated by net metered facilities multiplied by the weighted average retail rate. The analysis also reflects retail rate escalation that matches the anticipated growth rate of natural gas and also includes a discussion of the impact of reduced revenues on rates and on the financial solvency of distribution companies.[41]

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[40] Synapse reviewed 2012 energy efficiency annual reports in 22 states in order to gather program participant cost data from states recognized by ACEEE as leaders in energy efficiency programs. For the purpose of this research, we have defined leading or high impact states as the top 15 states in the 2013 ACEEE State Energy Efficiency Scorecard in terms of annual savings as a percentage of retail sales or absolute annual energy savings in terms of total annual MWh savings. The 22 states that are leaders in one or both of these criteria are: Arizona, California, Connecticut, Florida, Hawaii, Illinois, Indiana, Iowa, Maine, Massachusetts, Michigan, Minnesota, New Jersey, New York, North Carolina, Ohio, Oregon, Pennsylvania, Rhode Island, Texas, Vermont, and Washington.

[41] Utility lost revenues are not a new cost created by the net metered systems. Lost revenues are simply a result of the need to recover existing costs spread out over fewer sales. The existing costs that might be recovered through rate increases as a result of lost revenues are (a) not caused by the efficiency program themselves, and (b) are not a new, incremental cost. In economic terms, these existing costs are called "sunk" costs. Sunk costs should not be used to assess future resource investments because they are incurred regardless of whether the future project is undertaken. Consequently, the application

3.5. Literature Review of Costs and Benefits Not Monetized

Avoided Externality Costs

Externality costs are typically environmental damages incurred by society (over and above the amounts "internalized" in allowance prices). Some states choose to consider the externality costs associated with electricity generation in their policymaking and planning. Avoided externality costs from displaced air emissions are a benefit to the state and can be considered in benefit and cost analysis without necessarily including these non-market costs in an avoided cost rate. For example, the Societal Cost Test used by some states to screen energy efficiency measures includes avoided externality costs. In regions and states where utility commissions consider externality costs in their determination of total societal benefits, Synapse has used a value of $100 per metric ton of CO_2 as an externality cost.[42] We have not, however, monetized avoided externality costs for Mississippi.

Avoided Grid Support Services Costs

Distributed generation may contribute to reduced or deferred costs associated with grid support, including voltage control, reduced operating reserve requirements and reactive supply. Because most of the studies to date have focused on operating reserve requirement, and those benefits are embedded in our capacity benefits, our analysis does not include any additional avoided grid support services.

Avoided Outage Costs

Distributed generation facilities have the potential to help customers avoid outages if the facility is allowed to island itself off of the grid and self-generate during an outage event. For a cost-benefit analysis, the value of avoiding outages is typically represented by estimating a value of lost load (VOLL) as the amount customers would be willing to pay to avoid interruption of their electric service. A study conducted by London Economics International on behalf of ERCOT concluded that the VOLL for residential customers was approximately $110 per MWh and was between $125 per MWh and $6,468 per MWh for commercial and industrial customers.[43] An earlier literature review conducted for ISO New

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of the RIM test is not valid for analyzing the efficacy of net metered or distributed resources as it is a violation of this important economic principle.

[42] For example, see: Hornby, R. et al. 2013. *Avoided Energy Supply Costs in New England: 2013 Report*. Synapse Energy Economics. Available at: http://synapse-energy.com/project/avoided-energy-supply-costs-new-england.

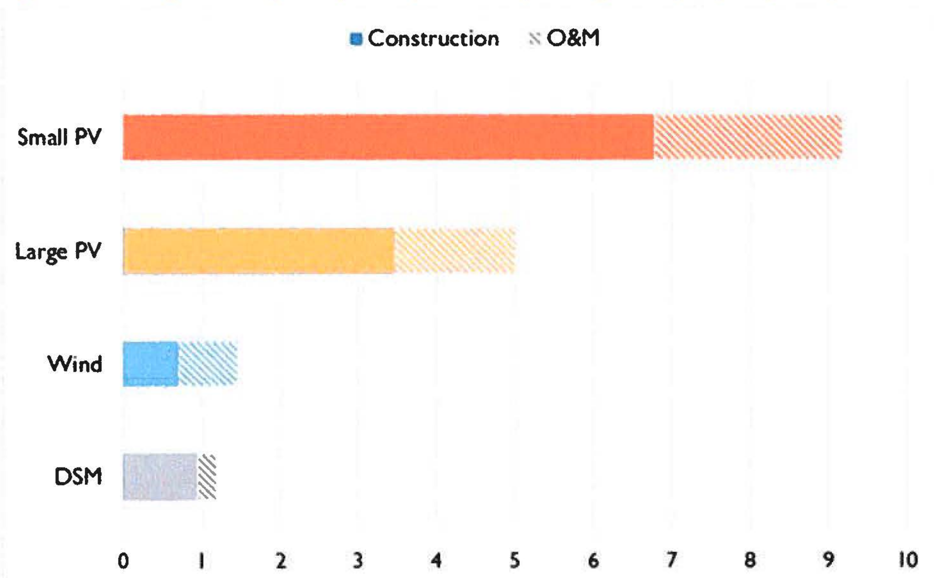
[43] Frayer, J., S. Keane, J. Ng. 2013. *Estimating the Value of Lost Load.* Prepared by London Economics on behalf of the Electric Reliability Council of Texas, Inc. Available at: http://www.ercot.com/content/gridinfo/resource/2014/mktanalysis/ERCOT_ValueofLostLoad_LiteratureReviewandMacroeconomic.pdf.

England found values between $2,400 per MWh and $20,000 per MWh.[44] Even if these values could be adapted to Mississippi customers, there is not sufficient evidence to indicate the extent to which solar net metering would improve reliability, and therefore these estimates cannot be translated into monetizable benefits of net metering at this time.

Economic Development Benefits

In states with growing net metering programs, the siting, installation, and maintenance of solar panels is an emergent industry. A recent Synapse study estimated the employment effects of investing in solar projects in another rural state: Montana. The study found that, compared to other clean energy technologies, small-scale photovoltaic provides the most job-years per average megawatt, as illustrated in Figure 13.[45] This level of detailed analysis was not conducted for Mississippi.

Figure 13. Average annual job impacts by resource per megawatt (20-year period)



Source: Synapse and NREL JEDI Model (industry spending patterns), IMPLAN (industry multipliers).

Solar Integration Costs

Solar integration costs are the investments distribution companies make in order to incorporate distributed resources into the grid. Typically, Synapse sees these costs escalate alongside increasing

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[44] Cramton, P., J. Lien. 2000. *Value of Lost Load.* Available at: http://isone.org/committees/comm_wkgrps/inactive/rsvsrmoc_wkgrp/Literature_Survey_Value_of_Lost_Load.rtf.

[45] Comings, T., et al. 2014. *Employment Effects of Clean Energy Investments in Montana*. Synapse Energy Economics for Montana Environmental Information Center and Sierra Club. Available at: http://www.synapse-energy.com/Downloads/SynapseReport.2014-06.MEIC.Montana-Clean-Jobs.14-041.pdf.

penetration levels. Our literature review found very little substantiated evidence that there are significant costs incurred by grid operators or distribution companies as a result of low levels of solar distributed resources. In a 2013 net metering proceeding in Colorado, Xcel Energy released its analysis for integrating distributed solar resources at a 2 percent penetration level. At that level, which is four times the level of penetration estimated for our analysis in Mississippi, Xcel Energy concluded that solar distributed generation would add a $2 per MWh cost to the system.[46] A 2012 study performed by Clean Power Research analyzing 15 percent penetration concluded that integration costs were about $23 per MWh.[47]

4. MISSISSIPPI NET METERING POLICY CASE RESULTS

Our Mississippi net metering policy case is based on the "mid" or reference inputs discussed above.

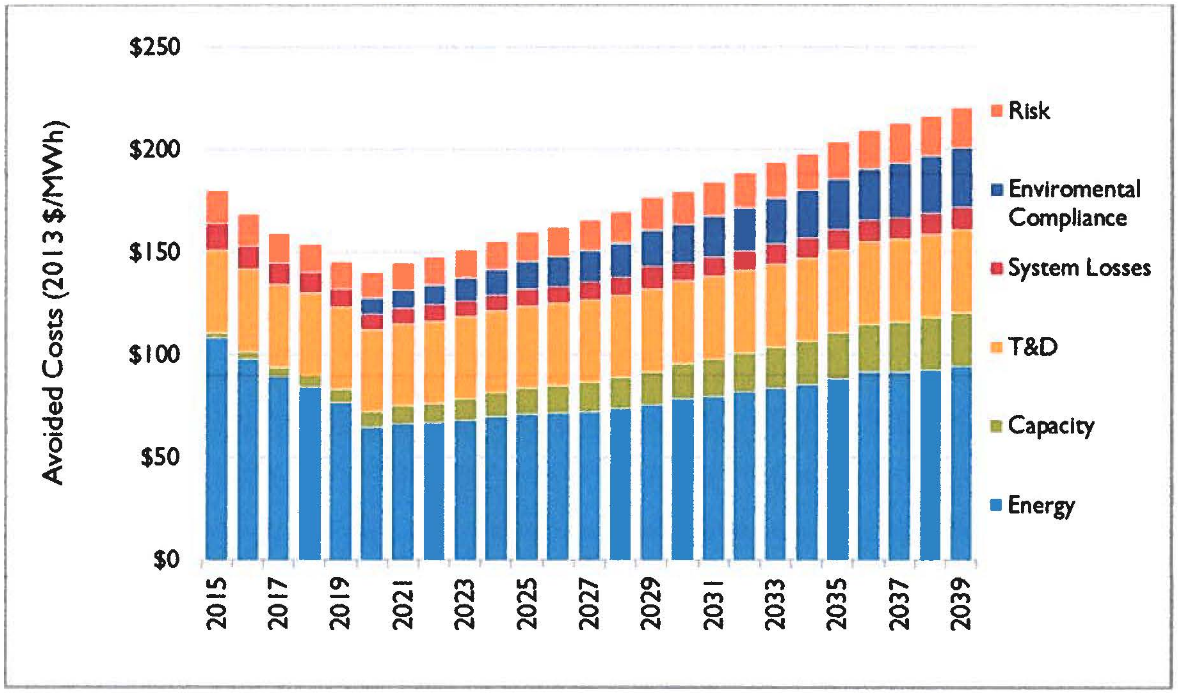
4.1. Policy Case Benefits

We estimated the annual potential avoided costs associated with a representative solar net metering program in Mississippi. Figure 14 demonstrates that the short-run benefits of net metering are dominated by avoided energy costs.

[46] Xcel Energy Services, Inc. 2013. *Costs and Benefits of Distributed Solar Generation on the Public Service Company of Colorado System*. Prepared in response to CPUC Decision No. C09-1223. Page 41. Available at: http://votesolar.org/wp-content/uploads/2013/12/11M-426E_PSCo_DSG_StudyReport_052313.pdf.

[47] Perez, R. et al. 2012. *The Value of Distributed Solar Electric Generation to New Jersey and Pennsylvania*. Clean Power Research for Mid-Atlantic Solar Energy Industries Association and Pennsylvania Solar Energy Industries Association. Available at: http://mseia.net/site/wp-content/uploads/2012/05/MSEIA-Final-Benefits-of-Solar-Report-2012-11-01.pdf.

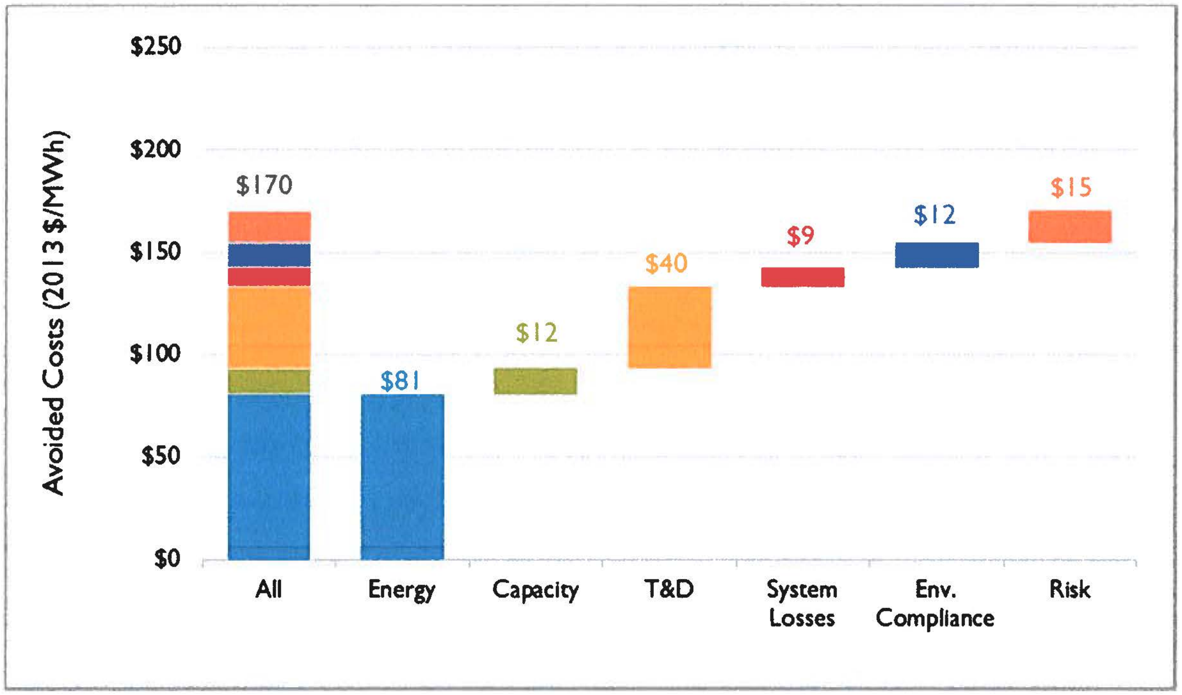
Figure 14. Annual potential benefits (avoided costs) of solar net metering in Mississippi



Avoided energy costs start at over $100 per MWh and decline over the first five years due to a gradual transition in the displaced marginal unit from a mix of oil and gas units to gas units alone. Because oil units are the most expensive units to operate, the benefits of net metering decline as less energy from oil units is displaced over time. Avoided capacity costs increase over the study period, rising from $3 per MWh in 2015 up to $26 per MWh at the end of the study period, due to the assumed increase over time in the value of capacity to Mississippi's distribution companies. Avoided environmental costs begin in 2020, the first year for which the Synapse CO_2 price forecast projects a non-zero value.

Figure 15 illustrates avoided costs of a net metering program in Mississippi on a 25-year levelized basis: $170 per MWh. Avoided energy costs account for the largest share of levelized benefits ($81 per MWh), followed by avoided T&D costs ($40 per MWh). The value associated with reduced risk is the third largest benefit ($15 per MWh).

Figure 15. 25-year levelized potential benefits (avoided costs) of solar net metering using risk-adjusted discount rate

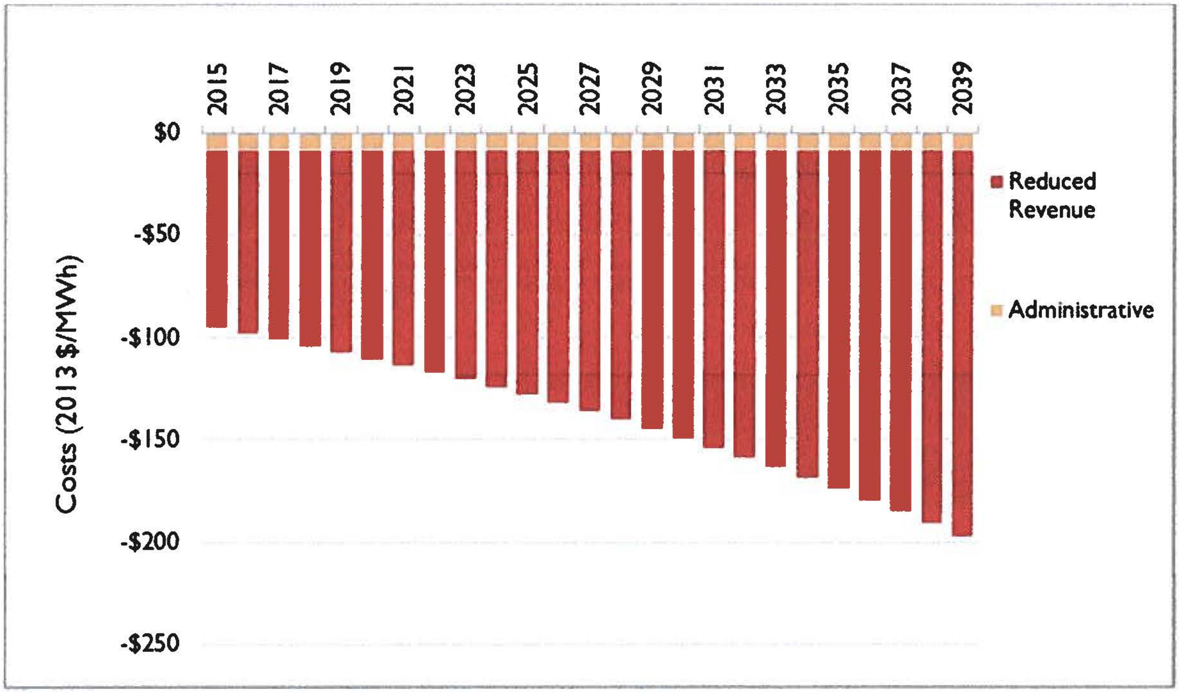


4.2. Policy Case Costs

Figure 16 reports annual potential utility costs of a representative solar net metering program in Mississippi. Reduced revenues to the utilities are projected to increase over the study period to reflect rate escalation. For this analysis, we assumed that rates in Mississippi would increase in proportion to natural gas prices.[48]

[48] This assumption is based on the fact that the volumetric portion of rates in Mississippi is primarily comprised of the variable costs of energy generation, the majority of which are fuel costs. Based on, among other things, the current portfolio of energy resources in the state, our calculations indicate that electric rates will correlate with natural gas prices.

Figure 16. Annual potential utility cost of solar net metering



4.3. Cost-Effectiveness Analysis

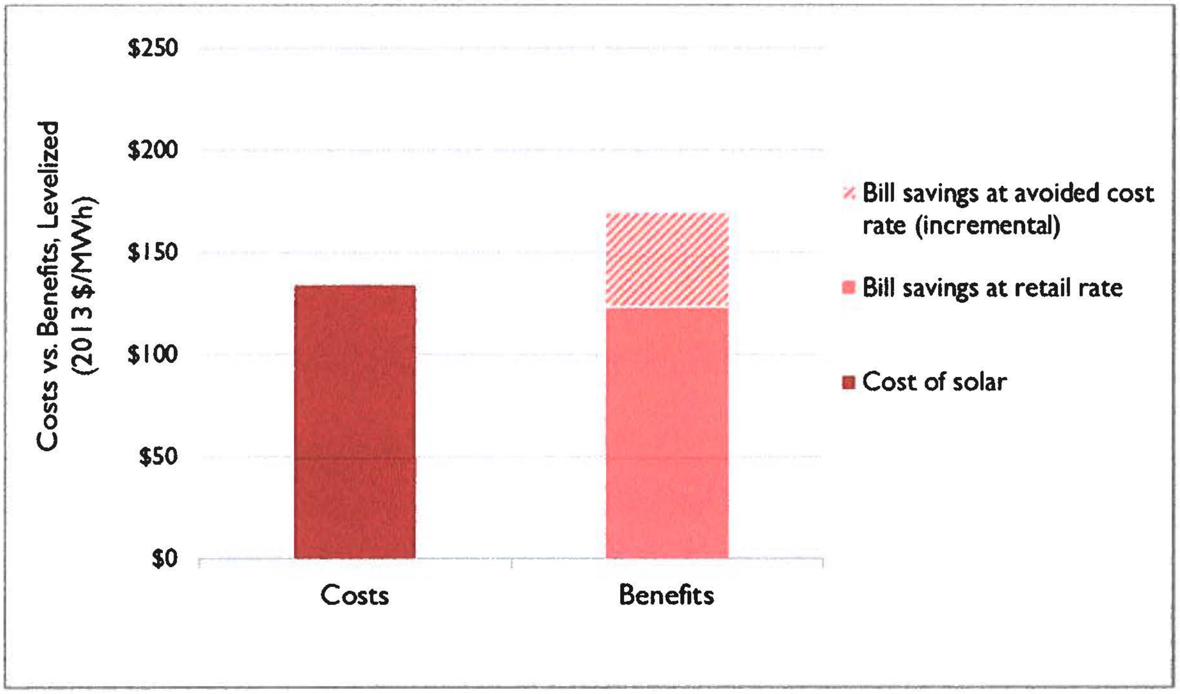
We performed cost-effectiveness analyses on a representative net metering program in Mississippi using several methods (refer to Section 2.3 above). Here we discuss:

- Participant perspective analysis using the Participant Cost Test (PCT)
- Utility perspective analysis using the revenue requirement savings-to-cost ratio
- Total resource perspective using the Total Resource Cost (TRC) test
- Societal perspective using the Societal Cost Test

Participant Perspective Analysis

To analyze the potential costs and benefits to participants of net metering, our analysis used the Participant Cost Test. Results of the Participant Cost Test depend on the way in which net metering customers are compensated. As shown in Figure 17, under net metering rules in which customers are only compensated at the variable retail rate, the levelized benefits ($124 per MWh) would be lower than levelized costs ($135 per MWh) resulting in a benefit-to-cost ratio below 1.0—suggesting that net metering would not be attractive to develop for economic reasons. If, instead, customers were compensated at the avoided cost rate ($170 per MWh) for every MWh of generated energy, projects would realize a return on investment. The minimum amount of return on investment that is needed to pursue a project is specific to the developer. A benefit-cost ratio of 1.0 means that the developer breaks even, which is unlikely to provide sufficient incentive to stimulate widespread adoption of net metering.

Figure 17. Levelized potential benefit/cost comparison under Participant Cost Test



As shown in Table 7, using the Participant Cost Test, under a net metering policy in which participants are only compensated at the retail rate, solar net metering would have a benefit-to-cost ratio of 0.92. If participants were paid the avoided costs, solar net metering would have a benefit-to-cost ratio of 1.26.

Table 7. Benefit-cost ratio under the participant cost test

	Compensated at retail rate	Compensated at avoided cost rate
B/C ratio	0.92	1.26

In order to determine what the 1.26 benefit-to-cost ratio would represent to a Mississippi ratepayer looking to develop rooftop solar, we ran an additional CREST model run assuming the customer would be compensated at the avoided cost rate for each unit of energy generated. If a solar net metered project were compensated at $170 per MWh (which we estimated to be the avoided cost rate) for every megawatt-hour and not just excess generation, then that project might expect an approximate 3.5 percent return on equity.

The Participant Cost Test evaluates cost effectiveness from the net metering participant's perspective. As discussed above, our modeling for costs of solar include a 0-percent return on investment such that a benefit-to-cost ratio of 1.0 reflects "break even" conditions. The greater the benefit-to-cost ratio, the more likely that solar net metering projects will be developed. A benefit-to-cost ratio less than 1.0 represents a situation in which costs to the participant exceed benefits. It is possible that some ratepayers in Mississippi might be willing to purchase solar net metering panels for reasons that are not purely driven by a desire to make a return on investment; for example, they may value a lower emission source of energy. One important caveat of the Participant Cost Test results shown in Table 7 is that no benefits or cost related to change in property value as a result of installing solar panels are assumed. A 2011 Lawrence Berkeley National Laboratory analysis concluded that:

> The research finds strong evidence that homes with PV systems in California have sold for a premium over comparable homes without PV systems. More specifically, estimates for average PV premiums range from approximately $3.9 to $6.4 per installed watt (DC) among a large number of different model specifications, with most models coalescing near $5.5/watt.[49]

A recent report conducted in Colorado by the Appraisal Institute, the nation's largest professional association of real estate appraisers, made a similar conclusion, stating, "solar photovoltaic systems typically increase market value and almost always decrease marketing time of single-family homes in the Denver metropolitan area."[50] The extent to which the real estate market would reflect the trends observed in California and Colorado is unclear. Moreover, according to a 2014 Sandia National Laboratories report, real estate value impacts are affected by the photovoltaic ownership structure (if it is leased or owned out right by the property owner).[51] Consequently, this analysis omitted this potential benefit of increased home value in the calculation of the benefit-cost ratios.

Utility Perspective Analysis

Two tests, the Rate Impact Measure and the Utility Cost Test, are sometimes used to determine the cost effectiveness of energy efficiency programs from the utility's perspective. The only difference between the RIM test and the UTC is the "lost revenues" (i.e., the reduction in the revenues as a result of reduced consumption). If the utility is to be made financially neutral to the impacts of the energy efficiency programs, then the utility would need to collect the lost revenues associated with the fixed cost portion of current rates. If the utility were to recover these lost revenues over time, then we would expect to observe an upward trend in future electricity rates.

One of the problems with the RIM test in the context of this study is that the lost revenues are not a *new* cost created by the net metering programs. Lost revenues are simply a result of the need to recover *existing* costs spread out over fewer sales. The existing costs that might be recovered through rate

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[49] Hoen, B. et. al. 2011. *An Analysis of the Effects of Residential Photovoltaic Energy Systems on Home Sales Prices in California*. Lawrence Berkeley National Laboratory. Available at: http://emp.lbl.gov/sites/all/files/lbnl-4476e.pdf.

[50] Appraisal Institute. 2013. "Solar Electric Systems Positively Impact Home Values: Appraisal Institute." Press release. Available at: http://www.appraisalinstitute.org/solar-electric-systems-positively-impact-home-values-appraisal-institute-/.

[51] Klise G.T., J.L. Johnson. 2014. *How PV System Ownership Can Impact the Market Value of Residential Homes*. Sandia National Laboratories. Available at: http://energy.sandia.gov/wp/wp-content/gallery/uploads/SAND2014-0239.pdf.

increases as a result of lost revenues are (a) not caused by the efficiency program themselves, and (b) are not a new, incremental cost. In economic terms, these existing costs are called "sunk" costs. Sunk costs should not be used to assess future resource investments because they are incurred regardless of whether the future project is undertaken. Application of the RIM test is a violation of this important economic principle.

Another problem with the RIM test is that it frequently will not result in the lowest cost to customers. Instead, it may lead to the lowest rates (all else being equal, and if the test is applied properly). However, achieving the lowest rates is not the primary or sole goal of utility planning and regulation; there are many goals that utilities and regulators must balance in planning the electricity system. Maintaining low utility system costs, and therefore low customer bills on average, is often given priority over minimizing rates. For most customers, the size of the electricity bills that they must pay is more important than the rates underlying those bills.

Most importantly, the RIM test does not provide the specific information that utilities and regulators need to assess the actual rate and equity impacts of energy efficiency or distributed generation. Such information includes the impacts on long-term average rates, the impacts on average customer bills, and the extent to which customers participate in efficiency programs or install distributed generation and thereby experience lower bills.

The Utility Cost Test provides some very useful information regarding the costs and benefits of energy efficiency resources. In theory, the UCT should include all the costs and benefits to the utility system over the long term, and therefore can provide a good indication of the extent to which average customer bills are likely to be reduced as a result of distributed energy resources. However, when applied to net metering, the results of the UTC are less indicative of how distributed generation will impact customers, primarily due to the wide variety in market participants and financing methods associated with distributed generation.

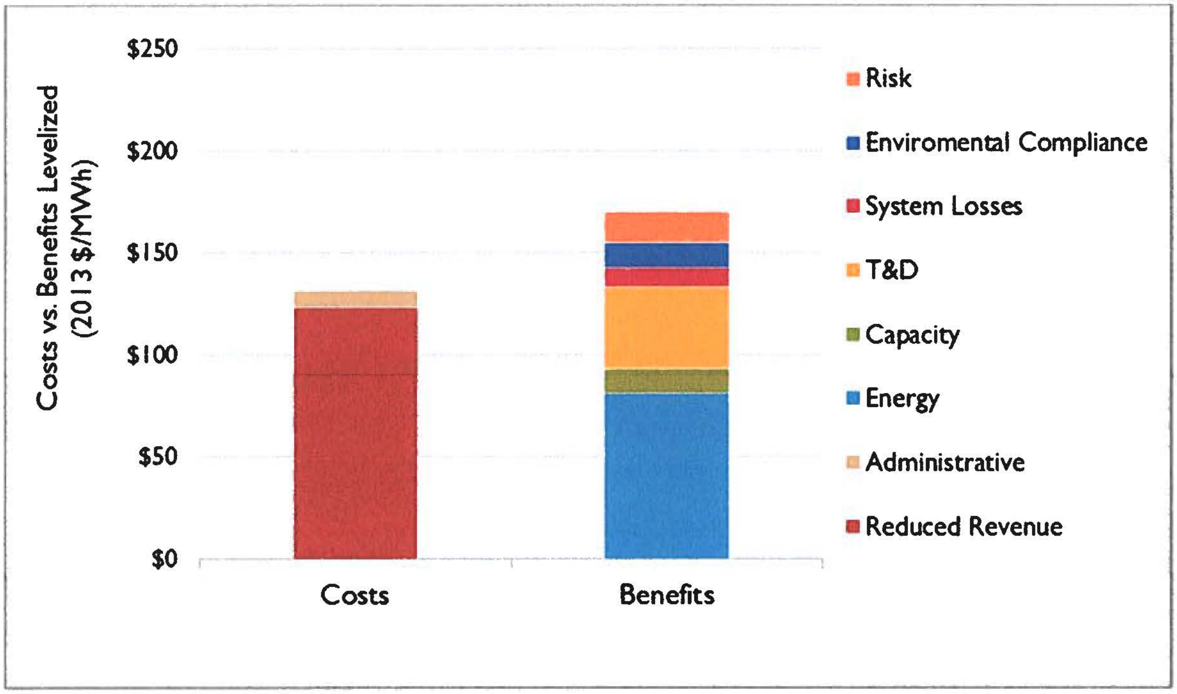
For these reasons, in this analysis we have chosen to use neither of these screening tests to investigate the impacts of net metering from the utility perspective.

