South Carolina Act 236 Cost Shift and Cost of Service Analysis

Prepared on behalf of the South Carolina Office of Regulatory Staff

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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)

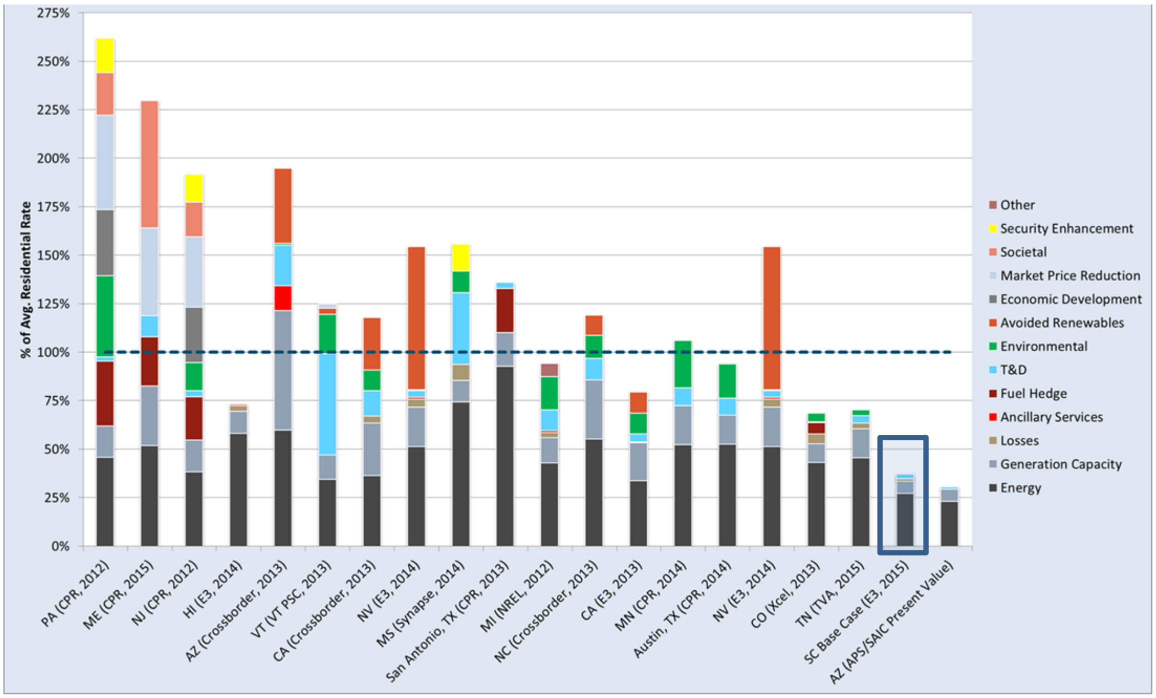
Figure 1: Value of Solar and NEM Benefit-Cost Methodologies Vary

EXAMPLES OF RECENT NEM VALUE STUDIES FROM STATES, UTILITIES, CONSULTANCIES, AND STAKEHOLDERS

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

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.

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[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.

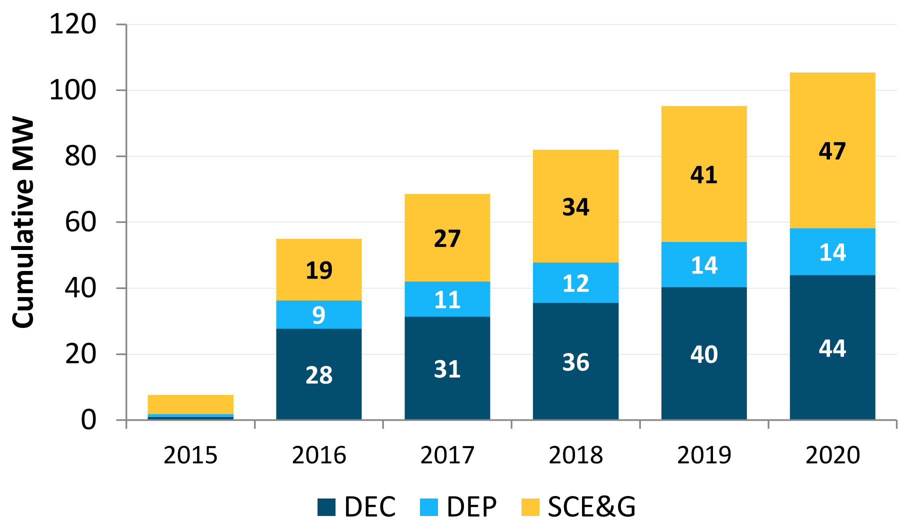
Figure 10: Detailed Description of Additional DER Program Costs

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.

