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NC SUSTAINABLE
ENERGY ASSOCIATION

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Clerk's Office
N.C. Utilities Commission

To: Chief Clerk Gail Mount
The North Carolina Utilities Commission
4325 Mail Service Center
Raleigh, NC 27699-4325

From: The North Carolina Sustainable Energy Association
P.O. Box 6465
Raleigh, NC 27628

Re: Late-filed Exhibit for 2012 Biennial Avoided Cost Proceeding
(Docket No. E-100, Sub 136)

Honorable Clerk and Commissioners:

I serve as counsel and policy director for the North Carolina Sustainable Energy Association ("NCSEA"), an intervenor in this proceeding.

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Rule 3.3 of the North Carolina Rules of Professional Conduct is entitled "Candor Toward the Tribunal." Comment 10 to the Rule provides in pertinent part as follows: "Having offered material evidence in the belief that it was true, a lawyer may subsequently come to know that the evidence is false. In such situations . . . the lawyer must take reasonable remedial measures."

During the evidentiary hearing in this proceeding, the Crossborder Energy study entitled "The Benefits and Costs of Solar Generation for Electric Ratepayers in North Carolina" was introduced into evidence as Exhibit KRR 7 to the testimony of Karl R. Rabago. A copy of the study that was introduced into evidence is attached as **Exhibit A** hereto.

The undersigned recently received a revised study in which certain numbers in Tables 2, 3, and 6 in the study report were changed to correct typographical errors and/or mathematical errors. The undersigned received the revised study via pdf and so red-lining the changes is beyond the undersigned's capabilities. The undersigned has, however, used Adobe software to highlight in yellow the changed numbers in the three tables. A copy of the revised study with the corrected numbers highlighted is attached as **Exhibit B** hereto. A copy of the revised study without highlighting is attached as **Exhibit C** hereto.

The undersigned has confirmed with the study authors that the changed numbers constitute "minor corrections to the numbers in Tables 2, 3, and 6. There were no changes to the bottom-line estimate of $26 million in annual net benefits from 400 MW of wholesale solar and 100 MW of solar DG." The undersigned has also confirmed with the study authors "that the error in Table 6 for DEP was simply the result of writing down the wrong number from the Excel spreadsheet into the third row of Table 6. There were no errors in any other rows of Table 6 for DEP, including the bottom line results. So no changes to Tables 2 or 3 for DEP were needed."

The undersigned has communicated the revised study to Karl R. Rabago, who has "reviewed both the original and revised versions. I see where the errors were made and I agree that the revisions do not impact my conclusions or necessitate any modification of my findings or recommendations."

NCSEA requests that the revised study, Exhibit C attached hereto, be added to the record as a late-filed exhibit and that, wherever the Commission might otherwise rely on Exhibit KRR 7 to the testimony of Karl R. Rabago, it rely instead on this late-filed exhibit.

NCSEA has circulated this letter to the parties to this proceeding. As of close of business on 27 January 2014, the undersigned has received no objections to its proposal. The only qualified response is as follows:

Exhibit KRR 7 was admitted into the record over the objection of Dominion North Carolina Power (DNCP), Duke Energy Carolinas, LLC (DEC), and Duke Energy Progress, Inc. (DEP). These parties recognize the need for candor to the tribunal. DNCP, DEC, and DEP therefore do not oppose introduction of the revised study as a late-filed exhibit on the conditions that their agreement to its introduction to the record does not waive their objection to admission of the original study and that the Commission extend coverage of their underlying objection to the original study to the late-filed exhibit so that their underlying objection is fully preserved in the event of any appeal.

Respectfully submitted,

Michael D. Youth
Counsel for NCSEA
N.C. State Bar No. 29533

CERTIFICATE OF SERVICE

I hereby certify that all persons on the docket service list have been served true and accurate copies of the foregoing letter and attached exhibits by hand delivery, first class mail deposited in the U.S. mail, postage pre-paid, or by email transmission with the party's consent.

This the 28th day of January, 2014.

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Crossborder Energy

Comprehensive Consulting for the North American Energy Industry

The Benefits and Costs of Solar Generation for Electric Ratepayers in North Carolina

R. Thomas Beach
Patrick G. McGuire

October 18, 2013

EXHIBIT

A

*2560 Ninth Street * Suite 213A * Berkeley, CA 94708 * (510) 549-6922 * tomb@crossborderenergy.com*

The Benefits and Costs of Solar Generation for Electric Ratepayers in North Carolina

This report provides an independent analysis of the benefits and costs of solar photovoltaic (PV) generation for electric ratepayers in the service territories of the major electric utilities in North Carolina – Duke Energy Carolinas (DEC), Duke Energy Progress (DEP), and Dominion North Carolina Power (DNCP). North Carolina Sustainable Energy Association asked Crossborder Energy to apply to the three North Carolina utilities the same approach to analyzing the benefits and costs of solar generation which we have used in similar studies in other states.[1]

This report identifies the benefits and costs of solar for both (1) wholesale utility-scale solar projects whose output is sold to the utilities and (2) solar distributed generation (solar DG or demand-side solar) installed on a customer's premises behind the customer's utility meter. This study explains which of the benefits of solar generation apply to both wholesale and demand-side solar, and which are limited to one of these different types of solar resources. On the cost side, it is important to recognize that wholesale solar and solar DG impose different types of costs on utility ratepayers. The ratepayer costs of wholesale solar are principally the capital and O&M costs of utility-scale solar generation, which the utility will pay directly through a power purchase contract with the solar project. In contrast, the customer who installs solar DG bears the capital and operating costs of the solar resource. With solar DG, the costs to other, non-participating ratepayers are principally the revenues which the utility loses as a result of the output of solar DG serving the customer's on-site load, plus the energy credits which the utility provides, through net energy metering, when the solar customer exports power to the grid. These exports serve the loads of nearby retail customers. The utility may also provide incentive payments to solar DG customers. Finally, both wholesale and demand-side solar may cause the utility to incur new costs to integrate intermittent solar generation into the grid. **Table 1** summarizes the principal costs and benefits of both wholesale solar and solar DG.

Table 1: *Benefits and Costs of Solar Generation for North Carolina Ratepayers*

Benefits	Wholesale Solar	Solar DG
Energy	✓	✓
Generation capacity	✓	✓
Transmission	✓ (≤ 5 MW)	✓
Distribution		✓
Avoided Emissions	✓	✓
Avoided Renewables	✓	✓
Costs		
Capital and operating costs	✓	
Lost retail rate revenues		✓
DG incentives		✓
Integration costs	✓	✓

[1] See "The Benefits and Costs of Solar Distributed Generation for Arizona Public Service" (May 2013), available at http://www.seia.org/research-resources/benefits-costs-solar-distributed-generation-arizona-public-service. Also, "Evaluating the Benefits and Costs of Net Energy Metering in California" (January 2013), available at http://votesolar.org/wp-content/uploads/2013/01/Crossborder-Energy-CA-Net-Metering-Cost-Benefit-Jan-2013-final.pdf .

In assessing the benefits and costs of solar generation from a utility ratepayer perspective, it is important to use a long-term time frame which recognizes that solar PV systems have useful lives of 20 to 30 years. A long-term perspective is also necessary to treat demand-side solar on the same basis as other supply- or demand-side resources. When a utility assesses the merits of adding a new power plant, or a new energy efficiency program, the company will look at the costs to build and operate the plant or the program over their useful lives, compared to the costs avoided by not operating or building other resource options. Solar DG should be evaluated over the same long-term time frame.

Solar generation can be installed at a wide range of scales, from a system serving a single home to utility-scale plants. Solar is feasible in a greater diversity of locations than other renewable technologies such as wind and hydro. Solar also can be installed with shorter lead times and on a wider variety of sites than conventional, large-scale fossil generation resources. Solar can combine with other small-scale, short-lead-time, demand-side resources, such as energy efficiency (EE) and demand response (DR) programs, to reduce a utility's need for supply-side generation, both in the near- and long-terms. An analysis of the benefits of solar should recognize its scalability and short lead times, by acknowledging that solar and demand-side programs combine to continuously avoid the need for supply-side resources, without the "lumpiness" associated with a conventional utility-scale power plant. Accordingly, we evaluate the benefits of solar based on the change in a utility's costs per unit of solar installed, without requiring solar to be installed in the same large increments as conventional fossil or nuclear generation.

This report relies on data from the North Carolina utilities' latest integrated resource plans (IRPs), supplemented with data from recent avoided cost proceedings and general rate cases. We also have used a limited amount of current data from the regional gas and electric markets in which the North Carolina utilities operate. This work relies to the greatest extent possible on public data and on transparent calculations of the benefits and costs. Our intent in using public data and transparent methodologies is to minimize debates over the input assumptions and to reduce reliance on opaque models. We agree with the Rocky Mountain Institute's recent meta-analysis of solar DG cost / benefit studies, which concluded that "in any benefit/cost study, it is critical to be transparent about assumptions, perspectives, sources and methodologies so that studies can be more readily compared, best practices developed, and drivers of results understood."[2] Where there is debate over certain benefits or costs of solar, we have provided ranges that we believe span the likely range of benefits or costs.

Our work concludes that the benefits of solar generation in North Carolina equal or exceed the ratepayer costs of solar resources, such that new solar resources will provide economic benefits for electric ratepayers in the state. The following **Tables 2 and 3** summarize our results, for wholesale solar and solar DG, respectively. The benefits of wholesale solar typically exceed the costs, even if one does not include the environmental benefits of mitigating carbon emissions. The costs of net metered solar DG for non-participating residential customers are at the low end of the range of benefits, while the benefits of solar DG exceed the costs in the commercial market, where marginal retail rates are lower. These results indicate that North Carolina ratepayers generally would benefit from the continued availability of net metering.

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[2] Rocky Mountain Institute. "A Review of Solar PV Benefit and Cost Studies" July 2013, at page 5. http://www.rmi.org/Knowledge-Center/Library/2013-13_eLabDERCostValue.

Based on the midpoints of the ranges of costs and benefits shown in Tables 2 and 3, the benefits of wholesale solar are 40% larger than the costs, and the benefits of solar DG are 30% greater. Were the North Carolina utilities to add 400 MW of wholesale solar and 100 MW of solar DG resources, the net benefits for ratepayers would be $26 million per year.

Table 2: *Benefits and Costs of Wholesale Solar (15-year levelized cents/kWh - 2013 $)*

Benefits	**DEC**	**DEP**	**DNCP**
Energy (includes line losses)	5.7 – 6.5	5.5 – 6.3	5.8 – 6.6
Generation capacity	1.9 – 3.2	2.1 – 3.2	3.0 – 3.9
Transmission capacity (< 5 MW)	0 – 1.0	0 – 0.7	0 – 0.9
Avoided Emissions	0.4 – 2.2	0.4 – 2.2	0.4 – 2.2
Avoided Renewables	1.0 – 2.0	1.0 – 2.0	1.0 – 2.0
Total Benefits	**9.0 – 14.9**	**9.0 – 14.4**	**10.2 – 15.6**
Costs			
Capital and O&M (All-in PPA)	7.0 – 9.0	7.0 – 9.0	7.0 – 9.0
Integration	0.3	0.3	0.3
Total Costs	**7.3 – 9.3**	**7.3 – 9.3**	**7.3 – 9.3**

Table 3: *Benefits and Costs of Solar DG (15-year levelized cents/kWh - 2013 $)*

Benefits	**DEC**	**DEP**	**DNCP**
Energy (includes line losses)	5.7 – 6.5	5.5 – 6.3	5.8 – 6.6
Generation capacity	2.2 – 3.7	2.4 – 3.7	3.5 – 4.5
Transmission capacity	1.0	0.7	0.9
Distribution capacity	0.2 – 0.5	0.2 – 0.5	0.2 – 0.5
Environmental	0.4 – 2.2	0.4 – 2.2	0.4 – 2.2
Avoided Renewables	0.1 – 2.2	0.1 – 2.2	0.1 – 2.2
Total Benefits	**9.6 – 16.1**	**9.3 – 15.6**	**10.9 – 16.9**
Costs			
Lost Revenues			
Residential	9.8 – 10.7	10.5 – 11.5	10.1 – 11.0
Commercial	7.7 – 8.4	9.7 – 10.6	8.7 – 9.4
Integration	0.3	0.3	0.3
Total Costs			
Residential	**10.1 – 11.0**	**10.8 – 11.8**	**10.4 – 11.3**
Commercial	**8.0 – 8.7**	**10.0 – 10.9**	**9.0 – 9.7**

1. Methodology

Solar DG is a long-term source of electric generation that uses a renewable resource. New solar systems will provide benefits for North Carolina ratepayers for the next 20 to 30 years. Data to perform a long-term (15-year) assessment of these benefits is available from utility avoided cost filings, from recent IRPs and general rate cases, and from market data. The core of this study is the calculation of 15-year levelized benefits and costs for solar resources on the DEC, DEP, and DNCP systems.

1.1 Benefits.

We briefly describe our approach to calculating each of the benefits of solar generation in North Carolina.

- **Energy.** DEC, DEP, and DNCP have currently-effective 15-year avoided energy prices in the range of 4.5 – 5.0 c/kWh for a base load profile, based on production cost modeling of their incremental energy costs over the next 15 years. These avoided energy rates are currently under review in North Carolina Utilities Commission (NCUC) Docket No. E-100, Sub 136. As these production cost models are confidential, we have separately projected 15-year avoided energy costs using a more transparent approach, based on natural gas forward market data, combined with the heat rates, variable O&M costs, and other operating parameters of the long-term fossil resources that solar generation will avoid. Other similar studies have taken a comparable approach to calculating long-term avoided energy costs.[3] We also have considered whether avoided energy costs should be adjusted to reflect the costs which some utilities have incurred to hedge the volatility in their natural gas costs. Finally, avoided energy costs should consider the daily profile of solar generation, which peaks during the early afternoon, making it a more valuable resource than a constant, "flat" profile in all daylight hours.

- **Generating Capacity.** The North Carolina utilities calculate 15-year avoided capacity prices under the assumption that a new combustion turbine (CT) is the least-cost source of new generating capacity. This is commonly called the "peaker" method. Although the details of these calculations are confidential, there is public data on CT costs in nearby markets which can be used to review filed capacity prices. The capacity value of solar, per unit of output, also must consider both the peaking profile of solar generation as well as its variability. Utilities and control area operators in the U.S. have developed well-accepted methods to value the contribution of solar PV resources to capacity resources. In North Carolina, the utilities appear to value solar's capacity at 40% to 50% of its nameplate capacity, comparable to the valuation adopted by the nearby PJM system.

- **Transmission Capacity.** The output of solar DG primarily serves on-site loads and never touches the grid, thus clearly reducing loads on the transmission grid. Given the penetration levels of solar DG on the system today, the power exported from solar DG

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[3] This is generally the approach taken in the avoided cost calculator that California Public Utilities Commission (CPUC) has approved for cost-effectiveness analyses of demand-side programs in California, including solar DG. See, generally, CPUC Decision 09-08-026. Energy and Environmental Economics (E3) has developed the avoided cost calculator under contract to the CPUC. See http://www.ethree.com/public_projects/cpuc5.php. The DG version of the model is titled "DERAvoidedCostModel_v3.9_2011 v4d.xlsm."

units is entirely consumed on the distribution system by the solar customer's neighbors, again unloading transmission capacity. Thus, much like energy-efficiency and demand response resources, solar DG can avoid transmission capacity costs, but only to the extent that solar is producing during the peak demand periods that drive load-related transmission investments. As DEC itself notes in describing its utility-owned solar DG program: "Power is produced at the site, reducing the need for extensive transmission lines or a complex infrastructure."[4] Wholesale solar facilities interconnected at the distribution level – typically, projects at or below 5 MW in size – also can avoid transmission capacity costs to the extent that their output is consumed on the distribution system and produces minimal impacts on the upstream transmission grid.

We understand that there has been debate in North Carolina over the magnitude of the avoided T&D benefits attributable to EE and DR programs, with the debate centering on the extent to which T&D costs are load-related. We calculate long-term marginal transmission costs for DEC and DEP using an approach that considers only load-related transmission. Our method uses a regression of each utility's historical and forecasted transmission investments as a function of load growth, to determine the change in these costs as a function of increases in peak demand. This is a longstanding methodology used by many utilities to determine marginal, load-related transmission costs.

- **Distribution Capacity.** Whether solar generation avoids distribution capacity is a more complex question than transmission capacity, for several reasons. First, distribution substations and circuits can peak at different times than the system as a whole, complicating the calculation of whether solar can reduce distribution system peaks. Second, the timing of load-related distribution expansions is location-specific, and many utilities do not know where or when solar DG will be developed. Third, the time frames for utility distribution plans often is only 3-5 years into the future, providing only limited insight into the impact of distributed solar resources with 20-year lives. Finally, larger solar facilities may require distribution upgrades to accept their output, although the costs of such upgrades usually are the responsibility of the solar project. Nonetheless, studies using a variety of techniques have identified at least a modest amount of avoided capacity-related distribution costs resulting from the installation of solar DG.

- **Line Losses.** New solar generation reduces losses on the margin, and marginal line losses are significantly higher than average losses. The North Carolina utilities state that they use marginal transmission loss factors in their avoided energy costs. However, solar facilities produce power during daylight hours over which system loads, and system losses, are above-average. In addition, solar DG can avoid distribution losses. Thus, the current loss factors in avoided cost prices are likely to understate the line loss benefits of solar generation.

- **Avoided Emissions.** The North Carolina utilities' avoided cost calculations appear to include the costs of emission allowances associated with criteria pollutants, but not of carbon dioxide (CO_2). However, the IRPs of the Duke utilities recognize the potential long-term need to reduce CO_2 emissions – for example, by maintaining an option to add

4 See "What are some advantages of solar energy?" http://www.duke-energy.com/north-carolina/renewable-energy/nc-solar-distributed-generation-program-FAQs.asp

nuclear generation – and include a base case CO_2 emission cost of $17 per ton in 2020, escalating to $44 per ton in 2032.[5] Accordingly, a long-term projection of the benefits of solar generation should recognize the value of these resources in mitigating carbon pollution. Given the uncertainty in the timing and magnitude of these costs, we have calculated a range of benefits from avoided CO_2 emissions.

- **Avoided Renewables Costs.** Bundled wholesale solar sold to the North Carolina utilities contributes to their compliance with state's Renewable Energy and Energy Efficiency Portfolio Standard (REPS) requirements, both today and in future years when those requirements will increase. The measure of the value of this compliance is the cost for an unbundled renewable energy certificate (REC) in North Carolina. If developers did not invest in wholesale solar systems and then sell the resulting RECs to the utility, of if solar DG customers did not invest in on-site solar and then sell or transfer their RECs, the utilities would have to make their own investments in renewable generation, presumably at a higher cost than the RECs available from developers and solar DG customers.

  Public data is not widely available in North Carolina on the cost of unbundled RECs today. We have estimated such costs based on a range of data, including (1) recent reports on a solar REC purchase by a municipal utility, (2) the utilities' reported 2012-2014 incremental costs associated with their compliance with the REPS requirement, and (3) cost premiums for green pricing programs in North Carolina.

  We assume that this category of avoided costs encompasses a number of the difficult-to-quantify benefits of renewable generation that are embodied in the attributes of a REC, including:

  - **Fuel Diversity.** Renewables generally have zero fuel costs (with the possible exception of some types of biomass), and present a different set of operating risks (lower capacity factors and intermittency) than conventional fossil resources. As a result, an increasing penetration of renewables will diversify a utility's fuel sources and resource mix, and reduce the risks of reliance on a small set of generation technologies.
  - **Price mitigation benefits.** Solar DG reduces the demand for electricity (and for the gas used to produce the marginal kWh of power). These reductions have the broad benefit of lowering prices across the gas and electric markets in North Carolina, to the benefit of all ratepayers. This benefit is also known as the "demand reduction induced price effect" (DRIPE), and has been quantified in several regions of the U.S.
  - **Grid security.** Renewable DG resources are installed as many small, distributed systems and thus are highly unlikely to fail at the same time. They are also located at the point of end use, and thus reduce the risk of outages due to transmission or distribution system failures. This reduces the economic impacts of power outages.
  - **Economic development.** Renewable DG results in more local job creation than fossil generation, enhancing tax revenues.

[5] DEC 2012 IRP, at Appendix A, p. 106.

1.2 Costs

The ratepayer costs for wholesale solar are the payments that the utilities will make to purchase solar generation under long-term power purchase agreements (PPAs). We estimate these costs using available data on the recent trends in the prices in PPAs for utility-scale solar projects. For solar DG, the principal costs are the revenues which the North Carolina utilities will lose from customers serving their own load with on-site solar, including the credits provided under net metering when solar generation is exported to the grid. We estimate the lost revenues for the rate schedules on which many solar customers take service. Finally, we include an estimate of the costs of additional operating reserves needed to integrate intermittent solar generation into the grid. We are not aware that any of the North Carolina utilities have performed and publicly-disclosed a solar integration study specific to their systems, so we use a typical value from utility-sponsored integration studies in other states.

The following sections discuss in more detail each of the benefits and costs of solar DG on the DEC, DEP, and DNCP systems. As noted above, solar is a long-term resource with an expected useful life of at least 20 years. Accordingly, when we calculate the benefits and costs of DG over a 15-year period, the result is a conservative estimate of the value of these long-term resources. We express our results as 15-year levelized costs using a discount rate of 7.7%.[6]

2. Benefits of Solar DG

2.1 Energy

The North Carolina utilities' 2012 resource plans make clear that, to meet near- and intermediate-term growth, the utilities will rely on energy efficiency and demand-side resources, renewable purchases to meet North Carolina's REPS standard, and new efficient natural gas-fired generation, with the possibility of adding new nuclear generation in the post-2020 time frame. In these plans, gas-fired generation is the predominant marginal resource, so if North Carolina utilities were to increase their procurement of wholesale or distributed solar resources, the resources likely to be displaced would be new gas-fired generation.

Accordingly, we would expect the utilities' long-term, 15-year avoided cost energy prices to reflect the energy costs of relatively efficient gas-fired generation resources. DEC's, DEP's and DNCP's current 15-year levelized avoided energy prices are in the range of 4.5 to 5.0 c/kWh. As a check on these values, we first developed a 15-year natural gas cost forecast for gas-fired generation in North Carolina. This forecast uses recent forward gas price data from the NYMEX Henry Hub market plus a market differential from the Henry Hub to Zone 5 on the Transco pipeline. Based on this gas cost forecast, we estimated the marginal heat rates over the next 15 years that would produce the utilities' current 15-year avoided energy costs. These marginal heat rates are about 9,000 Btu per kWh today, declining to about 7,500 Btu/kWh in 2027. These heat rates are reasonably representative of the efficient combined-cycle and gas turbine units that the North Carolina utilities expect to add over this period.

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6 This is average of DEC's and DEP's currently-authorized weighted average costs of capital, from these utilities' most recent general rate case decisions. See the May 30, 2013 NCUC order in Docket No. E-2, Sub 1023, at 11 (for DEP) and the September 24, 2013 NCUC order in Docket No. E-7, Sub 1026 at 10 (for DEC). For DNCP, we use the same 8.5% discount rate which the utility used in its most recent public avoided cost filing.

Renewable generation has no fuel costs and thus avoids the volatility associated with generation sources whose cost depends principally on fossil fuel prices. Our gas cost forecast is based on forward market natural gas prices; thus, it represents a cost of gas that the North Carolina utilities theoretically could fix for the next 15 years, thus in principle capturing the fuel price hedging benefit of renewable generation. However, such a hedging strategy may not be cost-less; for example, in 2011-2012 DEP incurred $121 million in above-market costs to hedge one-half of its 163 Bcf of gas purchases, a cost premium of $0.74 per MMBtu when spread over the utility's full portfolio of gas purchases. From the customer's perspective, DEP's financial hedges effectively increased the price of each MMBtu consumed by $0.74. These hedging costs are not included in current avoided cost prices. We include such costs to develop the high end of our range of avoided energy benefits; the low end of our range is the utilities' filed 15-year avoided energy costs, adjusted as described below to reflect the hourly profile of solar output.

North Carolina avoided cost prices are differentiated into on- and off-peak prices, and also can vary seasonally by peak vs. off-peak months. This differentiation captures some, but not all of the hourly variation in the energy benefits of solar. What is missing is the likelihood that the diurnal profile of solar output will have a higher value than a flat block of on-peak power, because solar output peaks in the early afternoon hours and produces significant power in the mid-afternoon hours of peak demand. We are able to assess the hourly value of solar directly for DCNP, because it operates in the PJM market with visible hourly locational marginal prices (LMPs). DNCP's solar-weighted avoided cost energy price is 14% higher than the annual average avoided cost energy price for a baseload profile.[7] We have applied the same premium to the average, base load avoided cost energy prices for DEC and DEP, as a reasonable estimate of the time-varying energy value of solar in North Carolina. **Table 4** summarizes the avoided energy value of solar generation for the three utilities.

Table 4: *Avoided Energy Value of Solar (15-year levelized, $ per kWh, 2013$)*

Component	DEC	DEP	DNCP
Avoided Energy Costs	5.7	5.5	5.8
Hedging Costs	0.8	0.8	0.8

2.2 Generation Capacity

The North Carolina utilities use the annualized fixed costs of a new combustion turbine as the measure of avoided capacity costs – the standard "peaker" method. **Table 5** shows the annualized CT capacity costs now embedded in the utilities' current 15-year avoided capacity prices, assuming that a resource operates at an 83% capacity factor.[8] The detailed CT capital cost and financing data used to set these current avoided cost prices are confidential, so we "back into" the CT fixed capacity costs in Table 5 for the three utilities by multiplying (1) the currently-effective avoided capacity credit times (2) the number of hours per year in the time period in which the capacity credit is paid, times (3) the 83% capacity factor. The table also shows other relevant, public sources of data on CT fixed costs.