Instead, we use a revenue requirement savings-to-cost ratio as an indicator of whether or not a net metering program will create upward or downward pressure on rates. Under a net metering policy where generation is compensated at the retail rate, utilities "pay" for the energy at the retail rate and receive a savings equivalent to the avoided cost rate. When the ratio, calculated by performing a 25-year levelization of avoided costs and dividing it by the 25-year levelized variable rate, is above 1.0, this indicates that there will be downward pressure on rates. When the ratio is below 1.0, it indicates that there will be upward pressure on rates. The results of this analysis cannot be directly translated into a rate or bill impact without additional analysis. Utility cost recovery and benefit sharing is dependent on future rate cases, program design, commission rulings, market changes, and other factors. Had the results of this test indicated that there would be upward pressure on rates, it would be necessary to perform additional analysis on rate and bill impacts on participants and non-participants in order to determine what, if any, regressive cross-subsidization was occurring.

For the revenue requirement savings-to-cost ratio, our analysis used a discount rate that reflects the utilities' cost of capital; for this analysis, we assumed this to be a 6-percent real discount rate. Use of this higher discount rate does not materially change the value of the avoided costs on a levelized basis.

Under our policy reference case assumptions, over the 25-year span of our analysis, the levelized savings (avoided costs) outweigh the levelized costs (retail variable rate plus administrative costs), as illustrated in Figure 18. This suggests that generation from net metering customers would put downward pressure on rates.

Figure 18. Levelized potential benefit/cost comparison under revenue requirement cost benefit analysis

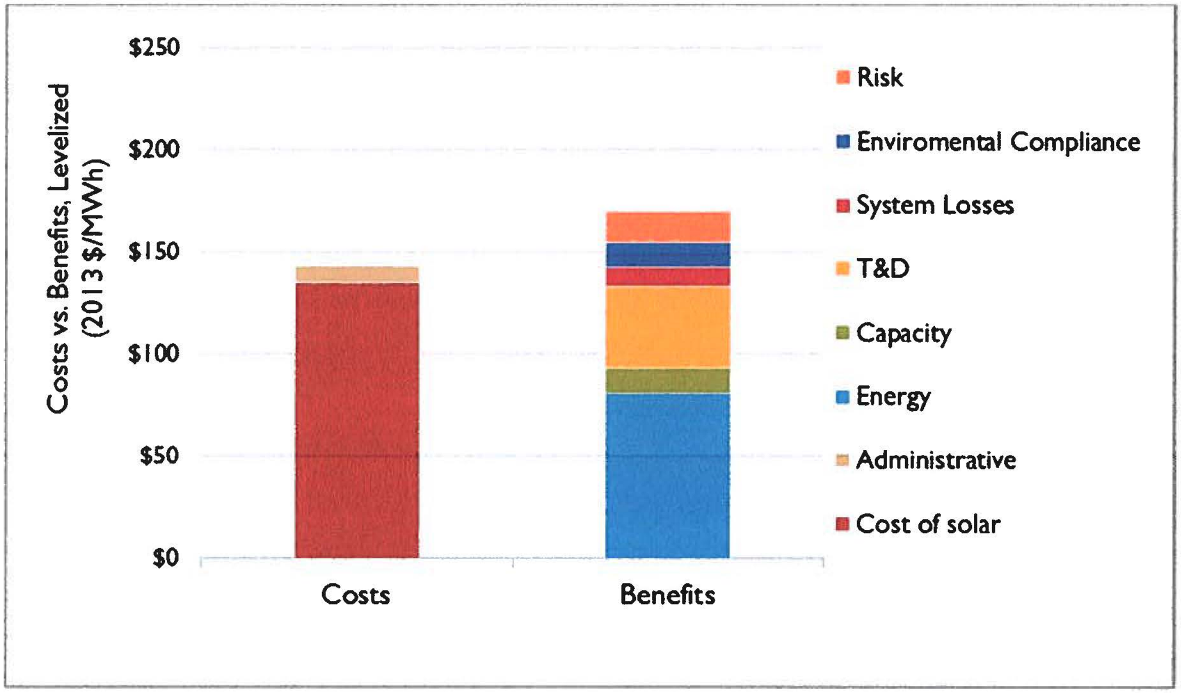


Total Resource Perspective

To determine the overall cost and benefits of a resource, this analysis employed the Total Resource Cost test, which compares net economic costs and benefits for the state as a whole but excludes avoided externality costs and economic development benefits. The test includes all of the avoided costs to the utility as benefits. It would also include any non-energy benefits as benefits if those could appropriately be accounted for. For our analysis, the cost associated with installing the solar panels and the administrative costs are the only costs reflected in our cost-benefit analysis using the TRC test. The analysis omits the potential for solar integration costs, as these are typically negligible at lower solar penetration.

As illustrated in Figure 19, under the assumptions of our policy reference case, solar net metering would provide net benefit to the state of Mississippi. With estimated benefits of $170 per MWh and estimated costs of $143 per MWh, net metered solar rooftop would result in $27 per MWh of net benefits to the state and passes the TRC with a benefit-to-cost ratio of 1.19.

Figure 19. Levelized potential benefit/cost comparison under Total Resource Cost Test



Societal Perspective

As stated above, the Societal Cost Test would include all the benefits and costs of the TRC test, plus any avoided externality costs and economic development benefits—including job creation and the potential for increased home value—if those could appropriately be accounted for. Since this analysis did not monetize these benefits (as explained in section 3.5), a Societal Cost Test benefit-cost analysis was not performed. Were these benefits included, the benefit-to-cost ratio would be higher than 1.19.

5. Sensitivity Analyses

We conducted sensitivity analyses—observing the impact of changing key modeling assumptions on our results—for the following inputs: oil and gas prices, projected capacity value, avoided T&D costs, and projected CO_2 emissions costs. All are compared to our policy case scenario, in which all variables are held at the Mid case.

5.1. Fuel Prices

Adjusting for high or low fuel prices has only a minor impact on the potential benefits of solar net metering, as illustrated in Figure 20. This figure also shows the levelized costs of solar for comparison. Changing fuel costs assumptions impacts the avoided energy, the avoided system losses, and the avoided risk benefits, with high fuel price assumptions resulting in increased benefits and low fuel price assumptions resulting in lower benefits. All three cases—High, Mid, and Low—result in a TRC benefit-to-cost ratio above 1.0, as shown in Table 8.

Figure 20. Results of fuel price sensitivities

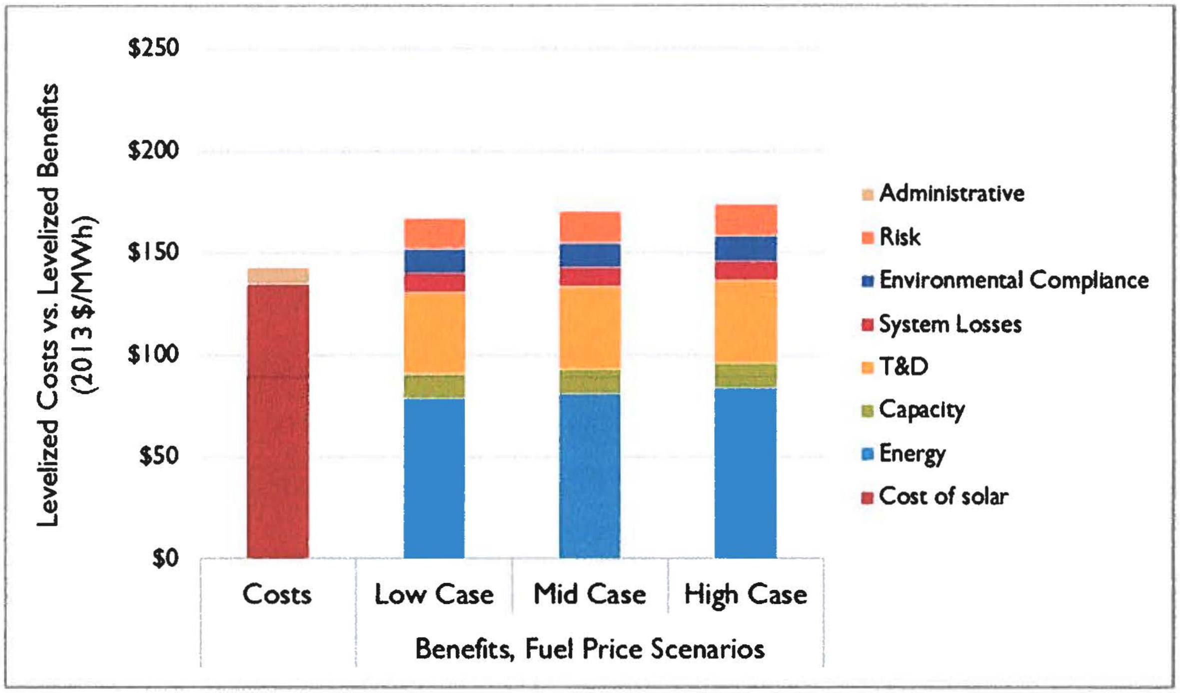


Table 8. Avoided energy benefits and TRC test benefit/cost ratios under fuel price sensitivities

	Low	Mid	High
Avoided Energy Benefit	$78/MWh	$81/MWh	$83/MWh
Fuel Price Sensitivities	1.17	1.19	1.21

5.2. Capacity Values

Adjusting for a high or low forecast of capacity value has some impact on the potential benefits of solar net metering, as illustrated in Figure 21. This figure also shows the levelized costs of solar for comparison. Changing capacity value projections impacts the avoided capacity cost and avoided risk benefits, with high capacity value projections resulting in increased benefits and low capacity value projections resulting in lower benefits. All three cases—High, Mid, and Low—result in a TRC benefit to cost ratio above 1.0, as shown in Table 9.

Figure 21. Results of capacity value projection sensitivities

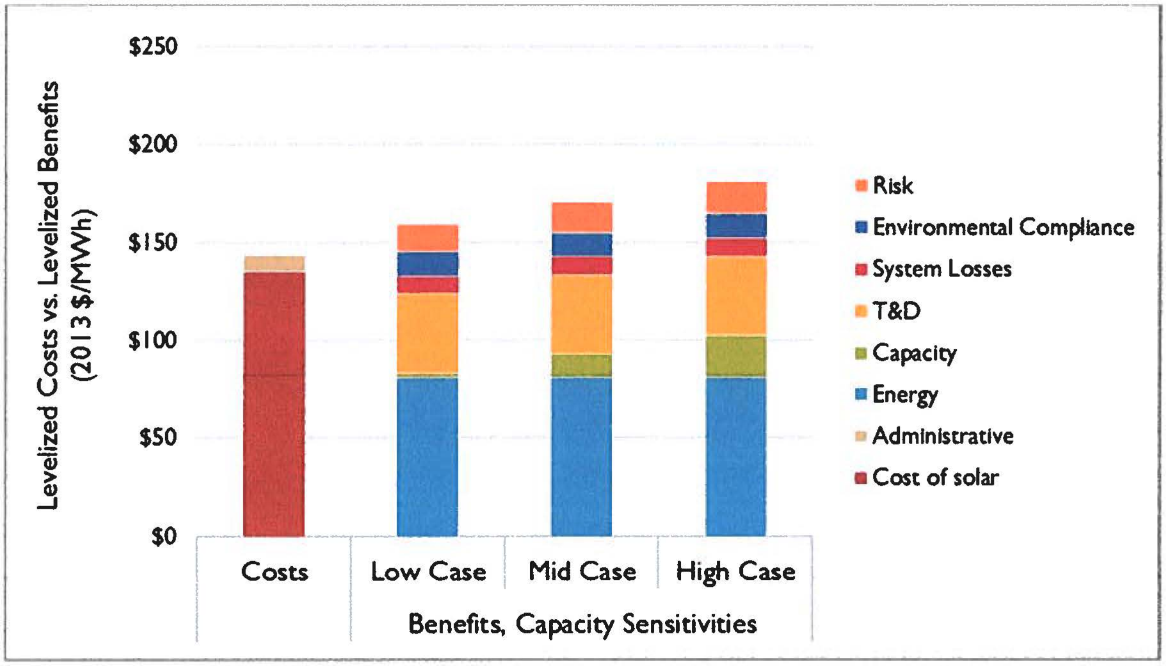


Table 9. Avoided capacity benefits and TRC test benefit/cost ratios under capacity value sensitivities

Capacity Value Sensitivities	Low	Mid	High
Avoided Capacity Benefit	$3/MWh	$12/MWh	$22/MWh
B/C Ratio under a TRC Test	1.11	1.19	1.26

5.3. Avoided T&D

Adjusting for high or low avoided T&D costs, which reflect the 25th and 75th percentile of our database of avoided T&D costs, had the most noticeable impacts on the potential benefits of solar net metering, as illustrated in Figure 22. Again, the figure shows the levelized costs of solar for comparison. Changing the costs of T&D impacts the avoided T&D costs and the avoided risk benefits, with high capacity value projections resulting in increased benefits and low capacity value projections resulting in lower benefits. All three cases—High, Mid, and Low—result in a TRC benefit to cost ratio above 1.0, as shown in Table 10.

Figure 22. Results of avoided T&D value sensitivities

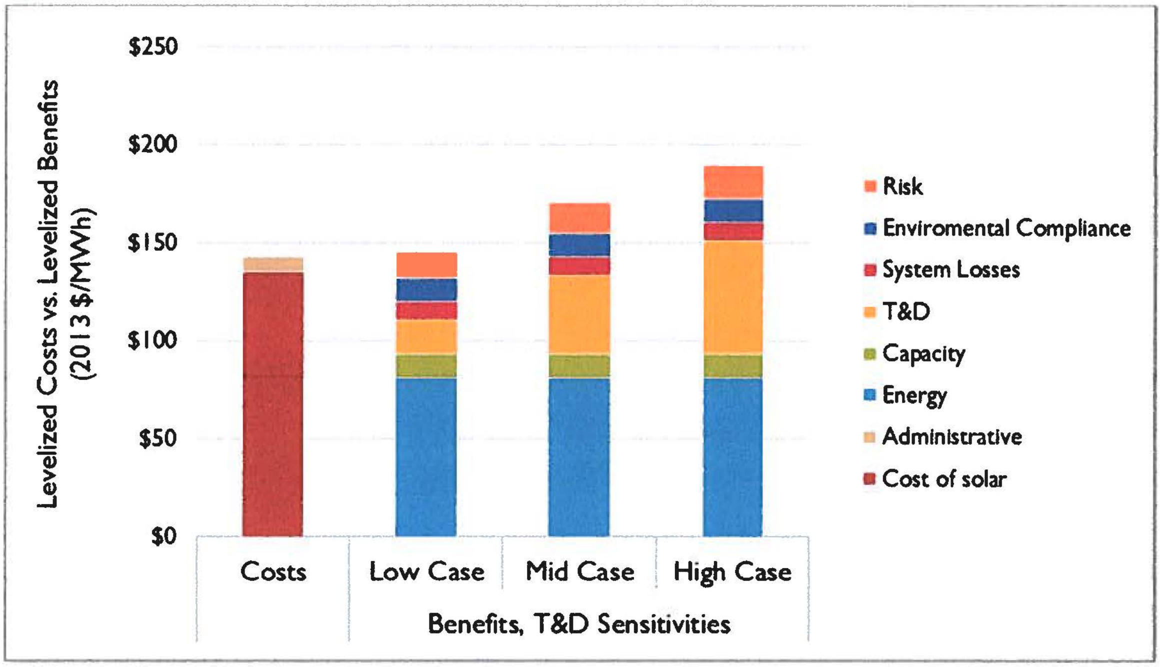


Table 10. Avoided T&D benefits and TRC test benefit/cost ratios under avoided T&D cost sensitivities

Avoided T&D Sensitivities	Low	Mid	High
Avoided T&D Benefits	$18/MWh	$40MWh	$58/MWh
B/C Ratio under a TRC Test	1.01	1.19	1.32

5.4. CO_2 Price Sensitivities

Adjusting for a high or low trajectory of CO_2 emissions costs has some impact on the potential benefits of solar net metering, as illustrated in Figure 23. This figure shows the levelized costs of solar for comparison. Changing CO_2 price forecasts impacts the avoided environmental compliance cost and avoided risk benefits, with the high projection resulting in increased benefits and low projection resulting in lower benefits. All three cases—High, Mid, and Low—result in a TRC benefit to cost ratio above 1.0, as shown in Table 11.

Figure 23. Results of CO_2 forecast sensitivities

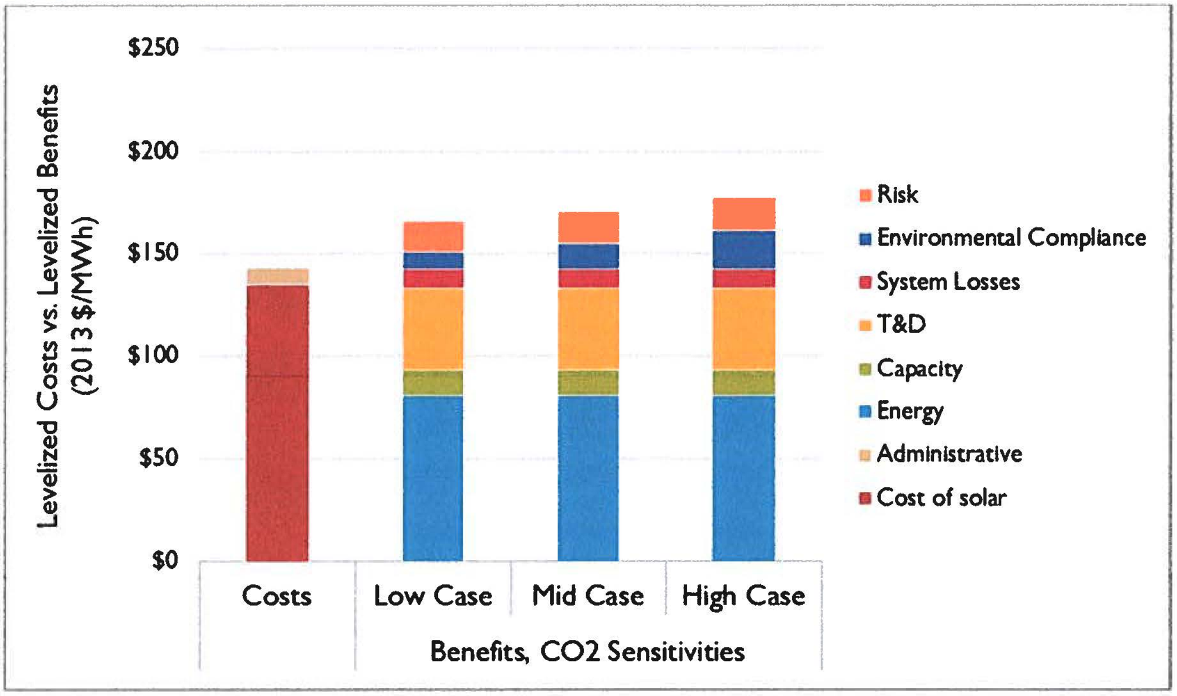


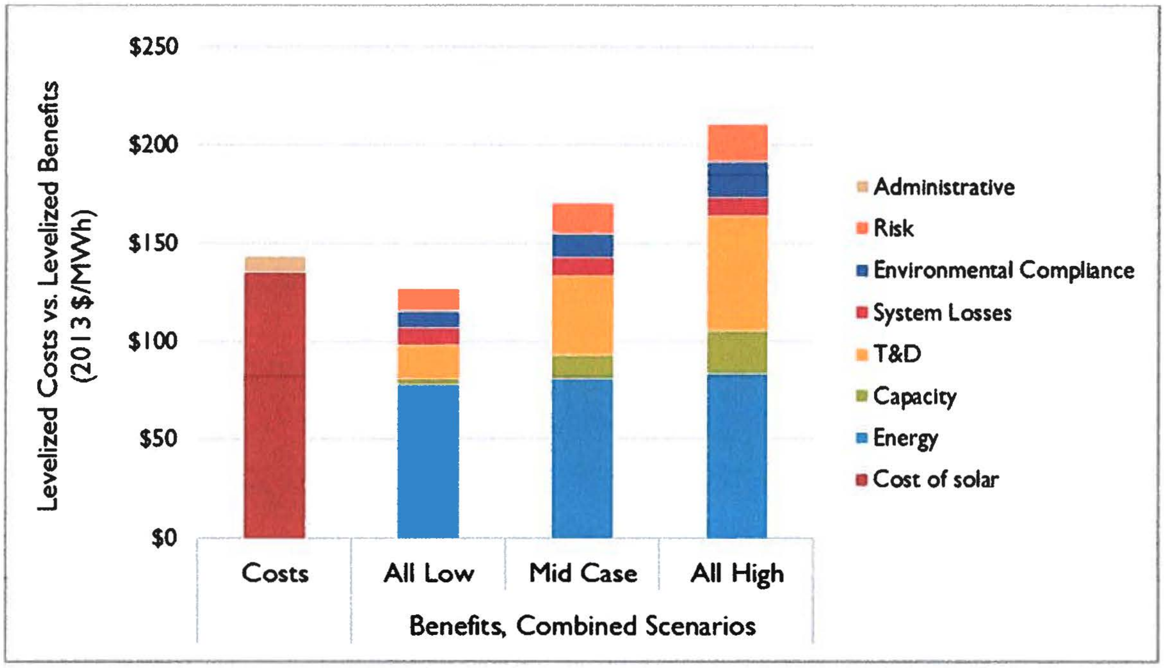
Table 11. Avoided environmental compliance costs and TRC benefit/cost ratios under CO_2 cost sensitivities

CO2 Price Sensitivities	Low	Mid	High
Avoided Environmental Compliance Costs	$8/MWh	$12/MWh	$18/MWh
B/C Ratio under a TRC Test	1.16	1.19	1.24

5.5. Combined Sensitivities

We modeled two combined sensitivities scenarios: (1) each variable was set to the assumption that would yield the lowest benefits for solar net metering; (2) each variable was set to the assumption that would yield the highest benefits for solar net metering. The levelized results of this analysis are shown in Figure 24.

Figure 24. Results of scenario testing under combined sensitivities



As shown in Table 12, solar net metering passes the Total Resource Cost test in all but one of the sensitivities described above.

Table 12. Summation of TRC Test benefit/cost ratios under various sensitivities

	Low	Mid	High
Fuel Price Sensitivity	1.17	1.19	1.21
Capacity Value Sensitivities	1.11	1.19	1.26
Avoided T&D Sensitivities	1.01	1.19	1.32
CO_2 Price Sensitivities	1.16	1.19	1.24
Combined Sensitivities	0.89	1.19	1.47

6. Conclusions

The analysis conducted and the results shown in this report reflect the potential costs and potential benefits that an illustrative net metering program could provide to Mississippians. From a Total Resource Cost perspective, solar net metered projects have the potential to provide a net benefit to Mississippi in nearly every scenario and sensitivity analyzed. These benefits will only be realized if customers invest in distributed generation resources. This may never happen if net metering participants are not expected to receive a reasonable rate of return on investment. Based on the results of the participant cost analysis, net metering participants in Mississippi would need to receive a rate beyond the average retail (variable) rate in order to pursue net metering. This suggests that Mississippi may want to consider an alternative structure to any net metering program they choose to adopt. One alternative structure would be to compensate distributed solar through a solar tariff structure similar to the ones used in Minnesota and by TVA, and under consideration in Maine.[52]

By appropriately using a solar tariff structure, it would be possible to structure Mississippi's proposed net metering rules to allow net benefits for participants and prevent cost shifting to non-participants. If all avoided costs are accurately and appropriately accounted for and the consumers are paid an avoided cost rate, then there is no cost shifting because the costs to non-participants (those customers without distributed generation) are equal to the benefits to non-participants. Net metering customers should be paid for the value of their distributed generation, but non-participants should not bear an undue burden as a consequence of net metering. This could be accomplished by compensating net metering customers at the avoided cost rate through a tariff structure. If participants will be compensated at the avoided cost rate, this value must be carefully calculated and updated periodically. The valuation process would include a rigorous quantification and monetization of all of the benefits and costs we identified and provided as preliminary estimates in this report.

[52] The Maine Solar Energy Act, Sec. 1. 35-A MRSA c. 34-B Available here: http://www.mainelegislature.org/legis/bills/bills_126th/billtexts/SP064401.asp

Appendix A: Value of Avoided Risk

The objective of this appendix is to review the current practices regarding the risk value used in avoided cost analyses, primarily for distributed generation, and to recommend a reasonable value for a risk adjustment factor to apply to the cost-benefit analysis of distributed solar generation in Mississippi.

There are a number of risk reduction benefits of renewable generation (and energy efficiency), whether those resources come from central stations or distributed sources. The difficulties in assigning a value to these benefits lie in (1) quantifying the risks, (2) identifying the risk reduction effects of the resources, and (3) quantifying those risk reduction benefits.

The most common practical approach has been to apply some adder (adjustment factor) to the avoided costs rather than to attempt a more thorough technical analysis. However, there is little consensus in the field as to what the value of that adder should be. Based on expert judgment and experience, Synapse suggests a 10 percent adder be applied when calculating avoided costs for renewables such as solar and wind. The literature review below demonstrates that there is wide variance in the range of values used in practice.

Theoretical Framework

First, we will look at the types of avoided costs that might be associated with distributed generation. The full range of possible benefits as identified in recent testimony by Rick Hornby in North Carolina is quite extensive, as indicated by Table 13. Typically, distributed generation avoided costs are based on direct costs that can be easily quantified, as indicated by "Yes" in the DG column below. In some situations, attempts are made to assign values to hard-to-quantify categories, such as environmental, health, and economic benefits. The table also indicates categories where there might be possible risk benefits associated with these avoided costs. For example, renewable generation reduces the probability and effects of energy price spikes, reducing risk in that category.

Table 13. Avoided cost and possible risk reduction benefit categories

	Avoided Cost Category	PURPA	DG	Risk Benefits
1	Energy costs (electricity generation costs)	Yes	Yes	Yes
2	Capacity cost for generation	Yes	Yes	Yes
3	Transmission costs	?	Yes	Maybe
4	Distribution costs	No	Yes	Maybe
5	T&D Losses	?	Yes	No
6	Environmental costs (direct)	Yes	Yes	Yes
7	Ancillary services and grid support	?	?	Maybe
8	Security and resiliency of grid	No	?	Yes
9	Avoided renewable costs	Yes	Yes	Maybe
10	Energy market impacts	No	?	Maybe
11	Fuel price hedge	No	?	Yes
12	Health benefits	No	?	Yes
13	Environmental and safety benefits (indirect)	No	?	Yes
14	Visibility benefits	No	?	Maybe
15	Economic activity and employment	No	?	Maybe

How does a risk factor fit into this context? First, one needs to identify what categories of avoided costs are being used, and then where risk benefits might occur. For example, with avoided energy costs there is the possibility that those costs might be extremely high in some hours. Distributed generation resources reduce that possibility. Distributed generation resources may even reduce the chance of a system outage.

There is also a major conceptual problem in applying a risk factor to basic avoided costs. While there are likely risk values associated with distributed generation, it is overly simplistic to assume that the risk value can be represented as a simple factor applied to the avoided costs. As shown in Table 13, there are many kinds of avoided costs that may or not be considered in a particular analysis, and only some of those categories might also have risk reduction benefits.

Options and Hedging

The Black-Scholes (B-S) model is a mathematical formulation for evaluating the value of an option, which is the right to buy or sell a resource at a given future time at a given price. This is most commonly used in financial markets for the purchase or sales of stock. Consider the following example of a stock whose future price is uncertain but is currently $50 per share, which the buyer thinks is too high. The buyer could purchase an option to buy the stock in six months at $45 per share (assuming such an option is available). Then in six months, if the actual price is more than $45 per share, the buyer might exercise his option and purchase the stock at that price. If the market price is lower, the buyer can let his option expire and buy the stock on the market. The B-S model is based on historical price data and determines how much such an option should cost. There are of course a large number of assumptions and complications in such calculations, but supposedly in a liquid and competitive market (where participants know how to apply the B-S model), the option price would have the B-S value. Another issue to consider is that the B-S model tends to fail under unusual market situations, such as in the economic recession of 2008.