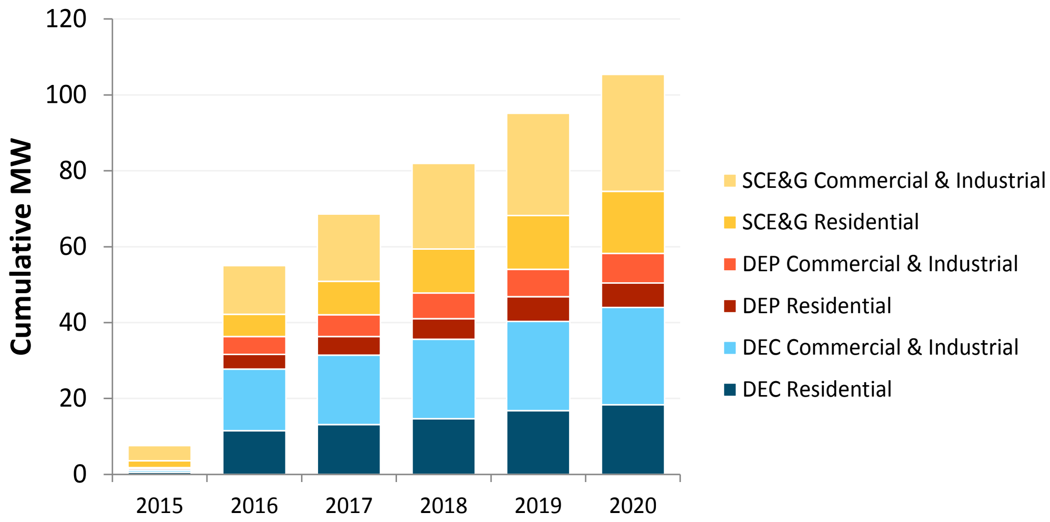
Figure 11 and Figure 12 illustrate the cumulative capacity growth in MW by utility and customer class through 2020 as forecasted for each Utility.