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7 In comparison, DEC's Option A avoided cost prices for an average solar profile in Charlotte are 4% higher than the annual average price for a base load profile.

8 Based on the 1.2 "performance adjustment factor" used to calculate these prices.

Table 5: *Annualized CT Fixed Capacity Costs (Distribution Voltage)*

Source	CT Fixed Capacity Cost *($/kW-year)*	Range *($/kW-year)*
DEC	$57	$57 - $104
DEP	$65	$65 - $104
DNCP	$75	$75 - $108
PJM Net CONE, Area 5	$108	
EIA, *AEO13*, Advanced CTs[9]	$100	

There is ongoing litigation in North Carolina concerning QF capacity prices, with parties challenging the utilities' filed and currently-effective capacity credits. Accordingly, we use a range for the value of avoided generating capacity, as shown in the third column of Table 5. At the low end of the range for DEC and DEP, we use the currently-filed utility values; at the high end, we average the public, transparent PJM and EIA data. For DNCP, as it is on the PJM system, we use the utility's filed cost as the low end, and the PJM values as the high end.[10]

We make three adjustments to these CT-based capacity values. First, we add the fixed reservation charges for firm transmission on the Transco interstate pipeline to provide the new gas-fired capacity with a firm gas supply, to the extent that these reservation charges exceed a typical market-based "basis" differential in natural gas prices between the U.S. Gulf Coast and North Carolina. In the long-run, natural gas pipelines need to be able to recover their full cost of service. Second, we assume that behind-the-meter solar DG will be reflected in utility planning as a reduction in peak demand. Accordingly, solar DG also will reduce each utility's capacity need by an additional amount equal to the required reserve margin (15%) times the effective solar capacity.

Third, a calculation of the capacity value of solar resources must recognize that solar is a resource whose availability depends on weather and the time of the day. Although peak solar output typically occurs in the early afternoon when demand is relatively high, the peak output does not correlate perfectly with the utility's peak demand, which tends to occur later in the afternoon. As a result, solar does not provide 100% of its nameplate capacity to the grid as reliable generating capacity.

Utilities and control area operators in the U.S. generally use one of two approaches to determine the effective capacity provided by a solar resource. The most complex, and often considered to be the most rigorous, approach is the Effective Load Carrying Capacity (ELCC) method. This approach uses a production simulation model of the electric system in question to determine how much load a kW of solar capacity can "carry" without a diminution in reliability. Thus, if 100 MW of solar generation provides the same level of reliability when it replaces 50 MW of a reference resource (such as a CT), the ELCC of the solar resource is 50 MW / 100 MW = 50%. ELCC analyses require computer models which are complex and expensive to license and run, and which are not transparent except to the analysts who run them. They also require hourly data on

[9] EIA data on CT costs is from http://www.instituteforenergyresearch.org/wp-content/uploads/2009/05/2.15.13-IER-Web-LevelizedCost-MKM.pdf at page 3. Includes levelized fixed costs, fixed O&M, and associated transmission investments. 2011 $ are escalated to 2013 $ at 2.5% per year.

[10] For the high case, we use PJM RPM clearing prices for capacity through 2016, and its Net Cost of New Entry (CONE) thereafter.

loads and solar output which are correlated in time. As a result of the limitations and complexities of ELCC analyses, most control area operators in the U.S. use the simpler and more transparent "capacity factor" approach to setting the capacity value of intermittent renewable resources. This method sets the capacity value of the renewable resource based on its demonstrated capacity factor during certain critical hours of peak demand. For example, Appendix B of PJM's Manual 21 specifies that the capacity value of a solar resource should be calculated based on its summer (June-August) capacity factor during the hours ending 3-6 p.m.[11] For a solar profile for Norfolk, Virginia, the PJM Manual 21 method yields capacity values of 46% of nameplate for a fixed array and 58% of nameplate for a single-axis tracking system.

In their IRPs, the North Carolina utilities appear to assume that a solar resource's capacity value is 40% to 50% of its nameplate, consistent with the PJM capacity factor valuation for fixed arrays. DEC and DEP have confirmed in non-confidential data responses in the NCUC avoided cost docket that their 2013 IRPs value solar at 42% of nameplate. They also assume that solar operates at a 17.4% capacity factor.[12]

Table 6 shows our final calculation of the range of benefits that solar provides from avoiding the need for generation capacity, over a 15-year period. We add the CT fixed costs and pipeline reservation costs, multiply the total by the 42% contribution of solar to reducing peak demand, then divide by the typical output of a solar resource in North Carolina (1,524 kWh per kW per year based on the 17.4% capacity factor). The resulting avoided generation capacity costs, in dollars per MWh, are shown in the table below, for the range of CT fixed costs in Table 5. Finally, we observe that behind-the-meter solar DG, unlike wholesale solar, reduces the utility's peak demand. As a result, solar DG also reduces the utility's capacity requirements to meet its reserve margin, which is about 15% for the North Carolina utilities. Thus, for solar DG we increase the avoided generation capacity value by 15% above the numbers shown in Table 6.

Table 6: *Avoided Generation Capacity Value ($ per kW-yr in 2013$)*

Component	DEC		DEP		DNCP	
	Low	High	Low	High	Low	High
CT Fixed Costs	57	104	65	104	75	108
Pipeline Reservation	12	12	12	12	12	12
Total	69	116	87	126	97	130
Solar Capacity as % of Nameplate	42%	42%	42%	42%	46%	46%
Solar Capacity Value *($ per kW-yr)*	29	49	32	49	45	60
Annual Output *(kWh / kW)*	1,524	1,524	1,524	1,524	1,524	1,524
Solar Capacity Value *(cents per kWh)*	1.9	3.2	2.1	3.2	3.0	3.9

11 *See* http://www.pjm.com/documents/manuals.aspx .

12 DEC and DEP response to NCSEA Data Request No. 4, Item 4-15 in Docket No. E-100, Sub 136.

2.3 Transmission Capacity

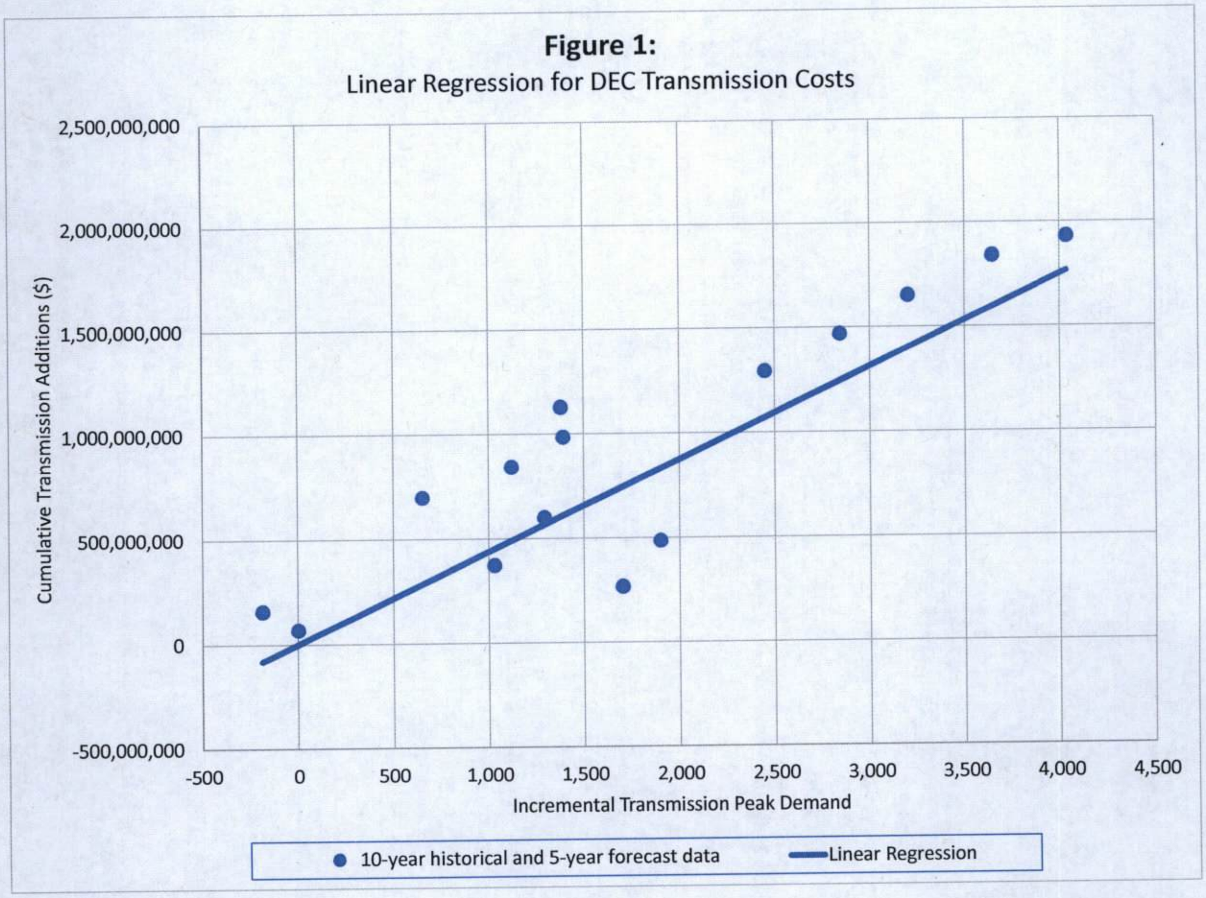
Most, if not all, solar DG output is either consumed behind the meter or on the distribution system by the neighbors of the DG system, and never touches the transmission system. Solar DG thus reduces the use of the transmission system, and will reduce peak demands on the transmission system even if solar output and peak demand are not perfectly correlated. This benefit is similar to the benefit of other demand-side programs in avoiding transmission and distribution (T&D) capacity-related costs.

North Carolina utilities include avoided capacity-related T&D costs in assessing the costs and benefits of EE and DR programs. However, the methodology used to calculate these avoided costs is not public and we are aware that there is debate over the magnitude of these avoided costs. In particular, the NC Public Staff have questioned whether DEC's assumed avoided T&D costs are too high because they include transmission costs that are reliability-related, and thus not driven by load increases.[13]

There is a well-accepted way to address this debate. We have calculated DEC's and DEP's long-term marginal transmission capacity costs using the industry-standard NERA regression method used by many utilities to determine their marginal T&D capacity costs which are load-related.[14] **Figure 1** shows, for DEC, the regression fit of cumulative transmission capital additions as a function of incremental demand growth. We convert the regression slope of $438 per kW using a real economic carrying charge of 7.41%, and add loaders for general plant and transmission O&M costs based on FERC Form 1 data. Our estimate of annualized marginal transmission costs for DEC is $37.45 per kW-year.

[13] See NC Public Staff witness Robert Hinton testimony in Docket E-7, Sub 1032 pre-filed on August 7, 2013. http://ncuc.commerce.state.nc.us/cgi-bin/webview/senddoc.pgm?dispfmt=&itype=Q&authorization=&parm2=TBAAAA02231B&parm3=000141791 .

[14] The NERA regression model fits incremental transmission costs to demand growth. The slope of the resulting regression line provides an estimate of the marginal cost of transmission associated with a change in load. The NERA methodology typically uses 10-15 years of historical expenditures on transmission and peak transmission system load, as reported in FERC Form 1, and a five-year forecast of future expenditures and load growth. Crossborder's analysis used DEC's FERC Form 1 data for the most recent 10 years (2003-2012), and a forecast of T&D project costs over the five future years (2013-2017) based on data from DEC's most recent general rate case (Docket E-7 Sub 1026, E-1 Data Item 23b). Future T&D project costs are allocated between transmission and distribution based on the historical division between these categories. Peak demand data is from Docket E-7, Sub 1026, E-1 Data Item 43a.



Transmission system peaks tend to coincide with system demand peaks, and thus we assume that solar's contribution to reducing transmission system peaks is the same as its contribution to avoided demand for generating capacity. Thus, we assume that each kW of solar DG capacity reduces DEC's peak transmission demand by 0.42 kW, and we convert avoided transmission capacity costs to dollars per MWh of solar DG output assuming an average annual output of 1,524 kWh per kW-AC. **Table 7** shows this calculation. The result for DEC is $10 per MWh (1.0 cents per kWh) for the transmission capacity costs avoided by solar DG; a parallel calculation for DEP yields avoided transmission capacity costs of 0.7 cents per kWh.

Table 7: *Calculation of Transmission Capacity Costs Avoided by Solar DG*

Component	DEC	DEP	*Units*
Marginal Transmission Capacity Cost (2014 $)	37	27	*per kW-year*
Solar Capacity as % of Nameplate	42%	42%	
Transmission Capacity Costs Avoided	16	11	*per kW-year*
Annual PV Output per kW-DC	1,524	1,524	*kWh per year*
Generation Capacity Cost Avoided by DSG	1.0	0.7	*cents / kWh*

As a check on this calculation, we have looked at DEC's filed avoided T&D benefits for several of its DR programs. These programs principally provide capacity benefits, and the avoided T&D portion of the benefits average about 40% of the generating capacity benefits. We understand that DEC and North Carolina Public Staff recently stipulated to the use of these T&D

benefits.[15] This level of T&D benefits is broadly consistent with our avoided transmission capacity costs in Table 7 compared to the avoided generation capacity benefits that we determined in Table 6.

Our approach for DNCP is different, given that DNCP is on the PJM system. For DNCP, we use the PJM rate for network integrated transmission service (the NITS rate), as a more direct measure of the costs which Dominion can avoid if solar reduces DNCP's peak demand on the PJM grid. As with avoided generation capacity costs, we apply the PJM solar capacity value percentage (46% of nameplate) to the avoided transmission costs, in recognition that peak solar output does not necessarily coincide with system peak demands. The resulting avoided transmission cost for DNCP is 0.9 cents per kWh.

2.4 Distribution

Solar DG also can reduce peak loads on distribution circuits, and thus avoid or delay the need to upgrade or re-configure the circuit if it is approaching capacity. However, circuits and substations on the distribution system can peak at different times than the system as a whole, which complicates the assessment of the extent to which solar DG can avoid or defer distribution capacity upgrades. As DG penetration grows, and a deeper understanding is gained of the impacts of DG on distribution circuit loadings, we anticipate that utility distribution planners will integrate existing and expected DG capacity into their planning, enabling DG to avoid or defer distribution capacity costs.[16] A comparable evolution has occurred over the last several decades, as the long-term impacts of EE and DR programs are now incorporated into utilities' capacity expansion plans for generation, transmission, and distribution, and it is generally recognized that these demand-side programs can help to manage demand growth even though the specific locations where these resources will be installed are difficult to predict.

The available studies which quantify the distribution capacity costs avoided by solar generation generally have calculated relatively modest values. **Table 8** below lists some of the studies which have calculated avoided distribution capacity costs. The most recent study, performed for the California Public Utilities Commission by the E3 consulting firm, based its calculations on marginal distribution costs in California and the correlation between solar output and distribution substation peaks. This study used data on distribution substation loads that is not typically available. Based on these studies, a reasonable range for avoided distribution capacity costs is 0.2 to 0.5 cents per kWh.

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[15] See the settlement filed August 19, 2013 in NCUC Docket E-7, Sub 1032, at page 6.

[16] A public summary of a confidential report on solar's modeled impacts on the DEC distribution system indicates that solar DG can also provide benefits such as voltage support and reduced line losses on feeder circuits, and that the value of solar along a circuit varies with proximity to the substation, load centers and other factors. See DEC witness Jonathan Byrd testimony in Docket E-7, Sub 1034, in the September 17, 2013 hearing transcript at p. 77-80 at http://ncuc.commerce.state.nc.us/cgi-bin/webview/senddoc.pgm?dispfmt=&itype=Q&authorization=&parm2=PAAAAA36131B&parm3=000141801. See the report summary filed as exhibit 4 to DEC witness Jonathan Byrd's testimony pre-filed on March 13, 2013 at http://ncuc.commerce.state.nc.us/cgi-bin/webview/senddoc.pgm?dispfmt=&itype=Q&authorization=&parm2=KAAAAA47031B&parm3=000141801 (beginning at pdf page 44).

Table 8: *Studies of Avoided Distribution Capacity Costs*[17]

State / Study / Date	Avoided Distribution Capacity Costs *(c/kWh)*	*Source*
AZ / R.W. Beck / 2009	0 to 0.31	*Fig. 6-2 at 6-14.*
PA-NJ / Clean Power / 2012	0.1 to 0.8	*Table 4*
AZ / Crossborder / 2013	0.2	*Table 1, at 2.*
AZ / SAIC / 2013	0	*pp. 2-10 to 2-12. No savings unless solar is targeted to circuits that are close to capacity.*
CA / CPUC-E3 / 2013 *(draft released 9/26/2013)*	0.6	*Includes sub-transmission and distribution costs. Based on correlation of distribution substation peaks to solar peaks.*
CO / Xcel Energy / 2013	0.05	*Table 1, at v and 27-36.*

2.5 Line Losses

The currently effective avoided energy prices for the North Carolina utilities include line loss adjustments in the range of 2% to 3%. The utilities state that these represent their marginal transmission line losses avoided by QF generation. There are several reasons why these loss adjustments are likely to be too low. First, solar projects generate during daylight hours over which system loads, and system losses, are above-average, while the QF loss factors may reflect a baseload output profile. Second, solar DG also avoids marginal distribution losses, which can be in the 5% to 8% range. Other studies have used combined marginal T&D loss factors in the 8% to 12% range.[18] In Virginia, Dominion appears to use at least an 8% distribution loss adjustment in settlements with competitive energy suppliers.[19] We have not included an additional line loss adjustment above the loss factor included in QF prices, but further data on distribution loss adjustments in North Carolina could justify additional benefits in this category of costs.

2.6 Avoided Emissions

Solar generation avoids emissions of both greenhouse gases and criteria air pollutants (SO_2, NO_x, and PM 10). It is our understanding that compliance costs for criteria pollutants are included in the production cost models used to determining avoided energy costs, but that future costs to mitigate greenhouse gas (GHG) emissions are not considered. We note that the North Carolina utilities do include future carbon emission costs in their IRPs. For example, DEC's 2012 IRP assumes a Base Case CO_2 emission cost of $17 per ton in 2020, escalating to $44 per ton in 2032.[20] The DEC IRP also includes a High Case for CO_2 emission costs of $31 per ton in 2020, escalating to $80 per ton in 2032.

[17] All of these studies except the newly-released draft CPUC-E3 study are referenced and discussed in the RMI meta-analysis cited in Footnote 2 above. The new CPUC-E3 draft net metering cost-benefit study is available at http://www.cpuc.ca.gov/PUC/energy/Solar/nem_cost_effectiveness_evaluation.htm .

[18] The CPUC-E3 2013 study referenced in Table 7, at Table 5 in Appendix C, shows loss factors ranging from 5.7% to 10.9%. The R.W. Beck Study in Arizona, at Table 4-3, shows T&D loss reductions of 11.2% to 12.2%. of solar output.

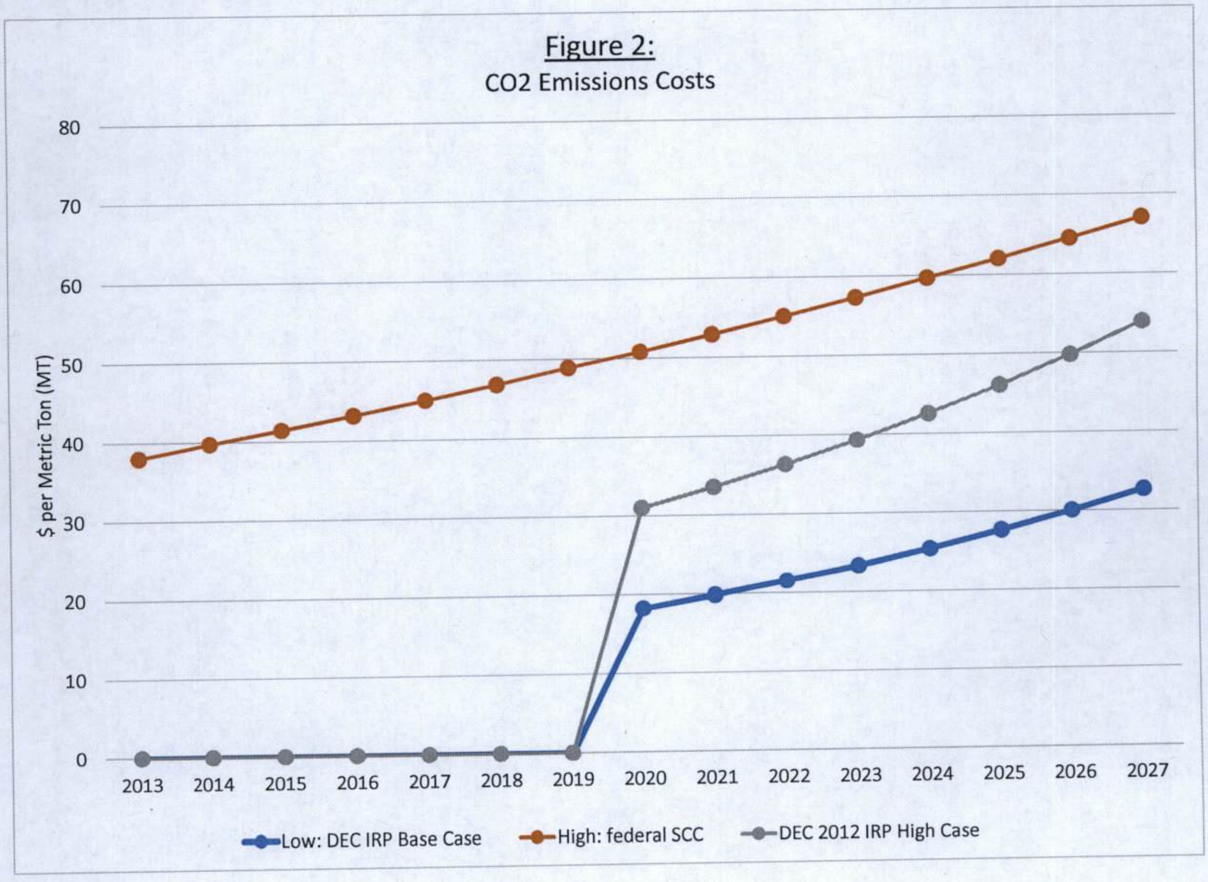
[19] See the loss expansion factors in http://www.dom.com/business/electric-suppliers/index.jsp .

[20] DEC 2012 IRP, at 106.

As another metric for the costs of mitigating CO_2 emissions, the federal government has announced that it will prioritize reductions of greenhouse gas (GHG) emissions by focusing on reducing pollution from electric power generation. This effort will employ a Social Cost of Carbon (SCC), with a base scenario of a carbon cost of $35 per metric ton CO_2 in 2012 (in 2007 $), growing at 2.1% per year plus inflation through 2050.[21] This is equivalent to a $34 per ton in 2013, rising to $46 per ton in 2020, and $61 per ton in 2027.

Given these developments, we believe that a reasonable range for the value of avoided GHG emissions uses DEC's IRP Base Case values as the low scenario, and the federal SCC as the high scenario. The SCC values in the high case also assume that CO_2 emission costs have an impact immediately, not just in 2020. Although it is clear that the U.S. (except for California and the Northeast) will not have a GHG allowance trading scheme in place for the power sector in the near future, it is more likely that there will be further regulatory actions from the Environmental Protection Agency to regulate carbon emissions from power plants. The SCC emission values can be considered a proxy for such regulatory actions.

Figure 2 shows these two projections of the costs of CO_2 emissions. We also indicate the DEC high CO_2 case from its 2012 IRP.



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[21] See http://www.whitehouse.gov/sites/default/files/omb/inforeg/social_cost_of_carbon_for_ria_2013_update.pdf at page 18.

We convert these costs of mitigating carbon emissions from dollars per ton to $/MMBtu with a natural gas emission factor, and then to an energy price (in $/MWh) using the natural gas-based marginal heat rates assumed in our avoided energy cost forecast. **Table 9** shows these results. This calculation assumes, conservatively, that the North Carolina utilities' marginal generation, and marginal emissions, are entirely from natural gas. The utilities' avoided cost filings show that, today, their marginal emissions are from a combination of natural gas, coal, and purchased power, with coal constituting 20% to 30% of the mix. This suggests that our assumption that 100% of marginal emissions are from natural gas understates the utilities' actual marginal emissions, and thus underestimates the emission savings from new renewable generation.

Table 9: *Avoided Emissions Costs*

Case	**CO2 Mitigation Costs** *($ per ton)*			**Avoided GHG Costs** *(15-year levelized cents / kWh)*
	2013	**2020**	**2034**	
Base	0	17	30	0.4
High	34	46	61	2.2

2.7 Avoided Renewables Costs

The North Carolina REPS requires utilities to serve at least 12.5% of their customers' electricity needs through new renewable energy sources or energy efficiency measures by 2021. The current REPS requirement is 3%; it increases to 6% in 2015 and 10% in 2018.

Wholesale Solar. We assume that the cost of wholesale solar purchased by the utilities will include the transfer of the associated REPS REC, such that wholesale solar will count directly toward meeting the REPS requirements. Thus, the cost of a REC represents the value of wholesale solar in meeting the utilities' REPS needs. We discuss below the available data on the cost of an unbundled REC in North Carolina.

