OPC-DC
Office of the People's Counsel
ADVOCACY | EDUCATION | PROTECTION

Office of the People's Counsel Value of Solar Study

Distributed Solar in the District of Columbia

Policy Options, Potential, Value of Solar and Cost-Shifting

Synapse Energy Economics, Inc.
Cambridge, Massachusetts
Melissa Whited
Ariel Horowitz, PhD
Thomas Vitolo, PhD
Wendy Ong
Tim Woolf

Distributed Solar in the District of Columbia

Policy Options, Potential, Value of Solar, and Cost-Shifting

Prepared for the Office of the People's Counsel for the District of Columbia

April 12, 2017

AUTHORS

Melissa Whited
Ariel Horowitz, PhD
Thomas Vitolo, PhD
Wendy Ong
Tim Woolf

Synapse Energy Economics, Inc.

485 Massachusetts Avenue, Suite 2
Cambridge, Massachusetts 02139

617.661.3248 | www.synapse-energy.com

CONTENTS

Acknowledgements

The DC Council directed the Office of the People's Counsel (OPC) to commission a study on emerging energy technologies. In accordance with the Council's directive, OPC determined that the District would benefit from having a comprehensive Value of Solar (VoS) Study explicitly designed to address the city's unique characteristics and needs. OPC embarked on this endeavor with two principal goals: (1) explore the potentials and barriers to distributed generation in the District, particularly solar photovoltaics, and determine the value of solar generation in the District; and (2) to assess the potentials and barriers to rooftop solar power generation in low-income communities in the District of Columbia.

OPC management and staff invested countless hours and sustained resources in this project. People's Counsel Sandra Mattavous-Frye and Deputy People's Counsel Karen Sistrunk initiated and actively participated in all aspects of the study. An OPC Staff Attorney was the initial case manager of the project. Keishaa Austin, Policy Analyst, managed the project from January 2017 thru its completion. Senior Economist, Dr. Yohannes Mariam served as in-house reviewer thru the project and staff members Doxie McCoy and Stephen Marenic provided valuable editorial support and comments in the final stages of the project. Jason Cumberbatch, Staff Engineer also provided input at various stages of the study.

One of OPC's primary goals in producing the study was to ensure it reflected various viewpoints from critical stakeholders. Toward this end, OPC acknowledges and commends the spirit of cooperation and collaboration shown by myriad industry representatives, subject matter experts, lay consumers and other interested parties. The VoS Study has greatly benefited from comments and input provided by stakeholders at various stages of the process, including more than 15 online participants for the October 5, 2016, webinar on the "Value of Solar in the District of Columbia: Methodology," presented by Synapse Energy Economics. Comments and recommendations were also provided by Mr. Amit Ronen of The George Washington University Solar Institute.

Likewise, the contents and quality of the study have been augmented by an ongoing and open dialogue with Pepco representatives who provided access to utility data and comments on the study. Specifically, OPC would like to thank the members of Pepco's technical team, led by Company President, Dr. Donna Cooper, who attended an informal data conference with OPC prior to the completion of the project. OPC is confident that the participation of these parties enhanced the final product.

Finally, we thank Synapse Energy Economics for producing an outstanding and seminal study that OPC believes will benefit many energy and environmental stakeholders in and around the District of Columbia.

INTRODUCTION AND BACKGROUND

This study was commissioned by the Office of the People's Counsel pursuant to a DC Council directive tasking OPC "to address emerging alternatives for energy choice for residential consumers" (Bill 21-158, the Fiscal Year 2016 Budget Support Act of 2015, June 30, 2015). OPC sought expert consultants to conduct a Value of Solar (VoS) Study for the District of Columbia that would make recommendations regarding policies to support distributed energy generation, assess the potential for various types of distributed energy generation systems (particularly solar photovoltaic or "PV") in the District, and quantify the value of solar in the District. The Office selected Synapse Energy Economics, a research and consulting firm specializing in energy, economic, and environmental topics. Synapse Energy Economics provides rigorous analysis of the electric power sector for public interest and governmental clients across the nation and internationally.

OPC recognized that the regulatory landscape in the District is undergoing seismic change which is largely attributable to national and local policies promoting energy efficiency (EE) and the growing importance of integrating distributed energy resources/generation (DER/DG) technologies into the mix of electricity generation resources. The District, for its part, has aggressively promoted and supported the development of innovative DER and EE programs. These policies include a Renewable Portfolio Standard (RPS) and the Renewable Portfolio Standard Expansion Amendment Act of 2016, requiring that 50 percent of retail sales should be from renewable energy by 2032, with a 5 percent solar carve out. In addition, District RPS regulation requires the establishment and enforcement of alternative compliance penalty payments for utilities when sufficient solar renewable credits (SRECs) cannot be purchased.

Despite these valiant efforts and a generally favorable market, the goals remain aspirational, and impediments to ensuring the equitable distribution of the benefits associated with these technologies remain a challenge. While the District has commendably pursued a positive course of action toward solar generation, this traction has advanced without a centralized District-specific empirical database from which policy makers can draw as they make decisions.

This Value of Solar Study is intended to fill the void and provide a centralized data pool. Specifically, the Study separately addresses policy and rate design options, technical and economic potential for DG; value of solar using utility system costs and societal costs; and looks at cost-shifting among consumers with and without solar generation systems. Specifically, OPC believes that a study on DC solar potential and value will be highly useful to policymakers and energy policy stakeholders, and provide a supportive predicate in advance of local initiatives. The Study is also driven by the increasing number of DC electric residential customers applying for a certification of solar energy facilities.

OPC also solicited a District-based energy consultant to study and produce a report on assessing the potential of rooftop solar and barriers to solar power generation in low-income communities in the District of Columbia. Jerome S. Paige and Associates (JSPA) was selected for this study. The JSPA Report is an independent study intended to separately address issues related to solar deployment among low-income District residents. The analysis of the two studies complement each other.

EXECUTIVE SUMMARY

Beginning in 2007, Washington DC established renewable portfolio standard (RPS) requirements for electricity suppliers.[1] These RPS requirements have subsequently been expanded, most recently in June 2016, to require that 50 percent of retail sales be met by renewable energy by 2032, with 5 percent coming from solar resources. Solar has grown quickly in recent years, yet current solar capacity falls far short of the District's target of approximately 70 megawatts (MW) for 2016.

Part I of this report analyzes barriers to solar in the District of Columbia, provides case studies of jurisdictions that have implemented policies to overcome such barriers, and provides recommendations for the District of Columbia. Part II estimates the technical and economic potential of solar in the District, Part III calculates the value of solar in the District, and Part IV estimates cost-shifting.

Part I: Addressing Barriers to Distributed Solar

The District currently offers numerous incentives and programs to encourage the adoption of distributed solar. These include net metering, community solar, and Solar Renewable Energy Credits (SRECs). The District has also undertaken a range of programs to help expand solar access, particularly for low-income residents. Most recently, the District established the Solar for All program, which sets a target of reducing the electricity bills of at least 100,000 of the District's low-income households through solar by the early 2030s. In addition, the District has begun to procure solar for many of its municipal buildings (including schools and government facilities), entering into a power purchase agreement for more than 11 MW of solar capacity.

Although the District has undertaken a number of initiatives to help drive greater adoption of distributed solar, continued efforts will be necessary to help the District meet its ambitious distributed solar goals. Recent efforts to reduce barriers to solar adoption have included increasing the net metering credit for community solar facilities, addressing interconnection barriers, and increasing the alternative compliance payment when sufficient SRECs cannot be obtained.

Common Barriers to Distributed Solar in the District of Columbia

The primary barriers to distributed solar relevant to the District are:

1. **Access to suitable space:** The District is a dense urban environment with a high percentage of residents who are renters. Only 28 percent of housing is owner-occupied single-family housing. Another 13 percent of housing is characterized as owner-occupied units in multi-family buildings, while 59 percent of housing is rented. The percentage of renters is much higher than the national average, which is significant for distributed generation (DG) development, as renters

[1] Public Service Commission of the District of Columbia, "Report on the Renewable Energy Portfolio Standard for Compliance Year 2015," May 2, 2016.

generally do not have the ability or incentive to install solar on their residence without the support of the landlord.

Barriers to solar exist even for many residents who own their homes, particularly for buildings with two or more units. Decisions to install solar panels become more complex where multiple owners share roof space, and solar may have to compete with alternative rooftop uses on such buildings, such as swimming pools, building HVAC systems, and shared entertainment areas.

Another real estate challenge facing the District is the historic nature of many of its neighborhoods. Currently the District's historic preservation guidelines require that solar panels be installed in a manner so that they are not visible from the street, which reduces the roof space available.

2. **Interconnection process**: In 2015, the District ranked 33rd out of 34 utilities in terms of time required for interconnecting small-scale solar.[2] Pepco's 2016 Annual Interconnection Report filed on March 31, 2017, indicates substantial reductions in its interconnection processing times.

3. **Program funding uncertainty:** Significant financial incentives are generally available to customers wishing to install distributed generation. For solar PV, these incentives include solar renewable energy credits (SRECs), as well as program-specific incentives funded through alternative compliance payments. However, both SREC prices and program incentives can vary from year-to-year, creating uncertainty regarding payback periods for solar investments. This uncertainity may dampen investments in solar.

4. **Upfront costs and customer financing:** Although the costs of solar have fallen substantially in recent years, solar PV still represents a significant investment with high up-front costs that many customers cannot afford. In 2016, the cost for a 4 kilowatt (kW) system was approximately $13,000.[3] Even leasing arrangements through third parties generally require minimum credit scores or debt-to-income ratios, which can exclude many low-income customers.[4]

5. **Ineffective price signals:** Net metering provides a simple and reliable method of compensating generation owners for the energy generated by their systems. It does this by providing a credit equal to the retail rate to customers. Until recently, full retail rate compensation was not available to community solar customers. Since instituting full retail rate compensation for community solar, however, applications for such projects have increased rapidly.

---

[2] MDV-SEIA, "Regional Interconnection Study: Evaluating Mandated Timelines and Compliance," 2015, 12.

[3] As of the first quarter of 2016, GTM Research and the Solar Energy Industries Association report that national average residential rooftop PV systems cost approximately $3.21/W. The majority of these costs (nearly 63%) are attributable to on-site labor, engineering, permitting and other soft costs, rather than the costs of the panels themselves. Both hardware and soft costs are declining -- residential hardware costs fell by over 4% in the past quarter, while soft costs decreased by almost 12%. *See:* GTM Research and Solar Energy Industries Association, "U.S. Solar Market Insight: Q2 2016," June 2016, 14, http://www2.seia.org/l/139231/2016-06-07/dy493.

[4] GRID Alternatives, Vote Solar, Center for Social Inclusion, "Low-Income Solar Policy Guide," March 11, 2016, http://www.lowincomesolar.org/wp-content/uploads/2016/03/Low-Income-Solar-Policy-Guide_3.11.16.pdf.

This report discusses and provides case studies for the policy options listed in the table below.

Table ES-1. Policy options outlined in report

Category	Policy Type	Incentive	Examples Discussed in Report
Financial Incentives	Compensation Mechanisms	Net Metering	Portland, Palo Alto
		Feed-in tariff	Austin, Palo Alto, Portland
		Value-of-Solar tariff	Austin, Minnesota
		Rooftop Hosting	San Antonio, Arizona Public Service
		Long-Term Tariff Incentive	Rhode Island
		Rebates	California
		Solar Renewable Energy Credits	District of Columbia, New Jersey
		Community Solar	New York, San Antonio, Seattle, Minnesota
	Rate Design	Solar customer fee per kW	Salt River Project
	Financing	SREC-based financing program	New Jersey
		$0 down loan options	Rhode Island, Connecticut
		Grants	Rhode Island
		Rebates	California, San Antonio
		PACE and PPA	Connecticut
	Tax Incentives	Production incentive credit	Seattle
		Sales tax exemption (State and/or local)	Rhode Island, New York
		Property Tax exemption (State and/or local)	Rhode Island, New York
		Invest in EE and PV	Rhode Island
Utility Incentives	Revenue Decoupling		District of Columbia
	Utility Ownership of Distributed Generation		San Antonio, Seattle, Arizona Public Service, Consumers Energy
	Penalties for RPS non-compliance		Washington, Montana, Missouri, District of Columbia
Non-Financial Incentives	Interconnection & Permitting Processes	Expedited review	Palo Alto
		Program conducts installation and interconnection processes	San Antonio
		Mandated time-limits	Connecticut
		Loosened restrictions for visually-compatible installations	St. Louis, Missouri
	Education, Training, and Outreach	Information workshops, presentations, webinars	Seattle, California
		Training (for public, utility staff and/or contractors)	Seattle, Connecticut
		Guidelines and Guidebooks	California, Seattle
		Online tools and calculators	California
		On-line support	New York, California
		One-on-one guidance through program process	Connecticut
		Community outreach	New York

Recommendations for the District of Columbia

The District has undertaken a wide range of efforts focused on stimulating growth in distributed solar, yet growth still lags targets. This lackluster growth appears to be largely unrelated to overall compensation levels for DG owners, as the estimated payback period for a typical residential solar array is only five years. This relatively fast payback is largely due to SRECs, but is also attributable to net metering and overall rate designs that, when combined with SRECs, provide reasonable compensation levels to customer-generators.

To explain why the District has not achieved its goals, we must look to other factors influencing customer adoption of distributed generation. From our review, the most significant factors appear to be related to (1) real estate constraints (particularly the high proportion of renters, historic district restrictions, and the lack of open space for large ground-mounted arrays); (2) financing barriers for low-income customers; (3) community solar challenges (including the newness of the program and challenges related to customer acquisition and engineering complexity); and (4) Pepco's historical performance in terms of efficient processing of interconnections.

Some of these challenges are being actively addressed by the District, while others have not yet been sufficiently remedied. Our analysis suggests that the following actions may help to address the barriers facing distributed generation in the District:

- Facilitate community solar through addressing engineering and customer acquisition challenges, expanding incentives, partnering with third-party community solar developers, and potentially allowing Pepco to provide community solar if the market does not.
- Expand municipal procurement of solar, encourage solar parking canopies, and possibly expand the definition of eligible solar generators.
- Ensure that historic district restrictions are appropriate and not overly strict.
- Continue to address financial challenges for low-income customers, such as through expansion of the Affordable Solar Program or implementation of a Green Bank.
- Consider implementing financial penalties or rewards (that cannot be passed through to customers) for Pepco that are tied to achieving solar targets and meeting interconnection deadlines.

The table below summarizes these barriers, current actions being taken, and additional recommendations.

Table ES-2. Recommendations for the District of Columbia

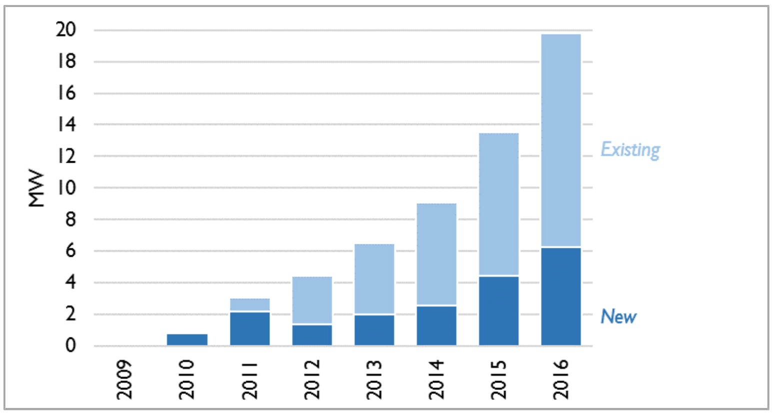
BARRIER	CURRENT ACTIONS TAKEN	RECOMMENDATIONS
High Proportion of Renters	• Provide access to community solar • Affordable Solar Program	• Address engineering and customer acquisition challenges for community solar • Consider allowing Pepco to own and rate base community solar facilities if the market does not provide adequate capacity • Expand the Affordable Solar Program • Encourage landlords to install solar with SREC and virtual metering benefits or through property or income tax benefits
Historic District Restrictions	• Provide access to community solar	• Conduct neighborhood planning discussions to develop more specific guidelines • Consider loosening restrictions regarding visibility, fire code, or zoning restrictions • Meet with community solar developers to determine whether any additional barriers exist
Lack of Open Space for Large Arrays	• Utilize municipal properties (building roof space, water treatment plant facilities, etc.)	• Continue to pursue municipal solar as a priority • Encourage solar parking canopies to utilize largest developable flat surfaces in the District • Allow community solar solely owned by DC residents located nearby but outside the District to qualify for DC SRECs • Foster residential rooftop project aggregation to reduce soft and hard costs through economies of scale
Financial Constraints for Low-Income Customers	• Provide access to community solar • Affordable Solar Program	• Address engineering and customer acquisition challenges for community solar • Consider allowing Pepco to own and rate base community solar facilities if the market does not provide adequate capacity • Implement a Green Bank program to provide financing • Expand the Affordable Solar Program
Customer Acquisition Costs for Multi-Family Buildings		• Consider allowing Pepco to own and rate base community solar facilities if the market does not provide adequate capacity • Provide resources and outreach to multi-family building owners
Pepco's Interconnection Application Processing Timelines	• Enforce timelines • Address authorization to operate lags	• Provide Pepco with incentives (penalties or rewards) associated with meeting solar interconnection or development targets
Cost Reduction	• DC Sustainable Energy Utility initiatives	• Require new construction to be solar-ready as part of the Construction Codes and/or expand the Green Building Act

Part II: Technical and Economic Potential Estimates

In order to evaluate the technical and economic potential for distributed generation in the District, Part II of this study began with an analysis of the distributed generation technologies available and an assessment of the feasibility of these technologies in Washington DC. We conducted a review of a diverse range of available technologies, including fuel cells, biomass and municipal solid waste combustion, small-scale distributed wind turbines, combined heat-and-power, energy storage, solar thermal, and solar photovoltaics (PV).

Of these technologies, solar PV has grown the fastest in recent years due to a combination of technical feasibility and policy incentives. Figure ES-1 below shows the cumulative and incremental growth in solar PV in the District since 2009. These same technological and financial factors suggest that such growth is likely to continue in the near term.

Figure ES-1. Solar PV cumulative and incremental capacity additions in the District of Columbia



Technical Potential

Due to the promising growth outlook for solar PV, the remainder of the analysis focused on this technology. To estimate the technical and economic potential of rooftop solar PV in the District, we analyzed residential and non-residential buildings using geographical information systems (GIS) data for the District. Buildings were first parsed by zoning districts, and then the total number of buildings (or total roof area) was calculated per building type. The building stock data were then de-rated (described more below) and translated into an equivalent capacity of solar PV. This PV capacity value provides an estimate of technical potential.

For small residential buildings, the technical potential of solar PV was estimated based on the number of such buildings that are suitable for solar installations and the average size of residential PV systems in the District. Suitable small residential buildings were defined as those located outside of historic districts, without existing PV systems, and with roofs of sufficiently low ages, slopes, and shading levels. This analysis found that there are approximately 85,000 suitable small residential buildings without existing PV systems in the District. Assuming an average residential system size of approximately 4.3 kW, this translates into an unrealized technical potential of 360 MW on small residential buildings alone. This amount of rooftop solar capacity can yield approximately 470 gigawatt-hours (GWh) of energy every year.

For large buildings (including commercial, industrial, government, and multifamily buildings), a similar analysis was conducted. However, this analysis was based on roof area instead of the number of buildings, as there is a much greater variation in solar PV system sizes on large buildings. Large building rooftop area was de-rated based on an assumed coefficient of rooftop availability, to account for shading and occupancy requirements of HVAC systems and similar mechanical equipment. Overall, it was found that the District has approximately 10.5 million square meters of available rooftop area, of which 2 percent is identifiably owned by the federal government and 3 percent is identifiably large multifamily buildings (with the remaining 95 percent consisting of commercial, industrial, local government, and mixed-use buildings). This amount of roof area translates into approximately 1,320 GW of additional solar PV potential, capable of generating 1,700 GWh of energy per year.

The table below summarizes the rooftop PV technical potential by building type in the District.

Table ES-3. Summary of rooftop PV technical potential in the District of Columbia (excluding parking lots)

Building Type	***Conservative***	***Reference***	***Optimistic***
Small Residential Capacity (MW)	**320**	**360**	**440**
Total GC&I, Multifamily, Federal Capacity (MW)	**620**	**1,320**	**2,030**
GC&I Capacity (MW)	580	1,250	1,920
Large Multifamily Capacity (MW)	20	40	60
Federal Capacity (MW)	20	30	50
Total Rooftop Capacity (MW)	**940**	**1,680**	**2,470**

Economic Potential

The technical potential analysis was followed by an analysis of the potential economic adoption of rooftop PV across all sectors and building types. Likely economic adoption of rooftop PV by customers can be estimated by first calculating the simple payback period, and then applying a market diffusion curve from the literature. Because of high SREC prices, solar PV sited in the District currently has a very low payback period of only four to six years for a typical residential customer. A payback period of five years was assumed for this analysis.

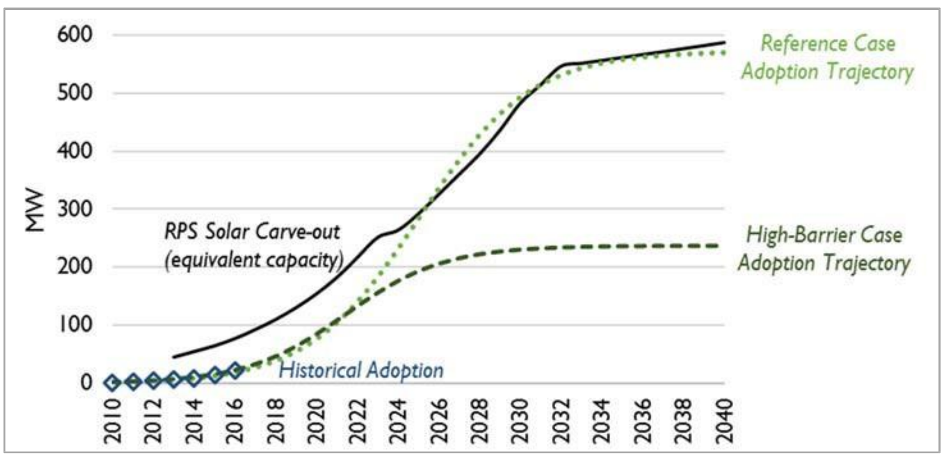
Based on correlations between the simple payback period and economic adoption rates found in the literature, this analysis predicted an ultimate adoption of approximately 560 MW of solar PV capacity across all building types in the District. Under this economic adoption trajectory, the District's economic solar potential would be saturated in the late 2030s.

To put these findings in perspective, if the entire technical potential of rooftop PV in the District were realized, the electricity generated by rooftop PV would approximately equal 20% of 2015 electricity sales.[5] The economic potential of rooftop PV is approximately 1/3 of the technical potential, equivalent to approximately 6% of electricity sales. Thus, if the District reached its economic potential for rooftop PV, the generation would slightly exceed the current solar carve-out of 5 percent.

Because the economics of solar PV in the District are largely driven by SREC prices, it is important to know when adoption of PV may meet the District's RPS solar carve-out target. When the solar carve-out target is reached, SREC prices would fall to a market-driven value rather than remain near the Alternative Compliance Payment value. Until the solar carve-out target is reached, SRECs will be closely linked to the Alternative Compliance Payment cap (which begins at $500/MWh and declines to $300/MWh over time).

This analysis shows that the total amount of solar PV in the District is likely to stay below the RPS solar carve-out target until at least the mid-2020s, after which point economic adoption is expected to largely track the carve-out target trajectory (Figure ES-2). However, if significant non-economic barriers to solar adoption prevent realization of the full economic potential, solar adoption may never reach the RPS solar carve-out target. Recent policy initiatives such as the Solar for All program may have a large impact on if, and when, the solar carve-out is met.

Figure ES-2. Adoption trajectories – reference case and significant non-economic barriers



[5] Note that we have not included parking lots or other land in this estimate.

Part III: Value of Solar in the District of Columbia

Part III of this report examines the value of solar in the District of Columbia. For this study, 18 categories of potential costs and benefits associated with solar PV were considered. Sixteen of those were categorized as "utility system" impacts, meaning that the cost or benefit affects all customers in the utility system, while two categories were deemed "societal" in that they also impact people outside of the District of Columbia. Table ES-5 lists the costs and benefits considered for this study.

Table ES-5. Potential distributed solar costs and benefits

Utility System Impacts	
Cost	Utility Interconnection and Operational Costs
	Increased Utility Administration Costs
Cost or Benefit	Distribution System Costs
	Ancillary Services
Benefit	Avoided Energy
	Avoided Transmission Losses
	Avoided Distribution Losses
	Avoided Transmission Capacity
	Avoided Generation Capacity
	Avoided RPS Compliance Costs
	Avoided Clean Power Plan Compliance Costs
	Avoided Carbon and Criterial Pollutants
	Energy DRIPE
	Capacity DRIPE
	REC SIPE
	Hedge Value
Societal Impacts	
Benefit	Outage Frequency Duration and Breadth
	Social Cost of Carbon

To the extent data or reasonable quantitative estimates of these impacts were available, estimates were made for each category over a 24-year study period. The costs were then subtracted from the benefits to determine the annual net benefits of distributed solar. The annual net benefits were then discounted to calculate the net present value of distributed solar, thereby accounting for the variance of benefits over time and the time value of money.

Value of Solar Results

The utility system total value of solar for 2017–2040, when levelized with a 3 percent discount rate, results in a value of $132.66/MWh (2015$). The societal total value for 2017–2040, when levelized with a 3 percent discount rate, results in a value of $194.40/MWh (2015$). The utility system value of solar and societal value of solar levelized results are presented in Figures ES-3 and ES-4, respectively.

Figure ES-3. Levelized utility system value of solar by component

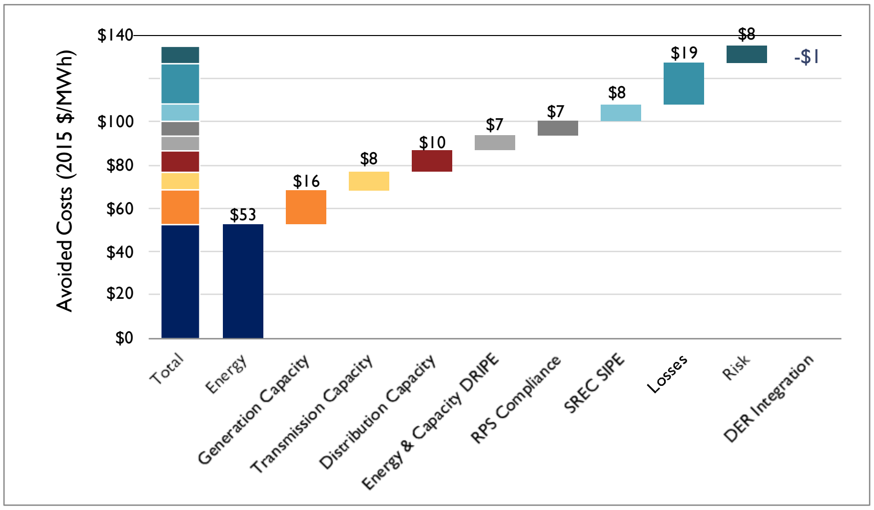
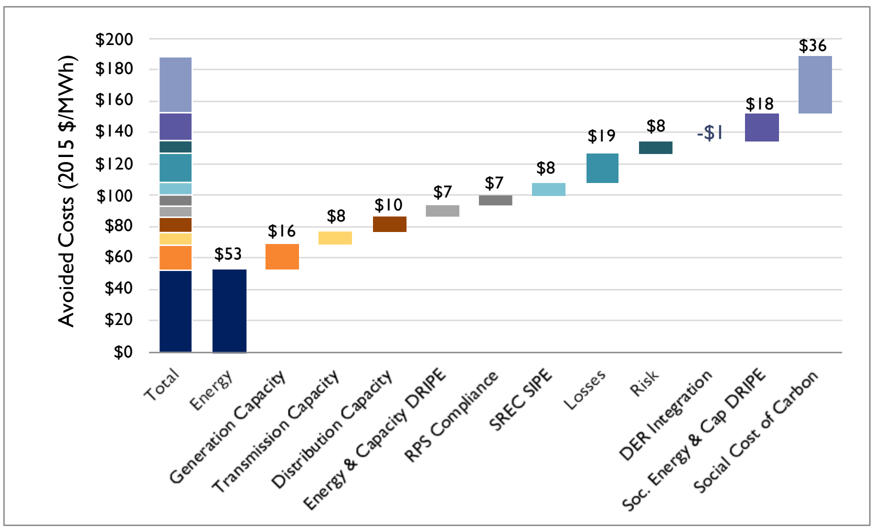


Figure ES-4. Levelized societal value of solar by component



The annual net benefits (in 2015$/MWh) are presented in Table ES-6 below.

Table ES-6. Reference case results

Year	Mid Utility System Total *2015$/MWh*	Mid Societal Total *2015$/MWh*
2017	$272.49	$356.04
2018	$80.89	$155.87
2019	$85.89	$154.58
2020	$92.68	$153.28
2021	$292.26	$407.08
2022	$141.30	$236.01
2023	$136.84	$221.40
2024	$129.57	$199.35
2025	$122.39	$178.55
2026	$113.35	$153.44
2027	$116.11	$156.89
2028	$117.86	$159.33
2029	$118.72	$160.03
2030	$120.90	$162.90
2031	$120.44	$163.12
2032	$119.53	$162.88
2033	$110.12	$154.14
2034	$110.27	$154.96
2035	$110.17	$155.53
2036	$110.54	$156.55
2037	$110.48	$157.14
2038	$110.26	$157.74
2039	$110.56	$158.86
2040	$108.95	$158.07

Sensitivities

The value of solar is highly dependent on future gas prices for several reasons. First, the avoided energy costs, which include losses and costs associated with risk, represents about half of the utility value of solar (over a third of the societal value). Second, the range of potential input values is quite wide. Keeping all other inputs at the “mid” level, using the “low” gas forecast reduces the value of solar by over $22/MWh. Conversely, the “high” gas price increases the value of solar by nearly $37/MWh.

The societal value of solar is also quite dependent on the social cost of carbon: it represents nearly a quarter of the total societal value, and increasing the discount rate to 5 percent for the social cost of carbon and the levelizing of the revenue stream reduces the social value to $174/MWh. This is a reduction of nearly $21/MWh. Conversely, reducing the discount rate to 2.5 percent increases the social value by $17/MWh to $211/MWh.

The value of solar is much less sensitive to high and low avoided generation capacity values. Applying a high or low generation capacity value stream rather than the base case only changes the value of solar by $2.69/MWh.

There is also a significant benefit to achieving compliance with the District's RPS solar carve-out. When sufficient solar resources are present in the District to comply with the carve-out, the cost of procuring SRECs (or paying Alternative Compliance Payments) will dramatically decline. This drop in SREC prices will represent a savings in the tens of millions of dollars, perhaps as high as $44 million. However, its contribution to value of solar is a more modest $7.77/MWh because that value is spread across the entire study period. Although the value of solar calculations only attributes the first year of compliance to solar installed in any one year, the utility system will realize those tens of millions of dollars of savings each year until 2024, when the reduced ACP (and inflation) reduces the benefit to $10 million per year through 2027.

Caveats and Limitations

Projecting future costs and benefits is complex and can change substantially over time and as the quantity of distributed solar increases. Avoided cost estimates are subject to inputs that can fluctuate greatly, such as the price of natural gas, legislation (especially renewable portfolio standards), and policies that drive the rate of adoption of distributed generation. The results of the value of solar study should be reviewed and updated regularly to ensure that regulatory, technological, and economic changes are incorporated into the model and the results.

Furthermore, a value of solar study is designed to analyze the impacts of a small amount of additional solar installed in the near-term, rather than large quantities of the resource installed many years in the future. Thus the results in this study should not be assumed to still hold for significant increases in PV deployment, or for many years into the future.

Part IV: Cost Shifting from Distributed Solar

The financial impact of distributed solar installations on non-solar customers, described as cost shifting, is one of the most widely debated issues in distributed solar policy. While cost shifting is closely related to value of solar estimates, a cost-shifting analysis focuses on *who* benefits, rather than only on whether the total benefits outweigh the total costs. Even where the value of solar is high, there is still the possibility that cost-shifting from solar to non-solar customers will occur.

Cost-shifting from solar to non-solar customers occurs largely due to the reduction in electricity sales from customers generating their own electricity. The electric utility's total costs may not decline as rapidly as the reduction in sales, leaving a revenue shortfall. To make up for this, the electric utility must increase rates, resulting in higher bills for non-solar customers. However, if distributed solar provides energy and capacity during the hours when it is most costly to produce and distribute electricity, the value of distributed solar may offset the need to increase rates due to lower sales. Whether distributed solar increases or decreases rates will depend on the magnitude and direction of each of these factors.

In very general terms, if the credits provided to solar customers exceed the average long-term avoided costs, then average long-term rates will increase, and vice versa.

Cost-shifting in the District of Columbia

In our base case analysis, Synapse found that over a 25-year study period at current distributed solar penetration levels, the typical residential non-solar customer in the District would experience an additional cost of $0.28 per year on average due to distributed solar. The direction of the cost-shifting varied over the study period, meaning that sometimes costs shifted towards solar hosts. Importantly, this analysis did not include the impacts of renewable portfolio standards or the District's solar carve-out as these requirements would be in place with or without the incremental distributed solar.

In addition to this base case, Synapse conducted several sensitivity analyses. These sensitivities included cost shifting under rapidly rising distribution system investments, $0 avoided costs for distribution system capacity, and cost shifting under various rate designs. We found that, in all cases examined, cost-shifting remains relatively modest at less than $1.00 annual impact per residential customer.

Changing the rate design for residential net metered customers was found to have a potentially significant impact on cost shifting. The District's current rate design—a declining block rate structure—is generally beneficial to solar hosts; removing it would reduce annual cost-shifting to $0.20 per customer on average. An alternative rate structure in the form of a summertime time-of-use rate design could actually reverse the cost-shifting such that non-solar customers would see a savings of $0.29 per year on average. We note that while time-of-use rates are a powerful rate design for addressing cost shifting, they should be applied with caution, as inappropriate designs could exacerbate peak demand on the grid.

Part I - Policy and Rate Design Options

1. BARRIERS TO DISTRIBUTED GENERATION DEVELOPMENT

A range of factors influence customer adoption of distributed generation technologies. Policies designed to incentivize adoption of distributed generation typically use a combination of mechanisms to achieve their goals and overcome the barriers that customers face. While the distributed generation challenges vary by jurisdiction, across the country, six barriers to distributed solar are particularly common:[6,7,8]

1. Limited access to suitable space (e.g., roofs or open areas)
2. Bureaucratic, lengthy permitting and interconnection processes
3. Insufficient or volatile funding for solar development programs
4. High upfront capital costs and lack of affordable financing
5. Ineffective price signals to customers
6. Lack of skilled workers to support solar technology deployment, including: system design, installation, and ongoing operations and maintenance

The District of Columbia has undertaken a number of initiatives to spur development of renewable distributed generation and address many of the barriers listed above. Below we briefly describe the current state of these barriers in the District, some of which have been overcome, and others that still pose a formidable challenge:[9]

1. **Access to suitable space:** The District is a dense urban environment with a high percentage of residents who are renters, which presents one of the most significant barriers to distributed generation. In the District, only 28 percent of housing takes the form of owner-occupied single-family units (either detached or row houses). Owner-occupied units in multi-family buildings constitute another 13 percent of housing, and the remainder of housing is rented, as shown in the figure below.[10]

[6] Cox, Sally, Terry Walters, and Sean Esterly, *Solar Power Policy Overview and Good Practices*, May 2015, http://www.nrel.gov/docs/fy15osti/64178.pdf.

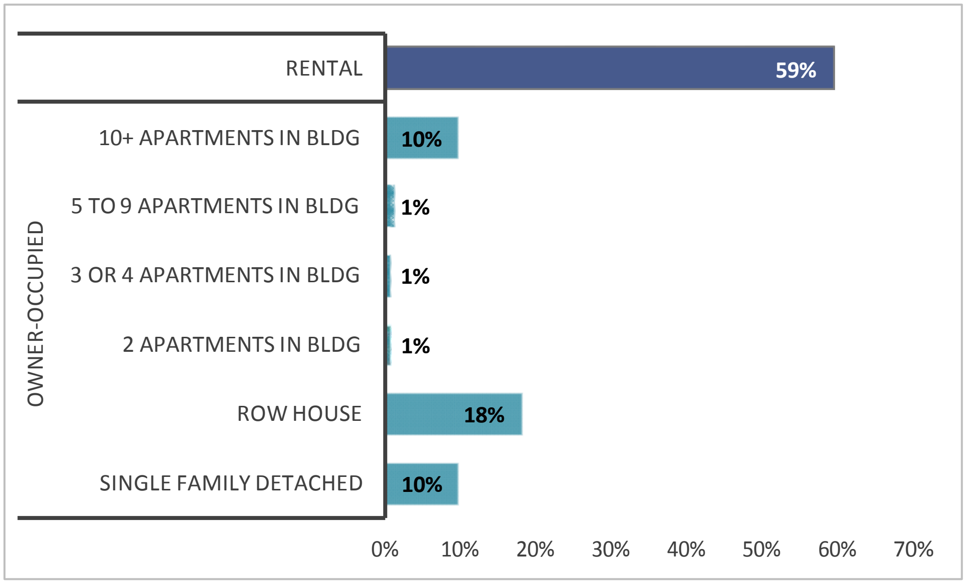
[7] Phone call with SolarCity, 15 June 2016.

[8] The Solar Foundation, "National Solar Jobs Census 2015," January 2016, http://www.thesolarfoundation.org/wp-content/uploads/2016/01/TSF-2015-National-Solar-Jobs-Census.pdf.

[9] Ibid.

[10] US Census Bureau, "Table 3. Homeownership Rates by State: 2005-Present, Q1 2016 Data," *Current Population Survey/Housing Vacancy Survey*, accessed July 18, 2016, http://www.census.gov/housing/hvs/data/rates.html.

Figure 1. Housing characteristics in the District of Columbia



Source: US Census Bureau, Homeownership Rates by State: 2005-Present, Q1 2016 Data.

The number of renters in the District is disproportionately large. According to the latest census data, less than 41 percent of District residents own their home, which is far lower than the national average of 65 percent.[11] Even among metropolitan areas, the District ranks second to last in terms of homeownership rates.[12] This high proportion of renters is significant for DG development, as renters generally do not have the ability or incentive to install solar on their residence without the support of the landlord.

Although it is possible for landlords and tenants to partner in an installation as a community renewable energy facility, in practice it is easier said than done. The complexity and transaction costs associated with doing so are likely to be too high for such an arrangement to be common without the participation of a third-party organization.[13]

Third-party community solar developers (such as Clean Energy Collective and GRID Alternatives)[14] have been successful at developing community solar installations in other jurisdictions.

[11] Ibid.

[12] US Census Bureau, "Table 6. Homeownership Rates for the 75 Largest Metropolitan Statistical Areas: 2015 to Present," *Current Population Survey/Housing Vacancy Survey*, accessed July 18, 2016, http://www.census.gov/housing/hvs/data/rates.html.

[13] Transaction costs include the time and effort to establish the subscriber organization, sell shares in the organization, and manage all subscription changes, transfers and cancellations.

[14] Clean Energy Collective is a for-profit clean energy company, while GRID Alternatives is a non-profit organization focused on low-income communities.

Further, the financial incentives must be high enough for *both* the building owner (the host)

However, where buildings are master-metered, the process may be more straightforward. In addition, the financial incentive for the landlord is higher, as the landlord pays the electricity bills and thus would directly experience the benefits of installing solar. This is significant in the District, as Pepco serves approximately 56,000 units in master-metered apartment buildings.[15] Nonetheless, there is no indication that many master-metered buildings in the District have invested in distributed solar.[16]

Nearly one third of owner-occupied units are in buildings with two or more units. Decisions to install solar panels also become more complex where multiple owners share roof space, thereby dampening demand for distributed generation. Further, for multi-family and commercial buildings, solar may have to compete with alternative rooftop uses, such as swimming pools, building HVAC systems, and shared entertainment areas. Rooftop solar installations may also compete with green roofs, as buildings may be unable to support the weight of both green roofs and solar arrays without modification.

Another real estate challenge facing the District is the historic nature of many of its neighborhoods. Currently the District's historic preservation guidelines require that solar panels be installed in a manner so that they are not visible from the street, which reduces the roof space available.[17] Alternatives to rooftop installations are limited, as the density of the city means that there is little open space available for large arrays to be installed in open areas or even over surface parking lots.

2. **Interconnection process**: The time required for the electric distribution company, Pepco, to process and approve interconnection of small solar systems generally exceeds that of peer utilities. According to EQ Research, the District ranked 33rd out of 34 utilities in terms of time required for interconnecting small-scale solar.[18]

3. **Program funding uncertainty:** Substantial financial incentives are generally available to customers wishing to install distributed generation. For solar PV, these incentives include SRECs, as well as program-specific incentives funded

[15] Potomac Electric Power Company, "Direct Testimony of David Velazquez," FC 1139, June 30, 2016, 3.

[16] It is not clear why this is the case. One reason may be that other investments are simply more lucrative, and thus the building owner does not wish to tie up his or her capital in a solar installation. Another possibility is that the roofs of such master-metered buildings tend to be less suitable for solar, either due to the presence of HVAC equipment, age of the roof, roof condition, or other structural concerns.

[17] The District's current historic preservation guidelines state as follows: "If installed on a flat roof, solar panels should be located so they are not visible from the public street. If located on a sloping roof building, they should only be installed on rear slopes that are not visible from a public street." DC Office of Planning, Historic Preservation Office, "District of Columbia Historic Preservation Guidelines: Roofs on Historic Buildings" (Washington, DC), accessed July 18, 2016, http://planning.dc.gov/sites/default/files/dc/sites/op/publication/attachments/DC%20Roof%20Guidelines.pdf.

[18] MDV-SEIA, "Regional Interconnection Study: Evaluating Mandated Timelines and Compliance," 2015, 12.

through alternative compliance payments. Unfortunately, both SREC prices and program incentives can vary from year-to-year, creating uncertainty regarding payback periods for solar investments.

4. **Upfront costs and customer financing:** The costs of solar have fallen markedly in recent years. In 2006, a typical 4 kW solar array[19] would cost a customer approximately $36,000 (installed).[20] In 2016, the cost for a 4 kW system would be approximately $13,000.[21] Despite the rapid decline in prices, solar PV still represents a considerable investment with high up-front costs that many customers cannot afford. For this reason, third-party ownership models have increasingly gained popularity and represent the dominant model for new solar installations in the United States. However, such models generally require minimum credit scores or debt-to-income ratios, which can exclude many low-income customers.[22]

5. **Ineffective price signals:** Net metering provides a simple and reliable method of compensating generation owners for the energy generated by their systems by providing a credit equal to the retail rate to customers. Recently, full retail rate compensation was also extended to community solar customers. Net metering is only effective when paired with rate designs that are based largely on volumetric (dollars per kilowatt-hour) prices. Currently the price signals faced by customers in the District are generally favorable for distributed generation development.

6. **Labor availability:** The District has approximately 138 solar companies, 18 of which are project developers.[23] With 1,000 solar jobs, the District ranks 6th out of 51 states for solar jobs per capita.[24] The District's high ranking suggests that it does not suffer from the same labor shortage experienced nationally.

---

[19] The median residential solar array size in the District of Columbia is 4.1 kW, according to data provided on the Public Service Commission website for eligible renewable generators.

[20] Barbose, Galen and Naim Dargouth, "Tracking the Sun VIII: The Installed Price of Residential and Non-Residential Photovoltaic Systems in the United States" (Lawrence Berkeley National Laboratory, August 2015), https://emp.lbl.gov/publications/tracking-sun-viii-installed-price.

[21] As of the first quarter of 2016, GTM Research and the Solar Energy Industries Association report that national average residential rooftop PV systems cost approximately $3.21/W. The majority of these costs (nearly 63%) are attributable to on-site labor, engineering, permitting and other soft costs, rather than the costs of the panels themselves. Both hardware and soft costs are declining—residential hardware costs fell by over 4% in the past quarter, while soft costs decreased by almost 12%. *See:* GTM Research and Solar Energy Industries Association, "U.S. Solar Market Insight: Q2 2016," June 2016, 14, http://www2.seia.org/l/139231/2016-06-07/dy493.

[22] GRID Alternatives, Vote Solar, Center for Social Inclusion, "Low-Income Solar Policy Guide," March 11, 2016, http://www.lowincomesolar.org/wp-content/uploads/2016/03/Low-Income-Solar-Policy-Guide_3.11.16.pdf.

[23] "Washington DC Solar," *SEIA*, accessed August 9, 2016, http://www.seia.org/state-solar-policy/washington-dc.

[24] The Solar Foundation, "State Solar Jobs Census Compendium 2015," accessed August 9, 2016, http://www.thesolarfoundation.org/wp-content/uploads/2016/02/Solar-Jobs-Census-Compendium-2015-Low-Res.pdf.

The following sections describe policies that have been implemented in the District or other jurisdictions to help overcome these challenges.

2. Overview of Distributed Generation in the District

2.1. Background

Beginning in 2007, Washington DC established renewable portfolio standard (RPS) requirements for electricity suppliers.[25] These RPS standards have subsequently been expanded, most recently in June 2016, to require that 50 percent of retail sales be met by renewable energy by 2032, with 5 percent coming from solar resources (including solar thermal).[26]

Since 2011, the District has also required that all new Commission-certified solar facilities be located in the District or on a distribution feeder serving the District. As of April 2016, nearly 40 MW of solar capacity was certified for the District's RPS program.[27] However, only 19 MW of this capacity is located within DC, divided almost evenly between residential and non-residential installations.[28] The remainder of the District's solar capacity—21 MW—is grandfathered capacity located outside the District.