In theory, one could apply this approach to the value of reducing energy price risk. Consider that the expected future price of electricity is $100 per MWh, but the buyer wants to protect him- or herself against it going above $110. The buyer could then purchase an option to buy at $110 per MWh 12 months from now. The cost of that option represents the cost of protection against all prices $110 and greater at that point in time. However, option markets for electricity prices are uncommon and trading is very thin.[53] Options for natural gas products are much more active and can be used as an electricity price hedge.[54]

One methodology that has been used in some analyses reviewed here is to calculate the hedge value of a renewable or energy efficiency resource based on an imputed option value. This of course depends strongly on the assumptions used, which have generally not been very transparent.

Let's consider an example of how this might be implemented. Say that the avoided energy cost is determined to be $50 per MWh, which represents the average of a range of possible values. Say furthermore that one doesn't care about modest price swings but is concerned about prices greater than $75 per MWh. Then one could think of purchasing a call option with a strike price of $75, which limits the price exposure to that price.[55] The cost of that option represents the hedge value of a resource that also eliminates that risk.

Futures Markets

Futures markets provide a way of hedging against changes in prices but lack the optional aspect. In a futures market, one has an obligation to buy or sell at a certain price at a given future date. Supposedly the futures price represents a balance between sellers who want to avoid a decline in prices and buyers who want to avoid an increase in prices. Thus the risks are in balance and the price is at a neutral point. Now if a buyer locks in a price there is the risk that the actual price is lower, but they are committed at a higher price and thus experience a loss. But the expectation is that gains and losses balance out, at least in the long term.

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53 CME Group maintains an options market that includes PJM electricity products but only for about two years out, and trading levels are zero for many product months. See: http://www.cmegroup.com/market-data/settlements.

54 EIA uses short-term natural gas energy options (which is a fairly robust market) to determine the confidence intervals for its short term natural gas price forecast. See: http://www.eia.gov/forecasts/steo/report/natgas.cfm.

55 The closer to the expected price, the more expensive would such an option be. For example, a call option at the expected price of $50 could easily be $5 or more based on risk associated with all the prices above that level.

Distributed Generation and Energy Efficiency

In many ways, the benefits of distributed renewable generation are very similar to those of energy efficiency. Both affect loads at the user level and have variable costs that are very low or zero. However, there is a key difference in timing. Energy efficiency reduces usage for specific end uses, resulting in savings proportional to that load. For example, improved lighting reduces the load when lights are being used. Different energy efficiency measures will have different load saving shapes, but they will be load-related. In contrast, distributed solar generation produces energy based on the amount of sunlight that is available and the configuration of the devices. This means that the energy from distributed solar generation is only roughly correlated with load, and thus may have a greater or lesser benefit than energy efficiency energy savings. Still, the methods for calculating the value of avoided risk associated with energy efficiency measures and distributed generation are comparable, which is why the literature review summarized below considers studies in energy efficiency as well as distributed generation.

Current Practices

In this section, we review materials related to the question of risk value. Taken as a whole, these studies and documents demonstrate the wide variance in the range of values used to calculate the value of avoided risk. These values are summarized in Table 14, below.

Table 14. Value of risk factors used in various scenarios

Source	Description	Risk Factor
State Regulatory Examples		
Vermont	Adder to the cost of supply alternatives when compared to demand-side management	10%
Oregon	Cost adjustment factor to cost of avoided electricity supply in efficiency screening; represents risk mitigation but also environmental benefits and job creation	10%
Avoided Energy Supply Cost Studies		
2009	Wholesale risk premium applied to wholesale energy and capacity prices	8-10%
2013 (non-Vermont)	Wholesale risk premium applied to wholesale energy and capacity prices	9%
2013 (Vermont)	Wholesale risk premium applied to wholesale energy and capacity prices	11.1%
Maryland OPC Risk Analysis		
DWN portfolio	Insurance premium for Demand-Side-Management-Wind-Natural Gas portfolio	3.5%
DWC portfolio	Insurance premium for Demand-Side-Management-Wind-Coal portfolio	2.5%
Northwest Power and Conservation Council		
Sixth Power Plan	Risk measured using the $TailVaR_{90}$ metric	-
Ceres Risk-Aware Electricity Regulation		
Ceres report	No distinct value, risk index relative to other resources	-
PacifiCorp 2013 IRP		
2013 IRP	Stochastic risk reduction credit as percentage of avoided costs	~10%
Rocky Mountain Institute Review of Solar PV Benefit and Cost Studies		
CPR NJ/PA	Fuel price hedge values as percentage of value of solar	~10%
NREL	Natural gas hedge value as percentage of avoided costs	0-12%

State Regulatory Examples

In the report *Best Practices in Energy Efficiency Program Screening*, Synapse authors identified two states that account for the risk benefit of energy efficiency directly in the criteria used to screen efficiency programs.[56] Vermont applies a 10 percent adder to the cost of supply alternatives when compared to demand-side management investments to account for the comparatively lesser risks of demand-side management. Oregon adds a 10 percent cost adjustment factor to the cost of avoided electricity supply when screening efficiency programs to represent the various benefits of energy efficiency that are not reflected in the market; these benefits include risk mitigation but also environmental benefits and job creation.

Avoided Energy Supply Cost (AESC) Studies

Since 2007, Synapse and a team of subcontractors have developed biannual projections of marginal energy supply costs that would be avoided due to reductions in electricity, natural gas, and other fuels resulting from energy efficiency programs offered to customers in New England.[57] In these studies, a risk factor identified as a "wholesale risk premium" is applied. This premium represents the difference in the price of electricity supply from full-requirement fixed price contracts and the sum of the wholesale market prices for energy, capacity, and ancillary-service in effect during that supply period. This premium accounts for the various costs that retail electricity suppliers incur on top of wholesale market prices, including costs to mitigate cost risks such as costs of hourly energy balancing transitional capacity, ancillary services, uplift, and the difference between projected and actual energy requirements due to unpredictable variations in weather, economic activity, and/or customer migration.

The wholesale risk premium is applied to both the wholesale energy and capacity prices. Estimates of this adder based on analysis of confidential supplier bids range from 8 to 10 percent. For the AESC 2013 study,[58] a value of 9 percent was used, except for Vermont where a mandated rate of 11.1 percent was used.[59]

Maryland OPC Risk Analysis Study

In 2008, Synapse conducted a project in conjunction with Resource Insight on behalf of the Maryland Office of the People's Counsel to identify the costs and risk benefits to residential customers of

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[56] Woolf, T., E. Malone, K. Takahashi, W. Steinhurst. 2012. *Best Practices in Energy Efficiency Program Screening*. Synapse Energy Economics for the National Home Performance Council.

[57] Hornby, R. et al. 2009. *Avoided Energy Supply Costs in New England: 2009 Report*. Synapse Energy Economics for the AESC Study Group, page 2-42.

[58] Hornby, R. et al. 2013. *Avoided Energy Supply Costs in New England: 2013 Report*. Synapse Energy Economics for the AESC Study Group, page 5-23, 24.

[59] The approved 10 percent Vermont risk value is applied to the cost of the energy efficiency measures and thus translates following state practice into a 11.1 percent adder to the avoided cost (i.e. 11.1% = 1.0/0.9).

alternative strategies for meeting their electricity requirements over a long-term planning period.[60] Synapse used a Monte Carlo analysis to examine the expected costs and risks of different procurement strategies for Standard Offer Service. A variety of strategies were considered, including contracts of varying duration as well as energy efficiency investments and longer-term contracts for new resources. The risk potential was determined by calculating the $TailVaR_{90}$ values (the average of the net present values for the costliest 10 percent of outcomes) for each portfolio. Although the risk and average costs were strongly correlated, there were some cases that were exceptions to this rule. For example, the DWN (Demand-Side-Management-Wind-Natural Gas) portfolio had a lower cost than the DWC portfolio (Demand-Side-Management-Wind-Coal), but a higher $TailVaR_{90}$ value. The results of course depend hugely on the assumptions used for the random variables, such as natural gas and carbon prices. Greater uncertainty in the carbon price would likely have changed that relationship. Although the risk was calculated, no explicit cost value was assigned to it since that depends on the value (or cost) of avoiding that risk.

Using the DWN and DWC portfolios from this report displayed in Table 15, we can infer a risk factor. For DWN, the expected cost was $12,023 million and the $TailVaR_{90}$ was $16,223 million, representing a possible increase of $4,200 million with a 10 percent probability. One could think then of hedging that with a 10 percent premium of $420 million, which corresponds to a risk factor of 3.5 percent. For the DWC case, that risk factor/insurance premium would be 2.5 percent. These risk factors only insure against part of the risk, and are specific to this particular analysis.

Table 15. Long-term NPV cost and $TailVaR_{90}$ risk by portfolio in Maryland procurement strategies study

		Difference from BAU			Spread Between $TVaR_{90}$ and Expected Cost	
Portfolio	Expected Cost ($M)	*Million Dollars*	*Percent*	$TVaR_{90}$ ($M)	*Million Dollars*	*Percent*
BAU	14,657			20,664	6,007	41%
Spot	13,723	(934)	-6%	19,333	5,609	41%
Clean BAU	13,082	(1,576)	-11%	17,849	4,767	36%
DWN	12,023	(2,634)	-18%	16,223	4,200	35%
DWC	12,263	(2,395)	-16%	15,259	2,997	24%
DWNC	12,095	(2,562)	-17%	15,643	3,548	29%

Source: "Risk Analysis of Procurement Strategies for Residential Standard Offer Service," p. 43

Northwest Power and Conservation Council (NWPCC)

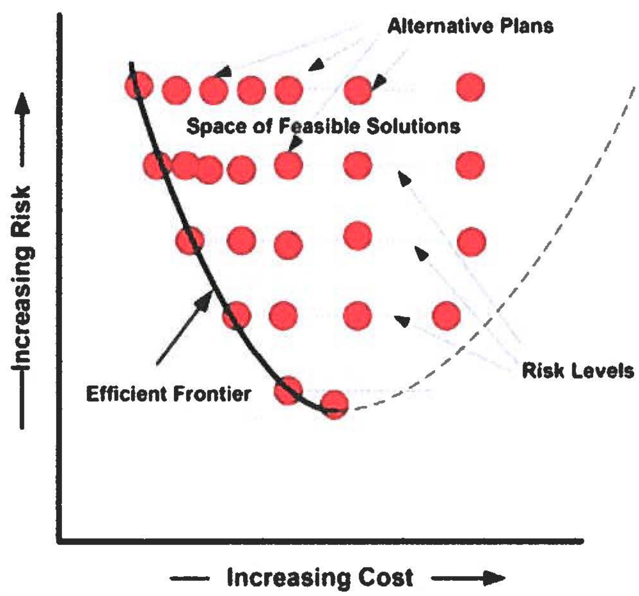
The Northwest Power and Conservation Council (NWPCC) has been assessing and developing plans for the future of energy resources in the Northwest region every five years since the organization was

60 Wallach, J., P. Chernick, D. White, R. Hornby. 2008. *Risk Analysis of Procurement Strategies for Residential Standard Offer Service*. Resource Insight and Synapse Energy Economics for the Maryland Office of the People's Counsel.

created in 1980.[61] An important element of these plans is risk assessment and management. Since the first Power Plan, NWPCC has analyzed the value of shorter lead times and rapid implementation of energy efficiency and renewable resources. Starting in the Fifth Power Plan in 2005, NWPCC extended its risk assessment to incorporate risks such as electricity risk uncertainty, aluminum price uncertainty, emission control cost uncertainty, and climate change.[62]

The NWPCC addressed risk by evaluating numerous energy resource portfolios against 750 futures. It compares the risk of one portfolio (measured using the $TailVaR_{90}$ metric) and the average value of a portfolio (the most likely cost outcome for the portfolio). Figure 25 provides an illustrative example of this analysis. The set of points corresponding to all portfolios is called a feasibility space, and the left-most portfolio in the feasibility space is the least-cost portfolio for a given level of risk. The line connecting the least-cost portfolios is called the efficient frontier, which allows the NWPCC to narrow their focus, typically to a fraction of 1 percent of these portfolios. NWPCC calls this entire approach to resource planning "risk-constrained, least-cost planning" (NWPCC 2010, pp. 9-5 to 9-6).

Figure 25. Efficient frontier of feasibility space



Source: NWPCC 2005, p.6-13.

Using this approach, the NWPCC has found "the most cost-effective and least risky resource for the region is improved efficiency of electricity use" (NWPCC 2010, page 3).

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61 Woolf, T., E. Malone, K. Takahashi, W. Steinhurst. 2012. *Best Practices in Energy Efficiency Program Screening*. Synapse Energy Economics for the National Home Performance Council.

62 Northwest Power and Conservation Council. 2010. *The Sixth Northwest Conservation and Electric Power Plan*. Available at: https://www.nwcouncil.org/energy/powerplan/6/plan.

Ceres Risk-Aware Electricity Regulation

A 2012 study by the non-profit organization Ceres evaluated the costs and risks of various energy resources, and, like NWPCC, found energy efficiency to be the least cost and least risky electricity resource.[63] Ceres used the following categories to evaluate risk: fuel price risk, construction cost risk, planning risk, reliability risk, new regulation risk, water constraint risk.

Fuel price risk stems from the volatility of prices, which historically have been driven by varying demand for and supply of natural gas. *Construction cost risk* is lower for energy efficiency as compared to other resources because conventional generation requires longer development timelines, which expose these resources to longer-term increases in the cost of labor and materials. For example, the construction cost schedule of the proposed Levy nuclear power plant in Florida has been delayed five years due to financial and design problems and its cost estimates has increased from $5 billion to $22.5 billion.[64] *Planning risk* is introduced when electric demand growth is lower than expected, since there is a risk that a portion of the capacity of new power plants may be unused for a long time. Ceres reported that in January 2012, lower-than-expected electricity demand along with unexpectedly low natural gas prices mothballed a brand-new coal-fired power plant in Minnesota. The utility (Great River Energy) was expected to pay an estimated $30 million in 2013 just for maintenance and debt service for the plant—energy efficiency resources that reduce load incrementally would never face this problem. *Reliability risk* is also mitigated by energy efficiency resources, which substantially reduce peak demand during times when reliability is most at risk and which slow the rate of growth of electricity peak and energy demands, providing utilities and generation companies more time and flexibility to respond to changing market conditions. *New regulation risk* is associated with the cost of complying with safety or environmental regulations, such as EPA's recently proposed Section 111(d) of the Clean Air Act, which will increase the cost of fossil fuel plants. Energy efficiency is not subject to these regulations and would in fact reduce the level of risk to the extent that efficiency displaces regulated resources. *Water constraint risk* includes the availability and cost of cooling and process water; energy efficiency is not subject to this risk, and again can mitigate the risk to the extent that efficiency resources displace conventional resources.

The Ceres report does not assign one value to avoided risk; however, it does rank resources based on relative levels of risk, and finds that distributed solar has one of the lowest composite risk scores of new generation sources. Ceres charts risk against increasing cost for these resources as shown in Figure 26.

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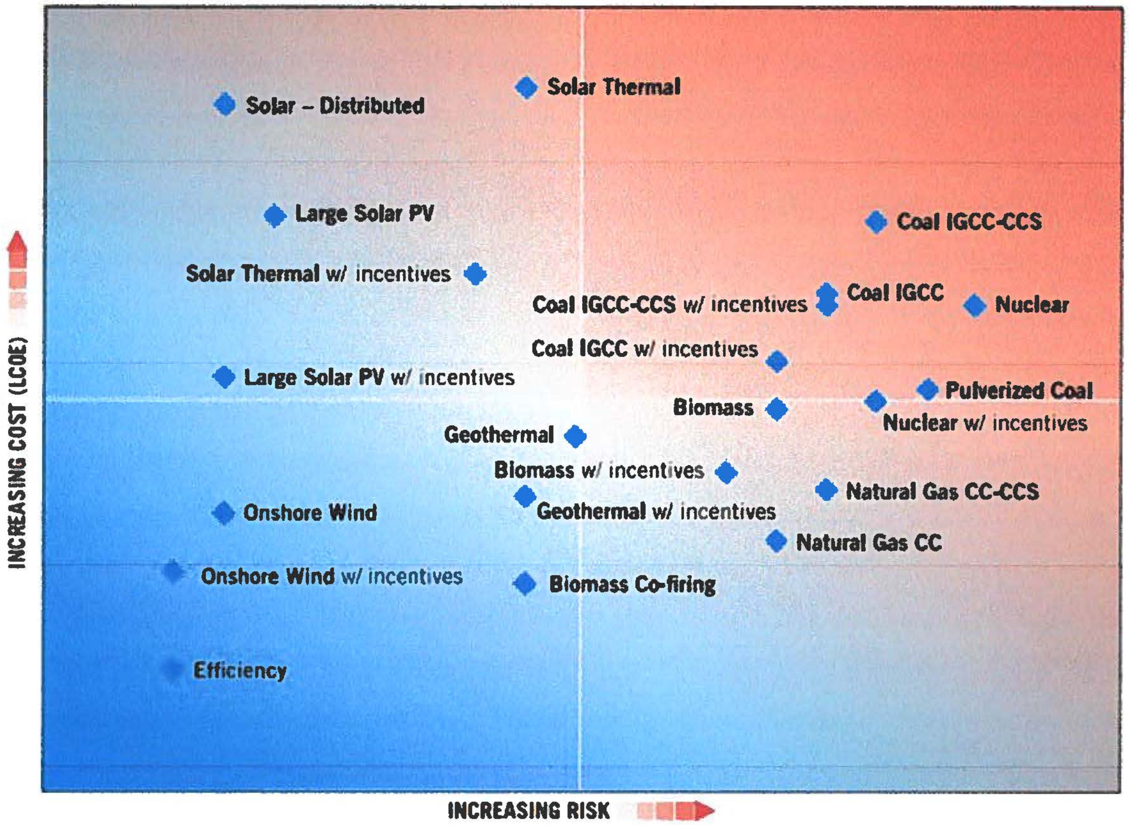
[63] Binz, R., R. Sedano, D. Furey, D. Mullen. 2012. ***Practicing Risk-Aware Electricity Regulation: What Every State Regulator Needs to Know.*** Ceres. Available at: http://www.ceres.org/resources/reports/practicing-risk-aware-electricity-regulation/view.

[64] Kaczor, B. 2010. "Florida PSC hearing testimony on nuclear rates." ***Bloomberg Businessweek.*** Available at: http://www.businessweek.com/ap/financialnews/D9HQ2TN80.htm.

Figure 26. Relative cost and risk of utility generation resources



Source: Ceres 2012, figure 17, p. 37

PacifiCorp 2013 Integrated Resource Plan

In its 2013 integrated resource plan, PacifiCorp applied a stochastic risk reduction credit of $7.05 per MWh for demand-side management resources. This figure was estimated by taking the difference between a comparison of deterministic PaR runs for the 2011 IRP preferred portfolio with and without demand-side management and a comparison of stochastic PaR runs for the 2011 IRP preferred portfolio with and without demand-side management and then dividing that difference by the MWh of demand-side management in the 2011 IRP preferred portfolio. Table N.1 of the IRP (on page 357) indicates total avoided costs of $75.75 per MWh; therefore, $7.05 is a little less than 10 percent of the avoided cost before the risk factor is applied.

Rocky Mountain Institute Review of Solar PV Benefit and Cost Studies

Rocky Mountain Institute (RMI) conducted a review of solar photovoltaic benefit and cost studies.[65] In that study, RMI considers financial and security risks; a number of other types of risk, such as environmental ones, are not considered. While RMI notes that there is little agreement on an approach to estimating the unmonetized values of financial and security risk, it does report the risk-related benefits for fuel price hedge as reported by studies performed by Clean Power Research in Texas and New Jersey/Pennsylvania, as well as studies by NREL and by a team of researchers led by Richard Duke (RMI 2013, 35). There is a wide range in these values and they are fairly substantial, ranging from about 0.5 cents per kWh to over 3.0 cents per kWh ($5 per MWh to $30 per MWh).

The Clean Power Research (CPR) hedge benefits are based on an analysis of the volatility of natural gas prices, which are then reflected in electricity prices. The cited Texas reports are short on numbers, but the New Jersey/Pennsylvania report has more specifics. In the latter report, CPR calculates the levelized value of solar in Pennsylvania and New Jersey from $256 to $318 per megawatt hour. The fuel price hedge values range from $24 to $47 per MWh, thus roughly in the order of 10 percent.

The cited NREL study[66] gives a natural gas hedge value for photovoltaics a range from 0.0 to 0.9 cents per kWh. Overall, the total photovoltaic benefits in that study range from about 7 to 35 cents per kWh ($70 to $350 per MWh). So the hedge value fraction ranges from roughly 0 to 12 percent of the total avoided costs.

Note also that the hedge values cited in the RMI study appear to depend largely on the volatility of natural gas prices, which is likely to be lower in the future due to increased supply and lower prices in the U.S.

Conclusions and Recommendations

There are certainly a variety of risk reduction benefits of renewable generation (and energy efficiency), whether those resources come from central stations or distributed sources. The difficulties in assigning a value to these benefits lie in:

1. Quantifying the risks,
2. Identifying the risk reduction effects of renewables, and
3. Quantifying those risk reduction benefits.

To do all three steps properly would be both difficult and contentious. None of the research and case studies reviewed above has attempted it. The nearest example is the NWPCC Power Plans.

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[65] Hansen, L., L. Virginia. 2013. *A Review of Solar PV Benefit and Cost Studies*. Rocky Mountain Institute. Available at: http://www.rmi.org/Knowledge-Center%2FLibrary%2F2013-13_eLabDERCostValue.

[66] Contreras, J.L., Frantzis, L., Blazewicz, S., Pinault, D., Sawyer, H. 2008. *Photovoltaics Value Analysis*. Navigant Consulting.

Current heuristic practice would support a 10 percent adder to the avoided costs for renewables such as solar and wind. There are both more avoided cost and risk reduction benefits associated with distributed generation (see Table 13). Thus, one would expect greater absolute risk reduction benefits with distributed generation, but there is insufficient information to determine how that might differ on a percentage basis.

Evaluation of Net Metering in Vermont Conducted Pursuant to Act 99 of 2014

Public Service Department
October 1, 2014

1 Introduction

Act 99 of the 2014 Vermont legislative session directed the Public Service Department (Department) to complete an evaluation of net metering in Vermont and file the resulting report with the Public Service Board. The report is required to include an analysis of each of the items described under 30 V.S.A. §8010(d)(1)-(9), paraphrased here:

- *§8010(d)(1) – Analyze Current Pace of Net Metering deployment Statewide and by Utility*
- *§8010(d)(2) – Recommend future pace of net metering deployment Statewide and by Utility*
- *§8010(d)(3) – "Existence and degree" of cross subsidy between Net Metered customers and Others.*
- *§8010(d)(4) – Effect of net metering on retail electricity provider infrastructure and revenue.*
- *§8010(d)(5) – Benefits to net metering customers of connecting to the distribution system*
- *§8010(d)(6) – Economic and environmental benefits of Net Metering*
- *§8010(d)(7) – Reliability and Supply diversification costs and benefits.*
- *§8010(d)(8) – Ownership and transfer of environmental attributes of energy generated by Net Metered Systems*
- *§8010(d)(9) – Best practices for net metering identified from other states*

This report to the Public Service Board (Board) addresses the legislative request. It builds directly from the report completed by the Department in January 2013 pursuant to Act 125 of the 2012 legislative session, updating assumptions and methodology as appropriate and described herein. Aspects of the methodology and approach that are not significantly changed from the 2013 Report will not be restated in this report. Instead, interested readers can find the 2013 Report on the Department's website at http://publicservice.vermont.gov/topics/renewable_energy/net_metering.

The Department undertook several steps to address the legislative request and evaluate net metering in Vermont. The Department issued a letter to stakeholders describing its proposed approach to the report, to which we received several sets of comments. Many of these comments urged the Department to hold a set of technical working group meetings inviting stakeholders to address each Act 99 criteria. Given time constraints and the Public Service Board process that will follow this report, significant stakeholder interaction and feedback was not solicited for this report. Rather, this report is intended to *start* the dialogue expected to take place via the upcoming Public Service Board process. The Department did hold a meeting for stakeholders to vet the updated structure and assumptions in the spreadsheet cost-benefit model.

Section 2 of this report begins with a brief background describing the changes to net metering contained in Act 99 of 2014, and the current status and pace of net metering deployment in Vermont. Section 3 updates the analysis of the existence and magnitude of any cross subsidy created by the current net metering program that was originally completed pursuant to Act 125 of 2012. Section 4 addresses lessons learned and guiding principles for net metering program design from a review of recent literature discussing these issues. Finally, Section 5 addresses the balance of the Act 99 criteria.

2 Background

A brief history of Vermont's net metering statute can be found in the 2013 Report. This section describes the changes to net metering contained in Act 99 of 2014. It will also update the current status and pace of net metering deployment Statewide and by utility.

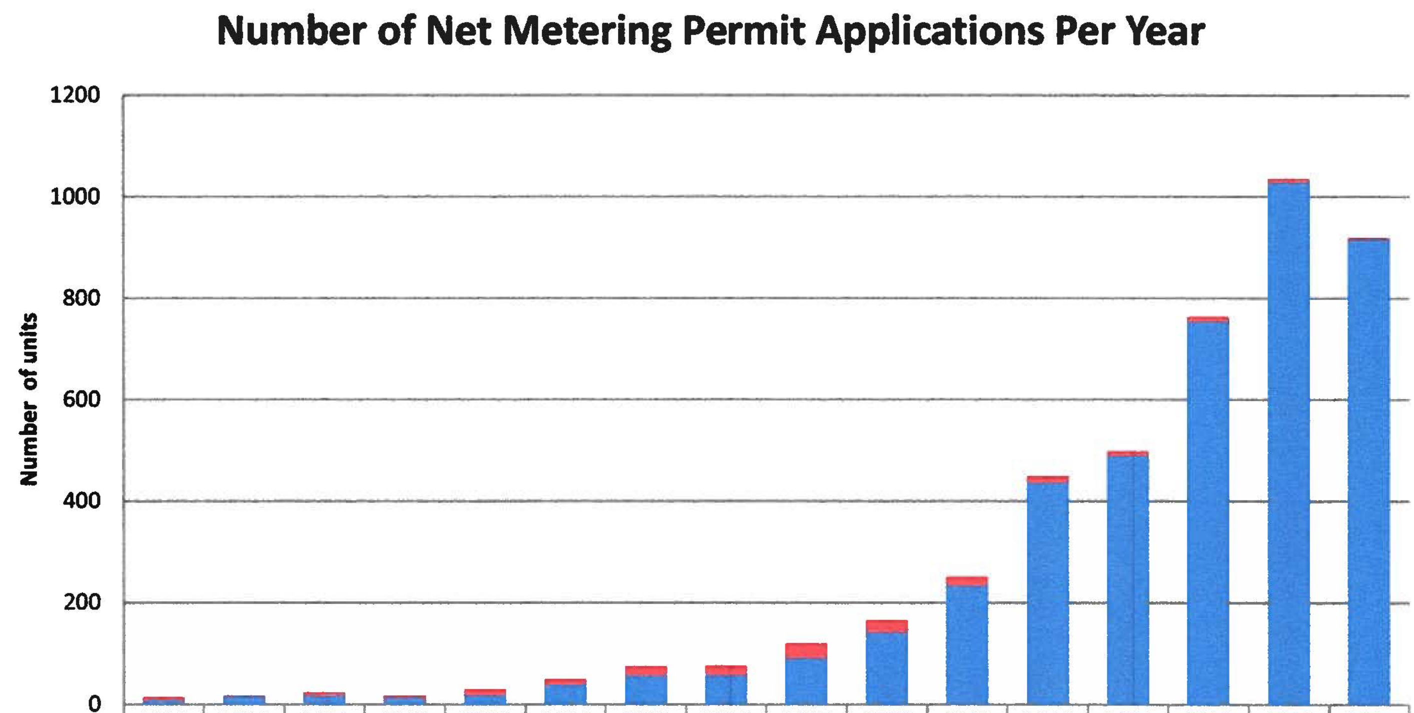
2.1 Act 99 of 2014

Act 99 of 2014 amended Vermont's net metering statute in the following relevant ways:

- Utilities must now allow net metering up to 15% of their peak capacity, changed from 4%.
- For systems over 15 kW the solar credit is now calculated by subtraction from 19 cents, down from 20 cents.
- Following the 10 year period of the solar credit, the systems are to be credited at the blended rate, rather than the highest residential rate. The solar credit is also calculated by reference to the blended rate.
- Net metered customers may now assign the renewable energy attributes of their generation to their utility for retirement on their behalf.
- Approval for various pilots and alternate net metering structures for utilities that have met certain criteria.

2.2 Current pace of net metering deployment statewide and by utility

Net metering has experienced rapid growth over the last seven years as the demand for local renewable energy has grown, costs have decreased, and access to renewables has broadened. As can be seen in Exhibit 1, solar PV has had the most substantial growth of all the renewable technologies. The number of PV systems applying for net metering permits annually has grown by a factor of more than seven since 2008.