Solar DG. Distributed solar does not necessarily count toward the REPS, if the customer who installs solar DG retains the RECs associated with their production. However, solar DG output reduces the utility's sales, and thus lowers its future REPS obligations by the solar output times the applicable REPS percentage (i.e. by 3% today, by 6% in 2015-2017, by 10% in 2018-2019, and by 12.5% in 2020). Over the 15-year period from 2013 – 2027, the average REPS obligation is 9.6%. Thus, solar DG provides at least this modest benefit in reducing future REPS obligations. In addition, we also understand that, although solar DG customers may net meter under any available rate schedule, customers can retain their RECs only if they take service under a time-of-use (TOU) tariff with demand charges; otherwise, they must surrender all RECs to the utility, without compensation.[22] Our review of the utilities' tariffs indicates that most residential and small commercial solar DG customers are likely to be better off net metering under an all-volumetric tariff, and conveying their RECs to the utility for free. We also understand that, even if a solar DG customer retains his RECs, the customer often does not or is not able to monetize them, in which case the value of the REC accrues to the general body of ratepayers in

[22] See http://www.dsireusa.org/incentives/incentive.cfm?Incentive_Code=NC05R&re=0&ee=0 . Also, NCUC order dated March 31, 2009 in Docket E-100, Sub 83.

North Carolina at no cost to them even though such a REC is not be counted for REPS compliance. In this last case, in effect, free RECs are donated to the system and North Carolina achieves a higher renewables penetration than required by the REPS program. Thus, the maximum benefit that solar DG provides to ratepayers is about 110% of the value of a REC – i.e. 100% from the REC conveyed to the utility for free, plus the extra 9.6% from the reduction in the utility's sales.

Cost of RECs. There is only limited public data on the cost of unbundled RECs in North Carolina today. We have estimated this cost based on a range of data, including the following:

- A recent filing by the Town of Fountain municipal utility publicly reporting a purchase of 2011-vintage solar RECs for $15 per MWh (1.5 cents per kWh).[23]

- The utilities' 2012-2014 incremental costs associated with their compliance with the 3% REPS requirement for these years, as reported in their 2013 REPS compliance filings. These incremental REPS costs for DEC and DEP are summarized in **Table 10** below. DNCP does not have a commission-approved REPS Rider to recover incremental REPS costs, although they have filed for one. North Carolina's REPS statute generally defines "incremental" REPS costs as the costs to procure renewable generation that exceed the utility's avoided costs.[24]

Table 10: *2012-2014 Incremental REPS Costs*

Component	DEC	DEP
Incremental REPS Costs *($ millions)*	$52.3	$63.3
REPS Requirement *(millions of kWh)*	5.29	3.36
Incremental REPS Costs *(cents / kWh)*	1.0	1.9

- Cost premiums for North Carolina's "green pricing" program. All of the North Carolina utilities have tariffs which offer customers the ability to purchase blocks of renewable power for a set premium. This "green pricing" program is administered by an independent non-profit, NC GreenPower. The premium for residential customers is 4 cents per kWh; commercial customers pay an additional 2.5 cents per kWh.[25] NC GreenPower states that 75% of its revenues are used to purchase RECs, and contributions appear to be deductible from federal income taxes as a charitable contribution.[26] The non-profit offers to purchase RECs from small renewable generators for 6 cents per kWh over 5 years (equivalent to a 15-year levelized price of 2.8 cents per kWh).[27] The NC GreenPower price represents a price premium that ratepayers are willing to pay to increase the percentage of renewable power they use to above the REPS requirement for grid power. Customers install solar DG for the same purpose. The NC GreenPower premiums are high compared to the other REC metrics, although the effective price is lower if the

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[23] See http://ncuc.commerce.state.nc.us/cgi-bin/webview/senddoc.pgm?dispfmt=&itype=Q&authorization=&parm2=WAAAAA23231B&parm3=000143195.

[24] North Carolina statutes § 62-133.8(h)(1).

[25] See the utilities' NC GreenPower tariffs.

26 See https://www.ncgreenpower.org/faq/ .

[27] See https://www.ncgreenpower.org/ncgp-announces-a-change-in-premium-payment-for-new-small-solar-pv-agreements-effective-june-3-2013/ .

payments are tax-deductible, and one would presume that the utilities would not offer this program as a tariffed service if NC GreenPower were overcharging consumers for the incremental cost of renewable generation, or if the utilities themselves could or were willing to meet the demand for the service at a lower cost.

Considering all of the above metrics, a reasonable range for the cost of a REC in North Carolina is 1.0 to 2.0 cents per kWh, with the lower end based on DEC's incremental REPS costs and the high end reflecting DEP's incremental REPS costs and the cost of RECs through NC GreenPower.

It is fair to ask what is included in the value of a REC, particularly if mitigating carbon pollution is accounted for separately.[28] We have discussed above a number of the difficult-to-quantify benefits of renewable generation that are encompassed in the value of a REC, including:

- Fuel Diversity
- Price mitigation benefits[29]
- Grid security[30]
- Economic development[31]

We assume that the cost of a REC provides a proxy for these benefits. When calculated separately and then summed, these benefits typically far exceed the cost of a REC. A number of studies have quantified one of more of these benefits, as referenced in the footnotes to the above list. For example, the Clean Power Research study of the value of solar DG in Pennsylvania and New Jersey estimated the price mitigation, grid security, and economic development benefits of solar PV in those states, and found those benefits together to range from $102 to $137 per MWh, in 20-year levelized dollars.[32]

Conclusion. The avoided renewables benefit of wholesale solar is the full cost of the RECs that we assume the utility acquires when it purchases solar generation under a wholesale PPA. This cost is 1 to 2 cents per kWh. For solar DG, the avoided renewables costs over the 2013-2027 period is, at a minimum, 9.6% of the cost of a REC, based on the reduced REPS costs when solar DG reduces utility sales. If solar DG customers convey their RECs to the utility, or cannot monetize their RECs, the attributes of these RECs will accrue to the general body of ratepayers in North Carolina. Thus, at the high end, the value of solar DG to North Carolina ratepayers is the 110% of the full cost of a REC.

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[28] North Carolina statute § 62-133.8(a)(6) defines a REC to not include the value of reducing CO_2 emissions.

[29] For example, a Lawrence Berkeley National Lab study has estimated that the consumer gas bill savings associated with increased amounts of renewable energy and energy efficiency, expressed in terms of $ per MWh of renewable energy, range from $7.50 to $20 per MWh. Wiser, Ryan; Bolinger, Mark; and St. Clair, Matt, "Easing the Natural Gas Crisis: Reducing Natural Gas Prices through Increased Deployment of Renewable Energy and Energy Efficiency" (January 2005), at ix, http://eetd.lbl.gov/EA/EMP .

[30] Hoff, Norris and Perez, *The Value of Distributed Solar Electric Generation to New Jersey and Pennsylvania* (November 2012), at Table ES-2.

[31] *Ibid.* Also, a 2013 study by RTI International and La Capra Associates found that north Carolina's clean energy and energy efficiency programs contributed $1.7 billion to the state's economy from 2007-2012, created or retained 21,163 job-years over this period, and will provide long-term ratepayer benefits for the state. The study can be found at http://energync.org/assets/files/RTI%20Study%202013.pdf .

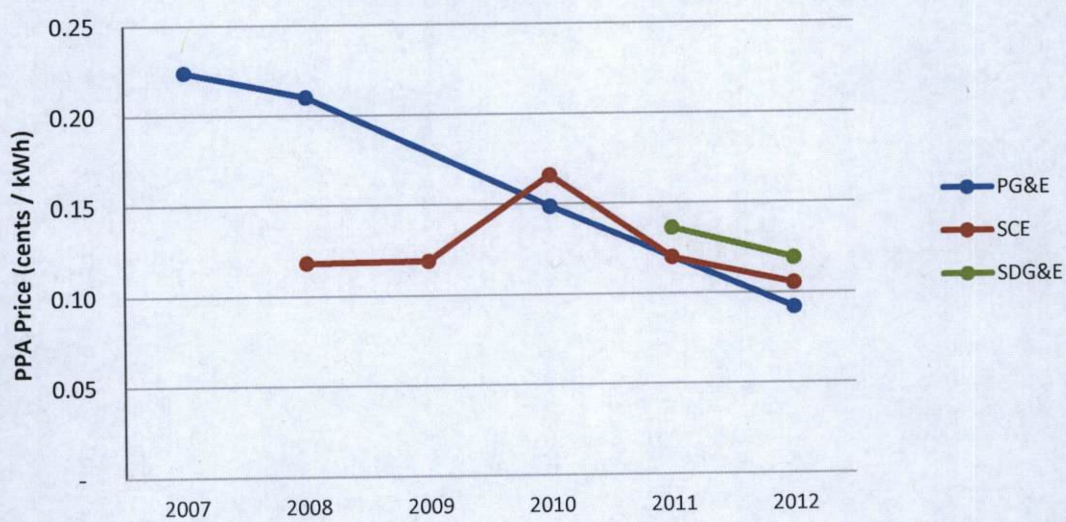
[32] *Ibid.*

3. Costs of Solar Generation

3.1 Wholesale Solar PPA Prices

Wholesale solar PPA prices provide perhaps the most dramatic evidence of the continued decline in solar PV costs. Solar PPA prices have fallen dramatically over the past several years, to the point that, in some regions of the U.S., solar is now competitive with other generation resources, including wind and natural gas. Xcel Energy in Colorado recently announced that it is proposing to add 170 MW of utility-scale solar to its system, with its CEO stating "[f]or the first time ever, we are adding cost competitive utility scale solar to the system."[33] The California electric utilities make public each year the average PPA prices for renewable contracts approved by the CPUC in the prior year. **Figure 3** shows the trend in the prices for their solar PV PPAs; CPUC contract approval can occur up to a year or more after bids are received, so the figure is indicative of prices through roughly 2011.[34] 2012 solicitations for solar PPAs in California in the 3 MW to 20 MW size range through the Renewable Auction Mechanism (RAM) have yielded market-clearing prices in the 8 to 9 cents per kWh range.[35]

Figure 3: California Solar PV PPA Prices



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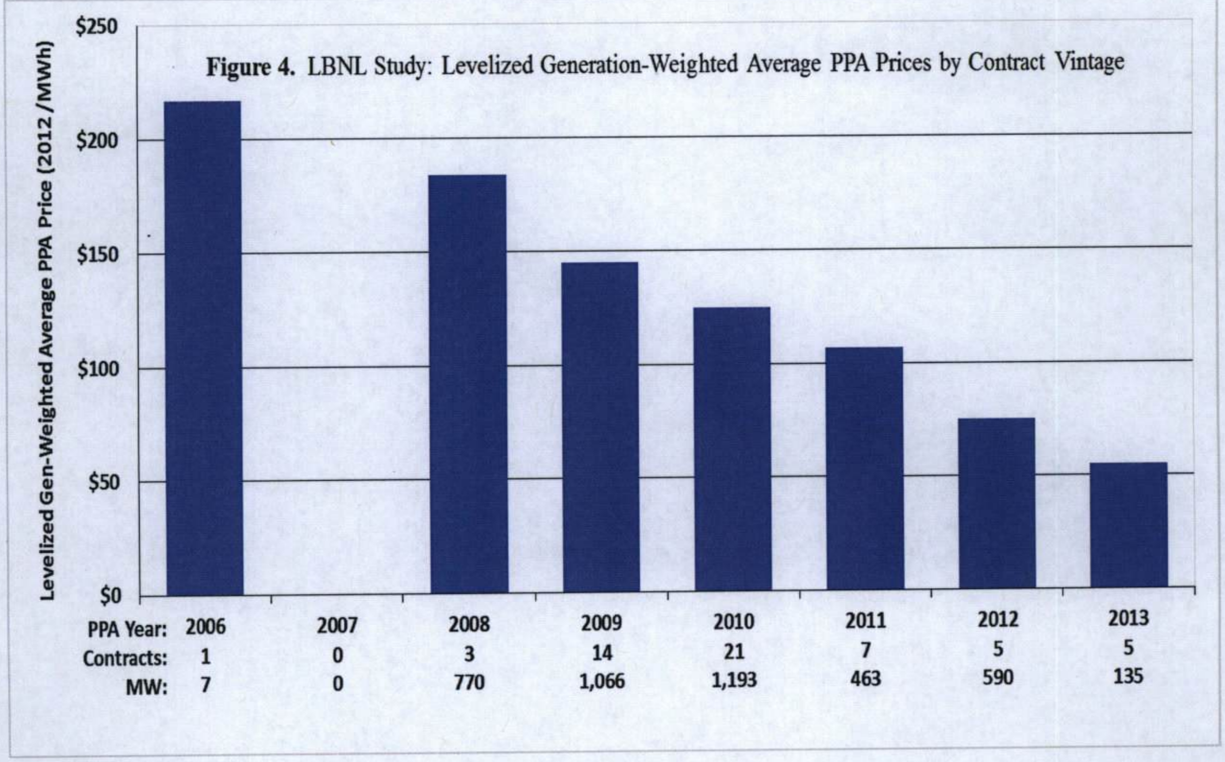
[33] See http://www.xcelenergy.com/About_Us/Energy_News/News_Releases/Xcel_Energy_proposes_adding_economic_solar,_wind_to_meet_future_customer_energy_demands .

[34] See http://www.cpuc.ca.gov/NR/rdonlyres/F0F6E15A-6A04-41C3-ACBA-8C13726FB5CB/0/PadillaReport2012Final.pdf .

[35] See http://www.cpuc.ca.gov/PUC/energy/Renewables/hot/Renewable+Auction+Mechanism.htm for details on the RAM program and the RAM auction results in MW. See http://votesolar.org/2012/03/30/ram-results-11-projects-130-mw-total-most-solar-all-under-8-9-centskwh/ for RAM prices from 2012.

The Lawrence Berkeley National Lab (LBNL) conducts and publishes regular national surveys of the installed costs of solar PV; these surveys include PPA prices for utility-scale solar projects. LBNL recently released its most recent survey of wholesale, utility-scale solar PPA prices, including data to September 2013.[36] LBNL samples the prices only for utility-scale solar PV projects that sell both electricity and RECs in the wholesale power market through a long-term PPA that includes the "bundled" sale of both power and RECs.[37] **Figure 4** illustrates the trend in utility-scale, wholesale solar PPA prices.[38] Based on the 2012-2013 data, utility-scale solar PPAs now appear to be in the range of $55 to $75 per MWh. The data for PPAs from 2012 and 2013 are for projects that are not yet on-line, and thus remain subject to some uncertainty over contract performance. However, LBNL's PPA data from earlier years is based on projects which in general are now on-line, which substantiates the trend of rapidly dropping PPA prices and provides confidence that most of the reported 2012-2013 PPA prices will result in successful projects.

Figure 4. LBNL Study: Levelized Generation-Weighted Average PPA Prices by Contract Vintage



LBNL also reports on the installed costs of utility-scale solar projects, by region. The most recent data indicates that costs in the southeastern U.S. (data from North Carolina and Florida) have dropped almost to par with costs in the western U.S. where the bulk of utility-scale solar projects are located.[39]

An important caveat to the LBNL data is that most of the PPAs sampled are in the western

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[36] See "Utility-scale Solar: An Empirical Analysis of Project Cost, Performance, and Pricing Trends in the United States" (September 2013, LBNL Publication 6408-E), hereafter "LBNL Study." Available at http://emp.lbl.gov/reports/re .

[37] *Ibid.*, at 19.

[38] *Ibid.*, Figure 16.

[39] *Ibid.*, at Figure 4.

U.S., which has higher solar insolation levels than the eastern U.S.[40] Using the NREL PVWATTS calculator, the expected annual output (in kWh per kW) of a fixed array in Charlotte is 11% lower than the average annual output of PV systems in Sacramento, Los Angeles, Phoenix, and Boulder. LBNL reports capacity factors for utility-scale solar projects in the U.S. Southeast that are about 20% lower than in the western U.S.[41] As a result, the LBNL data needs to be adjusted upwards to estimate potential wholesale solar PPA prices in North Carolina. Adjusting the LBNL 2012 - 2013 range of solar PPA prices ($55 to $75 per MWh) upward by 25% to reflect the North Carolina capacity factors are 20% lower than in the western U.S., and placing somewhat greater emphasis on the most recent 2013 data, yields a range of $70 to $90 per MWh (7 to 9 cents per kWh), which we believe to be a reasonable, current range for the cost of wholesale solar PPAs in North Carolina.[42]

3.2 Solar DG Costs – Lost Revenues

The primary costs of solar DG are the retail rate credits provided to solar customers through net metering, i.e. the revenues that the utility loses as a result of DG customers serving their own load and exporting power to the grid when the solar output exceeds the on-site load. The lost revenues are dependent on the utility's retail rate design, and can vary considerably based on the rate structure. Solar DG customers are primarily able to avoid volumetric, per kWh rates. They are much less able to avoid demand charges, and of course cannot avoid fixed monthly charges that do not depend on usage.

North Carolina utilities have a variety of retail rate structures. Residential rates consist largely of a single volumetric rate, with some seasonal (summer / winter) differentiation, plus a significant fixed monthly charge. DEP's residential solar customers must use a time-of-use rate with a demand charge (R-TOUD) in order to qualify for an incentive under DEP's SunSense program. Small commercial rates feature a declining block structure, such that the average rate decreases as usage goes up. Large industrial customers pay significant demand charges and time-of-use energy rates.

We have assumed that the lost revenues from residential solar DG are based on the customer's volumetric rate for the marginal usage served by the solar unit, and assume that the solar DG customer takes service under the rate schedule with the highest volumetric rates in order to maximize bill savings under net metering. The lost revenues from a small commercial solar customer under a declining block rate will depend on the size of the solar system relative to the customer's usage; we have generally assumed that the rates for usage above the first tier represent the marginal lost revenues.

Lost revenues on a 15-year levelized basis also depend on the assumed future escalation in future rates. A recent rate case settlement approved for DEC included a near-term, three-year rate increase averaging 1.7% per year.[43] EIA data shows that electric rates in North Carolina over the 20 year period from 1992 - 2011 increased at 1.4% per year. We have calculated a range of lost revenues based on future rate escalations from 1.0% to 2.5% per year. These results are shown in **Table 11**.

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[40] *Ibid.*, at 22.
[41] *Ibid.*, at Figure 11.
[42] Of course, this range of PPA prices all assume the availability of federal and state tax credits at 2013 levels.
[43] See http://www.duke-energy.com/north-carolina/nc-rate-case.asp.

3.3 Integration Costs

Finally, several utilities have completed studies on solar integration costs. A recent study which Arizona Public Service commissioned estimated integration costs of $2 per MWh in 2020 and $3 per MWh in 2030.[44] Xcel Energy in Colorado has calculated solar integration costs as $1.80 per MWh on a 20-year levelized basis.[45] Based on the high end of the range in these studies, we have added an assumed solar integration cost of $3 per MWh (0.3 cents per kWh).

Table 11 summarizes all of these costs of solar DG for North Carolina ratepayers.

Table 11: *Costs of Residential and Commercial Solar DG (15-year levelized cents / kWh)*

Class	DEC	DEP	DNCP
Lost Revenues			
Residential	9.8 – 10.7	10.5 – 11.5	10.1 – 11.0
Commercial	7.7 – 8.4	9.7 – 10.6	8.7 – 9.4
Integration	0.3	0.3	0.3
Total Costs			
Residential	**10.1 – 11.0**	**10.8 – 11.8**	**10.4 – 11.3**
Commercial	**8.0 – 8.7**	**10.0 – 10.9**	**9.0 – 9.7**

4. Conclusion

The benefits of solar generation in North Carolina equal or exceed the costs of this source of renewable generation. This conclusion is valid regardless of whether solar is developed as wholesale generation with the entire output sold to the utilities or as demand-side distributed generation under net metering. The quantitative results of our work are summarized in Tables 2 and 3. If one uses the midpoints of the ranges of costs and benefits shown in these tables, the benefits of wholesale solar exceed the costs by about 40% (a benefit / cost ratio of 1.43), and the benefits of solar DG are almost 30% larger than the costs (a benefit / cost ratio of 1.28). Over the next several years, if North Carolina utilities were to add 400 MW of wholesale solar and 100 MW of solar DG resources, the net benefits for ratepayers would be $26 million per year.

44 Black & Veatch, "Solar Photovoltaic (PV) Integration Cost Study" (B&V Project No. 174880, November 2012).

45 Xcel Energy Services for Public Service Company of Colorado, "Cost and Benefit Study of Distributed Solar Generation on the Public Service Company of Colorado System" (May 23, 2013), at Table 1, pages v and 41-42.

Crossborder Energy

Comprehensive Consulting for the North American Energy Industry

The Benefits and Costs of Solar Generation for Electric Ratepayers in North Carolina

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October 18, 2013

EXHIBIT

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The Benefits and Costs of Solar Generation for Electric Ratepayers in North Carolina

This report provides an independent analysis of the benefits and costs of solar photovoltaic (PV) generation for electric ratepayers in the service territories of the major electric utilities in North Carolina – Duke Energy Carolinas (DEC), Duke Energy Progress (DEP), and Dominion North Carolina Power (DNCP). North Carolina Sustainable Energy Association asked Crossborder Energy to apply to the three North Carolina utilities the same approach to analyzing the benefits and costs of solar generation which we have used in similar studies in other states.[1]

This report identifies the benefits and costs of solar for both (1) wholesale utility-scale solar projects whose output is sold to the utilities and (2) solar distributed generation (solar DG or demand-side solar) installed on a customer's premises behind the customer's utility meter. This study explains which of the benefits of solar generation apply to both wholesale and demand-side solar, and which are limited to one of these different types of solar resources. On the cost side, it is important to recognize that wholesale solar and solar DG result in different types of costs for utility ratepayers. The ratepayer costs of wholesale solar are principally the capital and O&M costs of utility-scale solar generation, which the utility will pay directly through a power purchase contract with the solar project. In contrast, the customer who installs solar DG bears the capital and operating costs of the solar resource. With solar DG, the costs to other, non-participating ratepayers are principally the revenues which the utility loses as a result of the output of solar DG serving the customer's on-site load, plus the energy credits which the utility provides, through net energy metering, when the solar customer exports power to the grid. These exports serve the loads of nearby retail customers. The utility may also provide incentive payments to solar DG customers. Finally, both wholesale and demand-side solar may cause the utility to incur new costs to integrate intermittent solar generation into the grid. **Table 1** summarizes the principal costs and benefits of both wholesale solar and solar DG.

Table 1: *Benefits and Costs of Solar Generation for North Carolina Ratepayers*

Benefits	Wholesale Solar	Solar DG
Energy	✓	✓
Generation capacity	✓	✓
Transmission	✓ (≤ 5 MW)	✓
Distribution		✓
Avoided Emissions	✓	✓
Avoided Renewables	✓	✓
Costs		
Capital and operating costs	✓	
Lost retail rate revenues		✓
DG incentives		✓
Integration costs	✓	✓

[1] See "The Benefits and Costs of Solar Distributed Generation for Arizona Public Service" (May 2013), available at http://www.seia.org/research-resources/benefits-costs-solar-distributed-generation-arizona-public-service. Also, "Evaluating the Benefits and Costs of Net Energy Metering in California" (January 2013), available at http://votesolar.org/wp-content/uploads/2013/01/Crossborder-Energy-CA-Net-Metering-Cost-Benefit-Jan-2013-final.pdf .

In assessing the benefits and costs of solar generation from a utility ratepayer perspective, it is important to use a long-term time frame which recognizes that solar PV systems have useful lives of 20 to 30 years. A long-term perspective is also necessary to treat demand-side solar on the same basis as other supply- or demand-side resources. When a utility assesses the merits of adding a new power plant, or a new energy efficiency program, the company will look at the costs to build and operate the plant or the program over their useful lives, compared to the costs avoided by not operating or building other resource options. Solar DG should be evaluated over the same long-term time frame.

Solar generation can be installed at a wide range of scales, from a system serving a single home to utility-scale plants. Solar is feasible in a greater diversity of locations than other renewable technologies such as wind and hydro. Solar also can be installed with shorter lead times and on a wider variety of sites than conventional, large-scale fossil generation resources. Solar can combine with other small-scale, short-lead-time, demand-side resources, such as energy efficiency (EE) and demand response (DR) programs, to reduce a utility's need for supply-side generation, both in the near- and long-terms. An analysis of the benefits of solar should recognize its scalability and short lead times, by acknowledging that solar and demand-side programs combine to continuously avoid the need for supply-side resources, without the "lumpiness" associated with a conventional utility-scale power plant. Accordingly, we evaluate the benefits of solar based on the change in a utility's costs per unit of solar installed, without requiring solar to be installed in the same large increments as conventional fossil or nuclear generation.

This report relies on data from the North Carolina utilities' latest integrated resource plans (IRPs), supplemented with data from recent avoided cost proceedings and general rate cases. We also have used a limited amount of current data from the regional gas and electric markets in which the North Carolina utilities operate. This work relies to the greatest extent possible on public data and on transparent calculations of the benefits and costs. Our intent in using public data and transparent methodologies is to minimize debates over the input assumptions and to reduce reliance on opaque models. We agree with the Rocky Mountain Institute's recent meta-analysis of solar DG cost / benefit studies, which concluded that "in any benefit/cost study, it is critical to be transparent about assumptions, perspectives, sources and methodologies so that studies can be more readily compared, best practices developed, and drivers of results understood."[2] Where there is debate over certain benefits or costs of solar, we have provided ranges that we believe span the likely range of benefits or costs.

Our work concludes that the benefits of solar generation in North Carolina equal or exceed the ratepayer costs of solar resources, such that new solar resources will provide economic benefits for electric ratepayers in the state. The following **Tables 2 and 3** summarize our results, for wholesale solar and solar DG, respectively. The benefits of wholesale solar typically exceed the costs, even if one does not include the environmental benefits of mitigating carbon emissions. The costs of net metered solar DG for non-participating residential customers are at the low end of the range of benefits, while the benefits of solar DG exceed the costs in the commercial market, where marginal retail rates are lower. These results indicate that North Carolina ratepayers generally would benefit from the continued availability of net metering.