Solar has grown quickly in recent years, with cumulative capacity located in the District increasing by 40 percent from 2014 to 2015 alone, as shown in Figure 2 below. Even when combined with capacity located outside the District, however, it falls far short of the District's target of 59 MW for 2015, and 70 MW for 2016.

---

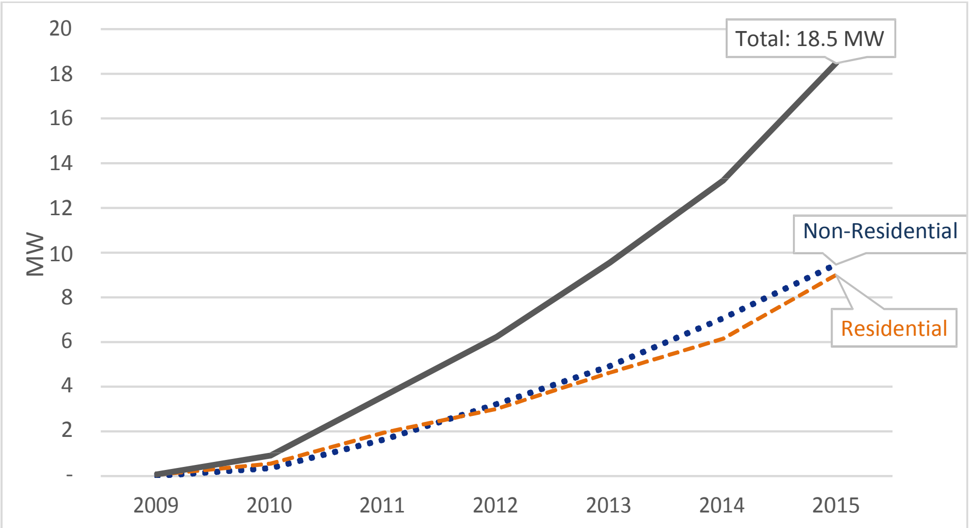
[25] Public Service Commission of the District of Columbia, "Report on the Renewable Energy Portfolio Standard for Compliance Year 2015," May 2, 2016.

[26] "Renewable Portfolio Expansion Amendment Act of 2016," Pub. L. No. B21-0650, accessed July 1, 2016, https://legiscan.com/DC/text/B21-0650/2015.

[27] Public Service Commission of the District of Columbia, "Report on the Renewable Energy Portfolio Standard for Compliance Year 2015."

[28] Data analysis based on the Eligible Renewable Generators List as of June 30, 2016, available at http://www.dcpsc.org/Electric/Renewable.asp.

Figure 2. Cumulative solar capacity located within the District of Columbia



Source: Eligible Renewable Generators List as of June 30, 2016.

The District has undertaken a number of initiatives to help drive greater adoption of distributed generation, and of solar in particular. For example, approximately 11 MW of new solar is slated to come online before the end of 2016, due to the District's effort to procure solar through one of the country's largest municipal purchase power agreements (PPAs).[29] However, additional efforts will be necessary to help the District meet its ambitious distributed solar goals.

In the sections that follow, we describe the District's policies and programs aimed at increasing distributed solar, followed by an examination of the strategies taken by other jurisdictions.

2.2. Financial Incentives

Net Metering

The District currently offers two types of net metering arrangements to customers: traditional net metering for customers who install solar on their premises[30] and a community solar option (described in the following section). Traditional net metering allows customers to offset their electricity consumption with their system's generation on a one-to-one basis. It has been widely implemented across the United States. In the District, net metering is available to residential and commercial customer generators with

[29] "DGS Renewable Energy," DC Green Schools Challenge, accessed July 7, 2016, http://www.dcgreenschoolschallenge.com/dgs-renewable-energy/.

[30] "Order Approving Adoption of Rules Governing Net Metering," Pub. L. No. Formal Case No. 945, accessed July 6, 2016, http://www.dcpsc.org/pdf_files/commorders/orderpdf/admin_9192007_931_1_945-E-1246.pdf.

solar systems up to 1 MW.[31] These customers are credited at the retail electricity rate for their rate class, excluding riders and other surcharges.[32] The credit is applied to the next monthly bill and to subsequent monthly bills, if necessary, until fully exhausted. Under the current residential tariff and incentives, payback for a 4.1 kW system is estimated to be approximately five years.[33]

Community Solar

The Community Renewable Energy Act of 2013 gives customers the option of purchasing locally produced renewable power from authorized community renewable energy facilities (CREFs). Pepco only started accepting applications for community solar installations on June 1, 2016,[34] and currently no CREFs are in operation in the District. However, since June, several CREF projects have been permitted, and many more are in the pipeline (as described below).

The concept behind community solar is to allow customers who are unable to install solar PV on their home or business to benefit from solar by purchasing a subscription or "share" of the electricity generated by the CREF.[35] The subscriber will then have a Community Net Metering credit applied to his or her electricity bill. In the District, all customers are eligible for community solar, and a customer can subscribe to more than one CREF. CREF installations are limited to 5 MW or less, must have at least two subscribers, and all individual billing meters must be located in the District.[36] Initially, regulations required CREF subscribers to be credited for the supply portion of their bill but not the distribution portion.[37] This changed on June 21, 2016 when the DC Council approved an amendment that changed the credit to the full retail rate.[38]

---

[31] "Formal Case No. 945, In the Matter of the Investigation into Electric Service Market Competition and Regulatory Practices," Pub. L. No. Order No. 15837 (2010), http://www.dcpsc.org/pdf_files/commorders/orderpdf/orderno_15837_FC945.pdf.

[32] In addition to riders and surcharges, net metered customers are responsible for any customer charges or demand charges applicable to their rate schedule. Pepco, "Rate Schedules for Electric Service in the District of Columbia," May 26, 2016, http://www.pepco.com/uploadedFiles/wwwpepcocom/Content/Page_Content/my-business/DC%20Current%20Rate%20Schedule%20Effective%20CREF%20060116(1).pdf.

[33] Synapse analysis based on an SREC payments of $435/MWh in Year 1 (based on average 2015 SREC compliance payments reported in the DC PSC's "Report on the Renewable Energy Portfolio Standard for Compliance Year 2015," declining to $38/MWh in Year 25, and an installed cost of $3.50/Watt (based on recent installed costs reported by GTM Research and Solar Energy Industries Association, "U.S. Solar Market Insight: Q2 2016") and $86 annual maintenance cost (based on NREL, "Distributed Generation Energy Technology Operations and Maintenance Costs," *National Renewable Energy Laboratory Energy Analysis*, February 2016, http://www.nrel.gov/analysis/tech_cost_om_dg.html).

[34] Pepco, "Community Renewable Energy Facility," *Pepco*, accessed June 17, 2016, http://www.pepco.com/community-commitment/renewable-energy/green-power-connection/dc/dc-community/.

[35] A CREF subscriber may offset no more than 120 percent of their electricity consumption over the previous 12 months.

[36] "DC Code - § 34–1518.01. Community Renewable Energy Facilities.," accessed July 6, 2016, http://dccode.org/simple/sections/34-1518.01.html.

[37] The CREF credit rate was originally comprised only of the following variable ($/kWh) standard offer service components for Schedule GS-LV-ND: generation, transmission, and administrative charge.

[38] Council of the District of Columbia, "Community Renewable Energy Credit Rate Clarification Amendment Act of 2016," B21-669 § (2016).

CREFs have the advantage of removing some barriers to entry for installing solar systems. For example, CREFs expand access to solar to renters or other customers without suitable roof space, and to customers who have limited access to financing. While the CREF program can help overcome these barriers, community solar projects often present more challenges than a single-family home project, including:[39]

- More complex permitting process
- Managing multiple contracts for multiple subscribers/households
- Obtaining sufficient commitment from subscribers to ensure the project will be financially viable
- Finding business owners and roof space that is suitable for solar PV systems

The industry structure in the District also presents certain challenges for community solar that many community solar installations in other parts of the country did not face. Historically, the majority of community solar programs have been established in the territories of cooperatives, public power, and municipal utilities. Of the 68 community solar programs in existence in 2015, 90 percent were active in the territories of cooperatives, public power, or municipal utilities.[40] Such utilities face different governance structures than investor-owned utilities, and can be directed by their members to pursue certain projects.[41] Further, in restructured states, distribution utilities cannot own generation.

These challenges do not mean that community solar is infeasible in the District, but rather that third parties will likely play a central role. Third parties can be either for-profit (such as Clean Energy Collective, Recurrent Energy, and Sunshare) or non-profit (such as GRID Alternatives). These entities manage site selection and development, handle customer acquisitions, and manage the operation of the community solar program. They have been particularly active in states with significant solar incentives such as Massachusetts and California, and are now beginning to operate in Washington DC. By the end of 2016, 10 CREF projects were under development in the District, with three having received authorization to install. The three CREFs with authorization to install have a combined capacity of approximately 150 kW and 60 subscribers.[42] While the third-party developers for these projects are not known, Arcadia Power, an online renewable energy company, has announced that it is developing four community solar projects in the District through its nationwide community solar platform.[43]

---

39 Phone call with SolarCity, June 15, 2016.

40 Smart Electric Power Association, "Community Solar Program Design Models," 2015.

41 Coughlin, Jason et al., "A Guide to Community Solar: Utility, Private, and Non-Profit Project Development" (U.S. Department of Energy, November 2010), http://www.nrel.gov/docs/fy11osti/49930.pdf.

42 Pepco, "Report - Community Renewable Energy Facilities Overview," January 10, 2017, http://edocket.dcpsc.org/edocket/docketsheets_pdf_FS.asp?caseno=RM9-2015-01&docketno=38&flag=D&show_result=Y.

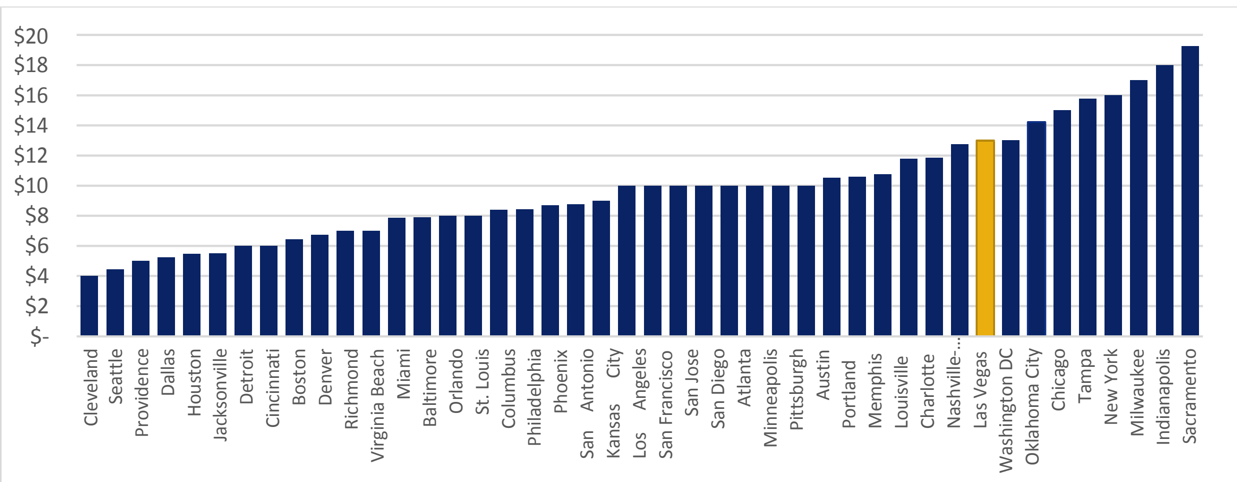
43 "Save with Arcadia Community Solar," *Arcadia Power*, February 16, 2017, https://www.arcadiapower.com/solar.

Rate Design

The manner in which customers are billed for electricity consumption has a direct impact on the financial viability of distributed solar under net metering arrangements. Residential customers are typically billed through a combination of fixed charges and variable rates (in cents/kWh), with compensation for distributed generation provided at (or close to) the variable rate.[44] Increasing the fixed charge reduces the variable rate, effectively also lowering the net metering compensation rate, and can thereby significantly reduce incentives for customers to install distributed generation.[45]

Among major U.S. cities, the District of Columbia's standard residential fixed charge of $13.00 per month is in the upper quartile, but is not the highest, as shown in the figure below. Customers in master-metered buildings pay a slightly lower fixed charge of $10.25 per month.[46] While reducing the fixed charge would increase the customers' incentives to net meter, the magnitude of this effect is dwarfed by other financial incentives available in the District, particularly SRECs (as discussed in the following section).[47]

Figure 3. Residential fixed charges in major U.S. cities



Source: Utility tariffs, as of August 2016.

The variable portion of customers' bills consists of both energy supply costs and delivery costs (distribution and transmission costs). Pepco's current distribution rates take the form of an inclining block rate, where consumption above 400 kWh is more than double the price of the first 400 kWh

---

44 This compensation rate does not include certain non-bypassable riders or fees.

45 Whited, Melissa, Tim Woolf, and Joseph Daniel, "Caught in a Fix: The Problem with Fixed Charges for Electricity" (Synapse Energy Economics, prepared for Consumers Union, February 9, 2016).

46 Pepco, "Rate Schedules for Electric Service in the District of Columbia."

47 In some cases, high penetration of distributed solar may lead to unacceptable levels of cost shifting. Where this is the case, rate design can be modified to reduce the credit that a solar customer receives. Increasing fixed charges is one way to do this, although other options (such as time-of-use rates) are generally preferable.

consumed. Inclining block rates can have a positive impact on incentives for net metered customers, as distributed generation offsets the higher block first, providing more value to the customer. This incentive is slight in the case of Pepco, however, since the inclining block rate only applies to the distribution portion of the customer's bill, while the majority of the customer's bill is based on flat rate supply charges.

Customer Incentives

Solar Renewable Energy Credits (SRECs)

SRECs offer customers a financial incentive to install distributed solar by allowing customer generators to sell their SRECs to electricity suppliers, who are required by law to purchase a minimum number of SRECs each year to fulfill the District's RPS solar carve-out.[48] Basic market forces determine an SREC's value. The supply of SRECs is proportional to the District's current installed solar capacity, while demand is proportional to the District's solar RPS requirements.[49]

Thus far, SREC supply has been low while demand from electricity suppliers is high. For example, in 2015, electricity suppliers were required to purchase SRECs equivalent to approximately 60 MW of solar capacity. However, the majority of electricity suppliers did not procure sufficient SRECs, and were therefore required to pay an alternative compliance payment.[50] The compliance fee prices are currently capped at $500/MWh.[51] Because SRECs are in short supply, SREC owners are able to sell at prices close to the alternative compliance payment cap. If the number of SRECs were to increase above the quantity required for RPS compliance, we would expect sellers to reduce their prices substantially, since only the lowest-priced SRECs would be purchased for compliance. Figure 4 shows that SREC prices in the District have been the highest in the country since mid-2012. In 2015, suppliers reported that average SREC prices were approximately $435.[52] By July 2016, SRECs were trading at a price of approximately $485/MWh.[53]

---

[48] "PSCDC - Renewable Energy Portfolio Standard Program," accessed July 7, 2016, http://www.dcpsc.org/Utility-Information/Electric/Renewables/Renewable-Energy-Portfolio-Standard-Program.aspx.

[49] DSIRE, "District of Columbia Renewable Portfolio Standard," accessed July 6, 2016, http://programs.dsireusa.org/system/program/detail/303.

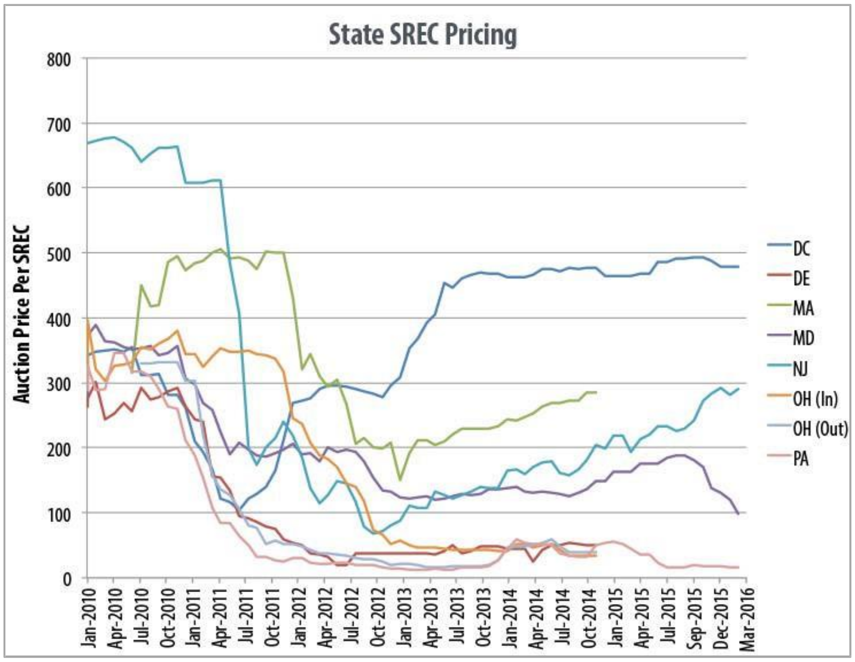
[50] Public Service Commission of the District of Columbia, "Report on the Renewable Energy Portfolio Standard for Compliance Year 2015," 12, 16.

[51] Public Service Commission of the District of Columbia, "Report on the Renewable Energy Portfolio Standard for Compliance Year 2015."

[52] Ibid., 19.

[53] EIS PJM, "Solar Weighted Average Price," PJM EIS Generation Attribute Tracking System, accessed July 11, 2016, https://gats.pjm-eis.com/gats2/PublicReports/SolarWeightedAveragePrice/Filter.

Figure 4. Compliance market SREC weighted average price, January 2010 to March 2016



Source: Green Power Network Renewable Energy Certificates (RECs) [54] and Marex Spectron[55]

SRECs can have a significant impact on customer payback periods for distributed solar. To demonstrate the sensitivity to SREC prices, we analyzed payback periods for a hypothetical 4.1 kW PV system with an installed cost of $3.50/watt under various SREC price assumptions.[56] If one assumes that a customer receives the 2015 average SREC prices of $435/MWh, the payback period is estimated to be five years.[57] Under an SREC price of $300 (approximately the price at which 10-year SREC annuities are currently trading),[58] the payback period lengthens only slightly, to six years.

Because SREC prices will fluctuate and eventually decline as the solar carve-out is met or the ACP cap falls, we also analyzed scenarios in which SREC prices declined at a gradual pace. If one begins with relatively high SREC prices (i.e., at $350/MWh and above), the payback period is not materially affected by a 10 percent annual decline in the SREC price. At significantly lower SREC prices, however, the payback period begins to lengthen. Holding all else equal, if one started with an SREC price of

54 "Green Power Network: Renewable Energy Certificates (RECs): REC Prices," accessed July 11, 2016, http://apps3.eere.energy.gov/greenpower/markets/certificates.shtml?page=5.

55 "Welcome to Marex Spectron," Marex Spectron, accessed July 12, 2016, http://www.marexspectron.com/.

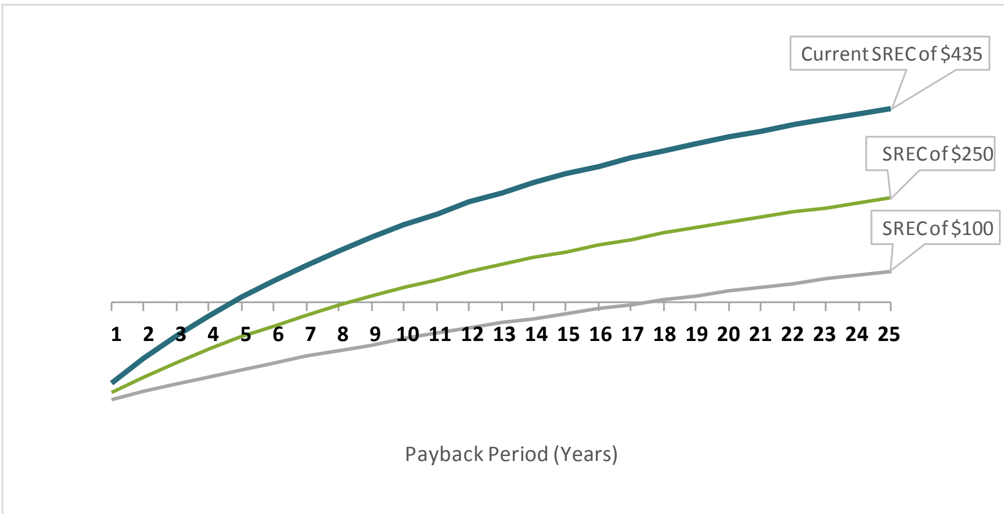
56 Our analysis assumed a $50/year maintenance cost, current Pepco net metering rates, and the federal tax credit of 30%.

57 This payback period was used as the base case assumption in our economic adoption analysis.

58 On February 14, 2017, Washington DC SRECs were trading just below the alternative compliance payment of $500/SREC. Sol Systems, a national solar finance firm, was offering Washington DC customers 3-year, 5-year, and 10-year annuities at prices between $300 and $380 per SREC. Data available at: http://www.solsystems.com/sell-your-srecs/the-srec-landscape/state-markets.

$250/MWh and allowed the SREC price to decline by 10 percent annually, the payback period would lengthen to nine years. At a starting SREC price of $100/MWh (also declining 10 percent annually), the payback period increases to 18 years.[59] The results of our analysis are shown in the figure below.

Figure 5. Analysis of payback periods under varying SREC prices



Due to changes in supply and demand, the SREC market is susceptible to natural market price volatility. Such volatility can create uncertainty for customers and result in boom-bust cycles as SREC prices fluctuate. For example, an over-supply of SRECs in one year could lead the prices to plummet, and PV installations could grind to a halt. However, since the required number of SRECs will continue to grow until 2030, prices will likely not remain low for long, unless the rate of growth of solar is faster than the growth of SREC requirements.

SREC annuities exist in some markets to provide solar customers the benefit of SREC price stability. The stability comes at a price; because SREC price and regulatory risk are considerable, annuities are offered at payment rates significantly below the SREC market rate. The longer the annuity (e.g. 3-year, 5-year, even 10-year), the lower the offered price per SREC.[60]

---

[59] If one does not apply a 10% annual decline in SREC prices, but instead holds SREC prices constant, the payback periods under $435, $250, and $100 are 5, 7, and 13 years, respectively. We note that other factors could also impact the payback period, such as a decline in hardware and installation costs, and the removal of the ITC. If the cost of solar were to decline to $2.50 per watt from $3.50 per watt, one would expect the payback period to shorten to 4 years. However, if the ITC were removed, the payback period would lengthen to 8 years.

[60] On February 14, 2017, Washington DC SRECs were trading just below the alternative compliance payment of $500/SREC. Sol Systems, a national solar finance firm, was offering Washington DC customers 3-year, 5-year, and 10-year annuities at prices between $300 and $380 per SREC.

The Affordable Solar Program (formerly Solar Advantage Plus Program)

The Affordable Solar Program was launched as the Solar Advantage Plus Program in January 2015 to cover the full cost of installing a solar PV system for eligible low-income residents in the District.[61] The program installed solar panels on single-family homes owned or rented by low-income residents,[62] thereby also reaching renters who typically have less incentive or ability to install solar PV. Funding for the program was provided through the Department of Energy & Environment (DOEE) and the program was implemented by the DC Sustainable Energy Utility (DCSEU).[63]

No system size limits were in place under the Affordable Solar Program, but customer incentives were capped at $10,000 (or $2.50 per watt), which equates to a system size of approximately 3 to 4 kW.[64] Installation and interconnection of the system must have been completed before September 30, 2016. Demand for the program was high, with the DCSEU slated to install solar on 140 homes in the 2016 fiscal year.[65]

Solar for All

The Solar for All program is a new initiative, created as part of the recently passed Renewable Portfolio Standard Expansion Amendment Act of 2016. The program requires the Department of Energy and Environment to "reduce by at least 50% the electric bills of at least 100,000 of the District's low-income households" by the early 2030s.[66] While the structure of the program's implementation has not yet been determined, the goal as stated is ambitious. As discussed in our economic adoption analysis, the resources installed under the auspices of the Solar for All program will be RPS-eligible and will therefore generate SRECs. Depending on the design of the program implementation, the amount of resource installed as part of the program may impact the timing of when the RPS solar carve-out is met.

The Small Business Solar Pilot Program

The Small Business pilot was launched jointly by the DOEE and DCSEU[67] to subsidize the cost of solar PV installation for eligible small businesses located in Wards 7 or 8 in the eastern portion of the District.[68] The program offered an incentive amount of $2.70 per watt up to 10 kW, meaning the maximum

[61] "Solar Advantage Plus Program," DSIRE, accessed July 12, 2016, http://programs.dsireusa.org/system/program/detail/5700.

[62] "Solar Advantage Plus Program | Department of Energy," Energy.gov, accessed July 12, 2016, http://energy.gov/savings/solar-advantage-plus-program.

[63] "District of Columbia Low Income Solar Policy Guide," *Low-Income Solar Policy Guide*, accessed July 12, 2016, http://www.lowincomesolar.org/models/single-family-district-of-columbia/.

[64] "Solar Advantage Plus Program."

[65] "Affordable Solar," accessed July 5, 2016, https://www.dcseu.com/for-my-home/affordable-solar.

[66] "Solar for All." DC DOEE. https://doee.dc.gov/publication/solarforall

[67] "Small Business Solar Pilot," *DC Sustainable Energy Utility*, accessed July 12, 2016, https://www.dcseu.com/for-my-business/small-business-solar.

[68] Pepco, "Rate Schedules for Electric Service in the District of Columbia."

incentive amount for each business is $27,000.[69] Solar PV systems installed under this program must have been operational by September 15, 2016.

2.3. Non-Financial Factors

Interconnection & Permitting Processes

Interconnection by Pepco

Generators wishing to connect to the electric grid must fulfill Pepco's Net Energy Metering and Interconnection Application process[70] and meet Pepco's Interconnection Standards.[71] Most residential systems qualify for the Level 1 Interconnection Application and Agreement.[72] Until recently, Level 1 customers were assessed an application fee of $100 (application fees can reach $1,000 for larger systems).[73]

The entire interconnection process in the District takes approximately 80 days,[74] starting from Pepco's receipt of an interconnection application to the final approval to commence operation. The following steps occur during this time period:

1) Within 10 days of receiving an application, Pepco is required to review the application and inform the customer of its completeness;
2) Within 15 days of the application being deemed complete, Pepco must determine whether the generator can be interconnected safely and reliably and provide the customer with an approval to install ("ATI");
3) The customer must have the system installed and inspected to obtain a certificate of completion;
4) Within 10 days of the certificate of completion, Pepco must complete a witness test (or waive that right);

---

69 "Small Business Solar Pilot."

70 Pepco, "Pepco Net Energy Metering and Small Generator Interconnection Application Checklist," accessed June 15, 2016, http://www.pepco.com/uploadedFiles/wwwpepcocom/Content/Page_Content/2015/March/GPC_Pepco_DC_NEM_ApplicationChecklist_2015_03_17.pdf.

71 *Chapter 9 of Title 15 DCMR Governing Net Energy Metering in the District of Columbia*, 2005, http://dcregisterarchives.dc.gov/sites/default/files/dc/sites/OS/release_content/attachments/13701/02-18-05_7.pdf.

72 Pepco, "Pepco Net Energy Metering and Small Generator Interconnection Application Checklist."

73 Formal Case 1119.

74 Pepco, "Pepco District of Columbia Application Process Steps," accessed June 20, 2016, http://www.pepco.com/uploadedFiles/wwwpepcocom/Content/Page_Content/community-commitment/renewable-energy/Green_Power_Connection/Pepco%20District%20of%20Columbia%20Application%20Process%20Steps_2015Dec31.pdf.

5) Pepco must install a net-metering capable meter; and

6) Finally, within 20 days of meeting the applicable requirements, Pepco must provide the customer with authorization to operate ("ATO") their system.[75]

Requirements for processing times have been in place since 2009, except for the final requirement, which was added in 2016[76] following continued complaints regarding delays in the interconnection process. Criticisms of Pepco's interconnection process have been lodged by many parties,[77] occasionally resulting in Commission action. For example, in February 2014, the Commission directed Pepco to take remedial actions to reduce the high number of applications rejected for being incomplete, and to provide better website instructions for navigating the application process.[78] In 2015, the Commission noted its concern regarding the increasingly large number of applications that were not processed by Pepco according to Commission deadlines, and the continued high volume of applications deemed incomplete.[79] In response, the Commission convened legislative-style hearings to review Pepco's implementation of interconnection standards. At these hearings, it was reported that another significant barrier was the time required by Pepco to issue the final ATO, which averaged 45 days in 2015.[80]

Consistent with the position advocated by the Office of People's Counsel[81] and other parties, Pepco and the Commission have taken steps recently to address some of these issues. In the 2016 Exelon-Pepco

---

[75] The first five criteria are required per DC's interconnection regulations, as specified in *Chapter 15-40: DISTRICT OF COLUMBIA SMALL GENERATOR INTERCONNECTION RULES, DC Regulations*, 40, accessed July 6, 2016, http://www.dcregs.dc.gov/Gateway/ChapterHome.aspx?ChapterNumber=15-40. The Pepco-Exelon merger agreement added the sixth criterion. *See:* DC Public Service Commission, "Order No. 18148 In the Matter of the Joint Application of Exelon Corp., PHI, Inc., Pepco, Exelon Energy Delivery Co., and New Special Purpose Entity, LLC for Authorization and Approval of Proposed Merger Transaction," FC 1119, March 23, 2016.

[76] DC Public Service Commission, "Order No. 18148 In the Matter of the Joint Application of Exelon Corp., PHI, Inc., Pepco, Exelon Energy Delivery Co., and New Special Purpose Entity, LLC for Authorization and Approval of Proposed Merger Transaction."

[77] Many parties, including citizens, solar developers, the DC Department of Energy and the Environment, and the Office of People's Counsel, provided comments and testimony regarding Pepco's interconnection process in Formal Case 1050. See, for example, Office of the People's Counsel, "Supplemental Comments of the Office of the People's Counsel for the District of Columbia," FC 1050, In the Matter of the Investigation of the Implementation of Interconnection Standards in the District of Columbia, August 20, 2015; Jason Cumberbatch, "Introductory Testimony on Behalf of the Office of the People's Counsel for the District of Columbia," FC 1050, In the Matter of the Investigation of the Implementation of Interconnection Standards in the District of Columbia, July 21, 2015.

[78] Specifically, the Commission stated, "…we believe that the number of incomplete applications in 2012, which was 257, is still too high. To lower this number in the future, we direct the Company to develop an educational program for customers and contractors to learn how to accurately complete the application and to understand how an incomplete application can affect the application process. Additionally, our review of the Green Power Connection website revealed that its instructions for navigating the application process are confusing." *See* DC Public Service Commission, "Order No. 17379 In the Matter of the Investigation of Implementation of Interconnection Standards in the District of Columbia," FC 1050, February 12, 2014, 11.

[79] DC Public Service Commission, "Order No. 17910 In the Matter of the Investigation of Implementation of Interconnection Standards in the District of Columbia," FC 1050, June 15, 2015.

[80] Tommy Wells, "Written Statement of District Department of the Environment Director Tommy Wells," FC 1050, In the Matter of the Investigation of the Implementation of Interconnection Standards in the District of Columbia, July 21, 2015, 4.

[81] Office of the People's Counsel, "Supplemental Comments of the Office of the People's Counsel for the District of Columbia."

merger approval, the Commission added a requirement that an ATO be issued within 20 days, and in July 2016 the Commission approved the elimination of the $100 application fee for Level 1 small capacity generation facilities.

Permitting by DCRA

Customers wishing to install solar on their roofs must also obtain the appropriate building permits from the District government. In 2016, the Department of Consumer and Regulatory Affairs (DCRA) implemented two process changes in an effort to reduce the time it takes to permit solar systems in the District.[82] The first change allows a licensed engineer or contractor to certify a project, if the system is less than a prescribed height and set back a prescribed distance. The second change removes the requirement of neighbor notifications for solar projects that do not involve either the installation of structural support of an adjacent building, structure, or premise; or the underpinning of a wall common to two adjoining buildings or units (a party wall).[83]

Finally, customers in Washington DC's more than 50 historic districts (30 of which are neighborhoods),[84] must meet with historic preservation staff in the DC Office of Planning, and also have their solar installation approved by the Historic Preservation Review Board, a group of citizens including architects and historians. Installations are not permitted to be visible from the street,[85] but beyond this requirement, few guidelines are offered and decisions to approve or deny a project can be determined largely based on the aesthetic preferences of the Board.[86]

An additional factor that can reduce the installation size on an appropriate rooftop site is the fire code. Commercial PV systems must meet code requirements in DC Fire Code 605.11, including a setback from all edges of 4 to 6 feet.[87] A reduced setback might allow for more panels, both helping the District meet its goals and helping to drive down the cost per kW of the project.

[82] DCRA, "Pilot Program for Solar System Permitting Process Change," accessed July 6, 2016, http://static1.squarespace.com/static/53beb24ee4b0fec1ec33e9ac/t/577beda1d1758e79c8a740a1/1467739554446/Solar+Pilot+Process+Change+Notification+Final.pdf.

[83] "What Is a Party Wall?," accessed July 6, 2016, http://www.mypropertyguide.co.uk/articles/display/10079/what-is-a-party-wall.htm.

[84] DC Office of Planning, *DC Historic Districts*, http://planning.dc.gov/page/dc-historic-districts.

[85] The District's current historic preservation guidelines state as follows: "If installed on a flat roof, solar panels should be located so they are not visible from the public street. If located on a sloping roof building, they should only be installed on rear slopes that are not visible from a public street." DC Office of Planning, Historic Preservation Office, "District of Columbia Historic Preservation Guidelines: Roofs on Historic Buildings."

[86] David Alpert, "Saving the Planet Is a Good Idea, Say Preservation Board Members, but Don't Do It Here," *Greater Greater Washington*, April 12, 2016, https://ggwash.org/view/41339/saving-the-planet-is-a-good-idea-say-preservation-board-members-but-dont-do-it-here.

[87] Washington DC Department of Consumer & Regulatory Affairs, "District of Columbia DCRA Solar Permitting Guidelines," July 2016. Page 2, accessed February 14, 2017, https://static1.squarespace.com/static/53beb24ee4b0fec1ec33e9ac/t/57b224f06a496370ca72637f/1471292658021/DCRA+Solar+Permitting+Guidelines+FINAL+7-25-16.pdf

Education, Training, and Outreach

Access to information plays an important role in facilitating adoption of distributed generation. In particular, websites that offer easy-to-follow guidelines, checklists, digital application forms, and links to additional resources can reduce the transaction costs involved in the process. The best government websites are user-centric; have simple, high image designs with not too much text; are mobile-friendly and accessible; and have a prominently displayed search function.[88]

The Department of Energy and Environment currently provides information on the District's solar initiatives on a single web page, titled "EnergySmart DC Solar Initiatives."[89] This website follows many of the aforementioned design principles, providing information on the Affordable Solar Program, Small Business Solar Pilot Program, and links to resources such as solar PV guidelines, interconnection information, and federal tax credits. Having this information on one page makes it less likely that customers will abandon their inquiry into solar because of navigation frustrations. On occasion, however, links are broken and information is out of date.[90]

Another effective outreach tool is an interactive solar map. Interactive web-based solar maps help engage local residents and businesses, and can also be a resource for users to assess their own solar potential.[91] Google's "Project Sunroof" and MapDwell currently provide such maps for the District at www.google.com/get/sunroof and www.mapdwell.com/en/solar/dc. Both websites provide users with rough estimates of the monetary savings associated with a solar purchase or lease, and assist users in connecting with solar vendors.

An additional website tool to consider is a Live Help function, to answer website users' questions, and assist them through the solar PV installation process.[92]

Bill inserts, frequently used to promote energy efficiency, are another tool that could be used to educate customers about SRECs, community solar options, or other solar-related issues. A brief pamphlet could be included in every electric customer's monthly bill envelope, or even targeted to specific neighborhoods, building types, or usage levels, in order to encourage solar deployment where it

---

[88] "What Do the Best Government Websites of 2015 Have in Common?," accessed August 6, 2016, http://www.govtech.com/internet/2015-Best-of-the-Web-Award-Winners-Announced.html.

[89] "EnergySmart DC Solar Initiatives," DC.gov Department of Energy & Environment, accessed July 6, 2016, http://doee.dc.gov/solar.

[90] For example, currently the link titled "How Solar Electric Systems Work" is broken, and in July 2016, the website still contained information on the Solar Advantage Plus program, which had been renamed to the Affordable Solar Program. This renaming was not clearly explained on the website.

[91] "6.4 Solar Mapping as an Outreach Tool | Global CCS Institute," accessed August 8, 2016, https://hub.globalccsinstitute.com/publications/solar-powering-your-community-guide-local-governments-second-edition/64-solar-mapping-outreach-tool.

[92] "What Makes the Best Government Website?," accessed August 8, 2016, http://www.governing.com/columns/tech-talk/col-best-government-website-features.html.

is most beneficial to the distribution grid.[93] In addition to including printed materials, the utility could also send information via email to the extent the customer has opted in to email communication.

An even more effective method of communicating to customers may be on the bill itself. Recent research regarding adoption of community solar has found that customers tend to give messages printed on the bill itself the highest priority. Messages emphasizing the ability to save money through solar may have the most impact when positioned near the monthly charge on the utility bill.[94]

Research has also shown that the following types of messages or program designs resonate the most with prospective community solar customers:

- Broad eligibility, e.g., emphasizing that every homeowner or renter is eligible
- No up-front fees or purchase costs
- Ability to offset most or all of the customer's bill
- Short contract durations, with month-to-month contracts most favored.[95]

Brownfields

Brownfields and Superfund sites have been used as sites for successful ground-mounted solar PV projects (known as "brightfields") [96] in a number of jurisdictions.[97] There are several advantages to utilizing such sites: ground-mounted PV projects can be significantly cheaper than rooftop projects, and the land may not have much value for housing or recreation due to its polluted state. Ground-mounted solar PV projects often require minimal or no soil disturbance, consistent with safety requirements for the site. The sites are often located in industrial areas or places with few abutters, helping to alleviate concerns about viewshed or the inconveniences associated with the noise and traffic during installation. Because the sites are often existing or former industrial sites, they often have robust interconnections with the electric grid.

Municipal landfills are a common example of brownfield sites that may be later used for ground-mounted solar development. Such sites are often elevated above the surrounding area, relatively flat, unshaded, and large enough to allow for economies of scale. This makes them ideal for solar

---

[93] Solar located on particular circuits may help to reduce distribution grid congestion levels or avoid reaching capacity limits.

[94] Smart Electric Power Association, "Accelerating Adoption of Community Solar," February 2016.

[95] Ibid.

[96] The White House, "Brightfields Initiative," August 1999, accessed February 14, 2017. Available at: https://clinton5.nara.gov/Initiatives/Climate/brightfields.html.

[97] For example, New York City is developing a 10 MW solar installation at the Freshkills landfill on Staten Island. *See:* Marc La Vorgna and Jake Goldman, "Mayor Bloomberg Announces City's Largest Solar Energy Installation to Be Built at Freshkills Park in Staten Island," NYC, *Office of the Mayor*, (November 25, 2013), http://www1.nyc.gov/office-of-the-mayor/news/381-13/mayor-bloomberg-city-s-largest-solar-energy-installation-be-built-freshkills-park#/0.

installations. Further, the land is often owned by the municipality, thereby reducing concerns related to permitting and financing.

Nevertheless, there are several challenges associated with brownfield or Superfund development. First, environmental engineering and permitting requirements and costs can be significant, possibly adding years to project development.[98] Second, brownfield site owners, developers, and contractors face risks from exposure to contamination at the site.[99] These risks can be very difficult to quantify *a priori*, and risk-averse developers with other siting options may simply avoid considering contaminated sites. Finally, contaminated sites in jurisdictions where land has high value (for industrial sites, residential, or even recreation) must compete with other uses of the site that are incompatible with ground-mounted solar. Those uses can include site remediation and new construction, or even the creation of recreational uses such as playing fields.

The District contains 95 brownfields, many of which are small sites with contamination related to fuel leaks, solvent spills, or asbestos.[100] The DC Department of Energy & Environment has detailed eight significant cleanup sites: the Anacostia River, the Pepco Benning Road site, the Washington Gas-East Station site, CSX Benning Yard, Poplar Point, Kenilworth Park, Riggs Park, and the DC United Soccer Stadium.[101] Because each brownfield site has its own complex story of ownership, remediation and mitigation requirements, solar potential, and other requirements, each site must be considered individually to determine if it can become a brightfield. Fortunately, the U.S. Environmental Protection Agency (EPA) has created a tool to assist in this process, the RE-Powering Mapper.[102]

2.4. Utility Incentives

Electric utilities, including Pepco, can influence the adoption of distributed generation in many ways:

- First, in order to connect to the grid, customers must complete Pepco's interconnection process. Pepco has significant control over this process, including the availability and clarity of information provided on its website, the ease of the application process, the responsiveness of its customer service, and the speed and accuracy with which applications are processed and the final approval to operate given. Difficulties

[98] Environmental assessments must be conducted to estimate the level of contamination, followed by more detailed chemical analyses and an examination of liability concerns. *See:* Todd K. BenDor, Sara S. Metcalf, and Mark Paich, "The Dynamics of Brownfield Redevelopment," *Sustainability* 3 (2011): 914–36.

[99] John Hannah, "Brownfield Redevelopment," *International Risk Management Institute*, December 2000, https://www.irmi.com/articles/expert-commentary/brownfield-redevelopment-a-risk-versus-reward-proposition.

[100] US Environmental Protection Agency, "Cleanups In My Community List Results," accessed February 14, 2017. Available at: https://www.epa.gov/cleanups/cleanups-my-community.

[101] DC Department of Energy & Environment, "Land Remediation and Development," accessed February 14, 2017. https://doee.dc.gov/service/land-remediation-and-development.

[102] US Environmental Protection Agency, "RE-Powering Mapping and Screening Tools," accessed February 14, 2017. Available at: https://www.epa.gov/re-powering/re-powering-mapping-and-screening-tools.

encountered by customers in this process increase the likelihood that customers will not complete the process.

- Second, Pepco also has some control over the fees assessed on DG customers, and the rate design that determines the value of their net metering credits. While all fees and rates must be approved by the Commission, Pepco generally takes the lead in proposing changes to fees or rates and can argue strongly for higher or lower fees and rates.

- Third, Pepco manages its distribution system and can propose to invest in new technologies or infrastructure upgrades to support additional distributed generation in areas that are approaching their maximum capacity. In addition, in areas where load is growing and new capacity investments are being considered, Pepco has the ability to propose non-traditional alternatives (such as greater distributed generation) to address the load growth. However, non-traditional alternatives to utility investments generally do not align with a utility's business model, which provides a rate of return on any capital investments. Thus the utility's support for distributed generation is often tepid without additional financial incentives.

- Fourth, customers are familiar with Pepco, and research has shown that utilities are more trusted than retailers, manufacturers, and other service providers in helping customers optimize their energy consumption.[103] Thus, utility-provided information regarding options for distributed generation could help connect customers with DG providers and reduce customer acquisition costs. For example, Pepco's website could feature vetted solar installers, or solar companies could pay to advertise on customer bills.

- Finally, Pepco can engage in lobbying for measures that support or discourage distributed generation, such as caps on the aggregate amount of solar or changes to the RPS legislation.

For this reason, aligning utility incentives with DG policy goals is an important aspect that regulators should address. Options include implementing revenue decoupling, performance metrics and incentives, and utility ownership of distributed generation.

Revenue Decoupling

In 2009, the Public Service Commission approved a revenue decoupling mechanism for Pepco, referred to as a "Bill Stabilization Adjustment" (BSA).[104] The BSA went into effect in January 2010 and allows for monthly adjustments to customers' bills in order to allow Pepco to collect its monthly allowed revenues.[105]

---

[103] Accenture, "The New Energy Consumer: Unleashing Business Value in a Digital World," July 2015, https://resapps.accenture.com/newenergyconsumer/unleashing-business-value-main.html.

[104] DC Public Service Commission, "Order No. 15556 In the Matter of the Application of Pepco for Authority to Increase Existing Retail Rates and Charges, Phase II," FC 1053, September 28, 2009.

[105] DC Public Service Commission, "Fact Sheet: Bill Stabilization Adjustment Begins in January 2010," January 28, 2010.

Revenue decoupling offers a means of removing the financial disincentive that the utility experiences regarding any demand-side resources, including distributed generation. Under traditional ratemaking, rates are held constant between rate cases, and any change in sales between rate cases would cause the utility's revenues to increase or decrease proportionally, depending on the direction of the sales. In contrast, revenue decoupling enables rates to be adjusted between rate cases to permit utilities to recover their allowed revenue—no more, and no less – regardless of the volume of sales.

Removing the link between revenues and sales is critical for mitigating utility disincentives regarding distributed generation.[106] As such, the adoption of a revenue decoupling mechanism can lead to an important shift in the mindset of utility management, where the utility becomes much less likely to opposed to demand-side resources. This shift often enables a much broader implementation of these resources.

Revenue decoupling mechanisms can be designed in many different ways, with different implications for utility customers. Where decoupling is implemented, it is critical that the mechanism be designed to protect customers. One of the most difficult and contentious aspects of revenue decoupling is the decision whether, and by how much, to adjust a utility's allowed revenues between rate cases.[107]

Performance Metrics and Incentives

Performance metrics and incentives can be used to encourage utilities to procure or support renewable resources and distributed generation. Renewable portfolio standards (with associated penalties or rewards for meeting targets) are a form of performance incentive mechanism that can be used to encourage development of distributed generation. In the District of Columbia, the solar carve-out is accompanied by a high alternative compliance payment that energy suppliers must pay if inadequate SRECs are procured.