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

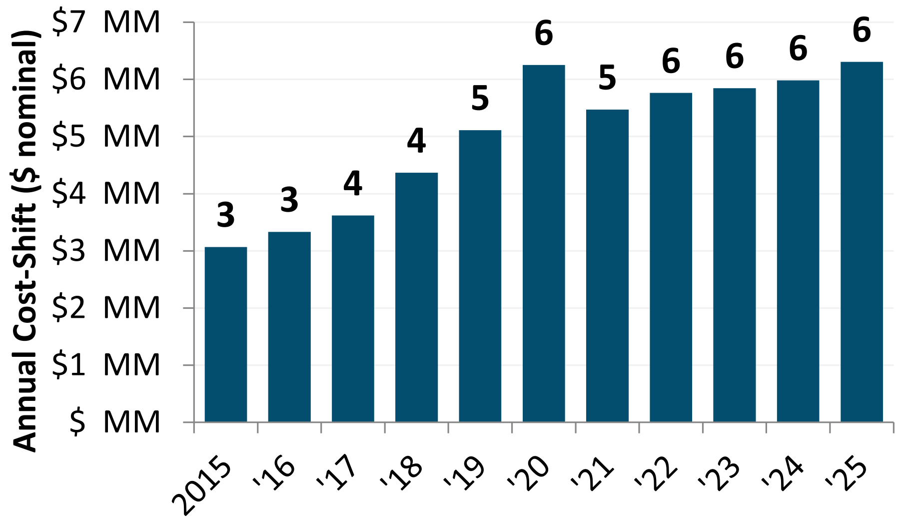


COST OF DER PROGRAMS

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

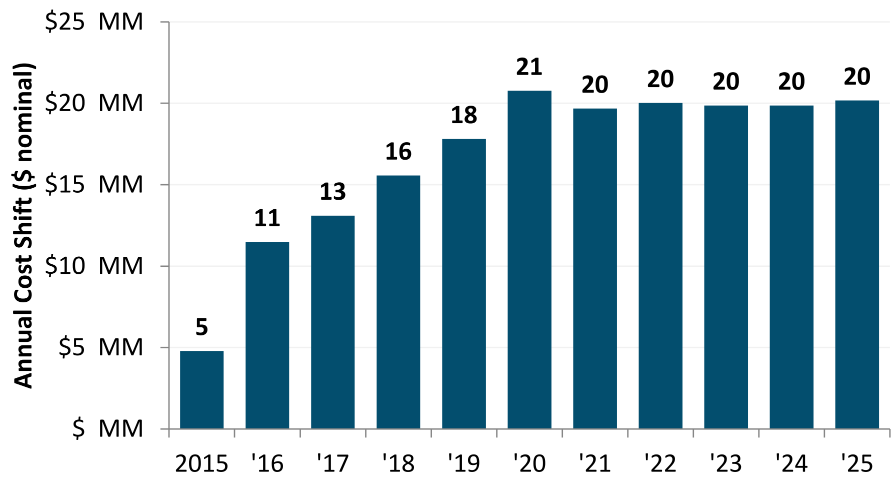
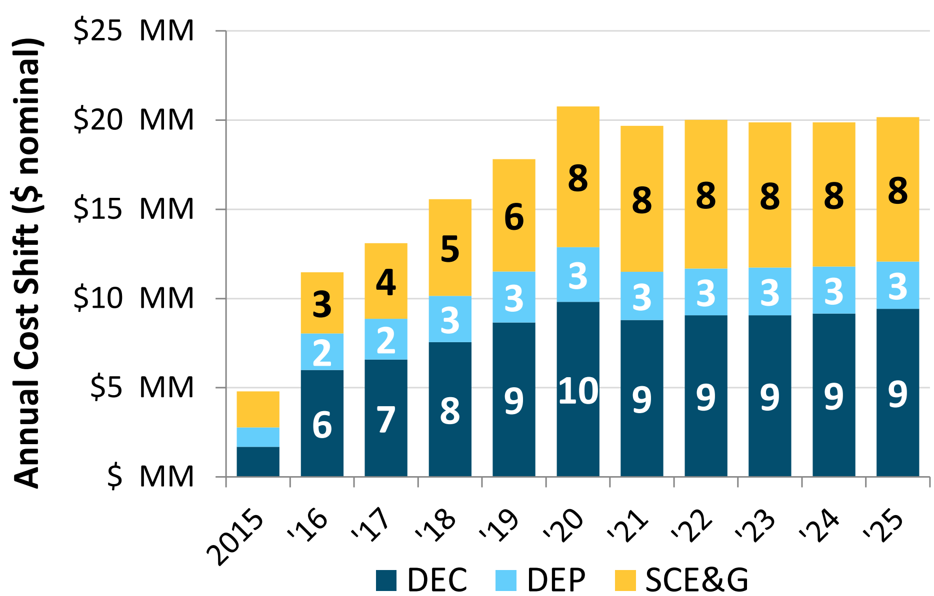


Figure 15 illustrates the annual cost shift that E3's analysis expects for each Utility under the Base Case Scenario.