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[2] Rocky Mountain Institute. "A Review of Solar PV Benefit and Cost Studies" July 2013, at page 5. http://www.rmi.org/Knowledge-Center/Library/2013-13_eLabDERCostValue.

Based on the midpoints of the ranges of costs and benefits shown in Tables 2 and 3, the benefits of wholesale solar are 40% larger than the costs, and the benefits of solar DG are 30% greater. Were the North Carolina utilities to add 400 MW of wholesale solar and 100 MW of solar DG resources, the net benefits for ratepayers would be $26 million per year.

Table 2: *Benefits and Costs of Wholesale Solar (15-year levelized cents/kWh - 2013 $)*

Benefits	**DEC**	**DEP**	**DNCP**
Energy (includes line losses)	5.7 – 6.5	5.5 – 6.3	5.8 – 6.6
Generation capacity	1.9 – 3.2	2.1 – 3.2	2.6 – 3.6
Transmission capacity (< 5 MW)	0 – 1.0	0 – 0.7	0 – 0.9
Avoided Emissions	0.4 – 2.2	0.4 – 2.2	0.4 – 2.2
Avoided Renewables	1.0 – 2.0	1.0 – 2.0	1.0 – 2.0
Total Benefits	**9.0 – 14.9**	**9.0 – 14.4**	**9.8 – 15.3**
Costs			
Capital and O&M (All-in PPA)	7.0 – 9.0	7.0 – 9.0	7.0 – 9.0
Integration	0.3	0.3	0.3
Total Costs	**7.3 – 9.3**	**7.3 – 9.3**	**7.3 – 9.3**

Table 3: *Benefits and Costs of Solar DG (15-year levelized cents/kWh - 2013 $)*

Benefits	**DEC**	**DEP**	**DNCP**
Energy (includes line losses)	5.7 – 6.5	5.5 – 6.3	5.8 – 6.6
Generation capacity	2.2 – 3.7	2.4 – 3.7	3.0 – 4.1
Transmission capacity	1.0	0.7	0.9
Distribution capacity	0.2 – 0.5	0.2 – 0.5	0.2 – 0.5
Environmental	0.4 – 2.2	0.4 – 2.2	0.4 – 2.2
Avoided Renewables	0.1 – 2.2	0.1 – 2.2	0.1 – 2.2
Total Benefits	**9.6 – 16.1**	**9.3 – 15.6**	**10.4 – 16.5**
Costs			
Lost Revenues			
Residential	9.8 – 10.7	10.5 – 11.5	10.1 – 11.0
Commercial	7.7 – 8.4	9.7 – 10.6	8.7 – 9.4
Integration	0.3	0.3	0.3
Total Costs			
Residential	**10.1 – 11.0**	**10.8 – 11.8**	**10.4 – 11.3**
Commercial	**8.0 – 8.7**	**10.0 – 10.9**	**9.0 – 9.7**

1. Methodology

Solar DG is a long-term source of electric generation that uses a renewable resource. New solar systems will provide benefits for North Carolina ratepayers for the next 20 to 30 years. Data to perform a long-term (15-year) assessment of these benefits is available from utility avoided cost filings, from recent IRPs and general rate cases, and from market data. The core of this study is the calculation of 15-year levelized benefits and costs for solar resources on the DEC, DEP, and DNCP systems.

1.1 Benefits.

We briefly describe our approach to calculating each of the benefits of solar generation in North Carolina.

- **Energy.** DEC, DEP, and DNCP have currently-effective 15-year avoided energy prices in the range of 4.5 – 5.0 c/kWh for a base load profile, based on production cost modeling of their incremental energy costs over the next 15 years. These avoided energy rates are currently under review in North Carolina Utilities Commission (NCUC) Docket No. E-100, Sub 136. As these production cost models are confidential, we have separately projected 15-year avoided energy costs using a more transparent approach, based on natural gas forward market data, combined with the heat rates, variable O&M costs, and other operating parameters of the long-term fossil resources that solar generation will avoid. Other similar studies have taken a comparable approach to calculating long-term avoided energy costs.[3] We also have considered whether avoided energy costs should be adjusted to reflect the costs which some utilities have incurred to hedge the volatility in their natural gas costs. Finally, avoided energy costs should consider the daily profile of solar generation, which peaks during the early afternoon, making it a more valuable resource than a constant, "flat" profile in all daylight hours.

- **Generating Capacity.** The North Carolina utilities calculate 15-year avoided capacity prices under the assumption that a new combustion turbine (CT) is the least-cost source of new generating capacity. This is commonly called the "peaker" method. Although the details of these calculations are confidential, there is public data on CT costs in nearby markets which can be used to review filed capacity prices. The capacity value of solar, per unit of output, also must consider both the peaking profile of solar generation as well as its variability. Utilities and control area operators in the U.S. have developed well-accepted methods to value the contribution of solar PV resources to capacity resources. In North Carolina, the utilities appear to value solar's capacity at 40% to 50% of its nameplate capacity, comparable to the valuation adopted by the nearby PJM system.

- **Transmission Capacity.** The output of solar DG primarily serves on-site loads and never touches the grid, thus clearly reducing loads on the transmission grid. Given the penetration levels of solar DG on the system today, the power exported from solar DG

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3 This is generally the approach taken in the avoided cost calculator that California Public Utilities Commission (CPUC) has approved for cost-effectiveness analyses of demand-side programs in California, including solar DG. See, generally, CPUC Decision 09-08-026. Energy and Environmental Economics (E3) has developed the avoided cost calculator under contract to the CPUC. See http://www.ethree.com/public_projects/cpuc5.php. The DG version of the model is titled "DERAvoidedCostModel_v3.9_2011 v4d.xlsm."

units is entirely consumed on the distribution system by the solar customer's neighbors, again unloading transmission capacity. Thus, much like energy-efficiency and demand response resources, solar DG can avoid transmission capacity costs, but only to the extent that solar is producing during the peak demand periods that drive load-related transmission investments. As DEC itself notes in describing its utility-owned solar DG program: "Power is produced at the site, reducing the need for extensive transmission lines or a complex infrastructure."[4] Wholesale solar facilities interconnected at the distribution level – typically, projects at or below 5 MW in size – also can avoid transmission capacity costs to the extent that their output is consumed on the distribution system and produces minimal impacts on the upstream transmission grid.

We understand that there has been debate in North Carolina over the magnitude of the avoided T&D benefits attributable to EE and DR programs, with the debate centering on the extent to which T&D costs are load-related. We calculate long-term marginal transmission costs for DEC and DEP using an approach that considers only load-related transmission. Our method uses a regression of each utility's historical and forecasted transmission investments as a function of load growth, to determine the change in these costs as a function of increases in peak demand. This is a longstanding methodology used by many utilities to determine marginal, load-related transmission costs.

- **Distribution Capacity.** Whether solar generation avoids distribution capacity is a more complex question than transmission capacity, for several reasons. First, distribution substations and circuits can peak at different times than the system as a whole, complicating the calculation of whether solar can reduce distribution system peaks. Second, the timing of load-related distribution expansions is location-specific, and many utilities do not know where or when solar DG will be developed. Third, the time frames for utility distribution plans often is only 3-5 years into the future, providing only limited insight into the impact of distributed solar resources with 20-year lives. Finally, larger solar facilities may require distribution upgrades to accept their output, although the costs of such upgrades usually are the responsibility of the solar project. Nonetheless, studies using a variety of techniques have identified at least a modest amount of avoided capacity-related distribution costs resulting from the installation of solar DG.

- **Line Losses.** New solar generation reduces losses on the margin, and marginal line losses are significantly higher than average losses. The North Carolina utilities state that they use marginal transmission loss factors in their avoided energy costs. However, solar facilities produce power during daylight hours over which system loads, and system losses, are above-average. In addition, solar DG can avoid distribution losses. Thus, the current loss factors in avoided cost prices are likely to understate the line loss benefits of solar generation.

- **Avoided Emissions.** The North Carolina utilities' avoided cost calculations appear to include the costs of emission allowances associated with criteria pollutants, but not of carbon dioxide (CO_2). However, the IRPs of the Duke utilities recognize the potential long-term need to reduce CO_2 emissions – for example, by maintaining an option to add

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[4] See "What are some advantages of solar energy?" http://www.duke-energy.com/north-carolina/renewable-energy/nc-solar-distributed-generation-program-FAQs.asp

nuclear generation – and include a base case CO_2 emission cost of $17 per ton in 2020, escalating to $44 per ton in 2032.[5] Accordingly, a long-term projection of the benefits of solar generation should recognize the value of these resources in mitigating carbon pollution. Given the uncertainty in the timing and magnitude of these costs, we have calculated a range of benefits from avoided CO_2 emissions.

- **Avoided Renewables Costs.** Bundled wholesale solar sold to the North Carolina utilities contributes to their compliance with state's Renewable Energy and Energy Efficiency Portfolio Standard (REPS) requirements, both today and in future years when those requirements will increase. The measure of the value of this compliance is the cost for an unbundled renewable energy certificate (REC) in North Carolina. If developers did not invest in wholesale solar systems and then sell the resulting RECs to the utility, of if solar DG customers did not invest in on-site solar and then sell or transfer their RECs, the utilities would have to make their own investments in renewable generation, presumably at a higher cost than the RECs available from developers and solar DG customers.

Public data is not widely available in North Carolina on the cost of unbundled RECs today. We have estimated such costs based on a range of data, including (1) recent reports on a solar REC purchase by a municipal utility, (2) the utilities' reported 2012-2014 incremental costs associated with their compliance with the REPS requirement, and (3) cost premiums for green pricing programs in North Carolina.

We assume that this category of avoided costs encompasses a number of the difficult-to-quantify benefits of renewable generation that are embodied in the attributes of a REC, including:

- o **Fuel Diversity.** Renewables generally have zero fuel costs (with the possible exception of some types of biomass), and present a different set of operating risks (lower capacity factors and intermittency) than conventional fossil resources. As a result, an increasing penetration of renewables will diversify a utility's fuel sources and resource mix, and reduce the risks of reliance on a small set of generation technologies.
- o **Price mitigation benefits.** Solar DG reduces the demand for electricity (and for the gas used to produce the marginal kWh of power). These reductions have the broad benefit of lowering prices across the gas and electric markets in North Carolina, to the benefit of all ratepayers. This benefit is also known as the "demand reduction induced price effect" (DRIPE), and has been quantified in several regions of the U.S.
- o **Grid security.** Renewable DG resources are installed as many small, distributed systems and thus are highly unlikely to fail at the same time. They are also located at the point of end use, and thus reduce the risk of outages due to transmission or distribution system failures. This reduces the economic impacts of power outages.
- o **Economic development.** Renewable DG results in more local job creation than fossil generation, enhancing tax revenues.

5 DEC 2012 IRP, at Appendix A, p. 106.

1.2 Costs

The ratepayer costs for wholesale solar are the payments that the utilities will make to purchase solar generation under long-term power purchase agreements (PPAs). We estimate these costs using available data on the recent trends in the prices in PPAs for utility-scale solar projects. For solar DG, the principal costs are the revenues which the North Carolina utilities will lose from customers serving their own load with on-site solar, including the credits provided under net metering when solar generation is exported to the grid. We estimate the lost revenues for the rate schedules on which many solar customers take service. Finally, we include an estimate of the costs of additional operating reserves needed to integrate intermittent solar generation into the grid. We are not aware that any of the North Carolina utilities have performed and publicly-disclosed a solar integration study specific to their systems, so we use a typical value from utility-sponsored integration studies in other states.

The following sections discuss in more detail each of the benefits and costs of solar DG on the DEC, DEP, and DNCP systems. As noted above, solar is a long-term resource with an expected useful life of at least 20 years. Accordingly, when we calculate the benefits and costs of DG over a 15-year period, the result is a conservative estimate of the value of these long-term resources. We express our results as 15-year levelized costs using a discount rate of 7.7%.[6]

2. Benefits of Solar DG

2.1 Energy

The North Carolina utilities' 2012 resource plans make clear that, to meet near- and intermediate-term growth, the utilities will rely on energy efficiency and demand-side resources, renewable purchases to meet North Carolina's REPS standard, and new efficient natural gas-fired generation, with the possibility of adding new nuclear generation in the post-2020 time frame. In these plans, gas-fired generation is the predominant marginal resource, so if North Carolina utilities were to increase their procurement of wholesale or distributed solar resources, the resources likely to be displaced would be new gas-fired generation.

Accordingly, we would expect the utilities' long-term, 15-year avoided cost energy prices to reflect the energy costs of relatively efficient gas-fired generation resources. DEC's, DEP's and DNCP's current 15-year levelized avoided energy prices are in the range of 4.5 to 5.0 c/kWh. As a check on these values, we first developed a 15-year natural gas cost forecast for gas-fired generation in North Carolina. This forecast uses recent forward gas price data from the NYMEX Henry Hub market plus a market differential from the Henry Hub to Zone 5 on the Transco pipeline. Based on this gas cost forecast, we estimated the marginal heat rates over the next 15 years that would produce the utilities' current 15-year avoided energy costs. These marginal heat rates are about 9,000 Btu per kWh today, declining to about 7,500 Btu/kWh in 2027. These heat rates are reasonably representative of the efficient combined-cycle and gas turbine units that the North Carolina utilities expect to add over this period.

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6 This is average of DEC's and DEP's currently-authorized weighted average costs of capital, from these utilities' most recent general rate case decisions. See the May 30, 2013 NCUC order in Docket No. E-2, Sub 1023, at 11 (for DEP) and the September 24, 2013 NCUC order in Docket No. E-7, Sub 1026 at 10 (for DEC). For DNCP, we use the same 8.5% discount rate which the utility used in its most recent public avoided cost filing.

Renewable generation has no fuel costs and thus avoids the volatility associated with generation sources whose cost depends principally on fossil fuel prices. Our gas cost forecast is based on forward market natural gas prices; thus, it represents a cost of gas that the North Carolina utilities theoretically could fix for the next 15 years, thus in principle capturing the fuel price hedging benefit of renewable generation. However, such a hedging strategy may not be cost-less; for example, in 2011-2012 DEP incurred $121 million in above-market costs to hedge one-half of its 163 Bcf of gas purchases, a cost premium of $0.74 per MMBtu when spread over the utility's full portfolio of gas purchases. From the customer's perspective, DEP's financial hedges effectively increased the price of each MMBtu consumed by $0.74. These hedging costs are not included in current avoided cost prices. We include such costs to develop the high end of our range of avoided energy benefits; the low end of our range is the utilities' filed 15-year avoided energy costs, adjusted as described below to reflect the hourly profile of solar output.

North Carolina avoided cost prices are differentiated into on- and off-peak prices, and also can vary seasonally by peak vs. off-peak months. This differentiation captures some, but not all of the hourly variation in the energy benefits of solar. What is missing is the likelihood that the diurnal profile of solar output will have a higher value than a flat block of on-peak power, because solar output peaks in the early afternoon hours and produces significant power in the mid-afternoon hours of peak demand. We are able to assess the hourly value of solar directly for DCNP, because it operates in the PJM market with visible hourly locational marginal prices (LMPs). DNCP's solar-weighted avoided cost energy price is 14% higher than the annual average avoided cost energy price for a baseload profile.[7] We have applied the same premium to the average, base load avoided cost energy prices for DEC and DEP, as a reasonable estimate of the time-varying energy value of solar in North Carolina. **Table 4** summarizes the avoided energy value of solar generation for the three utilities.

Table 4: *Avoided Energy Value of Solar (15-year levelized, $ per kWh, 2013$)*

Component	DEC	DEP	DNCP
Avoided Energy Costs	5.7	5.5	5.8
Hedging Costs	0.8	0.8	0.8

2.2 Generation Capacity

The North Carolina utilities use the annualized fixed costs of a new combustion turbine as the measure of avoided capacity costs – the standard "peaker" method. **Table 5** shows the annualized CT capacity costs now embedded in the utilities' current 15-year avoided capacity prices, assuming that a resource operates at an 83% capacity factor.[8] The detailed CT capital cost and financing data used to set these current avoided cost prices are confidential, so we "back into" the CT fixed capacity costs in Table 5 for the three utilities by multiplying (1) the currently-effective avoided capacity credit times (2) the number of hours per year in the time period in which the capacity credit is paid, times (3) the 83% capacity factor. The table also shows other relevant, public sources of data on CT fixed costs.

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7 In comparison, DEC's Option A avoided cost prices for an average solar profile in Charlotte are 4% higher than the annual average price for a base load profile.

8 Based on the 1.2 "performance adjustment factor" used to calculate these prices.

Table 5: *Annualized CT Fixed Capacity Costs (Distribution Voltage)*

Source	CT Fixed Capacity Cost *($/kW-year)*	Range *($/kW-year)*
DEC	$57	$57 - $104
DEP	$65	$65 - $104
DNCP	$75	$75 - $108
PJM Net CONE, Area 5	$108	
EIA, *AEO13*, Advanced CTs[9]	$100	

There is ongoing litigation in North Carolina concerning QF capacity prices, with parties challenging the utilities' filed and currently-effective capacity credits. Accordingly, we use a range for the value of avoided generating capacity, as shown in the third column of Table 5. At the low end of the range for DEC and DEP, we use the currently-filed utility values; at the high end, we average the public, transparent PJM and EIA data. For DNCP, as it is on the PJM system, we use the utility's filed cost as the low end, and the PJM values as the high end.[10]

We make three adjustments to these CT-based capacity values. First, we add the fixed reservation charges for firm transmission on the Transco interstate pipeline to provide the new gas-fired capacity with a firm gas supply, to the extent that these reservation charges exceed a typical market-based "basis" differential in natural gas prices between the U.S. Gulf Coast and North Carolina. In the long-run, natural gas pipelines need to be able to recover their full cost of service. Second, we assume that behind-the-meter solar DG will be reflected in utility planning as a reduction in peak demand. Accordingly, solar DG also will reduce each utility's capacity need by an additional amount equal to the required reserve margin (15%) times the effective solar capacity.

Third, a calculation of the capacity value of solar resources must recognize that solar is a resource whose availability depends on weather and the time of the day. Although peak solar output typically occurs in the early afternoon when demand is relatively high, the peak output does not correlate perfectly with the utility's peak demand, which tends to occur later in the afternoon. As a result, solar does not provide 100% of its nameplate capacity to the grid as reliable generating capacity.

Utilities and control area operators in the U.S. generally use one of two approaches to determine the effective capacity provided by a solar resource. The most complex, and often considered to be the most rigorous, approach is the Effective Load Carrying Capacity (ELCC) method. This approach uses a production simulation model of the electric system in question to determine how much load a kW of solar capacity can "carry" without a diminution in reliability. Thus, if 100 MW of solar generation provides the same level of reliability when it replaces 50 MW of a reference resource (such as a CT), the ELCC of the solar resource is 50 MW / 100 MW = 50%. ELCC analyses require computer models which are complex and expensive to license and run, and which are not transparent except to the analysts who run them. They also require hourly data on

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[9] EIA data on CT costs is from http://www.instituteforenergyresearch.org/wp-content/uploads/2009/05/2.15.13-IER-Web-LevelizedCost-MKM.pdf at page 3. Includes levelized fixed costs, fixed O&M, and associated transmission investments. 2011 $ are escalated to 2013 $ at 2.5% per year.

[10] For the high case, we use PJM RPM clearing prices for capacity through 2016, and its Net Cost of New Entry (CONE) thereafter.

loads and solar output which are correlated in time. As a result of the limitations and complexities of ELCC analyses, most control area operators in the U.S. use the simpler and more transparent "capacity factor" approach to setting the capacity value of intermittent renewable resources. This method sets the capacity value of the renewable resource based on its demonstrated capacity factor during certain critical hours of peak demand. For example, Appendix B of PJM's Manual 21 specifies that the capacity value of a solar resource should be calculated based on its summer (June-August) capacity factor during the hours ending 3-6 p.m.[11] For a solar profile for Norfolk, Virginia, the PJM Manual 21 method yields capacity values of 46% of nameplate for a fixed array and 58% of nameplate for a single-axis tracking system.

In their IRPs, the North Carolina utilities appear to assume that a solar resource's capacity value is 40% to 50% of its nameplate, consistent with the PJM capacity factor valuation for fixed arrays. DEC and DEP have confirmed in non-confidential data responses in the NCUC avoided cost docket that their 2013 IRPs value solar at 42% of nameplate. They also assume that solar operates at a 17.4% capacity factor.[12]

Table 6 shows our final calculation of the range of benefits that solar provides from avoiding the need for generation capacity, over a 15-year period. We add the CT fixed costs and pipeline reservation costs, multiply the total by the 42% contribution of solar to reducing peak demand, then divide by the typical output of a solar resource in North Carolina (1,524 kWh per kW per year based on the 17.4% capacity factor). The resulting avoided generation capacity costs, in dollars per MWh, are shown in the table below, for the range of CT fixed costs in Table 5. Finally, we observe that behind-the-meter solar DG, unlike wholesale solar, reduces the utility's peak demand. As a result, solar DG also reduces the utility's capacity requirements to meet its reserve margin, which is about 15% for the North Carolina utilities. Thus, for solar DG we increase the avoided generation capacity value by 15% above the numbers shown in Table 6.

Table 6: *Avoided Generation Capacity Value ($ per kW-yr in 2013$)*

Component	DEC		DEP		DNCP	
	Low	High	Low	High	Low	High
CT Fixed Costs	57	104	65	104	75	108
Pipeline Reservation	12	12	12	12	12	12
Total	69	116	77	116	87	120
Solar Capacity as % of Nameplate	42%	42%	42%	42%	46%	46%
Solar Capacity Value *($ per kW-yr)*	29	49	32	49	40	55
Annual Output *(kWh / kW)*	1,524	1,524	1,524	1,524	1,524	1,524
Solar Capacity Value *(cents per kWh)*	1.9	3.2	2.1	3.2	2.6	3.6

11 *See* http://www.pjm.com/documents/manuals.aspx .

12 DEC and DEP response to NCSEA Data Request No. 4, Item 4-15 in Docket No. E-100, Sub 136.

2.3 Transmission Capacity

Most, if not all, solar DG output is either consumed behind the meter or on the distribution system by the neighbors of the DG system, and never touches the transmission system. Solar DG thus reduces the use of the transmission system, and will reduce peak demands on the transmission system even if solar output and peak demand are not perfectly correlated. This benefit is similar to the benefit of other demand-side programs in avoiding transmission and distribution (T&D) capacity-related costs.

North Carolina utilities include avoided capacity-related T&D costs in assessing the costs and benefits of EE and DR programs. However, the methodology used to calculate these avoided costs is not public and we are aware that there is debate over the magnitude of these avoided costs. In particular, the NC Public Staff have questioned whether DEC's assumed avoided T&D costs are too high because they include transmission costs that are reliability-related, and thus not driven by load increases.[13]

There is a well-accepted way to address this debate. We have calculated DEC's and DEP's long-term marginal transmission capacity costs using the industry-standard NERA regression method used by many utilities to determine their marginal T&D capacity costs which are load-related.[14] **Figure 1** shows, for DEC, the regression fit of cumulative transmission capital additions as a function of incremental demand growth. We convert the regression slope of $438 per kW using a real economic carrying charge of 7.41%, and add loaders for general plant and transmission O&M costs based on FERC Form 1 data. Our estimate of annualized marginal transmission costs for DEC is $37.45 per kW-year.

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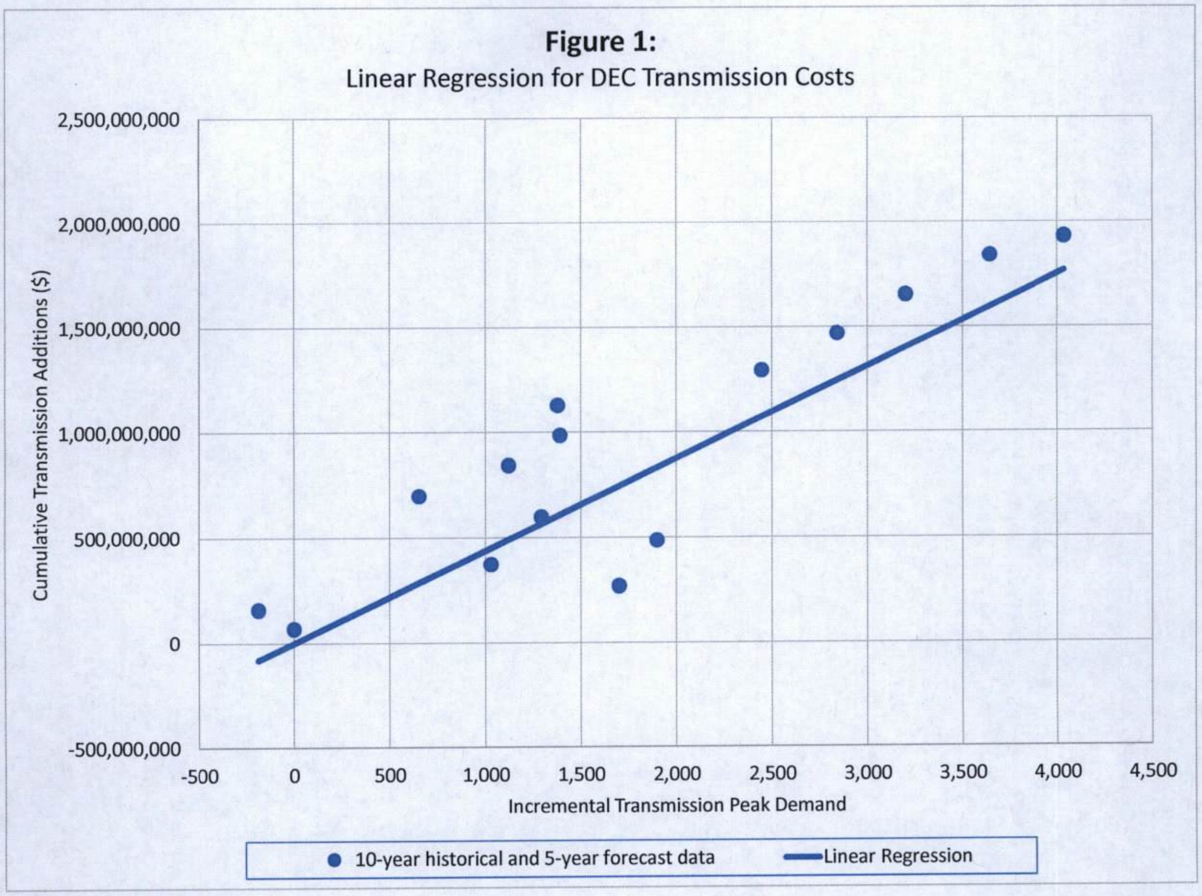
[13] See NC Public Staff witness Robert Hinton testimony in Docket E-7, Sub 1032 pre-filed on August 7, 2013. http://ncuc.commerce.state.nc.us/cgi-bin/webview/senddoc.pgm?dispfmt=&itype=Q&authorization=&parm2=TBAAAA02231B&parm3=000141791 .