Theoretically, such compliance payments can help address impediments to solar over which utilities have control. For example, utilities can influence the ability of distributed generation to interconnect to the grid and the compensation that these generators receive.

In practice, however, the costs of SREC non-compliance penalties may simply be passed on to ratepayers. Due to restructuring, Pepco procures electricity on behalf of DC customers through the market, or customers purchase directly from competitive suppliers. It is these suppliers, not Pepco, that are ultimately responsible for either buying sufficient SRECs or paying an alternative compliance payment. However, these fees may simply be bundled into the price of electricity procured from the market, thus flowing directly back to ratepayers. However, whether this actually occurs is unclear. The

[106] See the following section for a discussion of how utilities can influence the adoption of distributed generation.

[107] For an in-depth discussion see Tim Woolf and Mark Lowry, "Performance-Based Regulation in a High DER Future," January 2016, https://emp.lbl.gov/sites/all/files/lbnl-1004130_0.pdf.

Commission's RPS report notes that "To date, no electricity supplier has ever sought or received the Commission's approval to recover the cost of compliance fees."[108]

Regardless of whether competitive electricity suppliers or customers ultimately pay the alternative compliance payments, it is clear that Pepco does not pay them. Yet Pepco has much greater influence over the development of distributed solar in the District than competitive electricity suppliers, as described above. However, the non-compliance fees paid by electricity suppliers are unlikely to act as an incentive to Pepco, and it may therefore be worthwhile to revisit the utility incentives in place.

Utility Ownership of Distributed Generation

The District of Columbia has restructured its electricity market, meaning that energy is purchased through competitive wholesale markets, rather than by utility-owned generation sources. Restructuring commenced in 1999, when the DC Council passed the Electric Retail Competition and Consumer Protection Act. The Act authorized Pepco to divest its generation infrastructure. In 2001, Pepco sold five of its generation plants, and transferred the remaining two plants to an unregulated subsidiary, thus ending Pepco's direct involvement in energy generation. Currently, Pepco is a "wires-only" utility—its primary responsibility lies in maintaining the distribution system and delivering the energy purchased on the wholesale market.

Although utilities are generally prohibited from owning central-station power plants in restructured markets, some jurisdictions have been exploring utility ownership of distributed generation. Currently Pepco does not own or operate distributed generation in the District, but this could change in the future, were there to be sufficient rationale for doing so. For example, New York recently ruled that utilities may own cost-effective distributed energy resources where the market has failed to provide them.[109]

2.5. Municipal Solar

Municipal procurement of solar has many advantages that can spur distributed generation for the benefit of all customers. Electricity bill reductions resulting from the installation of solar reduce the operating revenues required, thereby freeing up taxpayer funds for other public uses, or lowering the overall tax revenues that must be collected.

In addition, many municipal properties offer useful real estate space for solar PV panels in terms of area and technical requirements. For example, many public buildings such as schools and police stations tend

[108] Public Service Commission of the District of Columbia, "Report on the Renewable Energy Portfolio Standard for Compliance Year 2015," 8.

[109] New York Public Service Commission, "Order Adopting Regulatory Policy Framework and Implementation Plan," Case 14-M-0101, Reforming the Energy Vision, February 26, 2015, http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId=%7b0B599D87-445B-4197-9815-24C27623A6A0%7d.

to have flat rooftops or surface parking lots that make them ideal for the installation and housing of solar panels.

Despite these advantages, relatively few cities have developed municipal solar. An obvious barrier to the development of municipal solar is cost. Local governments cannot take advantage of federal tax incentives because the cities/towns are tax-exempt entities. If the municipality were to self-finance the installation and maintenance of solar PV on government buildings, they would not receive any federal incentives, namely the 30 percent Federal Tax Credit and depreciation.

However, creative solutions are gaining in popularity. For states where a PPA with a third party is allowed,[110] the municipality could sign a PPA and capture both the tax credit and depreciation. A comparably cost-effective arrangement is to have the city purchase its solar from a private entity, which can capture all federal tax incentives and depreciation.[111] Thus, the city has to enter into partnerships with third parties to access federal solar incentives.

The District has done exactly this through its Department of General Services (DGS). In 2014, DGS issued a solicitation for more than 10 MW of solar PV capacity to be developed at approximately 50 municipal facilities.[112] In the end, the DC Council approved an on-site PPA with Nextility Inc. for more than 11 MW on the roofs of 34 buildings.[113] These 11 MW represent 44 percent of the 25 MW of municipal solar potential, estimated in the Institute for Local Self-Reliance (ILSR) 2015 "Public Rooftop Revolution" report.[114] This leaves the District with significant additional undeveloped municipal solar space.

Under the PPA, DGS purchases all the energy generated by these systems at a contractually established rate for 20 years. The rate will be $0.064 per kWh for four of the sites, and $0.059 per kWh for the remaining 30 sites, with 2 percent annual escalation.[115] Table 1 shows that the PPA's rates are considerably lower than the Standard Offer Service and Competitive Supplier options.

---

[110] As of June 2016, 26 states plus the District and Puerto Rico allow third-party PPAs. *See* "3rd Party Solar PV Power Purchase Agreement (PPA)," June 2016, http://ncsolarcen-prod.s3.amazonaws.com/wp-content/uploads/2016/06/3rd-Party-PPA.pdf.

[111] John Farrell, "Why Haven't Cities Covered Their Buildings in Solar?," CleanTechnica, accessed July 5, 2016, http://cleantechnica.com/2015/06/08/havent-cities-covered-buildings-solar/. John Farrell, "Public Solar Often a No-Go With Fed's Favor for Solar Tax Incentives," accessed July 8, 2016, https://ilsr.org/public-solar-often-no-go-feds-favor-solar-tax-incentives/.

[112] District of Columbia Department of General Services, "Solicitation Number: DCAM-14-CS-0123 Request for Proposals, On-Site Solar Power Purchasing Agreement at Various Municipal Facilities," March 25, 2014, http://dgs.dc.gov/sites/default/files/dc/sites/dgs/publication/attachments/RFP%20for%20On-Site%20Solar%20Power%20Purchasing%20Agreement%20at%20Various%20Municipal%20Facilities.pdf.

[113] *Nextility On-Site Solar Power Purchase Agreement (Contract No. DCAM-14-CS-0123A) Approval Emergency Act of 2015*, 2015, http://lims.dccouncil.us/Download/34781/PR21-0392-Introduction.pdf.

[114] John Farrell and Matt Grimley, "Public Rooftop Revolution" (Institute for Local Self-Reliance, June 2015), http://ilsr.org/wp-content/uploads/2015/06/Public-Rooftop-Revolution-report-ILSR.pdf.

[115] "Nextility On-Site Solar Power Purchase Agreement Contract No. DCAM 14-CS-0123A Approval Emergency Act of 2015 - Council Contract Summary," accessed June 30, 2016, https://trackbill.com/s3/bills/DC/21/B/454/texts/introduction.pdf.

Table 1. Solar PPA compared to standard offer and competitive supply

Purchase arrangement	Rate (per kWh)
PPA	$0.059 to $0.064
Pepco Standard Offer Service—Small Commercial[116]	$0.0764
Competitive Supplier*	$0.0749

*ConEdison Solutions, Small business, 17-month term[117]

[116] Pepco, "Rate Schedules for Electric Service in the District of Columbia."

[117] "ConEdison Solutions Fixed Price," *ConEdison Solutions*, accessed June 30, 2016, https://www.conedsolutions.com/CES_Enroll/?type=SC&state=DC&utility=PEPCODC&area.

3. OVERVIEW OF CASE STUDIES

The following sections describe policies implemented by a number of jurisdictions to overcome barriers to distributed generation development. The jurisdictions selected were chosen through a screening process that identified jurisdictions with relatively high levels of solar penetration, and that also could contribute relevant lessons learned regarding policies for the District.

In order to decide which states, cities, utilities, and other jurisdictions warranted further investigation, Synapse undertook the following screening process:

1. We compiled a list of states, cities, investor-owned utilities (IOUs), municipal utilities, and co-ops that have high levels of total installed solar PV capacity per capita.[118]

2. All states in the list were included in our list of entities to research. However, a state could be excluded if there was a good reason to do so.

3. Cities in the list were included if they met the following criteria:

    a. The city is located in the states list from Step 2; and

    b. The city in the top half of the group of cities for PV per capita.

    Even if these conditions were met, a city could be excluded from the list if there were compelling reasons to do so. Similarly, if a city did not meet the above conditions but there were compelling reasons to include them in the final list, they were included.

4. IOUs, co-ops and municipal utilities followed the same screening process for cities.

While we reviewed many jurisdictions, we focused the following sections on the six most relevant jurisdictions, with occasional examples from additional jurisdictions. The primary jurisdictions featured in this report are introduced below, followed by detailed discussion of the various policies that they have implemented.

[118] Sources: Massachusetts Net Energy Metering and Solar Task Force Final Report to the Legislature (2015); Shining Cities – Harnessing the Benefits of Solar Energy in America (2015), http://environmentamerica.org/sites/environment/files/reports/EA_ShiningCities2015_scrn.pdf. Accessed 10 June 2016; Smart Electric Power Alliance, 2015 Solar Market Snapshot Infographic and Top 10 Rankings, https://www.solarelectricpower.org/discover-resources/solar-tools/2015-solar-power-rankings.aspx, Accessed 10 June 2016.

3.1. Austin, Texas

Austin has a municipally owned electric utility overseeing approximately 21 MW of total installed solar capacity, which equates to about 24 W per capita.[119] As described further below, Austin Energy uses a value-of-solar feed-in tariff instead of net metering and also provides a rebate installation incentive. Since the rebate program started in 2004, more than 2,000 qualifying systems have been installed on residences, commercial buildings, schools, and government buildings, resulting in a total capacity of 8 MW on residences by 2012.[120]

3.2. San Antonio, Texas

San Antonio's municipally owned utility, CPS Energy, has attempted a range of solar policies over time, including both net metering and an installation rebate for customers.[121] Recently, CPS has been experimenting with innovative new ownership structures and an elimination of net metering after having found that their previous programs led to installation of DG primarily in high-income areas of the city. San Antonio citizens added over 2,000 DG systems between 2007, when CPS first instituted DG policies, and 2014.[122] Presently, San Antonio has approximately 88 MW total of solar capacity[123] (including several PPAs)[124] and a high amount of solar per capita at 63 W per person.[125]

3.3. Palo Alto, California

Palo Alto is a small city in California with a municipally owned electric utility. It has a large amount of installed solar capacity for its population, at 1,846 W per capita (spread over more than 800 projects).[126]

---

[119] Judee Burr, Lindsey Hallock, and Rob Sargent, "Shining Cities: Harnessing the Benefits of Solar Energy in America" (Environment America & Frontier Group, 2015), http://environmentamerica.org/sites/environment/files/reports/EA_ShiningCities2015_scrn.pdf.

[120] Austin Energy, "Energy Efficiency & Solar," October 8, 2013, http://austinenergy.com/wps/portal/ae/about/reports-and-data-library/data-library/energy-efficiency-solar/energy-efficiency-solar/.

[121] United States Department of Energy, "CPS Energy - Solar PV Rebate Program," accessed July 7, 2016, http://energy.gov/savings/cps-energy-solar-pv-rebate-program.

[122] Cris Eugster, "Solar Distributed Generation Program Update," June 11, 2014, http://therivardreport.com/wp-content/uploads/2014/06/city-council-briefing-solar-dg-6-11-14.pdf.

[123] Judee Burr, Lindsey Hallock, and Rob Sargent, "Shining Cities: Harnessing the Benefits of Solar Energy in America."

[124] CPS Energy, "Solar Power," accessed July 7, 2016, https://www.cpsenergy.com/en/about-us/programs-services/energy-generation/solar-power.html.

[125] Judee Burr, Lindsey Hallock, and Rob Sargent, "Shining Cities: Harnessing the Benefits of Solar Energy in America."

[126] Smart Electric Power Association, "2015 Solar Power Rankings," accessed July 7, 2016, https://www.solarelectricpower.org/discover-resources/solar-tools/2015-solar-power-rankings.aspx.

Palo Alto started allowing net metering in 1999 and the amount of net metered capacity has since grown to approximately 7.5 MW total out of a program cap of 9.5 MW.[127]

3.4. Seattle, Washington

In 2008, Seattle was designated as a Solar America City by the Department of Energy, thereby receiving a Solar America Cities grant. Even though the city's municipal utility, Seattle City Light, already had interconnection procedures for solar systems up to 100 kW, city residents still faced infrastructure, awareness, and economic barriers to solar deployment. To address this, Seattle formed the Emerald City Initiative which assembled a team of experienced partners in fields such as financial analysis, site analysis, education and outreach, community organizing, policy analysis, and advocacy. The initiative was led by Seattle City Light, which contributed the majority of funds to match the Solar America Cities grant.

The impact of this initiative was clear. The city went from having an installed PV capacity of approximately 200 kW in 2007 to approximately 1.1 MW in 2010, with Residential PV making up a large part of this capacity.[128] By 2016, Seattle had installed approximately 12 MW (18 W per person).[129]

3.5. Rhode Island

Rhode Island is notable in that it has a variety of programs that together have the potential to create a favorable environment for solar development. Like the District, Rhode Island has limited available land to support large solar projects. As a result, policy makers have focused their attention on distributed generation and implemented programs to support distributed generation, especially small-scale solar. Providence has been particularly successful in solar installation, reaching 4 MW by 2016 (23 W per person).[130]

3.6. New York

New York's solar incentives have helped to increase interconnection applications for solar projects from 1,200 in 2010 to 11,000 in 2015.[131] The NY-Sun program aims to add more than 3 GW of installed solar

---

[127] City Council Staff, "Net Energy Metering Successor Rate and Transition Policy" (City of Palo Alto, June 27, 2016), http://cityofpaloalto.org/civicax/filebank/documents/52890.

[128] U.S. Department of Energy, "Solar in Action - Seattle, Washington," October 2011, http://www1.eere.energy.gov/solar/pdfs/51061_seattle.pdf.

[129] Kim Norman, Rob Sargent, and Bret Fanshaw, "Shining Cities 2016 - How Smart Local Policies Are Expanding Solar Power in America," April 2016, http://www.environmentamerica.org/sites/environment/files/reports/EA_shiningcities2016_scrn.pdf.

[130] Ibid.

[131] "State News: New York PSC Notes Boom in Solar Power Development," NARUC, accessed June 28, 2016, http://www.naruc.org/bulletin/the-bulletin-062716/state-news-new-york-psc-notes-boom-in-solar-power-development/.

capacity by 2023 with the eventual goal of creating a sustainable and self-sufficient solar industry within the state.[132] In addition to its Megawatt Block Program,[133] an incentive program that follows a Declining Block Incentive mechanism, NY-Sun and the state have made strong efforts to help make sure all constituents can participate and benefit from solar development. New York State currently has approximately 638 MW of solar installed (32 W per person),[134] while New York City currently has approximately 84 MW of solar installed (10 W per person).[135]

3.7. Minnesota

Minnesota stands out as being the first state in the country to mandate the use of a value-of-solar tariff for certain DG customers. The state ranks low in cumulative solar capacity per capita (33rd in the country with 6 W per person) and 28th in the country for cumulative solar capacity (33 MW).[136] However, there are signs of large increases in solar development in the state. The state saw a 116 percent increase in installed solar capacity from 2014 to 2015, with 13 MW of solar electric capacity installed in 2015 alone.

3.8. California

As of March 2016, California maintained its place as the top state in the country for cumulative solar electric capacity installed, with 13,241 MW installed.[137] It also ranked number one in the country for solar capacity installed in 2015 (3,266 MW) and for number of solar jobs (75,598). It ranked third for solar capacity per capita (338 W per person).[138] California was one of the earliest adopters of policies to support the development of solar capacity, including one of the earliest Renewable Portfolio Standards in the country.[139] The adoption of substantial solar in the state has resulted in the cessation of some earlier rebate programs, but the state still has very supportive policy, incentive, net-metering, and interconnection rules.[140]

---

[132] "About NY-Sun - NYSERDA," accessed June 28, 2016, http://www.nyserda.ny.gov/All-Programs/Programs/NY-Sun/About.

[133] "Megawatt (MW) Block Dashboards - NYSERDA," accessed June 28, 2016, http://www.nyserda.ny.gov/All-Programs/Programs/NY-Sun/Megawatt-Block-Dashboards.

[134] "Top 10 Solar States," SEIA, accessed July 6, 2016, http://www.seia.org/research-resources/top-10-solar-states.

[135] Norman, Sargent, and Fanshaw, "Shining Cities 2016 - How Smart Local Policies Are Expanding Solar Power in America."

[136] Gideon Weissman, Bret Fanshaw, and Rob Sargent, "Lighting the Way 4 The Top States That Helped Drive America's Solar Energy Boom in 2015," July 2016, http://www.environmentamerica.org/sites/environment/files/reports/AME%20LightingTheWay%20Jul16%201.3.pdf.

[137] Solar Energy Industries Association, "Top 10 Solar States," accessed August 11, 2016, https://www.seia.org/user/login?destination=/research-resources/solar-data-cheat-sheet.

[138] Ibid.

[139] "History of California's Renewable Energy Programs," accessed August 11, 2016, http://www.energy.ca.gov/renewables/history.html.

[140] "2015 United States Solar Power Rankings," *Solar Power Rocks*, accessed August 11, 2016, https://solarpowerrocks.com/2015-solar-power-state-rankings/.

Aside from being the home to many large utility-scale solar facilities, the state has also targeted distributed solar PV through various initiatives, including its California Solar Initiative (CSI) program. As of August 2016, the CSI has resulted in the installation of 4,427 MW of solar electric capacity, and over 500,000 solar projects.

4. Financial Incentive Case Studies

4.1. Compensation Mechanisms

Financial considerations—particularly a system's payback period—play a critical role in spurring adoption of distributed generation. One of the most direct means of influencing the payback period is through the compensation that a customer receives for the services that the customer's system delivers to the grid. Compensation often takes the form of net metering credits at the retail electricity rate, but alternatives to this arrangement exist. Such alternative compensation options include feed-in-tariffs, value-of-solar tariffs, and PURPA avoided-cost tariffs. Some customers with distributed technologies may also be able to provide ancillary services (such as frequency response and voltage regulation) to the grid and be compensated for these services directly.

Austin, Texas: Value-of-Solar

The city of Austin uses a value-of-solar feed-in tariff instead of a net metering program. The amount of the Value-Of-Solar Rate is set on an annual basis through the Austin Energy budget process.[141] The rate fluctuates from year to year but is generally in the range of 10 to 12 cents per kWh. The methodology used to calculate the Value-Of-Solar Rate was originally set in 2012 and considers loss savings, energy savings, generation capacity savings, fuel price hedge value, transmission and distribution capacity savings, and environmental benefits.[142]

San Antonio, Texas: Rooftop Hosting Payments

San Antonio offers residents two options to benefit from distributed generation. The first is called SolarHost. In this program, CPS Energy (the city's municipal utility) installs solar panels on the roofs of eligible residences.[143] CPS Energy retains ownership of the panels and no up-front investment or lease payments on the part of the homeowner are required. Representatives from CPS have stated that the main goal of the program is to remove barriers to entry for low-income residents and avoid cross-subsidization.[144] Residential customers who are accepted into the SolarHost program are paid $0.03/kWh for the generation of the panels they host.[145] When ownership of the residence is transferred, the payment is transferred as well. Rental properties are allowed to participate in the

---

[141] City of Austin, "Value of Solar (Rider)," accessed July 6, 2016, http://austinenergy.com/wps/wcm/connect/c6c8ad20-ee8f-4d89-be36-2d6f7433edbd/ResidentialSolar.pdf?MOD=AJPERES.

[142] Karl Rabago et al., "Designing Austin Energy's Solar Tariff Using a Distributed PV Value Calculator" (Austin Energy and Clean Power Research), accessed July 6, 2016, http://www.cleanpower.com/wp-content/uploads/090_DesigningAustinEnergysSolarTariff.pdf.

[143] "SolarHost San Antonio," accessed July 6, 2016, http://www.solarhostsa.com/#HowItWorks.

[144] "CPS Energy Tackles the Cost Shift by Building Solar on Its Own Terms," *Utility Dive*, accessed July 6, 2016, http://www.utilitydive.com/news/cps-energy-tackles-the-cost-shift-by-building-solar-on-its-own-terms/406305/.

[145] Ibid.

program. Building owners can submit an application with the understanding that the value of the credit goes towards the holder of the CPS account registered at the building's address.

Alternatively, customers can join the Roofless Solar program and buy shares in a community solar project. This option is described further in the community solar section, below.

Palo Alto, California: Annually Adjusted Feed-in-Tariff

Palo Alto's municipal utility has a traditional net metering program, with a total program cap of 9.5 MW.[146] Surplus generation is compensated at the rate of $0.05841/kWh.[147] The city has recently proposed a Net Energy Metering Successor Rate to apply after the net metering program cap has been reached. The proposed new compensation structure is a feed-in tariff with a value of $0.07485/kWh.[148] The credit value is described as taking into account energy, avoided capacity charges, avoided transmission and ancillary service charges, avoided transmission and distribution losses, and environmental attributes, although no methodology is given. While the credit is currently higher than the traditional net metering rate, it is proposed to be updated annually. Current net metered customers will be grandfathered for a period of 20 years.

Portland, Oregon: Guaranteed Feed-in-Tariff

As an alternative to its existing net metering option,[149] Portland General Electric (PGE) customers with solar can choose a feed-in-tariff[150] option called the Solar Payment Option, which currently compensates customers at a rate much higher than the net metering rate for a period of 15 years.[151]

---

[146] City of Palo Alto, "Solar Programs in Palo Alto," accessed July 6, 2016, http://www.cityofpaloalto.org/gov/depts/utl/residents/resources/pcm/solar_programs_in_palo_alto.asp.

[147] City of Palo Alto, "Net Metering Net Surplus Electricity Compensation (Utility Rate Schedule E-NSE-1)," accessed July 6, 2016, http://www.cityofpaloalto.org/civicax/filebank/documents/25951.

[148] City Council Staff, "Net Energy Metering Successor Rate and Transition Policy."

[149] "Portland General Electric Company Schedule 203 Net Metering Service," 203, accessed June 25, 2016, https://www.portlandgeneral.com/-/media/public/documents/rate-schedules/sched_203.pdf?la=en.

[150] Legislative bills use the term "solar feed-in-tariff." However, since the rules and rates are set by the state, this program differs from the usual definition of feed-in-tariff. DSIRE, "Oregon Solar Volumetric Incentive and Payments Program," accessed July 1, 2016, http://programs.dsireusa.org/system/program/detail/3564.

[151] "Solar Payment Option - Install Solar, Wind & More | PGE," accessed June 20, 2016, https://www.portlandgeneral.com/residential/power-choices/renewable-power/install-solar-wind-more/solar-payment-option.

The feed-in-tariff program was started in 2010 in order to implement state legislation that required participating utilities[152] to establish volumetric incentive rate programs for solar PV. [153,154] Under the program, capacity is distributed twice a year during set enrollment windows.[155] The amount of capacity available is set by the Public Utilities Commission.[156] Capacity for small-scale systems (less than 10 kW) is distributed first through a lottery-based application process and then through a first-come, first-served process.[157]

Participants receive payments from PGE for the energy generated by their eligible solar installations, up to the amount of energy they consume. The payment amount is determined by the rate in place at the time of the Reservation Start Date. The rate, set by the Commission and re-evaluated for every enrollment window,[158] applies to the entire 15-year life of the agreement.[159] In 2015, Portland participants with small systems (10 kW or less), were paid a volumetric incentive rate of 31.6 cents/kWh.[160]

Unlike under the Net Metering option, customers under this tariff are not eligible for payment for credits in excess of their annual usage. Under the Solar Payment tariff, excess generation credits from the last monthly billing period is transferred to PGE's low-income assistance program at the average annual avoided cost rate.[161]

The Solar Payment Option program was successful enough to reach its goal of 27.7 MW by 2015 (for all utilities). As a result, PGE and the other two participating utilities, are no longer accepting new applications for the program.

---

[152] We use PGE as our example. The program design and implementation is the same across the participating utilities.

[153] EnergyTrust of Oregon, "Solar Feed-in Tariff Frequently Asked Questions," July 2014, https://energytrust.org/library/resources/FIT_FAQ.pdf.

[154] Oregon Public Utilities Commission, "Solar Photovoltaic Volumetric Incentive Program, Report to the Legislative Assembly," January 1, 2013, http://www.puc.state.or.us/docs/010213SolarPilotProgramReport.pdf.

[155] "Portland General Electric Solar Payment Option FAQ," accessed June 21, 2016, https://www.portlandgeneral.com/-/media/public/shared/documents/solar-payment-option-faq.pdf?la=en.

[156] "Division 84 Solar Photovoltaic Programs," accessed June 28, 2016, http://arcweb.sos.state.or.us/pages/rules/oars_800/oar_860/860_084.html.

[157] "Portland General Electric Solar Payment Option FAQ."

[158] Oregon Public Utilities Commission, "Solar Photovoltaic Incentive Program 2015 Report to the Legislative Assembly," January 1, 2015, https://www.oregonlegislature.gov/citizen_engagement/Reports/2015SolarReport.pdf.

[159] "Portland General Electric Company Schedule 215 Solar Payment Option Pilot Small Systems (10kW or Less)," 215, accessed June 21, 2016, https://www.portlandgeneral.com/-/media/public/documents/rate-schedules/sched_215.pdf?la=en.

[160] Ibid.

[161] "Portland General Electric Company Schedule 201 Qualifying Facility 10 MW or Less Avoided Cost Power Purchase Information," accessed June 21, 2016, https://www.portlandgeneral.com/-/media/public/business/power-choices-pricing/documents/business-sched-201.pdf?la=en.

Minnesota: Mandated Value-of-Solar Tariff

On June 21, 2016 the Minnesota Public Utilities Commission mandated the use of a VOS methodology to determine compensation rates for Community Solar Garden (CSG) customers.[162] This made Minnesota the first state in the country to put in place a VOS rate for IOU solar customers. Xcel's proposed VOS tariff[163] is based on the VOS methodology previously approved by the state in 2014.[164,165] Even then, Minnesota was a leader in being the first state to decide on a VOS methodology and small solar tariff option.[166]

While innovative, the VOS tariff has been met with some opposition. Developers have expressed opposition to the 1 MW cap, arguing that community distributed generation projects of this size have no economies of scale, thus making them too small to secure financing.[167] Developers will be further disincentivized if the VOS rate is lower than the current average retail rate for residential solar.

It is not possible to assess the success of the mandated VOS tariff for CSGs, since the Commission's order is so recent. However, implementation issues of the CSG program are outlined in Section 4.2 on Community Solar.

Rhode Island: Long-Term Tariff Incentive

Rhode Island's Renewable Energy Growth (REG) program was created in 2014[168] to promote the development of distributed generation, including solar, wind, and any other distributed generation technologies recommended by the Distributed Generation Standard Contract Board (DG Board). The REG program allows customers to sell their excess generation at a long-term (15 to 20 years) fixed, flat price designed to provide owners with a reasonable rate of return. Like PGE's program, the long-term fixed price is key to mitigating the risk of SREC prices falling, or the potential dismantling of the net

---

[162] "Order Denying Request for Clarification," E-002/M-13-867 § (2016), https://www.edockets.state.mn.us/EFiling/edockets/searchDocuments.do?method=showPoup&documentId={8B1522DD-6411-4C16-8274-42540E8B2C31}&documentTitle=20166-122455-01.

[163] Northern States Power Company, "Standard Contract for Solar*Rewards Community," July 21, 2016, https://www.edockets.state.mn.us/EFiling/edockets/searchDocuments.do?method=showPoup&documentId={52CB3982-8A73-4C21-BB79-269DEA68278A}&documentTitle=20167-123482-01.

[164] Benjamin L. Norris, Morgan C. Putnam, and Thomas E. Hoff, "Minnesota Value of Solar: Methodology," January 30, 2014, https://www.cleanpower.com/wp-content/uploads/MN-VOS-Methodology-2014-01-30-FINAL.pdf.

[165] "Order Approving Distributed Solar Value Methodology," Pub. L. No. Docket No. E-999/M-14-65, E-999/M-14-65 (2014), https://www.edockets.state.mn.us/EFiling/edockets/searchDocuments.do?method=showPoup&documentId={FC0357B5-FBE2-4E99-9E3B-5CCFCF48F822}&documentTitle=20144-97879-01.

[166] electricpulp.com, "MN Regulators Adopt First of Its Kind Value of Solar Rate | Fresh Energy," accessed August 9, 2016, http://fresh-energy.org/2016/07/mn-regulators-adopt-first-of-its-kind-value-of-solar-rate/.

[167] "Minnesota Public Utilities Commission Approves Size Caps, Rate Structure for Solar Projects," *Star Tribune*, accessed August 9, 2016, http://www.startribune.com/minnesota-utilities-commission-approves-size-caps-rate-structure-for-solar-projects/387872592/.

[168] "CHAPTER 39-26.6 The Renewable Energy Growth Program," accessed July 1, 2016, http://webserver.rilin.state.ri.us/Statutes/TITLE39/39-26.6/INDEX.HTM.

metering program. The REG statute requires a minimum of 3 MW be allocated to the small solar class (less than 25 kW) during the 2015, 2016, 2017, and 2018 program years.

For each program year, the DG Board and its consultant develop and recommend ceiling prices for generation from qualified resources. Current legislation[169] requires that the ceiling price be set to "allow a private owner to invest in a given project at a reasonable rate of return, based on recently reported and forecast information on the cost of capital, and the cost of generation equipment."[170]

Small-scale (up to 25 kW) and medium-scale (26 to 250 kW) solar applicants receive the ceiling price, and applications are awarded on a first-come first-served basis. Large and commercial applicants submit a competitive bid at or below the ceiling price, with the lowest cost projects awarded first.

Table 2 shows approved 2016 small-scale solar targets, ceiling price, term lengths, and annual enrollment targets, compared to higher 2015 numbers.

Table 2. 2015 and 2016 small-scale solar annual MW target, actual enrollment and standard PBI

	2015		2016	
Renewable Energy Class	**Enrollment Target**	**Ceiling Price (¢/kWh), Term**	**Enrollment Target**	**Ceiling Price (¢/kWh), Term**
Small-scale solar, Host owned (1-10 kW_{DC})	3.0 MW total	41.35 (15-yr Tariff)	5.5 MW total	37.65 (15-yr Tariff)
Small-scale solar, Host owned (1-10 kW_{DC})		37.75 (20-yr Tariff)		33.45 (20-yr Tariff)
Small-Scale Solar, 3rd Party Owner (1-10 kW_{DC})		No 15-yr Tariff		28.35 (15-yr Tariff)
Small-Scale Solar, 3rd Party Owner (1-10 kW_{DC})		32.95 (20-yr Tariff)		24.70 (20-yr Tariff)
Small-Scale Solar (11-25 kW_{DC})		29.80 (20-yr Tariff)		24.90 (20-yr Tariff)

Source: RI Renewable Energy Growth Program Solicitation and Enrollment Process Rules for Small-Scale Solar Projects.[171]
Docket 4536-A – First 2015 Rhode Island Renewable Energy Growth Program Open Enrollment Report, September 21, 2015.[172]
Docket 4536-A – Second 2015 RI Renewable Energy Growth Program Open Enrollment Report, December 21, 2015.[173]

---

[169] *RI Gen L § 39-26.6-3 (2015)*, http://law.justia.com/codes/rhode-island/2015/title-39/chapter-39-26.6/section-39-26.6-3.

[170] Sustainable Energy Advantage was contracted by the DG Board to develop and recommends ceiling prices on behalf of the Board. SEA uses the Cost of Renewable Energy Spreadsheet Tool (CREST) model to develop a set of recommendations to the DG Board who, after public meeting and discussion, recommend the proposed ceiling prices to the Commission.

[171] "National Grid, Rhode Island Renewable Energy Growth Program Solicitation and Enrollment Process Rules for Small-Scale Solar Projects," accessed July 5, 2016, https://www9.nationalgridus.com/narragansett/non_html/2016%20RE%20Growth%20Enrollment%20Small-Scale%20Solar%20%28Final%20to%20PUC%203-9-16%29.pdf.

[172] National Grid, "Docket 4536-A - First 2015 Rhode Island Renewable Energy Growth Program Open Enrollment Report," September 21, 2015, http://www.ripuc.org/eventsactions/docket/4536A-NGrid-2015-1st_Enrollment(9-21-15).pdf.

[173] National Grid, "Docket 4536-A - Second 2015 Rhode Island Renewable Energy Growth Program Open Enrollment Report," December 21, 2015, http://www.ripuc.org/eventsactions/docket/4536A-NGrid-2015-2ndEnrollmnt(12-18-15).pdf.

This price-setting strategy is advantageous as it allows policymakers to target particular goals, for example, growing the market quickly or rewarding solar projects with the lowest cost. However, calibrating these prices may be challenging and incorrect price setting could lead to unfavorable market dynamics.

4.2. Community Solar

San Antonio, Texas

In addition to its SolarHost program, San Antonio offers its residents the opportunity to participate in a program called RooflessSolar. This program is operated by Clean Energy Collective, a community solar developer. In the RooflessSolar program, residents can purchase shares in a yet-to-be-developed, locally sited community solar project. Each panel in a RooflessSolar project is estimated to cost a customer approximately $200 and provide the owner with approximately $25 of value every year, for a payback period of about nine years.[174] Customers can purchase enough capacity to provide up to 120 percent of their historical average consumption and can increase the size of their share at any time up to this limit.

Since the launch of the program in June 2015, roughly 72 percent of the project's 1.2 MW of capacity has been reserved. Installation of the more than 11,000 solar panels is currently ongoing at a 10-acre site just east of the city.[175]

New York

The Shared Solar program, launched in 2015 as part of the Shared Renewables initiative,[176] allows any utility customer (renters, homeowners, businesses, or municipalities) to subscribe to a "share" of a community distributed generation projects (solar) project. Each community distributed generation project needs to meet a set of requirements, including: having a sponsor and at least 10 members each allotted a minimum of 1,000 kWh per year. [177] Projects that began operation before May 1, 2016 must have at least 20 percent of their members be low-income residents; or the projects must be located in a utility-designated community distributed generation project Opportunity Zone. Opportunity Zones are

---

[174] Brendan Gibbons, "CPS Energy Debuts 'roofless' Solar Site near St. Hedwig," *San Antonio Express-News*, July 11, 2016, http://www.mysanantonio.com/news/local/article/CPS-Energy-debuts-roof-less-solar-site-near-8352316.php.

[175] Ibid.

[176] "Governor Cuomo Announces Expanded Access to Renewable Energy For Millions Of New Yorkers," *Governor Andrew M. Cuomo*, July 16, 2015, http://www.governor.ny.gov/news/governor-cuomo-announces-expanded-access-renewable-energy-millions-new-yorkers.

[177] "Shared Solar - NYSERDA," accessed June 23, 2016, http://www.nyserda.ny.gov/All-Programs/Programs/NY-Sun/Communities/Shared-Solar.

areas in which locational benefits of distributed generation are maximized and must make up at least 40 percent of the utility's service territory.[178]

Community DG subscribers receive the same full retail credit as all net metering customers.[179] In April 2016, a coalition of utilities and solar developers submitted a proposal with the Public Service Commission, proposing that Community DG subscribers continue to receive the full retail net metering credit, but developers begin to pay the utilities a "Developer Payment." Thus, the developers are partly paying for the subscriber's compensation. The Developer Payment increases over time, as customers are moved away from receiving full retail net metering credit to a future valuation whose components are the wholesale power system, electric distribution system, and societal benefits, e.g. environmental benefits.[180] This avoids changes to the net metering values customers see in their utility bill, while reducing the potential for cost shifting.

Each Community DG project would be assigned to a "Tranche" that dictates the compensation rate and Developer Payments. Each Tranche represents a pre-established amount of eligible capacity. Successive Tranches will have higher Developer Payments, and a decreasing difference between the customer's full net metering credit and the proposed valuation decreases, as Developer Payments increase. The coalition did not propose tranche sizes, instead recommending Tranches be determined by the Commission based on stakeholder input.

Construction on the first Community Solar project, sized at 84.6 kW, began in April 2016.[181] Meanwhile, other initiatives are underway to help connect community solar participants. For example, the Shared Solar NYC Gateway is an online platform that connects community solar developers with interested owners of potential host sites, as well as with prospective subscribers. The website allows residents and businesses to sign up for notifications about solar subscription opportunities in their local communities and works to educate potential host site owners and potential subscribers through Solarize marketing campaigns. The Solar NYC Gateway is a project of Sustainable City University of New York and the NYC Solar Partnership, which was founded in 2006 to help address "extensive barriers including technical, policy and lack of incentives, standardization or cohesion among agencies and utilities."[182]

---

[178] "Inside New York's Aggressive New Community Shared Renewables Program," *Utility Dive*, accessed July 4, 2016, http://www.utilitydive.com/news/inside-new-yorks-aggressive-new-community-shared-renewables-program/402896/.

[179] "In the Matter of the Value of Distributed Energy Resources," April 18, 2016, http://documents.dps.ny.gov/public/MatterManagement/CaseMaster.aspx?MatterCaseNo=15-E-0751&submit=Search+by+Case+Number.

[180] Ibid.

[181] "Construction Begins on the First Community Solar Project in New York State: Pv-Magazine," accessed July 6, 2016, http://www.pv-magazine.com/news/details/beitrag/construction-begins-on-the-first-community-solar-project-in-new-york-state_100024345/%20-%20axzz4DeFyXQxe.

[182] "NYC Solar Partnership," *NYC Solar Partnership | Solarize NYC | Shared Solar NYC*, February 16, 2017, http://sharedsolarnyc.com/nyc-solar-partnership/.

Seattle, Washington

Major barriers to solar in Seattle were high initial costs and lack of solar access, defined as "the ability of one property to continue to receive sunlight across property lines without obstruction…."[183] To address this, a Solar America Cities special projects grant received in 2010 was used to create a community solar program, sponsored by Seattle City Light. Market research, in the form of focus groups and phone surveys, was conducted to assess residents' receptiveness to different community solar program models. A number of factors drove the design of the program, including determining the price point at which customers could participate and understanding if all Seattle City Light customers had equitable access to the program. The first Community Solar project was completed in 2012.

Any Seattle City Light customer can participate in its Community Solar program by purchasing 1 to 125 solar "units," priced at $150 each.[184] Each unit represents a 28 watt portion of the system,[185] where a unit is sized to return at least $150 to the customer over the project lifetime. The charge for the solar units is spread across two installments on the customer's next two bills. Like net metering, Community Solar program participants are compensated at the full retail rate.[186]

Customers will continue to receive the solar benefits if they move within the Seattle City Light service area, making this program attractive to renters. If the customer moves outside the Seattle City Light service area, the credits can be transferred to another Seattle City Light account of the customer's choosing. Seattle City Light pays for the building, insurance, warranty, management, and maintenance costs of a large solar array, which is located at a site selected by the utility. As a result, the program participant does not have to pay any additional out-of-pocket fees in the future.[187]

Seattle City Light's Community Solar projects built in 2014 totaled just over 100 kW, and were sold out as of May 2015.[188]

---

183 "Solar Access," Wikipedia, the Free Encyclopedia, December 17, 2015, https://en.wikipedia.org/w/index.php?title=Solar_access&oldid=695657804.

184 "Seattle City Light Community Solar FAQs," accessed June 22, 2016, http://www.seattle.gov/light/solarenergy/commsolarfaq.asp.

185 Seattle City Light, "Solar Energy in Seattle - Seattle City Light Review Panel," October 2015, http://www.seattle.gov/Documents/Departments/CityLightReviewPanel/Documents/SolarPresentationToReviewPanel_20151013.pdf.

186 "Solar Energy FAQ," accessed June 23, 2016, http://www.seattle.gov/light/solarenergy/solarfaq.asp#net metering.

187 "Seattle City Light Community Solar FAQs."

188 "Seattle City Light Community Solar," accessed June 22, 2016, http://www.seattle.gov/light/solarenergy/commsolar.asp.

Minnesota

Minnesota's Community Solar Garden (CSG) program was launched in 2014.[189] A CSG is simply a large array of solar PV panels in which subscribers may purchase shares, called a "subscription," of the project's total capacity.[190] CSGs must have at least five subscribers; be entirely located within the service territory of the utility administering the program; and are capped at 1 MW in size. Subscribers must reside in the county in which the CSG is located,[191] and no one individual subscriber can subscribe to more than 40 percent of the CSG's output.[192]

The implementation of the 2014 CSG program was problematic, mainly due to an unexpected flood of applications and imprecise language in the CSG program order. As worded, the order allowed developers to take advantage of loopholes and violate the original intent of the program.

By June 2015, there were 900 active applications pending, representing 912 MW in capacity,[193] and all but one solar garden project had been approved for interconnection.[194] Delays were attributed to several factors. These included the volume of applications, inadequate staffing at Xcel, Xcel's failure to conform to the usual interconnection timelines, and developers not knowing how much available capacity exists at a specific point on Xcel's grid or how many projects are in the interconnection queue to a particular substation.[195] If there had been more transparency of the latter, developers would have been less likely to file applications with a lower probability of success and thereby avoided wasting both developers' and Xcel's resources. As part of the Partial Settlement Order of August 2015, the Commission required Xcel to comply with a more streamlined and transparent process, including providing monthly updates related to the solar garden interconnection queue. It further required Xcel to grant or deny developers permission to interconnect within 50 days of the application date.[196]

Prior to the Partial Settlement Order, the CSG program did not prohibit the co-location of multiple CSGs. This resulted in projects more closely resembling utility-scale PV that violated the community-focused spirit of the program and hampered the ability of the projects to avoid distribution system costs.[197] For

---

189 "Order Approving Solar-Garden Plan with Modifications" (2014), https://www.edockets.state.mn.us/EFiling/edockets/searchDocuments.do?method=showPoup&documentId={10BA0886-4539-4BC2-B896-8E0D8D26E5F4}&documentTitle=20149-103114-01.

190 "How It Works," accessed August 9, 2016, http://mncommunitysolar.com/how-it-works.

191 Minnesota Public Utilities Commission, "Order Adopting Partial Settlement as Modified," E-002/M-13-867, August 6, 2015, https://www.edockets.state.mn.us/EFiling/edockets/searchDocuments.do?method=showPoup&documentId={43AC9E59-AD57-44FE-A57A-5F8A572D3C74}&documentTitle=20158-113077-01.

192 Northern States Power Company, "Standard Contract for Solar*Rewards Community."

193 Minnesota Public Utilities Commission, "Order Adopting Partial Settlement as Modified."

194 Ibid.

195 Ibid.

196 Ibid.

197 One of these co-located solar-garden project was 40 MW in size. Ibid.

example, a single developer could submit multiple applications, each at the maximum 1 MW allowed, for a single site. To address this, the PUC ordered the definition of "Co-Located" to be made explicit; no more than 5 MW of co-located CSGs could be allowed on a single project site for applications submitted prior to the Order's effective date of September 25, 2016; and no more than 1 MW of co-located CSGs be allowed on a single project site for applications submitted after the Order's effective date of September 25, 2016. [198]

The lesson here is that it is crucial for all program terms and legislation to be precise and not leave room for various interpretations that can exploit the intent of the Community Solar program.

4.3. Rate Design

Salt River Project, Arizona

Under net metering, customers are effectively compensated at rates based on kilowatt-hour energy usage (and possibly also kilowatt demand) applicable to their rate class. However, changes to the underlying rate structure can profoundly impact customer economics. For example, increasing the fixed charge or adding a demand charge will reduce the customer's variable rate (assessed on kilowatt-hours), thereby reducing the effective compensation for customer generation.

Salt River Project (SRP) is an example of a solar policy that drastically *reduced* the number of customers seeking to build rooftop solar through adjusting the rates applicable to customers with distributed generation. In December 2014, SRP introduced a new price schedule called the Customer Generation Price Plan.[199] Plan participation is mandatory for all customer-generators who do not purchase all their energy from SRP. The new pricing plan added a fee averaging approximately $50 per month to all leased and owned solar systems, mainly via a new monthly demand charge.[200] The subsequent drop in new rooftop solar applications was dramatic. In the year before the new fees were implemented, an average of 675 solar systems were installed per month. In 2015, after the new fee went into effect, solar installations fell to 39 per month, a 94 percent decrease.[201]

---

[198] Ibid.

[199] Salt River Project Agricultural Improvement and Power District, "E-27 Customer Generation Price Plan for Residential Service," June 23, 2016, http://www.srpnet.com/prices/pdfx/April2015/E-27.pdf.

[200] Peter Fairley, "Utilities and Solar Companies Fight Over Arizona's Rooftops," IEEE Spectrum: Technology, Engineering, and Science News, June 19, 2015, http://spectrum.ieee.org/green-tech/solar/utilities-and-solar-companies-fight-over-arizonas-rooftops.

[201] Analysis of data from "ArizonaGoesSolar.org Salt River Project (SRP)," accessed June 24, 2016, http://www.arizonagoessolar.org/UtilityPrograms/SaltRiverProject.aspx.