	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
Fuel Cell	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Wind	5	1	6	5	11	10	18	18	28	23	16	12	9	10	7	2
Solar	9	17	18	13	19	39	57	58	92	141	232	435	490	752	1027	917
Methane	0	0	0	0	0	1	0	0	0	1	2	2	0	1	1	0

Exhibit 1. *Number of net metering applications & registrations annually. (Data as of 9/26/14.)*

With the recent rise in number of PV applications, solar now accounts for 93.5% of all net metering capacity. Wind turbines represent less than 3% of all net metered capacity and hydroelectric represents approximately 2.2% (see Exhibit 2). To date, there have been no net metered fuel cells or combined heat and power systems in Vermont.

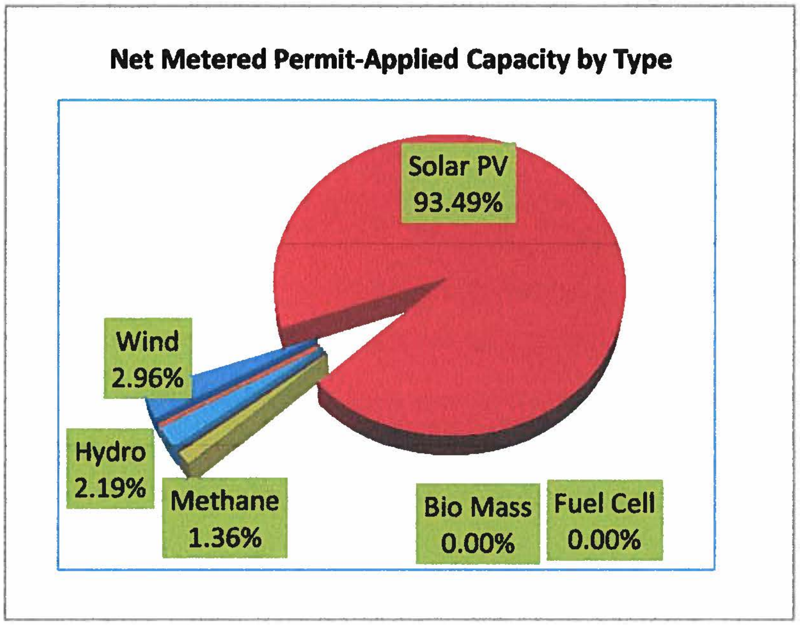
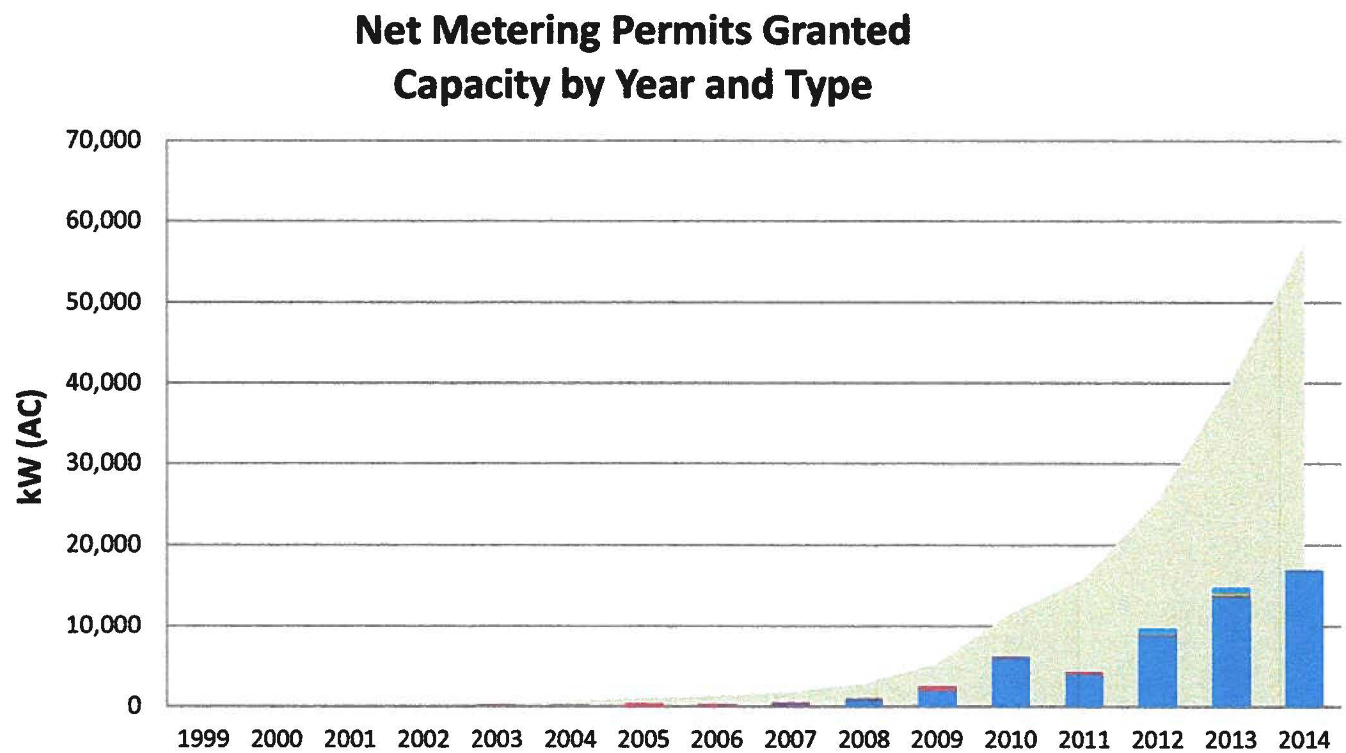


Exhibit 2. *Capacity of net metering permit applications by technology type (as of 9/26/14)*

The exponential increase in the number of PV system installations has driven not only the overall number of net metered systems but also the total growth of permitted net metered system capacity to 57.2 MW (see Exhibit 3). In addition to permitted systems, and additional 6.8 MW of proposed net metered projects have applied for permits but not yet received them, for a total of 64 MW.



	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
Cumulatve Capacity	50	99	177	224	436	670	980	1,255	1,749	2,798	5,307	11,568	15,828	25,496	40,274	57,188
Hydro	-	-	-	-	-	-	-	-	-	-	18	-	-	716	664	-
Methane	-	-	-	-	-	65	-	-	-	19	39	127	-	49	248	-
Wind	32	10	28	31	98	72	123	102	147	158	482	154	239	66	125	12
Solar	18	39	50	16	114	97	187	174	347	872	1,969	5,981	4,021	8,838	13,741	16,902

Exhibit 3. *Capacity of net metering permits granted by type and cumulative capacity. (Data as of 9/26/14.)*

The capacity histogram (Exhibit 4) shows that 48% of net metering systems that have applied for permits to date are less than 5 kW, 36% are between 5-10 kW and fewer than four percent are larger than 100kW. Notably, a significant number of 500kW applications have been submitted in 2014, potentially indicating a trend towards larger group net metering systems.

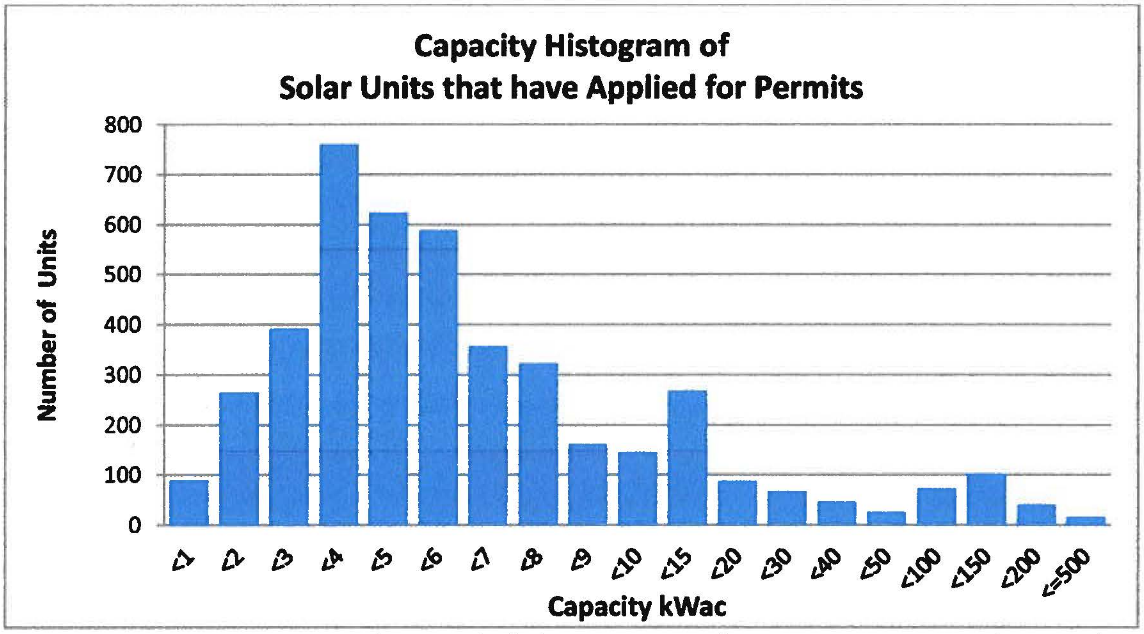


Exhibit 4. *Histogram by Capacity (in kW AC) of all net metered solar PV system permit applications (as of 9/26/14)*

While the growth has been rapid, 63.8 MW of net metered systems represents a small fraction of Vermont's overall electrical portfolio. GMP, VEC, WEC, Hardwick, Jacksonville and Morrisville have all exceeded the previous 4% capacity cap. If all permitted and constructed, net metered systems to date would produce less than 2% of the electric energy Vermont uses each year or approximately 80 GWh per year.

	Solar PV		Wind		Methane		Hydroelectric		Total	Approx.
Utility	**Count**	**Capacity**	**Count**	**Capacity**	**Count**	**Capacity**	**Count**	**Capacity**	**Capacity**	**% of peak**
Barton	8	43	2	19	0	0	0	0	62	2.0%
BED	96	1,836	4	15	1	248	0	0	2,099	3.1%
Enosburg	12	83	0	0	0	0	0	0	83	1.5%
GMP	3,376	50,010	107	1,231	7	489	10	1,399	53,128	6.9%
Hardwick	57	473	9	79	0	0	0	0	552	8.0%
Hyde Park	19	87	1	10	0	0	0	0	97	3.8%
Jacksonville	2	159	3	11	0	0	0	0	170	14.4%
Johnson	6	220	0	0	0	0	0	0	220	7.8%
Ludlow	0	0	0	0	0	0	0	0	0	0.0%
Lyndonville	43	276	2	99	0	0	0	0	374	1.7%
Morrisville	28	493	4	38	0	0	0	0	531	5.8%
Northfield	17	107	0	0	0	0	0	0	107	2.0%
Orleans	1	6	0	0	0	0	0	0	6	0.2%
Stowe	32	276	0	0	1	20	0	0	296	1.6%
Swanton	7	33	0	0	0	0	0	0	33	0.3%
VEC	498	4,174	45	332	1	96	0	0	4,602	5.5%
WEC	214	1,566	7	60	0	0	0	0	1,478	10.2%
TOTAL	**4,416**	**59,842**	**184**	**1,892**	**10**	**853**	**10**	**1,399**	**63,986**	**6.2%**

Exhibit 5. *Number of net metered permit applications and the capacity of those generators (in kW), by utility and type of generation, with the approximate percent of each utility's 2013 peak load.*

3 Existence and degree of cross-subsidy

The Department's Act 125 report described a statewide average analysis of the existence and degree of potential cross-subsidy between those customers participating in net metering and those not participating. This section describes several updates to that analysis and provides summary results by utility. The analysis uses the same logical structure as the Act 125 analysis. The reader is encouraged to review that report for examination of choices to include or exclude certain costs and benefits, the perspective from which the analysis is conducted, which generation to include, etc.

3.1 Costs and benefits

The Department's analysis includes the following costs:

- Lost revenue (due to participants paying smaller electric bills);
- Vermont solar credit, for solar PV systems; and
- Net metering-related administrative costs (engineering, billing, etc.).

The Department's analysis includes the following benefits:

- Avoided energy costs, including avoided costs of line losses and avoided internalized greenhouse gas emission costs;
- Avoided capacity costs, including avoided costs of line losses;
- Avoided regional transmission costs (costs for built or un-built pooled transmission facilities, or PTF, embodied in the ISO-NE Regional Network Service charge and other regional changes allocated in a similar fashion);
- Avoided in-state transmission and distribution costs (avoiding the construction of new non-PTF facilities). New for this report is the separation between transmission and distribution costs, in order to account for differences between utilities;
- Market price suppression in both energy and capacity markets; and
- Potential future regulatory value associated with retention of renewable energy credits in Vermont;

Net costs and benefits were calculated both including and excluding the value of avoided greenhouse gas emissions that are currently not internalized in the cost of energy or the value of renewable energy credits. Ratepayers face a risk that more costs associated with mitigation of greenhouse gases from electricity production will be internalized into energy prices in the future, potentially leading to stranded assets if resource decisions are made without consideration of the value of greenhouse gas emissions mitigation or abatement.

Costs and benefits are determined from a Vermont ratepayer perspective; transfers from entities which are not Vermont ratepayers to Vermont ratepayers are included; any potential transfers between Vermont ratepayers are not included. Utility-specific analysis attempts to measure costs or benefits that accrue to ratepayers of each utility.

The assumptions used for each of these costs and benefits are described in more detail in Section 3.2 below.

3.2 Modeling assumptions

The spreadsheet model[1] estimates the costs and benefits incurred as a result of any single net metering installation installed in 2015 or a later year. It projects costs and benefits over the 20-year period following installation, allowing examination of the potential changing costs and benefits over that period as well as calculation of a levelized net benefit or cost per kWh over 20 years. The Act 125 report includes a summary of what the spreadsheet model does not attempt to do; this list is still accurate, aside from the new attempt to capture differences between utilities and a revised treatment of the value of renewable attributes.

3.2.1 Utility-specific costs and benefits

In the context of this study, "costs" and "benefits" are measured from the ratepayer standpoint. The utility regulatory structure in Vermont (including GMP's alternative regulation plan, the co-op structure of VEC and WEC, and the municipal structure of the state's other utilities) results in the relevant set of costs and benefits faced by the state's utilities being passed to the state's ratepayers. As a result, the analytical framework treats utility costs as ratepayer costs, and utility benefits as ratepayer benefits.[2]

3.2.1.1 Costs

Net metering reduces utility revenue by enabling a participating customer to provide some of their own electricity (including, at times, spinning their meter backward while exporting energy), which reduces their monthly bill. In order to calculate the size of this reduction due to a modeled net metering installation, the model requires the energy produced per year, along with the expected average customer rate, and any solar credit. The Department collected current rates from each of the state's utilities. We used the residential rate structure, as changes in Act 125 established that nearly all net metered customers will see credit to their bills at the residential rate. Act 99 changed the calculation of credits to use the blended rate (defined as the average rate faced by an average residential customer over all of their usage), rather than the highest residential rate. We used the 2013 average residential consumption of each utility to calculate this blended rate.

Rates were forecast to change in the future using the same methodology employed in the Act 125 report. This methodology incorporates forecasts of energy, capacity, and transmission, and other costs, and accounts for internally consistent avoided energy costs and lost rate revenue.

The Department made no changes to how administrative costs were calculated, and did not vary them by utility.

The Department modeled the costs to non-participating ratepayers due to the current net metering program in each utility territory, including the alternate program in effect for Washington Electric Cooperative members. We understand the purpose of the Board investigation subsequent to this report is to consider alternate net metering program designs; these alternatives would be expected to have different costs.

[1] Available for download from http://publicservicedept.vermont.gov/topics/renewable_energy/net_metering.

[2] Externalities, such as the externalized portion of the value of greenhouse gas emission reductions, do not follow this pattern.

3.2.1.2 Benefits

3.2.1.2.1 Avoided energy cost

From the perspective of the regional electric grid or a utility purchasing power to meet its load, net metering looks like a load reduction. A utility therefore purchases somewhat less power to meet the needs of their customers. While Vermont utilities purchase much of their energy through long-term contracts, this kind of moment-by-moment change in load is reflected in changes in purchases or sales on the ISO-NE day-ahead or spot markets. The Department assumes that the energy source displaced or avoided by the use of net metering is energy purchased on the ISO-NE real-time spot markets (the difference between day-ahead and spot markets over the course of the year is relatively minor).

The Department calculated a hypothetical 2013-14 avoided energy cost on an hourly basis by multiplying the production of real Vermont generators by the hourly price set in the ISO-NE market. This annual total value was then updated to 2015 and beyond by scaling the annual total price according to a market price forecast. These calculations indicate that fixed solar PV had a weighted average avoided energy price 9% lower than the annual ISO-NE average spot market price, 2-axis tracking solar PV is equal to the annual average spot market price, and small wind is 29% higher. This is a change from the Act 125 report, and is driven primarily by the recent high ISO-NE market prices in the winter.

The Department assumed that the capacity factor for each solar technology is projected capacity factor using the NREL PVWatts tool for a location in Montpelier, using all PVWatts default settings. The assumed capacity factor for wind is the 2013-14 capacity factor of the real Vermont generator used to calculate the correlation. Separating the capacity factor from the price-performance correlation allows the analysis to correct for differences between the typical capacity factors expected over many years for a generic facility and the capacity factors exhibited for a particular generator in only one year.

The Department's market energy price forecast is based on that developed filed by the Department in Docket 8010, related to the setting of avoided costs in the context of Public Service Board Rule 4.100. This is a forecast of Vermont's Locational Marginal Price – for energy measured at the VELCO system border. Energy generated by net metering systems, however, is produced on distribution circuits and often used locally; the difference between the energy avoided at the VELCO border and the energy produced at the net metering system is line losses. The Department updated line loss values consistent with the recent updated analysis completed for the marginal line losses avoided from load reductions associated with energy efficiency in proceeding EEU-2013-07. Across different costing periods, these marginal losses average approximately 11%.

Exhibit 6: *Department assumptions and forecasts of avoided energy, capacity, regional transmission, and in-state transmission and distribution costs, along with assumed self-consistent residential rate forecast, developed for this study. Values are in nominal dollars.*

	Energy ($/MWh)	Capacity ($/kW-month)	Regional transmission (PTF) ($/kW-month)	Vermont Transmission (non-PTF) ($/kW-month)	Vermont Distribution (non-PTF) ($/kW-month)
2015	$67.51	$3.01	$8.17	$3.42	$9.26
2016	$59.04	$3.27	$8.75	$3.46	$9.36
2017	$55.24	$5.41	$9.33	$3.52	$9.53
2018	$47.64	$9.84	$9.93	$3.50	$9.46
2019	$49.31	$11.97	$10.56	$3.57	$9.65
2020	$50.23	$12.18	$11.23	$3.64	$9.84
2021	$54.62	$12.43	$11.95	$3.68	$9.97
2022	$53.71	$12.68	$12.71	$3.73	$10.08
2023	$58.30	$12.95	$13.52	$3.74	$10.12
2024	$59.70	$13.22	$14.39	$3.78	$10.23
2025	$65.27	$13.49	$15.30	$3.84	$10.38
2026	$66.99	$13.77	$16.28	$3.88	$10.49
2027	$72.34	$14.07	$17.32	$3.91	$10.59
2028	$73.12	$14.37	$18.42	$3.95	$10.69
2029	$80.24	$14.64	$19.59	$3.98	$10.78
2030	$81.48	$14.91	$20.84	$4.02	$10.87
2031	$84.42	$15.17	$22.17	$4.05	$10.95
2032	$80.03	$15.45	$23.58	$4.08	$11.03
2033	$85.70	$15.73	$25.09	$4.10	$11.10
2034	$84.57	$16.01	$26.69	$4.13	$11.17
2035	$91.27	$16.30	$28.39	$4.15	$11.24
2036	$91.82	$16.59	$30.20	$4.17	$11.29
2037	$97.62	$16.89	$32.12	$4.19	$11.34
2038	$97.63	$17.20	$34.17	$4.21	$11.39
2039	$107.50	$17.51	$36.35	$4.22	$11.42
2040	$108.13	$17.82	$38.67	$4.23	$11.45

3.2.1.2.2 Avoided capacity cost

From the bulk grid perspective, net metering systems look like a reduction in demand, and therefore reduce the utility's cost for capacity. There are multiple potential methods to measure the effective capacity of generators with respect to different purposes. In determining the peak coincidence factors described in this and the following subsections, the Department examined the timing of the relevant peaks: ISO-NE's peak for capacity costs, Vermont summer peaks for in-state transmission costs, monthly Vermont peaks for RNS costs, and utility-specific peak hours for distribution costs. The ability of variable generators to help avoid ISO-NE capacity costs depends on the level of generation during the summer hours when ISO-NE's region-wide grid demand peaks. The Department calculated coincidence values by averaging the production from generic fixed and tracking solar PV systems as well as an example small wind generator during the months and hours (e.g. July hours ending 5pm or August hours ending 3pm) of the ISO-NE peaks since 2003.

Exhibit 7: *Department assumptions of net-metered generators' performance during peak times used to calculate values of avoided capacity, avoided regional RNS cost, and avoided in-state transmission infrastructure. Each value shows the fraction of the system's rated capacity that is assumed in the calculation of the value of the three avoided costs. For example, in calculating the value of avoided capacity costs due to a fixed solar PV system with a nameplate capacity of 100 kW, the system is assumed to reduce capacity costs by the same amount as a system that can output 52 kW and is always running or perfectly dispatchable.*

	Capacity	RNS	In-state Transmission
Fixed PV	0.520	0.210	0.536
Tracking PV	0.579	0.230	0.551
Wind	0.082	0.121	0.058

The capacity price forecast assumed by the Department, and used by default in the model, is based on that developed for use in Docket 8010 relating to avoided costs and Rule 4.100. The resulting capacity price forecast (in nominal dollars) is shown above in Exhibit 6.

3.2.1.2.3 Avoided regional transmission costs

Regional Network Service (RNS) charges are charged by ISO-NE to each of the region's utilities to pay for the cost of upgrades to the region's bulk transmission infrastructure. These are costs that have already been incurred, or are required to meet reliability standards, and thus cannot be entirely avoided – only their allocation among New England ratepayers can be changed. Avoiding these costs through net metering shifts the costs to ratepayers in other states. RNS charges are allocated to each utility based on its share of the monthly peak load within Vermont. Exhibit 7 shows the values for relevant peak coincidence calculated by considering the production expected from generators of each type during the hours of each month when peaks have occurred since 2003.

The values assigned to this cost are based on the ISO-NE forecast of the next 3 years' worth of RNS charges, and escalated based on historical increases in the Handy-Whitman Index of public utility construction costs. The resulting regional transmission price forecast (in nominal dollars) is shown above in Exhibit 6.

3.2.1.2.4 Avoided in-state transmission and distribution costs

In-state transmission and distribution costs are those costs incurred by the state's distribution utilities or VELCO and which are not subject to regional cost allocation. The values used in this model are derived from those developed by a working group consisting of representatives from the state's distribution, transmission, and efficiency utilities, and the Department in proceeding EEU 2011-02 for the update to the electric energy efficiency cost-effectiveness screening tool.

The Department updated the net metering model to separately consider avoided in-state transmission and distribution costs. Burlington Electric Department's forecasts contained in their Integrated Resource Plan show that even without the effects of energy efficiency, there are no load growth related infrastructure investments planned within the next 20 years. Thus, they are assumed to not have any avoided distribution costs. All other utilities are assumed to have avoided distribution costs consistent with the statewide average cost.

The in-state transmission and distribution upgrades deferred due to load reduction or on-site generation (such as net metering) are driven by reliability concerns. Therefore, rather than average peak coincidence for a net metering technology, the critical value is how much generation the grid can rely on seeing at peak times. Therefore, the Department calculated "reliability" peak coincidence values, separate from the "economic" peak coincidence used in avoided capacity and regional transmission cost calculations. The Department calculated reliability peak coincidence for in-state transmission by calculating the weighted average production from generators of each type during the July afternoon hours when Vermont's summer peak has occurred since 2003. These values are shown in Exhibit 7.

The Department calculated distribution peak coincidence values separately for each of the state's distribution utilities. The methodology is implemented in a spreadsheet tool available for download from the Department's website.[3] The methodology was as follows: First, the Department examined the 2013 hourly loads from each of the state's utilities. Load-growth-related distribution infrastructure needs are driven by the extremes of utility load, so the first step was to identify the 5% of all hours (438 hours over the year) during which the utility had the highest load. These were then collected into month-hour pairs (such as the hour ending 6pm in January of the hour ending 3pm in July). Month-hours with at least 9 high-load hours were then identified for each utility. This filter produced lists of between 13 and 26 month-hour pairs during which avoided load would be most likely to avoid the need for infrastructure investments. The next step was to calculate the average production for each type of generation during these high-load hours, compared with the generator's peak capacity. Exhibit 8 shows the resulting coincidence factors.

Exhibit 8. *Utility-specific distribution peak coincidence factors for each generator type.*

Utility	PV: Fixed	PV: 2-Axis Tracker	Small Wind
VT Average	0.223	0.269	0.124
Barton	0.026	0.065	0.176
BED	0.404	0.484	0.074
Enosburg	0.160	0.201	0.098
GMP	0.219	0.261	0.115
Hardwick	0.009	0.027	0.194
Hyde Park	0.062	0.052	0.205
Jacksonville	0.145	0.229	0.156
Johnson	0.218	0.308	0.140
Ludlow	0.077	0.101	0.147
Lyndonville	0.128	0.196	0.144
Morrisville	0.287	0.310	0.105
Northfield	0.054	0.072	0.165
Orleans	0.262	0.378	0.118
Stowe	0.103	0.151	0.128
Swanton	0.306	0.374	0.113
VEC	0.033	0.083	0.180
WEC	0.000	0.001	0.193

[3] Available for download from http://publicservicedept.vermont.gov/topics/renewable_energy/net_metering.

3.2.1.2.5 Market price suppression

Reductions in load shift the relationship between the supply curve and demand curve for both energy and capacity, resulting in changes in market price. Because net metering looks like load reduction, the Department has approximated the market price suppression effect using analysis based on the 2013 Avoided Energy Supply Cost (AESC) study's calculation of the demand reduction induced price effect ("DRIPE") for Vermont. This is the same (but updated) source as used in the Act 125 report.

3.2.1.2.6 Value associated with renewable energy credits

The model allows for assignment of a value that ratepayers see that is attributable to the environmental attributes of the energy generated by a net metered system. Act 99 allows net metering participants to assign the environmental attributes associated with their generation to the utility for retirement. In addition, future policy design considerations in the coming year's Public Service Board process will likely incorporate discussion of the value and ownership of environmental attributes. For the purposes of this report, the Department has assumed a fixed value of $30/MWh in nominal terms, with a switch in the spreadsheet to turn this value on and off.

Ownership of Renewable Energy Credits ("RECs") conveys upon the owner the right to claim the use of renewable energy. If a net metered customer retains their RECs, they may claim that the load served by their utility account is in some or whole part renewable. If a customer transfers their RECs to their utility under Act 99 for retirement on their behalf, they may make the same claim. However, if a customer transfers the RECs to a third party, then the customer may no longer make that claim. There is potential future regulatory value in REC retirement to utilities, if Vermont were to adopt a renewable portfolio standard that used RECs as a compliance mechanism. Vermont may only claim environmental benefits of net metering projects (e.g. avoided greenhouse gas emissions) toward state targets if RECs are retained or purchased for retirement in Vermont.

3.2.1.2.7 Climate change

The Department's analysis calculates the costs and benefits of net metering to the state's non-participating ratepayers both with and without the estimated externalized cost of greenhouse gas emissions. It should be noted that these benefits from a marginal net metering installation in Vermont do not flow to Vermonter ratepayers in direct monetary terms. Instead, they reflect both a societal cost that is avoided and the size of potential risk that Vermont ratepayers avoid by reducing greenhouse gas emissions. If these environmental costs were fully internalized, for example into the cost of energy, ratepayers would bear those costs. The Department is assuming a value of $100 per metric ton of CO_2 emissions reduced (in $2013); this is the societal value adopted by the Public Service Board for use in energy efficiency screening, and is intended to reflect the marginal cost of abatement. About $5, rising to approximately $10, of the $100/ton is internalized in forecasted energy costs through the Regional Greenhouse Gas Initiative, so the analysis incorporates an additional cost of about $90-95 (in $2013) for cases in which costs of environmental externalities are included.

CO_2 emission reductions are calculated by using the 2012 ISO-New England marginal emission rate of 854 lbs/MWh.[4] ISO-NE grid operations and markets almost always result in a gas generator dispatched as the marginal plant, so this value is comparable to the emissions from a natural gas generator. The Department's analysis does not track or account for emissions or abatement of other greenhouse gasses.

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[4] http://www.iso-ne.com/static-assets/documents/genrtion_resrcs/reports/emission/2012_emissions_report_final_v2.pdf

3.3 Results of Cross-Subsidization Analysis

3.3.1 Systems Examined

This report presents the results of the cross-subsidization analysis for 6 systems:

- A 4 kW fixed solar PV system, net metered by a single residence;
- A 4 kW 2-axis tracking solar PV system, net metered by a single residence;
- A 4 kW wind generator, net metered by a single residence;
- A 100 kW fixed solar PV system, net metered by a group;
- A 100 kW 2-axis tracking solar PV system, net metered by a group; and
- A 100 kW wind generator, net metered by a group.