[14] The NERA regression model fits incremental transmission costs to demand growth. The slope of the resulting regression line provides an estimate of the marginal cost of transmission associated with a change in load. The NERA methodology typically uses 10-15 years of historical expenditures on transmission and peak transmission system load, as reported in FERC Form 1, and a five-year forecast of future expenditures and load growth. Crossborder's analysis used DEC's FERC Form 1 data for the most recent 10 years (2003-2012), and a forecast of T&D project costs over the five future years (2013-2017) based on data from DEC's most recent general rate case (Docket E-7 Sub 1026, E-1 Data Item 23b). Future T&D project costs are allocated between transmission and distribution based on the historical division between these categories. Peak demand data is from Docket E-7, Sub 1026, E-1 Data Item 43a.



Transmission system peaks tend to coincide with system demand peaks, and thus we assume that solar's contribution to reducing transmission system peaks is the same as its contribution to avoided demand for generating capacity. Thus, we assume that each kW of solar DG capacity reduces DEC's peak transmission demand by 0.42 kW, and we convert avoided transmission capacity costs to dollars per MWh of solar DG output assuming an average annual output of 1,524 kWh per kW-AC. **Table 7** shows this calculation. The result for DEC is $10 per MWh (1.0 cents per kWh) for the transmission capacity costs avoided by solar DG; a parallel calculation for DEP yields avoided transmission capacity costs of 0.7 cents per kWh.

Table 7: *Calculation of Transmission Capacity Costs Avoided by Solar DG*

Component	DEC	DEP	*Units*
Marginal Transmission Capacity Cost (2014 $)	37	27	*per kW-year*
Solar Capacity as % of Nameplate	42%	42%	
Transmission Capacity Costs Avoided	16	11	*per kW-year*
Annual PV Output per kW-DC	1,524	1,524	*kWh per year*
Generation Capacity Cost Avoided by DSG	1.0	0.7	*cents / kWh*

As a check on this calculation, we have looked at DEC's filed avoided T&D benefits for several of its DR programs. These programs principally provide capacity benefits, and the avoided T&D portion of the benefits average about 40% of the generating capacity benefits. We understand that DEC and North Carolina Public Staff recently stipulated to the use of these T&D

benefits.[15] This level of T&D benefits is broadly consistent with our avoided transmission capacity costs in Table 7 compared to the avoided generation capacity benefits that we determined in Table 6.

Our approach for DNCP is different, given that DNCP is on the PJM system. For DNCP, we use the PJM rate for network integrated transmission service (the NITS rate), as a more direct measure of the costs which Dominion can avoid if solar reduces DNCP's peak demand on the PJM grid. As with avoided generation capacity costs, we apply the PJM solar capacity value percentage (46% of nameplate) to the avoided transmission costs, in recognition that peak solar output does not necessarily coincide with system peak demands. The resulting avoided transmission cost for DNCP is 0.9 cents per kWh.

2.4 Distribution

Solar DG also can reduce peak loads on distribution circuits, and thus avoid or delay the need to upgrade or re-configure the circuit if it is approaching capacity. However, circuits and substations on the distribution system can peak at different times than the system as a whole, which complicates the assessment of the extent to which solar DG can avoid or defer distribution capacity upgrades. As DG penetration grows, and a deeper understanding is gained of the impacts of DG on distribution circuit loadings, we anticipate that utility distribution planners will integrate existing and expected DG capacity into their planning, enabling DG to avoid or defer distribution capacity costs.[16] A comparable evolution has occurred over the last several decades, as the long-term impacts of EE and DR programs are now incorporated into utilities' capacity expansion plans for generation, transmission, and distribution, and it is generally recognized that these demand-side programs can help to manage demand growth even though the specific locations where these resources will be installed are difficult to predict.

The available studies which quantify the distribution capacity costs avoided by solar generation generally have calculated relatively modest values. **Table 8** below lists some of the studies which have calculated avoided distribution capacity costs. The most recent study, performed for the California Public Utilities Commission by the E3 consulting firm, based its calculations on marginal distribution costs in California and the correlation between solar output and distribution substation peaks. This study used data on distribution substation loads that is not typically available. Based on these studies, a reasonable range for avoided distribution capacity costs is 0.2 to 0.5 cents per kWh.

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[15] See the settlement filed August 19, 2013 in NCUC Docket E-7, Sub 1032, at page 6.

[16] A public summary of a confidential report on solar's modeled impacts on the DEC distribution system indicates that solar DG can also provide benefits such as voltage support and reduced line losses on feeder circuits, and that the value of solar along a circuit varies with proximity to the substation, load centers and other factors. See DEC witness Jonathan Byrd testimony in Docket E-7, Sub 1034, in the September 17, 2013 hearing transcript at p. 77-80 at http://ncuc.commerce.state.nc.us/cgi-bin/webview/senddoc.pgm?dispfmt=&itype=Q&authorization=&parm2=PAAAAA36131B&parm3=000141801. See the report summary filed as exhibit 4 to DEC witness Jonathan Byrd's testimony pre-filed on March 13, 2013 at http://ncuc.commerce.state.nc.us/cgi-bin/webview/senddoc.pgm?dispfmt=&itype=Q&authorization=&parm2=KAAAAA47031B&parm3=000141801 (beginning at pdf page 44).

Table 8: *Studies of Avoided Distribution Capacity Costs*[17]

State / Study / Date	Avoided Distribution Capacity Costs *(c/kWh)*	*Source*
AZ / R.W. Beck / 2009	0 to 0.31	*Fig. 6-2 at 6-14.*
PA-NJ / Clean Power / 2012	0.1 to 0.8	*Table 4*
AZ / Crossborder / 2013	0.2	*Table 1, at 2.*
AZ / SAIC / 2013	0	*pp. 2-10 to 2-12. No savings unless solar is targeted to circuits that are close to capacity.*
CA / CPUC-E3 / 2013 *(draft released 9/26/2013)*	0.6	*Includes sub-transmission and distribution costs. Based on correlation of distribution substation peaks to solar peaks.*
CO / Xcel Energy / 2013	0.05	*Table 1, at v and 27-36.*

2.5 Line Losses

The currently effective avoided energy prices for the North Carolina utilities include line loss adjustments in the range of 2% to 3%. The utilities state that these represent their marginal transmission line losses avoided by QF generation. There are several reasons why these loss adjustments are likely to be too low. First, solar projects generate during daylight hours over which system loads, and system losses, are above-average, while the QF loss factors may reflect a baseload output profile. Second, solar DG also avoids marginal distribution losses, which can be in the 5% to 8% range. Other studies have used combined marginal T&D loss factors in the 8% to 12% range.[18] In Virginia, Dominion appears to use at least an 8% distribution loss adjustment in settlements with competitive energy suppliers.[19] We have not included an additional line loss adjustment above the loss factor included in QF prices, but further data on distribution loss adjustments in North Carolina could justify additional benefits in this category of costs.

2.6 Avoided Emissions

Solar generation avoids emissions of both greenhouse gases and criteria air pollutants (SO_2, NO_x, and PM 10). It is our understanding that compliance costs for criteria pollutants are included in the production cost models used to determining avoided energy costs, but that future costs to mitigate greenhouse gas (GHG) emissions are not considered. We note that the North Carolina utilities do include future carbon emission costs in their IRPs. For example, DEC's 2012 IRP assumes a Base Case CO_2 emission cost of $17 per ton in 2020, escalating to $44 per ton in 2032.[20] The DEC IRP also includes a High Case for CO_2 emission costs of $31 per ton in 2020, escalating to $80 per ton in 2032.

[17] All of these studies except the newly-released draft CPUC-E3 study are referenced and discussed in the RMI meta-analysis cited in Footnote 2 above. The new CPUC-E3 draft net metering cost-benefit study is available at http://www.cpuc.ca.gov/PUC/energy/Solar/nem_cost_effectiveness_evaluation.htm .

[18] The CPUC-E3 2013 study referenced in Table 7, at Table 5 in Appendix C, shows loss factors ranging from 5.7% to 10.9%. The R.W. Beck Study in Arizona, at Table 4-3, shows T&D loss reductions of 11.2% to 12.2%. of solar output.

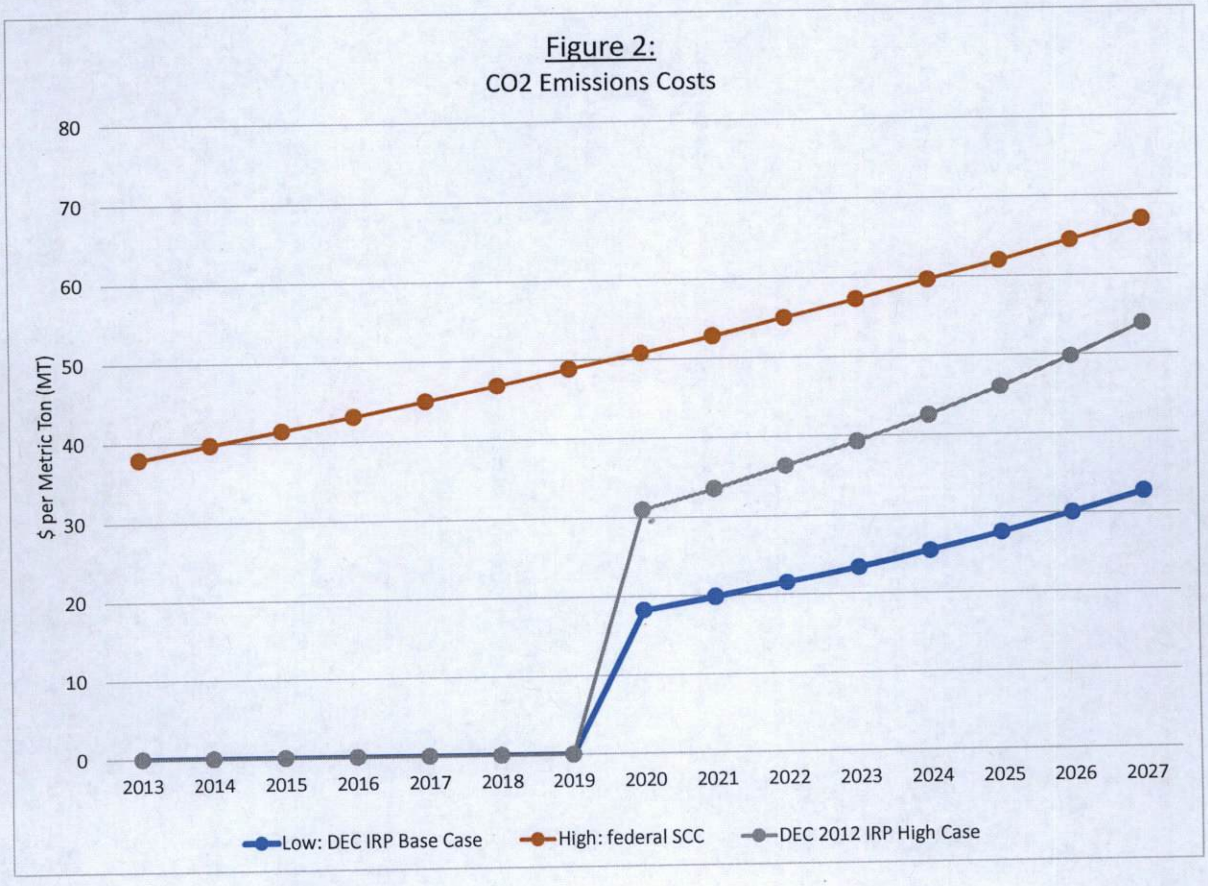
[19] See the loss expansion factors in http://www.dom.com/business/electric-suppliers/index.jsp .

[20] DEC 2012 IRP, at 106.

As another metric for the costs of mitigating CO_2 emissions, the federal government has announced that it will prioritize reductions of greenhouse gas (GHG) emissions by focusing on reducing pollution from electric power generation. This effort will employ a Social Cost of Carbon (SCC), with a base scenario of a carbon cost of \$35 per metric ton CO_2 in 2012 (in 2007 \$), growing at 2.1% per year plus inflation through 2050.[21] This is equivalent to a \$34 per ton in 2013, rising to \$46 per ton in 2020, and \$61 per ton in 2027.

Given these developments, we believe that a reasonable range for the value of avoided GHG emissions uses DEC's IRP Base Case values as the low scenario, and the federal SCC as the high scenario. The SCC values in the high case also assume that CO_2 emission costs have an impact immediately, not just in 2020. Although it is clear that the U.S. (except for California and the Northeast) will not have a GHG allowance trading scheme in place for the power sector in the near future, it is more likely that there will be further regulatory actions from the Environmental Protection Agency to regulate carbon emissions from power plants. The SCC emission values can be considered a proxy for such regulatory actions.

Figure 2 shows these two projections of the costs of CO_2 emissions. We also indicate the DEC high CO_2 case from its 2012 IRP.



[21] See http://www.whitehouse.gov/sites/default/files/omb/inforeg/social_cost_of_carbon_for_ria_2013_update.pdf at page 18.

We convert these costs of mitigating carbon emissions from dollars per ton to \$/MMBtu with a natural gas emission factor, and then to an energy price (in \$/MWh) using the natural gas-based marginal heat rates assumed in our avoided energy cost forecast. **Table 9** shows these results. This calculation assumes, conservatively, that the North Carolina utilities' marginal generation, and marginal emissions, are entirely from natural gas. The utilities' avoided cost filings show that, today, their marginal emissions are from a combination of natural gas, coal, and purchased power, with coal constituting 20% to 30% of the mix. This suggests that our assumption that 100% of marginal emissions are from natural gas understates the utilities' actual marginal emissions, and thus underestimates the emission savings from new renewable generation.

Table 9: *Avoided Emissions Costs*

Case	**CO2 Mitigation Costs** *(\$ per ton)*			**Avoided GHG Costs** *(15-year levelized cents / kWh)*
	2013	**2020**	**2034**	
Base	0	17	30	0.4
High	34	46	61	2.2

2.7 Avoided Renewables Costs

The North Carolina REPS requires utilities to serve at least 12.5% of their customers' electricity needs through new renewable energy sources or energy efficiency measures by 2021. The current REPS requirement is 3%; it increases to 6% in 2015 and 10% in 2018.

Wholesale Solar. We assume that the cost of wholesale solar purchased by the utilities will include the transfer of the associated REPS REC, such that wholesale solar will count directly toward meeting the REPS requirements. Thus, the cost of a REC represents the value of wholesale solar in meeting the utilities' REPS needs. We discuss below the available data on the cost of an unbundled REC in North Carolina.

Solar DG. Distributed solar does not necessarily count toward the REPS, if the customer who installs solar DG retains the RECs associated with their production. However, solar DG output reduces the utility's sales, and thus lowers its future REPS obligations by the solar output times the applicable REPS percentage (i.e. by 3% today, by 6% in 2015-2017, by 10% in 2018-2019, and by 12.5% in 2020). Over the 15-year period from 2013 – 2027, the average REPS obligation is 9.6%. Thus, solar DG provides at least this modest benefit in reducing future REPS obligations. In addition, we also understand that, although solar DG customers may net meter under any available rate schedule, customers can retain their RECs only if they take service under a time-of-use (TOU) tariff with demand charges; otherwise, they must surrender all RECs to the utility, without compensation.[22] Our review of the utilities' tariffs indicates that most residential and small commercial solar DG customers are likely to be better off net metering under an all-volumetric tariff, and conveying their RECs to the utility for free. We also understand that, even if a solar DG customer retains his RECs, the customer often does not or is not able to monetize them, in which case the value of the REC accrues to the general body of ratepayers in

[22] See http://www.dsireusa.org/incentives/incentive.cfm?Incentive_Code=NC05R&re=0&ee=0 . Also, NCUC order dated March 31, 2009 in Docket E-100, Sub 83.

North Carolina at no cost to them even though such a REC is not be counted for REPS compliance. In this last case, in effect, free RECs are donated to the system and North Carolina achieves a higher renewables penetration than required by the REPS program. Thus, the maximum benefit that solar DG provides to ratepayers is about 110% of the value of a REC – i.e. 100% from the REC conveyed to the utility for free, plus the extra 9.6% from the reduction in the utility's sales.

Cost of RECs. There is only limited public data on the cost of unbundled RECs in North Carolina today. We have estimated this cost based on a range of data, including the following:

- A recent filing by the Town of Fountain municipal utility publicly reporting a purchase of 2011-vintage solar RECs for $15 per MWh (1.5 cents per kWh).[23]

- The utilities' 2012-2014 incremental costs associated with their compliance with the 3% REPS requirement for these years, as reported in their 2013 REPS compliance filings. These incremental REPS costs for DEC and DEP are summarized in **Table 10** below. DNCP does not have a commission-approved REPS Rider to recover incremental REPS costs, although they have filed for one. North Carolina's REPS statute generally defines "incremental" REPS costs as the costs to procure renewable generation that exceed the utility's avoided costs.[24]

Table 10: *2012-2014 Incremental REPS Costs*

Component	DEC	DEP
Incremental REPS Costs *($ millions)*	$52.3	$63.3
REPS Requirement *(millions of kWh)*	5.29	3.36
Incremental REPS Costs *(cents / kWh)*	1.0	1.9

- Cost premiums for North Carolina's "green pricing" program. All of the North Carolina utilities have tariffs which offer customers the ability to purchase blocks of renewable power for a set premium. This "green pricing" program is administered by an independent non-profit, NC GreenPower. The premium for residential customers is 4 cents per kWh; commercial customers pay an additional 2.5 cents per kWh.[25] NC GreenPower states that 75% of its revenues are used to purchase RECs, and contributions appear to be deductible from federal income taxes as a charitable contribution.[26] The non-profit offers to purchase RECs from small renewable generators for 6 cents per kWh over 5 years (equivalent to a 15-year levelized price of 2.8 cents per kWh).[27] The NC GreenPower price represents a price premium that ratepayers are willing to pay to increase the percentage of renewable power they use to above the REPS requirement for grid power. Customers install solar DG for the same purpose. The NC GreenPower premiums are high compared to the other REC metrics, although the effective price is lower if the

[23] See http://ncuc.commerce.state.nc.us/cgi-bin/webview/senddoc.pgm?dispfmt=&itype=Q&authorization=&parm2=WAAAAA23231B&parm3=000143195.
[24] North Carolina statutes § 62-133.8(h)(1).
[25] See the utilities' NC GreenPower tariffs.
26 See https://www.ncgreenpower.org/faq/ .
[27] See https://www.ncgreenpower.org/ncgp-announces-a-change-in-premium-payment-for-new-small-solar-pv-agreements-effective-june-3-2013/ .

payments are tax-deductible, and one would presume that the utilities would not offer this program as a tariffed service if NC GreenPower were overcharging consumers for the incremental cost of renewable generation, or if the utilities themselves could or were willing to meet the demand for the service at a lower cost.

Considering all of the above metrics, a reasonable range for the cost of a REC in North Carolina is 1.0 to 2.0 cents per kWh, with the lower end based on DEC's incremental REPS costs and the high end reflecting DEP's incremental REPS costs and the cost of RECs through NC GreenPower.

It is fair to ask what is included in the value of a REC, particularly if mitigating carbon pollution is accounted for separately.[28] We have discussed above a number of the difficult-to-quantify benefits of renewable generation that are encompassed in the value of a REC, including:

- Fuel Diversity
- Price mitigation benefits[29]
- Grid security[30]
- Economic development[31]

We assume that the cost of a REC provides a proxy for these benefits. When calculated separately and then summed, these benefits typically far exceed the cost of a REC. A number of studies have quantified one of more of these benefits, as referenced in the footnotes to the above list. For example, the Clean Power Research study of the value of solar DG in Pennsylvania and New Jersey estimated the price mitigation, grid security, and economic development benefits of solar PV in those states, and found those benefits together to range from $102 to $137 per MWh, in 20-year levelized dollars.[32]

Conclusion. The avoided renewables benefit of wholesale solar is the full cost of the RECs that we assume the utility acquires when it purchases solar generation under a wholesale PPA. This cost is 1 to 2 cents per kWh. For solar DG, the avoided renewables costs over the 2013-2027 period is, at a minimum, 9.6% of the cost of a REC, based on the reduced REPS costs when solar DG reduces utility sales. If solar DG customers convey their RECs to the utility, or cannot monetize their RECs, the attributes of these RECs will accrue to the general body of ratepayers in North Carolina. Thus, at the high end, the value of solar DG to North Carolina ratepayers is the 110% of the full cost of a REC.

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[28] North Carolina statute § 62-133.8(a)(6) defines a REC to <u>not</u> include the value of reducing CO_2 emissions.

[29] For example, a Lawrence Berkeley National Lab study has estimated that the consumer gas bill savings associated with increased amounts of renewable energy and energy efficiency, expressed in terms of $ per MWh of renewable energy, range from $7.50 to $20 per MWh. Wiser, Ryan; Bolinger, Mark; and St. Clair, Matt, "Easing the Natural Gas Crisis: Reducing Natural Gas Prices through Increased Deployment of Renewable Energy and Energy Efficiency" (January 2005), at ix, http://eetd.lbl.gov/EA/EMP .

[30] Hoff, Norris and Perez, *The Value of Distributed Solar Electric Generation to New Jersey and Pennsylvania* (November 2012), at Table ES-2.

[31] *Ibid.* Also, a 2013 study by RTI International and La Capra Associates found that north Carolina's clean energy and energy efficiency programs contributed $1.7 billion to the state's economy from 2007-2012, created or retained 21,163 job-years over this period, and will provide long-term ratepayer benefits for the state. The study can be found at http://energync.org/assets/files/RTI%20Study%202013.pdf .