4.4. Financing and Customer Incentives

Seattle, Washington

A number of incentives are offered to program participants in Seattle: annual production incentive credits from Washington state administered by Seattle City Light (at a base rate of $0.15 per kWh up to $5,000, and up to $0.54 per kWh if PV modules and/or inverters are manufactured in state), a state sales tax exemption of 75 percent, and federal tax incentives. If the system is a community solar system, the base rate is $0.30 per kWh, with higher incentive levels if the system's components are manufactured in state.[202] Seattle City Light is reimbursed for its incentive payment by claiming an annual state tax credit. However, there is a cap on the state funds available to the utility. As the cap is approached, the utility can either reduce its incentive payments to customers; or it can stop accepting new solar applications for the state incentive program and at that point continue paying existing customers at the current incentive rate. As citywide solar development increases, Seattle City Light's incentive cap is close to being reached, and the utility is expected to reduce its solar incentive payments.[203]

Rhode Island

National Grid and the state offer many incentives that help bolster solar development in the state. National Grid just launched its SolarWise program that provides solar-related services to help customers with the REG enrollment process.[204] The program incentivizes customers to invest in both solar PV and energy efficiency by increasing the REG incentive amount by different percentages based on the additional energy savings.

The state offers many tax breaks for solar PV customers.[205] The Renewable Energy Products Sales and Use Tax Exemption gives a 100 percent exemption from the state's sales and use tax for solar electric systems.[206] There is also a local property tax exemption for renewable energy systems which allows cities and towns to exempt, by ordinance, solar systems from property taxation.[207]

---

[202] "Solar Energy FAQ Are Incentives Available?," accessed July 1, 2016, http://www.seattle.gov/light/solarenergy/solarfaq.asp#incentives.

[203] Seattle City Light, "Solar Incentive Cap Frequently Asked Questions," accessed June 22, 2016, http://www.seattle.gov/light/solarenergy/docs/solar_incentive_cap_faq.pdf.

[204] "National Grid's 2016 SolarWise Rhode Island 'Customer Guide,'" accessed June 26, 2016, https://www9.nationalgridus.com/narragansett/non_html/SolarWise_Customer_Guide.pdf.

[205] DSIRE, "Rhode Island Programs," accessed July 7, 2016, http://programs.dsireusa.org/system/program?state=RI.

[206] DSIRE, "Rhode Island Renewable Energy Products Sales and Use Tax Exemption," accessed July 8, 2016, http://programs.dsireusa.org/system/program/detail/1237.

[207] DSIRE, "Rhode Island Local Option - Property Tax Exemption for Renewable Energy Systems," accessed July 7, 2016, http://programs.dsireusa.org/system/program/detail/2801.

As an alternative to REG, customers can apply for loans and grants via the Renewable Energy Fund.[208] The Renewable Energy Fund funds the small-scale solar grants (Commerce RI) program, which covers up to $10,000 for each solar PV project.[209]

Solarize Rhode Island offers customers access to flexible financing for their solar systems, including a $0-down loan option,[210] and information on savings for hardware and installation.

New Jersey

New Jersey has approximately 1,700 MW of solar capacity installed,[211] making it one of the few states to exceed 1 GW of capacity. As of April 2016, 793 MW came from installed distributed solar PV, putting the state second to only California for distributed solar PV installed capacity.[212] One factor in the state's success is its SREC-based financing model, which uses SREC revenues to provide loans to customers.

In 2008, the New Jersey Board of Public Utilities directed the state's four electric distribution companies to develop long-term contracting or financing programs specific to the development of solar systems.[213] New Jersey's largest utility, Public Service Electric and Gas's (PSE&G) answer to this is its Solar Loan Program, which is financed through SRECs.[214] This program provides loans typically in the amount of 40 to 60 percent of the solar system cost. The remainder of the cost is paid for or financed separately by the customer. A loan term of 10 years is available to both residential and non-residential customers at an interest rate of 11.1 percent.[215] Customers have the option to pay off their loan using the revenue generated from SRECs from their system. As part of the loan application, the customer offers an SREC floor price bid. If the bid is accepted, the customer will, at the very least, receive the floor price per SREC for the entire loan's duration.

---

208 "Small Scale Projects - Commerce Corporation," *Commerce RI*, accessed July 7, 2016, http://commerceri.com/finance-business/renewable-energy-fund/small-scale-projects/.

209 DSIRE, "Rhode Island Small-Scale Solar Grants (Commerce RI)," accessed July 7, 2016, http://programs.dsireusa.org/system/program/detail/5361.

210 "Solarize Rhode Island," *Solarize Rhode Island*, accessed July 7, 2016, http://solarizeri.com/.

211 Solar Energy Industries Association, "New Jersey Solar," *SEIA*, accessed June 22, 2016, http://www.seia.org/state-solar-policy/new-jersey.

212 U.S. Energy Information Administration, "EIA Today in Energy - Electricity Data Now Include Estimated Small-Scale Solar PV Capacity and Generation," accessed June 28, 2016, http://www.eia.gov/todayinenergy/detail.cfm?id=23972.

213 "Amendments to the Minimum Filing Requirements for Energy Efficiency, Renewable Energy, and Conservation Programs; And For Electric Distribution Company Submittals of Filing in Connection with Solar Financing," Pub. L. No. Docket No. Eo06100744 (2008), http://www.njcleanenergy.com/files/file/Board%20Orders/7-30-08-8E.pdf.

214 "PSE&G's Solar Loan Program," accessed June 16, 2016, https://www.pseg.com/home/save/solar/index.jsp.

215 "New Jersey Solar Incentives, New Jersey Solar Facts," *Cost of Solar*, November 6, 2013, http://costofsolar.com/new-jersey-solar-incentives-new-jersey-solar-facts/.

SREC-based financing programs are offered by the state's other three main utilities as well.[216] These financing programs work in tandem with the state's strong RPS requirements.[217] Since utilities can meet their requirements by purchasing SRECs from solar power producers (including residential sellers) and retiring them, there is strong demand for SRECs. This pushes SREC prices up and thus reduces the loan payback time.

New York

NY-Sun's "Affordable Solar" incentive program was launched in 2015.[218] It gives eligible low-income customers additional incentive to install solar by doubling the existing NY-Sun incentive for solar installations for the first 6 kW of capacity.[219]

In addition, New York offers numerous tax incentives to encourage solar development. Customers can apply the Residential Solar Tax Credit, which is equal to 25 percent of the cost of equipment and installation and capped at $5,000.[220] There is also a state and local Solar Sales Tax Exemption, applicable to 100 percent of the solar energy system.[221] If permitted by local government, a 100 percent property tax exemption can be applied for 15 years.[222]

Connecticut

The Connecticut Green Bank[223] (formerly the Clean Energy Finance and Investment Authority) offers several financing options for different customer classes.[224] A green bank is "a public financing authority that leverages private capital with limited public-purchase dollars to accelerate the growth of clean

---

216 "NJ Solar PV Program - ACE, RECO & JCP&L," accessed June 21, 2016, https://njsolarprogram.navigant.com/SitePages/Home.aspx.

217 DSIRE, "New Jersey Renewable Portfolio Standard," accessed June 22, 2016, http://programs.dsireusa.org/system/program/detail/564.

218 "NYSERDA Announces New Affordable Solar Program," December 10, 2015, http://www.solarbycir.com/nyserda-announces-new-affordable-solar-program/.

219 "Affordable Solar - NYSERDA," accessed June 28, 2016, http://www.nyserda.ny.gov/All-Programs/Programs/NY-Sun/Customers/Available-Incentives/Affordable-Solar.

220 "Solar Energy System Equipment Credit," *New York State Department of Taxation and Finance*, accessed June 28, 2016, https://www.tax.ny.gov/pit/credits/solar_energy_system_equipment_credit.htm.

221 DSIRE, "New York Solar Sales Tax Exemption," accessed June 28, 2016, http://programs.dsireusa.org/system/program/detail/1234.

DSIRE, "New York Local Option - Solar Sales Tax Exemption," accessed June 28, 2016, http://programs.dsireusa.org/system/program/detail/4857.

222 DSIRE, "New York Local Option - Solar, Wind & Biomass Energy Systems Exemption," accessed June 28, 2016, http://programs.dsireusa.org/system/program/detail/192.

223 The Connecticut Green Bank was established in July 2011 as part of Senate Bill No. 1243 Public Act 11-80.

224 "Green Energy Solutions in Connecticut | CT Green Bank," *Connecticut Green Bank*, accessed August 10, 2016, http://www.ctgreenbank.com/programs/all-programs/.

energy markets."[225] Green banks offer a variety of products and services, such as direct, wholesale, and subordinated debt; loan loss reserve; securitization;[226,227] and data collection. Green banks offer financing mechanisms and help with customer acquisition to target a range of markets, including DG customers; community solar; energy efficiency; and energy storage.[228] The Connecticut Green Bank is the country's first full-scale green bank,[229] but green banks also exist in New York, Hawaii, California, New Jersey, Maryland, and Rhode Island. They are currently being studied or developed further in Rhode Island, Maryland, Delaware, Nevada, and Vermont.[230]

The Connecticut Green Bank's key products are its lease programs, loan programs, and Commercial Property Assessed Clean Energy (C-PACE) program.[231, 232] Initial capital and funding sources come from a utility bill surcharge and Regional Greenhouse Gas Initiative (RGGI) funds.[233] One program is the Solar Lease 2 (SL2) Commercial Program, a solar tax equity fund created by the Green Bank. The SL2 program followed on from the successful CT Solar Lease program. The CT Solar Lease program, which ran from 2008 to 2011,[234] provided zero down payment options to homeowners,[235] and was also the first program to combine private capital with ratepayer funds to take advantage of federal incentives.[236]

The SL2 program addresses the barriers to entry faced by small business and non-profits. These entities may not have the capital and/or credit-worthiness to finance solar installations or the ability to appeal to private investors. Non-profits further suffer by being unable to make use of solar tax credits due to

---

225 Nick Kline, "Green Banks: Leveraging Private Investment with Public Capital," July 20, 2016, http://nrri.org/wp-content/uploads/2016/07/NRRI-Webinar-7.20.2016-Nick-Kline.pdf.

226 "PACE Financing," *Wikipedia, the Free Encyclopedia*, June 9, 2016, https://en.wikipedia.org/w/index.php?title=PACE_financing&oldid=724430106.

227 "Securitization," *Wikipedia, the Free Encyclopedia*, May 29, 2016, https://en.wikipedia.org/w/index.php?title=Securitization&oldid=722718080.

228 Kline, "Green Banks: Leveraging Private Investment with Public Capital."

229 Robert Schmitt, "Connecticut Green Bank Recognized for Connecticut Solar Lease Commercial Program," *Connecticut Green Bank*, June 15, 2016, http://www.ctgreenbank.com/green-bank-recognized/.

230 Kline, "Green Banks: Leveraging Private Investment with Public Capital."

231 "Green Energy Solutions in Connecticut | CT Green Bank."

232 Connecticut Green Bank is not the sole C-PACE provider in the state. Other qualified capital providers are the CleanFund and Greenworks Lending: "Qualified Capital Providers | C-Pace," accessed August 10, 2016, http://www.cpace.com/capitalproviders.

233 Kline, "Green Banks: Leveraging Private Investment with Public Capital."

234 KK1729, "PACE Talk: PACE Power Purchase Agreements (PPA) Is a Game Changer for Connecticut and Beyond," *PACENation*, March 11, 2015, http://www.pacenation.us/pace-talk-pace-power-purchase-agreements-ppa-is-a-game-changer-for-connecticut-and-beyond/.

235 JMurphy, "CT Solar Lease," Text, *Energize Connecticut*, (August 2, 2013), http://www.energizect.com/your-home/solutions-list/ct-solar-lease.

236 Clean Energy States Alliance, "State Leadership in Clean Energy Awards New Solutions for Market Transformation," June 2016, http://www.cesa.org/assets/2016-Files/SLICE/New-Solutions-for-Market-Transformation.pdf.

their tax exempt status.[237] The SL2 program combines low-cost, long-term PPAs and leases with the C-PACE program. With C-PACE, jurisdictions typically issue bonds and partner with private-sector investors to finance the up-front costs of the project. The property owner repays these costs through regular assessments on the property's tax bill. As a result, the project is made more attractive to investors who have confidence the PPA will be repaid. The long-term length of at least 15 years[238] is attractive to property owners because it allows electricity and other cost savings to exceed the assessment payment amount.[239]

While the SL2 program targets small businesses and non-profits, it is notable in that it opens up solar programs to otherwise excluded classes. As of 2016, there are 46 existing commercial projects with 10 MW deployed. A further 18 commercial projects and 7 MW deployment was expected in 2016.[240]

California

The California Energy Commission's (CEC) New Solar Homes Partnership (NSHP) was launched in January 2007 as part of the state's solar rebate program, the California Solar Initiative (CSI).[241, 242] The NSHP has a budget of $400 million and aimed to install 360 MW of solar capacity on new homes by the end of 2016. The program provides financial incentives to homeowners, builders, and developers to install solar PV systems on new homes that also meet energy efficiency criteria.[243] To be eligible for the program, the projects must be new residential construction in Pacifica Gas and Electric Company (PG&E), California Edison Company (SCE), San Diego Gas & Electric Company (SDG&E), and Bear Valley Electric Service (BVES) electrical service territories; be a minimum of 15 percent above the 2008 Title 24 Building

---

237 Schmitt, "Connecticut Green Bank Recognized for Connecticut Solar Lease Commercial Program."

238 KK1729, "PACE Talk."

239 "Commercial PACE," *PACENation*, accessed August 10, 2016, http://www.pacenation.us/commercialpace/.

240 Connecticut Green Bank, "Tax Equity Investment Solutions - Solar PPA Fund ('SL3') Request for Proposals ('RFP')," accessed August 10, 2016, http://www.ctgreenbank.com/wp-content/uploads/2016/06/SolarPPAFundRFP.pdf.

241 "CEC - New Solar Homes Partnership | Department of Energy," accessed August 10, 2016, http://energy.gov/savings/cec-new-solar-homes-partnership.

242 "Interim Order Adopting Policies and Funding for the California Solar Initiative," Pub. L. No. Decision 06-01-024, Decision 06-01-024 (2006), http://docs.cpuc.ca.gov/word_pdf/FINAL_DECISION/52898.pdf.

243 "New Solar Homes Partnership - Frequently Asked Questions," accessed August 10, 2016, http://www.gosolarcalifornia.ca.gov/nshp/faqs.php.

Energy Efficiency Standards[244] or compliant with 2013 Building Energy Efficiency Standards;[245] have PV systems be 1 kW or larger; and be installed by appropriately licensed California solar contractors.[246]

The program has two incentive structures. One is for conventional or market-rate housing, affordable housing residential projects with systems owned by non-tax-exempt entities, and affordable housing common area projects. The other is for affordable housing residential projects with systems owned by tax-exempt entities.[247]

Incentive levels depend on the housing type and expected performance of the system. The incentives follow a declining block incentive structure in which incentive levels drop as specific capacity targets are achieved.[248] Incentives are capped at 75 percent of system cost for affordable housing and 50 percent for all other projects.[249] The owner of the system retains the RECs generated by their system.[250]

The NSHP program has been a success, with enrollment increasing by 320 percent between 2009 and 2016.[251] Additional funding and program continuation were approved by the California PUC in June 2016.[252]

Portland, Oregon

Portland is an example of how housing organizations can partner with other organizations to help typically underserved populations benefit from solar PV. Community Vision, Inc. is a non-profit that provides individualized housing, supported living, homeownership, and employment services to people with disabilities.[253] Solar For All is a non-profit that helps fund the installation of solar PV systems in low-income housing projects.[254] Their partnership advances the shared goal of both organizations of

---

244 "Building Energy Efficiency Program - California Energy Commission," accessed August 10, 2016, http://www.energy.ca.gov/title24/.

245 "2013 Building Energy Efficiency Standards - California Energy Commission," accessed August 10, 2016, http://www.energy.ca.gov/title24/2013standards/index.html.

246 California Energy Commission, "New Solar Homes Partnership (NSHP)," July 8, 2016, http://www.gosolarcalifornia.ca.gov/nshp/training/documents/2016-07-08_workshop/NSHP_Workshop_Presentation.pdf.

247 California Energy Commission, "New Solar Homes Partnership Guidebook Ninth Edition Commission Guidebook," July 2015, http://www.energy.ca.gov/2015publications/CEC-300-2015-003/CEC-300-2015-003-ED9-CMF.pdf.

248 "CEC - New Solar Homes Partnership | Department of Energy."

249 "DSIRE," accessed August 10, 2016, http://programs.dsireusa.org/system/program/detail/2744.

250 California Energy Commission, "New Solar Homes Partnership Guidebook Ninth Edition Commission Guidebook."

251 California Energy Commission, "New Solar Homes Partnership Market Report," May 2016, http://www.energy.ca.gov/2016publications/CEC-300-2016-005/CEC-300-2016-005.pdf.

252 "Decision Funding Authorizations and Related Measures for Continuation of the New Solar Homes Partnership Program," Decision 16-06-006 § (2016), http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M163/K266/163266780.PDF.

253 "Community Vision, Inc. About Us," accessed June 28, 2016, http://cvision.org/about-us/.

254 "Solar For All, Providing Low Income Families Free Solar Energy to Reduce Their Utility Bills and Carbon Footprints," *Solar For All*, accessed June 28, 2016, http://www.solarforall.org/.

installing solar panels for low-income and disabled individuals. [255] In addition, Portland's neighborhood associations engaged in bulk purchases to help reduce the hardware costs.[256]

[255] "First Installation Completed!," *Solar For All*, accessed July 7, 2016, http://www.solarforall.org/content/first-installation-completed.

[256] This program was referred to as "Solarize Portland," (https://www.portlandoregon.gov/bps/51902) and was similar to the bulk purchases currently conducted in the District of Columbia through DC SUN (http://www.dcsun.org/).

5. Case Studies Addressing Non-Financial Factors

5.1. Interconnection and Permitting Processes

When interconnection and permitting processes are time-consuming, complex, or opaque, they create uncertainty, increase customer frustration, and reduce customers' willingness to undertake a solar project. Recommendations to decrease interconnection waiting times include setting firm timetables for utilities to approve or deny requests; developing strategies to accommodate increases in interconnection applications; implementing polices to expedite PV system permitting and inspection; and having utilities and local jurisdictions partner to streamline the permitting and interconnection process.[257] Examples of steps that jurisdictions have taken are provided below.

San Antonio, Texas

In San Antonio's SolarHost program, all installation and interconnection processes are conducted by the program rather than by property owners. Property owners need only fill out a simple online form consisting of little more than a customers' name, address, and roof characteristics, to be considered for the program.[258] Applications are then screened using satellite imagery of the roofs, followed by an on-site inspection by program staffers.[259]

Palo Alto, California

Residents of Palo Alto can apply for a PV permit over-the-counter and receive an interconnection and building permit for their system the same day.[260] Appointments are available but not required. Systems of 10 kW or less are eligible for expedited review.

Connecticut

Connecticut Light and Power's average Permission to Operate time of five days in 2014 made it the fastest utility (out of 50 utility service territories with the most net-metered Residential PV customers) that year.[261] The state's mandated regulations and rules, applicable to the state's two IOUs, set limits on the time utilities and customers have to fulfill each stage of the interconnection process, and they are a significant reason for such short wait times. State interconnection guidelines dictate that for the Fast

---

[257] Chelsea Barnes, "Comparing Utility Interconnection Timelines for Small-Scale Solar PV" (EQ Research, July 2015), http://eq-research.com/wp-content/uploads/2015/07/IC-PTO-Timeline-Report-7-2015.pdf.

[258] "SolarHost San Antonio Form," accessed July 6, 2016, http://www.solarhostsa.com/?page_id=571.

[259] David Hendricks, "CPS Energy's Solar Rent-a-Roof Program Has Big Appeal," *San Antonio Express-News*, September 8, 2015, http://www.expressnews.com/business/business_columnists/david_hendricks/article/CPS-Energy-s-solar-rent-a-roof-program-has-big-6490747.php.

[260] City of Palo Alto, "PV Permitting and Interconnection," accessed July 6, 2016, http://www.cityofpaloalto.org/gov/depts/utl/residents/resources/pcm/pv_permitting_and_interconnection.asp.

[261] Barnes, "Comparing Utility Interconnection Timelines for Small-Scale Solar PV."

Track Process,[262] the electric distribution company has 15 days do an initial review of the application. If the proposed interconnection passes the screening criteria, the electric distribution company has five business days to provide the customer generator with the agreement contract.[263]

St. Louis, Missouri

Historic preservation rules can present a challenge to customers wishing to install solar, particularly when such rules require that solar installations not be visible from the street. For this reason, cities such as St. Louis have loosened their restrictions to allow for solar that is “visually compatible.” The Preservation Board for the city of St. Louis may also grant exceptions for visible solar installations where it is determined that "all efforts have been made to minimize the visual presence of the installation."[264]

5.2. Education, Training, and Outreach

Seattle, Washington

Customer acquisition relies to a large degree on educating potential customers on the benefits, land-use and technical requirements, and financial incentives for solar PV. To assist with this, Seattle developed a guide to the different permits and permitting process,[265] conducted workshops over the course of a year, and gave presentations and tours of solar homes. Emphasis was placed on keeping workshops unbiased and informational.

The city’s training was not just limited to customers; utility staff also received training on the interconnection process. Seattle sought input on its interconnection process from a range of stakeholders, such as regional utilities, regional solar contractors, and the Solar Electric Power Association (SEPA). It also created an interconnection task force and provided training workshops to utility staff. One useful lesson learned was that buy-in from staff is just as important as managers; strong support from staff members eager for the training is useful.[266]

[262] The Connecticut Light and Power Company and The United Illuminating Company, “Guidelines for Generator Interconnection Fast Track and Study Processes,” May 12, 2016, https://www.uinet.com/wps/wcm/connect/189354804138460aaf4eef7a239a91d1/web_Guidelines+for+Generator+Interconnection+Fast+Track+and+Study+Process+-+5-12-10.pdf?MOD=AJPERES&CACHEID=189354804138460aaf4eef7a239a91d1.

[263] Ibid.

[264] Ben Adler, “Old Meets New: The Debate Over Photovoltaics in Historic Districts,” *EcoBuilding Pulse*, May 9, 2013, http://www.ecobuildingpulse.com/news/old-meets-new-the-debate-over-photovoltaics-in-historic-districts_o.

[265] “Seattle Permits Solar Energy Systems,” May 20, 2015, http://www.seattle.gov/DPD/Publications/CAM/cam420.pdf.

[266] U.S. Department of Energy, “Solar in Action - Seattle, Washington.”

New York

The New York State Energy Research and Development Authority (NYSERDA) has a wide range of solar installation tools and databases for customers. They help inform potential and existing solar customers about system costs and savings, their site's solar potential, projects installed under NYSERDA's Residential Solar Electric Program, and incentive program statistics and status.[267] Links to these resources are all on a single webpage,[268] which makes it less likely for customers to abandon their inquiries into solar due to difficulty in navigating within and between these resources.

NY-Sun has a "PV Trainers Network" which provides NYSERDA support to jurisdictions with the aim of accelerating solar development. Support includes workshops, in-depth training, technical assistance, and relevant codes and documents.[269] Customers can submit questions to subject matter experts online, sign-up for trainings, or host trainings. Again, the easy user-interface of these available resources decreases the chance that a customer will lose interest because of web-design issues.

NY-Sun offers support for "Solarize campaigns," locally organized community outreach aimed at getting groups of homes and businesses in one area to install solar to achieve economies of scale. Support includes campaign materials, technical assistance, and paper and online guides to effective campaigning.[270]

Connecticut

The Connecticut Green Bank had to make investors comfortable with the idea of using the C-PACE mechanism to secure investments into low, non-investment grade credits. The Green Bank also established the initial set of documentation that fully explains and captures the whole financing structure of the program. Lastly, the Green Bank created an outreach and marketing strategy to train local solar developers to understand and offer the SL2 option to their customers.[271] This served the dual purpose of acquiring customers and growing the program.

To help launch the program, the Green Bank held a special webinar, and the bank also offers specialized one-on-one support to new contractor partners.[272]

---

267 "Solar Installation Data and Tools - NYSERDA," accessed July 7, 2016, http://www.nyserda.ny.gov/All-Programs/Programs/NY-Sun/Solar-Data.

268 Ibid.

269 "NY-Sun PV Trainers Network," accessed July 7, 2016, https://training.ny-sun.ny.gov/.

270 NYSERDA, "Solarize Your Community - NYSERDA," accessed July 7, 2016, http://www.nyserda.ny.gov/All-Programs/Programs/NY-Sun/Communities/Solarize.

271 "Clean Energy States Alliance | CESA News," accessed August 10, 2016, http://cesa.org/about-us/member-news/newsitem/expanding-access-to-solar-financing-in-connecticut.

272 KK1729, "PACE Talk."

California

The NSHP offers a full suite of program training, online tools, user support, and program-related literature. The program hosts live training events, as well as short tutorial videos to guide customers and builders through the NSHP process.[273] The program offers an online application tool, which also allows users to see incentive levels, capacity goals, approved capacity, and capacity under review.[274] Users can also download a calculator to calculate their incentive amount. [275]

The program offers marketing and technical assistance to builders, as well as training for building officials and salespeople.[276] Customers and home-builders can become informed by having access to documents related to the NSHP. Materials available include: the current and previous versions of the NSHP Guidebook,[277] NSHP market reports and case studies; webinar presentations, recordings, and comments; all forms, which are also editable electronically; sample forms; news releases and announcements; and related documents and reports on formal proceedings or report sections.[278] The program website offers further support to customers by directing them to solar-specific contacts at the CEC, and each participating utility.[279] The combination of all these make for a transparent, well supported process for informed users.

Cambridge, Massachusetts

Cambridge launched its Sunny Cambridge program for Residential customers in April 2016. The city-wide initiative enables residents living in single and multi-family housing to make educated decisions on a solar purchase through a single website.[280, 281] The well designed and easy-to-navigate site gives customers a plethora of information including: information on solar technologies, a solar panel savings calculator, solar financing information, reviews of installers, product manufacturers, and financing

---

[273] "New Solar Homes Partnership Training and Classes," accessed August 11, 2016, http://www.gosolarcalifornia.ca.gov/nshp/training/.

[274] "New Solar Home Program (NSHP)," accessed August 10, 2016, https://www.newsolarhomes.org/WebPages/public/RebateLevelView.aspx.

[275] "New Solar Homes Partnership - Frequently Asked Questions."

[276] California Energy Commission, "New Solar Homes Partnership Guidebook Ninth Edition Commission Guidebook."

[277] Ibid.

[278] "Documents for the New Solar Homes Partnership - NSHP - Go Solar California," accessed August 11, 2016, http://www.gosolarcalifornia.ca.gov/documents/nshp.php.

[279] "Consumer Contacts - Go Solar California," accessed August 11, 2016, http://www.gosolarcalifornia.ca.gov/contacts/consumers.php.

[280] "City of Cambridge Launches Residential Solar Program - City of Cambridge, Massachusetts," accessed August 10, 2016, https://www.cambridgema.gov/citynewsandpublications/news/2016/04/cityofcambridgelaunchesresidentialsolarprogram.

[281] "Sunny Cambridge | EnergySage," accessed August 10, 2016, https://www.energysage.com/sunnycambridge/.

companies, and the option to subscribe to a solar news feed.[282] The site also has tools to engage the user, such as an interactive solar map of Cambridge.

Aside from being a portal of information, Sunny Cambridge gives users access to an online solar marketplace. This marketplace is a product of EnergySage, a Boston clean tech startup,[283] which allows customers to get quotes from the network of pre-screened solar installers in the company's database.[284] The result is beneficial to all parties involved. Customers receive the best price for their solar needs; installers gain access to potential customers and save on marketing costs; and EnergySage receives a small commission from the installer with a successful transaction.[285]

5.3. Brownfields

New York, New York

New York City has more than 3,000 vacant brownfield sites spread throughout the city and is encouraging solar developers to use some of these sites for producing clean energy.[286] To facilitate solar development on these sites, the city established the New York City Brownfield Partnership to connect developers with engineers, land-use planners, financial analyses, and environmental consultants and attorneys. The developers receive free consulting regarding liability and remediation of contaminated properties. The city's guide to brownfield development links to seven different resources, including a searchable database, targeted technical and financial assistance providers, the NYC Office of Remediation, and Brownfield Incentive Grants program.[287]

[282] "EnergySage | Compare Quotes from Pre-Screened Solar Installers," *EnergySage*, accessed August 10, 2016, http://news.energysage.com/.

[283] Ibid.

[284] May 13 and 2016, "Game Changers: These Entrepreneurs Know How to Make Green Things Grow - The Boston Globe," *BostonGlobe.com*, accessed August 10, 2016, https://www.bostonglobe.com/magazine/2016/05/13/these-entrepreneurs-know-how-make-green-things-grow/xyVnJn86ele7iGPQNhG0nO/story.html.

[285] "About Us: How We Make Money | EnergySage," accessed August 10, 2016, https://www.energysage.com/about/how-we-make-money.

[286] Jared Green, "Cities Use Brownfields to Go Solar," *The Dirt*, April 13, 2011, https://dirt.asla.org/2011/04/13/cities-use-brownfields-to-go-solar/.

[287] The NYC Brownfield Partnership website is available at http://www.nycbrownfieldpartnership.org/?page_id=615.

6. Case Studies Addressing Utility Incentives

6.1. Penalties for RPS Non-Compliance

Utility non-compliance with RPS requirements is penalized in some states, but states differ in whether or not the penalty can be recovered from ratepayers. If the utility has the ability to pass on penalties to ratepayers, there is little utility management incentive to comply with the RPS requirement, since the utility itself has no "skin in the game."

Non-compliance penalties usually take one of three forms: (1) a financial penalty based on per unit deficiency; (2) penalties when there is regulatory enforcement of non-compliance; or (3) an Alternative Compliance Payment (ACP) where suppliers have the option of paying for the Renewable Energy Credits (RECs) required to meet compliance.[288] Penalties that cannot be passed on to ratepayers tend to fall into the per-unit deficiency or regulatory enforcement categories. Table 3 shows the penalty amounts for states with regulatory enforcement of RPS, while Table 4 shows the penalty amounts for states which have a per-unit deficiency penalty.

Table 3. Non-compliance penalties in states with regulatory enforcement of RPS

State	Penalty Amount	Comments
California	Not specified	Commission tasked with adopting a schedule for non-compliance
Minnesota	Less than estimated cost of compliance	Commission-determined penalty may not exceed the lesser of the cost of constructing facilities or purchasing credits
North Carolina	Not specified	Commission has existing authority to enforce compliance

Source: DSIRE

Table 4. States with per unit deficiency non-compliance penalties

State	Penalty Amount	Comments
Missouri	At least 2x market value of RECs or SRECs	
Montana	$10 per MWh deficit	Utility or competitive suppliers have a 3-month grace period for RPS compliance
Washington	$50 per MWh deficit	

Source: DSIRE

The applicability of such penalties to the District is limited due to the restructured nature of the market, meaning that it is the competitive suppliers, rather than Pepco, that are responsible for any compliance

[288] Joint Response from DTE Energy, Consumers Energy and MEGA, Renewable Energy Question 21.

payments. Nevertheless, it is clear that many jurisdictions have deemed it necessary to provide utilities with an incentive to reach RPS targets in order to ensure that management attention is sufficiently focused on these policy goals.

6.2. Utility Ownership of Distributed Generation

Municipal utilities and cooperatives have been at the forefront of utility ownership of distributed generation, particularly for community solar installations (as is the case in Seattle and San Antonio), but now also for individual installations (such as San Antonio's SolarHost program). However, these municipal utilities and cooperatives are all non-profit entities and thus have different business models and regulatory restrictions than investor-owned utilities like Pepco.

Investor-owned utility ownership of solar can be problematic when it reduces competition in the market, or results in higher resource costs due to rate-basing the investment. Where the market is not operating effectively, however, utility ownership of distributed solar could provide benefits to customers.

Arizona Public Service

Arizona Public Service recently began implementing a pilot program in which the utility owns and rate bases residential solar installations.[289] These installations are targeted to specific areas of the system where they are most valuable, and customers receive a payment of $30 per month in exchange for hosting the installation. The program was approved as a pilot program intended to serve several purposes, including meeting the state's RPS goals, as well as to "address solar availability to underserved customers."[290]

Consumers Energy, Michigan

In 2015, Consumers Energy Company filed an application with the Michigan Public Service Commission to implement a 10 MW community solar pilot program, which would be owned and operated by the utility. [291] The program was approved by the Michigan Public Service Commission on May 14, 2015, subject to the reconvening of the Solar Working Group to help establish the VOS tariff.

---

[289] Subject to Commission approval, after the project is in service. No pre-approval or guarantee of cost recovery was provided.

[290] Arizona Public Service Commission, "Decision 74878," Docket E-01345A-13-0140, In The Matter of Arizona Public Service Company for Approval of Its 2014 Renewable Energy Standard Implementation Plan for Reset of Renewable Energy Adjustor, December 23, 2014.

[291] Docket Number U-17752, http://efile.mpsc.state.mi.us/efile/viewcase.php?casenum=17752.

Subscriptions are available to customers in 0.5 kW increments, and customers receive a bill credit calculated based on the value of solar. As of January 23, 2017, 1,898 customers had enrolled, representing 85 percent of the total capacity available.[292]

[292] Consumers Energy, "Consumers Energy Solar Gardens Report," Case No. U-17752 – In the Matter of the Application of Consumers Energy Company for Authority to Reconcile Its Renewable Energy Plan Costs Associated with the Plan Approved in Case Nos. U-15805, U-16543, U-16581, and U-17301, February 1, 2017, http://efile.mpsc.state.mi.us/efile/docs/17752/0053.pdf.

7. Policy Options for the District of Columbia

Numerous policy options are available for supporting further development of distributed generation. In this report, we have discussed the options listed in the table below. The following section makes recommendations regarding specific policies that may help further spur distributed generation in the District of Columbia.

Table 5. Policy options outlined in report

<table>
<tr><th>Category</th><th>Policy Type</th><th>Incentive</th><th>Examples Discussed in Report</th></tr>
<tr><td rowspan="18">Financial Incentives</td><td rowspan="8">Compensation Mechanisms</td><td>Net Metering</td><td>Portland, Palo Alto</td></tr>
<tr><td>Feed-in tariff</td><td>Austin, Palo Alto, Portland</td></tr>
<tr><td>Value-of-Solar tariff</td><td>Austin, Minnesota</td></tr>
<tr><td>Rooftop Hosting</td><td>San Antonio, Arizona Public Service</td></tr>
<tr><td>Long-Term Tariff Incentive</td><td>Rhode Island</td></tr>
<tr><td>Rebates</td><td>California</td></tr>
<tr><td>Solar Renewable Energy Credits</td><td>District of Columbia, New Jersey</td></tr>
<tr><td>Community Solar</td><td>New York, San Antonio, Seattle, Minnesota</td></tr>
<tr><td>Rate Design</td><td>Solar customer fee per kW</td><td>Salt River Project</td></tr>
<tr><td rowspan="5">Financing</td><td>SREC-based financing program</td><td>New Jersey</td></tr>
<tr><td>$0 down loan options</td><td>Rhode Island, Connecticut</td></tr>
<tr><td>Grants</td><td>Rhode Island</td></tr>
<tr><td>Rebates</td><td>California, San Antonio</td></tr>
<tr><td>PACE and PPA</td><td>Connecticut</td></tr>
<tr><td rowspan="4">Tax Incentives</td><td>Production incentive credit</td><td>Seattle</td></tr>
<tr><td>Sales tax exemption (State and/or local)</td><td>Rhode Island, New York</td></tr>
<tr><td>Property Tax exemption (State and/or local)</td><td>Rhode Island, New York</td></tr>
<tr><td>Invest in EE and PV</td><td>Rhode Island</td></tr>
<tr><td rowspan="3">Utility Incentives</td><td colspan="2">Revenue Decoupling</td><td>District of Columbia</td></tr>
<tr><td colspan="2">Utility Ownership of Distributed Generation</td><td>San Antonio, Seattle, Arizona Public Service, Consumers Energy</td></tr>
<tr><td colspan="2">Penalties for RPS non-compliance</td><td>Washington, Montana, Missouri, District of Columbia</td></tr>
<tr><td rowspan="11">Non-Financial Incentives</td><td rowspan="4">Interconnection & Permitting Processes</td><td>Expedited review</td><td>Palo Alto</td></tr>
<tr><td>Program conducts installation and interconnection processes</td><td>San Antonio</td></tr>
<tr><td>Mandated time-limits</td><td>Connecticut</td></tr>
<tr><td>Loosened restrictions for visually-compatible installations</td><td>St. Louis, Missouri</td></tr>
<tr><td rowspan="7">Education, Training, and Outreach</td><td>Information workshops, presentations, webinars</td><td>Seattle, California</td></tr>
<tr><td>Training (for public, utility staff and/or contractors)</td><td>Seattle, Connecticut</td></tr>
<tr><td>Guidelines and Guidebooks</td><td>California, Seattle</td></tr>
<tr><td>Online tools and calculators</td><td>California</td></tr>
<tr><td>On-line support</td><td>New York, California</td></tr>
<tr><td>One-on-one guidance through program process</td><td>Connecticut</td></tr>
<tr><td>Community outreach</td><td>New York</td></tr>
</table>

8. RECOMMENDATIONS FOR THE DISTRICT OF COLUMBIA

The District has undertaken a wide range of efforts focused on stimulating growth in distributed generation. Yet growth still lags targets, particularly for distributed solar. This lackluster growth appears to be largely unrelated to overall compensation levels for DG owners, as the estimated payback period for a 4.1 kW solar array is only five years. This relatively fast payback is largely due to SRECs, but is also attributable to net metering and overall rate designs that, when combined with SRECs, provide reasonable compensation levels to customer-generators. While some volatility in SREC prices is likely, market fundamentals indicate that demand for SRECs will continue to outpace supply in the near future, helping to keep prices high.

Thus to explain why DC has not achieved its goals, we must look to other factors influencing customer adoption of distributed generation. From our review, the most significant factors appear to be related to (1) real estate constraints (particularly the high proportion of renters, historic district restrictions, and the lack of open space for large ground-mounted arrays); (2) financing barriers for low-income customers; (3) community solar challenges (including the newness of the program and challenges related to customer acquisition and engineering complexity); and (4) Pepco's historical performance in terms of efficient processing of interconnections.

Some of these challenges are being actively addressed by the District (as described previously), while others have not yet come to the fore or have not been sufficiently remedied. Our analysis suggests that the following actions may help to address the barriers facing distributed generation in the District:

- Facilitate community solar through addressing engineering and customer acquisition challenges, expanding incentives, partnering with third-party community solar developers, and potentially allowing Pepco to provide community solar if the market does not.
- Expand municipal procurement of solar to maximize available real estate, encourage solar parking canopies, and expand the definition of eligible solar generators.
- Ensure that historic district restrictions are appropriate and not overly strict.
- Continue to address financial challenges for low-income customers, such as through expansion of the Affordable Solar Program or implementation of a Green Bank.
- Consider implementing financial penalties or rewards (that cannot be passed through to customers) for Pepco that are tied to achieving solar targets and meeting interconnection deadlines.

The table below summarizes these barriers, current actions being taken, and additional recommendations.

Table 6. Recommendations for the District of Columbia

BARRIER	CURRENT ACTIONS TAKEN	RECOMMENDATIONS
High Proportion of Renters	• Provide access to community solar • Affordable Solar Program	• Address engineering and customer acquisition challenges for community solar • Consider allowing Pepco to own and rate base community solar facilities if the market does not provide adequate capacity • Expand the Affordable Solar Program • Encourage landlords to install solar with SREC and virtual metering benefits or through property or income tax benefits
Historic District Restrictions	• Provide access to community solar	• Conduct neighborhood planning discussions to develop more specific guidelines • Consider loosening restrictions regarding visibility, fire code, or zoning restrictions • Meet with community solar developers to determine whether any additional barriers exist
Lack of Open Space for Large Arrays	• Utilize municipal properties (building roof space, water treatment plant facilities, etc.)	• Continue to pursue municipal solar as a priority • Encourage solar parking canopies to utilize largest developable flat surfaces in the District • Allow community solar solely owned by DC residents located nearby but outside the District to qualify for DC SRECs • Foster residential rooftop project aggregation to reduce soft and hard costs through economies of scale
Financial Constraints for Low-Income Customers	• Provide access to community solar • Affordable Solar Program	• Address engineering and customer acquisition challenges for community solar • Consider allowing Pepco to own and rate base community solar facilities if the market does not provide adequate capacity • Implement a Green Bank program to provide financing • Expand the Affordable Solar Program
Customer Acquisition Costs for Multi-Family Buildings		• Consider allowing Pepco to own and rate base community solar facilities if the market does not provide adequate capacity • Provide resources and outreach to multi-family building owners
Pepco's Interconnection Application Processing Timelines	• Enforce timelines • Address ATO lags	• Provide Pepco with incentives (penalties or rewards) associated with meeting solar targets
Cost Reduction	• DCSEU initiatives	• Require new construction to be solar-ready as part of the Construction Codes and/or expand the Green Building Act

Part II - Technical and Economic Potential for Distributed Generation in the District of Columbia

This portion of the report analyzes the technical and economic potential for distributed generation in the District of Columbia, focusing on distributed solar technologies. This analysis was conducted in several stages, beginning with an assessment of the range of potential distributed generation technologies that can be feasibly integrated into Pepco's distribution grid within the next five to 10 years, followed by an analysis of the technical potential for solar photovoltaics, and concluding with an estimate of economically feasible potentials.

9. ANALYSIS OF DISTRIBUTED GENERATION OPTIONS

The first step was to review a range of distributed generation technologies to determine which technologies could be feasibly and economically developed in the District of Columbia. RPS-eligible distributed generation technologies in the District of Columbia are: solar PV, solar thermal, small wind,[293] biomass, landfill gas, and fuel cells using renewable fuels.[294] While combined heat and power (CHP) is not RPS-eligible, both its maturity in the marketplace and its cost effectiveness warrant inclusion in the list of technologies examined.

Each of these technologies was reviewed based on two criteria. First, is there more than a trivial quantity of technically feasible supply? Second, are the economics sufficiently attractive or likely to become so in the next five to 10 years? The sections below summarize the key findings from this review for each key technology type.

9.1. Technology Types

Solar PV

Solar photovoltaic (PV) generation is both technically and economically viable in the District, largely due to the falling costs associated with solar PV and the SREC payments available to customers with PV systems. Nationally, the median installed cost of residential solar PV has decreased from more than $12 per watt in 1998 to approximately $4 per watt in 2015, as shown in the figure below.[295] At the same time, SREC prices in the District have been among the highest in the nation.[296] Today, an average-sized PV system in the District has an estimated payback period of approximately five years.

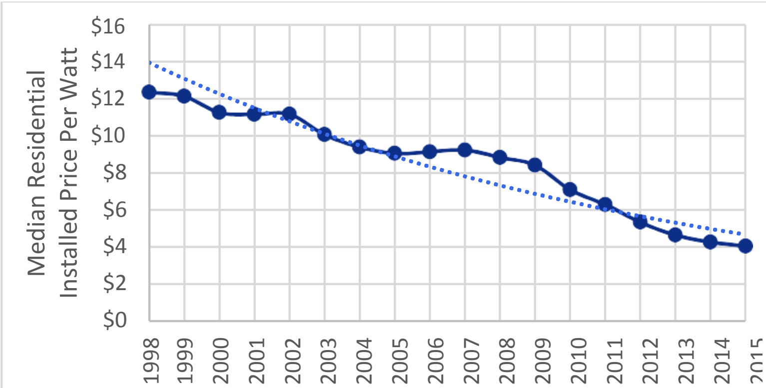
293 "Small wind" is defined as wind turbines up through 100 kW (in nominal capacity): Alice C. Orrell and Nikolas F. Foster, "2015 Distributed Wind Market Report," Prepared for the US Department of Energy (Pacific Northwest National Laboratory, August 2016), http://energy.gov/sites/prod/files/2016/08/f33/2015-Distributed-Wind-Market-Report-08162016_0.pdf.

294 DSIRE, "District of Columbia Renewable Portfolio Standard."

295 Galen Barbose and Naim Darghouth, "Tracking the Sun IX: The Installed Price of Residential and Non-Residential Photovoltaic Systems in the United States," Tracking the Sun (Lawrence Berkeley National Laboratory, August 2016), https://emp.lbl.gov/publications/tracking-sun-ix-installed-price.

296 "Green Power Network: Renewable Energy Certificates (RECs): REC Prices."

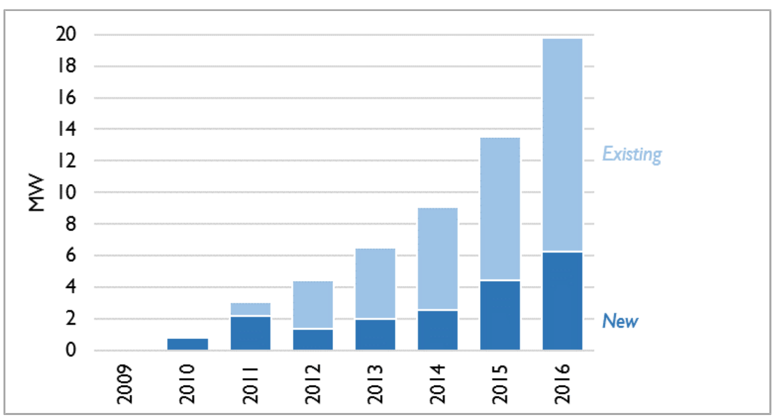
Figure 6. Median residential installed price of solar



Source: Barbose and Darghouth, Tracking the Sun IX, August 2016.

As of December 2016, approximately 22 MW of solar PV had been installed in the District.[297] Figure 7 shows annual installations of solar PV capacity (with data through mid-November 2016). As can be seen by the chart, the capacity of solar PV installed annually has grown considerably over the past five years. Solar PV appears to be the most likely technology to drive the majority of growth in distributed generation, particularly if technology costs continue to fall.

Figure 7. Solar PV cumulative and incremental capacity additions in the District of Columbia



Note: 2016 values are through mid-November. Source: DC PSC Eligible Renewable Generators List, December 9, 2016.