3.3.2 Results for Systems Installed in 2015

The methodology described in section 3.2 allows the model to calculate costs incurred and benefits received from each typical net-metered generator on an annual basis. These values may also be combined into a 20-year levelized value. A levelized value is the constant value per kWh generated that has the same present value as the projected string of costs and/or benefits over the 20-year study period. This section presents graphs of the statewide average annual costs and benefits along with levelized costs, benefits, and net costs (costs minus benefits). The graphs presented below depict the ratepayer perspective.[5] The tables are presented for net benefits for both the ratepayer and a statewide/societal perspective.[6] For each system we separately present the ratepayer-perspective numbers for each utility.

[5] The ratepayer perspective calculation uses the higher discount rate (7.44%) and includes a REC value. RECs were assumed to have a fixed value of $30/MWh, so the reader may adjust for a no-REC-value case by subtracting 3 cents ($0.03) from the benefits values.

[6] The statewide/societal calculation uses a lower discount rate (4.95%), includes avoided externalized GHG costs and does not include a REC value. We have selected a "parochial" version of society which counts avoided RNS costs and Vermont-specific market price suppression; each of these involve transfers between Vermont and other New England states and might not be included in a societal test with a broader perspective.

3.3.2.1 4 kW fixed solar PV system, net metered by a single residence

A 4 kW fixed solar PV system would generate about nearly 5,000 kWh annually with a capacity factor of 14.2%.

Exhibit 9. ***Per-kWh costs (red line) and benefits (colored areas) for a 4 kW fixed solar PV system installed in 2015, from a ratepayer perspective.***

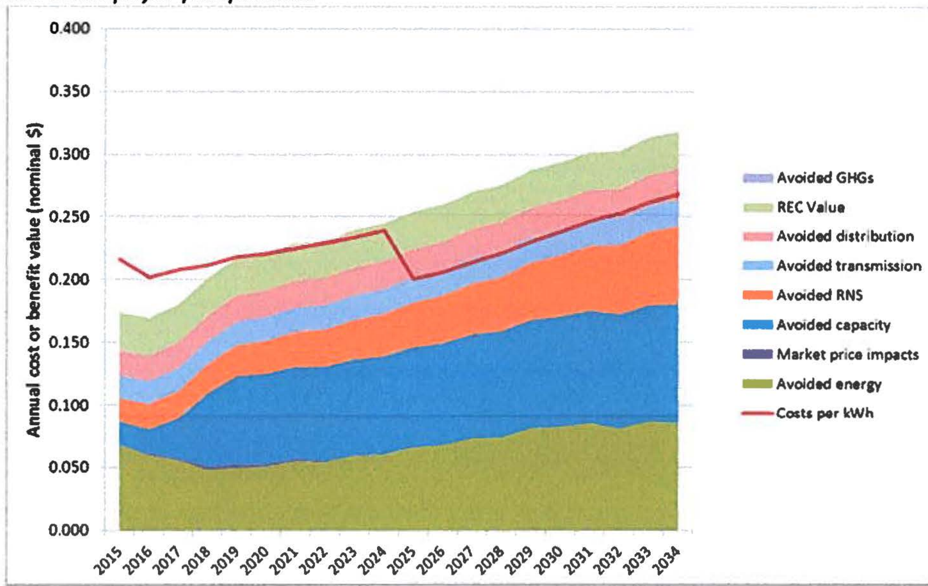

Exhibit 10. ***Levelized cost, benefit, and net benefit of a 4 kW fixed solar PV residential system installed in 2015 to other ratepayers or society. Units are $ per kWh generated.***

	Cost	Benefit	Net Benefit
Ratepayer	$0.229	$0.237	$0.009
Statewide/Society	$0.230	$0.256	$0.026

Exhibit 11. *Levelized cost, benefit, and net benefit of a 4 kW fixed solar PV residential system installed in 2015 to other ratepayers, by utility. Refer to Section 3.2 for a description of why these values vary by utility. Units are $ per kWh generated.*

Utility	Cost	Benefit	Net Benefit
Barton	$0.229	$0.217	($0.011)
BED	$0.224	$0.215	($0.010)
Enosburg	$0.229	$0.231	$0.002
GMP	$0.226	$0.237	$0.011
Hardwick	$0.232	$0.216	($0.017)
Hyde Park	$0.232	$0.221	($0.011)
Jacksonville	$0.227	$0.229	$0.003
Johnson	$0.231	$0.237	$0.006
Ludlow	$0.206	$0.223	$0.017
Lyndonville	$0.221	$0.228	$0.006
Morrisville	$0.225	$0.244	$0.019
Northfield	$0.217	$0.220	$0.003
Orleans	$0.212	$0.241	$0.030
Stowe	$0.236	$0.225	($0.011)
Swanton	$0.207	$0.246	$0.039
VEC	$0.233	$0.218	($0.014)
WEC[7]	$0.155	$0.215	$0.059

[7] Due to its unique program, WEC's costs and benefits depend on the fraction of the customer's use that is offset by the net metered system. For this and each other example system, the Department assigned the household a usage comparable to the average residential energy use among WEC members.

3.3.2.2 4 kW tracking solar PV system, net metered by a single residence

A 4 kW 2-axis tracking solar PV system would generate about 6,600 kWh annually with a capacity factor of 18.8%.

Exhibit 12. *Per-kWh costs (red line) and benefits (colored areas) for a 4 kW 2-axis tracking solar PV system installed in 2015, from a ratepayer perspective.*

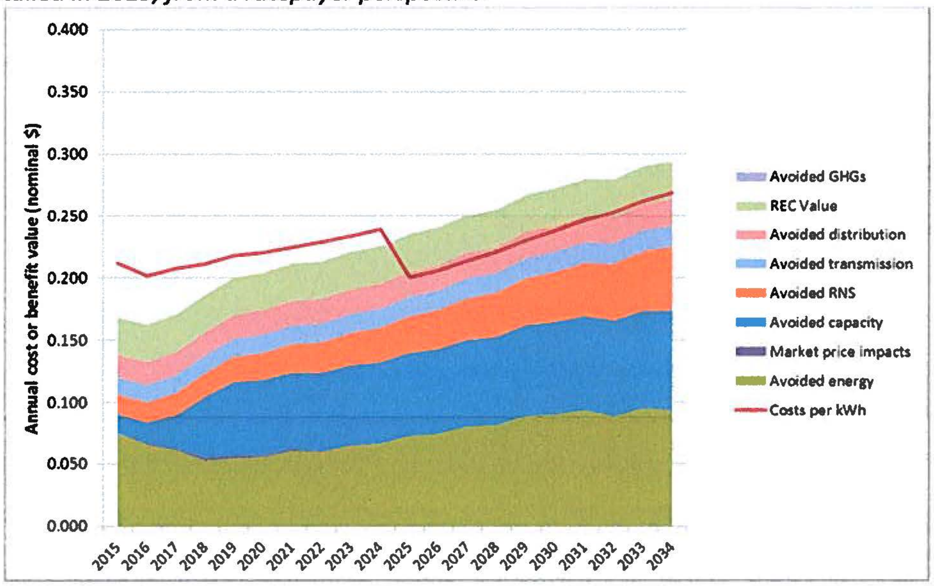

Exhibit 13. *Levelized cost, benefit, and net benefit of a 4 kW 2-axis tracking solar PV residential system installed in 2015 to other ratepayers or society. Units are $ per kWh generated.*

	Cost	Benefit	Net Benefit
Ratepayer	$0.228	$0.221	($0.007)
Statewide/Society	$0.229	$0.238	$0.009

Exhibit 14. *Levelized cost, benefit, and net benefit of a 4 kW 2-axis tracking solar PV residential system installed in 2015 to other ratepayers, by utility. Refer to Section 3.2 for a description of why these values vary by utility. Units are $ per kWh generated.*

Utility	Cost	Benefit	Net Benefit
Barton	$0.228	$0.205	($0.023)
BED	$0.224	$0.200	($0.024)
Enosburg	$0.229	$0.216	($0.013)
GMP	$0.225	$0.220	($0.005)
Hardwick	$0.232	$0.202	($0.030)
Hyde Park	$0.232	$0.204	($0.027)
Jacksonville	$0.227	$0.218	($0.009)
Johnson	$0.231	$0.224	($0.007)
Ludlow	$0.205	$0.208	$0.003
Lyndonville	$0.221	$0.215	($0.006)
Morrisville	$0.225	$0.224	($0.001)
Northfield	$0.217	$0.206	($0.011)
Orleans	$0.211	$0.229	$0.018
Stowe	$0.235	$0.212	($0.023)
Swanton	$0.207	$0.229	$0.022
VEC	$0.232	$0.207	($0.025)
WEC	$0.109	$0.201	$0.092

3.3.2.3 4 kW wind generator, net metered by a single residence

A 4 kW wind generator generates approximately 3,400 kWh per year, with a capacity factor of 9.6%. If such a generator were sited optimally, it could have a higher capacity factor and generate more electricity. However, the per-kWh costs and benefits described here would be unlikely to change significantly.

Exhibit 15. *Per-kWh costs (red line) and benefits (colored areas) for a 4 kW wing generator installed in 2015, from a ratepayer perspective.*

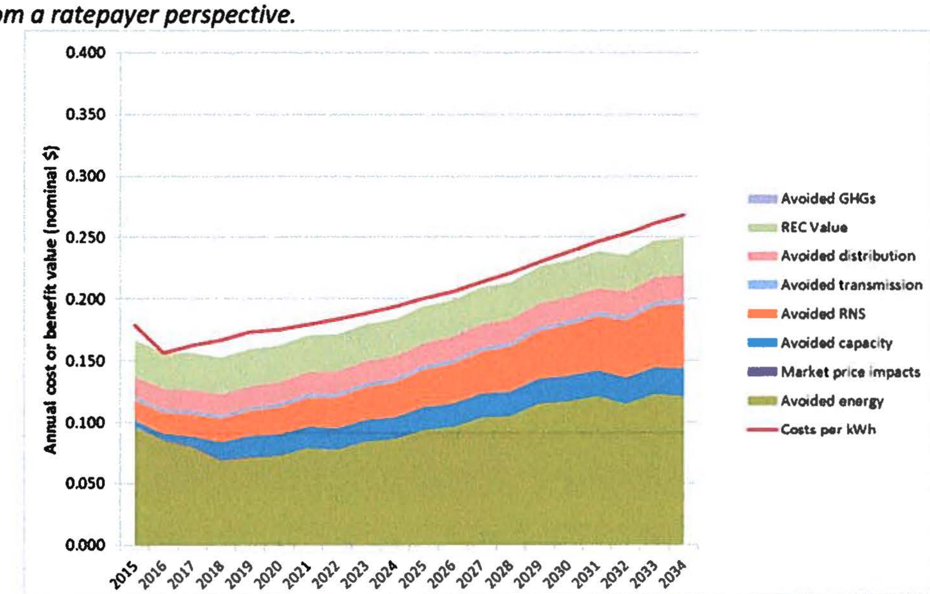

Exhibit 16. *Levelized cost, benefit, and net benefit of a 4kW wind generator installed in 2015 to other ratepayers or society. Units are $ per kWh generated.*

	Cost	Benefit	Net Benefit
Ratepayer	$0.198	$0.188	($0.009)
Statewide/Society	$0.201	$0.204	$0.003

Exhibit 17. *Levelized cost, benefit, and net benefit of a 100kW wind generator installed in 2015 to other ratepayers, by utility. Refer to Section 3.2 for a description of why these values vary by utility. Units are $ per kWh generated.*

Utility	Cost	Benefit	Net Benefit
Barton	$0.197	$0.196	($0.001)
BED	$0.187	$0.170	($0.017)
Enosburg	$0.198	$0.184	($0.014)
GMP	$0.194	$0.187	($0.007)
Hardwick	$0.207	$0.199	($0.008)
Hyde Park	$0.206	$0.200	($0.006)
Jacksonville	$0.193	$0.193	($0.000)
Johnson	$0.203	$0.191	($0.012)
Ludlow	$0.141	$0.192	$0.051
Lyndonville	$0.180	$0.191	$0.012
Morrisville	$0.189	$0.185	($0.004)
Northfield	$0.169	$0.194	$0.025
Orleans	$0.155	$0.187	$0.032
Stowe	$0.215	$0.189	($0.026)
Swanton	$0.144	$0.187	$0.043
VEC	$0.207	$0.197	($0.011)
WEC	$0.176	$0.199	$0.022

3.3.2.4 100 kW fixed solar PV system, group net metered

A 100 kW fixed solar PV system would generate about 125,000 kWh annually with a capacity factor of 14.2%.

Exhibit 18. *Per-kWh costs (red line) and benefits (colored areas) for a 100kW fixed solar PV system, group net metered, installed in 2015, from a ratepayer perspective.*

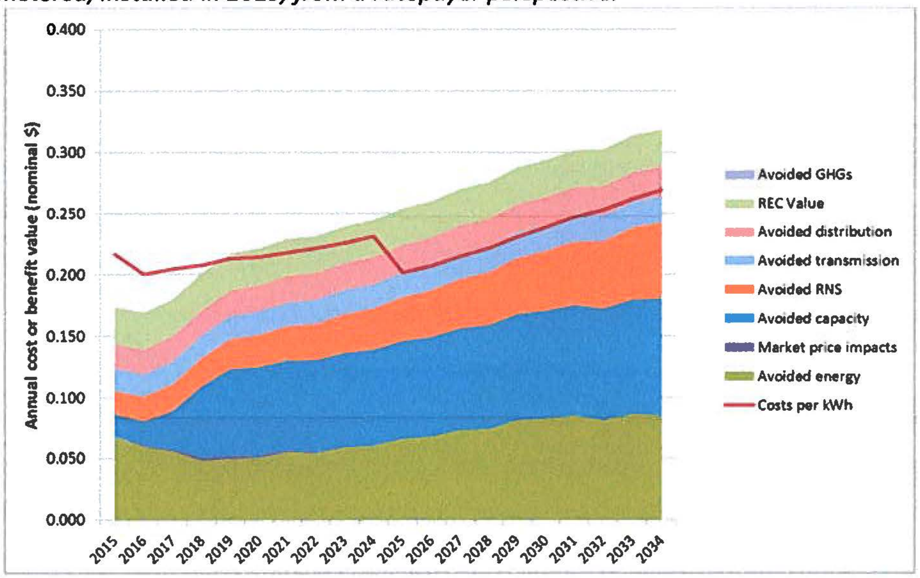

Exhibit 19. *Levelized cost, benefit, and net benefit of a 100kW fixed solar PV system, group net metered, installed in 2015 to other ratepayers or society. Units are $ per kWh generated.*

	Cost	Benefit	Net Benefit
Ratepayer	$0.226	$0.237	$0.011
Statewide/Society	$0.227	$0.256	$0.028

Exhibit 20. *Levelized cost, benefit, and net benefit of a 100kW fixed solar PV system, group net metered, installed in 2015 to other ratepayers, by utility. Refer to Section 3.2 for a description of why these values vary by utility. Units are $ per kWh generated*

Utility	Cost	Benefit	Net Benefit
Barton	$0.226	$0.217	($0.009)
BED	$0.222	$0.215	($0.007)
Enosburg	$0.226	$0.231	$0.005
GMP	$0.223	$0.237	$0.014
Hardwick	$0.230	$0.216	($0.014)
Hyde Park	$0.230	$0.221	($0.008)
Jacksonville	$0.224	$0.229	$0.005
Johnson	$0.228	$0.237	$0.009
Ludlow	$0.203	$0.223	$0.020
Lyndonville	$0.219	$0.228	$0.009
Morrisville	$0.223	$0.244	$0.021
Northfield	$0.215	$0.220	$0.006
Orleans	$0.209	$0.241	$0.032
Stowe	$0.233	$0.225	($0.008)
Swanton	$0.204	$0.246	$0.041
VEC	$0.230	$0.218	($0.012)
WEC	$0.170	$0.215	$0.044

3.3.2.5 100 kW tracking solar PV system, group net metered

A 100 kW 2-axis tracking solar PV system would generate about 165,000 kWh annually with a capacity factor of 18.8%.

Exhibit 21. *Per-kWh costs (red line) and benefits (colored areas) for a 100kW 2-axis tracking solar PV system, group net metered, installed in 2015, from a ratepayer perspective.*

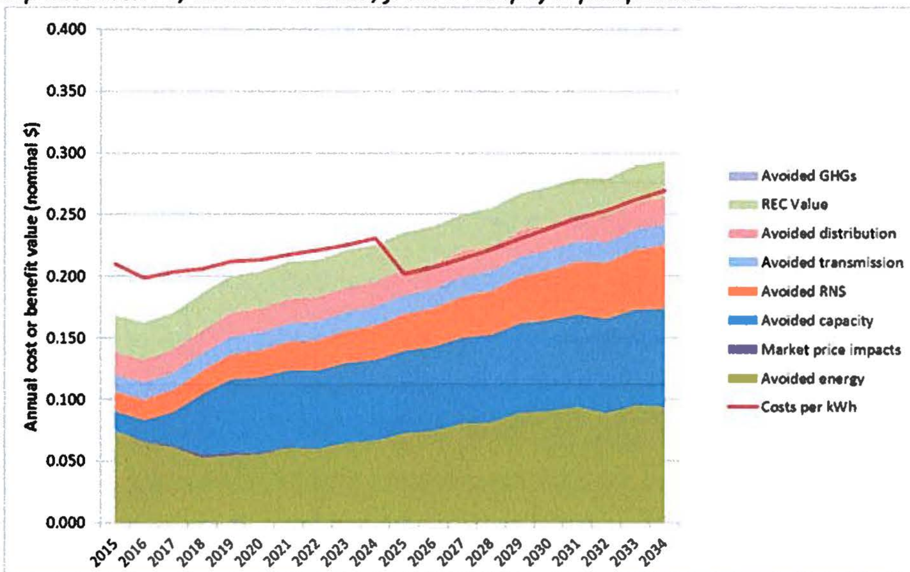

Exhibit 22. *Levelized cost, benefit, and net benefit of a 100kW 2 axis tracking solar PV system, group net metered, installed in 2015 to other ratepayers or society. Units are $ per kWh generated.*

	Cost	Benefit	Net Benefit
Ratepayer	$0.225	$0.221	($0.004)
Statewide/Society	$0.226	$0.238	$0.012

Exhibit 23. *Levelized cost, benefit, and net benefit of a 100kW 2 axis tracking solar PV system, group net metered, installed in 2015 to other ratepayers, by utility. Refer to Section 3.2 for a description of why these values vary by utility. Units are $ per kWh generated.*

Utility	Cost	Benefit	Net Benefit
Barton	$0.225	$0.205	($0.019)
BED	$0.220	$0.200	($0.020)
Enosburg	$0.225	$0.216	($0.009)
GMP	$0.222	$0.220	($0.001)
Hardwick	$0.228	$0.202	($0.026)
Hyde Park	$0.228	$0.204	($0.024)
Jacksonville	$0.223	$0.218	($0.005)
Johnson	$0.227	$0.224	($0.003)
Ludlow	$0.202	$0.208	$0.007
Lyndonville	$0.217	$0.215	($0.002)
Morrisville	$0.221	$0.224	$0.003
Northfield	$0.213	$0.206	($0.007)
Orleans	$0.207	$0.229	$0.022
Stowe	$0.232	$0.212	($0.020)
Swanton	$0.203	$0.229	$0.026
VEC	$0.228	$0.207	($0.022)
WEC	$0.128	$0.201	$0.073

3.3.2.6 100 kW wind generator, group net metered

A 100 kW wind generator generates approximately 84,000 kWh per year, with a capacity factor of 9.6%. If such a generator were sited optimally, it could have a significantly higher capacity factor and generate more electricity. However, the per-kWh costs and benefits described here would be unlikely to change significantly.

Exhibit 24. *Per-kWh costs (red line) and benefits (colored areas) for a 100kW wind generator, group net metered, installed in 2015, from a ratepayer perspective.*

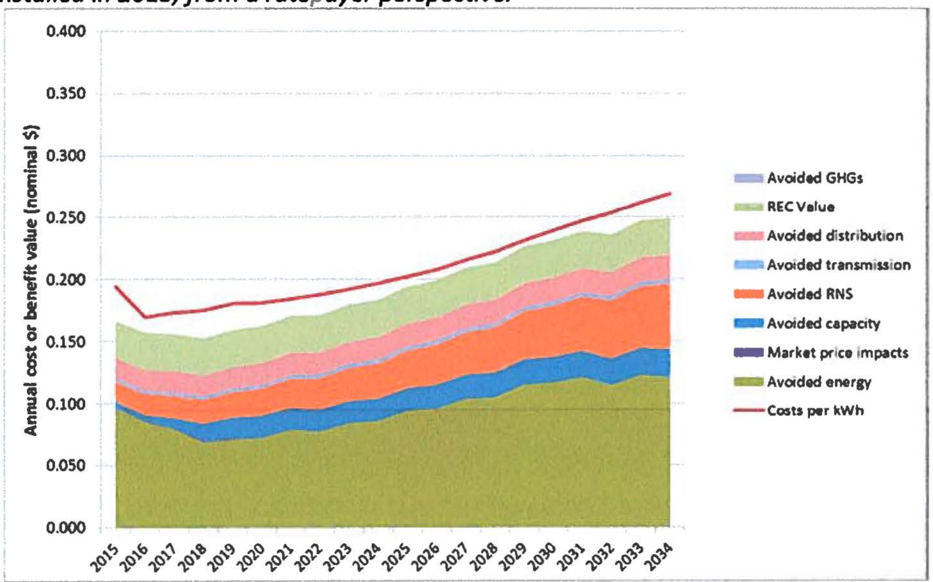

Exhibit 25. *Levelized cost, benefit, and net benefit of a 100kW wind generator, group net metered, installed in 2015 to other ratepayers or society. Units are $ per kWh generated.*

	Cost	Benefit	Net Benefit
Ratepayer	$0.204	$0.188	($0.016)
Statewide/Society	$0.207	$0.204	($0.003)

Exhibit 26. *Levelized cost, benefit, and net benefit of a 100kW wind generator, group net metered, installed in 2015 to other ratepayers, by utility. Refer to Section 3.2 for a description of why these values vary by utility. Units are $ per kWh generated.*

Utility	Cost	Benefit	Net Benefit
Barton	$0.204	$0.196	($0.008)
BED	$0.193	$0.170	($0.024)
Enosburg	$0.205	$0.184	($0.020)
GMP	$0.200	$0.187	($0.013)
Hardwick	$0.213	$0.199	($0.015)
Hyde Park	$0.213	$0.200	($0.012)
Jacksonville	$0.200	$0.193	($0.007)
Johnson	$0.209	$0.191	($0.019)
Ludlow	$0.147	$0.192	$0.044
Lyndonville	$0.186	$0.191	$0.005
Morrisville	$0.195	$0.185	($0.010)
Northfield	$0.175	$0.194	$0.019
Orleans	$0.162	$0.187	$0.026
Stowe	$0.221	$0.189	($0.033)
Swanton	$0.150	$0.187	$0.036
VEC	$0.214	$0.197	($0.017)
WEC	$0.171	$0.199	$0.028

3.3.3 Concluding Remarks on Cross-Subsidization

The analysis presented in the preceding sections indicates that the aggregate net cost over 20 years to non-participating ratepayers due to net metering under the current policy framework is close to zero, and there may be a net benefit. Analysis of the differences between utilities indicates that winter-peaking utilities, which see fewer benefits from net metered solar PV, will incur a larger share of the net cost than summer peaking utilities or those utilities with lower retail rates. As such, for the post-2016 period, the Department recommends that the Board consider whether or not changes to the current program structure to allow flexibility for the program to vary by utility would better serve the state.

It is appropriate to note that cross-subsidies are common in utility ratemaking. While rates strive to assign costs to those who cause them, this cannot be done exactly. The classic example is the comparison of urban and rural rates – the rural ratepayers have caused the construction of an extensive distribution system, form which the urban customers do not directly benefit, yet all pay equally for distribution network costs. This challenge is a portion of why rural electrification required explicit government action in the early part of the last century. Society as a whole has benefited from universal electrification, and concern about this cross-subsidy has generally faded. While policymakers can strive to minimize cross-subsidization in the net metering context, a precise elimination is unlikely and would hold net metering policies to a higher standard than that achieved by other ratemaking.

Net benefits from net metering systems, are either positive or negative depending on the details of utility rate structures, benefits from avoided distribution infrastructure, and the inclusion or exclusion of the value of renewable energy and greenhouse gas emission reductions. Notably, wind net metered systems performed much better in the model based on 2013-14 data than it did for the previous Act 125 model. This is largely due to wind's operation more often during the recent high prices for energy in the winter, and the more comprehensive treatment of winter distribution peaks in this report. As such, small wind as modeled performs even better for some utilities whose peak demand is during dark, winter hours. On the other hand, solar PV has much greater coincidence of generation with times of regional and some local peak demand than does wind power. This phenomenon underscores the year-to year, and utility-to-utility, variability associated with the benefits from net metering technology. It will be important to consider this variability in considering program design, but as described further below (see Section 4), designing a program with stability in mind can mitigate single year price and value volatility. Further, structures could be considered that incent technologies to be developed and/or sited in ways that focus on peak benefits – whether they relate to energy and capacity prices or a utility's peak demand.

The Department suggests that there is value in having a common methodology for the quantification of the value of distributed generation (represented in the benefits side of the above calculations). This will allow interested parties to identify areas of agreement and disagreement on the value of DG resources, and potentially reach consensus regarding assumptions. To that end, the Department has made the spreadsheets used to calculate all of the results presented here publicly available. There need not be a direct link between the value provided by DG resources and the amount or form of compensation provided through a net metering program – Vermont's current policy approaches a lack of cross-subsidy while not explicitly linking compensation to benefits. It may be that in order to achieve long-term objectives for DG deployment, compensation needs to be above value provided for particular technologies or particular time-periods – such compensation above value could be delivered through a net metering tariff, or through alternate incentives structures, and may depend on the availability and structure of funding.

4 Lesson learned for net metering identified from other states

While Act 99 requires that the Department address "best practices" from other jurisdictions, our review of the literature and the current state of distributed generation regulation across the country indicates that it is premature to identify "best practices." Instead, this section identifies lessons learned from other jurisdictions and describes "guiding principles" published in recent literature and offered for consideration here.

4.1 Literature review

The 2013 *Freeing the Grid*[8] report from the Interstate Renewable Energy Council and the Vote Solar Initiative provides a good summary of the nation's net metering policies; an independent catalog of the range of existing net metering policies was not completed for this report. Instead, this section of the report will summarize two key reports, one from the National Renewable Energy Laboratory ("NREL", with assistance from the Regulatory Assistance Project, "RAP") and the other from RAP, which provide both overview and detail on regulatory options for addressing high penetrations of distributed generation (particularly solar). Together, they provide a framework for Vermont to evaluate existing and potential tools to expand or modify our net metering program, drawn from lessons learned across the country.

[8] Barnes, J., Culley, T., Haynes, R., Passera, L., Wiedman, J., and Jackson, R. (2013). Freeing the Grid: Best Practices in State Net Metering Policies and Interconnection Procedures. New York, NY and San Francisco, CA. Interstate Renewable Energy Council and The Vote Solar Initiative. Retrieved from http://freeingthegrid.org/wp-content/uploads/2013/11/FTG_2013.pdf.

4.1.1 "Regulatory Considerations Associated with the Expanded Adoption of Distributed Solar"

In their November 2013 technical report, *Regulatory Considerations Associated with the Expanded Adoption of Distributed Solar,*[9] NREL and RAP provide a useful primer on the range of issues – from cost-benefit analyses to business models and ratemaking options – that regulators should consider when undertaking redesign of mechanisms to accommodate increasing penetrations of distributed solar. The authors recommend that regulators borrow methods learned from energy efficiency program design and regulation in order to address increased distributed solar, or even seek to simultaneously address issues related to distributed generation (DG), demand side management, and energy efficiency in order to achieve optimal regulatory and rate-making solutions.

The authors refrain from advocating any particular tool or combination of tools, stress that there is no one-size-fits all solution, and posit that new regulatory tools or combinations of existing tools will emerge as regulators begin to address the increasing pace of distributed solar deployment happening across the U.S. They suggest the optimal solution will make sense at any scale of solar deployment, rendering revisions and exceptions unnecessary; but if that should prove an impossible task, then regulators should at least anticipate high penetration levels and set in motion a transparent, predictable process to design tariffs that will address those levels.

The study discusses ratemaking options, spanning the universe of existing tools employed by regulators to accommodate distributed solar. They are framed in terms of performance, limits and downsides, and relevant utility type (i.e. investor-owned, cooperative, municipal) and include: net metering, fixed charges, stand-by rates, time-based pricing, two-way rates, minimum monthly billing, and creation of a new customer class for photovoltaic customers. Helpful case studies of places where these various tools are being deployed are included (e.g., implementation of a value of solar tariff – a type of two-way rate – in Minnesota). Notably, the report provides a list of "Questions for Framing the Regulatory Discussion." These questions are attached to this report as an appendix in recognition of its wholesale value to the present discussion.