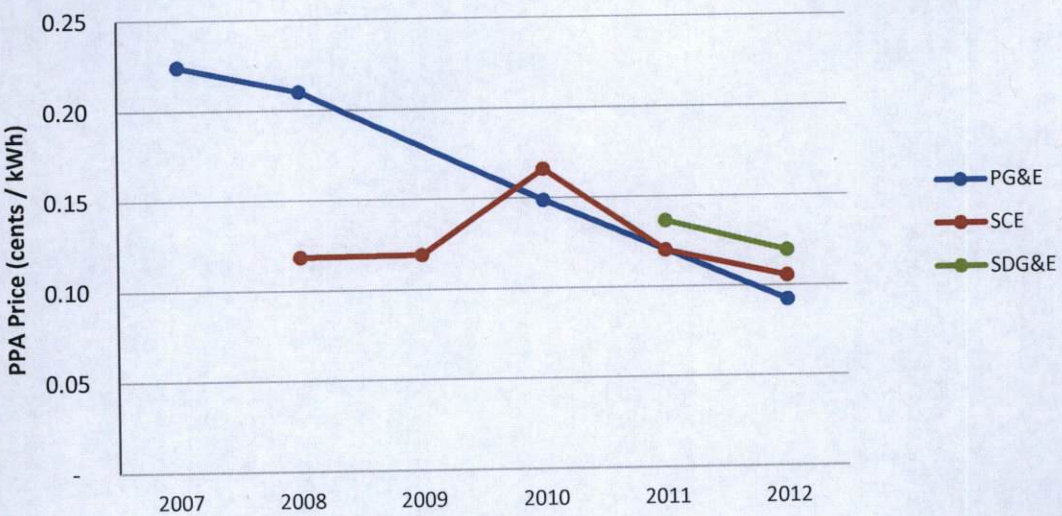
[32] *Ibid.*

3. Costs of Solar Generation

3.1 Wholesale Solar PPA Prices

Wholesale solar PPA prices provide perhaps the most dramatic evidence of the continued decline in solar PV costs. Solar PPA prices have fallen dramatically over the past several years, to the point that, in some regions of the U.S., solar is now competitive with other generation resources, including wind and natural gas. Xcel Energy in Colorado recently announced that it is proposing to add 170 MW of utility-scale solar to its system, with its CEO stating "[f]or the first time ever, we are adding cost competitive utility scale solar to the system."[33] The California electric utilities make public each year the average PPA prices for renewable contracts approved by the CPUC in the prior year. **Figure 3** shows the trend in the prices for their solar PV PPAs; CPUC contract approval can occur up to a year or more after bids are received, so the figure is indicative of prices through roughly 2011.[34] 2012 solicitations for solar PPAs in California in the 3 MW to 20 MW size range through the Renewable Auction Mechanism (RAM) have yielded market-clearing prices in the 8 to 9 cents per kWh range.[35]

Figure 3: California Solar PV PPA Prices



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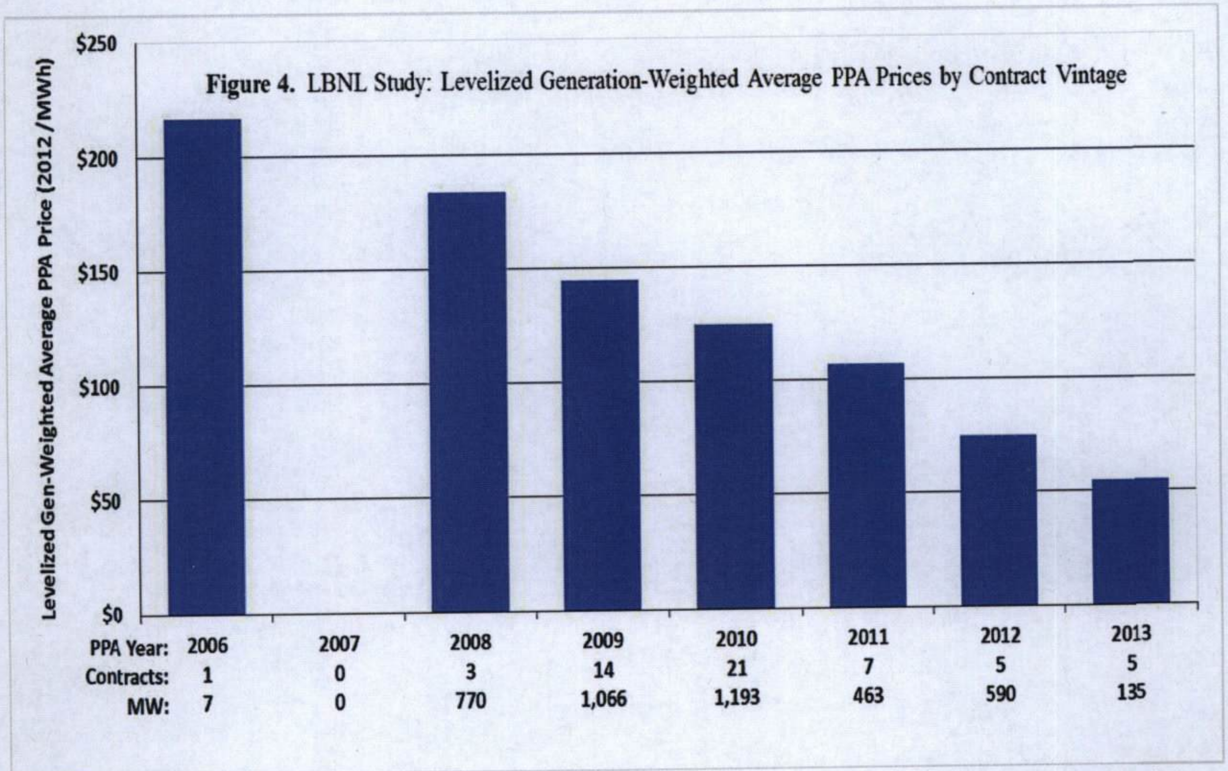
[33] See http://www.xcelenergy.com/About_Us/Energy_News/News_Releases/Xcel_Energy_proposes_adding_economic_solar,_wind_to_meet_future_customer_energy_demands .

[34] See http://www.cpuc.ca.gov/NR/rdonlyres/F0F6E15A-6A04-41C3-ACBA-8C13726FB5CB/0/PadillaReport2012Final.pdf .

[35] See http://www.cpuc.ca.gov/PUC/energy/Renewables/hot/Renewable+Auction+Mechanism.htm for details on the RAM program and the RAM auction results in MW. See http://votesolar.org/2012/03/30/ram-results-11-projects-130-mw-total-most-solar-all-under-8-9-centskwh/ for RAM prices from 2012.

The Lawrence Berkeley National Lab (LBNL) conducts and publishes regular national surveys of the installed costs of solar PV; these surveys include PPA prices for utility-scale solar projects. LBNL recently released its most recent survey of wholesale, utility-scale solar PPA prices, including data to September 2013.[36] LBNL samples the prices only for utility-scale solar PV projects that sell both electricity and RECs in the wholesale power market through a long-term PPA that includes the "bundled" sale of both power and RECs.[37] **Figure 4** illustrates the trend in utility-scale, wholesale solar PPA prices.[38] Based on the 2012-2013 data, utility-scale solar PPAs now appear to be in the range of $55 to $75 per MWh. The data for PPAs from 2012 and 2013 are for projects that are not yet on-line, and thus remain subject to some uncertainty over contract performance. However, LBNL's PPA data from earlier years is based on projects which in general are now on-line, which substantiates the trend of rapidly dropping PPA prices and provides confidence that most of the reported 2012-2013 PPA prices will result in successful projects.



LBNL also reports on the installed costs of utility-scale solar projects, by region. The most recent data indicates that costs in the southeastern U.S. (data from North Carolina and Florida) have dropped almost to par with costs in the western U.S. where the bulk of utility-scale solar projects are located.[39]

An important caveat to the LBNL data is that most of the PPAs sampled are in the western

[36] See "Utility-scale Solar: An Empirical Analysis of Project Cost, Performance, and Pricing Trends in the United States" (September 2013, LBNL Publication 6408-E), hereafter "LBNL Study." Available at http://emp.lbl.gov/reports/re .

[37] *Ibid.*, at 19.

[38] *Ibid.*, Figure 16.

[39] *Ibid.*, at Figure 4.

U.S., which has higher solar insolation levels than the eastern U.S.[40] Using the NREL PVWATTS calculator, the expected annual output (in kWh per kW) of a fixed array in Charlotte is 11% lower than the average annual output of PV systems in Sacramento, Los Angeles, Phoenix, and Boulder. LBNL reports capacity factors for utility-scale solar projects in the U.S. Southeast that are about 20% lower than in the western U.S.[41] As a result, the LBNL data needs to be adjusted upwards to estimate potential wholesale solar PPA prices in North Carolina. Adjusting the LBNL 2012 - 2013 range of solar PPA prices ($55 to $75 per MWh) upward by 25% to reflect the North Carolina capacity factors are 20% lower than in the western U.S., and placing somewhat greater emphasis on the most recent 2013 data, yields a range of $70 to $90 per MWh (7 to 9 cents per kWh), which we believe to be a reasonable, current range for the cost of wholesale solar PPAs in North Carolina.[42]

3.2 Solar DG Costs – Lost Revenues

The primary costs of solar DG are the retail rate credits provided to solar customers through net metering, i.e. the revenues that the utility loses as a result of DG customers serving their own load and exporting power to the grid when the solar output exceeds the on-site load. The lost revenues are dependent on the utility's retail rate design, and can vary considerably based on the rate structure. Solar DG customers are primarily able to avoid volumetric, per kWh rates. They are much less able to avoid demand charges, and of course cannot avoid fixed monthly charges that do not depend on usage.

North Carolina utilities have a variety of retail rate structures. Residential rates consist largely of a single volumetric rate, with some seasonal (summer / winter) differentiation, plus a significant fixed monthly charge. DEP's residential solar customers must use a time-of-use rate with a demand charge (R-TOUD) in order to qualify for an incentive under DEP's SunSense program. Small commercial rates feature a declining block structure, such that the average rate decreases as usage goes up. Large industrial customers pay significant demand charges and time-of-use energy rates.

We have assumed that the lost revenues from residential solar DG are based on the customer's volumetric rate for the marginal usage served by the solar unit, and assume that the solar DG customer takes service under the rate schedule with the highest volumetric rates in order to maximize bill savings under net metering. The lost revenues from a small commercial solar customer under a declining block rate will depend on the size of the solar system relative to the customer's usage; we have generally assumed that the rates for usage above the first tier represent the marginal lost revenues.

Lost revenues on a 15-year levelized basis also depend on the assumed future escalation in future rates. A recent rate case settlement approved for DEC included a near-term, three-year rate increase averaging 1.7% per year.[43] EIA data shows that electric rates in North Carolina over the 20 year period from 1992 - 2011 increased at 1.4% per year. We have calculated a range of lost revenues based on future rate escalations from 1.0% to 2.5% per year. These results are shown in **Table 11**.

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[40] *Ibid.*, at 22.
[41] *Ibid.*, at Figure 11.
[42] Of course, this range of PPA prices all assume the availability of federal and state tax credits at 2013 levels.
[43] See http://www.duke-energy.com/north-carolina/nc-rate-case.asp.

3.3 Integration Costs

Finally, several utilities have completed studies on solar integration costs. A recent study which Arizona Public Service commissioned estimated integration costs of $2 per MWh in 2020 and $3 per MWh in 2030.[44] Xcel Energy in Colorado has calculated solar integration costs as $1.80 per MWh on a 20-year levelized basis.[45] Based on the high end of the range in these studies, we have added an assumed solar integration cost of $3 per MWh (0.3 cents per kWh).

Table 11 summarizes all of these costs of solar DG for North Carolina ratepayers.

Table 11: *Costs of Residential and Commercial Solar DG (15-year levelized cents / kWh)*

Class	DEC	DEP	DNCP
Lost Revenues			
Residential	9.8 – 10.7	10.5 – 11.5	10.1 – 11.0
Commercial	7.7 – 8.4	9.7 – 10.6	8.7 – 9.4
Integration	0.3	0.3	0.3
Total Costs			
Residential	**10.1 – 11.0**	**10.8 – 11.8**	**10.4 – 11.3**
Commercial	**8.0 – 8.7**	**10.0 – 10.9**	**9.0 – 9.7**

4. Conclusion

The benefits of solar generation in North Carolina equal or exceed the costs of this source of renewable generation. This conclusion is valid regardless of whether solar is developed as wholesale generation with the entire output sold to the utilities or as demand-side distributed generation under net metering. The quantitative results of our work are summarized in Tables 2 and 3. If one uses the midpoints of the ranges of costs and benefits shown in these tables, the benefits of wholesale solar exceed the costs by about 40% (a benefit / cost ratio of 1.43), and the benefits of solar DG are almost 30% larger than the costs (a benefit / cost ratio of 1.27). Over the next several years, if North Carolina utilities were to add 400 MW of wholesale solar and 100 MW of solar DG resources, the net benefits for ratepayers would be $26 million per year.

44 Black & Veatch, "Solar Photovoltaic (PV) Integration Cost Study" (B&V Project No. 174880, November 2012).

45 Xcel Energy Services for Public Service Company of Colorado, "Cost and Benefit Study of Distributed Solar Generation on the Public Service Company of Colorado System" (May 23, 2013), at Table 1, pages v and 41-42.

Crossborder Energy

Comprehensive Consulting for the North American Energy Industry

The Benefits and Costs of Solar Generation for Electric Ratepayers in North Carolina

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October 18, 2013

EXHIBIT

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The Benefits and Costs of Solar Generation for Electric Ratepayers in North Carolina

This report provides an independent analysis of the benefits and costs of solar photovoltaic (PV) generation for electric ratepayers in the service territories of the major electric utilities in North Carolina – Duke Energy Carolinas (DEC), Duke Energy Progress (DEP), and Dominion North Carolina Power (DNCP). North Carolina Sustainable Energy Association asked Crossborder Energy to apply to the three North Carolina utilities the same approach to analyzing the benefits and costs of solar generation which we have used in similar studies in other states.[1]

This report identifies the benefits and costs of solar for both (1) wholesale utility-scale solar projects whose output is sold to the utilities and (2) solar distributed generation (solar DG or demand-side solar) installed on a customer's premises behind the customer's utility meter. This study explains which of the benefits of solar generation apply to both wholesale and demand-side solar, and which are limited to one of these different types of solar resources. On the cost side, it is important to recognize that wholesale solar and solar DG result in different types of costs for utility ratepayers. The ratepayer costs of wholesale solar are principally the capital and O&M costs of utility-scale solar generation, which the utility will pay directly through a power purchase contract with the solar project. In contrast, the customer who installs solar DG bears the capital and operating costs of the solar resource. With solar DG, the costs to other, non-participating ratepayers are principally the revenues which the utility loses as a result of the output of solar DG serving the customer's on-site load, plus the energy credits which the utility provides, through net energy metering, when the solar customer exports power to the grid. These exports serve the loads of nearby retail customers. The utility may also provide incentive payments to solar DG customers. Finally, both wholesale and demand-side solar may cause the utility to incur new costs to integrate intermittent solar generation into the grid. **Table 1** summarizes the principal costs and benefits of both wholesale solar and solar DG.

Table 1: *Benefits and Costs of Solar Generation for North Carolina Ratepayers*

Benefits	Wholesale Solar	Solar DG
Energy	✓	✓
Generation capacity	✓	✓
Transmission	✓ (≤ 5 MW)	✓
Distribution		✓
Avoided Emissions	✓	✓
Avoided Renewables	✓	✓
Costs		
Capital and operating costs	✓	
Lost retail rate revenues		✓
DG incentives		✓
Integration costs	✓	✓

[1] See "The Benefits and Costs of Solar Distributed Generation for Arizona Public Service" (May 2013), available at http://www.seia.org/research-resources/benefits-costs-solar-distributed-generation-arizona-public-service. Also, "Evaluating the Benefits and Costs of Net Energy Metering in California" (January 2013), available at http://votesolar.org/wp-content/uploads/2013/01/Crossborder-Energy-CA-Net-Metering-Cost-Benefit-Jan-2013-final.pdf .

In assessing the benefits and costs of solar generation from a utility ratepayer perspective, it is important to use a long-term time frame which recognizes that solar PV systems have useful lives of 20 to 30 years. A long-term perspective is also necessary to treat demand-side solar on the same basis as other supply- or demand-side resources. When a utility assesses the merits of adding a new power plant, or a new energy efficiency program, the company will look at the costs to build and operate the plant or the program over their useful lives, compared to the costs avoided by not operating or building other resource options. Solar DG should be evaluated over the same long-term time frame.

Solar generation can be installed at a wide range of scales, from a system serving a single home to utility-scale plants. Solar is feasible in a greater diversity of locations than other renewable technologies such as wind and hydro. Solar also can be installed with shorter lead times and on a wider variety of sites than conventional, large-scale fossil generation resources. Solar can combine with other small-scale, short-lead-time, demand-side resources, such as energy efficiency (EE) and demand response (DR) programs, to reduce a utility's need for supply-side generation, both in the near- and long-terms. An analysis of the benefits of solar should recognize its scalability and short lead times, by acknowledging that solar and demand-side programs combine to continuously avoid the need for supply-side resources, without the "lumpiness" associated with a conventional utility-scale power plant. Accordingly, we evaluate the benefits of solar based on the change in a utility's costs per unit of solar installed, without requiring solar to be installed in the same large increments as conventional fossil or nuclear generation.

This report relies on data from the North Carolina utilities' latest integrated resource plans (IRPs), supplemented with data from recent avoided cost proceedings and general rate cases. We also have used a limited amount of current data from the regional gas and electric markets in which the North Carolina utilities operate. This work relies to the greatest extent possible on public data and on transparent calculations of the benefits and costs. Our intent in using public data and transparent methodologies is to minimize debates over the input assumptions and to reduce reliance on opaque models. We agree with the Rocky Mountain Institute's recent meta-analysis of solar DG cost / benefit studies, which concluded that "in any benefit/cost study, it is critical to be transparent about assumptions, perspectives, sources and methodologies so that studies can be more readily compared, best practices developed, and drivers of results understood."[2] Where there is debate over certain benefits or costs of solar, we have provided ranges that we believe span the likely range of benefits or costs.

Our work concludes that the benefits of solar generation in North Carolina equal or exceed the ratepayer costs of solar resources, such that new solar resources will provide economic benefits for electric ratepayers in the state. The following **Tables 2 and 3** summarize our results, for wholesale solar and solar DG, respectively. The benefits of wholesale solar typically exceed the costs, even if one does not include the environmental benefits of mitigating carbon emissions. The costs of net metered solar DG for non-participating residential customers are at the low end of the range of benefits, while the benefits of solar DG exceed the costs in the commercial market, where marginal retail rates are lower. These results indicate that North Carolina ratepayers generally would benefit from the continued availability of net metering.

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2 Rocky Mountain Institute. "A Review of Solar PV Benefit and Cost Studies" July 2013, at page 5. http://www.rmi.org/Knowledge-Center/Library/2013-13_eLabDERCostValue.

Based on the midpoints of the ranges of costs and benefits shown in Tables 2 and 3, the benefits of wholesale solar are 40% larger than the costs, and the benefits of solar DG are 30% greater. Were the North Carolina utilities to add 400 MW of wholesale solar and 100 MW of solar DG resources, the net benefits for ratepayers would be $26 million per year.

Table 2: *Benefits and Costs of Wholesale Solar (15-year levelized cents/kWh - 2013 $)*

Benefits	**DEC**	**DEP**	**DNCP**
Energy (includes line losses)	5.7 – 6.5	5.5 – 6.3	5.8 – 6.6
Generation capacity	1.9 – 3.2	2.1 – 3.2	2.6 – 3.6
Transmission capacity (< 5 MW)	0 – 1.0	0 – 0.7	0 – 0.9
Avoided Emissions	0.4 – 2.2	0.4 – 2.2	0.4 – 2.2
Avoided Renewables	1.0 – 2.0	1.0 – 2.0	1.0 – 2.0
Total Benefits	**9.0 – 14.9**	**9.0 – 14.4**	**9.8 – 15.3**
Costs			
Capital and O&M (All-in PPA)	7.0 – 9.0	7.0 – 9.0	7.0 – 9.0
Integration	0.3	0.3	0.3
Total Costs	**7.3 – 9.3**	**7.3 – 9.3**	**7.3 – 9.3**

Table 3: *Benefits and Costs of Solar DG (15-year levelized cents/kWh - 2013 $)*

Benefits	**DEC**	**DEP**	**DNCP**
Energy (includes line losses)	5.7 – 6.5	5.5 – 6.3	5.8 – 6.6
Generation capacity	2.2 – 3.7	2.4 – 3.7	3.0 – 4.1
Transmission capacity	1.0	0.7	0.9
Distribution capacity	0.2 – 0.5	0.2 – 0.5	0.2 – 0.5
Environmental	0.4 – 2.2	0.4 – 2.2	0.4 – 2.2
Avoided Renewables	0.1 – 2.2	0.1 – 2.2	0.1 – 2.2
Total Benefits	**9.6 – 16.1**	**9.3 – 15.6**	**10.4 – 16.5**
Costs			
Lost Revenues			
Residential	9.8 – 10.7	10.5 – 11.5	10.1 – 11.0
Commercial	7.7 – 8.4	9.7 – 10.6	8.7 – 9.4
Integration	0.3	0.3	0.3
Total Costs			
Residential	**10.1 – 11.0**	**10.8 – 11.8**	**10.4 – 11.3**
Commercial	**8.0 – 8.7**	**10.0 – 10.9**	**9.0 – 9.7**

1. Methodology

Solar DG is a long-term source of electric generation that uses a renewable resource. New solar systems will provide benefits for North Carolina ratepayers for the next 20 to 30 years. Data to perform a long-term (15-year) assessment of these benefits is available from utility avoided cost filings, from recent IRPs and general rate cases, and from market data. The core of this study is the calculation of 15-year levelized benefits and costs for solar resources on the DEC, DEP, and DNCP systems.

1.1 Benefits.

We briefly describe our approach to calculating each of the benefits of solar generation in North Carolina.

- **Energy.** DEC, DEP, and DNCP have currently-effective 15-year avoided energy prices in the range of 4.5 – 5.0 c/kWh for a base load profile, based on production cost modeling of their incremental energy costs over the next 15 years. These avoided energy rates are currently under review in North Carolina Utilities Commission (NCUC) Docket No. E-100, Sub 136. As these production cost models are confidential, we have separately projected 15-year avoided energy costs using a more transparent approach, based on natural gas forward market data, combined with the heat rates, variable O&M costs, and other operating parameters of the long-term fossil resources that solar generation will avoid. Other similar studies have taken a comparable approach to calculating long-term avoided energy costs.[3] We also have considered whether avoided energy costs should be adjusted to reflect the costs which some utilities have incurred to hedge the volatility in their natural gas costs. Finally, avoided energy costs should consider the daily profile of solar generation, which peaks during the early afternoon, making it a more valuable resource than a constant, "flat" profile in all daylight hours.

- **Generating Capacity.** The North Carolina utilities calculate 15-year avoided capacity prices under the assumption that a new combustion turbine (CT) is the least-cost source of new generating capacity. This is commonly called the "peaker" method. Although the details of these calculations are confidential, there is public data on CT costs in nearby markets which can be used to review filed capacity prices. The capacity value of solar, per unit of output, also must consider both the peaking profile of solar generation as well as its variability. Utilities and control area operators in the U.S. have developed well-accepted methods to value the contribution of solar PV resources to capacity resources. In North Carolina, the utilities appear to value solar's capacity at 40% to 50% of its nameplate capacity, comparable to the valuation adopted by the nearby PJM system.

- **Transmission Capacity.** The output of solar DG primarily serves on-site loads and never touches the grid, thus clearly reducing loads on the transmission grid. Given the penetration levels of solar DG on the system today, the power exported from solar DG

[3] This is generally the approach taken in the avoided cost calculator that California Public Utilities Commission (CPUC) has approved for cost-effectiveness analyses of demand-side programs in California, including solar DG. See, generally, CPUC Decision 09-08-026. Energy and Environmental Economics (E3) has developed the avoided cost calculator under contract to the CPUC. See http://www.ethree.com/public_projects/cpuc5.php. The DG version of the model is titled "DERAvoidedCostModel_v3.9_2011 v4d.xlsm."

units is entirely consumed on the distribution system by the solar customer's neighbors, again unloading transmission capacity. Thus, much like energy-efficiency and demand response resources, solar DG can avoid transmission capacity costs, but only to the extent that solar is producing during the peak demand periods that drive load-related transmission investments. As DEC itself notes in describing its utility-owned solar DG program: "Power is produced at the site, reducing the need for extensive transmission lines or a complex infrastructure."[4] Wholesale solar facilities interconnected at the distribution level – typically, projects at or below 5 MW in size – also can avoid transmission capacity costs to the extent that their output is consumed on the distribution system and produces minimal impacts on the upstream transmission grid.

We understand that there has been debate in North Carolina over the magnitude of the avoided T&D benefits attributable to EE and DR programs, with the debate centering on the extent to which T&D costs are load-related. We calculate long-term marginal transmission costs for DEC and DEP using an approach that considers only load-related transmission. Our method uses a regression of each utility's historical and forecasted transmission investments as a function of load growth, to determine the change in these costs as a function of increases in peak demand. This is a longstanding methodology used by many utilities to determine marginal, load-related transmission costs.

- **Distribution Capacity.** Whether solar generation avoids distribution capacity is a more complex question than transmission capacity, for several reasons. First, distribution substations and circuits can peak at different times than the system as a whole, complicating the calculation of whether solar can reduce distribution system peaks. Second, the timing of load-related distribution expansions is location-specific, and many utilities do not know where or when solar DG will be developed. Third, the time frames for utility distribution plans often is only 3-5 years into the future, providing only limited insight into the impact of distributed solar resources with 20-year lives. Finally, larger solar facilities may require distribution upgrades to accept their output, although the costs of such upgrades usually are the responsibility of the solar project. Nonetheless, studies using a variety of techniques have identified at least a modest amount of avoided capacity-related distribution costs resulting from the installation of solar DG.

- **Line Losses.** New solar generation reduces losses on the margin, and marginal line losses are significantly higher than average losses. The North Carolina utilities state that they use marginal transmission loss factors in their avoided energy costs. However, solar facilities produce power during daylight hours over which system loads, and system losses, are above-average. In addition, solar DG can avoid distribution losses. Thus, the current loss factors in avoided cost prices are likely to understate the line loss benefits of solar generation.

- **Avoided Emissions.** The North Carolina utilities' avoided cost calculations appear to include the costs of emission allowances associated with criteria pollutants, but not of carbon dioxide (CO_2). However, the IRPs of the Duke utilities recognize the potential long-term need to reduce CO_2 emissions – for example, by maintaining an option to add

[4] See "What are some advantages of solar energy?" http://www.duke-energy.com/north-carolina/renewable-energy/nc-solar-distributed-generation-program-FAQs.asp

nuclear generation – and include a base case CO_2 emission cost of $17 per ton in 2020, escalating to $44 per ton in 2032.[5] Accordingly, a long-term projection of the benefits of solar generation should recognize the value of these resources in mitigating carbon pollution. Given the uncertainty in the timing and magnitude of these costs, we have calculated a range of benefits from avoided CO_2 emissions.

- **Avoided Renewables Costs.** Bundled wholesale solar sold to the North Carolina utilities contributes to their compliance with state's Renewable Energy and Energy Efficiency Portfolio Standard (REPS) requirements, both today and in future years when those requirements will increase. The measure of the value of this compliance is the cost for an unbundled renewable energy certificate (REC) in North Carolina. If developers did not invest in wholesale solar systems and then sell the resulting RECs to the utility, of if solar DG customers did not invest in on-site solar and then sell or transfer their RECs, the utilities would have to make their own investments in renewable generation, presumably at a higher cost than the RECs available from developers and solar DG customers.

  Public data is not widely available in North Carolina on the cost of unbundled RECs today. We have estimated such costs based on a range of data, including (1) recent reports on a solar REC purchase by a municipal utility, (2) the utilities' reported 2012-2014 incremental costs associated with their compliance with the REPS requirement, and (3) cost premiums for green pricing programs in North Carolina.