Solar Thermal

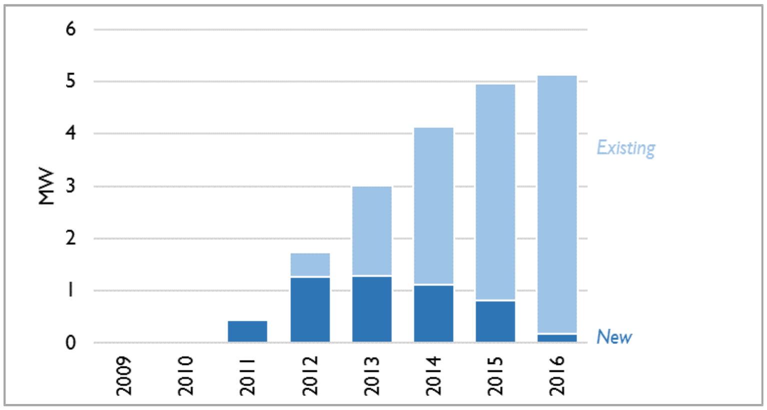
Solar thermal has limited technical and economic viability in the District. Solar thermal is an RPS-eligible resource under the DC RPS. However, the costs of this technology have not fallen as rapidly as PV costs.

---

297 Public Service Commission of the District of Columbia, "Eligible Renewable Generators List," *Renewable Energy Portfolio Standard Program*, downloaded December 9, 2016, http://www.dcpsc.org/PSCDC/media/PDFFiles/Electric/Eligible_Renewable_Generators_List.xls.

While solar PV installations have accelerated in recent years, annual solar thermal installations have fallen (Figure 8). This suggests that solar thermal will continue to play a small, but not insignificant role in the District.

Figure 8. Solar thermal cumulative and incremental capacity additions in the District of Columbia



Note: 2016 values are through mid-November. Source: DC PSC Eligible Renewable Generators List, December 9, 2016.

Combined Heat and Power

While CHP (also referred to as cogeneration) is not an RPS-eligible technology, its maturity in the marketplace and cost effectiveness suggests continued growth as a DG resource. CHP does not refer to a specific technology or fuel source, but rather is a distributed resource located at or near a customer's site that "can increase overall energy efficiency by cogenerating power while meeting heating and cooling needs."[298] CHP systems efficiently produce both useful thermal energy and electricity using the same fuel stock, reducing a customer's energy consumption from the grid.

There are two types of CHP systems: "topping cycle" and "bottoming cycle." The topping cycle uses fuel to first generate electricity or mechanical energy, with a portion of the waste heat then converted to useful thermal energy. This is the most common form. In contrast, bottoming cycle first produces heat through combustion or another form of chemical reaction, from which some of the heat is recovered to generate electricity. In general, CHP systems are used where there is a sustained requirement for thermal energy and are generally sized to meet the thermal needs of the energy user. The thermal needs therefore influence the amount of electricity that is produced.[299]

---

[298] DNV GL. *A Review of Distributed Energy Resources*, prepared for the New York Independent System Operator. September 2014. Available at http://production.presstogo.com/fileroot7/gallery/DNVGL/files/original/d46c666cfabe45e380048daeeebe104b.pdf.

[299] International Energy Agency. *Combined Heat and Power: Evaluating the Benefits of Greater Global Investment.* 2008.

CHP is particularly suited to commercial, industrial, and institutional applications that have relatively constant thermal loads.[300] A recent example of a CHP application in the District is the installation of a cogeneration plant at the Capitol Power Plant, which may soon begin to produce electricity again in addition to providing steam and chilled water for 23 facilities on Capitol Hill.[301] The plant uses natural gas as its primary fuel.[302]

Currently, the District of Columbia has five CHP installations with a total of nearly 23 MW of electrical generation capacity.[303] The majority of this capacity is located in two recent installations – the George Washington University and the Blue Plains Advanced Wastewater Treatment Plant – which became operational in 2015. The combined capacity of these two locations is 18.5 MW.

The District's potential is many times higher than current installations. Recent DOE analysis pegs the District's technical potential at 908 MW.[304] There is in excess of 757 MW of DG CHP technical potential in a wide variety of building or campus types, including commercial office buildings, multi-family buildings, hotels, hospitals, colleges and universities, government buildings, and military sites. However, 609 MW of CHP potential is concentrated at only four sites and might not be considered "distributed" under some definitions. An additional 753 sites representing 299 MW of capacity are associated with sites with a potential of 20 MW or less.[305]

The current state of CHP and its potential for development in New York City may offer insight into CHP's potential for the District. Both the District and New York City have hot summers and cool winters that require space chilling and heating, and therefore a steady thermal load. The District's need for affordable housing[306] and urban development trend calls for mixed-use properties which can utilize the thermal and electric power from CHP.[307] The two areas also face similar physical and regulatory hurdles,

---

300 OAR US EPA, "Distributed Generation," Overviews and Factsheets, accessed October 3, 2016, https://www.epa.gov/energy/distributed-generation.

301 US GAO, "Capitol Power Plant: Architect of the Capitol Should Update Its Long-Term Energy Plan before Committing to Major Energy Projects," Report to Congressional Committees (Washington, DC: US Governmental Accountability Office, September 2015), www.gao.gov/assets/680/672302.pdf.

302 Architect of the Capitol, "Capitol Power Plant," December 15, 2015, https://www.aoc.gov/capitol-buildings/capitol-power-plant.

303 U.S. Department of Energy, "U.S. DOE Combined Heat and Power Installation Database: Combined Heat and Power Installations in District of Columbia," accessed October 7, 2016, https://doe.icfwebservices.com/chpdb/state/DC.

304 U.S. Department of Energy, "Combined Heat and Power (CHP) Technical Potential in the United States," March 2016. Page 41. Available at: http://www.energy.gov/sites/prod/files/2016/04/f30/CHP%20Technical%20Potential%20Study%203-31-2016%20Final.pdf.

305 Ibid., Page D-15.

306 Peter Tatian et al., "Affordable Housing Needs Assessment for the District of Columbia Phase II," May 2015, http://www.urban.org/research/publication/affordable-housing-needs-assessment-district-columbia/view/full_report.

307 Alexis Saba et al., "The Opportunities for and Hurdles to Combined Heat and Power in New York City," May 2013, https://academiccommons.columbia.edu/download/fedora_content/download/ac:178487/CONTENT/CHP.Saba_.Paper_.pdf.

such as dense and complex utility infrastructure, permitting, and approval hurdles.[308,309] In 2013, much of New York City's 160 MW of distributed generation consisted of CHP installations, typically located in large residential complexes, universities, and hospitals.[310] Currently New York City has 76 MW of CHP installed, with around 70 MW sourced by natural gas.[311] However, the city's CHP potential is much higher than this; it is estimated to be approximately 1,570 MW.[312] The state's Reforming the Energy Vision initiative has set a target of increasing CHP by 10 percent.[313] Continued CHP development in New York and recent CHP development in the District imply that CHP will continue to grow as a distributed generation option in the District.

Small-Scale Distributed Wind

A wind generator is considered distributed if it meets one or both of the following characteristics: some of the generation is used to serve on-site load or it is directly connected to the distribution system (rather than the transmission system).[314] While some types of distributed wind installations are far too large for the District's dense urban environment, small-scale distributed wind (up to 100 kW in nominal capacity) could feasibly be implemented in the District.

To date, no distributed wind facilities exist within the District, according to the PSC's list of eligible renewable generators.[315] This lack of development likely stems largely from the fact that the economics of distributed wind do not compare favorably to other options. For example, the 2015 average installed cost of small wind turbines in the United States was $5,760 per kW.[316] This is considerably higher than the median cost of residential solar for 2015, which was approximately $4,000 per kW in 2015.[317]

Further, distributed wind has generally not seen significant growth, even where geography is favorable. As shown in Table 7, the top states in terms of distributed small wind capacity are Iowa, Nevada, California, Minnesota, and Alaska. All five of these states have significant rural areas where zoning

---

[308] Ibid.

[309] Bianca Howard et al., "Combined Heat and Power's Potential to Meet New York City's Sustainability Goals," *Energy Policy* 65 (February 2014): 444–54.

[310] The City of New York, "A Stronger, More Resilient New York - Chapter 6 Utilities," June 11, 2013, http://www.nyc.gov/html/sirr/downloads/pdf/final_report/Ch_6_Utilities_FINAL_singles.pdf.

[311] "U.S. DOE Combined Heat and Power Installation Database | Facilities in NY," accessed October 4, 2016, https://doe.icfwebservices.com/chpdb/state/NY.

[312] Howard et al., "Combined Heat and Power's Potential to Meet New York City's Sustainability Goals."

[313] Elisa Wood, "New York REV to Increase Combined Heat and Power (CHP) by 10%," *Microgrid Knowledge*, September 25, 2015, https://microgridknowledge.com/new-york-rev-to-increase-combined-heat-and-power-chp-by-10/.

[314] Orrell and Foster, "2015 Distributed Wind Market Report."

[315] Public Service Commission of the District of Columbia, "Eligible Renewable Generators List."

[316] Orrell and Foster, "2015 Distributed Wind Market Report."

[317] Barbose and Darghouth, "Tracking the Sun IX: The Installed Price of Residential and Non-Residential Photovoltaic Systems in the United States."

codes, historic districts, or small lot sizes are less of a barrier than in urban areas. Yet even in these five states with the largest installed capacity, distributed wind represents a very small fraction of total electric capacity.

Table 7. Distributed small wind capacity as percentage of total electricity capacity

STATE	2003-2015 CUMULATIVE DISTRIBUTED SMALL WIND CAPACITY (MW)	CUMULATIVE DISTRIBUTED WIND CAPACITY AS % OF 2014 TOTAL ELECTRICITY CAPACITY
IOWA	15.2	0.09
NEVADA	12.6	0.12
CALIFORNIA	12.4	0.02
MINNESOTA	10.1	0.07
ALASKA	9.2	0.37

Sources: 2015 Distributed Wind Market Report, EIA Electricity Detailed State Data.[318]

Finally, it is worth noting that the neighboring rural utility to the southeast, Southern Maryland Electric Cooperative, reports that it has only six net metered customers with distributed wind, up from five customers in 2011. These six customers have a combined capacity of only 36 kW.[319]

The lack of market penetration of small wind in these states, combined with the higher costs of small wind over residential solar, makes small wind an unlikely candidate for significant growth in the District.

Biomass / Municipal Solid Waste

The District's limited real estate substantially limits its biogas/methane generation potential. A 2013 study estimates the District's biogas/methane potential to be only 11.5 MW,[320] with wastewater comprising approximately 80 percent of the potential. The Blue Plains Advanced Wastewater Treatment Plant, a 14 MW biomass/digester gas CHP generator, opened in 2015. Its capacity exceeds the technical potential for the District because the facility also serves portions of Prince George's and Montgomery counties in Maryland, as well as Fairfax and Loudoun counties in Virginia.[321] Because the District's

[318] "1990 - 2014 Existing Nameplate and Net Summer Capacity by Energy Source, Producer Type and State (EIA-860)," accessed October 3, 2016, https://www.eia.gov/electricity/data/state/; Orrell and Foster, "2015 Distributed Wind Market Report."

[319] Southern Maryland Electric Cooperative, Inc.'s Response to Maryland Public Service Commission Data Request 01, September 30, 2016.

[320] GDS Associates, "Renewable Energy Technologies Potential for the District of Columbia," 2013, Table 1-1. http://doee.dc.gov/sites/default/files/dc/sites/ddoe/publication/attachments/RENEWABLE%20ENERGY%20TECHNOLOGIES%20POTENTIAL%20FOR%20THE%20DISTRICT%20OF%20COLUMBIA%20.pdf.

[321] District of Columbia Water and Sewer Authority, "Areas Served by DC Water," 2016, accessed October 7, 2016, https://www.dcwater.com/about/areas_served.cfm.

biomass technical potential is both rather small and appears to be nearly or wholly reached, it has been removed from consideration as a viable DG option.

Fuel Cells

Fuel cells that are powered by qualifying biomass or methane from landfills or wastewater treatment plants are RPS-eligible.[322] A fuel cell system has a markedly lower thermal efficiency than a comparably sized gas combustion engine CHP system, while having system and installation costs over 2.5 times greater.[323] Thus, the economics of biogas-powered stationary fuel cells for distributed generation exclude this technology as a viable DG option for the District.

Storage

Energy storage systems in the form of small, on-site battery banks can operate synergistically with distributed PV systems to help reduce customers' energy bills if electric rate structures incentivize battery use. Batteries may also be used with distributed solar to provide backup power in the event of a power interruption or as part of a more complex microgrid configuration. As battery control technology continues to improve, electric vehicle batteries may become part of smart, integrated residential or commercial systems.

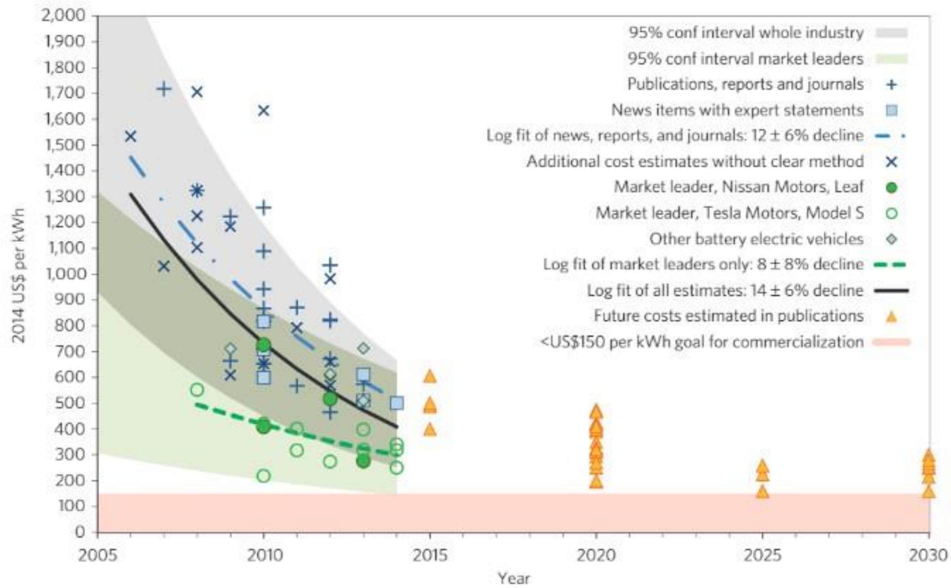
---

[322] Methane from the anaerobic decomposition of organic materials in a landfill or wastewater treatment plant; and qualifying biomass criteria: "DC Code - § 34–1431. Definitions.," accessed October 3, 2016, https://beta.code.dccouncil.us/dc/council/code/sections/34-1431.html.

[323] Publications Office of the European Union, "Advancing Europe's Energy Systems: Stationary Fuel Cells in Distributed Generation," 2015, https://www.rolandberger.com/publications/publication_pdf/roland_berger_fuel_cells_study_20150330.pdf.

Prices for battery storage systems have declined rapidly in recent years (as shown in Figure 9).[324] This is primarily due to the increased adoption of electric vehicles, which use similar lithium-ion batteries.[325] The economics of combining batteries with PV have therefore become much more favorable over time, and are projected to fall further, as shown in the graph below.

Figure 9. Historical trajectories of lithium-ion battery costs and forecasted cost projections



Source: Nykvist and Nilsoon, 2015

The cost savings of distributed storage for individual customers are highly dependent on the customer's rate structure. Customers who are subject to demand charges (based on the customer's monthly maximum hourly or sub-hourly usage) can use storage to shave peak hour energy consumption, potentially resulting in considerable bill savings. For example, a National Renewable Energy Laboratory (NREL) study found that commercial and industrial buildings can use batteries to reduce demand charges by up to $100,000/year.[326] However, such rate designs are typically only applied to commercial and industrial customers.

---

324 Björn Nykvist and Måns Nilsson, "Rapidly Falling Costs of Battery Packs for Electric Vehicles," *Nature Climate Change* 5, no. 4 (March 23, 2015): 329–32, doi:10.1038/nclimate2564.

325 The $150/kWh price target referenced in Figure 9 is an electric-vehicle specific goal, based on projections of the cost of ownership of conventional internal combustion engine vehicles. Due to a variety of factors, commercial adoption of electric vehicles is increasing rapidly despite the fact that Li-ion batteries remain costlier than this target. The economics of batteries for distributed, stationary use are dependent on very different factors and the market for distributed batteries will likely develop in different areas and at different speeds than the market for electric vehicles.

326 J. Neubauer and M. Simpson, "Deployment of Behind-The-Meter Energy Storage for Demand Charge Reduction" (NREL/TP-5400-63162. Golden, CO: National Renewable Energy Laboratory. Accessed January 26, 2015: http://www.nrel. gov/docs/fy15osti/63162. pdf, 2014), http://www.nrel.gov/docs/fy15osti/63162.pdf.

For residential customers, the cost savings of batteries are often limited due to the scarcity of policies that would reduce the cost (e.g., such as tax incentives), and rate designs that limit the economic benefits. In areas with time-of-use rate structure options, residential customers can use batteries to adjust consumption such that it falls mainly during low-price hours. However, a relatively large-capacity battery system is needed to perform significant load shifting and the price differential between peak and off-peak hours is generally too small to justify investing in batteries at current prices.[327]

In areas where behind-the-meter batteries can be compensated for providing ancillary services, such as frequency regulation, the combined effects of gaining revenue from the battery's operation and optimizing the value of on-site PV generation can result in cost savings for customers. One recent study found that the frequency regulation market in PJM can provide such benefits in Washington DC.[328] However, this study notes that the ancillary services market in PJM is relatively small and those investing in batteries risk the market becoming saturated. This would decrease prices and therefore the possible revenue from battery systems.

9.2. Results of Technology Analysis

From this review, Synapse determined that solar PV, solar thermal, and CHP are the three economically viable distributed generation technologies with adequate technical potential within the District of Columbia in the next five to 10 years, based on current technology cost trajectories and rate structures. In addition, limited application of energy storage may prove cost effective for commercial and industrial customers that face demand charges.

This assessment of DG technology viability is not to suggest that there will be no adoption of other DG technologies, but rather that the economic and siting challenges of these other technologies *relative to solar and CHP* render their aggregate contribution *de minimis.*

---

[327] Garrett Fitzgerald et al., "The Economics of Battery Energy Storage: How Multi-Use, Customer-Sited Batteries Deliver the Most Services and Value to Customers and the Grid" (Rocky Mountain Institute, October 2015), http://www.rmi.org/Content/Files/RMI-TheEconomicsOfBatteryEnergyStorage-FullReport-FINAL.pdf.

[328] Seth Mullendore et al., "Resilience for Free: How Solar+Storage Could Protect Multifamily Affordable Housing from Power Outages at Little or No Net Cost," Resilient Power (Clean Energy Group, October 2015), http://www.cleanegroup.org/wp-content/uploads/Resilience-for-Free-October-2015.pdf.

10. DISTRIBUTED SOLAR TECHNICAL POTENTIAL

Since 2010, distributed solar PV has grown from less than 1 MW to more than 22 MW in Washington, DC. Nearly 40 percent of DC's solar capacity was added in 2016 alone. However, available real estate for distributed solar in the District is limited. The realities of the existing housing stock in the District create a tension between available space and the District's ambitious solar targets. The District is a dense urban environment with a high percentage of renters and multi-family housing. In addition, the city has more than 30 neighborhoods that have been designated as historic districts. Regulations for historic districts require that solar panels cannot be installed in a manner that allows them to be visible from the street, which limits that solar potential in these areas.[329]

Our research indicates that these physical challenges are likely to comprise some of the most significant barriers facing growth of distributed solar today. Specifically, we found in Part I that under the current residential tariff and incentives, payback for a 4.1 kW PV system is estimated to be approximately five years, which should lead to widespread adoption of the technology.[330] However, growth to date has been much slower than expected under such favorable economics.

Given the challenges associated with limited real estate, Synapse constructed a model to assess physical rooftop availability and calculate the technical potential for rooftop solar in the District. In addition, we developed a cumulative growth curve of residential PV capacity using data from the Public Service Commission's eligible renewable generators list[331] and from PJM's Generation Attribute Tracking System[332] in order to estimate the growth rate for solar going forward. We limited the maximum adoption percentage based on payback acceptance curves.[333]

A variety of publicly available data sources were compiled as inputs to the technical potential model, which we describe below. Our focus was to obtain the best-available set of District-specific data following a process that can be replicated by interested stakeholders in other jurisdictions. We supplemented this data with some general or nation-wide coefficients, as described below.

---

[329] DC Office of Planning, *DC Historic Districts*, http://planning.dc.gov/page/dc-historic-districts.

[330] Synapse analysis based on an SREC payments of $435/MWh in Year 1 (based on average 2015 SREC compliance payments reported in the DC PSC's "Report on the Renewable Energy Portfolio Standard for Compliance Year 2015," declining to $38/MWh in year 25, and an installed cost of $3.50/Watt (based on recent installed costs reported by GTM Research and Solar Energy Industries Association, "U.S. Solar Market Insight: Q2 2016.") and $86 annual maintenance cost (based on NREL, "Distributed Generation Energy Technology Operations and Maintenance Costs.").

[331] The list of eligible renewable energy generators is available at: http://www.dcpsc.org/PSCDC/media/PDFFiles/Electric/Eligible_Renewable_Generators_List.xls.

[332] PJM Generation Attribute Tracking System data available at: https://gats.pjm-eis.com/gats2/PublicReports/RPSEligibleCertificatesByStatusReportingYear/Filter.

[333] Pieter Gagnon and Ben Sigrin, "Distributed PV Adoption – Sensitivity to Market Factors," (NREL Presentation, February 2016), http://www.nrel.gov/docs/fy16osti/65984.pdf.

10.1. Historical Installation Data

Data on existing solar PV installations was sourced from the Public Service Commission's list of approved renewable energy generators.[334] Synapse processed this data to find all system records belonging to both small-residential and other buildings in the District.[335] The resultant records were then used to find the historical number and average size of residential systems, as well as cumulative capacity; and the historical number, cumulative capacity, average system size, and variance in system size for government, commercial, and industrial (GC&I) and large multi-family systems. We did not calculate variance for small residential systems as the data were tightly clustered and fairly consistent year-to-year. Summary statistics for all installations (through mid-November 2016) are shown below.

Table 8. Summary statistics for all installed PV systems

	SMALL RESIDENTIAL	GC&I AND MULTI-FAMILY
NUMBER	2,265	243
CUMULATIVE CAPACITY	10.83 MW	11.42 MW
AVERAGE SIZE	4.78 kW	47.01 kW
MEDIAN	4.16 kW	14.88 kW
VARIANCE	N/A	6.6 kW

Source: Public Service Commission of the District of Columbia, "Eligible Renewable Generators List," December 9, 2016.

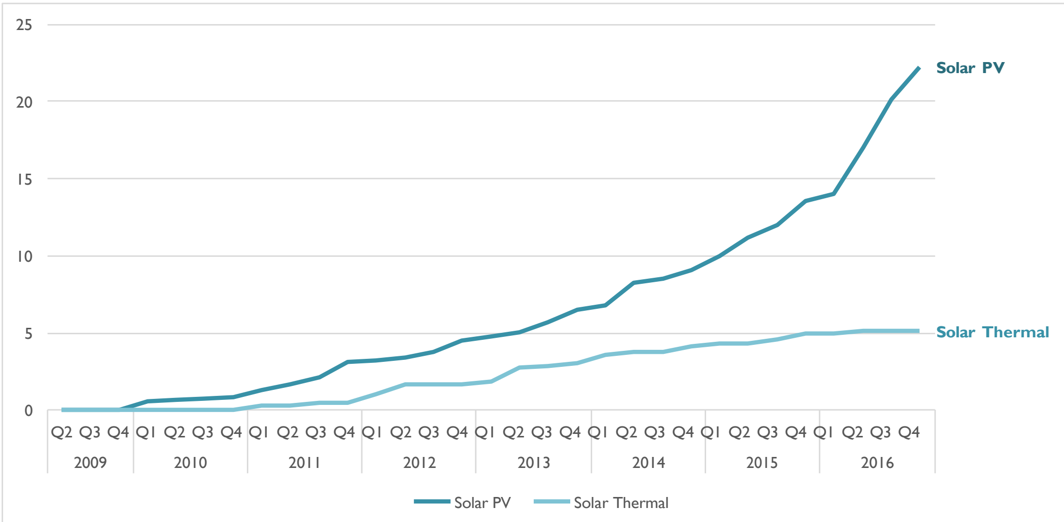
The date of Commission approval served as an approximation for the date that installation was interconnected to the utility grid.[336] The resulting calculations show that cumulative solar PV capacity in the District has steadily increased over time, while solar thermal growth has slowed considerably, as shown in the figure below.

[334] Public Service Commission of the District of Columbia, "Eligible Renewable Generators List," *Renewable Energy Portfolio Standard Program*, downloaded November 2, 2016, http://www.dcpsc.org/PSCDC/media/PDFFiles/Electric/Eligible_Renewable_Generators_List.xls.

[335] Records were filtered to find those that included the word "Residence." This method may give false negatives and under-report the number of small residential systems.

[336] While there may be a lag in the time from when the installation was interconnected to PSC approval, we expect that such a lag would be minor, in part because there is a significant financial incentive for customers to gain PSC approval in order to be eligible for solar renewable energy certificates.

Figure 10. Solar PV and solar thermal installations in DC 2009 – November 2016

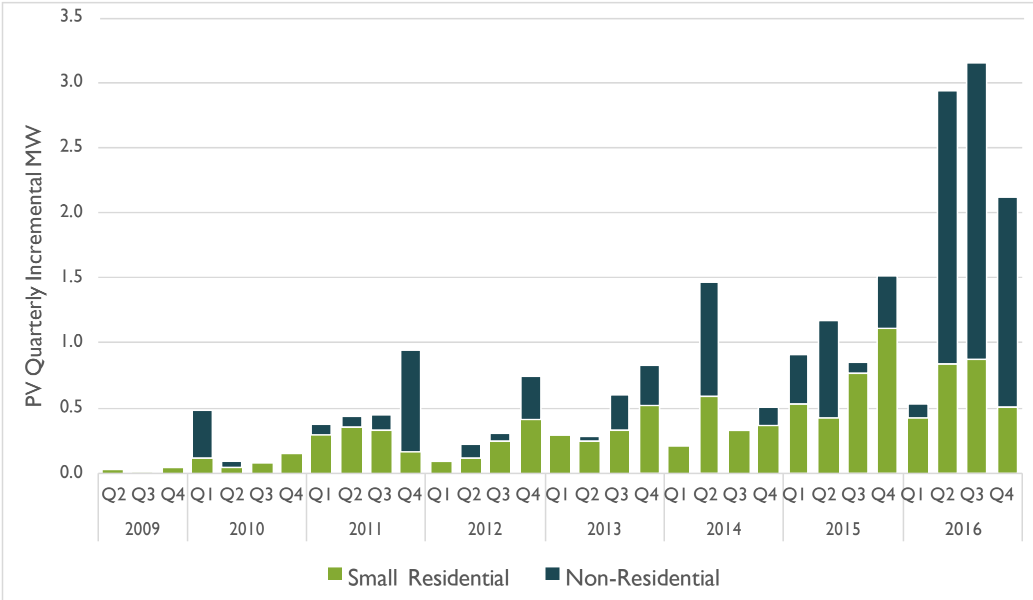


Source: Public Service Commission of the District of Columbia, "Eligible Renewable Generators List," December 9, 2016.

Quarterly incremental PV capacity additions through mid-November 2016 are shown in the figure below, divided into small residential and non-residential/large multi-family categories. As can be seen in the graph, the number of installations in the last three quarters of 2016 dwarf those of previous quarters, primarily driven by growth in the non-residential/large multi-family sector. These installations include numerous school and municipal building installations, which are being completed through a Department of General Services solicitation for more than 10 MW of solar PV capacity to be developed at approximately 50 municipal facilities.[337] Appendix B provides a map of the solar installations in the District as of 2015, while a list of the non-residential/large multi-family installations in 2016 (through mid-November) is included in Appendix C.

[337] District of Columbia Department of General Services, "Solicitation Number: DCAM-14-CS-0123 Request for Proposals, On-Site Solar Power Purchasing Agreement at Various Municipal Facilities."

Figure 11. Quarterly incremental solar PV and solar thermal capacity additions in the District of Columbia



Source: Public Service Commission of the District of Columbia, "Eligible Renewable Generators List," December 9, 2016.

Since 2011, small residential system sizes have consistently averaged between 4 and 5 kW.[338] The average and median system sizes are close to one another and follow the same trend, suggesting that residential system sizes fall in a relatively tight and symmetrical distribution.

Figure 12. Median and average residential PV installation size by year

Source: Public Service Commission of the District of Columbia, "Eligible Renewable Generators List," December 9, 2016.

338 For this analysis, the average of the yearly median system size (4.3 kW) was used as the going-forward assumption of small residential PV system size. Use of a median, rather than averaging yearly averages, reduces the impact of unusually large or small systems.

Non-residential installations have been less consistent in terms of both system sizes and total annual additions. Over 6 MW of non-residential PV had been added as of mid-November 2016, which is nearly four times the quantity of non-residential PV added during any other year. Presently, non-residential cumulative capacity totals approximately 11.4 MW. Average non-residential system size has also varied considerably; while only very small systems were installed upon the program's inception in 2009, the 2016 average system size exceeds 71 kW. The difference between average and median system sizes is greater for large buildings than for small residential systems, suggesting greater variation in the range of system sizes installed in a given year.

10.2. Small Residential Rooftop Data

For the residential sector, GIS maps were used to identify small residential buildings and those located within historic districts. Then the total number of available and suitable roofs was calculated, where rooftop availability is defined as roofs that are not already occupied with PV systems, and suitable roofs are defined as those with a slope and age suitable for accommodating PV panels. Data on rooftop suitability from NREL and rooftop age from the American Community Survey (ACS) were used to decrement the total number of residential rooftops and determine the technical potential for small residential PV.

GIS Data

Data on the number of rooftops in the district, rooftop areas and slopes, age, and availability for PV were employed as inputs to calculate the technical potential for solar PV in the District. GIS map layers available on the DC Open Data website[339] were used as the source for building footprints, rooftop slopes, and boundaries of zoning and historic districts. Effectively, these maps show all zoning boundaries and plots of land in the District, but associate metadata (such as building footprint) with each plot. These layers can be used to isolate plots fitting particular criteria. For example, for the purposes of this analysis, small (normally one- to three-family) residential buildings were defined as those located in residential zoning districts and under 5,000 square feet in area.[340]

Using this data, Synapse estimated that there are approximately 141,800 small residential buildings in the District. We also identified small residential buildings in historic districts and assumed that 50 percent of those buildings were ineligible for PV installations, given that installations are not permitted to be visible from the street.[341] Approximately 24,200 residences are located in historic districts.

[339] http://opendata.dc.gov/.

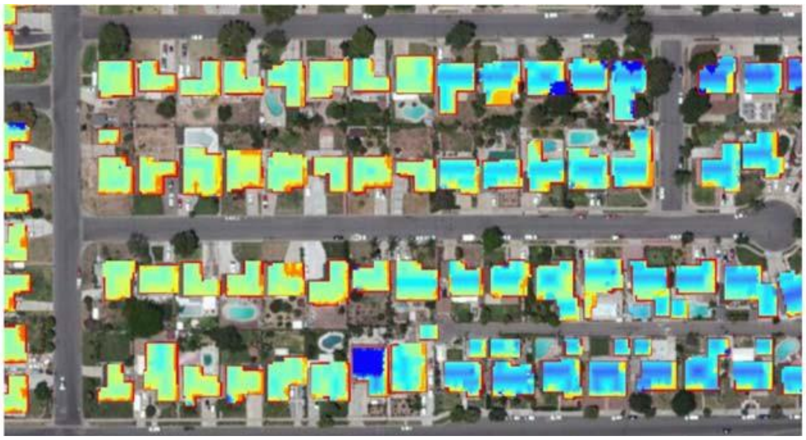
[340] Buildings smaller than approximately 55 square feet were filtered from the data set as they were likely to be accessory structures.

[341] The District's current historic preservation guidelines state as follows: "If installed on a flat roof, solar panels should be located so they are not visible from the public street. If located on a sloping roof building, they should only be installed on rear slopes that are not visible from a public street." DC Office of Planning, Historic Preservation Office, "District of Columbia Historic Preservation Guidelines: Roofs on Historic Buidings."

Rooftop Suitability

Light detection and ranging (LiDAR) data from NREL's National Solar Radiation Database[342] were used to find the tilt, orientation, and shading of rooftops in the District. An example of NREL's LiDAR data is shown below.[343]

Figure 13. Example of NREL LiDAR data



Source: Gagnon et al, 2016.

Suitable rooftops were defined as those that are less than 60 degrees in tilt; oriented facing east, southeast, south, southwest, or west; and are sufficiently unshaded and sufficiently large to be considered an occupied structure. The average fraction of small buildings with roofs suitable for PV installations across zip codes in the District was found to be 81 percent.

Rooftop Age

American Housing Survey (AHS) housing characteristic data for 2013[344] were used to determine the distribution of owner-occupied residential structures and roof ages in the District. The AHS divides housing structures into age bins of five to 10 year durations, as shown in Table 9. Structure age data were then translated into a percentage of rooftops young enough to be eligible for a PV installation, assuming a normal distribution around a 25-year roof life.[345] This assumption results in distribution of roof ages within each structure age bin, as shown in Figure 14.

---

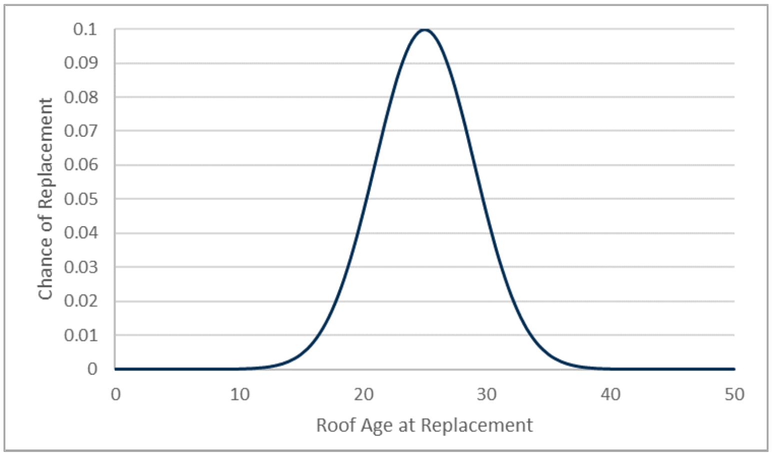
[342] NREL, "National Solar Radiation Database," *NSRDB Viewer*, 2016, https://nsrdb.nrel.gov/nsrdb-viewer.

[343] Pieter Gagnon et al., "Rooftop Solar Photovoltaic Technical Potential in the United States," (Presentation, January 2016).

[344] American Housing Survey, 2013 American Housing Survey for the Washington DC Metropolitan Area, General Housing Data, Table C-01-AH-M, available at census.gov.

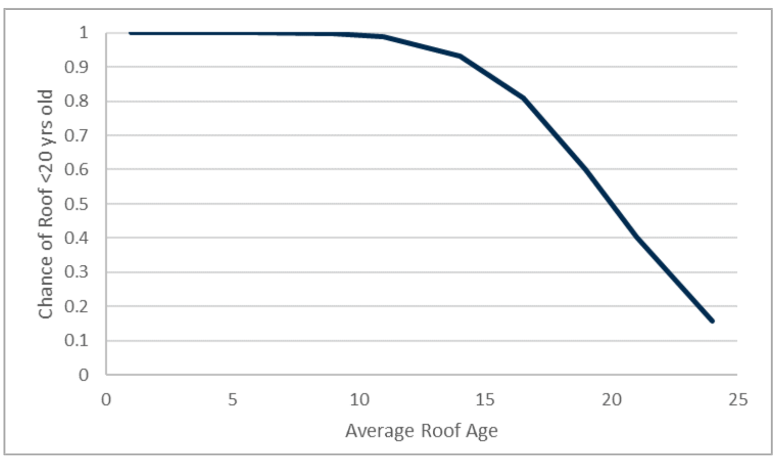
[345] Average of data from Fannie Mae Estimated Useful Life tables, available online at: https://www.fanniemae.com/content/guide_form/4099f.pdf. 25-year life represents conservative average useful life of an assumed mix of roof systems of different materials (asphalt shingle, metal, slate, wood shingle). Sensitivities, discussed below, can be interpreted as variations in this assumed mix of materials.

Figure 14. Normal distribution of roof age at replacement



Synapse further assumed that it would not be cost-effective to install solar on a roof over 20 years old (since the roof would likely need replacement before the end of the PV system's life). When combined with the assumed distribution of roof ages at replacement, this analysis produces an *average* roof age over all the roofs in each structure bin as well as a *probability* that any given roof within that structure bin will be young enough to host a solar installation. These results are shown in Figure 15, below.

Figure 15. Probability of roof age less than 20 years given average roof age within bin



Ambitious and conservative case assumptions were also tested.[346]

The total percentage of roofs young enough for solar was calculated by multiplying the percent of buildings in each age bin by the percent of roofs less than 20 years old in that age bin (assuming a normal distribution around a 25-year roof age at replacement), and then summing the results. This can be expressed using the following equation:

[346] Ambitious and conservative cases assumed average roof ages of 30 and 20 years and a maximum eligibility ages of 25 and 15 years, respectively.

$$\Sigma(\% \text{ of buildings in structure age bin})_i * (\% \text{ of roofs} <20 \text{ years old in structure age bin})_i$$

Using this methodology, we calculated that approximately 82 percent of roofs in the District are likely to be young enough to host solar PV installations. We do not intend this method to provide a robust statistical distribution of rooftop ages in the District—rather, it results only in a reasonable estimate of the percentage of roofs that should be considered eligible for solar based on their age alone. As such, a value of "100%" eligible for roofs on structures older than 20 years indicates only that the particular structure age bin happens to coincide with an integer multiple of the assumed roof replacement cycle length. Significant variation in actual roof age statistics would be expected due to individual circumstances.

Despite the foregoing caveats, the ultimate roof eligibility estimate is relatively robust; ambitious assumptions result in a roof age de-rate factor of 86 percent and conservative assumptions result in a factor of 73 percent. This tight clustering of results suggests that the factor itself has relatively low uncertainty.

Table 9. Rooftop ages in the District of Columbia

Structure Age Bin	*% of Units*	*% of Roofs Eligible*	*% of Units Eligible*
2010 to 2013	2%	100%	2%
2005 to 2009	5%	100%	5%
2000 to 2004	9%	93%	8%
1995 to 1999	9%	60%	5%
1990 to 1994	8%	16%	1%
1985 to 1989	11%	100%	11%
1980 to 1984	7%	100%	7%
1975 to 1979	7%	93%	6%
1970 to 1974	6%	60%	3%
1960 to 1969	12%	100%	12%
1950 to 1959	10%	99%	10%
1940 to 1949	5%	40%	2%
1930 to 1939	3%	100%	3%
1920 to 1929	2%	81%	1%
1919 or earlier	4%	100%	4%
Total:	**100%**		**82%**

Source: 2013 American Housing Survey for the Washington DC Metropolitan Area.

Results of Residential Rooftop Analysis

Following the estimation of rooftop age data, Synapse used two different assumption sets to determine a reasonable upper bound and lower bound of technical potential. First, in order to determine an upper bound, we assumed that roof age and roof slope are heavily correlated, so that all roofs young enough for PV installations would also have a slope suitable for PV. To determine a conservative lower bound, we assumed that roof age and roof slope are fully independent and therefore both de-rates were used. Moreover, conservative roof age assumptions were used to arrive at an aggressive de-rate of 73 percent eligibility, rather than the 82 percent estimated above.

These factors were applied to the total number of available small residential roofs, as follows:

$$N_{available} = (N_{total} - N_{occupied} - 0.5 * N_{Historical}) * p_{young} * p_{suitable}$$

Where $N_{available}$ is the number of small residential rooftops available for new PV systems, N_{total} is the total number of small residential roofs as determined using the GIS data described above, $N_{occupied}$ is the number of existing small residential PV systems, p_{young} is the percentage of roofs that are assumed to be young enough to host PV systems, and $p_{suitable}$ is the percentage of small roofs that are considered to be suitable for PV by NREL.

The conservative assumptions described above lead to an estimated 75,400 small residential roofs that are available and suitable for PV, while the optimistic assumptions lead to an estimated 103,000 roofs. The reference case yields and estimate of 84,800 small residential roofs available and suitable for solar.

The table below summarizes the assumptions used to calculate a reference case, as well as conservative and optimistic cases, for the number of available small residential roofs.

Table 10. Small residential assumptions and estimated rooftop availability

Parameter	*Variable Name*	*Conservative*	*Reference*	*Optimistic*
Total Number of Small Residential Rooftops	N_{total}	141,800	141,800	141,800
Rooftops Occupied with PV	$N_{occupied}$	2,300	2,300	2,300
Rooftops in Historic Districts	$N_{Historical}$	24,200	24,200	24,200
Number of Eligible Small Residential Roofs	---	127,500	127,500	127,500
Rooftop Age De-Rate	P_{young}	73%	82%	100%
Rooftop Suitability De-Rate	$P_{suitable}$	81%	81%	81%
Total Available Small Residential Rooftops	$\mathbf{N_{available}}$	**75,400**	**84,800**	**103,000**

10.3. Government, Commercial, and Industrial; Federal; and Large Multi-Family Rooftop Data

GIS Data

As with the small residential sector, GIS map layers available on the DC Open Data website[347] were used as the source for building footprints and rooftop slopes. Larger buildings in residential districts were

[347] http://opendata.dc.gov/.

classified as large residential. Buildings in non-residential districts were classified as government, commercial and industrial, or federal. Federal buildings were identified using a map layer containing records of plots in the District owned by the federal government. These classification methods may be prone to errors as they do not identify individual buildings by, for example, occupancy or business permits. However, they are likely to provide a reasonable estimate of the total roof area by building type.

Available Roof Area

Synapse calculated available GC&I and large multi-family building roof-area available for solar PV by first determining the total roof area from the map layers described above and then subtracting the roof area represented by buildings with extant PV systems. Currently, the District has approximately 25 million square meters of roof area in the non-residential sector. However, not all of this area is available for new rooftop PV installations. For example, some roof area is already occupied with PV. The total roof area occupied with existing PV systems was estimated to be approximately 92,000 square meters, based on the total capacity of existing systems and an assumed coefficient of occupied area per kW of PV.[348] This assumption may slightly overstate the amount of available rooftop space: because it is unlikely that existing systems will be augmented with new panels, a more conservative assumption would be that the entirety of the roof space on buildings with existing PV systems should be considered unavailable for new solar (as opposed to only the roof space already occupied with existing systems themselves). However, because the absolute number of existing systems on large buildings is small compared to the total number of buildings, this assumption has a negligible effect on the results of the technical potential analysis.

Presence of existing PV systems is only one reason that roof area may be considered unavailable for new solar. In addition, a portion of large building roofs is generally occupied by HVAC systems or other mechanical equipment, and is therefore unavailable for PV installation. To reflect this, the unoccupied roof area was de-rated based on one of three estimated coefficients. In the conservative case, the de-rate coefficient was estimated to be the historical average percent of roof area occupied by PV on non-residential buildings in the District based on a random sample of non-residential buildings that have installed PV.[349] The conservative coefficient value was estimated as 20 percent.

In the optimistic case, a coefficient of roof availability of 65 percent was used. This expresses the maximum expected percentage of a given roof that may be available for PV. The coefficient, which incorporates both average shading and impacts of HVAC and other types of mechanical systems, was

[348] IRENA, "Solar Photovoltaics," Renewable Energy Technologies: Cost Analysis Series, June 2012, https://www.irena.org/DocumentDownloads/Publications/RE_Technologies_Cost_Analysis-SOLAR_PV.pdf.

[349] The sample was drawn from the PSC eligible renewable generators list, and then the total roof area for each building was calculated based on data from Mapdwell. The size of the PV system was developed using the reported installed capacity of the PV system, and standard industry data for the size of PV panels.

developed by Navigant Consulting on behalf of the Energy Foundation.[350] The reference case was estimated to be the average of the historical percentage and the Navigant coefficient, which effectively assumes that customers will install larger systems (in proportion to their roof sizes) in the future, but that they will not install the maximum system size possible. The reference coefficient was 42 percent.

The calculation of the total available roof area on large buildings in the District can be expressed using the following equation:

$$A_{available} = (A_{total} – A_{occupied}) * p_{available}$$

Where $A_{available}$ is the available roof area, A_{total} is the total roof area as determined using the GIS analysis described above, $A_{occupied}$ is the rooftop area occupied by existing PV systems, and $p_{available}$ is the percentage of roof space assumed to be available for PV.

The conservative assumptions described above lead to an estimated 4.9 million square meters of roof area that are available and suitable for PV, while the optimistic assumptions lead to an estimated 16.2 million square meters. The reference case yields an estimate of 10.5 million square meters of roof area available and suitable for solar.

The table below summarizes the assumptions used to calculate a reference case, as well as conservative and optimistic cases, for the area of large building roofs.

Table 11. GC&I, large residential, and federal assumptions and estimated rooftop area availability

Parameter	*Variable Name*	*Conservative*	*Reference*	*Optimistic*
Total Area of Large Building Roofs (m^2)	A_{total}	24,990,000	24,990,000	24,990,000
Area of Existing Systems (m^2)	$A_{occupied}$	92,000	92,000	92,000
Unoccupied Roof Area (m^2)	---	24,898,000	24,898,000	24,898,000
Rooftop Area Availability De-Rate Coefficient	$p_{available}$	20%	42%	65%
Total Available Large Building Roof Area (m^2)	$\mathbf{A_{available}}$	**4,901,000**	**10,527,000**	**16,152,000**

The total rooftop area above was apportioned into general GC&I (including multi-family buildings in mixed-used zones), multi-family buildings in residential zones, and federal buildings using percentages calculated based on the percentages of total roof space in different zones as determined using the GIS analysis described above. The results of the GIS analysis for GC&I buildings are tabulated below.