The authors place emphasis throughout the paper on the various avenues by which regulators can influence the actions of utilities and – consequentially – the climate for solar deployment within a state. One option they discuss is for regulators and utilities to consider strategically placed distributed solar in the resource planning process, as one among a suite of potential least cost options to increase system reliability. The Vermont System Planning Committee (VSPC) serves as a venue today for discussions of utility infrastructure planning; the VSPC plays a role in the identification of constrained areas where DG could provide "sufficient benefit" in the context of the Standard Offer program and in the incorporation of DG into load forecasts.

Finally, the authors point to gaps in the knowledge base that need to be addressed in order for regulators to make informed decisions, such as the benefits and costs of distributed solar at high penetration levels, and the changes in cost-of-service figures and utility financials that will inevitably transpire if and when high penetrations of distributed solar are achieved. As noted in section 5.4, Vermont may be reaching these high penetrations of distributed solar sooner rather than later.

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[9] Bird, L., Mclaren, J., Heeter, J., Linvill, C., Shenot, J., Sedano, R., & Migden-Ostrander, J. (2013). Regulatory Considerations Associated with the Expanded Adoption of Distributed Solar (NREL/TP-6A20-60613). Golden, CO: National Renewable Energy Laboratory. Retrieved from http://www.nrel.gov/docs/fy14osti/60613.pdf.

4.1.2 "Designing Distributed Generation Tariffs Well"

In their 2013 paper, *Designing Distributed Generation Tariffs Well*,[10] the Regulatory Assistance Project focuses specifically on the design of tariffs that fairly compensate both customer-sited DG resources as well as utility services to customers. They note the importance of other regulatory tools to accommodate solar and distributed resources, such as those mentioned in the NREL paper discussed above, but focus on a discussion of tariffs and specifically advocate for two-way distribution tariffs, where both generators and utilities are fairly and accurately compensated for the specific services provided.

The authors are quick to acknowledge barriers to enacting perfect tariffs, such as immaturity of hardware and information technologies as well as legacy imperfections built into retail rate design, but stress the importance of improving upon existing compensation mechanisms in a way that moves toward greater fairness and accuracy while setting the stage for an easy transition to more sophisticated mechanisms (i.e. a transactive energy economy, where multiple parties including utilities, distributed generators, and aggregators are fairly and accurately compensated for the services provided) as technologies and markets evolve.

The RAP highlights that keeping tariffs simple and practical – as advocated by Bonbright[11] – is especially important in examining replacements for relatively well understood tools such as net metering. Beyond that, they then consider whether a serious cross-subsidy problem actually exists; and, if so, which tariff and rate design approaches might address the cross-subsidy. Finally, they propose to solve any remaining sources of stakeholder conflict with additional regulatory treatment (e.g. decoupling).

The RAP report examines issues important for consideration by regulators as they evaluate benefits, costs, and net value of DG to various stakeholders (DG adopters, non-adopter ratepayers, utilities, and society more broadly) as part of the tariff design process. This includes a discussion of sources of mutual benefit and sources of conflict among stakeholder value propositions drawn from examples in various states and jurisdictions. The report considers rate design options and alternative ratemaking approaches for fairly reconciling the needs and perspectives of various stakeholders. The options examined (through the lens of Bonbright's "Principles of Public Utility Rates," also discussed in the NREL paper) include: enacting a fixed charge for distribution costs; imposing a demand charge-based distribution charge and time-of-use (TOU) rate; and implementing a bidirectional distribution rate. (A different take on these approaches is illustrated in Exhibit 27 below.) The impacts of these various approaches on

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[10] Linvill, C., Shenot, J., and Lazar, J. (2013). Designing Distributed Generation Tariffs Well: Fair Compensation in a Time of Transition. Montpelier, VT: The Regulatory Assistance Project. Retrieved from http://www.raponline.org/document/download/id/6898.

[11] Bonbright, J.C. (1961). Principles of Public Utility Rates. New York, NY: Utilities Reports, Inc. & Columbia University Press. The principles, as summarized in the RAP paper, include:

- Tariffs should be practical: simple, understandable, acceptable to the public, feasible to apply, and free from controversy as to their interpretation.
- Tariffs should keep the utility viable, effectively yielding the total revenue requirement and resulting in relatively stable cash flow and revenues from year to year.
- Rates should be relatively stable such that customers experience only minimal unexpected changes that are seriously adverse.
- Tariffs should fairly apportion the utility's cost of service among consumers and should not unduly discriminate against any customer or group of customers.
- Tariffs should promote economic efficiency in the use of energy as well as competing products and services while ensuring the level of reliability desired by customers.

representative ratepayer groups – apartment dwellers, typical residences, large residences, and photovoltaic customers – are then examined.

The RAP authors suggest that today's tools – net metering and feed-in tariffs – may achieve simplicity (per Bonbright) but fall short on precision (per a transactive energy economy). However, they offer suggestions for "Getting NEM and FIT Right" in the meantime.

For net metering, these include: recognizing the premium value of renewable resources, which may justify full retail rate value; avoiding fixed monthly customer charges, which tend to penalize apartment dwellers and urban residents; and considering time-of-use arrangements in tariffs to encourage prices that are closer to the value of power consumed.

For feed-in-tariffs, suggestions include: providing stable and long terms (of at least ten years); allowing for different types of resources that offer unique attributes; considering auctions; committing to a stable policy that still allows for reasonable modification of prices and terms; and making sure program caps are not unreasonably restrictive.

Finally, the RAP authors provide 12 specific recommendations for regulators, reproduced here (additional detail on each is provided in the paper's conclusion):

1. Recognize that value is a two way street.
2. Distributed generation should be compensated at levels that reflect all components of relevant value over the long term.
3. Select and implement a valuation methodology.
4. Remember that cross-subsidies may flow to or from DG owners.
5. Don't extrapolate from anomalous situations.
6. Infant-industry subsidies are a long tradition.
7. Remember that interconnection rules and other terms of service matter.
8. Tariffs should be no more complicated than necessary.
9. Support innovative business models and delivery mechanisms for DG.
10. Keep the discussion of incentives separate from rate design.
11. Keep any discussion of the throughput incentive separate.
12. Consider mechanisms for benefitting "have not" consumers.

4.2 Literature review insights

There are a number of options for the future design of net metering in Vermont. Exhibit 27 highlights a range of possible models for the evolution of net metering in different jurisdictions. Reformed net metering programs (those, like Vermont's, that go beyond simple "spin the meter backward" net metering) can be divided into those which retain a single-rate approach, but reform some piece of that rate (e.g. a fixed charge, demand charge, or other solar charge), and those which use more than one rate (such as a solar value rate). As can be seen, program attributes vary by approach.

	CAMP 1	CAMP 2				
	Continue NEM	Reforming the Solar Customer Transaction (NEM reform)				
RATE CONSTRUCT	Single Transaction (Rate) Approach				Two or More Transactions (Rates)	
	Apply NEM	Reform Existing Rates (all customers or solar only)			Solar Rate	Reform All Rates
MODEL	Current Rates	Increased Fixed Charge and/or Minimum Bill	Demand Charge	Stand-by or Solar Charge	Independent Energy Sale and Solar Purchase Rates	Value of Services
ATTRIBUTES	• Currently applicable rates result in an acceptable transaction • Solar penetration does not warrant action	• Add or increase basic service charge ($/month) • Raise min bill requirements ($/month)	• Add or increase customer fee for demand ($/kW/month)	• Charge for stand-by capacity, based on DG system size ($/kW/month or ($/kW/yr)	• Retain existing rates for services provided from utility to cust. • Establish second rate to purchase from customer	• Design rates to reflect itemized services from utility to cust. and from cust. to utility

Exhibit 27. *Summary table of rate structure options for net metering, including options that use one rate and include specific charges and options that use more than one rate. Figure courtesy of Julia Hamm, Solar Electric Power Association.*[12]

In addition to the guiding principles articulated by NREL and RAP, there are other considerations that will affect the success of any redesigned net metering program. For instance, the numerous changes in Vermont net metering statutes over the last decade have highlighted the value of stability in policy and financial programs. This stability allows time for the market to understand and respond to policy goals without the fear of potential swift program changes that might deter innovative solutions. Another consideration should be the value of price certainty for investors; a reasonably predictable credit for generation may allow for more accessible financing of small generation.

It is important to note that the pace of deployment doesn't necessarily only depend on net metering program tariff design. Other, complementary efforts such as tax policy or separate incentive funding mechanisms should be considered in the upcoming process.

The RAP and NREL reports clearly articulate that there is no "best practice" which Vermont can simply emulate; there is no "one size fits all" policy framework that can simply be adopted. Instead, the design of future programs must begin with a critical review of the pertinent issues relevant to Vermont stakeholders to determine feasible options and make informed decisions. While it is unlikely that a perfect tariff could be established that equally addresses concerns of ratepayers and developers (including both home and business owners) installing net metered distributed generation across all of Vermont's utilities, striking the appropriate balance between potentially competing interests will help determine the success of the future of net metering in Vermont.

[12] Originally presented at the RPS Collaborative Summit, September 23, 2014. Reproduced with permission.

5 Other topics required by Act 99

5.1 Economic and environmental benefits of net metering

The cost and benefit discussion in Section 3 above describes the economic and environmental costs and benefits of net metering that are quantifiable on a per-kWh or per-kW basis. In addition to these costs and benefits, there are impacts which are hander to quantify on that basis. These include the direct employment of Vermonters in the design, permitting, construction, and operation of net metered generators. The Solar Foundation has identified that Vermont has the most solar jobs per capita of any state in the country. These jobs are to some large part a result of the state's aggressive adoption of net metered solar PV generation. In addition, the recent Clean Energy Development Fund *Clean Energy Industry Report*, which surveyed clean energy firms around the state, estimates that over 1,500 Vermonters work in the solar industry in some fashion, the greatest of any renewable energy technology. Maintaining a sustainable economic sector that develops clean energy resources is also a component of the state's recent Comprehensive Economic Development Strategy. The Department did not attempt to quantify these types of benefits in the analysis presented in Section 3; however the spreadsheet model offers the opportunity to add, on a per kWh basis, such values to the benefit of net metered technologies.

The Department considered attempting to quantify the reductions in air pollutants other than carbon dioxide due to net metering, but initial evaluation indicated there is significant uncertainty in the valuation of such emission reductions, and that the values are likely to be comparatively small regardless.[13]

5.2 Reliability and supply diversification costs and benefits

The benefit discussion in Section 3.2 above describes the reliability benefits that can occur due to net metered generators which reduce stress on the transmission and distribution grids during peak hours. At greater levels of deployment on particular circuits, net metered generators could result in "reverse" flows on energy on electric circuits not designed for those flows; equipment upgrades may be required at that point in order to maintain reliability.

Vermont has long valued diversification in its electric energy supply portfolio. For example, extensive dependence on any one fuel, such as oil, coal, nuclear, biomass, or natural gas, can leave ratepayers at risk that increases in the cost of that fuel would result in rate spikes. Vermont utilities have pursued a policy of constructing their portfolios with a substantial fraction made up from contracts for or ownership of different types of generation, and with fixed prices, known price escalation (e.g. with inflation), or prices with "collars" that prevent or dampen spikes. This has served a purpose of maintaining stable rates, leading to predictability for business and household costs. (The downside is that Vermont has not benefitted when one fuel or another falls sharply in price.) Many renewable generators for which there is no direct fuel cost (e.g. solar, wind, and hydroelectric) have economic structures that are fundamentally compatible with this desire for rate stability.

The benefits for rate stability of this sort that flow from net metering programs depend on the structure whereby participating customers are credited by their utility for their generation. Under a feed-in-tariff model or other fixed price arrangement between customer and utility, other ratepayers benefit from

[13] For example, the ISO-NE marginal emissions rate of NO_x was 0.22 lb/MWh in 2012. A rooftop solar PV system might generate 5 MWh/year, and avoid 1.1 lb. of NO_x emissions. Recent Federal rulemakings value NO_x emission reductions at between $476 and $4,893 per ton, or a maximum of less than $2.50 per pound.

price stability. A retail rate based structure has somewhat more risk, but retail rates are generally relatively smoothly increasing (historically roughly in line with overall inflation in Vermont), due to the many components that comprise a utility's cost of service. The lack of fuel price volatility makes most renewable net metered generators a good fit (in this respect) for Vermont utility portfolios.

5.3 Benefits to net metering customers of connecting to the distribution system

The analysis is Section 3 of this report discusses the costs and benefits of net metering form the utility or non-participating ratepayer point of view. Net metering also has costs and benefits from the standpoint of the participating net metered generator. Access to the electric distribution system, as opposed to being "off grid," allows a net metered customer to avoid the need to deploy energy storage, match supply and demand on-site, or use a diesel or other fuel-based generator. The grid also provides assurance of access to electrical power above that which and off-grid generator may provide. Use of a shared energy generation, transmission, and distribution infrastructure can be a societally least-cost way to meet energy service demand. Net metering customers benefit from the presence of the grid to transmit excess generation to other customers, and to draw upon at times when the net metered generator is not generating enough power to meet the customer's needs. "Virtual" group net metered customers use the distribution, and perhaps even the transmission, systems to connect the power generated by a remote generator to their account (although, as the name implies, this is done through accounting, rather than direct electrical flows).

5.4 The future pace of net metering deployment statewide and by utility

The Department recommends that Vermont ratepayers and utilities take maximum advantage of the current Federal tax incentive structure to build well-sited[14] distributed net metered generators, including solar PV, in the state between now and the end of 2016, when Federal tax treatment for solar PV may change. The design of a future net metering system for the time after 2016, which is the subject of the Public Service Board investigation to follow submission of this report, should be sensitive to the impact of Federal incentive policy. The investigation should also be informed by the amount of distributed solar PV and other generation built in the state and in each utility's service territory by the end of 2016. The Department therefore recommends that the Board take a relatively flexible approach to the setting of any targets for the pace of future deployment.

It is likely that the solar PV industry in Vermont and around the country will see a boom from now until the end of 2016. The economic activity and jobs associated with that boom will boost the clean energy sector in Vermont. Once Federal tax treatment changes, however, the industry will be at risk of a significant drop in activity, with associated economic hardship for particular firms and their employees. If this bust is sharp and deep, it may hamper the industry's ability to rebound, and thus the state's ability to meet long-term renewable energy goals. To that end, stakeholders and the Public Service Board should consider industry impacts when evaluating the impacts of different policy options for the post-2016 period.

At the current pace of permit applications, it is possible that the total permitted net metering may approach 150 MW by the end of 2016. Combined with other distributed generators built under the Standard Offer program or under PPA or utility ownership, this could mean 250 MW or more solar PV permitted in the state. This will have noticeable impacts on the state's load shape, and the load shapes

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[14] Encouragement for generators sited on "ideal" locations such as brownfields, landfills, industrial parks, etc. may be an appropriate consideration for the upcoming Public Service Board process.

of each of the state's utilities. In particular, it may push all summer peaks to near or past sunset in the summer.[15] This would have a significant impact on the value delivered by solar PV in terms of avoided in-state transmission and distribution infrastructure, as well as RNS costs. A slower transition throughout New England may impact the ISO-NE peak, shifting it later in the day as well, which will impact the energy and capacity markets. One unknown facing future distributed generation deployment is the level of deployment at which reverse flows and other integration challenges, with associated costs, begin to appear on the grid.[16]

Taking into account the context described in the previous three paragraphs, the Department recommends that the Board and stakeholders strive for a sustained pace of deployment while avoiding market booms or busts. Given the roughly 20-25 year lifetime of most distributed generators, the expectation of continued technological progress and associated falling real prices, and the likely continued development in grid management systems and technologies (including energy storage), renewable energy deployment toward 2050 goals can afford to take a longer-term view. This should be balanced with a need to remain flexible in order to take full advantage of changes in technology, Federal programs and policies, and evolving business models. The Board, and state policymakers in general, should strive for policies that balance the costs and benefits of distributed generation, including net metered generation, remain flexible, and aim for overall targets regarding renewable electricity (such as those established in 30 VSA 8005a) and renewable energy in all sectors.

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[15] Given this shift, it may be worthwhile to consider policies that incent developers to increase focus on peak benefits at some expense of energy generation. An inexact calculation of a west-facing solar PV system in the Department's cost-benefit model indicates that a west-facing fixed solar PV system might produce as much as 15% more value per kWh generated than a south-facing system.

[16] Reliability issues such as maintenance of voltage and frequency events, and potential for accelerated ramping potentially necessary to meet peak demand have been the subject of significant discussion at the ISO-NE Distributed Generation Forecast Working Group. Information is available at http://iso-ne.com/committees/planning/distributed-generation

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Appendix: "Questions for Framing the Regulatory Discussion"

An excerpt from *National Renewable Energy Laboratory's Regulatory Considerations Associated with the Expanded Adoption of Distributed Solar.* Bird et. al. November 2013.

7 Questions to Frame the Regulatory Discussion

Policymakers and regulators in each state face the challenge of crafting policy and regulatory responses that fit their respective contexts. Differences in solar insolation, electricity prices, policy priorities, and the regulatory context of states have resulted in different regulatory responses to the development of distributed PV; one size will not fit all going forward. However, many of the questions regulators will need to ask to determine the path forward are similar. The following set of questions is intended to help policymakers and regulators identify pertinent issues, determine feasible options, and make better informed decisions.

1. How much distributed PV adoption does the state expect to experience in the coming decade, given retail electricity rates, incentives, and PV cost trajectories?
    A. Have there been significant changes in the rate of distributed PV deployment in the state over time? What were the main drivers for these changes (e.g., state policy, regulatory changes, industry changes/cost decreases)?
    B. If there is a specific deployment target indicated by state policy, will it likely be met or exceeded? Are there challenges or barriers that need to be addressed to meet current policy goals/targets?
2. How does current and expected deployment compare with that in other states that have similar resource quality and retail electricity prices?
    A. How have other states responded to challenges or barriers in meeting their state targets? Can we learn from their experiences to help us meet our goals at least cost and least risk?
    B. Do the differences in deployment between states indicate relative strengths or weaknesses in our state's approach, or are they indicative of other factors?
    C. What do the experiences from other states indicate about the best way to prepare a state and its utilities for the higher penetration levels? Are the utilities in our state well positioned to accommodate higher PV penetration levels if state or federal policy or economics drive significant increases beyond projected levels?
3. Are the state's utilities positioned to undertake infrastructure upgrades that may be necessary to accommodate higher levels of distributed PV?
    A. Under what conditions and at what deployment levels might additional system upgrades be required to accommodate distributed PV?
    B. Under current regulatory mechanisms, who is responsible for paying for necessary upgrades?
    C. Is the responsible party and cost recovery mechanism clearly defined for all foreseen scenarios?
4. Are the state's utilities positioned to capture the potential benefits of intentionally locating distributed PV at specific locations on the utility system?
    A. Is the expected distributed PV deployment clustered in one or more areas of the grid? What are the implications of this clustering to the system, the utilities and the customers?

B. Can PV be strategically located on the system to optimize the T&D system benefits? What would be the financial savings of doing so?

C. Is it appropriate to consider policies that would encourage the location of distributed PV at specific locations? If so, what signals can be used to encourage the strategic placement of distributed PV in locations that maximize the benefits?

5. Given the expected penetration levels, how will distributed PV affect each stakeholder group?

   A. What are the key benefits of distributed PV from a utility perspective? What are the key costs?

   B. What are the key benefits from the perspective of a customer with and without distributed solar? What are the key costs?

   C. How are distributed solar customers and non-participating customers affected by current policy and rate structures?

   D. What role will the various stakeholders (including utility and third-party providers) play in the development of distributed PV if the current environment persists? What is the desired role?

   E. Are there risks being borne by utility ratepayers that would be more appropriately proportioned to third-party providers or other stakeholders?

   F. How can the benefits and costs of distributed PV be appropriately proportioned to all stakeholders?

6. Are stranded assets a possibility?

   A. What opportunities are there for distributed resources to reduce or delay the costs of system upgrades?

   B. What are the financial risks of making T&D infrastructure and generation investments today if penetrations of distributed systems are higher than expected?

   C. How can these risks of incurring stranded assets be minimized?

   D. How can the value of the utility grid (or the value lost by disconnecting from the grid) be quantified?

   E. What are the impacts of higher distributed PV adoption on utility financial health if no changes in the utility business model, regulatory treatment or rate design are implemented? How much will expected penetrations of distributed PV affect system fixed costs, utility revenues, and customer bills?

   F. What financial metrics should we track to monitor the financial health of our utility?

   G. From a financial perspective, at what level of distributed PV penetration will the utility have difficulty ensuring system reliability?

7. Are there opportunities to learn from past policy experiences with respect to rate design, utility compensation, third-party providers, and impacts on non-participants?

   A. What lessons can be learned from other states or countries?

B. What lessons can be learned from the experience of the telecommunications industry?

C. What parallels are there with respect to the adoption of other new technologies that give consumers alternatives to traditional service?

8. Is the state policy and regulatory model one that facilitates retail competition and consumer choice? If so, how can the utility system be maintained while facilitating customer choice (i.e., for options such as distributed PV), enabling competition, and keeping electricity affordable?

9. Regardless of whether the state is tending toward more restructuring or trending toward more traditional regulation, the question will remain: How are customers who choose to retain traditional, integrated service affected by higher penetrations of PV?

10. How can the need for the utilities to meet their revenue requirements be balanced with the societal goal of promoting PV and assuring that nonparticipating customers are not unduly burdened with rate responsibility?

11. Regardless of whether one is tending toward more restructuring or toward more traditional regulation the question will remain: What are the costs and benefits of distributed PV for different stakeholders?

    A. What benefits and costs of distributed PV are our state counting as accruing to participating solar customers and non-participating customers? What are the benefits/costs to broader society? To the utilities?

    B. What are the key gaps in the state of knowledge regarding the costs and benefits of distributed PV on the system?

    C. What data or resources are available to help fill these knowledge gaps so that our state can ensure the appropriate sources of costs and benefits are included as we evaluate the impact of policies and regulatory treatments?

12. Is the state policy and regulatory model of the future one of modified rate of return regulation with limited retail competition and consumer choice? If so, what combination of rate tools and rate designs are needed to facilitate PV choice and cover fixed system costs in our state?

    A. What rate structures address revenue issues without encouraging PV customers to flee the grid?

    B. What are the pros and cons of establishing tariffs based on fixed charges, demand charges, or minimum monthly bills? What are the equity issues of applying fixed or demand charges or minimum monthly bills to distributed solar customers only, as compared to all ratepayers?

    C. What would be the implications of applying fixed charges, demand charges, or minimum monthly bills on the effectiveness of energy efficiency programs?

    D. How should the utility's role as "the provider of last resort" be accounted for in rates?

E. What are the impacts of disaggregated rates and value of solar tariffs on customer equity, utility revenues, and grid security/reliability? What types of information and analyses are needed to develop a disaggregated rate, or a value of solar tariff?

13. What are the barriers to the adoption of new utility business models? What regulatory changes need to occur to facilitate the development of new utility business models?

    A. What business models best ensure recovery of system costs and equitability among ratepayers?

    B. Which business models are best suited to regulated utilities?

    C. What are the regulatory obstacles to the implementation of a business model in which utilities function as grid services providers, without necessarily engaging in power supply (e.g., energy services utility)? What aspects of this model are desirable, from a regulatory standpoint? What aspects are less desirable?

South Carolina Act 236 Cost Shift and Cost of Service Analysis

Prepared on behalf of the South Carolina Office of Regulatory Staff

December 18, 2015

Energy+Environmental Economics

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Executive Summary

The Distributed Energy Resource Program Act, known as Act 236, encouraged the implementation of programs designed to promote customer- and utility-owned distributed energy resources (DER). Under Act 236, the three largest investor-owned utilities (Utilities or IOUs) are encouraged to generate or purchase a portion of their electricity from renewable energy resources in South Carolina. The Utilities are also encouraged to create programs to incent customers to generate their own renewable energy.

Act 236 also required the Office of Regulatory Staff (ORS), with input from the Utilities and other interested parties, to investigate and report to the Public Service Commission of South Carolina the extent to which cost shifting can be attributed to DER adoption within current ratemaking practices. ORS enlisted the assistance of Energy and Environmental Economics, Inc. (E3) to perform an analysis and report the findings. This document includes the results of that study and is presented on behalf of ORS to fulfill its requirements under Act 236, as set forth in S.C. Code Ann. § 58-27-1050.

Many of the assumptions in this analysis are based on information provided to E3 by the Utilities with the help of ORS. E3 would like to thank both ORS and the Utilities for their detailed and prompt responses to multiple data requests and follow-up questions.

The DER Programs of each of South Carolina's Utilities offer a variety of incentives to residential and commercial customers wishing to install a renewable energy facility. These incentives include bill credits, rebates for installation costs, subsidized community solar subscriptions, and the assignment of full retail value (1:1 Rate) to power produced under a net energy metering (NEM) agreement. All of these incentives, along with their associated administrative costs, and the overall benefits of DER are examined in this report.

Specifically, the report examines the following:

+ Any **cost shifts** resulting from DER adoption, with and without the DER Programs; and,
+ The contribution of different customers to their utility's full **cost of service**.

The key conclusions of the report are as follows:

+ The cost shifting resulting from NEM adoption prior to Act 236 was *de minimus* due to the small number of participants.
+ If Utilities were to reach the DER adoption targets set in Act 236 without additional incentives, the cost shifting would be small and difficult to isolate. The Utilities forecast that installed DER capacity will reach approximately 105 megawatts (MW) by the end of 2020. If the installed DER capacity is higher or lower than expected, the result would be a proportional increase or decrease in the estimated shifts.
+ By 2020, Residential Customers will pay approximately $0.80 per month, Commercial Customers will pay approximately $3.50 per month, and Industrial Customers will pay $100 per month more because of the DER Programs.
+ Although more data is required before widespread conclusions can be drawn, the Utilities' rate structures may need to evolve to be more economically efficient and to alleviate the potential for cost shifting or for an uneconomic bypass of the utilities' fixed cost recovery. Specifically, fixed charges may need to increase or alternative rate designs may need to be considered.

Table of Contents

Introduction

Energy and Environmental Economics, Inc. (E3) was retained by the South Carolina Office of Regulatory Staff (ORS) to assist with and support the implementation of certain aspects of South Carolina's Distributed Energy Resource (DER) Program Act, commonly known as Act 236 (or the Act).[1] Act 236 was a landmark bill that resulted in consensus among diverse stakeholders, a consensus that has rarely been achieved in other States. The Act created a path for South Carolina to benefit from new clean energy technologies and potentially foster the growth of new industry. While the Act's stated goal is to promote the establishment of a reliable, efficient, and diversified portfolio of DER for South Carolina, the General Assembly was also mindful of the potential costs associated with DER[2] and ordered the examination of its effect on ratepayers.

The purpose of this report is to meet the following requirement in Act 236:

> The Office of Regulatory Staff, with guidance and feedback from the electrical utilities and other interested parties, shall investigate and report to the Public Service Commission on fixed costs, fixed charges, and the extent of cost shifting that is attributable to distributed energy resources within current utility cost of service ratemaking methodologies, cost allocations, and rate designs, with a focus on the implications distributed energy resources could have for that business model in the future. The report shall review how to ensure a fair allocation of costs and benefits

[1] http://www.scstatehouse.gov/sess120_2013-2014/bills/1189.htm

[2]Renewable energy resources are defined in Act 236 as follows: "solar photovoltaic and solar thermal resources, wind resources, hydroelectric resources, geothermal resources, tidal and wave energy resources, recycling resources, hydrogen fuel derived from renewable resources, combined heat and power derived from renewable resources, and biomass resources." This report defines DER likewise.

> between consumers who utilize distributed energy resources and consumers who do not utilize distributed energy resources, as well as suggesting any necessary or prudent changes to existing or future rate structures. The report shall include a general overview of cost shifting that is attributable to or arising from historical cost of service ratemaking related to the current utility business model, specifically the cost of service ratemaking methodology, the cost allocations and rate designs. The findings shall include public comment and be reported to the Public Service Commission by December 31, 2015.

This report presents the results of E3's examination of the current cost of service studies for South Carolina's three largest investor-owned utilities (Utilities or IOUs)—South Carolina Electric & Gas Company (SCE&G), Duke Energy Progress, LLC (DEP), and Duke Energy Carolinas, LLC (DEC)—in the context of current and future DER deployment. The report is divided into the following sections:

+ **Cost-Shifting Analysis:**
    - Historical DER Adoption: Examines whether historic Net Metering (NEM),[3] as it has been administered in South Carolina since 2008, has caused costs to be shifted from customer-generators to non-customer-generators or from one customer class to another.
    - Impact of DER Adoption: Examines whether growth in DER adoption in the future, without the incentives Utilities have offered through DER Programs, would cause costs to be shifted from customer-generators to non-customer-generators or from one customer class to another. This section also discusses the method used in South Carolina for valuing DER generation and compares it

[3] Net metering in this context refers to the rate paid by the utility to a customer for all distributed energy resource generation that is both consumed on-site and exported back to the grid at a 1:1 per kilowatt-hour basis (excluding non-volumetric charges like the Basic Facilities Charge). The credit for this energy is paid for at a net metering rate per each utility's net metering tariff and flows through as a bill credit on a customer generator's utility bill. At the end of the billing cycle, the grid-supplied electricity and the credits for any exported electricity are reconciled, and any net surplus credits can be carried forward to the next billing cycle. Any bill credits that are unused in any given month "rollover."

to methods and studies from other jurisdictions around the country.