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

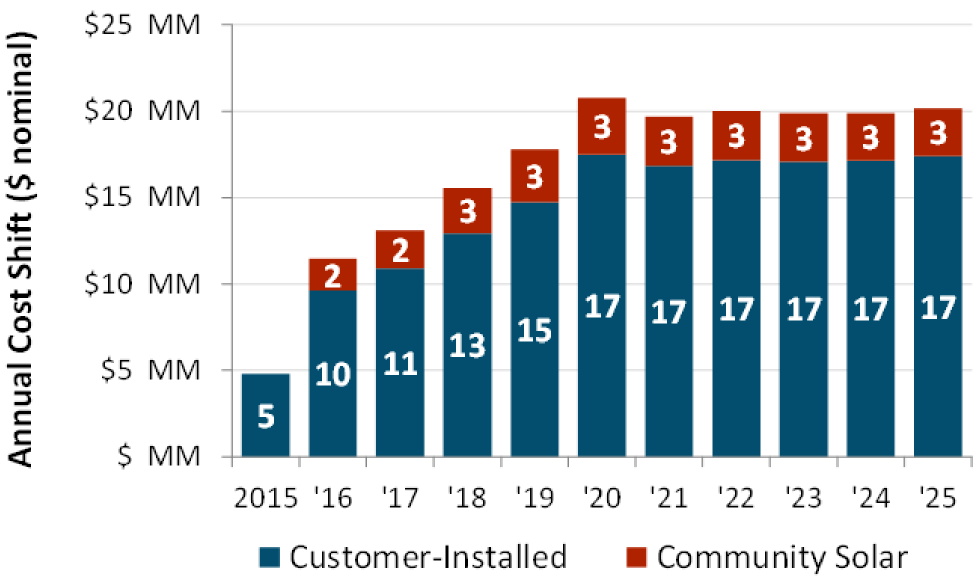


[24] Cost Shift results for 2015 are: DEC – $1.7 MM; DEP – $1.1 MM; and SCE&G – $2.0 MM

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

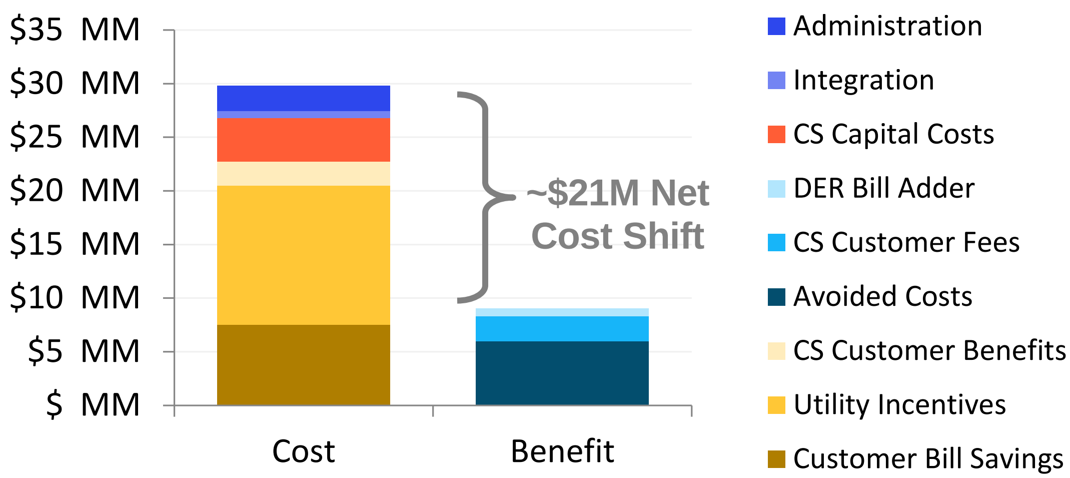
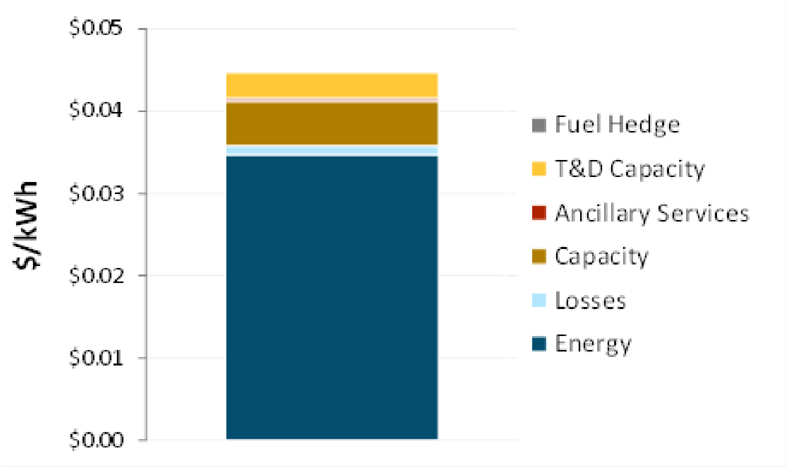