[350] Maya Chaudhari, Lisa Frantzis, and Tom Hoff, “PV Grid Connected Market Potential under a Cost Breakthrough Scenario,” September 2004, http://www.ecotopia.com/apollo2/photovoltaics/pvmktpotentialcostbreakthrunavigant200409.pdf.

Table 12. Large building roof area by type, from GIS analysis

Description	*Rooftop Area (m²)*	*%*
Large buildings (total)	24,990,000	100%
*Non-federal **GC&I***	23,729,000	95%
Federal building rooftop area	510,000	2%
***Multi-family** in residential zones*	751,000	3%

Synapse calculated the technical potential on federal buildings and included this number in the overall technical potential. However, the economic potential analysis excluded federal buildings based on the assumption that the federal government has different economic considerations than the population as a whole.

Parking

The total land area of parking lots in the district was identified using the Parking Lots and Alleys layer available from the DC Open Data website. Federally owned parking lots were identified using the same methodology used to identify federally owned buildings. An analysis of the technical potential of solar PV installations in parking lots is included here for informational purposes only. Parking lots were not included in the economic analysis for several reasons. First, the economics of installing PV on a parking lot may differ from that of rooftop installations, due to differing infrastructure and interconnection needs. Second, parking may be a temporary use of a lot that is slated for future development. Finally, the rooftop analysis suggested that there is more than enough rooftop technical potential to meet the District's solar carve-out.

GIS analysis found that there are 6.8 million square meters of non-federal parking lot land area in the District, as well as 1.9 million square meters of federal parking lot land area.

10.4. Historical Generation and Capacity Factor

Capacity Factor

Estimates of the energy output of a solar panel must take into account the capacity factor of the system. The capacity factor is the ratio of the system's predicted generation to its nameplate value, which varies significantly by location. An average capacity factor for the District of Columbia was estimated using data from NREL's PVWatts calculator and found to be 14.7 percent.[351]

To validate the estimated capacity factor, we divided the historical eligible renewable capacity by the number of eligible Solar Renewable Energy Certificates generated in each year. The number of SRECs produced each year was sourced from PJM's Generation Attribute Tracking System (GATS) for

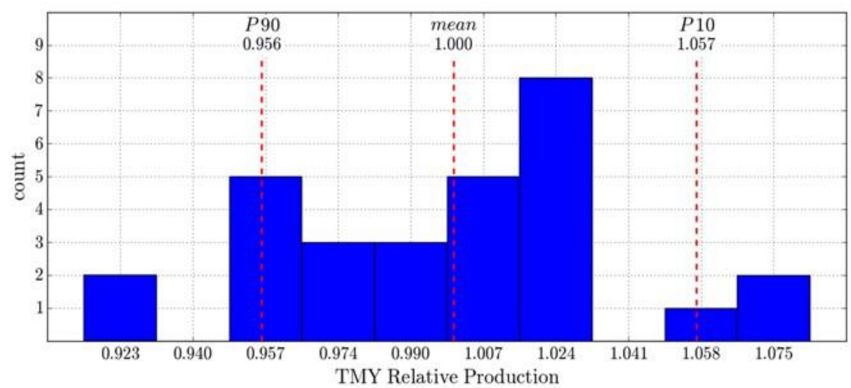
[351] NREL, PVWatts Calculator, available at http://pvwatts.nrel.gov/pvwatts.php.

compliance years 2008 to 2016.[352] This analysis suggested that the PVWatts capacity factor is reasonable.

Variation Due to Weather

For optimistic and conservative cases, expected generation was adjusted based on statistical variation in system output due to differences in weather from year-to-year. For example, the number of cloudy days and precipitation levels will vary from year-to-year, which in turn affects PV output. This variation is reported by PVWatts, which uses historical weather data to calculate PV output. The variation in results is shown in the histogram below. The graph shows that 10th and 90th percentiles for weather variations result in solar PV output varying between 96 and 106 percent of the reference case value.

Figure 16. Expected variation in PV system production based on variations in weather year-to-year



Source: PVWatts calculator for Sterling, VA.

352 PJM GATS data for the District are available at https://gats.pjm-eis.com/gats2/PublicReports/RPSEligibleCertificatesByStatusReportingYear/Filter.

11. Technical Potential

11.1. Small Residential

For small residential systems, the total number of available rooftops was multiplied by the expected residential system size to find the technical potential of capacity. The expected system size was calculated as the average of median system sizes for the years 2012 through 2016 and was found to be 4.3 kW.[353] This value was then multiplied by the capacity factor to find the generation technical potential, as follows:

$$C_R = N_{available} * c_{Avg}$$
$$G_R = C_R * f$$

Where C_R is the total capacity on small residential rooftops, c_{Avg} is the expected (average of medians) system capacity, $N_{available}$ is the number of eligible roofs, G_R is the expected generation on small residential roofs, and f is the capacity factor. Table 13 summarizes the parameters used to calculate total small residential capacity and generation and the results of the analysis.

The expected unrealized technical potential for PV on small residential buildings was calculated to be 360 MW, with an expected yearly generation of approximately 470 GWh. Using conservative assumptions, technical potential could be as low as 320 MW. Using optimistic assumptions, as much as 440 MW of potential may exist. These results suggest that only approximately 3 percent of the District's residential technical potential has been realized to date,[354] leaving significant room for expansion.

Table 13. Small residential technical potential

Parameter	*Variable Name*	*Conservative*	*Reference*	*Optimistic*
Total Available Small Residential Rooftops	$N_{available}$	75,400	84,800	103,000
Expected System Size (kW)	c_{Avg}	4.3	4.3	4.3
Expected Total Capacity (MW)	$\mathbf{C_R}$	**320**	**360**	**440**
Expected Capacity Factor	f	14.7%	14.7%	14.7%
Variation in Yearly Generation	---	96%	100%	106%
Expected Yearly Generation (GWh)	$\mathbf{G_R}$	**400**	**470**	**600**

[353] This number was assumed to not be artificially limited by Pepco interconnection rules, as it is in line with residential system sizes in other jurisdictions. Interconnection barriers are addressed in the "high non-economic barriers" adoption case below.

[354] Existing capacity is 10.8 MW, which is approximately 3 percent of 371 MW (the sum of unrealized technical potential and existing capacity).

11.2. Government, Commercial, Industrial, Large Multi-Family, and Parking

For GC&I, federal, and large multi-family systems, we estimated technical potential (in terms of capacity) by multiplying the total available rooftop area for each building type by a coefficient of PV system capacity (kW) per square meter. The coefficient expresses the total PV output that can be expected per module area, with an adjustment based on area occupied by non-productive power electronics. Expected capacity per area varies based on factors such as assumed module type and efficiency. A value of 0.125 kW/m^2 was sourced from the International Renewable Energy Agency (IRENA).[355]

This value was then multiplied by the capacity factor to find the technical potential of generation:

$$C_{GC\&I} = A_{Available} * c_{Area}$$
$$G_{GC\&I} = C_{GC\&I} * f$$

Where $C_{GC\&I}$ is the total capacity on GC&I, federal, and large multi-family roofs, c_{Area} is the expected system capacity per available roof area, A is the total available roof area, $G_{GC\&I}$ is the expected generation on large building roofs, and f is the capacity factor. Technical potential for parking lots was calculated using an identical methodology. More accurate estimates can be made by applying rooftop exposure and shading data. However, because this dataset was not publicly available for the District, it is not employed in this analysis.

The parameters used to calculate total large-building and parking lot capacity and the results of the analysis are summarized in Table 14.

Table 14. GC&I, large residential, federal technical potential

Parameter	*Variable Name*	*Conservative*	*Reference*	*Optimistic*
Total Available Large Building Roof Area (m^2)	$A_{available}$	4,901,000	10,527,000	16,152,000
Capacity per Area (kW/m^2)	$A_{occupied}$	0.125	0.125	0.125
Expected Total Capacity (MW)	$\mathbf{C_{GC\&I}}$	**620**	**1,320**	**2,030**
Expected Capacity Factor	f	14.7%	14.7%	14.7%
Variation in Yearly Generation	---	96%	100%	106%
Expected Yearly Generation (GWh)	$\mathbf{G_{GC\&I}}$	**750**	**1,700**	**2,750**

These results suggest that the District has a large expected unrealized technical potential on government, commercial, and industrial (GC&I), federal, and multi-family buildings, totaling approximately 1.3 GW of capacity. The technical potential may vary widely depending on key input assumptions. In particular, the assumed rooftop availability coefficient makes a significant difference in the calculated technical potential. To the extent that rooftop availability may be lower in the District

[355] IRENA, "Solar Photovoltaics."

than nationwide, a more conservative estimate may be more reliable. The low bound estimate for GC&I technical potential is 620 MW, which is considerably lower than the mid estimate.

Relatively little technical potential was found for large, multi-family residential buildings and federal buildings, totaling 40 and 32 MW respectively. In the case of large residential buildings, it is likely that many multi-family buildings are in mixed-use zones, which were classified as general GC&I in this analysis. In the case of federal buildings, the estimate represents only buildings that are owned by the federal government, as opposed to buildings that are rented or leased by federal agencies.

The analysis also found that there are approximately 236 MW of PV technical potential on federally owned parking lots and approximately 849 MW of PV technical potential on other parking lots, for a total of 1.4 GW of potential. These results were not corrected to remove existing systems as, to our knowledge, very few PV systems on parking lots currently exist in the District.

Table 15, below, summarizes the results of the technical potential analysis for all building types (not inclusive of parking lots).[356]

Table 15. Summary of rooftop PV technical potential in the District of Columbia (excluding parking lots)

Building Type	***Conservative***	***Reference***	***Optimistic***
Small Residential Capacity (MW)	**320**	**360**	**440**
Total GC&I, Multi-family, Federal Capacity (MW)	**620**	**1,320**	**2,030**
GC&I Capacity (MW)	580	1,250	1,920
Large Multi-family Capacity (MW)	20	40	60
Federal Capacity (MW)	20	30	50
Total Rooftop Capacity (MW)	**940**	**1,680**	**2,470**

[356] Total estimates are in line with other rooftop PV technical potential estimates for the District from Mapdwell (2.0 GW; https://www.mapdwell.com/en/solar/dc/stats) and NREL (1.3 GW; http://www.nrel.gov/docs/fy16osti/65298.pdf).

12. ECONOMIC POTENTIAL

The analysis above identifies technical potential but does not predict economic potential, which is likely to be lower than the technically maximum possible. Adoption of PV is driven by economic considerations. The key parameter controlling economic adoption is the payback period: the number of years before the owner of a PV installation "breaks even," or recoups the cost of the PV system through lowered energy bills and, in areas such as the District, SREC payments.

Synapse examined a variety of economic adoption scenarios to determine possible adoption trajectories for PV in the District. First, we calculated total economic potential. Then, we modeled adoption trajectories assuming constant economics. Finally, we modeled adoption trajectories assuming that solar adoption would be limited by the solar carve-out for that year.[357]

12.1. Methods and Assumptions

Payback Period

Simple payback periods were calculated based on an installed cost of $3.50/watt,[358] an $86 annual maintenance cost, [359] typical customer load patterns produced by DOE's Building America House Simulation Protocols,[360] and current electricity rates (assuming full net metering). Payback periods for a 4.1 kW residential PV system in the District are highly dependent on SREC prices, as shown in the table below.

[357] Whether the carve-out could be expected to be met in a particular year was modeled under various scenarios.

[358] GTM Research and Solar Energy Industries Association, "U.S. Solar Market Insight: Q2 2016."

[359] NREL, "Distributed Generation Energy Technology Operations and Maintenance Costs."

[360] Customer load profiles are available at http://en.openei.org/datasets/dataset/commercial-and-residential-hourly-load-profiles-for-all-tmy3-locations-in-the-united-states.

Table 16. SRECs and associated simple payback period for 4.1 kW system

SREC ($/MWh)	*Payback (Years)*
500	4
450	5
400	5
350	5
300	6
250	7
200	8
150	10
100	12
50	17
0	26

As long as the total amount of PV capacity in the District is below the District's mandated solar carve-out, the price of SRECs is assumed to be the legislatively determined alternative compliance payment value. The current ACP schedule, as summarized in Table 17, is expected to gradually ramp down over the next 20 years. This suggests that the payback period will also change. However, as described below, economic adoption is not instantaneous and therefore it would be mathematically complex to model both changing adoption percentages and changing payback periods simultaneously. To simplify the analysis, we assumed a constant payback period and tested three separate cases.

Based on the schedule in Table 16, a constant 5-year payback period was assumed as the reference case value for the analysis. This value implicitly assumes that SREC prices will stay at or near the ACP price through the analysis period, or until the total installed solar capacity reaches the solar carve-out limit. The interaction of economic adoption and the solar carve-out is discussed under Adoption Trajectories, below.

Low and high economic potential cases were also analyzed, with payback periods of 17 and four years, respectively. These cases can also be interpreted as representing variation in customer incentives apart from SRECs, technology costs, and rate designs. For example, if PV modules become less expensive, a shorter payback period would be expected. By contrast, if net metering were not available or was offset by high fixed charges, payback time would be expected to increase.

Table 17. Alternative compliance payment schedule

Year	*ACP ($/MWh)*
2016	500
2017	500
2018	500
2019	500
2020	500
2021	500
2022	500
2023	500
2024	400
2025	400
2026	400
2027	400
2028	400
2029	300
2030	300
2031	300
2032	300
2033+	50

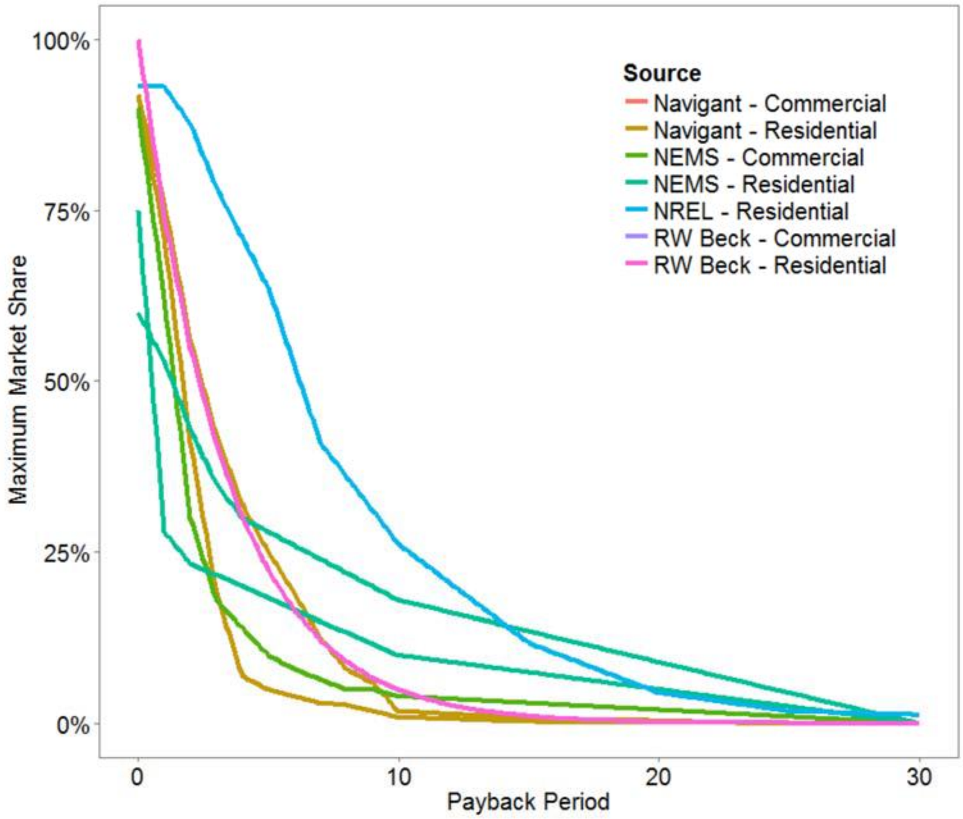
Ultimate Adoption

Ultimate customer adoption levels at different payback periods and for different cohorts of consumers (*e.g.*, residential and non-residential) have been estimated by a number of different authorities. The ultimate adoption level is expressed as a percentage of technical potential, rather than a percentage of all customers. This value represents the extent to which customers who are able to install solar can be expected to install PV systems. It should be noted that the willingness of customers to adopt solar based on payback periods may not lead to actual project implementation if other types of barriers exist. For example, Navigant estimates that adoption levels may be reduced by as much as 60 percent if widespread interconnection challenges exist that create significant cost increases or result in project delays or cancellation.[361]

Estimates of market penetration can vary substantially based on what underlying data are used to estimate the curves and when the estimate was made. Such adoption curves may need to be adjusted over time as market factors change.

[361] J. Paidipati et al., "Rooftop Photovoltaics Market Penetration Scenarios," February 2008, http://www.nrel.gov/docs/fy08osti/42306.pdf.

Figure 17. Market diffusion curves from the literature



Source: Ben Sigrin et al., "The Distributed Generation Market Demand Model (dGen): Documentation" (NREL, February 2016).

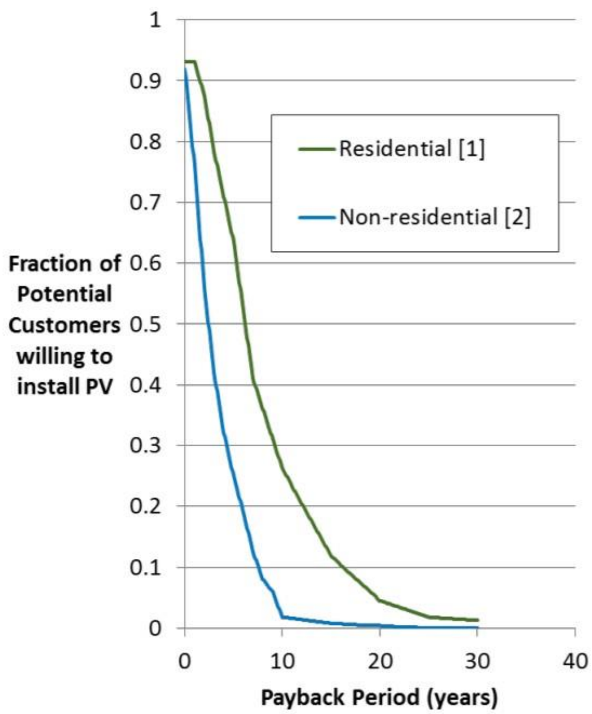
However, despite their differences, all curves from the literature show a similar L-shape.[362] Two features are notable: first, the curves generally do not reach 100 percent adoption even at a payback period of zero years (*i.e.*, instantaneous payback). This suggests that some consumers will not install PV regardless of how attractive the economics are. Second, the distinct elbow in the curves suggest that PV installation is generally considered favorable at payback periods of less than eight to 10 years, and is considered relatively unfavorable if payback requires a longer investment of time.

---

[362] Navigant Consulting, *See:* Ibid., the Energy Information Administration's National Energy Modeling System (NEMS), *See:* EIA, "The Electricity Market Module of the National Energy Modeling Systems: Model Documentation Report," US Energy Information Administration (Washington, DC: Department of Energy, 2004), NREL, *See:* Ben Sigrin and Easan Drury, "Diffusion into New Markets: Economic Returns Required by Households to Adopt Rooftop Photovoltaics," in *AAAI Energy Market Prediction Symposium* (AAAI Energy Market Prediction Symposium, Washington, DC, 2014)., and R.W. Beck, *See:* R.W. Beck, Inc., "Distributed Renewable Energy Operating Impacts and Valuation Study," Prepared for Arizona Public Service, 2009.

For the purposes of this analysis, the most recent NREL ultimate adoption curves for residential and non-residential consumers were used to find the economic potential of PV in the District.[363] These curves are shown in Figure 18, below.[364] In addition, we tested a conservative case using the U.S. Energy Information Administration (EIA) NEMS curves seen in Figure 17. This case simulates the adoption that may be expected given extremely significant non-economic barriers.

Figure 18. Market diffusion curves as estimated by NREL



Source: NREL's dSolar model as presented by Gagnon and Sigrin, February 2016.

The ultimate adoption percentages were found using the curves identified above and are summarized in the table below.

Table 18. Estimated ultimate adoption potential

Cohort	*Low*	*Reference*	*High*
Residential	9%	64%	72%
GC&I	1%	26%	32%

363 Ben Sigrin et al., "The Distributed Generation Market Demand Model (dGen): Documentation" (NREL, February 2016).

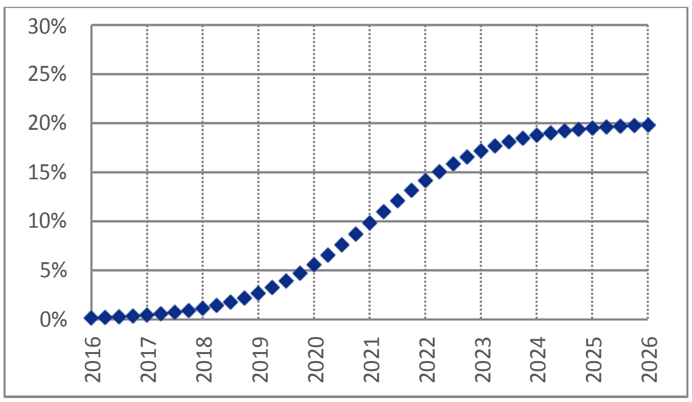
364 Gagnon and Sigrin, "Distributed PV Adoption – Sensitivity to Market Factors."

Saturation Time and Adoption Trajectory

The ultimate adoption values in the curves above can be used to find the total amount of solar PV adoption that is expected after the market is saturated. In other words, these values express the percentage of capacity that will be realized eventually, assuming market conditions do not shift significantly. However, these values do not express how adoption is expected to increase over time. Instead, new technology adoption often follows an "S-curve," which can be specified using the Bass Diffusion Model.[365] Under this model, growth begins slowly, enters into a rapid growth phase, and then begins to slow as it nears market saturation (i.e., the maximum percentage of the population that might ultimately adopt the product). S-curve trajectories for different adoption scenarios were prepared following the Bass Diffusion Model.

A hypothetical S-curve for distributed solar is shown in Figure 19, below, based on the assumption that the market will saturate at 20 percent over a 10-year period.[366]

Figure 19. Hypothetical s-curve of distributed solar adoption



Assumes that market saturation at 20 percent occurs in 10 years.

12.2. Scenario Analysis

Economic Potentials

Using the payback and ultimate adoption assumptions described above, Synapse calculated a total economic potential for each of the technical potential values found above. We calculated economic potential as:

$$C_E = C_R * u_R + C_{GC\&I} * u_{GC\&I}$$

[365] Frank Bass, "A New Product Growth for Model Consumer Durables," *Management Science* 15, no. 5 (January 1969).

[366] The shape that the S-curve takes will vary based on parameters referred to as the "coefficient of innovation" and the "coefficient of imitation." Further research is required to accurately specify these parameters.

Where C_E is the total economic potential of capacity, C_R and $C_{GC\&I}$ are the technical potentials for small residential and large non-federal buildings as found above, and u_R and $u_{GC\&I}$ are the ultimate adoption percentages for residential and non-residential buildings. The calculated value represents the total non-federal rooftop economic potential, inclusive of small residential and large buildings but exclusive of parking lots.

Economic potentials for each combination of the low, reference, and high cases of expected payback period and the conservative, reference, and optimistic technical potentials calculated above are summarized in Table 19.

Table 19. Economic potential - Capacity

Capacity (MW)		*Technical Potential Case*		
		Conservative	Reference	Optimistic
Economic Potential Case	Low	30	40	50
	Reference	360	560	790
	High	430	680	960

The remainder of the economic analysis focuses on capacity. However, the table below summarizes expected generation, in GWh, for the technical and economic potential combinations. Variation in generation due to yearly weather differences can be approximated as 5 percent of the values in Table 20.

Table 20. Economic potential - Generation

Generation (GWh)		*Technical Potential Case*		
		Conservative	Reference	Optimistic
Economic Potential Case	Low	40	50	70
	Reference	470	730	1,020
	High	550	870	1,230

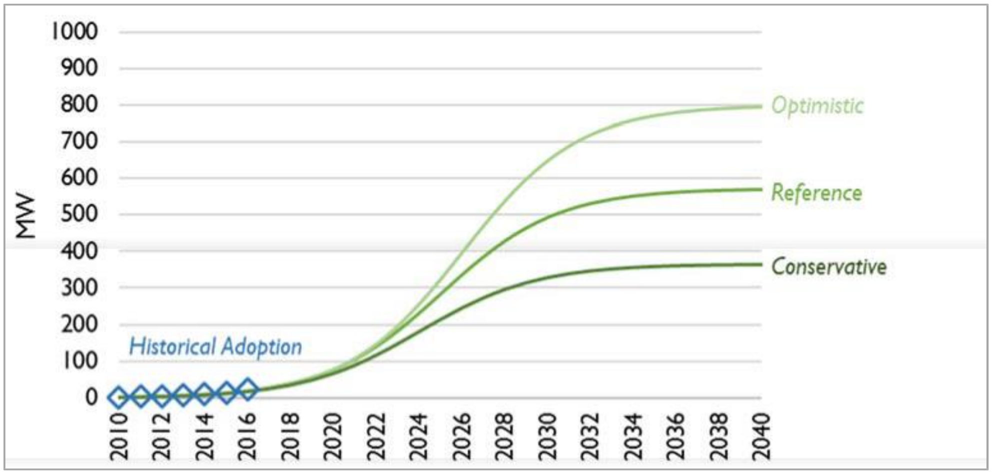
Adoption Trajectories

Once the total expected economic potential values were calculated, adoption trajectories were fit to historical data using the s-curve model described above. These adoption trajectories are not inclusive of the Solar for All program which, as above, is not impacted by the economic considerations of participants. These trajectories also assume that payback period will remain constant regardless of whether the solar carve-out is exceeded.

Reference Case

Figure 20 shows fitted adoption trajectories assuming reference case economics (*i.e.*, a 5-year payback period) and the range of conservative, reference, and optimistic technical potentials.

Figure 20. Adoption trajectories – Reference case economics

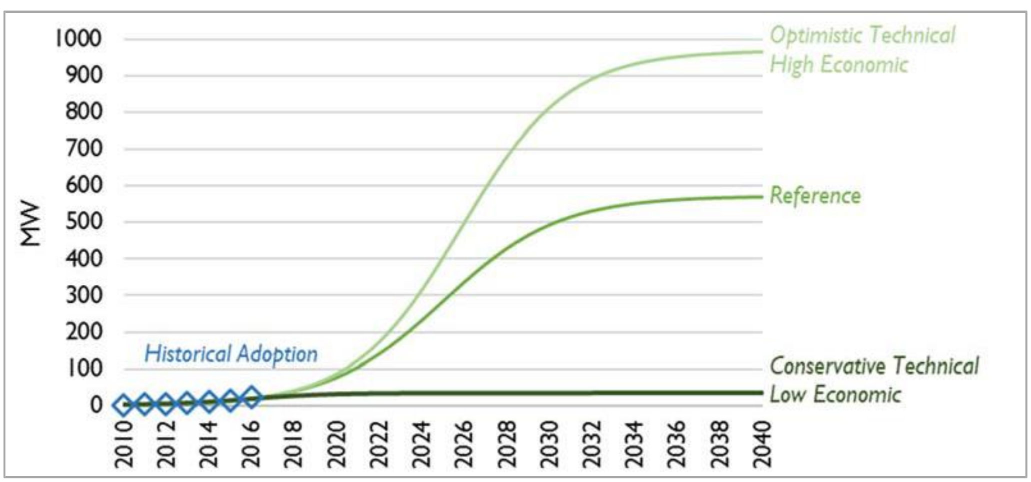


These trajectories suggest that rapid expansion in solar installations should be expected over the next six to 10 years, with solar adoption leveling out in the early 2030s under conservative technical potential assumptions and the late 2030s in the optimistic case. In the reference case, saturation is reached in approximately 2035. These trajectories show that the economic potential varies by a factor of slightly more than two depending on the technical potential.

Best and Worst Case

Figure 21 shows adoption trajectories for the reference case and the absolute best (optimistic technical and high economic) and worst (conservative technical and low economic) cases.

Figure 21. Adoption trajectories – Best and worst case range of results



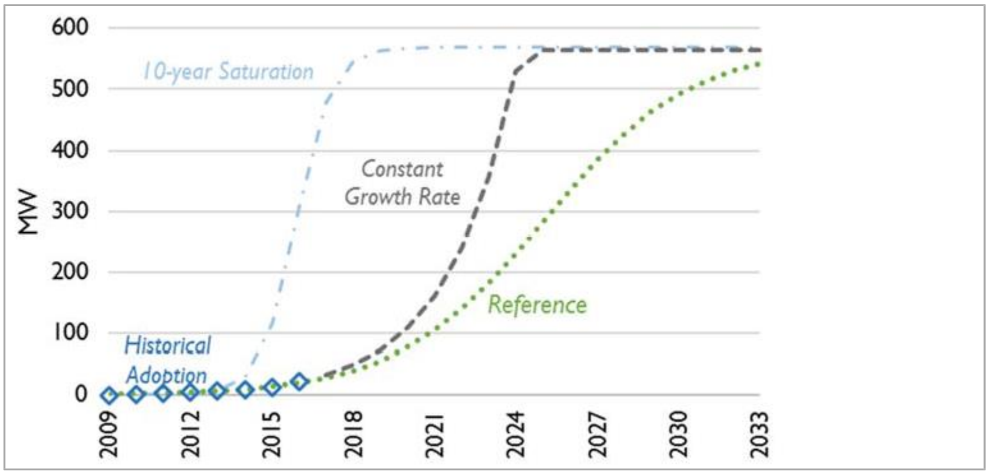
The wide variation between these trajectories shows the impact of the assumptions used to estimate economic potential. In the conservative technical and low economic potential case, solar adoption is found to be essentially flat between now and 2040. In contrast, in the optimistic technical and high economic case, solar adoption is found to increase by two orders of magnitude in the next 35 years.

These results demonstrate the strong impact of payback assumptions on economic potential, arising from the L-shaped adoption curves shown above.

Theoretical Adoption Trajectories

In addition to these cases, we modeled two theoretical cases using the reference value of economic potential. First, a trajectory was prepared assuming that the economic potential would be reached in 2019, 10 years after the inception of the DC RPS. This period was found to be the approximate saturation time for rooftop PV in Germany,[367] which was taken as a reasonable proxy for a situation with favorable economics and low non-economic barriers. This trajectory represents what may have been expected in the District in the absence of the extant non-economic barriers to adoption, and it exceeds historical adoption. Second, a trajectory was prepared assuming that the average year-on-year growth rate for the years 2011 through 2015, calculated as 49 percent, would continue until the economic potential was reached.

Figure 22. Theoretical adoption trajectories



In both of these theoretical cases, solar PV adoption is found to increase more rapidly than in the reference case. This suggests, first, that non-economic barriers are playing a substantial role in slowing the adoption of rooftop PV in the District. Second, although increased solar adoption is expected in the reference case, the annual growth rate of solar adoption is expected to decrease in the reference case.

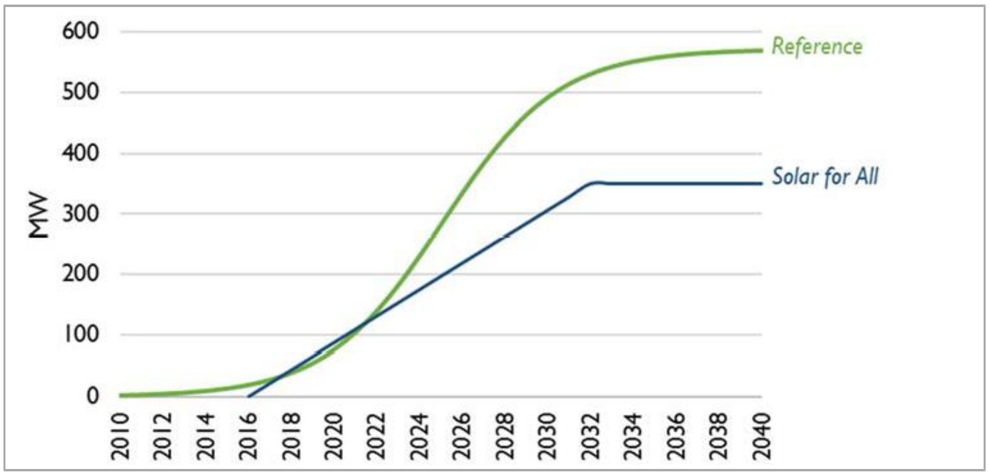
Solar for All Program

In addition to the solar carve-out, the District recently embarked on a dramatic expansion of its Solar for All program. This program is intended to halve the energy bills of a large portion of the District's low-income population. It will do so by supplying these residents with free solar installations, whether on their own rooftops or through community solar installations. The Solar for All program is scheduled to

[367] Harry Wirth, "Recent Facts about Photovoltaics in Germany" (Fraunhofer ISE, October 14, 2016), https://www.ise.fraunhofer.de/en/publications/veroeffentlichungen-pdf-dateien-en/studien-und-konzeptpapiere/recent-facts-about-photovoltaics-in-germany.pdf.

commence installations in 2017 and reach completion by the end of 2032. The total capacity of PV expected to be installed under the program is not clear. An ultimate value of 350 MW was assumed for this study, and it was assumed that installations would increase linearly over the lifetime of the program. The expected Solar for All trajectory (with the Reference case economic adoption trajectory for comparison purposes) in shown in Figure 23.

Figure 23. Adoption trajectories – Solar for All



Because of the structure of the Solar for All program, it is not clear how the capacity installed under the program will interact with economic adoption. Two limiting assumptions can be made: first, that none of the low-income residents who receive PV as part of the Solar for All program would have installed solar otherwise and therefore Solar for All capacity is additive to economic adoption; second, that the Solar for All program is fully represented by the economic adoption trajectory and therefore no additional capacity should be modeled.

Interaction with Solar Carve-Out

Because economic adoption in the District is driven by high SREC prices, it is important to know when the solar carve-out might be reached, as crossing this threshold would have a significant impact on the economics of new solar installations. Once solar capacity in the District is at or above the value of the solar carve-out, the price of SRECs would revert to a market price rather than the ACP. The market price would likely be lower than the ACP. At this point, solar installations would be expected to flatten. Eventually, an equilibrium would be expected in which installations roughly match the value of the carve-out. However, it is not clear how long establishment of such an equilibrium would take. Nevertheless, the carve-out value itself can be taken as a reasonable upper bound on solar installations.

The equivalent capacity of the solar carve-out was calculated using the capacity factor described in the technical potential section above and a District-specific load forecast from DC DOEE, which assumes growth in sales of 0.9 percent per year.[368] The table below summarizes the expected equivalent capacity value of the carve-out through 2032, after which point the carve-out requirement remains constant at 5 percent of sales.

Figure 24. Solar carve-out capacity and energy

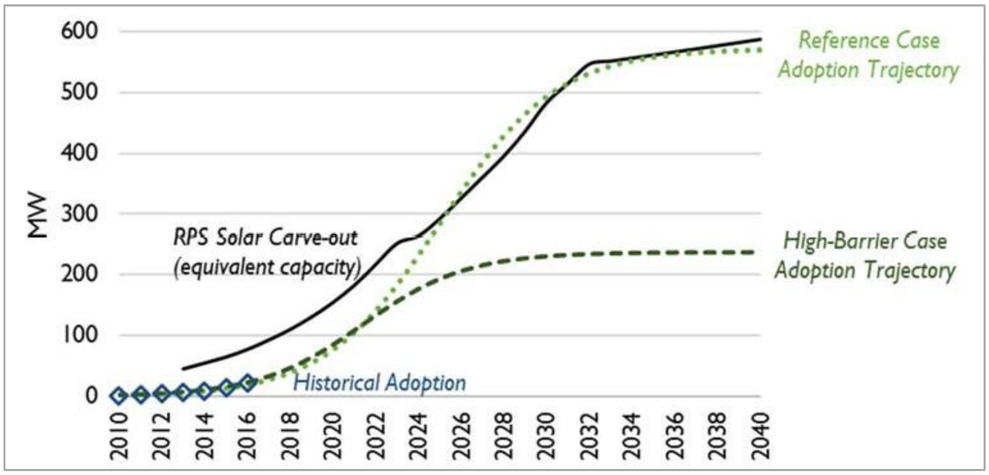
Year	*Solar Carve-Out (% of Sales)*	*Sales Forecast (GWh)*	*Solar Carve-Out (MWh)*	*Solar Carve-Out (MW)*
2009	0.02%			
2010	0.03%			
2011	0.40%			
2012	0.50%			
2013	0.50%	11,877	59,385	46
2014	0.60%	11,984	71,904	56
2015	0.70%	12,092	84,644	66
2016	0.83%	12,201	100,658	78
2017	0.98%	12,310	120,638	94
2018	1.15%	12,421	142,842	111
2019	1.35%	12,533	169,196	131
2020	1.58%	12,646	199,807	155
2021	1.85%	12,760	236,060	183
2022	2.18%	12,874	280,010	217
2023	2.50%	12,990	324,750	252
2024	2.60%	13,107	340,780	265
2025	2.85%	13,225	376,909	293
2026	3.15%	13,344	420,333	326
2027	3.45%	13,464	464,508	361
2028	3.75%	13,585	509,444	396
2029	4.10%	13,707	562,005	436
2030	4.50%	13,831	622,386	483
2031	4.75%	13,955	662,876	515
2032	5.00%	14,081	704,044	547

Using this trajectory, we determined the intersection of adoption trajectories and the solar carve-out. Two illustrative cases are shown in Figure 25 and Figure 26.

[368] DC Department of the Environment, "Electric and Natural Gas Energy Efficiency and Demand Response Potential for the District of Columbia," April 17, 2015, http://doee.dc.gov/sites/default/files/dc/sites/ddoe/publication/attachments/ELECTRIC%20AND%20NATURAL%20GAS%20ENERGY%20EFFICIENCY%20AND%20DEMAND%20RESPONSE%20POTENTIAL%20FOR%20THE%20DISTRICT%20OF%20COLUMBIA.pdf.

First, in Figure 25, the reference case adoption trajectory is compared to an economic adoption trajectory assuming a more conservative ultimate adoption curve than in the reference case. This scenario represents a case in which there are significant non-economic barriers to PV adoption.[369] In the reference case, economic adoption is expected to approximately track with the carve-out starting in 2026. By contrast, the carve-out is never met in the high-barrier case. This result demonstrates that non-economic barriers may prevent the District from accomplishment of its solar adoption goals, regardless of how attractive a proposition PV installation is from a purely economic standpoint.

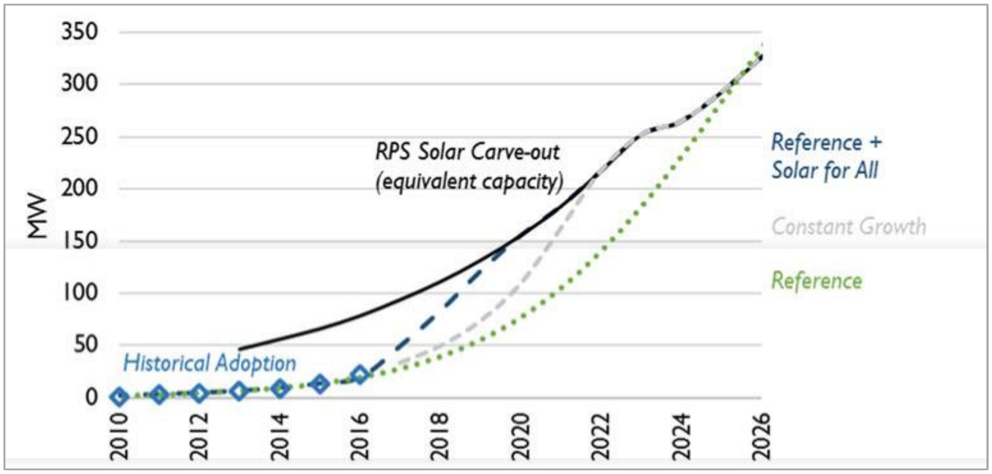
Figure 25. Adoption trajectories – reference case and significant non-economic barriers



Second, Figure 26 shows the reference case adoption trajectory, the constant growth trajectory mentioned above, and a trajectory representing the sum of reference case economic adoption plus the assumed Solar for All trajectory. When the Solar for All trajectory is added to the reference case economic adoption trajectory, the carve-out is reached in 2020. By contrast, the reference case trajectory does not intersect the carve-out until 2026. The constant growth case is in between, intersecting in the year 2022. Notably, the carve-out would be expected to be reached in 2020 if the Solar for All trajectory is added to the economic adoption trajectory regardless of the assumed technical potential case. This suggests that the Solar for All program may have a significant impact on the economics of PV in the District in the near term, unless implementation of the program is relatively slow. However, it also demonstrates that there is likely more than enough economic and Solar for All potential to reach the District's ambitious adoption goals.

[369] Such as interconnection limits or long application processing times.

Figure 26. Adoption trajectories – Constant growth



The table below summarizes the year the carve-out would be expected to be met under different adoption trajectories. The results suggest that, if the carve-out is to be met, such an intersection is most likely to occur in the mid-2020s.

Table 21. Year expected carve-out would be met

Scenario	***Year Carve-Out Met***
Reference	2026
Optimistic Technical/High Economic	2024
Optimistic Technical/Reference Economic	2025
Conservative Technical/Low Economic	N/A
Conservative Technical/Reference Economic	N/A
Constant Growth Rate	2022
Economic + Solar for All	2020
High Barrier	N/A

12.3. Summary

To put these findings in perspective, if the entire technical potential of rooftop PV in the District were realized, the electricity generated by rooftop PV would approximately equal 20% of 2015 electricity sales.[370] The economic potential of rooftop PV is approximately 1/3 of the technical potential, equivalent to approximately 6% of electricity sales. Thus, if the District reached its economic potential for rooftop PV, the generation would slightly exceed the current solar carve-out of 5 percent.

[370] Note that we have not included parking lots or other land in this estimate.

Part III - Value of Solar

13. VALUE OF SOLAR STUDY FRAMEWORK

13.1. Objective and Overview

Distributed solar PV can offer the utility system and society a host of benefits, ranging from avoided energy and capacity costs, to reduced environmental impacts. At the same time, distributed solar may impose costs on the system, such as distribution system upgrade costs and increased administration costs. To determine the value of solar to the utility system and all electricity customers in the District, one must conduct a cost-benefit analysis in which all relevant costs and benefits are quantified and analyzed. Table 22 lists the benefits and costs that were analyzed for this study.

Table 22. Potential distributed solar costs and benefits

Utility System Impacts	
Cost	Utility Interconnection and Operational Costs
	Increased Utility Administration Costs
Cost or Benefit	Distribution System Costs
	Ancillary Services
Benefit	Avoided Energy
	Avoided Transmission Losses
	Avoided Distribution Losses
	Avoided Transmission Capacity
	Avoided Generation Capacity
	Avoided RPS Compliance Costs
	Avoided Clean Power Plan Compliance Costs
	Avoided Carbon and Criterial Pollutants
	Energy DRIPE
	Capacity DRIPE
	REC SIPE
	Hedge Value
Societal Impacts	
Benefit	Outage Frequency Duration and Breadth
	Social Cost of Carbon

The basic concept behind calculating the value of solar is straightforward. First, the relevant costs of a resource are forecasted over a long-term planning horizon, along with all the relevant benefits (otherwise referred to as avoided costs). The costs are then subtracted from the benefits to determine the annual net benefits of distributed solar. The annual net benefits are then discounted to calculate the net present value of distributed solar, thereby accounting for the variance of benefits over time and the time value of money. The net benefits are generally presented in terms of dollars per megawatt-hour. The benefits can also be divided by the costs to provide a benefit-cost ratio.

In practice, projecting future costs and benefits is complex and can change significantly over time and as the quantity of distributed solar increases. Avoided cost estimates are subject to inputs that can fluctuate greatly, such as the price of natural gas, legislation (especially renewable portfolio standards), and policies that drive the rate of adoption of distributed generation. Therefore, considerable expertise and judgment is required, and the intermediate and final results should be reviewed and updated regularly to ensure that regulatory, technological, and economic changes are incorporated into the model and the results.

Furthermore, a value of solar study is designed to analyze the impacts of a small amount of additional solar installed in the near-term, rather than large quantities of the resource installed many years in the future. The results in this study should not be assumed to still hold for a significant increase of solar capacity in the District, or for the levelized value of solar many years in the future.

13.2. Principles

To ensure that the value of solar is consistent with the jurisdiction's policies and is calculated as accurately as possible, the following principles should be followed.

Alignment with Policy Goals

Each jurisdiction has its own unique energy policy goals, which should inform the value of solar analysis. While most, if not all, jurisdictions seek to maintain just and reasonable rates and provide safe, reliable service, jurisdictions may have other energy policy goals such as:

- reduce revenue requirements;
- promote customer equity;
- improve system resiliency;
- promote resource diversity;
- reduce price volatility;
- improve local economic conditions; and
- reduce the environmental impact of energy consumption.[371]

Identification of the jurisdiction's energy policy goals is necessary to inform the decision of the costs and benefits that are appropriate for inclusion in the analysis, and the appropriate cost-effectiveness test to use.