- DER Adoption Resulting from DER Program Participation: Explores the potential for future cost shifting due to the incentives offered by Utilities under the DER Programs approved on July 15, 2015. It also discusses the effect that the recovery mechanism established in Act 236 has on cost shifting between customer classes.

+ **Cost of Service Analysis:**
  - Cost-Shifting in Traditional Ratemaking Methodologies: Examines the prevalence of shifting costs in generally accepted methods of retail rate design and presents various stakeholder perspectives on acceptable justifications for cost shifting.

  - Economic Rates: Explores the possibility of adjusting rates to align more closely with cost causation and estimates how rate structures may change.

Cost Shifting Analysis

Historic DER Adoption

From 2008 to the implementation of Act 236, NEM has been the primary means by which IOU customers in South Carolina were able to use customer-sited DER to reduce their electric bills. For every kilowatt hour (kWh) generated, the customer was able to offset the cost of a kWh consumed; and if the customer's generation exceeded the customer's consumption, the full retail value of the excess energy (1:1 Rate) was "banked" to offset future bills. Renewable sources eligible for NEM programs, until Act 236 was approved, included solar, wind, biomass and micro-hydro resources. The maximum capacity for residential systems was 20 kilowatts (kW) and 100 kW for non-residential systems. The IOUs total allowed customer-installed capacity was limited to 0.2% of the Utility's prior calendar year's retail peak load in South Carolina.

In 2014, when Act 236 was signed into law, approximately 400 customers were enrolled in legacy IOU NEM programs across the state and no IOU-sponsored programs existed, beyond NEM, to incentivize adoption of customer-sited DER.

The first aim of the analysis undertaken in this report is to determine whether the costs to serve historical NEM generators have been transferred or shifted from customers that install renewable generation resources, such as solar photovoltaic (PV) panels on their roofs, to other customers that do not, i.e. non-participating ratepayers.

From a cost recovery standpoint, NEM may become problematic when NEM customer-generators are able to reduce their energy charges to the extent that the utility's ability to recover its fixed costs is impeded. As described in comments provided to ORS, "Installing DER resources allows certain customers to displace significant amounts of their volumetric usage but usually does not proportionally reduce the fixed cost of serving those customers. The result can be an under-recovery of costs from DER customers, and over time, an over-recovery from non-DER customers."

It is worth noting that, generally speaking, some cost shifting is a common occurrence in regulated electric retail rate design. Electric retail rates have historically been designed to collect the utility's cost to serve[4] from several large groups or classes of relatively homogenous customers, like residential or commercial customers, that have similar usage patterns and therefore similar costs to serve.

Utilities design retail rates, especially those for residential customers, assuming that all customers in a class are average customers. Utilities then create an average set of rates that will, on average, collect the required revenues needed by the utility to serve that average customer. This succession of averages is used to set rates to collect the utility's full revenue requirement, or its full cost to serve. In other words, average customers would pay exactly what it costs the utility to serve them. However, if customers use more electricity than the average customer, they may pay the utility more than what it cost the utility to serve that customer. Conversely, if a customer uses less electricity than average, they may pay the utility less than what it cost the utility to serve them. As explained by one stakeholder, "A customer whose net power usage is small or non-existent is not paying a proportionate share of costs incurred by the utility to own, operate, and maintain the electric system and support facilities on which that customer relies. That cost is being, in effect, borne by other customers and this is what is commonly referred to as 'cost shifting.'"

It is worth noting that some rates, such as time-of-use rates, rely on information external to cost of service studies. Although these rates do not use the average customer model as the basis for their design, the possibility of shifting costs among customers still exists.

[4] As explained in the January 2014, State Regulation of Public Utilities Review Committee Energy Advisory Council's Distributed Energy Resources Report, the cost of service entails a utility determining a revenue requirement that reflects the total amount that must be collected through rates in order for it (the utility) to recover its costs and have an opportunity to earn a reasonable rate of return. Therefore, the cost of service used to determine regulated electric retail rates consists of two basic components:

1) the recovery of reasonable and necessary operating expenses, including depreciation, and
2) the return on investments through the allowed rate of return on invested capital.

See http://www.scstatehouse.gov/committeeinfo/EnergyAdvisoryCouncil/EAC%20Report%201-14-14.pdf for more information on cost of service and ratemaking in South Carolina.

The cost shift can be mitigated or exacerbated with changes in the customers' electric consumption patterns, such as adding a DER. In fact, with the addition of a DER system on a customer's premise, that customer is now an electric generator as well as a consumer, creating a unique set of costs and benefits. Considering the cost shifting inherent in traditional ratemaking and the small number of customers participating in NEM since 2008, determining if costs to serve customer-generators have been shifted to non-customer-generators is impossible. It is reasonable to conclude that if cost shifting has occurred as a result of the implementation of NEM in 2008, the shift has been *de minimus* given the small number of customers participating in NEM since 2008.

Impact of DER Adoption Without Incentives

Act 236 set a goal for DER adoption to be equal to 2% of the previous five-year average retail peak demand[5] among South Carolina's largest IOUs by the close of 2020. Utility-scale installations between 1 and 10 megawatt (MW) comprise half of the 2% target, and the other half is comprised of customer-scale installations less than 1 MW. A quarter of the customer-scale capacity is reserved for installations smaller than 20 kW. Although the cost shifting caused by previous levels of DER generation was likely insignificant, achieving the DER targets established in Act 236, i.e. 105 MW of customer-sited DER in 2021, may cause cost shifting. This section discusses the quantifiable costs and benefits of DER generation and explores a method of evaluating its effect on ratepayers.[6]

As one stakeholder articulated in comments to ORS, "With respect to distributed generation, a critical aspect of understanding the direction and magnitude of any shift is full and accurate quantification of the value of distributed generation." Act 236 required the Public Service Commission of South Carolina (Commission) to conduct a proceeding to develop a "methodology" to evaluate "the benefits and costs

[5] The average 5-year retail peak demand for each IOU from 2009-2013 is as follows: SCE&G - 4,208 MW DEC - 3,774 MW and DEP - 1,217 MW. The 105 MW referenced above is the customer-sited only portion (excludes utility-scale DER) and is based on 2% of forecasted utility peak demand in 2021;

[6] Larger utility-scale installations (1-10 MW) are not explicitly examined in this report as these installations will most likely sell their output to each IOU under more traditional power purchase agreements (PPAs) and will not be incentivized like customer-scale installations. Traditional PPAs do not shift costs between ratepayers, but rather are borne by all ratepayers in a similar fashion to other supply costs.

of customer generation"[7] (Methodology). The Methodology to quantify the value of DER generation was developed by stakeholders and ultimately approved by the Commission in Docket No. 2014-246-E. This Methodology begins with a Utility's avoided costs and layers additional components if they result in quantifiable benefits or costs to the Utility's system. The Methodology contains several placeholders to reflect that the benefits and costs of DERs may change significantly over time. For example, there are currently no monetized carbon or greenhouse gas costs for IOUs in South Carolina, but it is possible for avoided carbon costs to become a meaningful monetized benefit of DER under the proposed Environmental Protection Agency (EPA) Section 111(d) rule of the Clean Air Act.[8] The value of DER will be updated annually coincident with each Utility's annual fuel review.

While advocates of renewable energy point to numerous environmental and societal benefits that could be included in an analysis of the value of DER, the directive of Act 236 was to develop a methodology that would "ensure that the electrical utility recovers its cost of providing electrical service to customer-generators and customers who are not customer-generators."[9] Therefore, the Methodology is limited to the quantifiable benefits and costs currently experienced by the Utility. Likewise, the analysis performed for this report focuses on the quantifiable benefits and costs to the Utility with recognition that those benefits and costs experienced by the Utility are ultimately passed on to its ratepayers.

JURISDICTIONAL COMPARISON

A multitude of organizations in a number of different states have developed more than a dozen studies to determine the value of DER. However, because methods, purposes, and levels of analytical rigor differ between studies, results vary significantly by jurisdiction and even by study within the same jurisdiction. For example, many of these studies do not evaluate the cost-effectiveness of DER systems and focus solely on calculating or quantifying the benefits of DER, often including non-monetized benefits such as environmental externalities.

Figure 1 and Figure 2 show differences in methodologies and results between studies as follows:

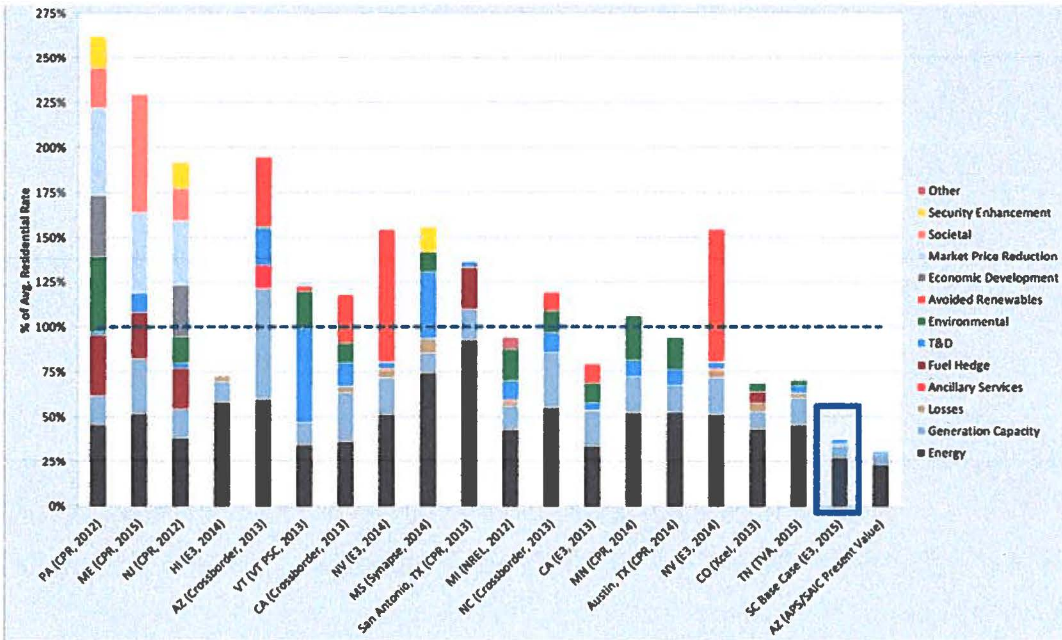
[7] Section 58-40-20 (F) of Act 236.
[8] http://www2.epa.gov/carbon-pollution-standards/what-epa-doing
[9] Section 58-40-20 (F)(1)

Figure 1: Value of Solar and NEM Benefit-Cost Methodologies Vary

Included	●
Included as a sensitivity	◉
Represented/captured in other values	○

EXAMPLES OF RECENT NEM VALUE STUDIES FROM STATES, UTILITIES, CONSULTANCIES, AND STAKEHOLDERS																									
STATE	STUDY	BENEFITS ANALYZED												COSTS ANALYZED				BENEFIT/COST TESTS							
		Avoided Energy (incl. O&M, fuel costs)	Avoided Fuel Hedge	Avoided Capacity (generation and reserve)	Avoided Losses	Avoided or Deferred T&D Investment	Avoided Ancillary Services	Market Price Reduction	Avoided Renewables Procurement	Monetized Environmental	Social Environmental	Security Enhancement/Risk	Societal (incl. economic/jobs)	PV Integration	Program Administration	Bill Savings (Utility Revenue Loss)	Utility/DER Incentives	Total Resource Cost Test (TRC)	Program Administrator/Utility Cost Test (PACT/UCT)	Cost of Service (COS) Analysis	Ratepayer Impact Measure (RIM)	Participant Cost Test (PCT)	Societal Cost Test (SCT)	Revenue Requirement Savings: Cost Ratio	Net Cost Comparison of NEM, FIT, Other
ARIZONA	Crossborder Energy (2013)	●		●	●	●	●	○	●	●		○	○	●		●	◉				●				
ARIZONA	APS/SAIC (2013)	●		●	○	●																			
CALIFORNIA	E3 (2013)	●		●	●	●	●		●	●				●	●	●				●	●				
CALIFORNIA	Crossborder Energy (2013)	●		●	●	●	●		●	●				●	●	●					●				
COLORADO	Xcel (2013)	●	●	●	●	●	○			●				●											
HAWAII	E3 (2014)	●		●	●	◉	●				◉														●
MAINE	Clean Power Research (2015)	●	●	●	○	●	○	●			●			●											
MASSACHUSETTS	La Capra Associates (2013)	●		●	○	●		●	●	●		◉	◉			●	●	●			●				
MICHIGAN	NREL (2012)	●	●	●	●	●	●		○	●															
MINNESOTA	Clean Power Research (2014)	●	○	●	●	●					●														
MISSISSIPPI	Synapse Energy Economics (2014)	●	●	●	●	●				●				●	●	●		●				●		●	
NORTH CAROLINA	Crossborder Energy (2013)	●	●	●	○	●	○	○	●	●	◉	○	○	●		●	●								
NEW JERSEY	Clean Power Research (2012)	●	●	●	●	●		●	○		●	●	●	●											
SOUTH CAROLINA	E3 (2015)	●		●	●	●	●			●				●	●	●	●			●	●				
NEVADA	E3 (2014)	●		●	●	●	●		●	●				●	●	●	●	●	●		●	●	●		
PENNSYLVANIA	Clean Power Research (2012)	●	●	●	●	●		●	○		●	●	●	●											
TENNESSEE	TVA (2015)	●		●	○	●				●	◉														
TEXAS (AUSTIN)	Clean Power Research (2014)	●	○	●	●	●			○	●															
TEXAS (SAN ANTONIO)	Clean Power Research (2013)	●	○	●	●	●				●															
VERMONT	Vermont PSC (2013)	●		●	○	●	●	●	●	●	◉				●	●					●				

Figure 2: Value of Solar and NEM Benefit-Cost Studies by Sponsor[10]



It is important to note that these benefits and costs are not consistent in methodologies, perspectives, or analytical rigor. Therefore, the various benefits are divided into a smaller number of subcategories for ease of comparison across studies. For example, the Societal category can include health impacts from sulfur oxides (SO_x) and nitrogen oxides (NO_x) along with Social Carbon Costs, depending on the study. The Environmental categories can include monetized carbon dioxide (CO_2) impacts along with other potential benefits. Given these caveats, this comparison serves as a useful context for this study and the results presented, but each study's results are unique and may or may not be useful as a direct comparison.

[10] Note, this chart is not meant to represent a benefit-cost test, but merely to serve as a comparison of how various potential benefits both direct (energy, generation capacity, losses, ancillary services, transmission and distribution, environmental, avoided renewables, and market price effect) and indirect (fuel hedge, societal, economic development, security enhancement, and other) have been calculated in each study. The average rates are aggregate numbers that include both fixed and variable charges, as reported by the U.S. Energy Information Administration.

E3's examination of these studies concludes that the categories of costs and benefits included in South Carolina's Methodology are in line with categories used by other jurisdictions.

DER BENEFITS

In this report, the value of DER is based on the Methodology approved by the Commission to quantify the benefits and costs of net metered DER generation. The most obvious potential benefits of DER to the Utility, and ultimately to the ratepayers, include reducing the need for fuel, reducing the need to construct generation facilities in the future, and reducing line losses, among others. Figure 3 describes each of the potential benefits the Utility may experience as a result of DER installations on its system.

Figure 3: Detailed Description of Ratepayer Benefits from DERs

Benefit Category	Component	Description	Calculation Methodology/Value
Utility Avoided Costs (Value of DER)	**Avoided Energy**	Reduction in variable costs to the Utility from conventional energy sources, i.e. fuel use and power plant operations, associated with the adoption of DER.	Component is the marginal value of energy derived from production simulation runs per the Utility's most recent Integrated Resource Planning (IRP) study and/or Public Utility Regulatory Policy Act (PURPA) Avoided Cost formulation. Based on Utility-provided forecast and E3 analysis.
	Energy Losses/Line Losses	Reduction of electricity losses by the Utility from the points of generation to the points of delivery associated with the adoption of DER.	Component is the generation, transmission, and distribution loss factors from either the Utility's most recent cost of service study or its approved Tariffs. Average loss factors are more readily available, but marginal loss data is more appropriate and should be used when available. Based on Utility-provided data and E3 analysis.
	Avoided Capacity	Reduction in the fixed costs to the Utility of building and maintaining new conventional generation resources associated with the adoption of DER.	Component is the forecast of marginal capacity costs derived from the Utility's most recent IRP and/or PURPA Avoided Cost formulation. These capacity costs

Benefit Category	Component	Description	Calculation Methodology/Value
			should be adjusted for the appropriate energy losses. Based on Utility-provided data and E3 analysis.
	Ancillary Services	Reduction of the costs of services for the Utility such as operating reserves, voltage control, and frequency regulation needed for grid stability associated with the adoption of DER.	Component includes the increase/decrease in the cost of each Utility's providing or procurement of ancillary services. E3 assumption of 1% of Avoided Energy costs used.
	T&D Capacity	Reduction of costs to the Utility associated with expanding, replacing and/or upgrading transmission and/or distribution capacity associated with the adoption of DER.	Marginal transmission and distribution (T&D) costs will need to be determined to expand, replace, and/or upgrade capacity on each Utility's system. Due to the nature of DER generation, this analysis will be highly locational as some distribution feeders may or may not be aligned with the DER generation profile although they may be more aligned with the transmission system profile/peak. These capacity costs should be adjusted for the appropriate energy losses. Based on Utility-provided data and E3 analysis.
	Avoided Criteria Pollutants	Reduction of SO_x, NO_x, and particulate matter (PM10) emission costs to the Utility due to reduction in production from the Utility's marginal generating resources associated with the adoption of DER generation.	The monetized costs of these criteria pollutants are accounted for in the Avoided Energy Component, but, if not, they should be accounted for separately.
	Avoided CO_2 Emissions Cost	Reduction of CO_2 emissions due to increase/reduction in production from each Utility's marginal generating resources associated with the adoption of DER generation.	The cost of CO_2 emissions may be included in the Avoided Energy Component, but, if not, they should be accounted for separately.

DER COSTS

Customers who install DER remain reliant on the utility's generation for times when their DER is not generating sufficient power to meet their onsite demand. Therefore the utility must maintain back up generation, transmission and distribution systems to serve these customers when their DER is not generating sufficient power. The utility continues to incur the full cost of maintaining back up generation, transmission and distribution systems, and metering to serve these customers. Additionally, integrating DER into the grid and administering non-traditional billing methods may be an additional utility cost. Figure 4 describes the costs to the utility that are included in E3's evaluation.

Figure 4: Detailed Description of Ratepayer Costs Attributable to DER

Cost Category	Component	Description	Calculation Methodology/Value
Customer Bill Savings	**DER Customer Bill Savings or Utility Revenue Reduction**	Direct savings on a customer's bill which represent revenue a Utility will not collect from customers as a result of the installation of DER	Based on publicly available customer billing data and data provided by the Utilities
Integration Costs	**Utility Integration & Interconnection Costs**	The Utility's costs to interconnect and integrate DER	Determined by detailed studies and/or literature reviews that have examined the costs of integration and interconnection associated with the adoption of DER
Administration Costs	**Utility Administration Costs**	The Utility's costs to administer DER Programs	Includes the incremental costs associated with DER such as administration of the DER Program, billing DER customers, etc.

SCENARIOS

In order to capture the uncertainty associated with the future value of DER, the following scenarios, differentiated by the type of DER benefits were considered. The Low Value Scenario is based on fewer components being included in the value of DER Methodology. The Base Value Scenario includes most components. The High Value Scenario includes all the components included in the Base Value and approximates a value for the carbon cost place holder. A description of benefits included in each scenario is shown in Figure 5.

Figure 5: Description of Benefits Included in Each Scenario

	DER Benefits Examined
Low Value Scenario	Energy + Losses
Base Scenario	Energy + Losses + Capacity + Ancillary Services + T&D Capacity + Criteria Pollutants
High Value Scenario	Energy + Losses + Capacity + Ancillary Services + T&D Capacity + Criteria Pollutants + CO_2 Costs

RATEPAYER IMPACTS OF DER ADOPTION ON THE GRID

An industry standard comparison or cost-benefit test can be applied in order to answer the specific question of whether customers that adopt DER impose cost shifts on customers that do not. The cost-benefit test used in this analysis is called the Ratepayer Impact Measure (RIM), which is a standard analytical cost-benefit framework used for decades to evaluate various types of ratepayer-funded energy efficiency programs.[11] The RIM test was established in the Standard Practice Manual (SPM)[12] and adapted for use in South Carolina.

The RIM test compares the costs and benefits of DER from the perspective of the Utility's ratepayers. If the costs to the Utility exceed the benefits, the Utility will need to increase rates in order remain revenue neutral and collect its revenue requirement, including its authorized rate of return, from its ratepayers. If rates increase, a cost shift will likely occur because all customers, even those who do not adopt DER, will experience higher rates.

[11] Over 50% of states in the U.S. use this cost-benefit metric to evaluate at least one type of ratepayer funded energy program. See http://ilsagfiles.org/SAG_files/Subcommittees/IPA-TRC_Subcommittee/6-16-2015_Meeting/NEBs_Sources/ACEEE_2012%20report.pdf.
[12] http://www.cpuc.ca.gov/nr/rdonlyres/004abf9d-027c-4be1-9ae1-ce56adf8dadc/0/cpuc_standard_practice_manual.pdf

Figure 6 lists the benefits and costs of customer-installed DER included in the RIM comparison and Figure 7 illustrates how results are interpreted to discern the impact on ratepayers.

Figure 6: Benefit and Cost Components of the RIM Cost Test

Utility/Ratepayer Benefits	Utility/Ratepayer Costs
Avoided Utility Costs	Customer Bill Reductions
	Integration Costs
	Administrative Costs

Figure 7: Cost Test Result Interpretations

	If Benefits GREATER than Costs	If Benefits LESS than Costs
Ratepayer Impact Measure (RIM)	Average utility rates decrease	Average utility rates increase

The cost/benefit analysis resulting from the RIM test enables E3 to determine if there is cost shifting due to DER adoption under the current rate structure without additional incentives to drive adoption. However, E3 notes that the value of a DER to the utility system is skewed by the current utility rate structure. Current rate structures embed fixed cost recovery in volumetric energy charges – a framework that may result in some degree of cost shifting anytime customers substantially reduce the energy charges on their electric bills. Therefore, if customers utilize DER to reduce the amount they pay in energy charges, the fixed costs of serving those customers will be shifted to other customers unless the value of the energy they generate is equal to or exceeds the full retail rate under NEM.

E3's conclusion, in light of currently available data and the current value of DER the Utilities submitted in their recent NEM tariff, is that DER generation does not equal or exceed the full retail rate – at this time. Several stakeholders noted that the current value the Utilities assigned to DER is preliminary and disposes E3's analysis based on three possible scenarios to be insufficient. One writes "several benefit components are missing," and should be added.

Another stakeholder states that the Base Case and High Value scenarios that value DER higher than the current NEM tariffs are "quite speculative." This stakeholder warns that "ancillary resources like load following and voltage support may increase in response to the variable nature of solar generation" and that "the costs of switching and regulating equipment" could cause transmission and distribution costs to increase.

A third stakeholder points to the NEM tariff and the accompanying incentive that IOUs are paying to keep NEM generation at the 1:1 rate as the best indicator of how the value of DER will evolve with experience. This stakeholder believes that the DER NEM incentive "does illustrate that under current rate designs, costs are being shifted from customers adopting DER to all customers."

Although considering DER adoption without incentives is the most accurate way to evaluate its impact to ratepayers, nearly all stakeholders agree and legacy NEM programs have proven that, absent incentives, DER adoption is likely to remain too low to provide measureable benefits or costs to the utility's system.

DER Adoption Resulting from DER Programs

The poor participation in NEM since the program's approval in 2008 indicates that, absent some incentive or dramatic decreases in the cost of DERs, the levels of DER adoption outlined in Act 236 are unlikely to be achieved by 2021.

A prominent feature of Act 236 is the encouragement that the IOUs establish DER Programs. Under Act 236, the IOUs are allowed to create programs and offer incentives "to encourage customers of the electrical utility to purchase or lease renewable energy facilities." [13] Since NEM has been available since 2008 and very few customers have chosen to participate, stakeholders agreed that the Utilities would need to offer incentives if they were to reach the targets set in Act 236. On July 15, 2015, in three separate dockets, the Commission approved the DER Programs filed by each IOU. All three of the Utilities' DER Programs include the 1:1

[13] Section 58-39-130 (C)(2)

Rate for NEM, community solar,[14] and other incentives to encourage DER installations up to 1 MW. Figure 8 describes the incentives each IOU proposed in their initial suite of programs.

Figure 8: Detailed Description of DER Program Incentives

	Type of Incentive	Details
South Carolina Electric & Gas Company[15]	Performance-Based incentive	Incentives are limited to 42 MW of installed capacity as follows: • 33 MW for systems sized 20 kW - 1 MW; and • 9 MW for systems under 20 kW Incentives for the Residential NEM systems include the 1:1 rate and the following additional credit: • 4 cents/kWh for first 2.5 MW of installations • 3 cents/kWh for 2.51 - 5 MW • 2 cents/kWh for 5.1 - 7.5 MW • 1 cent/kWh for 7.6 - 9 MW Incentives for Non-Residential systems are as follows: • 20 cents/kWh for systems less than 20 kW • 18 cents/kWh for systems 20 kW to 100 kW • 14 cents/kWh for systems 100 kW to 1,000 kW • 22 cents/kWh for systems for tax exempt schools, churches and municipalities
Duke Energy Progress, LLC[16]	Rebate Program	Incentives are limited to 13 MW of installed capacity as follows: • 10 MW for systems sized 20 kW - 1 MW; and • 3 MW for systems under 20 kW Incentives for Residential and Non-Residential systems: • Up-Front Rebate of $1.00 per watt (dc) • For each successive 375 kW of installed residential solar and 1,125 kW of non-residential solar DEP may review and propose new rebates within 25% of the current level. • Any adjustment greater than 25% must be approved by the Commission.

[14] Community solar, or shared solar, is a program that allows utility ratepayers the ability to own or lease a share of a larger solar array and share in a portion of the benefits of that installation. These programs are designed for customers that wish to participate in DER Programs but are unable or unwilling to install PV on or at their residences or businesses.
[15] http://programs.dsireusa.org/system/program/detail/5779
[16] http://programs.dsireusa.org/system/program/detail/5778

Duke Energy Carolinas, LLC[17]	Rebate Program	Incentives are limited to 40 MW of installed capacity as follows: • 30 MW for systems sized 20 kW - 1 MW; and • 10 MW for systems under 20 kW Incentives for Residential and Non-Residential systems: • Up-Front Rebate of $1.00 per watt (dc) • For each successive 2,000 kW of installed residential solar and 6,000 kW of non-residential solar DEC may review and propose new rebates within 25% of the current level. • Any adjustment greater than 25% must be approved by the Commission.

The Utilities are allowed to recover the costs of the DER Programs during their annual fuel review. Avoided costs are to be collected via a separate component of the overall fuel factor. These costs are allocated and recovered using the same method IOUs currently use to allocate and recover variable environmental costs. Incremental costs are collected as a separate charge on the customers' bills. Incremental costs include all costs a utility prudently incurs to implement a DER Program, such as labor, operation and maintenance, infrastructure upgrades and incentives paid above avoided cost rates.[18]

To conduct a cost-benefit analysis in the context of the DER Programs, the list of costs expands to include the incentives the Utilities pay, and the list of benefits must also include the fees and cost recovery collected from participating customers.

The additional categories not evaluated in the original value of DER Methodology are shown in Figure 9 and Figure 10.

[17] http://programs.dsireusa.org/system/program/detail/5777
[18] Section 58-39-140 (A)

Figure 9: Detailed Description of Additional DER Program Benefits

Benefit Category	Component	Description	Calculation Methodology/Value
DER Bill Adder	DER Charge	The DER participants' allocable portion of the cost shift as collected through the DER Charge. This charge is subject to a cap of $1/month for residential customers, $10/month for commercial customers, and $100/month for industrial customers.	Based on Utility forecasts and E3 analysis.
Community Solar Fees	Community Solar Fees	These are the fees that the Utilities forecast customers will pay to participate in their community solar programs.	Based on Utility forecasts and description of the Utility proposed community solar programs.