  We assume that this category of avoided costs encompasses a number of the difficult-to-quantify benefits of renewable generation that are embodied in the attributes of a REC, including:

  - **Fuel Diversity.** Renewables generally have zero fuel costs (with the possible exception of some types of biomass), and present a different set of operating risks (lower capacity factors and intermittency) than conventional fossil resources. As a result, an increasing penetration of renewables will diversify a utility's fuel sources and resource mix, and reduce the risks of reliance on a small set of generation technologies.
  - **Price mitigation benefits.** Solar DG reduces the demand for electricity (and for the gas used to produce the marginal kWh of power). These reductions have the broad benefit of lowering prices across the gas and electric markets in North Carolina, to the benefit of all ratepayers. This benefit is also known as the "demand reduction induced price effect" (DRIPE), and has been quantified in several regions of the U.S.
  - **Grid security.** Renewable DG resources are installed as many small, distributed systems and thus are highly unlikely to fail at the same time. They are also located at the point of end use, and thus reduce the risk of outages due to transmission or distribution system failures. This reduces the economic impacts of power outages.
  - **Economic development.** Renewable DG results in more local job creation than fossil generation, enhancing tax revenues.

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5 DEC 2012 IRP, at Appendix A, p. 106.

1.2 Costs

The ratepayer costs for wholesale solar are the payments that the utilities will make to purchase solar generation under long-term power purchase agreements (PPAs). We estimate these costs using available data on the recent trends in the prices in PPAs for utility-scale solar projects. For solar DG, the principal costs are the revenues which the North Carolina utilities will lose from customers serving their own load with on-site solar, including the credits provided under net metering when solar generation is exported to the grid. We estimate the lost revenues for the rate schedules on which many solar customers take service. Finally, we include an estimate of the costs of additional operating reserves needed to integrate intermittent solar generation into the grid. We are not aware that any of the North Carolina utilities have performed and publicly-disclosed a solar integration study specific to their systems, so we use a typical value from utility-sponsored integration studies in other states.

The following sections discuss in more detail each of the benefits and costs of solar DG on the DEC, DEP, and DNCP systems. As noted above, solar is a long-term resource with an expected useful life of at least 20 years. Accordingly, when we calculate the benefits and costs of DG over a 15-year period, the result is a conservative estimate of the value of these long-term resources. We express our results as 15-year levelized costs using a discount rate of 7.7%.[6]

2. Benefits of Solar DG

2.1 Energy

The North Carolina utilities' 2012 resource plans make clear that, to meet near- and intermediate-term growth, the utilities will rely on energy efficiency and demand-side resources, renewable purchases to meet North Carolina's REPS standard, and new efficient natural gas-fired generation, with the possibility of adding new nuclear generation in the post-2020 time frame. In these plans, gas-fired generation is the predominant marginal resource, so if North Carolina utilities were to increase their procurement of wholesale or distributed solar resources, the resources likely to be displaced would be new gas-fired generation.

Accordingly, we would expect the utilities' long-term, 15-year avoided cost energy prices to reflect the energy costs of relatively efficient gas-fired generation resources. DEC's, DEP's and DNCP's current 15-year levelized avoided energy prices are in the range of 4.5 to 5.0 c/kWh. As a check on these values, we first developed a 15-year natural gas cost forecast for gas-fired generation in North Carolina. This forecast uses recent forward gas price data from the NYMEX Henry Hub market plus a market differential from the Henry Hub to Zone 5 on the Transco pipeline. Based on this gas cost forecast, we estimated the marginal heat rates over the next 15 years that would produce the utilities' current 15-year avoided energy costs. These marginal heat rates are about 9,000 Btu per kWh today, declining to about 7,500 Btu/kWh in 2027. These heat rates are reasonably representative of the efficient combined-cycle and gas turbine units that the North Carolina utilities expect to add over this period.

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6 This is average of DEC's and DEP's currently-authorized weighted average costs of capital, from these utilities' most recent general rate case decisions. See the May 30, 2013 NCUC order in Docket No. E-2, Sub 1023, at 11 (for DEP) and the September 24, 2013 NCUC order in Docket No. E-7, Sub 1026 at 10 (for DEC). For DNCP, we use the same 8.5% discount rate which the utility used in its most recent public avoided cost filing.

Renewable generation has no fuel costs and thus avoids the volatility associated with generation sources whose cost depends principally on fossil fuel prices. Our gas cost forecast is based on forward market natural gas prices; thus, it represents a cost of gas that the North Carolina utilities theoretically could fix for the next 15 years, thus in principle capturing the fuel price hedging benefit of renewable generation. However, such a hedging strategy may not be cost-less; for example, in 2011-2012 DEP incurred $121 million in above-market costs to hedge one-half of its 163 Bcf of gas purchases, a cost premium of $0.74 per MMBtu when spread over the utility's full portfolio of gas purchases. From the customer's perspective, DEP's financial hedges effectively increased the price of each MMBtu consumed by $0.74. These hedging costs are not included in current avoided cost prices. We include such costs to develop the high end of our range of avoided energy benefits; the low end of our range is the utilities' filed 15-year avoided energy costs, adjusted as described below to reflect the hourly profile of solar output.

North Carolina avoided cost prices are differentiated into on- and off-peak prices, and also can vary seasonally by peak vs. off-peak months. This differentiation captures some, but not all of the hourly variation in the energy benefits of solar. What is missing is the likelihood that the diurnal profile of solar output will have a higher value than a flat block of on-peak power, because solar output peaks in the early afternoon hours and produces significant power in the mid-afternoon hours of peak demand. We are able to assess the hourly value of solar directly for DCNP, because it operates in the PJM market with visible hourly locational marginal prices (LMPs). DNCP's solar-weighted avoided cost energy price is 14% higher than the annual average avoided cost energy price for a baseload profile.[7] We have applied the same premium to the average, base load avoided cost energy prices for DEC and DEP, as a reasonable estimate of the time-varying energy value of solar in North Carolina. **Table 4** summarizes the avoided energy value of solar generation for the three utilities.

Table 4: *Avoided Energy Value of Solar (15-year levelized, $ per kWh, 2013$)*

Component	DEC	DEP	DNCP
Avoided Energy Costs	5.7	5.5	5.8
Hedging Costs	0.8	0.8	0.8

2.2 Generation Capacity

The North Carolina utilities use the annualized fixed costs of a new combustion turbine as the measure of avoided capacity costs – the standard "peaker" method. **Table 5** shows the annualized CT capacity costs now embedded in the utilities' current 15-year avoided capacity prices, assuming that a resource operates at an 83% capacity factor.[8] The detailed CT capital cost and financing data used to set these current avoided cost prices are confidential, so we "back into" the CT fixed capacity costs in Table 5 for the three utilities by multiplying (1) the currently-effective avoided capacity credit times (2) the number of hours per year in the time period in which the capacity credit is paid, times (3) the 83% capacity factor. The table also shows other relevant, public sources of data on CT fixed costs.

[7] In comparison, DEC's Option A avoided cost prices for an average solar profile in Charlotte are 4% higher than the annual average price for a base load profile.

[8] Based on the 1.2 "performance adjustment factor" used to calculate these prices.

Table 5: *Annualized CT Fixed Capacity Costs (Distribution Voltage)*

Source	CT Fixed Capacity Cost *($/kW-year)*	Range *($/kW-year)*
DEC	$57	$57 - $104
DEP	$65	$65 - $104
DNCP	$75	$75 - $108
PJM Net CONE, Area 5	$108	
EIA, *AEO13*, Advanced CTs[9]	$100	

There is ongoing litigation in North Carolina concerning QF capacity prices, with parties challenging the utilities' filed and currently-effective capacity credits. Accordingly, we use a range for the value of avoided generating capacity, as shown in the third column of Table 5. At the low end of the range for DEC and DEP, we use the currently-filed utility values; at the high end, we average the public, transparent PJM and EIA data. For DNCP, as it is on the PJM system, we use the utility's filed cost as the low end, and the PJM values as the high end.[10]

We make three adjustments to these CT-based capacity values. First, we add the fixed reservation charges for firm transmission on the Transco interstate pipeline to provide the new gas-fired capacity with a firm gas supply, to the extent that these reservation charges exceed a typical market-based "basis" differential in natural gas prices between the U.S. Gulf Coast and North Carolina. In the long-run, natural gas pipelines need to be able to recover their full cost of service. Second, we assume that behind-the-meter solar DG will be reflected in utility planning as a reduction in peak demand. Accordingly, solar DG also will reduce each utility's capacity need by an additional amount equal to the required reserve margin (15%) times the effective solar capacity.

Third, a calculation of the capacity value of solar resources must recognize that solar is a resource whose availability depends on weather and the time of the day. Although peak solar output typically occurs in the early afternoon when demand is relatively high, the peak output does not correlate perfectly with the utility's peak demand, which tends to occur later in the afternoon. As a result, solar does not provide 100% of its nameplate capacity to the grid as reliable generating capacity.

Utilities and control area operators in the U.S. generally use one of two approaches to determine the effective capacity provided by a solar resource. The most complex, and often considered to be the most rigorous, approach is the Effective Load Carrying Capacity (ELCC) method. This approach uses a production simulation model of the electric system in question to determine how much load a kW of solar capacity can "carry" without a diminution in reliability. Thus, if 100 MW of solar generation provides the same level of reliability when it replaces 50 MW of a reference resource (such as a CT), the ELCC of the solar resource is 50 MW / 100 MW = 50%. ELCC analyses require computer models which are complex and expensive to license and run, and which are not transparent except to the analysts who run them. They also require hourly data on

[9] EIA data on CT costs is from http://www.instituteforenergyresearch.org/wp-content/uploads/2009/05/2.15.13-IER-Web-LevelizedCost-MKM.pdf at page 3. Includes levelized fixed costs, fixed O&M, and associated transmission investments. 2011 $ are escalated to 2013 $ at 2.5% per year.

[10] For the high case, we use PJM RPM clearing prices for capacity through 2016, and its Net Cost of New Entry (CONE) thereafter.

loads and solar output which are correlated in time. As a result of the limitations and complexities of ELCC analyses, most control area operators in the U.S. use the simpler and more transparent "capacity factor" approach to setting the capacity value of intermittent renewable resources. This method sets the capacity value of the renewable resource based on its demonstrated capacity factor during certain critical hours of peak demand. For example, Appendix B of PJM's Manual 21 specifies that the capacity value of a solar resource should be calculated based on its summer (June-August) capacity factor during the hours ending 3-6 p.m.[11] For a solar profile for Norfolk, Virginia, the PJM Manual 21 method yields capacity values of 46% of nameplate for a fixed array and 58% of nameplate for a single-axis tracking system.

In their IRPs, the North Carolina utilities appear to assume that a solar resource's capacity value is 40% to 50% of its nameplate, consistent with the PJM capacity factor valuation for fixed arrays. DEC and DEP have confirmed in non-confidential data responses in the NCUC avoided cost docket that their 2013 IRPs value solar at 42% of nameplate. They also assume that solar operates at a 17.4% capacity factor.[12]

Table 6 shows our final calculation of the range of benefits that solar provides from avoiding the need for generation capacity, over a 15-year period. We add the CT fixed costs and pipeline reservation costs, multiply the total by the 42% contribution of solar to reducing peak demand, then divide by the typical output of a solar resource in North Carolina (1,524 kWh per kW per year based on the 17.4% capacity factor). The resulting avoided generation capacity costs, in dollars per MWh, are shown in the table below, for the range of CT fixed costs in Table 5. Finally, we observe that behind-the-meter solar DG, unlike wholesale solar, reduces the utility's peak demand. As a result, solar DG also reduces the utility's capacity requirements to meet its reserve margin, which is about 15% for the North Carolina utilities. Thus, for solar DG we increase the avoided generation capacity value by 15% above the numbers shown in Table 6.

Table 6: *Avoided Generation Capacity Value ($ per kW-yr in 2013$)*

Component	DEC		DEP		DNCP	
	Low	High	Low	High	Low	High
CT Fixed Costs	57	104	65	104	75	108
Pipeline Reservation	12	12	12	12	12	12
Total	69	116	77	116	87	120
Solar Capacity as % of Nameplate	42%	42%	42%	42%	46%	46%
Solar Capacity Value *($ per kW-yr)*	29	49	32	49	40	55
Annual Output *(kWh / kW)*	1,524	1,524	1,524	1,524	1,524	1,524
Solar Capacity Value *(cents per kWh)*	1.9	3.2	2.1	3.2	2.6	3.6

11 *See* http://www.pjm.com/documents/manuals.aspx .

12 DEC and DEP response to NCSEA Data Request No. 4, Item 4-15 in Docket No. E-100, Sub 136.

2.3 Transmission Capacity

Most, if not all, solar DG output is either consumed behind the meter or on the distribution system by the neighbors of the DG system, and never touches the transmission system. Solar DG thus reduces the use of the transmission system, and will reduce peak demands on the transmission system even if solar output and peak demand are not perfectly correlated. This benefit is similar to the benefit of other demand-side programs in avoiding transmission and distribution (T&D) capacity-related costs.

North Carolina utilities include avoided capacity-related T&D costs in assessing the costs and benefits of EE and DR programs. However, the methodology used to calculate these avoided costs is not public and we are aware that there is debate over the magnitude of these avoided costs. In particular, the NC Public Staff have questioned whether DEC's assumed avoided T&D costs are too high because they include transmission costs that are reliability-related, and thus not driven by load increases.[13]

There is a well-accepted way to address this debate. We have calculated DEC's and DEP's long-term marginal transmission capacity costs using the industry-standard NERA regression method used by many utilities to determine their marginal T&D capacity costs which are load-related.[14] **Figure 1** shows, for DEC, the regression fit of cumulative transmission capital additions as a function of incremental demand growth. We convert the regression slope of $438 per kW using a real economic carrying charge of 7.41%, and add loaders for general plant and transmission O&M costs based on FERC Form 1 data. Our estimate of annualized marginal transmission costs for DEC is $37.45 per kW-year.

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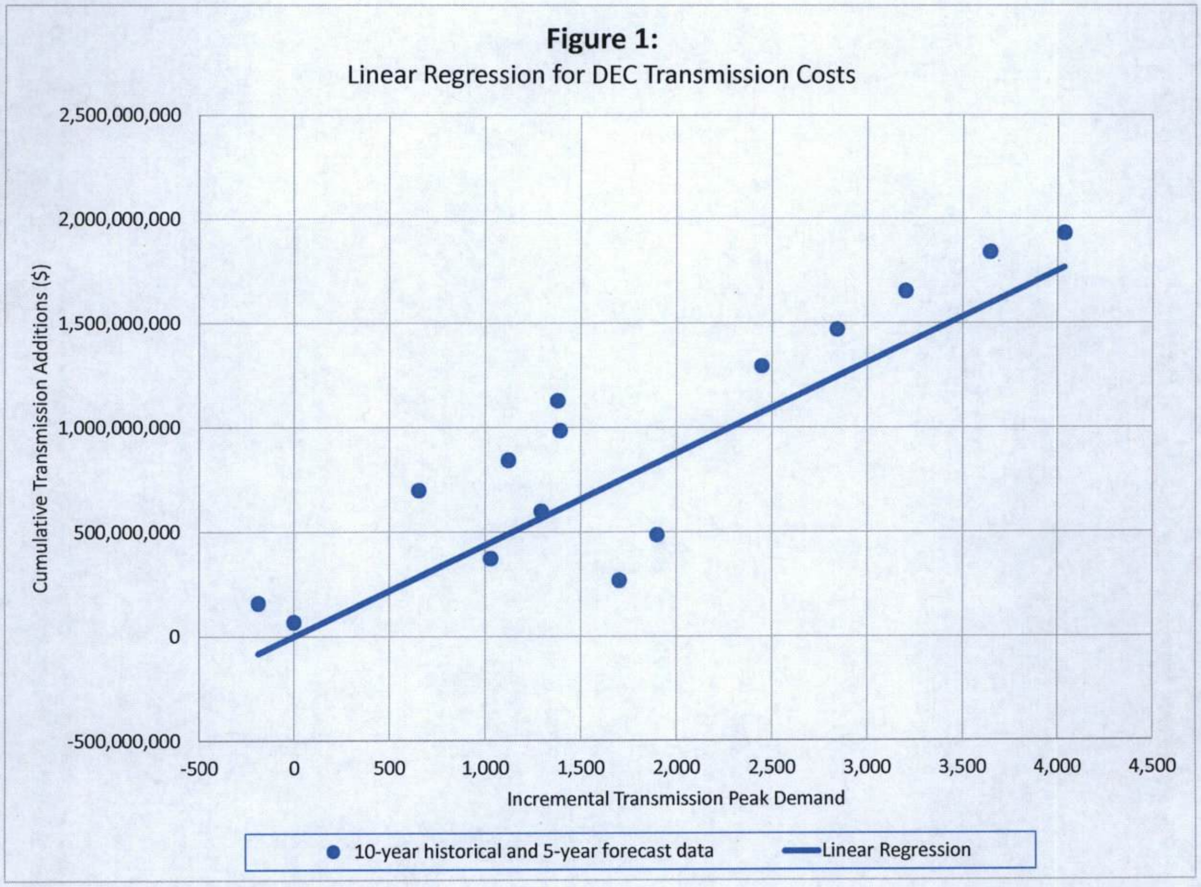
[13] See NC Public Staff witness Robert Hinton testimony in Docket E-7, Sub 1032 pre-filed on August 7, 2013. http://ncuc.commerce.state.nc.us/cgi-bin/webview/senddoc.pgm?dispfmt=&itype=Q&authorization=&parm2=TBAAAA02231B&parm3=000141791 .

[14] The NERA regression model fits incremental transmission costs to demand growth. The slope of the resulting regression line provides an estimate of the marginal cost of transmission associated with a change in load. The NERA methodology typically uses 10-15 years of historical expenditures on transmission and peak transmission system load, as reported in FERC Form 1, and a five-year forecast of future expenditures and load growth. Crossborder's analysis used DEC's FERC Form 1 data for the most recent 10 years (2003-2012), and a forecast of T&D project costs over the five future years (2013-2017) based on data from DEC's most recent general rate case (Docket E-7 Sub 1026, E-1 Data Item 23b). Future T&D project costs are allocated between transmission and distribution based on the historical division between these categories. Peak demand data is from Docket E-7, Sub 1026, E-1 Data Item 43a.



Transmission system peaks tend to coincide with system demand peaks, and thus we assume that solar's contribution to reducing transmission system peaks is the same as its contribution to avoided demand for generating capacity. Thus, we assume that each kW of solar DG capacity reduces DEC's peak transmission demand by 0.42 kW, and we convert avoided transmission capacity costs to dollars per MWh of solar DG output assuming an average annual output of 1,524 kWh per kW-AC. **Table 7** shows this calculation. The result for DEC is $10 per MWh (1.0 cents per kWh) for the transmission capacity costs avoided by solar DG; a parallel calculation for DEP yields avoided transmission capacity costs of 0.7 cents per kWh.

Table 7: *Calculation of Transmission Capacity Costs Avoided by Solar DG*

Component	DEC	DEP	Units
Marginal Transmission Capacity Cost (2014 $)	37	27	*per kW-year*
Solar Capacity as % of Nameplate	42%	42%	
Transmission Capacity Costs Avoided	16	11	*per kW-year*
Annual PV Output per kW-DC	1,524	1,524	*kWh per year*
Generation Capacity Cost Avoided by DSG	1.0	0.7	*cents / kWh*

As a check on this calculation, we have looked at DEC's filed avoided T&D benefits for several of its DR programs. These programs principally provide capacity benefits, and the avoided T&D portion of the benefits average about 40% of the generating capacity benefits. We understand that DEC and North Carolina Public Staff recently stipulated to the use of these T&D

benefits.[15] This level of T&D benefits is broadly consistent with our avoided transmission capacity costs in Table 7 compared to the avoided generation capacity benefits that we determined in Table 6.

Our approach for DNCP is different, given that DNCP is on the PJM system. For DNCP, we use the PJM rate for network integrated transmission service (the NITS rate), as a more direct measure of the costs which Dominion can avoid if solar reduces DNCP's peak demand on the PJM grid. As with avoided generation capacity costs, we apply the PJM solar capacity value percentage (46% of nameplate) to the avoided transmission costs, in recognition that peak solar output does not necessarily coincide with system peak demands. The resulting avoided transmission cost for DNCP is 0.9 cents per kWh.

2.4 Distribution

Solar DG also can reduce peak loads on distribution circuits, and thus avoid or delay the need to upgrade or re-configure the circuit if it is approaching capacity. However, circuits and substations on the distribution system can peak at different times than the system as a whole, which complicates the assessment of the extent to which solar DG can avoid or defer distribution capacity upgrades. As DG penetration grows, and a deeper understanding is gained of the impacts of DG on distribution circuit loadings, we anticipate that utility distribution planners will integrate existing and expected DG capacity into their planning, enabling DG to avoid or defer distribution capacity costs.[16] A comparable evolution has occurred over the last several decades, as the long-term impacts of EE and DR programs are now incorporated into utilities' capacity expansion plans for generation, transmission, and distribution, and it is generally recognized that these demand-side programs can help to manage demand growth even though the specific locations where these resources will be installed are difficult to predict.

The available studies which quantify the distribution capacity costs avoided by solar generation generally have calculated relatively modest values. **Table 8** below lists some of the studies which have calculated avoided distribution capacity costs. The most recent study, performed for the California Public Utilities Commission by the E3 consulting firm, based its calculations on marginal distribution costs in California and the correlation between solar output and distribution substation peaks. This study used data on distribution substation loads that is not typically available. Based on these studies, a reasonable range for avoided distribution capacity costs is 0.2 to 0.5 cents per kWh.

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[15] See the settlement filed August 19, 2013 in NCUC Docket E-7, Sub 1032, at page 6.

[16] A public summary of a confidential report on solar's modeled impacts on the DEC distribution system indicates that solar DG can also provide benefits such as voltage support and reduced line losses on feeder circuits, and that the value of solar along a circuit varies with proximity to the substation, load centers and other factors. See DEC witness Jonathan Byrd testimony in Docket E-7, Sub 1034, in the September 17, 2013 hearing transcript at p. 77-80 at http://ncuc.commerce.state.nc.us/cgi-bin/webview/senddoc.pgm?dispfmt=&itype=Q&authorization=&parm2=PAAAAA36131B&parm3=000141801. See the report summary filed as exhibit 4 to DEC witness Jonathan Byrd's testimony pre-filed on March 13, 2013 at http://ncuc.commerce.state.nc.us/cgi-bin/webview/senddoc.pgm?dispfmt=&itype=Q&authorization=&parm2=KAAAAA47031B&parm3=000141801 (beginning at pdf page 44).

Table 8: *Studies of Avoided Distribution Capacity Costs*[17]

State / Study / Date	Avoided Distribution Capacity Costs *(c/kWh)*	*Source*
AZ / R.W. Beck / 2009	0 to 0.31	*Fig. 6-2 at 6-14.*
PA-NJ / Clean Power / 2012	0.1 to 0.8	*Table 4*
AZ / Crossborder / 2013	0.2	*Table 1, at 2.*
AZ / SAIC / 2013	0	*pp. 2-10 to 2-12. No savings unless solar is targeted to circuits that are close to capacity.*
CA / CPUC-E3 / 2013 *(draft released 9/26/2013)*	0.6	*Includes sub-transmission and distribution costs. Based on correlation of distribution substation peaks to solar peaks.*
CO / Xcel Energy / 2013	0.05	*Table 1, at v and 27-36.*

2.5 Line Losses

The currently effective avoided energy prices for the North Carolina utilities include line loss adjustments in the range of 2% to 3%. The utilities state that these represent their marginal transmission line losses avoided by QF generation. There are several reasons why these loss adjustments are likely to be too low. First, solar projects generate during daylight hours over which system loads, and system losses, are above-average, while the QF loss factors may reflect a baseload output profile. Second, solar DG also avoids marginal distribution losses, which can be in the 5% to 8% range. Other studies have used combined marginal T&D loss factors in the 8% to 12% range.[18] In Virginia, Dominion appears to use at least an 8% distribution loss adjustment in settlements with competitive energy suppliers.[19] We have not included an additional line loss adjustment above the loss factor included in QF prices, but further data on distribution loss adjustments in North Carolina could justify additional benefits in this category of costs.

2.6 Avoided Emissions

Solar generation avoids emissions of both greenhouse gases and criteria air pollutants (SO_2, NO_x, and PM 10). It is our understanding that compliance costs for criteria pollutants are included in the production cost models used to determining avoided energy costs, but that future costs to mitigate greenhouse gas (GHG) emissions are not considered. We note that the North Carolina utilities do include future carbon emission costs in their IRPs. For example, DEC's 2012 IRP assumes a Base Case CO_2 emission cost of $17 per ton in 2020, escalating to $44 per ton in 2032.[20] The DEC IRP also includes a High Case for CO_2 emission costs of $31 per ton in 2020, escalating to $80 per ton in 2032.

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[17] All of these studies except the newly-released draft CPUC-E3 study are referenced and discussed in the RMI meta-analysis cited in Footnote 2 above. The new CPUC-E3 draft net metering cost-benefit study is available at http://www.cpuc.ca.gov/PUC/energy/Solar/nem_cost_effectiveness_evaluation.htm .

[18] The CPUC-E3 2013 study referenced in Table 7, at Table 5 in Appendix C, shows loss factors ranging from 5.7% to 10.9%. The R.W. Beck Study in Arizona, at Table 4-3, shows T&D loss reductions of 11.2% to 12.2%. of solar output.

[19] See the loss expansion factors in http://www.dom.com/business/electric-suppliers/index.jsp .