Inclusion Standard

Value of solar studies generally differ from practices used to determine the compensation for Qualified Facilities (QFs) under the Public Utility Regulatory Policies Act of 1978 (PURPA) in an important way. Avoided cost dockets used to determine PURPA QF compensation generally employ the inclusion

[371] Woolf, Tim, Erin Malone, and Frank Ackerman. 2014. "Cost-Effectiveness Screening Principles and Guidelines for Alignment with Policy Goals, Non-Energy Impacts, Discount Rates, and Environmental Compliance Costs." Synapse Energy Economics. http://www.neep.org/sites/default/files/resources/Forum_C-E_Screening_Guidelines_Final_No_2014.pdf.

standard of “known and measurable.” This standard allows for forecasting future prices based on currently enacted regulations and already built or expected infrastructure, and uses costs or benefits that can be measured directly.

In non-PURPA solar valuations, a less restrictive standard may be used.[372] For example, a “quantifiable” standard allows the inclusion of costs and benefits that cannot be measured directly, so long as the costs or benefits can both be calculated and be represented in dollars. In other cases, reasonable approximations for important costs or benefits are used until more detailed information is available.

But For

The “but for” principle frames the economic valuation by setting up the comparison between the *status quo* case, where some quantity of distributed solar is not installed, versus a future in which some quantity of distributed solar is installed. This framework addresses the question: “What is the total difference in all future costs and benefits between a future without some quantity of distributed solar and a future that includes that quantity of distributed solar?” It is important to emphasize that the study is limited to understanding the impacts of installing a moderate quantity of distributed solar since the incremental benefits and costs of the resource will likely change over time and as penetration grows. For example, as penetration levels increase above approximately 10 percent of peak load, the likelihood of significant integration costs grow. Because the magnitude of such costs are not yet well understood, the value of solar analysis should be revisited as penetration increases and costs change.

Once and Only Once

It is important to include each cost or benefit in a value of solar study once and only once. In other words, there should be no double counting, nor should any quantifiable costs or benefits be ignored or omitted. Adherence to this principle requires precision and care. For example, in some cases the measurement of a cost category wholly embeds a separate, distinct cost category. In such cases, the second category should not be included a second time. In other situations, the cost facing the utility is only a portion of the full cost, and the remainder of that cost might appear in a different category, such as the societal cost. Finally, what may be a cost to one entity might be an equal sized benefit to another entity, and care must be taken to determine the appropriate net cost or benefit.

Analysis Timeframe

A value of solar study estimates the costs and benefits associated with a small amount of additional distributed solar in the near term. For the purposes of this study, it was assumed that the additional quantity of solar would be installed in 2017.

---

[372] See, for example, South Carolina’s solar valuation methodology. Settlement Agreement, South Carolina Public Service Commission Docket No. 2014-246-E at II.5.

For purposes of evaluating the costs and benefits of distributed solar, the analysis timeframe should be long enough to capture the life-cycle benefits and costs of the resource. In other words, the analysis timeframe should extend through the life of the resource, generally estimated to be approximately 25 years. Due to data limitations, the analysis timeframe for this study was limited to 24 years.[373]

13.3. Cost-Effectiveness Perspectives

The value of solar can vary considerably depending upon which costs and benefits are deemed relevant. Defining the relevant costs and benefits is dependent upon the "perspective" of interest: that of the utility system as a whole, that of solar customers, that of non-solar customers and solar customers combined, or that of society.

Value of solar studies generally use cost-effectiveness methodologies that are based on, or at least consistent with, the five cost-effectiveness tests commonly used for assessing energy efficiency.[374] These tests are the Utility Cost Test, the Total Resource Cost Test, the Societal Cost Test, the Rate Impact Measure Test, and the Participant Cost Test.

It is essential to understand precisely what information each test can provide, and what that information indicates regarding the cost-effectiveness of distributed solar resources. Each of the tests has advantages and limitations that must be considered when applying them.

It is essential to understand precisely what information each test can provide, and what that information indicates regarding the cost-effectiveness of distributed solar resources.

Because each test conveys different information, jurisdictions may wish to consider several perspectives when assessing the value of solar. The Utility Cost Test and the Societal Cost Test generally provide the most balanced assessments of costs and benefits, although results from the Total Resource Cost (TRC) Test may provide some additional useful information. The Rate Impact Measure (RIM) Test should be avoided for the purposes of analyzing cost effectiveness, although it is recommended that jurisdictions also evaluate rate and bill impacts using a separate analysis.

A summary of each test is provided below:

1. **Utility Cost Test:** The purpose of the Utility Cost Test is to indicate whether a resource's benefits will exceed its costs from the perspective of the utility system. It does not, as the name implies, represent the perspective of the utility (in terms of utility management and investors). Instead it represents the perspective of the utility system; that is, the perspective of utility customers as a whole. This test provides the simplest, most direct indication of the future costs and benefits of distributed solar resources on all customers. It is a fundamental metric used in utility resource decision-making, including integrated resource

[373] Because cost forecasts are typically done in five- or 10-year increments, data for 2041 were not readily available. For this reason, the study period was limited to 24 years instead of 25 years.

[374] See for example (*E3 2016, E3 2015, IREC 2012).

planning. Therefore, it should be one of the primary tests used to indicate cost-effectiveness of distributed solar resources.

The costs included are any utility system costs that are incurred to implement a distributed solar resource including: program costs (e.g., for administering a net metering program); interconnection costs (customer-specific costs for interconnecting a solar facility to the distribution grid); and integration cost (costs for upgrading the distribution grid to account for the generation of the distributed solar facility).

The benefits included are all utility system costs that are avoided by the distributed solar resource, including avoided energy costs, avoided generation capacity, market price suppression effects, avoided transmission and distribution costs, avoided line losses, and avoided environmental compliance costs.

2. **Total Resource Cost Test:** The purpose of the TRC test is to indicate whether the benefits of distributed solar exceed its costs from the perspective of the utility system and the host customer. This test includes all costs and benefits of the Utility Cost Test, plus the host customer costs (all equipment, installation, and maintenance costs, or solar lease payments). In theory, the TRC test should also include the benefits experienced by the solar customer. But in practice, these benefits to solar customers are rarely, if ever, included. Therefore, this test should be used with caution, and with an understanding of it limitations, when assessing the cost-effectiveness of distributed solar resources.

3. **Societal Cost Test:** This test provides the most comprehensive indication of future costs and benefits of distributed solar resources, including the impacts related to energy policy goals, such as promoting local jobs and economic development and reducing environmental impacts. Therefore, it should be one of the primary tests, along with the Utility Cost Test, used to indicate cost-effectiveness of distributed solar resources.

4. **Rate Impact Measure Test:** The RIM test is different from the other tests in that it attempts to measure cost-shifting and impacts on non-solar customers. However, this test conflates cost-effectiveness with cost-shifting, with the result that it does not provide useful information regarding either. For this reason, it should not be used to indicate the cost-effectiveness of distributed solar resources. Instead, cost-shifting from distributed solar resources should be analyzed using separate rate and bill impact analysis.

5. **Participant Cost Test:** This test provides a relatively narrow indication of the future costs and benefits of distributed solar resources on solar customers only. It does not provide information regarding the cost-effectiveness of distributed solar resources relative to other electricity resources.

In the District of Columbia, the Societal Cost Test has historically been used to determine the cost-effectiveness of energy efficiency and other demand-side resources. In this study, we analyze the value of solar in terms consistent with the Societal Cost Test as well as the Utility Cost Test, and present both results for consideration.

Defining the "Utility System"

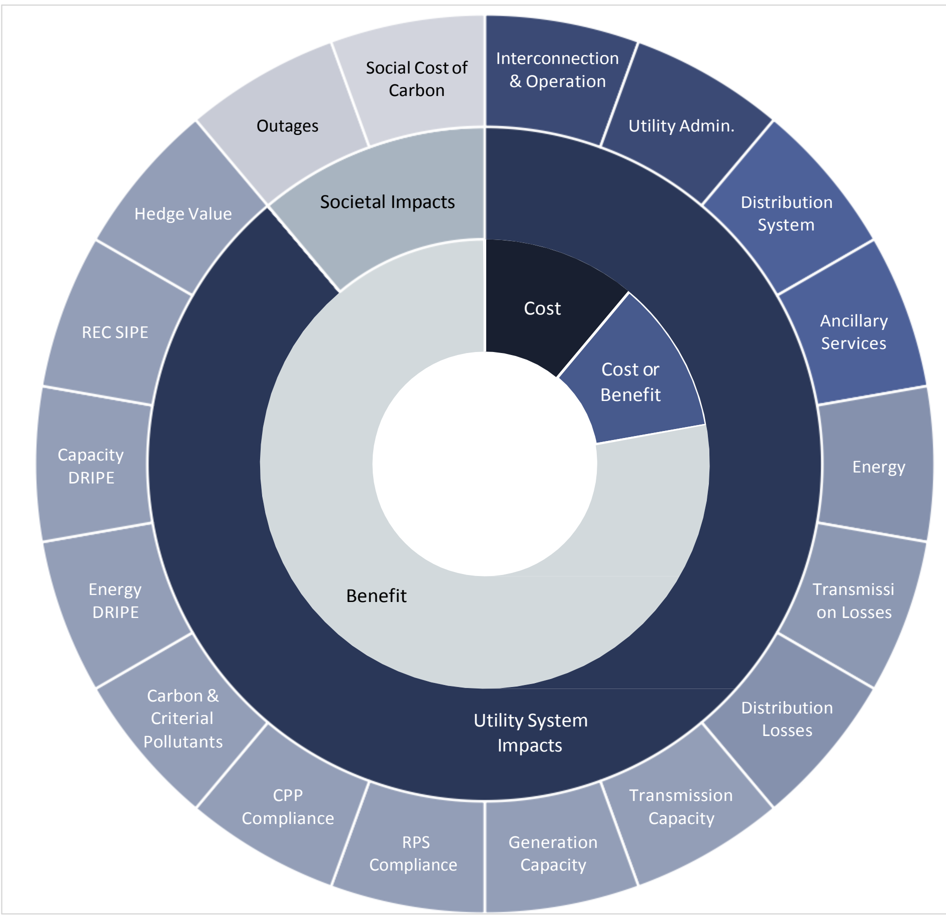
Impacts on the utility system are a key way in which District of Columbia electric customers are impacted by distributed solar. However, because the District is part of a restructured market, the definition of "utility system" differs from the definition for a vertically integrated utility.

The District of Columbia is served by a single distribution utility, Pepco, while energy is provided from the wholesale market through either third-party suppliers or through procurement by Pepco. The "utility system" as defined in this context includes all impacts to Pepco DC's revenue requirements, as well as the District of Columbia's share of PJM-wide impacts that flow through to customers in the District.

14. VALUE OF SOLAR COMPONENTS AND METHODOLOGY

This chapter identifies the various costs and benefits quantified in this study, the methodology used to quantify the impact, and the estimated contribution of that cost or benefit to the value of solar in the District of Columbia. Eighteen costs and benefits attributable to distributed solar were identified for this study, 16 of which were categorized as utility system impacts, and two as societal impacts. The graph below shows how each cost or benefit was categorized.

Figure 27. Impacts of distributed solar



14.1. Utility System Costs

Utility Interconnection and Operational Costs

<u>Definition and Concept</u>

This category represents the additional interconnection and operational costs the utility will face as additional distributed solar is installed. Interconnection costs refer to the one-time costs incurred by the utility when connecting a distributed solar system to the distribution grid. Utility operational costs relate to any changes in costs associated with operating the distribution grid now that the new distributed solar system has been interconnected and is operating. The operational costs may be a function of distributed solar density on a specific part of the distribution grid, and may change over time as technological and code improvements result in improved distributed solar system interaction with the distribution grid.

For Pepco DC, these costs are primarily incurred during the application and verification phases, as well as the costs associated with the installation of a new meter. Prior to a customer installing a solar PV system, Pepco engineers must review the customer's application to ensure that the customer's system can be successfully integrated into Pepco DC's distribution network. Once installed, Pepco DC must review documentation to ensure the system passed all necessary inspections. Pepco DC then installs a net-capable meter, and finally authorizes the customer to operate. The costs that Pepco DC incurs, net of the net metering application fee or any other payments made by the customer during this process, constitute the interconnection and operational costs.

<u>Methodology and Data Sources</u>

Pepco Holdings, Inc. provided the costs that it had incurred between 2013 and 2015 related to processing interconnection requests across its territories, including Delaware, Maryland, and the District.[375] Pepco Holdings also provided the number of net energy metering meters installed, a proxy for the number of net metering installations.[376] Based on these data, Synapse calculated that Pepco incurred an average of $126.12 per application in 2015.

To estimate forward-looking interconnection request costs on a per-MWh basis, average solar PV installation sizes for 2015 and 2016 were estimated using the Public Service Commission's eligible renewable generators list.[377] We used data for 2015 and 2016, as these years exhibited significantly more installations than in years past and are likely to better represent system sizes going forward. Pepco's costs were then divided by the generation produced by an average system. The cost that the utility incurs to interconnect customers is faced entirely in the first year because the analysis must be done once for each unit before interconnection is permitted. Table 23 shows the marginal utility interconnection and operational costs.

[375] Pepco response to OPC DR 4-12.

[376] Pepco response to OPC DR 4-12.

[377] The list of eligible renewable energy generators is available at: http://www.dcpsc.org/PSCDC/media/PDFFiles/Electric/Eligible_Renewable_Generators_List.xls.

Results

Table 23. Utility interconnection and operational costs

Year	DER Integration *2015$/MWh*
2017	($9.39)
2018	$0.00
2019	$0.00
2020	$0.00
2021	$0.00
2022	$0.00
2023	$0.00
2024	$0.00
2025	$0.00
2026	$0.00
2027	$0.00
2028	$0.00
2029	$0.00
2030	$0.00
2031	$0.00
2032	$0.00
2033	$0.00
2034	$0.00
2035	$0.00
2036	$0.00
2037	$0.00
2038	$0.00
2039	$0.00
2040	$0.00

Increased Utility Administration Costs

Definition and Concept

Unlike utility integration costs that are associated with operating the distribution grid, utility administration costs are customer-related costs, such as billing, troubleshooting, and any change in costs associated with arrears. While these costs must always be considered, it is atypical for there to be marginal utility administration costs associated with net metering.

To the extent that the ongoing billing costs do not change for net metering customers that portion of the utility administration category would have no benefit or cost. Similarly, if distributed solar customers make more troubleshooting calls or are more likely to go into arrears, Pepco DC faces additional costs that would be included here.

Methodology and Data Sources

While Pepco DC provided information regarding utility administration costs, these costs did not appear to be marginal costs, i.e., costs that accrue as additional net metering customers join the system. Because the provided costs were not marginal costs, they were not included in the value of solar estimate.

Results

$0.

14.2. Utility System Costs or Benefits

Distribution System Costs

Definition and Concept

This category represents any increase in costs associated with utility investments in the distribution grid needed to integrate additional distributed solar, as well as any decrease in costs associated with the avoidance of building and maintaining distribution infrastructure due to distribution system power flow reductions associated with the distributed PV.

Depending on the network topology, the transformers and other hardware, the location of the distributed solar on the distribution grid, utility policies related to interconnection, and a long list of other factors, an incremental distributed solar installation could impose additional costs on the distribution system. For example, where PV penetration is particularly high, transformer upgrades or reconductoring may be needed to mitigate reverse power flow and voltage issues. On the other hand, customer-sited PV results in a reduction in power flows over the distribution system during hours of PV production. To the extent that the circuit demand peaks during hours of PV production, distributed PV can allow the utility to defer a system upgrade or allow the use of less expensive hardware at the time of replacement.

Methodology and Data Sources

Non-coincident area peak distributional marginal costs were taken from Pepco DC's marginal cost of service study. These costs were based on forecasted marginal primary distribution and secondary distribution capacity costs for the 2015–2019 timeframe, expressed in $/kW. The avoided costs associated with distributed PV can be estimated by multiplying the reduction in non-coincident area peak attributed to distributed solar by the forecasted marginal costs. Distribution costs are avoided only once for a distributed PV installation, modeled in the first year.

Because solar PV may not be generating at full nameplate capacity during times of peak load, the capacity value of solar must be reduced to the solar capacity contribution value—the amount of expected power being generated during times of peak load. The solar capacity contribution value used in this analysis is the value established by PJM, 38 percent.[378] It is possible that the PJM-wide contribution value underestimates the capacity value in the District because solar located in Washington, DC is south of most of PJM. On the other hand, demand peaks in the afternoon, and Washington, DC's location on the eastern portion of PJM likely renders solar capacity in the District less valuable that solar located farther west. A more precise solar capacity value could be obtained by performing a detailed hourly analysis for distribution-connected solar PV located in the District. The solar capacity was reduced from nameplate to its solar capacity contribution value for this avoided distribution capacity calculation. Although some circuits peak later in the day and will not receive as much distribution system cost avoidance, other circuits peak closer to noontime and will receive more distribution cost avoidance than the solar capacity contribution value allows. Therefore, the results should only be used for high level cost-benefit analysis and not be applied on a feeder level. Table 24 contains the avoided distribution system costs.

[378] PJM, "PJM Manual 21 Rules and Procedures for Determination of Generation Capacity." Revision 11, March 5, 2014. See B.3.j, page 19. Available at: https://www.pjm.com/~/media/documents/manuals/m21.ashx.

Results

Table 24. Avoided distribution system costs

Year	Avoided Distribution Capacity *2015$/MWh*
2017	$167.27
2018	$0.00
2019	$0.00
2020	$0.00
2021	$0.00
2022	$0.00
2023	$0.00
2024	$0.00
2025	$0.00
2026	$0.00
2027	$0.00
2028	$0.00
2029	$0.00
2030	$0.00
2031	$0.00
2032	$0.00
2033	$0.00
2034	$0.00
2035	$0.00
2036	$0.00
2037	$0.00
2038	$0.00
2039	$0.00
2040	$0.00

Ancillary Services

Definition and Concept

Ancillary services help to maintain reliability of the transmission system and support the transmission of electric power from sellers to purchasers. As defined by the Federal Energy Regulatory Commission, ancillary services supplied with generation include: [379]

- Load following
- Reactive power-voltage regulation
- System protective services

[379] Federal Energy Regulatory Commission. "Glossary." Available at: https://www.ferc.gov/market-oversight/guide/glossary.asp.

- Loss compensation service
- System control
- Load dispatch services
- Energy imbalance services

Each of these services results in costs incurred by the utilities. To the extent that incremental distributed PV increases or decreases that cost, that change would represent a net increase or decrease in the cost of ancillary services. Ancillary services are provided by PJM, the regional transmission operator, and are billed to each utility in accordance with that utility's needs.

Advanced inverters installed within a few years may allow for a reduction of costs associated with reactive power and voltage regulation. Should smart inverters become the typical installation due to customer choice, building code, electrical standard, or Pepco DC requirement, those ancillary service benefits should be included in the value of solar calculation.

<u>Methodology and Data Sources</u>

Synapse performed a review of Pepco DC and PJM documentation related to ancillary service costs as a function of solar PV, as well as a review of value of solar studies from around the country.[380] While advanced inverters are expected to become a requirement across the country in the near future, the advanced characteristics are not yet finalized. Further, the impact on ancillary service cost has yet to be quantified.

<u>Results</u>

$0/MWh. As explained in a 2014 value of solar study from Virginia (also in PJM), "previous VOS studies have come to differing conclusions about the extent to which distributed solar either decreases or increases the need for grid support services, but agree that the overall impact is likely marginal. … As such, the [Virginia Solar Stakeholder Group] recommends only addressing grid support services as part of the broad VOS methodology."[381]

---

[380] See for example Rocky Mountain Institute, "A Review of Solar PV Benefit & Cost Studies," 2nd Edition, September 2013, page 33. Available at: http://www.rmi.org/cms/Download.aspx?id=10793&file=eLab_DERBenefitCostDeck_2nd_Edition&title=A+Review+of+Solar+PV+Benefit+and+Cost+Studies.pdf.

[381] Damian Pitt and Gilbert Michaud. "Analyzing the Costs and Benefits of Distributed Solar Generation in Virginia." October 31, 2014. Available at: http://mdvseia.org/wp-content/uploads/2014/12/SSG-Value-of-Solar-Study-Final-10-31-14.pdf.

14.3. Utility System Benefits

Avoided Energy Costs

Definition and Concept

Defined as the avoided cost associated with generating energy were it not for the distributed generator under consideration (in this case, distributed solar), the energy costs avoided depend on the conditions of the broader electric power grid. The specific physical infrastructure, system load, time of day, congestion on the transmission system, and several other factors determine which electric system generator operates on the margin and would therefore be displaced due to the addition of distributed solar. That marginal generator's avoided fuel costs and avoided variable operations and maintenance costs represent the avoided energy benefit within that hour.

Pepco DC operates as a participant in the PJM wholesale marketplace. Therefore, solar power produced in the District can impact generation across the 13-state region and, furthermore, the PJM wholesale energy marketplace valuation is used to determine the avoided energy benefit.

Methodology and Data Sources

Avoided energy is based on the typical PV system output as provided in NREL's PVWatts Calculator,[382] using a fixed tilt system at a 20-degree tilt. It is important to capture hourly detail, as wholesale energy prices vary substantially over the course of a day, a week, and a year. Distributed solar output is centered around mid-day (with none at night) and is higher in summer than winter, whereas PJM wholesale energy prices tend to be higher on weekdays, highest in summer afternoons, and lowest in the early morning during spring and autumn months. To calculate the total avoided energy benefit across each year, we correlate each hour's generation in PVWatts to a system marginal energy cost, based on historical data for the PJM Interconnect for 2015.[383] This study uses 2015 locational marginal prices for the PEPCO zone of PJM, and subtracts out the congestion and marginal loss portions of the cost, which costs are accounted for elsewhere in this study under the once and only once principle.

The cost of avoided fuel is the dominant factor in avoided input costs, and the historically low natural gas prices that have driven system locational marginal prices to the low levels of the past several years are likely to rebound in the future. For future years, we assume these prices follow the trajectory of regional electricity generation system prices within EIA's Annual Energy Outlook (AEO) 2016, released in September 2016.[384] The AEO Reference case projects the development of the power system through 2040, inclusive of evolving technology costs and environmental regulations such as the Clean Power Plan. The AEO Reference Case is used to scale up the base-year weighted energy cost of $36.35/MWh,

382 NREL PVWatts Calculator. Available at: http://pvwatts.nrel.gov.

383 PJM Hourly Integrated Real Time LMP data for 2015. Available at: http://pjm.com/markets-and-operations/energy/real-time/monthlylmp.aspx.

384 EIA. AEO 2016 Final Report. September 15, 2016. Available at: http://www.eia.gov/forecasts/aeo/.

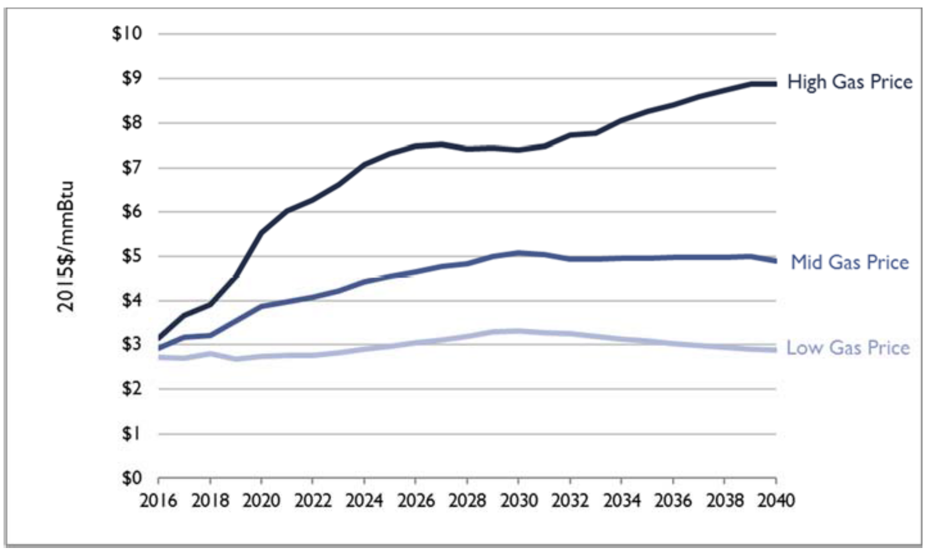
based on generation prices in the region of PJM in which Pepco DC resides, the RFC East region. Low and high avoided energy scenarios are created using the electric power natural gas prices associated with the High Oil and Gas Resource and Technology and the Low Oil and Gas Resource and Technology AEO 2016 cases.

While there are other credible long-range gas price forecasts,[385] Synapse believes that the EIA gas price forecast is appropriate for a variety of reasons. First, the EIA forecast is public, free, and produced by a federal agency. In contrast, many other gas price forecasts require confidentiality, can only be obtained at considerable cost, and use methodologies that are subject to far less scrutiny than EIA's AEO forecast. Additionally, there can be a temptation to use the gas price forecast that results in a higher (or lower) value of solar; always using the EIA forecast removes that potential source of contention.

Results

The value of the avoided energy for 2017 was calculated to be $36.53/MWh. Results for the remainder of the study period are provided in the table below. In addition, Synapse modeled the avoided energy costs under low and high natural gas price sensitivities using the natural gas price vectors faced by electric generators in EIA's High Oil and Gas Resource and Technology and the Low Oil and Gas Resource and Technology cases, respectively. The gas prices used to calculate the value of solar in the District can be found in Figure 28.

Figure 28. Gas price input curves



Note that the results found in Table 25 include the utility cost for criteria embedded pollutants and RGGI carbon costs. It does not include avoided congestion costs or transmission losses.

[385] Examples include forecasts by NERA Economic Consulting, IHS CERA, and Bloomberg.

Table 25. Avoided energy costs

Year	Low Avoided Energy *2015$/MWh*	Mid Avoided Energy *2015$/MWh*	High Avoided Energy *2015$/MWh*
2017	$31.04	$36.53	$42.16
2018	$32.15	$37.00	$44.90
2019	$30.72	$40.62	$52.31
2020	$31.54	$44.53	$63.66
2021	$31.78	$45.60	$69.11
2022	$31.79	$46.89	$72.02
2023	$32.54	$48.46	$75.99
2024	$33.28	$50.81	$81.35
2025	$34.09	$52.24	$84.18
2026	$35.00	$53.42	$85.96
2027	$35.84	$54.82	$86.37
2028	$36.66	$55.43	$85.18
2029	$37.73	$57.37	$85.56
2030	$38.07	$58.46	$85.01
2031	$37.66	$57.79	$85.98
2032	$37.32	$56.79	$88.67
2033	$36.64	$56.83	$89.33
2034	$36.05	$56.99	$92.52
2035	$35.44	$56.96	$95.04
2036	$34.80	$57.29	$96.62
2037	$34.38	$57.28	$98.58
2038	$33.87	$57.15	$100.37
2039	$33.27	$57.42	$102.03
2040	$33.20	$56.21	$102.06

Avoided Transmission Losses

Definition and Concept

Electricity produced at large generation stations must be transmitted to the local distribution grid on high voltage transmission lines. Due to resistance, some of that power is lost, resulting in less power available at load than was generated. Distributed generators, including distributed solar, avoid transmission losses because the power generated is never sent along transmission lines. Thus, distributed solar provides a utility system benefit by avoiding transmission losses that would otherwise occur. Because losses on the transmission system grow with the square of the current on the line, hours with high use incur substantially more losses than hours with low use. It is therefore important to incorporate the temporal nature of PV in the loss analysis. Furthermore, because value of solar studies are analyses of marginal impact, it is the *marginal* losses, not average loss, that is relevant to the analysis. As discussed by Lazar and Baldwin in a 2011 Regulatory Assistance Project report, marginal losses on a line are typically 1.5 times the average loss on the line at that moment.[386]

Along with congestion charges, transmission losses are embedded as a "Loss Price" in the wholesale energy prices paid by Pepco DC.[387] This allows for a straightforward calculation of avoided average transmission losses allowed by incremental distributed solar in each hour.

Methodology and Data Sources

Although most PJM documentation refers to transmission losses on a $/MWh basis, the percentage loss is necessary to calculate the impacts of transmission losses on a variety of avoided cost categories in a value of solar study. For this reason, Synapse used PJM's published average on-peak loss rate of 3 percent.[388] To convert from average to marginal, the value must be multiplied by 1.5, as described above. This multiplier could be further refined if a study is undertaken to quantify the marginal transmission loss rate associated with each region of the RTO.

Results

4.5 percent marginal transmission loss rate. This resulting transmission loss factor is used to gross up the avoided energy, avoided generation capacity, avoided transmission capacity, avoided environmental compliance, energy DRIPE, capacity DRIPE, and avoided social cost of carbon categories before summing the value of solar categories.

Avoided Distribution Losses

Definition and Concept

The distribution loss category could theoretically represent a cost under specific conditions, but in practice is generally shown to be a benefit. Similar to transmission losses, some power flowing on a distribution circuit is lost to resistance. Any distributed solar generation consumed on site reduces power flow on the distribution grid, and therefore avoids distribution losses. Excess distributed solar power injected to the grid faces lower losses when "flowing" to the next meter than power injected at the substation, except in rare circumstances. As with transmission losses, distribution losses grow with the square of the current, and are therefore much higher when the circuit is at peak use. Marginal distribution losses are roughly 1.5 times the average loss at that time interval.

---

[386] Jim Lazar and Xavier Baldwin. "Valuing the Contribution of Energy Efficiency to Avoided Marginal Line Losses and Reserve Requirements. August 2011. Available at: http://www.raponline.org/wp-content/uploads/2016/05/rap-lazar-eeandlinelosses-2011-08-17.pdf.

[387] PJM, "Marginal Losses Implementation Training," Winter 2007. Available at: http://www.pjm.com/~/media/training/new-initiatives/ip-ml/marginal-losses-implementation-training.ashx.

[388] Ibid., p. 12 and p. 83.

Because distribution infrastructure is unique to the utility, it can be difficult to apply average results to individual utilities. This is especially true in the District, where the distribution infrastructure is both more likely to be underground and does not include any rural or exurban circuits.

<u>Methodology and Data Sources</u>

Pepco performed a distribution loss study in 2015.[389] The value reported in that study of 6.85 percent appears to be average distribution system losses across a 24-hour period, thereby underestimating the losses for daylight hours. Multiplying the average by 1.5 allows for a marginal calculation. This method likely underestimates the marginal distribution system loss rate associated with solar PV. A solar-specific distribution system level analysis would be necessary to refine this estimate, but it requires considerable effort to obtain the necessary data and has not yet been conducted by the utility or its consultants.

<u>Results</u>

10.3 percent marginal distribution loss rate. Similar the transmission loss factor, this resulting distribution loss factor is used to gross up the avoided energy, avoided generation capacity, avoided distribution capacity, avoided transmission capacity, avoided environmental compliance, energy DRIPE, capacity DRIPE, and avoided social cost of carbon categories before summing the value of solar categories.

Avoided Transmission Capacity

<u>Definition and Concept</u>

Transmission capacity must be built to maintain reliability as peak load grows, generators are built or retired, fuel prices change, or even administrative changes are made. To the extent that distributed solar reduces a utility's peak load, it reduces the need for new transmission expenditures.

Cost allocation of transmission projects within PJM is somewhat available, but can be extremely complex. Furthermore, planned transmission projects are frequently delayed, re-configured, or face significant changes in estimated cost. Therefore, it can be difficult to use future transmission cost expectations to understand the potential for distributed solar to avoid those transmission costs.

<u>Methodology and Data Sources</u>

Historical transmission capacity expenditures, expressed as a total transmission rate in $/kW-yr, were provided by Pepco DC. Transmission capacity spending by Pepco DC had been increasing annually, but appears to have leveled off over the past three years. Rather than attempt to project if or how that spending will continue to increase, the transmission capacity expenditures from the most recent year (2015) were simply projected to remain constant. The avoided costs were then divided by the solar

[389] Pepco response to OPC DR 2-10, Attachment B, Page 1.

carrying contribution made by solar PV to account for solar PV's peak output not completely aligned with peak load requirements. Avoided transmission capacity costs are found in Table 26.

<u>Results</u>

Table 26. Avoided transmission capacity costs

Year	Avoided Transmission Capacity *2015$/MWh*
2017	$7.88
2018	$7.88
2019	$7.88
2020	$7.88
2021	$7.88
2022	$7.88
2023	$7.88
2024	$7.88
2025	$7.88
2026	$7.88
2027	$7.88
2028	$7.88
2029	$7.88
2030	$7.88
2031	$7.88
2032	$7.88
2033	$7.88
2034	$7.88
2035	$7.88
2036	$7.88
2037	$7.88
2038	$7.88
2039	$7.88
2040	$7.88

Avoided Generation Capacity

<u>Definition and Concept</u>

To ensure reliability, utility systems must be built with enough generation capacity to meet the peak load of the year. They must also have additional reserves to account for planned and unplanned outages in generation or transmission, as well as any forecast errors due to unseasonable weather or other factors. The greater the extent of PV generation at the time of the greatest need for generation capacity, the greater the generation capacity benefit provided by PV.

As a member of PJM, Pepco DC procures generation capacity through the PJM Reliability Pricing Model (RPM) capacity auction, proportional to Pepco DC's expected load at the hour of PJM's coincident peak load. PJM's coincident peak load typically occurs on a July weekday afternoon[390] when there is moderate distributed solar generation.

Methodology and Data Sources

PJM RPM auction results for the PEPCO zone (in nominal dollars) were used to determine capacity prices through the 2019/2020 auction year. For capacity price forecasts beyond that, Synapse developed price estimates consistent with the following observations:

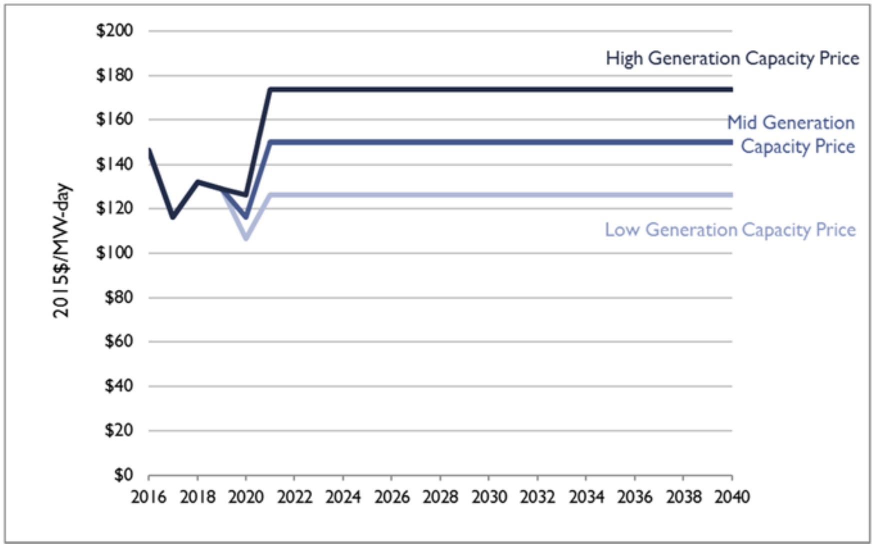
1. In years of transmission constraint (2012/2013 – 2016/2017), the PEPCO zone results were higher than the remainder of PJM, substantially higher in some years.
2. As a percent of PEPCO Net Cost of New Entry (Net CONE), the PEPCO RPM result has declined from 108 percent in 2010/2011 to 41 percent in the 2019/2020 auction.
3. The PEPCO Net CONE value has been less than the PJM-wide Net CONE value since 2012/2013.

The most recent five-year net CONE average (adjusted for inflation) was used as the forecasted future value of Net CONE, both for PEPCO and PJM-wide. To calculate a forecast of capacity value through 2040, Synapse calculated the historical ratio of RPM results to Net CONE, and multiplied that fraction by the forecasted Net CONE. The low forecast is the RTO-wide result and it assumes no transmission constraints, an outcome that has been achieved in the three most recent auctions. The high forecast was estimated to be the PEPCO result, a value that embeds transmission constraints that, although they have not appeared in the past three years, are a historical consideration. The "mid" forecast is the mean of the high and low forecasts.

Figure 29 provides the generation capacity price input curves used in this study.

390 All 10 peak load days in PJM's history have occurred on weekdays in July, typically between hour end 15 and hour end 19. See: https://www.pjm.com/markets-and-operations/~/media/markets-ops/ops-analysis/top-10-all-time-summer-winter-peak-load-days.ashx.

Figure 29. Generation capacity price input curves



All three avoided generation capacity cost projections are found in Table 27.

Results

Table 27. Avoided generation capacity costs

Year	Low Avoided Generating Capacity *2015$/MWh*	Mid Avoided Generating Capacity *2015$/MWh*	High Avoided Generating Capacity *2015$/MWh*
2017	$12.50	$12.50	$12.50
2018	$14.20	$14.20	$14.20
2019	$13.89	$13.89	$13.89
2020	$11.46	$12.52	$13.58
2021	$13.58	$16.12	$18.67
2022	$13.58	$16.12	$18.67
2023	$13.58	$16.12	$18.67
2024	$13.58	$16.12	$18.67
2025	$13.58	$16.12	$18.67
2026	$13.58	$16.12	$18.67
2027	$13.58	$16.12	$18.67
2028	$13.58	$16.12	$18.67
2029	$13.58	$16.12	$18.67
2030	$13.58	$16.12	$18.67
2031	$13.58	$16.12	$18.67
2032	$13.58	$16.12	$18.67
2033	$13.58	$16.12	$18.67
2034	$13.58	$16.12	$18.67
2035	$13.58	$16.12	$18.67
2036	$13.58	$16.12	$18.67
2037	$13.58	$16.12	$18.67
2038	$13.58	$16.12	$18.67
2039	$13.58	$16.12	$18.67
2040	$13.58	$16.12	$18.67

Avoided RPS Compliance Costs

Definition and Concept

More than half of the states within the United States have an RPS policy whereby utilities are required to procure RECs corresponding to a percentage of retail sales. To the extent that a distributed energy resource such as distributed solar is net metered, its generation reduces the sales the utility records and, therefore, the number of RECs that utility must procure and retire for RPS compliance.

Pepco DC must comply with an RPS based on retail sales. The District of Columbia's RPS includes a Tier I obligation that grows from 9.5 percent of sales in 2015 to 50 percent of sales in 2032 and thereafter. It contains a solar carve-out requirement that grows from 0.7 percent in 2015 to 5 percent in 2032 and thereafter. Every megawatt-hour of electricity generated by distributed solar avoids the purchase of a fraction of a Tier I REC and the fraction of an SREC associated with that year. Currently, the District RPS allows Pepco DC to comply with the RPS using Tier I RECs purchased within PJM, or within an adjacent control area. SRECs, on the other hand, are only eligible if located in the District or if connected to a distribution feeder that feeds the District. Therefore, there is a significant quantity of RECs that can be used for RPS compliance in the District, but the supply of SRECs is much tighter.

Methodology and Data Sources

For Tier I RECs, Synapse generated a low, medium, and high forecast for REC prices faced by energy suppliers serving the District. The low forecast is the price of wind RECs in its most recent compliance year, $2.15/REC. Whereas other (non-solar) renewable generation technologies eligible for Tier I RPS compliance in the District do not have prospects for significant growth, wind generation does. Therefore, wind RECs are expected to represent a significant share of incremental RECs used for RPS compliance in the District. Because $2.15/REC represents a near-floor price for RECs nationwide, Synapse preserved that value for its low Tier I REC price forecast, resulting in a downward drifting price floor expressed in real dollars. The price paid for wind RECs within PJM is much closer to $13.00/REC, and that is the price of compliance RECs in the other PJM states discussed above. Because this price forecast is based on current RPS laws within the District, it was also used as the baseline forecast.

The District's Tier I REC eligibility represents a wider geographic area than typical for an RPS policy. To the extent that the District either tightens its eligible REC policy to align it with many other RPS states, or to the extent that District energy suppliers must begin procuring wind RECs within PJM because its out-of-PJM supply is exhausted, the marginal REC price will become the price of wind RECs within PJM: $13.00/REC. Synapse's high Tier I REC price forecast assumes a marginal price that increases from $2.15/REC in 2015$ to $13.00/REC linearly over the 2018 to 2022 timeframe.

For SRECs, Synapse also developed three forecasts, each containing three sections. The first portion of each forecast pegs the price of an SREC at 96.7 percent of the ACP. Because the District currently lacks adequate solar PV production to comply with the solar carve-out, the market price of SRECs is very near ACP. This will continue until the quantity of solar PV generated SRECs is adequate to meet the RPS solar carve-out. Once that parity is achieved, the SREC price will fall considerably to the value for which the subsidy is merely adequate to stimulate enough solar PV installations annually to maintain pace with the increasing solar carve-out requirements. This is calculated to be $280/MWh. In the later years, the ACP is reduced considerably, eventually falling below the subsidy requirement. At that point, the SREC price will shift again, this time back to 96.7 percent of the now much lower ACP. To forecast the year in which solar PV in the district becomes adequate to comply with the full solar carve-out, Synapse accounted for solar from two distinct groups: the community solar created in conjunction with the Community Renewable Energy Act of 2013, and the expected annual solar installation rate associated with the payback period the forecasted SREC price would support. Synapse's baseline SREC price forecast includes adequate solar PV generation complying with the carve-out in 2021. A more accelerated solar PV installation rate would achieve adequate generation in 2020; a less accelerated rate would achieve adequate generation in 2022.

Every megawatt-hour of distributed solar generation avoids the REC price times the RPS Tier I fraction of sales requirement in that year, as shown in the equation below.

$$\textit{Avoided REC Cost} = \textit{REC Price} * \textit{RPS Tier I Fraction of Sales Requirement}$$

Thus if the REC price is $13.00/MWh and the RPS Tier I Fraction of Sales requirement is 50 percent, the avoided REC cost is $6.50/MWh. Note that the solar carve-out requirement represents a portion of the Tier I obligation. Therefore, the net Tier I REC obligation under the RPS is the Tier I obligation minus the solar carve-out obligation. The avoided SREC Cost can be calculated similarly, using the SREC price and the solar carve-out requirement.

Results

Avoided Tier I compliance costs are shown in Table 28 below.

Table 28. Avoided Tier I REC compliance costs

Year	Net Tier I RPS Requirement %	Low Tier I REC Price Estimate *2015$/MWh*	Mid Tier I REC Price Estimate *2015$/MWh*	High Tier I REC Price Estimate *2015$/MWh*	Low Avoided Tier I RPS Compliance *2015$/MWh*	Mid Avoided Tier I RPS Compliance *2015$/MWh*	High Avoided Tier I RPS Compliance *2015$/MWh*
2017	12.52%	$2.07	$2.07	$2.07	$0.26	$0.26	$0.26
2018	14.35%	$2.03	$2.03	$4.39	$0.29	$0.29	$0.63
2019	16.15%	$1.99	$1.99	$6.74	$0.32	$0.32	$1.09
2020	18.42%	$1.95	$1.95	$9.11	$0.36	$0.36	$1.68
2021	18.15%	$1.90	$1.90	$11.50	$0.35	$0.35	$2.09
2022	17.83%	$1.86	$1.86	$11.24	$0.33	$0.33	$2.00
2023	17.50%	$1.82	$1.82	$11.03	$0.32	$0.32	$1.93
2024	20.40%	$1.79	$1.79	$10.82	$0.37	$0.37	$2.21
2025	23.15%	$1.76	$1.76	$10.62	$0.41	$0.41	$2.46
2026	25.85%	$1.72	$1.72	$10.42	$0.45	$0.45	$2.69
2027	28.55%	$1.69	$1.69	$10.21	$0.48	$0.48	$2.92
2028	31.25%	$1.66	$1.66	$10.01	$0.52	$0.52	$3.13
2029	33.90%	$1.62	$1.62	$9.81	$0.55	$0.55	$3.33
2030	37.50%	$1.59	$1.59	$9.61	$0.60	$0.60	$3.60
2031	41.25%	$1.56	$1.56	$9.40	$0.64	$0.64	$3.88
2032	45.00%	$1.52	$1.52	$9.20	$0.68	$0.68	$4.14
2033	45.00%	$1.49	$1.49	$9.00	$0.67	$0.67	$4.05
2034	45.00%	$1.46	$1.46	$8.80	$0.66	$0.66	$3.96
2035	45.00%	$1.42	$1.42	$8.61	$0.64	$0.64	$3.87
2036	45.00%	$1.39	$1.39	$8.42	$0.63	$0.63	$3.79
2037	45.00%	$1.36	$1.36	$8.24	$0.61	$0.61	$3.71
2038	45.00%	$1.33	$1.33	$8.06	$0.60	$0.60	$3.63
2039	45.00%	$1.30	$1.30	$7.89	$0.59	$0.59	$3.55
2040	45.00%	$1.28	$1.28	$7.73	$0.57	$0.57	$3.48

Avoided solar carve-out compliance costs are shown in Table 29 below.