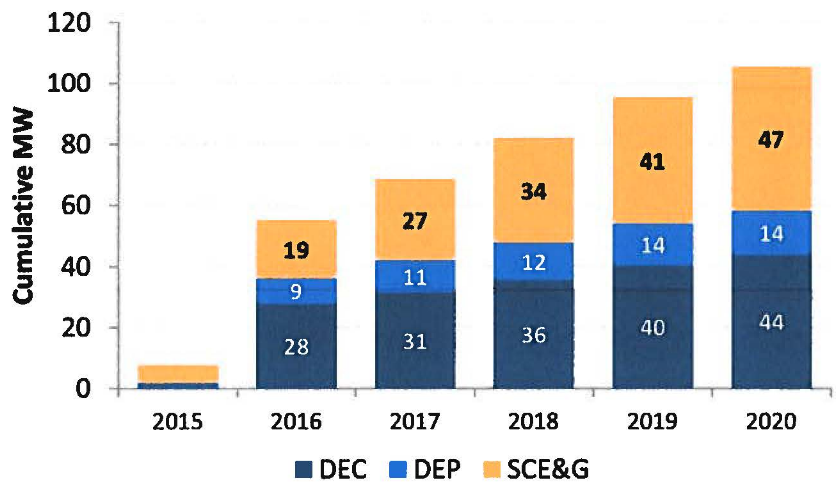
Figure 10: Detailed Description of Additional DER Program Costs

Cost Category	Component	Description	Calculation Methodology/Value
Customer Bill Savings	DER Customer Bill Savings or Utility Revenue Reduction	Direct savings on a customer's bill which represent revenue a Utility will not collect from customer as a result of the installation of DER	Based on publicly available customer billing data and data provided by the Utilities
DER Program Incentives	Ratepayer-Funded Incentive Costs	Costs borne by all ratepayers to incent DER Program participation	DER program incentive costs including net metering incentives, upfront rebates, bill credits, and community solar program subsidies based on E3 estimates and Utility forecasts
Community Solar Costs	Community Solar Costs	The Utility's costs to build and operate the community solar programs	Based on E3 analysis of Utility forecasts and program design

Figure 9 catalogs the additional benefits that the DER Programs will accrue for all ratepayers. Specifically, the two categories are the fees that DER customers will pay toward covering the cost of the programs.[19] Figure 10 lists the costs of incentives specific to the DER Programs. The incentives are necessary to boost DER generation to the levels outlined in Act 236.

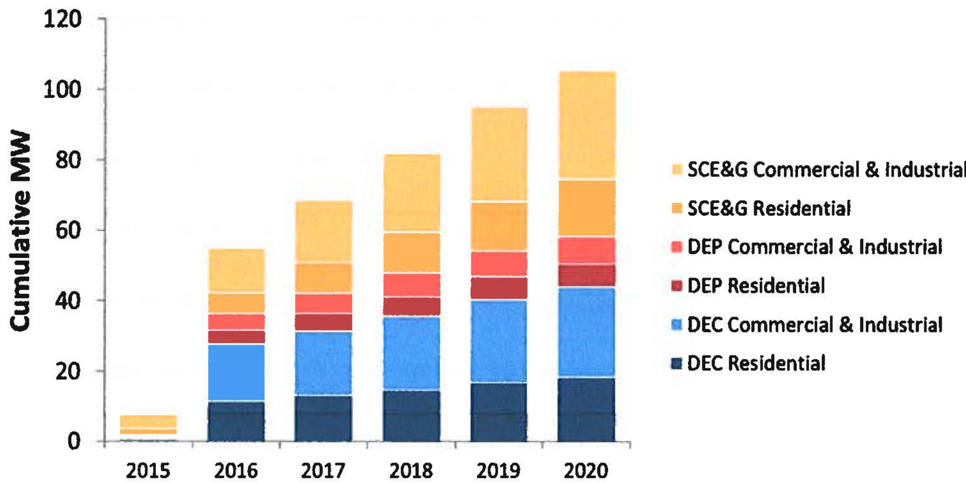
Figure 11 and Figure 12 illustrate the cumulative capacity growth in MW by utility and customer class through 2020 as forecasted for each Utility.

Figure 11: Cumulative Utility DER Program Installation Forecast[20] in Megawatts[21]



[19] All customers will pay the DER Charge, discussed in more detail later in this Report. The benefit included here is only the DER Charge that is collected from customers using DER to reduce their electric bills.
[20] E3 analysis includes customer-scale installations (i.e. NEM, bill credits and community solar only) and does not include utility-scale installations.
[21] Cumulative Utility DER Program Installation Forecast for 2015 is: DEC– 1.0 MW; DEP– 0.8 MW; and SCE&G– 5.8 MW.

Figure 12: Detailed DER Installation Forecast by Utility and Customer Class

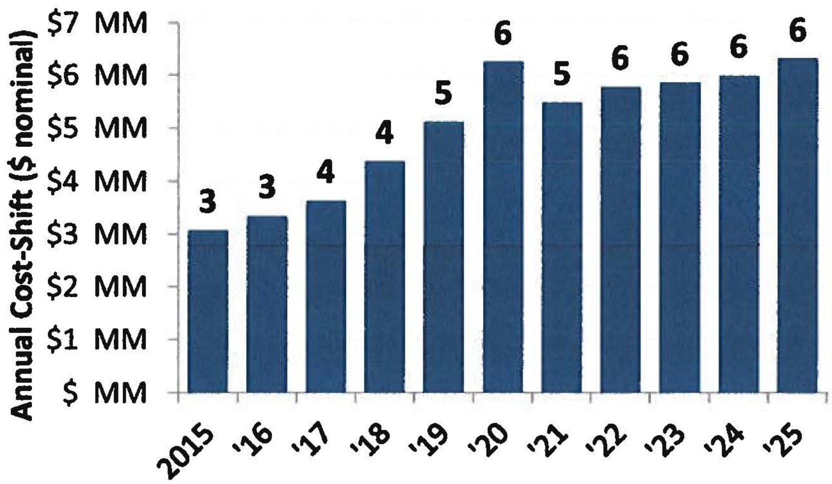


COST OF DER PROGRAMS

Building from South Carolina's legacy NEM program, E3 considered the cost of providing NEM at the 1:1 Rate to the number of customers the Utilities forecast serving under the NEM tariffs. Figure 13 shows a summary of the costs through 2025, the period in which the NEM tariffs will be in effect and only evaluated the cost shifts associated with the NEM tariffs.[22] The results shown are for the Base Case Scenario. Results for the Low Value and High Value Scenarios varied proportionally.

[22] See the Order No. 2015-194 in Docket No. 2014-246-E.

Figure 13: Summary of Shifted Costs for NEM Only - Base Case



E3 estimates that, on average, approximately $5 million annually will be shifted from NEM customers to non-NEM customers if participation levels reach Utility forecasts. For the purpose of this analysis, E3 assumed that cost shifting associated with NEM will be zero after 2025. Again this only considers the cost shift associated with NEM and does not include any DER incentives.

When evaluating the impact of the full suite of DER Programs including incentives, the expected shift in costs from participating customers to non-participating customers due to the implementation of the DER Programs is approximately $21 million per year (in nominal dollars) through 2020.[23] In the Low Value Scenario, the cost shift would be approximately $22 million per year through 2020; and in the High Value Scenario, the shift is approximately $20 million per year through 2020.

Figure 14 shows that approximately $21 million in aggregate annual costs shift, by year, through 2020.

[23] E3's evaluation assumed a 25-year amortization of all DER Program costs. While this is appropriate for this evaluation, it should be noted that the IOUs are only amortizing a portion of DER Program costs over a 25-year period and the DER Program expenses are expected to exceed $21 million per year.

Figure 14: Summary of Shifted Costs for all DER Programs – Base Case

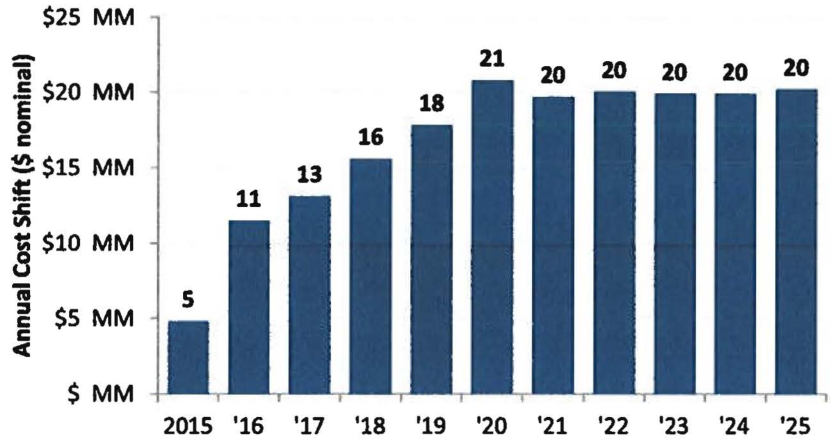
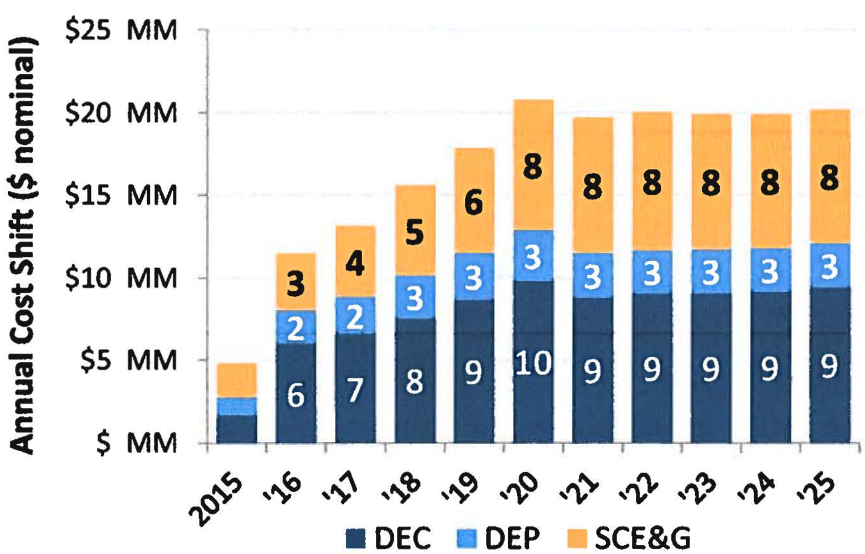


Figure 15 illustrates the annual cost shift that E3's analysis expects for each Utility under the Base Case Scenario.

Figure 15: Summary Cost Shift Results by Utility – Base Case[24]

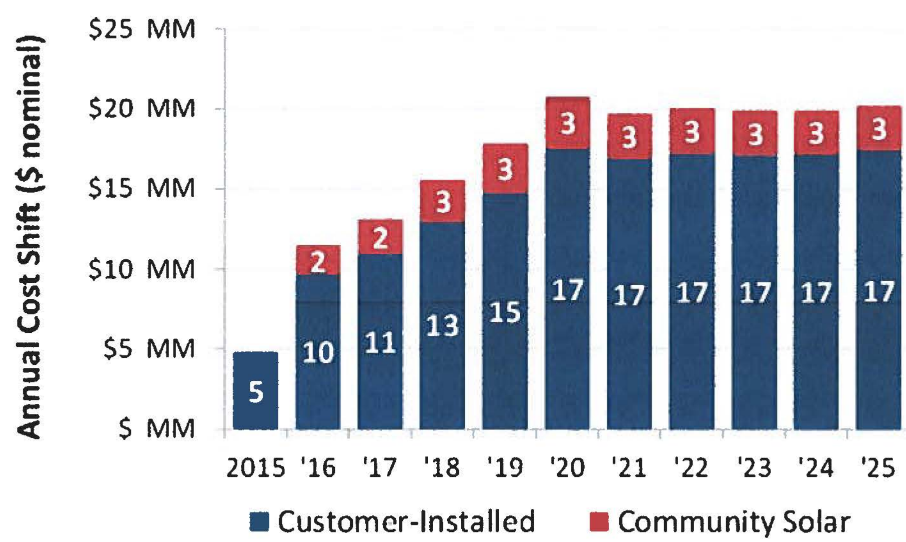


[24] Cost Shift results for 2015 are: DEC – $1.7 MM; DEP – $1.1 MM; and SCE&G – $2.0 MM

The allocation of costs being shifted within each Utility is relatively proportional to the Utility's installed capacity of DER. By the end of 2020, when the DER Programs are closed to new participants, the annual cost is expected to reach $30 million for the IOUs combined. However, the benefits are expected to total approximately $9 million for a net cost shift of $21 million per year. Due to program designs and statutory caps on recovery, DER Programs expenses are expected to be incurred and recovered beyond 2020.

Below, Figure 16 illustrates the cost-shift allocation between customer-installed systems and community solar systems. Note that the cost-shift associated with customer-installed systems includes both the cost of the 1:1 NEM bill credits and the other Utility incentives that customers installing these systems receive.

Figure 16: Summary Cost Shift Results from Customer-Installed and Community Solar - Base Case[25]



[25] The breakdown of the cost shift in 2020 is: Customer-Installed - $17.5 MM and Community Solar - $3.3 MM, which equate to $20.8 MM

Figure 17 illustrates the costs and benefits by category for all installed systems. Figure 18 details the avoided cost benefit categories as dollar per kWh for each component included in the calculation for the Base Case.

Figure 17: Breakdown of Cost Shift in 2020

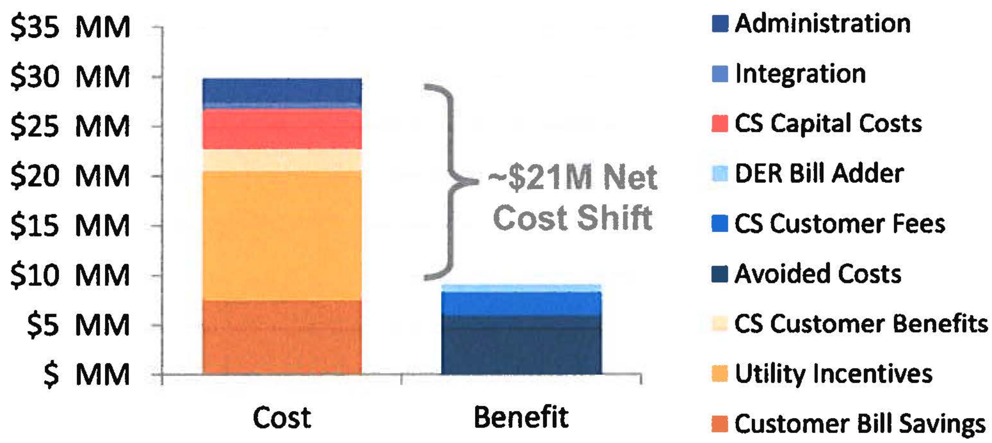
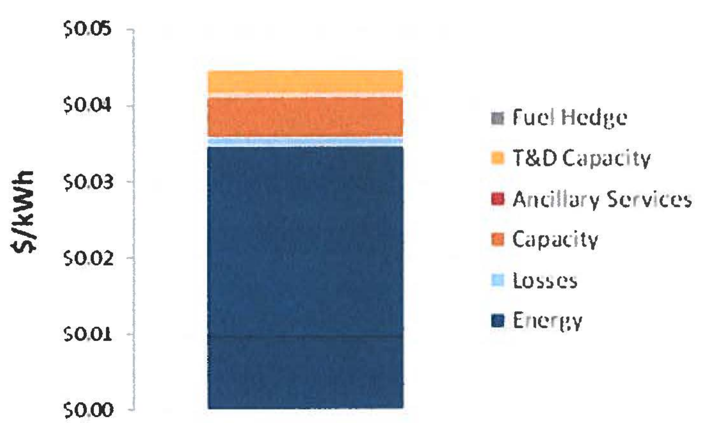


Figure 18: Avoided Cost Breakdown – Base Case



DER PROGRAM COST RECOVERY

Utilities' avoided costs are to be collected via a separate component of the overall fuel factor. These costs are allocated and recovered using the same method IOUs currently use to allocate and recover variable environmental costs. DER Program incremental costs are collected via a separate charge called the DER Charge. Per Act 236, the amount each Utility can collect through the DER Charge each year is limited to the following amount per account: Residential -- $12, Commercial -- $120, Industrial -- $1,200.

The results of E3's analysis of cost shifting related to DER Program participation are presented in total nominal dollars per year for the life of the DER Program (2015-2020[26]). The amount of costs shifted from DER Program participants to non-participants (which correlates directly with the forecasted number of DER installations) is then translated into monthly bill impacts for residential, commercial, and industrial customers through 2025, although some DER Program incentives may be incurred and recovered beyond 2025.

Cost shifts are translated to predict the impact DER Programs are expected to have on customers' bills. The following three figures illustrate the increase to non-participant's monthly bills as a result of DER Programs and assume cost shifting stays within each customer class and the amounts remain consistent with forecasts.

E3 estimates that the average amount the IOUs need to collect from residential and commercial customers to recover costs incurred to incent customer participation in the DER Programs will not exceed the amounts allowed under the DER Program recovery caps. According to data provided by the IOUs, by 2020, residential bills will increase by approximately $0.80 per month and commercial class customers will experience an increase of approximately $3.50 per month in order to recover the costs caused by the DER Programs.

[26] Act 236 has the DER Program and adoption targets being met by 2021 but the Settlement Agreement in Docket No. 2014-246-E has the net metering incentive in place until 2025.

Figure 19 and Figure 20 illustrate the effect DER Program expenses will have on residential and commercial bills, respectively, through 2025.

Figure 19: Utility Estimated DER Charge – Residential

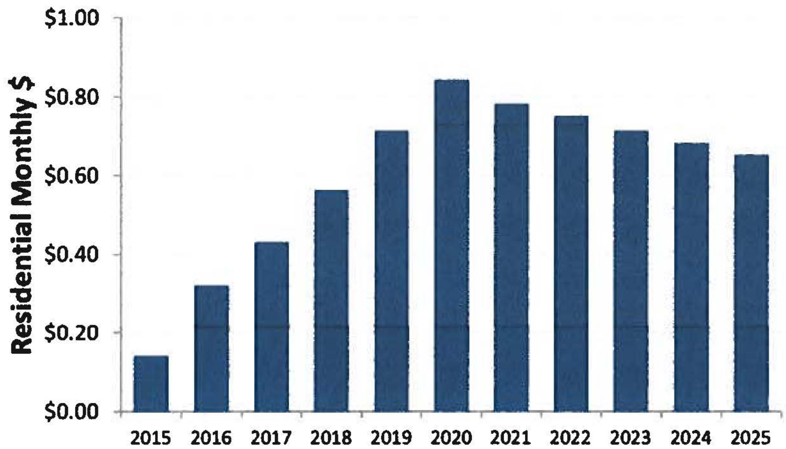
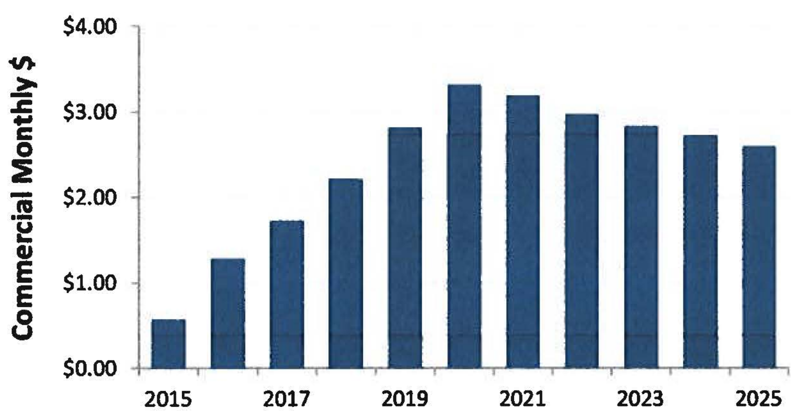


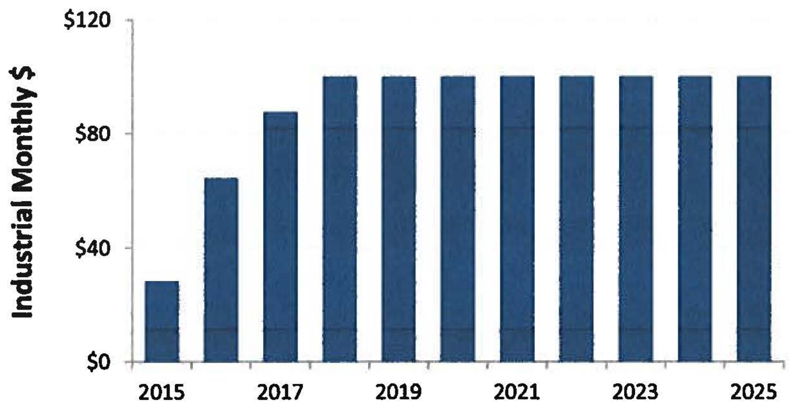
Figure 20: Utility Estimated DER Charge – Commercial



Industrial class customers will experience an increase of $100 per month by 2018, the most allowed under the statutory recovery caps.

Figure 21 illustrates the amounts IOUs expect to collect in DER Charges and to allocate in DER Program expenses through 2025 for the industrial class.

Figure 21: Utility Estimated DER Charge - Industrial



The DER expenses that should be allocated and recovered from industrial class customers are more than the amount allowed under the recovery caps prescribed in Act 236. The caps limit recovery to $100 per month[27] from each industrial account, but E3's analysis indicates the full cost of serving industrial DER Program customers will average $160 per month, approximately 0.5% of the average industrial monthly bill.[28] Since the caps prevent all the costs from being recovered through the industrial class's DER Charge, unrecovered costs will be reallocated from year to year.

[27] Another stakeholder suggests that the cost to serve industrial DER Program customers could be as much as $440 to $675 per month.
[28] Source: EIA form 816, 2014

Cost of Service Analysis

The State Regulation of Public Utilities Review Committee Energy Advisory Council's 2014 Distributed Energy Resources Report[29] describes cost of service and retail rate design in South Carolina as follows:

> Generally, South Carolina utilities have designed retail rates with an eye towards Bonbright's ratemaking objectives[30] which are often cited in various rate-related proceedings. These objectives – encompassing revenue requirements, revenue collections and practical concerns – serve as guiding principles to rate design. However, in practice utilities are faced with significant trade-offs in setting rates. For example, setting rates so as to promote economically efficient consumption would ideally entail a real-time pricing mechanism where the price customers pay for energy is dependent on the cost to produce that energy at the time it is being demanded. Yet for residential customers and to a lesser degree for other customers as well, most utilities eschew more accurate price signals in favor of practicality.
>
> Another example of a ratemaking trade-off relates to the objective of apportioning rates fairly within customer classes. South Carolina utilities generally do not differentiate individual households within the residential customer class for rate-setting purposes; as a consequence,

[29] http://www.scstatehouse.gov/committeeinfo/EnergyAdvisoryCouncil/EAC%20Report%201-14-14.pdf

[30] Traditional Bonbright rate design principles:

- Effectiveness
  - Recover the utility's allowed capital and operating costs and a fair return
- Fairness
  - Fairly apportion the cost of service among different customers (rates reflect cost causation)
  - Avoid undue discrimination
- Efficiency
  - Promote the efficient use of energy (and competing products and services)
  - Support economic efficiency – set prices to reflect marginal costs
- Stability
  - Ensure revenues (and cash flow) are stable from year to year
  - Minimize unexpected rate changes that may be adverse to existing customers
- Simplicity, understandability, public acceptability, and feasibility of application

residential rates are uniform across housing types and sizes and across urban, suburban, and rural locations.

A final example of ratemaking trade-offs is the tension between the need of the utility to recover its costs of serving customers and the objective of maintaining stable rates. External factors like stricter regulations, prevailing economic conditions, advancing technology and even weather can impact rate stability. These are just a few of the trade-offs inherent in the ratemaking process. As distributed generation becomes more and more attractive to energy users, additional trade-offs are likely to emerge, and these trade-offs represent both challenges and opportunities for utility rate-setting.

Historically, there have been three primary mechanisms for revenue collection often termed cost recovery in the utility sector:

1. Basic facilities charge (BFC) ($/month),
2. Volumetric energy charge (cents per kWh), and/or a
3. Demand charge (dollars per kW)

Typical South Carolina residential customers are charged for electricity through the basic facilities charge ($/month) and a volumetric energy charge (cents per kWh). The volumetric energy charge is termed a "bundled energy rate" because it reflects the bundling of costs to serve the customer—including the variable and most fixed costs associated with generation, transmission, and distribution of electricity—that are bundled into an "all-in" energy rate, as opposed to appearing on the customer's bill as line items. This rate structure is easy to understand and provides a simple price signal to customers to reduce their energy consumption. The fixed charge on a customer's bill (specifically, the BFC) represents (on a state average) 8% of a customer's bill, while the fixed costs to serve a typical residential customer are approximately 55% - 75% of the bill.

Cost Shifting in Traditional Ratemaking Methodologies

As discussed earlier, rates are typically designed for the average customer in each class. If a customer varies from the average, that customer could over-pay or under-pay the utilities' cost to serve. Utilities have designed their rates to collect only a portion of the fixed costs (metering, billing, poles, wires, transformers, etc.) through the fixed basic facility or demand charges. The remaining fixed costs are embedded in the volumetric or energy charge. Concern arises when customers use DER to reduce their volumetric charges and thereby reduce their contribution towards recovering the utility's fixed costs based on that customer's full cost to serve. Those costs are invariably shifted to other customers in future rate cases.

However, various stakeholders identified many occurrences of cost shifting not associated with DER or DER Programs. For example, one stakeholder writes, "Policy and ratemaking decisions and trade-offs in South Carolina have led to significant cost shifts, and continue to do so today. Cost shifts relating to nuclear financing, vacation home electric rates, urban versus rural residential electric rates, contribution to system peak demand, and economic development credits are currently prevalent in the Palmetto State, including for investor-owned utility systems."

In fact, this stakeholder goes on to say that cost shifting is often justified by larger policy or ratemaking decisions. "We neither support nor oppose cost shifting on principle, but rather recognize that achieving key policy goals may result in some shifted costs."

Other stakeholders caution against recommending changes to the traditional rate structure until more information can be gathered. "Given the inherent dynamism involved with DER—with new technologies and new customer applications continuing to be introduced," one stakeholder writes, "a cautious approach to recommend future rate design is warranted." Most stakeholders acknowledge that more information is necessary before any widespread conclusions about cost shifting due to DER adoption are drawn.

One stakeholder writes, "With respect to future rates, the information gained through the operation of the approved benefit cost methodology and from incremental customer DER adoption during the Settlement Agreement period [2015-2025] will assist in the evaluation of potential changes in the future. Future structural changes to customer rates will ultimately depend on the actual changes experienced by utilities due to increased customer adoption of DER as well as other myriad dynamic load conditions."

Economic Rates

Recommending sweeping changes in current rate structures is premature given the limited amount of data concerning DER adoption – i.e. its scale, magnitude, and value – that is available at present. ORS will explore the possible changes that may be warranted in the future, and make such recommendations as may be appropriate when data becomes available.

An examination of data from the Utilities' cost-of-service studies revealed that the BFC across Utilities, especially in the residential classes, do not fully recover the Utilities' fixed costs. Therefore, when DER generation reduces a customer's volumetric charges, some fixed costs may be under-recovered. E3's conclusion is that BFCs and demand charges across all customer classes may need to be increased if the Utilities are to recover their fixed costs and mitigate potential cost shifting. This would be a marked departure from the status quo where residential and small commercial customers do not have a demand charge or the meters to properly implement one.

Several stakeholders expressed opposition to the suggestion that fixed charges may need to increase to cover fixed costs. One writes that, "other potential rate design changes should not be foreclosed at this early stage, and an increased basic facility charge should not be assumed to be the best rate design option for South Carolina." This stakeholder joins others in suggesting that minimum billing be included in any consideration of alternative rate design. Another stakeholder points to time-of-use rates as a viable way "to reflect cost causation."

One stakeholder argued that an examination of cost shifting must look not only at costs being between DER-adopting customers and non-adopting customers, but also between the state's socioeconomic sectors. While E3 agrees that an assessment of the effect of DER adoption on low-income or fixed-income populations would be helpful, the data to perform such an assessment has not been collected on a statewide basis. Low-income and fixed-income customers may not be low-usage customers, and the granularity required to examine the effects of increasing fixed charges and lowering volumetric charges is not available at this time.

Other stakeholders worried that lowering volumetric charges may dilute price signals and discourage conservation. The net effect could "lead to wasteful use of electricity that can cause additional costs for the utility to meet its peak load."

Nearly all stakeholders expressed concern over dramatic rate changes and one stakeholder commented that, "Any changes to current rate structures should be made only after careful evaluation, thought and consideration and only in the context of a rate case. Major changes to rate structures may not be necessary." Additionally, some stakeholders posit that DER adoption should be part of a larger conversation. "These efforts encompass not just minor adjustments in rates or rate design, but also involve broader discussions of existing utility business models and the future of the electric industry."

Conclusions

This report complies with the requirements of Act 236 to analyze cost shifts associated with DERs in South Carolina. Although the structure and outcomes of the Utilities' DER Programs are in line with the goals and intentions of Act 236 to incent and encourage DER installation and industry, the study finds evidence that DER Programs may shift costs from DER Program participants to other customers who are not participants.

Furthermore, the analysis of Utility Cost of Service studies affirms the majority of costs are being collected via volumetric charges on classes like residential. Nevertheless, for the level of DER installation forecasted, the effect on customer bills over the next ten years is expected to be at or below the statutory caps, a sum that represents a minimal economic impact on non-participants while simultaneously encouraging DER installations and industry as was the intention of Act 236.

In order to mitigate cost shifting now and in the future, a utility's fixed cost may need to be recovered through its BFC and/or a demand charge, or through other rate design changes. Implementing a rate design change of this magnitude would take time and thorough analyses of bill impacts and the effects on current and future ratepayers.

Cost shifting and rate structures will evolve as Utility avoided cost data, community solar installation cost data, installation capacities, and customer usage patterns change going forward, and as benefits and costs of DERs change in the future.