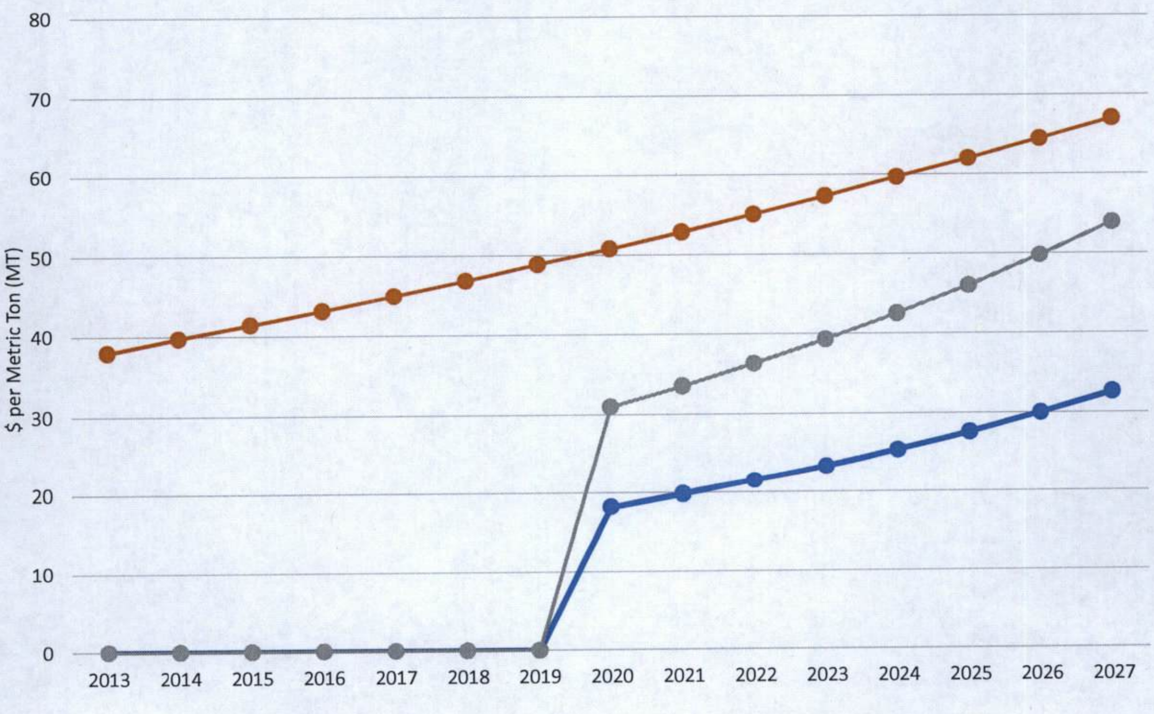
[20] DEC 2012 IRP, at 106.

As another metric for the costs of mitigating CO_2 emissions, the federal government has announced that it will prioritize reductions of greenhouse gas (GHG) emissions by focusing on reducing pollution from electric power generation. This effort will employ a Social Cost of Carbon (SCC), with a base scenario of a carbon cost of \$35 per metric ton CO_2 in 2012 (in 2007 \$), growing at 2.1% per year plus inflation through 2050.[21] This is equivalent to a \$34 per ton in 2013, rising to \$46 per ton in 2020, and \$61 per ton in 2027.

Given these developments, we believe that a reasonable range for the value of avoided GHG emissions uses DEC's IRP Base Case values as the low scenario, and the federal SCC as the high scenario. The SCC values in the high case also assume that CO_2 emission costs have an impact immediately, not just in 2020. Although it is clear that the U.S. (except for California and the Northeast) will not have a GHG allowance trading scheme in place for the power sector in the near future, it is more likely that there will be further regulatory actions from the Environmental Protection Agency to regulate carbon emissions from power plants. The SCC emission values can be considered a proxy for such regulatory actions.

Figure 2 shows these two projections of the costs of CO_2 emissions. We also indicate the DEC high CO_2 case from its 2012 IRP.

Figure 2:
CO2 Emissions Costs



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[21] See http://www.whitehouse.gov/sites/default/files/omb/inforeg/social_cost_of_carbon_for_ria_2013_update.pdf at page 18.

We convert these costs of mitigating carbon emissions from dollars per ton to $/MMBtu with a natural gas emission factor, and then to an energy price (in $/MWh) using the natural gas-based marginal heat rates assumed in our avoided energy cost forecast. **Table 9** shows these results. This calculation assumes, conservatively, that the North Carolina utilities' marginal generation, and marginal emissions, are entirely from natural gas. The utilities' avoided cost filings show that, today, their marginal emissions are from a combination of natural gas, coal, and purchased power, with coal constituting 20% to 30% of the mix. This suggests that our assumption that 100% of marginal emissions are from natural gas understates the utilities' actual marginal emissions, and thus underestimates the emission savings from new renewable generation.

Table 9: *Avoided Emissions Costs*

Case	**CO2 Mitigation Costs** *($ per ton)*			**Avoided GHG Costs** *(15-year levelized cents / kWh)*
	2013	**2020**	**2034**	
Base	0	17	30	0.4
High	34	46	61	2.2

2.7 Avoided Renewables Costs

The North Carolina REPS requires utilities to serve at least 12.5% of their customers' electricity needs through new renewable energy sources or energy efficiency measures by 2021. The current REPS requirement is 3%; it increases to 6% in 2015 and 10% in 2018.

Wholesale Solar. We assume that the cost of wholesale solar purchased by the utilities will include the transfer of the associated REPS REC, such that wholesale solar will count directly toward meeting the REPS requirements. Thus, the cost of a REC represents the value of wholesale solar in meeting the utilities' REPS needs. We discuss below the available data on the cost of an unbundled REC in North Carolina.

Solar DG. Distributed solar does not necessarily count toward the REPS, if the customer who installs solar DG retains the RECs associated with their production. However, solar DG output reduces the utility's sales, and thus lowers its future REPS obligations by the solar output times the applicable REPS percentage (i.e. by 3% today, by 6% in 2015-2017, by 10% in 2018-2019, and by 12.5% in 2020). Over the 15-year period from 2013 – 2027, the average REPS obligation is 9.6%. Thus, solar DG provides at least this modest benefit in reducing future REPS obligations. In addition, we also understand that, although solar DG customers may net meter under any available rate schedule, customers can retain their RECs only if they take service under a time-of-use (TOU) tariff with demand charges; otherwise, they must surrender all RECs to the utility, without compensation.[22] Our review of the utilities' tariffs indicates that most residential and small commercial solar DG customers are likely to be better off net metering under an all-volumetric tariff, and conveying their RECs to the utility for free. We also understand that, even if a solar DG customer retains his RECs, the customer often does not or is not able to monetize them, in which case the value of the REC accrues to the general body of ratepayers in

[22] See http://www.dsireusa.org/incentives/incentive.cfm?Incentive_Code=NC05R&re=0&ee=0 . Also, NCUC order dated March 31, 2009 in Docket E-100, Sub 83.

North Carolina at no cost to them even though such a REC is not be counted for REPS compliance. In this last case, in effect, free RECs are donated to the system and North Carolina achieves a higher renewables penetration than required by the REPS program. Thus, the maximum benefit that solar DG provides to ratepayers is about 110% of the value of a REC – i.e. 100% from the REC conveyed to the utility for free, plus the extra 9.6% from the reduction in the utility's sales.

Cost of RECs. There is only limited public data on the cost of unbundled RECs in North Carolina today. We have estimated this cost based on a range of data, including the following:

- A recent filing by the Town of Fountain municipal utility publicly reporting a purchase of 2011-vintage solar RECs for $15 per MWh (1.5 cents per kWh).[23]

- The utilities' 2012-2014 incremental costs associated with their compliance with the 3% REPS requirement for these years, as reported in their 2013 REPS compliance filings. These incremental REPS costs for DEC and DEP are summarized in **Table 10** below. DNCP does not have a commission-approved REPS Rider to recover incremental REPS costs, although they have filed for one. North Carolina's REPS statute generally defines "incremental" REPS costs as the costs to procure renewable generation that exceed the utility's avoided costs.[24]

Table 10: *2012-2014 Incremental REPS Costs*

Component	DEC	DEP
Incremental REPS Costs *($ millions)*	$52.3	$63.3
REPS Requirement *(millions of kWh)*	5.29	3.36
Incremental REPS Costs *(cents / kWh)*	1.0	1.9

- Cost premiums for North Carolina's "green pricing" program. All of the North Carolina utilities have tariffs which offer customers the ability to purchase blocks of renewable power for a set premium. This "green pricing" program is administered by an independent non-profit, NC GreenPower. The premium for residential customers is 4 cents per kWh; commercial customers pay an additional 2.5 cents per kWh.[25] NC GreenPower states that 75% of its revenues are used to purchase RECs, and contributions appear to be deductible from federal income taxes as a charitable contribution.[26] The non-profit offers to purchase RECs from small renewable generators for 6 cents per kWh over 5 years (equivalent to a 15-year levelized price of 2.8 cents per kWh).[27] The NC GreenPower price represents a price premium that ratepayers are willing to pay to increase the percentage of renewable power they use to above the REPS requirement for grid power. Customers install solar DG for the same purpose. The NC GreenPower premiums are high compared to the other REC metrics, although the effective price is lower if the

[23] See http://ncuc.commerce.state.nc.us/cgi-bin/webview/senddoc.pgm?dispfmt=&itype=Q&authorization=&parm2=WAAAAA23231B&parm3=000143195.

[24] North Carolina statutes § 62-133.8(h)(1).

[25] See the utilities' NC GreenPower tariffs.

26 See https://www.ncgreenpower.org/faq/ .

[27] See https://www.ncgreenpower.org/ncgp-announces-a-change-in-premium-payment-for-new-small-solar-pv-agreements-effective-june-3-2013/ .

payments are tax-deductible, and one would presume that the utilities would not offer this program as a tariffed service if NC GreenPower were overcharging consumers for the incremental cost of renewable generation, or if the utilities themselves could or were willing to meet the demand for the service at a lower cost.

Considering all of the above metrics, a reasonable range for the cost of a REC in North Carolina is 1.0 to 2.0 cents per kWh, with the lower end based on DEC's incremental REPS costs and the high end reflecting DEP's incremental REPS costs and the cost of RECs through NC GreenPower.

It is fair to ask what is included in the value of a REC, particularly if mitigating carbon pollution is accounted for separately.[28] We have discussed above a number of the difficult-to-quantify benefits of renewable generation that are encompassed in the value of a REC, including:

- Fuel Diversity
- Price mitigation benefits[29]
- Grid security[30]
- Economic development[31]

We assume that the cost of a REC provides a proxy for these benefits. When calculated separately and then summed, these benefits typically far exceed the cost of a REC. A number of studies have quantified one of more of these benefits, as referenced in the footnotes to the above list. For example, the Clean Power Research study of the value of solar DG in Pennsylvania and New Jersey estimated the price mitigation, grid security, and economic development benefits of solar PV in those states, and found those benefits together to range from $102 to $137 per MWh, in 20-year levelized dollars.[32]

Conclusion. The avoided renewables benefit of wholesale solar is the full cost of the RECs that we assume the utility acquires when it purchases solar generation under a wholesale PPA. This cost is 1 to 2 cents per kWh. For solar DG, the avoided renewables costs over the 2013-2027 period is, at a minimum, 9.6% of the cost of a REC, based on the reduced REPS costs when solar DG reduces utility sales. If solar DG customers convey their RECs to the utility, or cannot monetize their RECs, the attributes of these RECs will accrue to the general body of ratepayers in North Carolina. Thus, at the high end, the value of solar DG to North Carolina ratepayers is the 110% of the full cost of a REC.

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28 North Carolina statute § 62-133.8(a)(6) defines a REC to <u>not</u> include the value of reducing CO_2 emissions.

29 For example, a Lawrence Berkeley National Lab study has estimated that the consumer gas bill savings associated with increased amounts of renewable energy and energy efficiency, expressed in terms of $ per MWh of renewable energy, range from $7.50 to $20 per MWh. Wiser, Ryan; Bolinger, Mark; and St. Clair, Matt, "Easing the Natural Gas Crisis: Reducing Natural Gas Prices through Increased Deployment of Renewable Energy and Energy Efficiency" (January 2005), at ix, http://eetd.lbl.gov/EA/EMP .

30 Hoff, Norris and Perez, *The Value of Distributed Solar Electric Generation to New Jersey and Pennsylvania* (November 2012), at Table ES-2.

31 *Ibid.* Also, a 2013 study by RTI International and La Capra Associates found that north Carolina's clean energy and energy efficiency programs contributed $1.7 billion to the state's economy from 2007-2012, created or retained 21,163 job-years over this period, and will provide long-term ratepayer benefits for the state. The study can be found at http://energync.org/assets/files/RTI%20Study%202013.pdf .

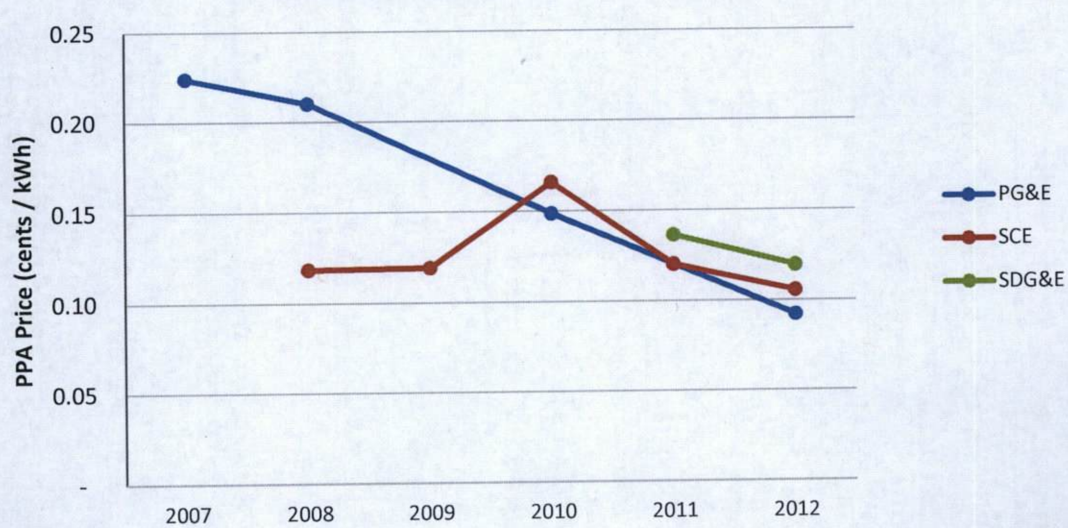
32 *Ibid.*

3. Costs of Solar Generation

3.1 Wholesale Solar PPA Prices

Wholesale solar PPA prices provide perhaps the most dramatic evidence of the continued decline in solar PV costs. Solar PPA prices have fallen dramatically over the past several years, to the point that, in some regions of the U.S., solar is now competitive with other generation resources, including wind and natural gas. Xcel Energy in Colorado recently announced that it is proposing to add 170 MW of utility-scale solar to its system, with its CEO stating "[f]or the first time ever, we are adding cost competitive utility scale solar to the system."[33] The California electric utilities make public each year the average PPA prices for renewable contracts approved by the CPUC in the prior year. **Figure 3** shows the trend in the prices for their solar PV PPAs; CPUC contract approval can occur up to a year or more after bids are received, so the figure is indicative of prices through roughly 2011.[34] 2012 solicitations for solar PPAs in California in the 3 MW to 20 MW size range through the Renewable Auction Mechanism (RAM) have yielded market-clearing prices in the 8 to 9 cents per kWh range.[35]

Figure 3: California Solar PV PPA Prices



[33] See http://www.xcelenergy.com/About_Us/Energy_News/News_Releases/Xcel_Energy_proposes_adding_economic_solar,_wind_to_meet_future_customer_energy_demands .

[34] See http://www.cpuc.ca.gov/NR/rdonlyres/F0F6E15A-6A04-41C3-ACBA-8C13726FB5CB/0/PadillaReport2012Final.pdf .

[35] See http://www.cpuc.ca.gov/PUC/energy/Renewables/hot/Renewable+Auction+Mechanism.htm for details on the RAM program and the RAM auction results in MW. See http://votesolar.org/2012/03/30/ram-results-11-projects-130-mw-total-most-solar-all-under-8-9-centskwh/ for RAM prices from 2012.

The Lawrence Berkeley National Lab (LBNL) conducts and publishes regular national surveys of the installed costs of solar PV; these surveys include PPA prices for utility-scale solar projects. LBNL recently released its most recent survey of wholesale, utility-scale solar PPA prices, including data to September 2013.[36] LBNL samples the prices only for utility-scale solar PV projects that sell both electricity and RECs in the wholesale power market through a long-term PPA that includes the "bundled" sale of both power and RECs.[37] **Figure 4** illustrates the trend in utility-scale, wholesale solar PPA prices.[38] Based on the 2012-2013 data, utility-scale solar PPAs now appear to be in the range of $55 to $75 per MWh. The data for PPAs from 2012 and 2013 are for projects that are not yet on-line, and thus remain subject to some uncertainty over contract performance. However, LBNL's PPA data from earlier years is based on projects which in general are now on-line, which substantiates the trend of rapidly dropping PPA prices and provides confidence that most of the reported 2012-2013 PPA prices will result in successful projects.

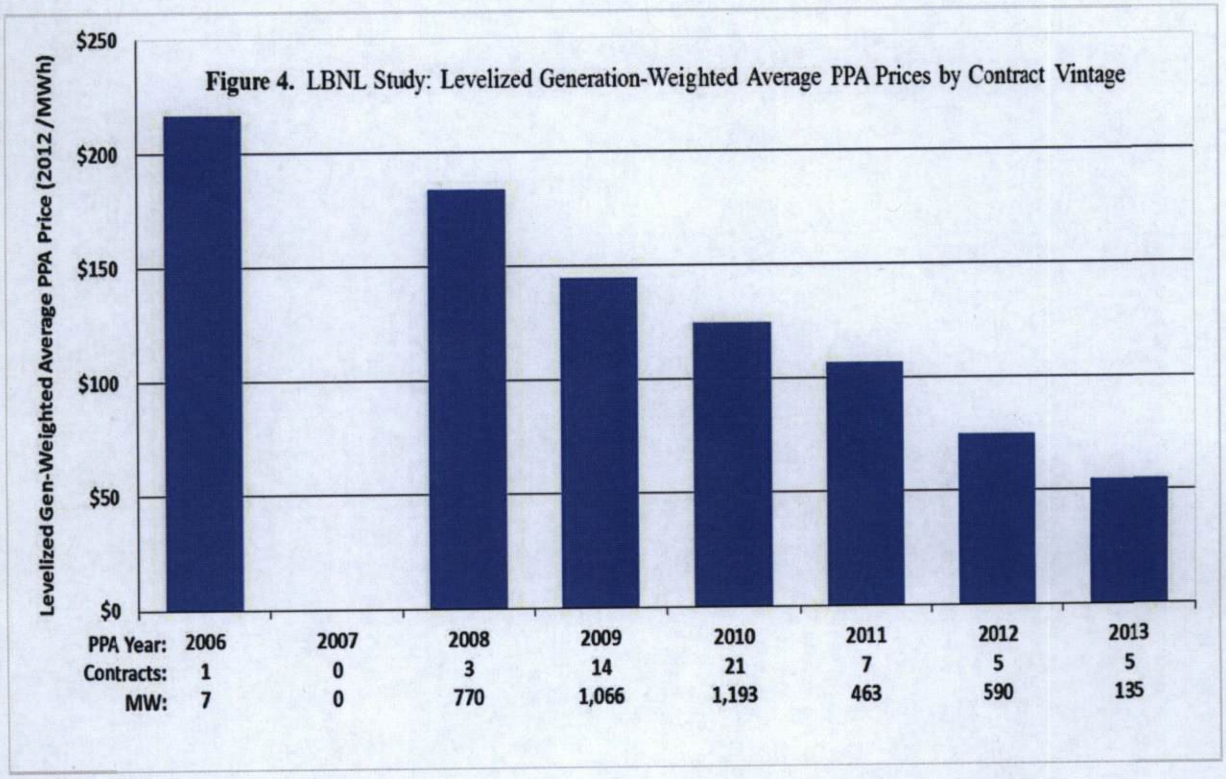


Figure 4. LBNL Study: Levelized Generation-Weighted Average PPA Prices by Contract Vintage

LBNL also reports on the installed costs of utility-scale solar projects, by region. The most recent data indicates that costs in the southeastern U.S. (data from North Carolina and Florida) have dropped almost to par with costs in the western U.S. where the bulk of utility-scale solar projects are located.[39]

An important caveat to the LBNL data is that most of the PPAs sampled are in the western

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36 See "Utility-scale Solar: An Empirical Analysis of Project Cost, Performance, and Pricing Trends in the United States" (September 2013, LBNL Publication 6408-E), hereafter "LBNL Study." Available at http://emp.lbl.gov/reports/re .

37 *Ibid.*, at 19.

38 *Ibid.*, Figure 16.

39 *Ibid.*, at Figure 4.

U.S., which has higher solar insolation levels than the eastern U.S.[40] Using the NREL PVWATTS calculator, the expected annual output (in kWh per kW) of a fixed array in Charlotte is 11% lower than the average annual output of PV systems in Sacramento, Los Angeles, Phoenix, and Boulder. LBNL reports capacity factors for utility-scale solar projects in the U.S. Southeast that are about 20% lower than in the western U.S.[41] As a result, the LBNL data needs to be adjusted upwards to estimate potential wholesale solar PPA prices in North Carolina. Adjusting the LBNL 2012 - 2013 range of solar PPA prices ($55 to $75 per MWh) upward by 25% to reflect the North Carolina capacity factors are 20% lower than in the western U.S., and placing somewhat greater emphasis on the most recent 2013 data, yields a range of $70 to $90 per MWh (7 to 9 cents per kWh), which we believe to be a reasonable, current range for the cost of wholesale solar PPAs in North Carolina.[42]

3.2 Solar DG Costs – Lost Revenues

The primary costs of solar DG are the retail rate credits provided to solar customers through net metering, i.e. the revenues that the utility loses as a result of DG customers serving their own load and exporting power to the grid when the solar output exceeds the on-site load. The lost revenues are dependent on the utility's retail rate design, and can vary considerably based on the rate structure. Solar DG customers are primarily able to avoid volumetric, per kWh rates. They are much less able to avoid demand charges, and of course cannot avoid fixed monthly charges that do not depend on usage.

North Carolina utilities have a variety of retail rate structures. Residential rates consist largely of a single volumetric rate, with some seasonal (summer / winter) differentiation, plus a significant fixed monthly charge. DEP's residential solar customers must use a time-of-use rate with a demand charge (R-TOUD) in order to qualify for an incentive under DEP's SunSense program. Small commercial rates feature a declining block structure, such that the average rate decreases as usage goes up. Large industrial customers pay significant demand charges and time-of-use energy rates.

We have assumed that the lost revenues from residential solar DG are based on the customer's volumetric rate for the marginal usage served by the solar unit, and assume that the solar DG customer takes service under the rate schedule with the highest volumetric rates in order to maximize bill savings under net metering. The lost revenues from a small commercial solar customer under a declining block rate will depend on the size of the solar system relative to the customer's usage; we have generally assumed that the rates for usage above the first tier represent the marginal lost revenues.

Lost revenues on a 15-year levelized basis also depend on the assumed future escalation in future rates. A recent rate case settlement approved for DEC included a near-term, three-year rate increase averaging 1.7% per year.[43] EIA data shows that electric rates in North Carolina over the 20 year period from 1992 - 2011 increased at 1.4% per year. We have calculated a range of lost revenues based on future rate escalations from 1.0% to 2.5% per year. These results are shown in **Table 11**.

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[40] *Ibid.*, at 22.
[41] *Ibid.*, at Figure 11.
[42] Of course, this range of PPA prices all assume the availability of federal and state tax credits at 2013 levels.
[43] See http://www.duke-energy.com/north-carolina/nc-rate-case.asp.

3.3 Integration Costs

Finally, several utilities have completed studies on solar integration costs. A recent study which Arizona Public Service commissioned estimated integration costs of $2 per MWh in 2020 and $3 per MWh in 2030.[44] Xcel Energy in Colorado has calculated solar integration costs as $1.80 per MWh on a 20-year levelized basis.[45] Based on the high end of the range in these studies, we have added an assumed solar integration cost of $3 per MWh (0.3 cents per kWh).

Table 11 summarizes all of these costs of solar DG for North Carolina ratepayers.

Table 11: *Costs of Residential and Commercial Solar DG (15-year levelized cents / kWh)*

Class	DEC	DEP	DNCP
Lost Revenues			
Residential	9.8 – 10.7	10.5 – 11.5	10.1 – 11.0
Commercial	7.7 – 8.4	9.7 – 10.6	8.7 – 9.4
Integration	0.3	0.3	0.3
Total Costs			
Residential	**10.1 – 11.0**	**10.8 – 11.8**	**10.4 – 11.3**
Commercial	**8.0 – 8.7**	**10.0 – 10.9**	**9.0 – 9.7**

4. Conclusion

The benefits of solar generation in North Carolina equal or exceed the costs of this source of renewable generation. This conclusion is valid regardless of whether solar is developed as wholesale generation with the entire output sold to the utilities or as demand-side distributed generation under net metering. The quantitative results of our work are summarized in Tables 2 and 3. If one uses the midpoints of the ranges of costs and benefits shown in these tables, the benefits of wholesale solar exceed the costs by about 40% (a benefit / cost ratio of 1.43), and the benefits of solar DG are almost 30% larger than the costs (a benefit / cost ratio of 1.27). Over the next several years, if North Carolina utilities were to add 400 MW of wholesale solar and 100 MW of solar DG resources, the net benefits for ratepayers would be $26 million per year.

44 Black & Veatch, "Solar Photovoltaic (PV) Integration Cost Study" (B&V Project No. 174880, November 2012).

45 Xcel Energy Services for Public Service Company of Colorado, "Cost and Benefit Study of Distributed Solar Generation on the Public Service Company of Colorado System" (May 23, 2013), at Table 1, pages v and 41-42.