Figure 18: Avoided Cost Breakdown – Base Case



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

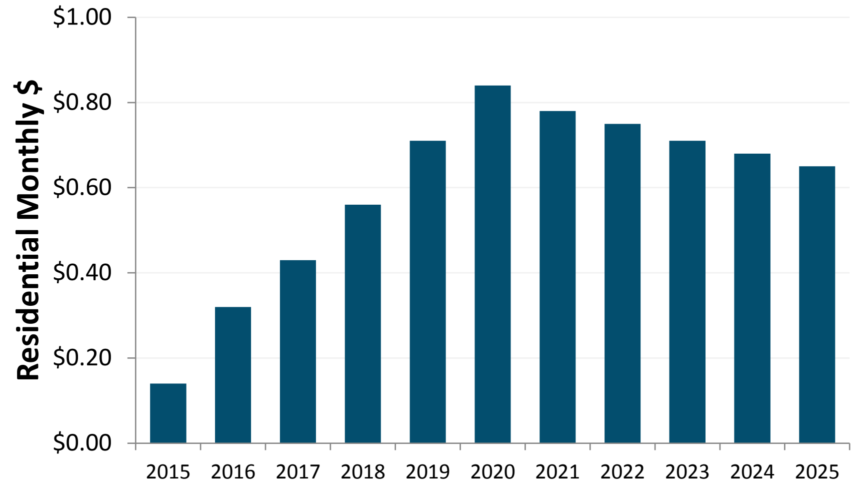
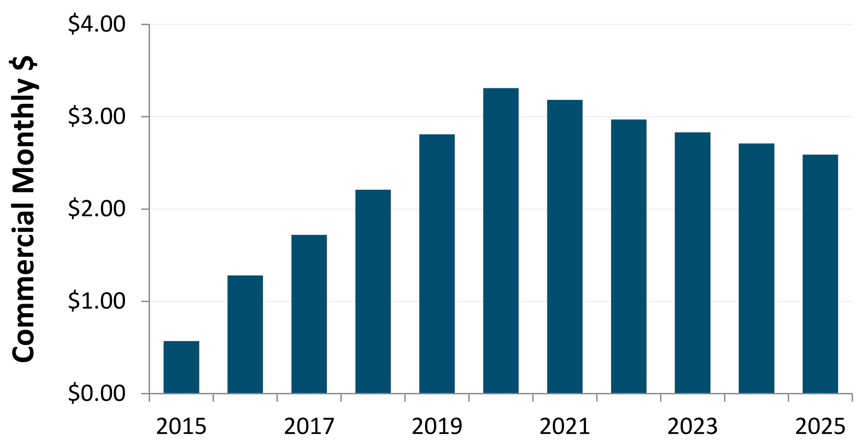


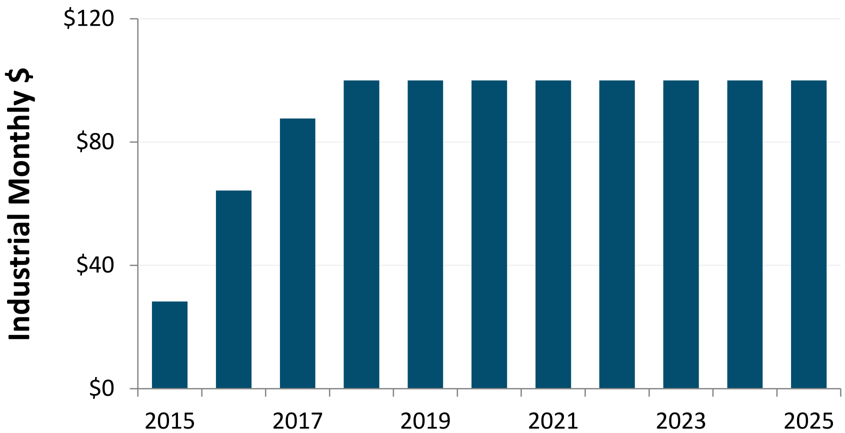
Figure 20: Utility Estimated DER Charge – Commercial



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.