Table 29. Avoided solar carve-out compliance costs

Year	RPS Solar Carveout Requirement %	Low SREC Price Estimate 2015$/MWh	Mid SREC Price Estimate 2015$/MWh	High SREC Price Estimate 2015$/MWh	Low Avoided Solar Carveout RPS Compliance 2015$/MWh	Mid Avoided Solar Carveout RPS Compliance 2015$/MWh	High Avoided Solar Carveout RPS Compliance 2015$/MWh
2017	0.98%	$464.93	$464.93	$464.93	$4.56	$4.56	$4.56
2018	1.15%	$455.95	$455.95	$455.95	$5.24	$5.24	$5.24
2019	1.35%	$447.03	$447.03	$447.03	$6.03	$6.03	$6.03
2020	1.58%	$280.00	$437.65	$437.65	$4.42	$6.91	$6.91
2021	1.85%	$280.00	$280.00	$427.52	$5.18	$5.18	$7.91
2022	2.18%	$280.00	$280.00	$280.00	$6.09	$6.09	$6.09
2023	2.50%	$280.00	$280.00	$280.00	$7.00	$7.00	$7.00
2024	2.60%	$280.00	$280.00	$280.00	$7.28	$7.28	$7.28
2025	2.85%	$280.00	$280.00	$280.00	$7.98	$7.98	$7.98
2026	3.15%	$280.00	$280.00	$280.00	$8.82	$8.82	$8.82
2027	3.45%	$280.00	$280.00	$280.00	$9.66	$9.66	$9.66
2028	3.75%	$280.00	$280.00	$280.00	$10.50	$10.50	$10.50
2029	4.10%	$218.93	$218.93	$218.93	$8.98	$8.98	$8.98
2030	4.50%	$214.42	$214.42	$214.42	$9.65	$9.65	$9.65
2031	4.75%	$209.83	$209.83	$209.83	$9.97	$9.97	$9.97
2032	5.00%	$205.28	$205.28	$205.28	$10.26	$10.26	$10.26
2033	5.00%	$33.47	$33.47	$33.47	$1.67	$1.67	$1.67
2034	5.00%	$32.74	$32.74	$32.74	$1.64	$1.64	$1.64
2035	5.00%	$32.01	$32.01	$32.01	$1.60	$1.60	$1.60
2036	5.00%	$31.32	$31.32	$31.32	$1.57	$1.57	$1.57
2037	5.00%	$30.64	$30.64	$30.64	$1.53	$1.53	$1.53
2038	5.00%	$29.98	$29.98	$29.98	$1.50	$1.50	$1.50
2039	5.00%	$29.35	$29.35	$29.35	$1.47	$1.47	$1.47
2040	5.00%	$28.73	$28.73	$28.73	$1.44	$1.44	$1.44

Avoided Clean Power Plan Compliance Costs

Definition and Concept

The Clean Power Plan is an EPA policy that limits carbon dioxide emissions from fossil fuel-powered electric generating units. The EPA has established both mass-based and rate-based limits for 47 states. Alaska and Hawaii are currently exempt due to a lack of adequate data necessary for EPA to establish limits. Vermont and Washington, DC are exempt because neither have any fossil fueled electric generators covered by the CPP regulations. Because the state compliance plans for the 47 states have not been submitted at the time of publication, CPP compliance costs are limited to a range of values that are perhaps less precise than other forecasts.

Although the District is not compelled by the CPP, the 13 member states of PJM are. Furthermore, because distributed solar generation in the District results in less fossil fueled generation elsewhere in PJM, distributed solar within Washington, DC does result in lower energy prices within PJM. Therefore, distributed solar in the District does, in fact, provide a Clean Power Plan compliance benefit.

Methodology and Data Sources

If and when Clean Power Plan compliance begins, compliance costs will be embedded in locational marginal prices, much like criteria pollution compliance costs are today. Synapse used $0/MWh as the utility benefit of distributed solar with respect to the CPP, for the following reasons:

1. A September 2016 PJM report finds that levelized compliance costs are only $0.61/MWh for regional compliance,[391] and
2. The savings that distributed solar within Pepco DC generate will be socialized across all PJM members; Pepco DC represents less than one half of one percent of energy sales within PJM.[392,393]

Because of these two factors, the CPP benefit would be on the order of $0.003/MWh, representing less than one hundredth of one percent of the total value of solar. The Avoided CPP Compliance Cost benefits should be revisited once neighboring states have submitted CPP compliance plans.

Results

$0/MWh.

---

[391] PJM Interconnection, "EPA's Final Clean Power Plan Compliance Pathways Economic and Reliability Analysis," September 1, 2016. Page 2. Available at: http://www.pjm.com/~/media/documents/reports/20160901-cpp-compliance-assessment.ashx.

[392] EIA, "2015 Utility Bundled Retail Sales – Total", February 19, 2016. Available at: https://www.eia.gov/electricity/sales_revenue_price/pdf/table10.pdf.

[393] PJM Interconnection, "PJM 2015 Annual Report," May 2016. Available at: http://www.pjm.com/~/media/about-pjm/newsroom/annual-reports/2015-annual-report.ashx.

Avoided Carbon and Criteria Pollutants

Definition and Concept

Electric generation units are subject to a variety of federal and state regulations related to criteria pollutants. Compliance with these regulations typically involves the purchase and retirement of criteria pollutant or carbon emissions allowances. Therefore, solar generation—which does not emit any criteria pollutants or carbon and therefore has no additional compliance cost—can help avoid compliance costs associated with criteria pollutants or carbon allowances.

Electric generation units within PJM are subject to the Mercury and Air Toxics Standards Rule and the Cross-State Air Pollution Rule, as well as rules like New Jersey's high electric demand day rule.[394] Some generators within PJM emit criteria pollutants regulated by these rules, and compliance with the regulations adds cost. Because PV does not emit any criteria pollutants, every MWh of energy produced by a distributed solar generator within the District can avoid the criteria pollutant costs associated with a generator elsewhere in PJM.

Similarly, the Regional Greenhouse Gas Initiative, a regional carbon trading scheme, includes Maryland and Delaware, both PJM states. Every ton of carbon emissions from generators in those states comes with an additional cost ultimately passed on to energy purchasers. In hours when distributed solar results in less generation from fossil-fired generators located in Delaware or New Jersey, RGGI compliance costs are avoided.

Methodology and Data Sources

The criteria air pollutant costs and RGGI compliance costs are included in PJM wholesale energy prices. If desired by stakeholders, Synapse could estimate what portion of avoided energy prices represent criteria air pollutants and RGGI compliance. The estimate would have no impact on the total value of solar calculation, because any cost credited to the Carbon and Criteria Pollutants category would be netted from the Energy category.

Results

The very small Carbon and Criteria Pollutants costs realized by the utility system is embedded in the Energy results. The societal benefit of reduced carbon emissions is found later in this report.

Energy Demand Reduction Induced Price Effect (DRIPE)

Definition and Concept

The Demand Reduction Induced Price Effect is the price suppression that occurs in a competitive wholesale energy market when reduced demand results in a lower clearing price of energy, indirectly reducing the energy bills of all consumers of energy in that hour. While the price reductions across all

[394] Monitoring Analytics, LLC. "2016 Quarterly State of the Market Report for PJM: January through June." Page 281. Available at: http://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2016/2016q2-som-pjm-sec8.pdf.

hours in a year are quite small when expressed in $/MWh, the total savings across all megawatt-hours of energy over the course of a year, expressed in dollars, are often substantial.[395] The benefits of energy DRIPE are not permanent—they dissipate over a few years as the marketplace re-equilibrates to the lower level of demand.

Because energy suppliers in the District procure energy from the PJM wholesale market, energy DRIPE will occur when the energy demanded is reduced due to distributed solar in the Pepco territory. A 10 cent reduction in price in a given hour of moderate demand (100,000 MW PJM-wide) results in a total savings of $10,000 *in that hour*. However, those savings are spread across all PJM energy consumers; the District's approximately 0.5 percent share amounts to only $5 of benefit. The remaining $9,995 of savings are enjoyed by ratepayers within PJM but outside of the Pepco DC territory; those savings in this example could represent societal savings but do not represent a benefit to the utility system in Washington, DC.

<u>Methodology and Data Sources</u>

A 2014 study of PJM's energy DRIPE determined a DRIPE energy ratio of 1.17, implying that every 1 percent reduction of energy consumption results in a 1.17 percent reduction in price.[396] Although the DRIPE energy ratio does not apply to significant changes in consumption, the District is small enough relative to PJM that the resulting PJM-wide energy reduction will be modest. Because DRIPE is shared throughout the RTO, customers in the District will only receive roughly 1.57 percent of the benefits. The remaining 98.43 percent of the energy DRIPE benefits flow to other PJM ratepayers and represent a societal benefit. Because there is significant generator build and generator retirement within PJM, Synapse assumed that DRIPE energy benefits dissipate quickly, in a linear manner over a five-year timeframe. Because energy DRIPE results are a function of the price of energy on the system, the energy price sensitivities generate energy DRIPE sensitivities.

<u>Results</u>

Table 30 contains the energy DRIPE results.

[395] Paul Chernick and John J. Plunkett, "Price Effects as a Benefit of Energy-Efficiency Programs," 2014. Page 1. Available at: http://aceee.org/files/proceedings/2014/data/papers/5-1047.pdf.

[396] Max Neubauer et. al., "Ohio's Energy Effiuciency Standard: Impacts on the Ohio Wholesale Electricity Market and Benefits to the State." Report number E138. April, 2013. Pages 27 and 28. Available at: http://www.ohiomfg.com/legacy/communities/energy/OMA-ACEEE_Study_Ohio_Energy_Efficiency_Standard.pdf.

Table 30. Energy DRIPE

	Low		Mid		High	
Year	Pepco DC Energy DRIPE	Remaineder of PJM Energy DRIPE	Pepco DC Energy DRIPE	Remaineder of PJM Energy DRIPE	Pepco DC Energy DRIPE	Remaineder of PJM Energy DRIPE
	2015$/MWh	*2015$/MWh*	*2015$/MWh*	*2015$/MWh*	*2015$/MWh*	*2015$/MWh*
2017	$0.57	$35.75	$0.67	$42.07	$0.78	$48.55
2018	$0.47	$29.62	$0.55	$34.09	$0.66	$41.37
2019	$0.34	$21.23	$0.45	$28.07	$0.58	$36.15
2020	$0.23	$14.53	$0.33	$20.51	$0.47	$29.32
2021	$0.12	$7.32	$0.17	$10.50	$0.25	$15.92
2022	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
2023	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
2024	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
2025	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
2026	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
2027	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
2028	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
2029	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
2030	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
2031	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
2032	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
2033	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
2034	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
2035	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
2036	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
2037	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
2038	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
2039	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
2040	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00

Generation Capacity Demand Reduction Induced Price Effect (DRIPE)

Definition and Concept

Similar to energy DRIPE, generation capacity DRIPE exists because distributed solar output results in a utility requiring less capacity at its peak, provided that distributed solar is providing any power during the hour of utility peak load. The reduction in generation capacity required by the utility results in a reduction in generation capacity demanded across the wholesale market, and therefore, DRIPE. As with energy DRIPE, the benefits of capacity DRIPE are also not permanent, dissipating over time as the marketplace for capacity adjusts to the demand reduction.

As Pepco DC participates in the PJM RPM capacity auction, distributed solar on the Pepco DC distribution system will result in capacity DRIPE in PJM, provided the distributed solar is expected to be generating power in the hour that sets Pepco DC's capacity obligation.

Methodology and Data Sources

Capacity DRIPE was calculated in an avoided costs study performed for Maryland in 2014, including for Pepco.[397] Synapse employed the capacity DRIPE capacity price differentials from that study, adjusted for inflation, the Pepco DC fraction of the Pepco zone (of which Pepco DC represents 40.7 percent), and for Synapse's more accelerated decay of DRIPE. Because PJM's RPM capacity auctions occur in future years, the five years of DRIPE for this study year were applied in the years 2021 through 2026.

Results

The capacity DRIPE results are found in Table 31.

Table 31. Capacity DRIPE

Year	Pepco DC Capacity DRIPE	Remainder of Pepco Capacity DRIPE
	2015$/MWh	*2015$/MWh*
2017	$0.00	$0.00
2018	$0.00	$0.00
2019	$0.00	$0.00
2020	$0.00	$0.00
2021	$40.68	$59.26
2022	$35.40	$51.56
2023	$28.70	$41.81
2024	$19.16	$27.91
2025	$10.33	$15.05
2026	$0.00	$0.00
2027	$0.00	$0.00
2028	$0.00	$0.00
2029	$0.00	$0.00
2030	$0.00	$0.00
2031	$0.00	$0.00
2032	$0.00	$0.00
2033	$0.00	$0.00
2034	$0.00	$0.00
2035	$0.00	$0.00
2036	$0.00	$0.00
2037	$0.00	$0.00
2038	$0.00	$0.00
2039	$0.00	$0.00
2040	$0.00	$0.00

[397] Exeter Associates, "Avoided Energy Costs in Maryland," April 2014. http://webapp.psc.state.md.us/Intranet/casenum/NewIndex3_VOpenFile.cfm?filepath=C:%5CCasenum%5C9100-9199%5C9154%5CItem_525%5C%5CAvoidedEnergyCostsinMaryland.pdf.

Renewable Energy Certificate Supply Induced Price Effect

Definition and Concept

Like DRIPE, the Supply Induced Price Effect exists when additional supply added to the marketplace results in a price reduction effect. A REC has only two uses: regulatory compliance and voluntary compliance. The voluntary compliance market is national – wind and solar RECs are widely considered equal regardless of geographic provenance because carbon emissions are a global pollutant. The voluntary market price is approximately $1–$3/REC, because there is a tremendous supply of Tier I RECs that cannot be used for compliance anywhere due to the geographic provenance of many Tier I RECs being incompatible with the regional requirement of each state's RPS policy.[398] The lower bound for compliance RECs is therefore the voluntary market price. The price ceiling for compliance RECs is that jurisdiction's alternative compliance payment.

Whereas the slope of the supply curve in energy and generation capacity markets is moderate—additional units of supply cost slightly more than previous units—the slope of the curve between the low and high price of RECs is dramatic. Because a utility with surplus compliance RECs can only sell them to other utilities with compliance needs or on the voluntary market, and because a utility's market demand for RECs is defined legislatively, a market with more RECs supplied than needed for compliance has a REC price equal to the voluntary market. On the other hand, because a utility must make an ACP for every REC it fails to acquire for compliance, the price of RECs in a shortage market is on the order of a dollar less than ACP. While it is possible for a market to find an equilibrium of a REC price equal to the subsidy necessary for the wind or solar developers to bring their product to market, in practice REC prices across the country tend to be near $1/REC or near ACP, depending on the RPS requirements of the region.

The Tier I RECs that Pepco DC can obtain are very inexpensive because many can only otherwise be used on the voluntary market. For this reason, Tier I REC DRIPE does not have appreciable potential for Pepco DC. Solar RECs, on the other hand, have tremendous potential.

The solar carve-out in the District requires SRECs minted in the District, resulting in a tight geographic market. Furthermore, the ACP is quite high—$500 through 2023, $400 through 2028, $300 through 2032, finally declining to $50 in 2033 and thereafter. The SREC requirement grows steadily to 5.0 percent in 2032.[399] In recent years, District energy suppliers have not been able to obtain enough SRECs to meet their regulatory obligation, and therefore the SREC prices has been very near ACP.

If enough distributed solar were to come online to create a surplus of SRECs, the market price for all District compliance SRECs would fall from nearly-ACP to the price necessary to subsidize enough

398 U.S. Department of Energy, "Green Power Markets – Renewable Energy Certificates (RECs)," March 30, 2016. Available at: http://apps3.eere.energy.gov/greenpower/markets/certificates.shtml?page=1.

399 DC ACT 21-466, In the District of Columbia, July 25, 2016. Available at: http://lims.dccouncil.us/Download/35409/B21-0650-SignedAct.pdf.

installations each year for Washington, DC to meet its solar carve-out requirement for that year. If the price were to fall from $495 to $280 in 2023 when the obligation is 2.5 percent, the price reduction would represent a savings equal to $5.375 per MWh of sales—a half-cent reduction of price per kWh. This suggests that there may be additional regulatory changes in the District's RPS, but it also suggests that there is potentially tremendous value of SREC DRIPE in the District in the year it is achieved.

Methodology and Data Sources

Synapse used the same REC and SREC price forecasts and District-wide solar adoption rate forecast described earlier. Forecasted sales are also necessary in order to determine the number of SRECs required by the RPS. Because the sensitivities around solar adoption only result in an acceleration or delay of solar carve-out compliance by one year earlier or later, the SREC SIPE benefit will only occur for one year—the first year when the SREC price falls from nearly ACP to the necessary subsidy value.

Results

The SREC Supply-Induced Price Effect is shown in Table 32 below.

Table 32. SREC supply induced price effect

Year	Low SREC SIPE *2015$/MWh*	Mid SREC SIPE *2015$/MWh*	High SREC SIPE *2015$/MWh*
2017	$0.00	$0.00	$0.00
2018	$0.00	$0.00	$0.00
2019	$0.00	$0.00	$0.00
2020	$0.00	$0.00	$157.65
2021	$0.00	$147.52	$0.00
2022	$138.12	$0.00	$0.00
2023	$0.00	$0.00	$0.00
2024	$0.00	$0.00	$0.00
2025	$0.00	$0.00	$0.00
2026	$0.00	$0.00	$0.00
2027	$0.00	$0.00	$0.00
2028	$0.00	$0.00	$0.00
2029	$0.00	$0.00	$0.00
2030	$0.00	$0.00	$0.00
2031	$0.00	$0.00	$0.00
2032	$0.00	$0.00	$0.00
2033	$0.00	$0.00	$0.00
2034	$0.00	$0.00	$0.00
2035	$0.00	$0.00	$0.00
2036	$0.00	$0.00	$0.00
2037	$0.00	$0.00	$0.00
2038	$0.00	$0.00	$0.00
2039	$0.00	$0.00	$0.00
2040	$0.00	$0.00	$0.00

Hedge Value

Definition and Concept

The price of oil, natural gas, coal, and nuclear fuels all fluctuate over time due to a variety of forces applied on the market including known macroeconomic trends, technological improvements, and political decisions. The variable costs in generating electricity from fossil and nuclear plants are contingent on such fuel prices. Therefore the wholesale market price of electricity is subject to price swings of electric generator fuels, particularly natural gas and, in some regions, coal as well. Although the price of natural gas has been relatively stable recently, gas prices had exceeded $12/mmBtu as recently as mid-2008, but have been between $2/mmBtu and $4/mmBTU since 2009.[400]

Because many renewable generators have no fuel costs, the cost of their generation is not subject to fuel price fluctuations. Therefore, these generators provide a fuel hedge to the utility system; the greater the percentage of MWh generated by fixed-price generators, the narrower the range of potential costs that energy suppliers face for future energy procurement. To the extent that such risk is embedded in energy prices and is passed on to end-use customers, distributed solar can benefit customers in the Pepco utility system.

In addition to energy price risks associated with fuel, there are also risks associated with construction costs. Large engineering projects may exceed their construction budgets, sometimes significantly. Unlike the construction risks associated with customer-sited PV, the merchant generators, energy suppliers, and sometimes the distribution utility bear the cost of the construction risk associated with generation capacity, transmission capacity, and distribution capacity. To the extent that such risk is embedded in the costs that are passed on to end-use customers, distributed solar can reduce such costs.

Like construction costs, internal processes also have risks due to regulatory or legal changes, evolving customer behavior, and more. Therefore, the costs incurred by utilities due to distributed PV were also multiplied by the risk premium.

Finally, because RPS compliance requires the purchasing and retiring of RECs (and SRECs) procured through contracting on the open market, and because the obligations are also subject to changes by regulatory bodies, the risk premium is applied to avoided Tier I RPS compliance, and avoided solar carve-out RPS compliance.

Washington, DC energy suppliers procure energy from the PJM wholesale market. Because both natural gas and coal are on the generation margin many hours a year, the expected fuel price fluctuations of natural gas and coal can have a significant impact on electricity prices for the District's customers.

The hedge value of distributed solar can be divided into two parts—utility system value and societal value. To the extent that distributed solar reduces the costs of energy and capacity paid by customers in

[400] EIA, "Average annual natural gas spot price in 2015 was at lowest level since 1999," Figure 1. Available at: http://www.eia.gov/todayinenergy/detail.php?id=24412.

the District, distributed solar provides a benefit to the utility system. The other value of the hedge is societal, as less volatile energy prices have value to customers.

Methodology and Data Sources

Unfortunately, a lack of data, market transparency, and research has made calculating the benefit of a fuel hedge to a utility or to society extremely difficult. There is broad agreement that there are hedge benefits, but proposed methodologies are not typically based on underlying principles and methodological proposals vary widely.

In line with a variety of other studies and methods, Synapse applied a 10 percent risk premium to cost and benefit categories where market or deployment risk was present, and only in the years for which there was risk.[401] Categories include avoided energy, avoided generation capacity, avoided distribution capacity, avoided transmission capacity, avoided environmental compliance, avoided Tier I RPS compliance, avoided solar carve-out RPS compliance, and DER integration. Because generation capacity is purchased years in advance, the risk premium does not begin until 2020. Because there is little or no risk of the SREC price falling significantly below ACP in the near term, the risk premium is not applied to avoided solar carve-out RPS obligation costs until the year the solar carve-out is expected to be met without ACP, 2020 in the base case. For categories not listed, no risk premium is applied.

Results

A 10 percent risk premium is applied to the avoided energy, avoided generation capacity, avoided distribution capacity, avoided transmission capacity, avoided environmental compliance, avoided Tier I RPS compliance, avoided solar carve-out RPS compliance, and DER integration categories, with generation capacity and solar carve-out RPS obligation costs considered riskless until 2020. Although the results do not differentiate between different residential customers, it is likely that the hedge value of solar is worth more to low-income residents. A higher percentage of their income must go toward their electric bill, thereby making them more sensitive to price volatility.

14.4. Societal Benefits

Outage Frequency, Duration, and Breadth

Definition and Concept

Like all electric utilities, Pepco DC makes remarkable efforts to ensure reliability. However, human error, equipment failures, weather, and even small animals can cause outages of varying frequency, duration, or breadth. There is value in any reduction in outage frequency, duration, or breadth, although the value

[401] Elizabeth A. Stanton et. al., "Net Metering in Mississippi," September 19, 2014. Appendix A, Table 14. Available at: http://www.synapse-energy.com/sites/default/files/Net%20Metering%20in%20Mississippi.pdf.

varies by customer, time of day, his or her ability to predict and prepare for the outage, and duration of the outage.

Distributed solar does not currently impact outages because the system inverters are designed to shut down all power flow from the panels in the event of a system outage. This both prevents inappropriate voltage or current from flowing to electric load within the home and prevents excess generation from flowing onto the distribution system where it could cause harm to an electric linesman working to resolve the outage. However, in the future smart inverters could be installed in distributed solar systems. These inverters could allow for daylight electric use on-site, perhaps allow excess generation to be usable by other customers on the distribution grid, or, if paired with battery storage, allow for electric consumption during nighttime hours.

While the inverter technology issue applies nationally, the avoided cost of a blackout is specific to the region. The value of lost load in the District is a function of the residential, commercial, and institutional building infrastructure in the District.

Methodology and Data Sources

Because smart inverters are not yet widely adopted in the United States, it is difficult to credibly forecast when this equipment will be deployed in the field and how useful it will be in reducing outages for distributed solar customers. Furthermore, Pepco DC only benefits if these deployments result in lower expenditures for the utility, a possibility that is even more difficult to credibly forecast. Because the benefits are not expected to accrue for many years (resulting in low present value due to discounting) and because there is an absence of credible forecasts for when or the extent to which smart inverters will provide benefits, no value was assigned in this category.

Results

$0/MWh.

Social Cost of Carbon

Definition and Concept

The social cost of carbon is an estimate of the damages caused globally due to increased carbon dioxide emissions and climate change. It is intended to reflect the resulting damages to agricultural productivity, human health, property, and ecosystems.

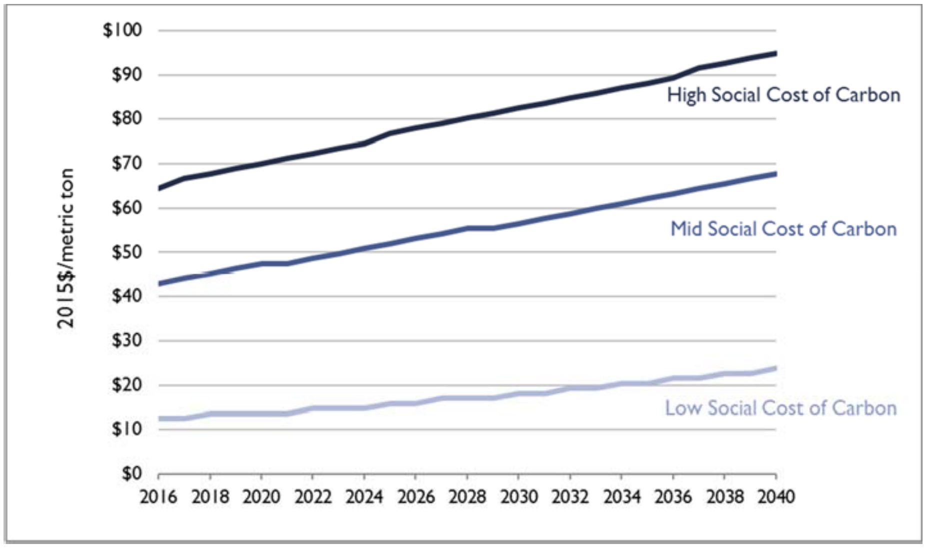
Methodology and Data Sources

The Social Cost of Carbon was originally established by a federal interagency working group in response to a federal court ruling. In 2015, EPA released an update to the social cost of carbon.[402] The costs are expressed in real dollars per metric ton. To generate 2015$/MWh values, Synapse relied upon PJM's

[402] EPA, "EPA Fact Sheet," December 2015. Available at https://www.epa.gov/climatechange/social-cost-carbon.

forecast of gas and coal capacity to determine the fraction of gas- and coal-fired generation on the margin over the period of the study.[403] The emissions rates for coal and gas,[404, 405] weighed by the gas and coal capacity forecast, provide the marginal emissions rate within PJM. Figure 30 contains the social cost of carbon input curves used in this value of solar study.

Figure 30. Social Cost of Carbon input curves



[403] PJM Interconnection, "EPA's Final Clean Power Plan Compliance Pathways Economic and Reliability Analysis," September 1, 2016. Available at: http://www.pjm.com/~/media/library/reports-notices/clean-power-plan/20160901-cpp-compliance-assessment.ashx.

[404] EIA, "Table 8.2. Average Tested Heat Rates by Prime Mover and Energy Source, 2007 – 2015." Available at: http://www.eia.gov/electricity/annual/html/epa_08_02.html.

[405] EIA, "Frequently Asked Questions: How much carbon dioxide is produced when different fuels are burned?" June 14, 2016. Available at: https://www.eia.gov/tools/faqs/faq.cfm?id=73&t=11.

Results

Table 33. Avoided Social Cost of Carbon

Year	Low Avoided Social Carbon *2015$/MWh*	Mid Avoided Social Carbon *2015$/MWh*	High Avoided Social Carbon *2015$/MWh*
2017	$8.33	$29.52	$44.66
2018	$9.05	$30.16	$45.24
2019	$9.01	$30.79	$45.81
2020	$8.98	$31.42	$46.38
2021	$8.94	$31.29	$46.94
2022	$9.65	$31.91	$47.50
2023	$9.61	$32.53	$48.05
2024	$9.57	$33.14	$48.60
2025	$10.27	$33.74	$49.88
2026	$10.23	$34.35	$50.42
2027	$10.92	$34.94	$50.96
2028	$10.88	$35.54	$51.49
2029	$10.84	$35.40	$52.02
2030	$11.52	$35.99	$52.54
2031	$11.47	$36.57	$53.06
2032	$12.15	$37.15	$53.58
2033	$12.10	$37.72	$54.10
2034	$12.76	$38.29	$54.61
2035	$12.72	$38.86	$55.11
2036	$13.38	$39.42	$55.62
2037	$13.33	$39.98	$56.82
2038	$14.03	$40.68	$57.52
2039	$14.03	$41.39	$58.22
2040	$14.73	$42.09	$58.92

Other Societal Benefits

Residents of the District also receive a variety of other benefits that are difficult to quantify but nonetheless should be acknowledged. Society bears the costs of air pollutants such as SO_2, NO_X, and particulate matter in excess of the value of the emissions' tradable allowances. Reduced fuel consumption at power plants likely correlates with fewer fuel spills or other contamination of soil or water. In addition, increased distributed solar in the District may contribute new jobs to the District, resulting in reduced unemployment and need for social services while increasing tax revenue. These benefits were not given a positive financial value for this study, as insufficient data are available to quantify them at this time. Further research in this area is needed.

Results

$0/MWh.

15. Value of Solar Results

15.1. Reference Case

When the annual costs and benefits presented above have their units converted to 2015$/MWh and are then combined, the net result is positive (i.e., a benefit) in each year of the study period. However, this benefits fluctuates considerably, with the highest benefits occurring nearer the beginning of the study period. These results are presented in Table 34 below.

Table 34. Reference case results

Year	Mid Utility System Total *2015$/MWh*	Mid Societal Total *2015$/MWh*
2017	$272.49	$356.04
2018	$80.89	$155.87
2019	$85.89	$154.58
2020	$92.68	$153.28
2021	$292.26	$407.08
2022	$141.30	$236.01
2023	$136.84	$221.40
2024	$129.57	$199.35
2025	$122.39	$178.55
2026	$113.35	$153.44
2027	$116.11	$156.89
2028	$117.86	$159.33
2029	$118.72	$160.03
2030	$120.90	$162.90
2031	$120.44	$163.12
2032	$119.53	$162.88
2033	$110.12	$154.14
2034	$110.27	$154.96
2035	$110.17	$155.53
2036	$110.54	$156.55
2037	$110.48	$157.14
2038	$110.26	$157.74
2039	$110.56	$158.86
2040	$108.95	$158.07

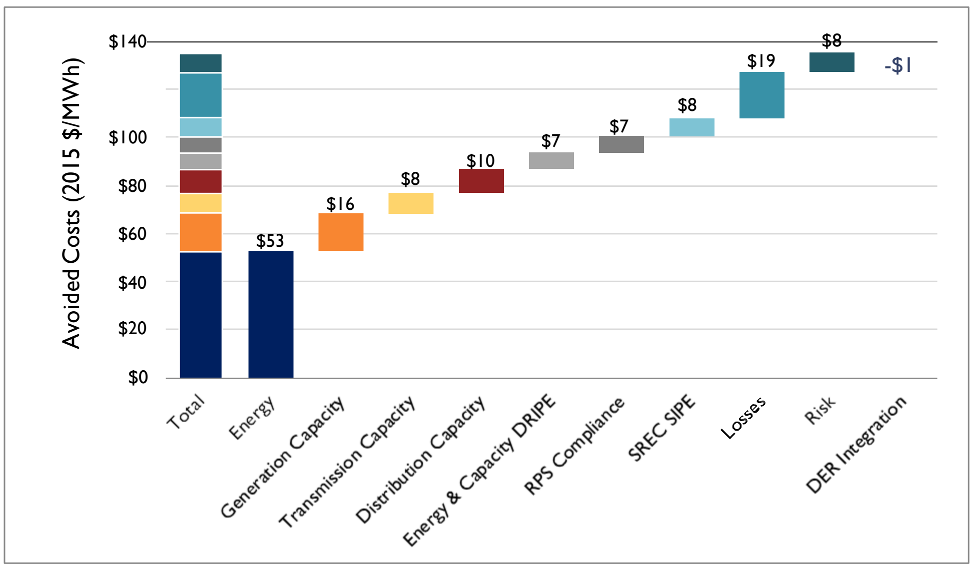
15.2. Reference Case Results—Levelized

The annual values presented above were converted into a levelized value of solar by levelizing the categories' 2015$/MWh values over the study period using a discount rate. The discount rate reflects a "time preference," a way to weigh short-term benefits and long-term benefits in an apples-to-apples comparison. Rather than use Pepco's weighted average cost of capital (WACC), a lower discount rate was used for several reasons. First, many of the avoided costs are not capital costs at all—avoided energy costs (including line losses) and avoided RPS costs, for example. Because these costs (or avoided costs) are passed through without the need for capital investment, the discount rate is necessarily less than the Pepco's WACC.

Second, many jurisdiction-specific policy goals imply a greater emphasis on future benefits. Indeed, all public policy efforts undertaken by the District to reduce or mitigate climate change impacts are policies focused on long-term costs and benefits, consistent with a lower discount rate. Finally, while the utility may be able to generate returns on the order of 9 or 10 percent, few residents have access to such high returns on investment. In deference to the academic literature on social discount rates, Synapse chose to use the same discount rates employed by EPA in its Social Cost of Carbon analysis.[406,407]

The utility system total value of solar for 2017–2040, when levelized with a 3 percent discount rate, results in a value of $132.66/MWh (2015$). The societal total value for 2017–2040, when levelized with a 3 percent discount rate, results in a value of $194.40 (2015$). The utility value of solar and societal value of solar levelized results are presented in Figure 31 and Figure 32, respectively.

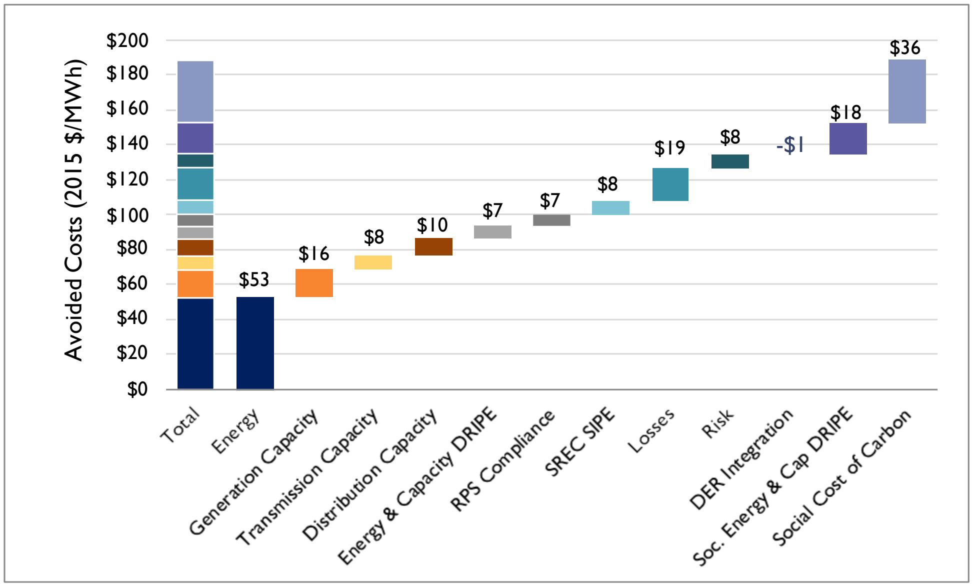
Figure 31. Levelized utility value of solar by component



[406] Maureen Cropper, "How Should Benefits & Costs Be Discounted in an Intergenerational Context?" 2011. Available at http://www.rff.org/files/sharepoint/WorkImages/Download/RFF-Resources-183_Feature-Cropper.pdf.

[407] Interagency Working Group on Social Cost of Greenhouse Gases, United States Government, "Technical Support Document: - Technical Update of the Social Cost of Carbon for Regulatory Impact Analysis – Under Executive Order 12866 –" August 2016. Available at https://www.epa.gov/sites/production/files/2016-12/documents/sc_co2_tsd_august_2016.pdf.

Figure 32. Levelized societal value of solar by component



15.3. Sensitivities

While there many categories with high and low sensitivities, some of them must be moved in unison (e.g. avoided energy and energy DRIPE), whereas others are independent. Some categories may be anti-correlated in the long run, such as avoided energy and avoided generation capacity. Therefore, choosing sensitivities to generate the highest (or lowest) modeled value of solar represents a very unlikely outcome. In addition, Synapse modeled the impact of each of the three discount rates used by the social cost of carbon: 5 percent, 3 percent, and 2.5 percent.

As expected, the value of solar is highly dependent on future gas prices. This is both because the avoided energy including losses and costs associated with risk represents about half of the utility value of solar (over one third of the societal value) in the District, and because the range of potential input values is quite wide. Keeping all other inputs at the "mid" level, using the low gas forecast reduces the value of solar by over $22/MWh. Conversely, the "high" gas price increases the value of solar by nearly $37/MWh.

The societal value of solar is also quite dependent on the social cost of carbon, which represents nearly one fourth of the total societal value. Increasing the discount rate to 5 percent for the social cost of carbon and the levelizing of the revenue stream reduces the social value to $174/MWh, a reduction of nearly $21/MWh. Conversely, reducing the discount rate to 2.5 percent increases the social value by $17/MWh to $211/MWh.

Although avoided generation capacity value represents the third largest component value, its high and low sensitivity value streams do not result in a dramatic change in forecasted PJM capacity auction prices. Therefore, employing the high or the low generation capacity value stream rather than the base case only changes the value of solar by $2.69/MWh.

While the SREC SIPE value is significant in the first year of solar carve-out compliance (and $0 all other years), its contribution to value of solar is a more modest $7.77/MWh because that value is spread across the entire study period. It will, however, represent a significant change in cash flow for that year: the dramatic decline in SREC prices that will occur when Pepco DC achieves solar carve-out compliance will represent a savings in the tens of millions of dollars, perhaps as high as $44 million. Whereas the value of solar calculations only attribute the first year of compliance to solar installed in any one year, the utility system will realize those tens of millions of dollars of savings each year until 2024, when the reduced ACP (and inflation) reduces the benefit to $10 million per year through 2027.

Part IV - Cost-Shifting Analysis

16. Cost-Shifting Overview

The potential for cost-shifting from solar to non-solar customers is one of the most important issues facing utilities and regulators. It should be analyzed as concretely and comprehensively as possible. Cost-shifting is related to the value of solar conducted in Part III, but is a separate analysis that provides an entirely different perspective on customer impacts stemming from distributed solar. It is important to recognize that even where the value of solar is high and distributed solar is shown to be cost-effective, cost-shifting may still occur.

Cost-shifting from distributed solar customers to non-solar customers occurs in the form of rate impacts, which result in higher bills for non-solar customers. Rates increase or decrease to reflect changes in electricity sales levels, changes in costs, or both. A comprehensive, long-term rate impact analysis will account for both of these effects, thereby providing the necessary information to help understand this critical issue.

Note, however, that the cost-shifting analysis performed here accounts only for the impacts to utility revenues and sales caused by distributed solar, not the impact of mandates such as renewable portfolio standards and solar carve-outs. In other words, the cost of meeting the District's solar carve-out through the purchase of SRECs or alternative compliance payments is taken as a given in this analysis and is not assumed to be *caused* by the installation of distributed solar. Rather, the utility or electricity suppliers are assumed to comply with such mandates one way or another, whether or not distributed solar is actually installed. Instead, the cost-shifting analysis presented here examines whether distributed solar is causing cost-shifting through the recovery of "lost revenues," or through imposing additional costs on the distribution system. These concepts are examined more below.

When evaluating cost-shifting, it is important to also analyze both long-term and short-term rate impacts to understand the full picture. Generally, the benefits of distributed solar may not be realized for several years while a decrease in electricity sales occurs immediately. This can result in short-term rate increases, followed by long-term rate decreases. Thus a short-term rate impact analysis will not fully capture the impacts of distributed solar, and should not be performed without also evaluating long-term rate impacts.

16.1. The Causes of Cost-Shifting

In their most simplified form, electricity rates are set by dividing the utility's revenue requirement (in millions of dollars) over its sales (typically measured in kilowatt-hours).

$$Rates = \frac{Revenue\,Requirement}{Sales}$$

Thus rate impacts are primarily caused by two factors:

1. **Changes in costs:** Holding all else constant, if a utility's revenue requirement decreases, rates will decrease. Conversely, if a utility's revenue requirement increases, rates will increase. Distributed solar can avoid many utility costs, which can reduce utility revenue requirements. Distributed solar can also impose costs on the utility system (such as interconnection and distribution system upgrade costs.)

2. **Changes in electricity sales:** If a utility has to recover its revenues over fewer sales, rates will increase. This is commonly referred to as recovering "lost revenues" and is an artifact of the decrease in sales, not any change in actual costs incurred by the utility. Rather, the rate increase is due solely to the *distribution* of costs among solar and non-solar utility customers. This impact is therefore only relevant to a rate impact analysis, which captures distributional impacts, not a cost-benefit analysis or value of solar analysis.[408]

Whether distributed solar increases or decreases rates will depend on the magnitude and direction of each of these factors. If in one year distributed solar decreases the utility's revenue requirement by a larger percentage than sales decrease, rates can decline.[409] In reality, cost reductions may not reduce a utility's revenue requirement substantially in the near-term for two reasons.

First, in the short term, the utility will still have to recover its sunk costs—the investments that the utility made in the past and amortized over many years.[410] These sunk costs will not be reduced by distributed solar, but will continue to be recovered through the utility's revenue requirement until they have been fully depreciated.

Second, distributed solar can help to avoid certain utility investments, and these avoided costs should be accounted for in a cost-benefit analysis. In the long run, if the average net avoided costs to the utility system (in $/kWh) are equal to the credit received by the solar customer, then no cost-shifting over the study period is expected to occur.[411] If the net avoided costs are less than the credit received by the solar customer, rates will increase and cost-shifting will occur. Similarly, if net avoided costs are greater than the credit received, then a reduction in rates may occur.

As noted above, however, the timing of any benefits to the utility system is important to include in a rate impact analysis. Distributed solar will not help to defer or avoid capacity upgrades when no

---

408 Cost-benefit analyses generally ignore distributional impacts, adhering instead to the Kaldor-Hicks efficiency criterion. This criterion focuses on maximizing total net benefits so that, in theory, any losers could be compensated and made no worse off than they were before. Although cost-benefit analyses can be made to incorporate "distributional weights" to account for equity concerns, this is difficult to do and rarely done in practice. A rate and bill impact analysis offers a means of assessing distributional impacts in a manner that is more transparent, comprehensive, and theoretically sound than the traditional application of the RIM Test.

409 Whether or not rates actually decrease is dependent upon whether the utility's revenues are recalculated and new rates are set. However, there may be a lag of several years before a new rate case commences and new rates are set.

410 The utility is also allowed the opportunity to recover a return on its investments.

411 The net avoided costs account for both the benefits and any additional costs imposed on the utility system by distributed solar.

upgrades are planned for the near term. In time, generation, transmission, or distribution capacity upgrades may eventually be needed, and distributed solar can help to defer or avoid these investments, particularly when such investments are driven by additional load growth.[412] However, such benefits will only help to reduce revenue requirements in the years that they would have otherwise occurred.

[412] To the extent that solar generation reduces peak loads on the distribution system, new infrastructure (such as substation upgrades) may be deferred or even entirely avoided. Solar generation may also help to provide thermal performance benefits through reducing peak demand, minimizing system losses, and improving reactive demand compensation.

17. COST-SHIFT ANALYSIS

To analyze whether cost-shifting is occurring for residential customers, we relied upon the following inputs:

- **Net avoided costs of solar that impact customer bills**: We included annual discounted estimates for avoided energy, avoided generation capacity, avoided transmission and distribution capacity, avoided line losses, and avoided environmental compliance costs. Wholesale market price impacts (DRIPE) were excluded, as these are largely experienced by customers outside of the District. Risk benefits and environmental externalities were also excluded, as these do not flow through directly to customer bills.[413] We then added the increased utility costs related to distributed solar (i.e., costs associated with interconnecting solar customers.) The sum of the avoided costs and the increased utility costs gives us the *net avoided costs* from solar.

- **Current residential retail rates:** Standard residential rates were used for this analysis, and were classified according to whether they were bypassable by the solar customer (i.e., whether they could be netted out on a customer's bill) or non-bypassable.

- **Residential customer counts and energy consumption:** The number of standard residential customers presented in Pepco's most recent rate case filing was 187,807, with average residential customer usage of 664 kWh/month.[414] The number of customers was escalated at a rate of 1.13 percent consistent with recent forecasts.[415] Usage levels were held constant for the duration of the study period (25 years).

- **Residential class revenue requirement:** The revenue requirement was estimated by multiplying the average residential customer's usage by the rates in place as of in fall of 2016. (Note that the electricity market supply cost was also included, even though Pepco is a distribution-only utility, in order to be consistent with the inclusion of avoided energy and capacity costs.) The revenue requirement was held constant for the duration of study period.[416]

- **Annual residential distributed solar generation**: The average distributed solar customer's PV system was modeled at a size of 4.93 kW_{DC} [417] generating an average of 438 kWh per month

---

[413] Because energy supply and generation capacity costs are pass-through costs, we assumed that the supply costs embedded in retail rates would move in tandem with wholesale market forces. For this reason, we kept the first-year avoided energy and generation capacity costs constant throughout the study period, since retail rates were also held constant.

[414] PEPCO Exhibit (F)-2, Class Cost of Service Study, Formal Case 1139, June 30, 2016, Pages 52-53.

[415] Compound annual growth estimates for District households were sourced from the Metropolitan Washington Council of Governments' Round 9.0 Cooperative Forecasting Summary Tables, adopted November 9, 2016, available at https://www.mwcog.org/documents/2016/11/16/cooperative-forecasts-employment-population-and-household-forecasts-by-transportation-analysis-zone-cooperative-forecast-demographics-housing-population/

[416] As noted above, avoided wholesale market costs were estimated to remain at 2017 levels for the duration of the study period in order to be consistent with the assumption that retail rates would be held constant.

[417] Based on average residential solar installations in the District to date, per the DC PSC Eligible Renewable Generators List, December 9, 2016.

(offsetting 66 percent of grid consumption).[418] Total annual residential solar generation was estimated by multiplying the typical annual generation by the number of current residential solar customers (approximately 2,300).[419]

Using these inputs, the cost shift was calculated as the reduction in utility revenues due to PV generation that is not offset by the avoided costs to the utility system. The initial utility revenue requirement (including pass-through supply costs) for residential customers can be expressed as:

$$RevReq_{No\,PV} = (CustMos * Customer\,Charge) + (kWh_{No\,PV} * Retail\,Rate_{No\,PV})$$

Where:

$RevReq_{NoPV}$ is the annual revenue requirement without distributed generation.

CustMos is the number of residential customers multiplied by 12 months.

$kWh_{No\,PV}$ is the number of kilowatt-hours consumed by the residential class without distributed solar.

Retail $Rate_{No\,PV}$ is the total residential retail rate assessed on a per kWh basis, including supply costs.

The gross lost revenues to the utility from the addition of distributed solar can be expressed as:

$$Lost\,Revenues = (TotResSolarGen * Bypassable\,Rate_{No\,PV})$$

Where:

Lost Revenues is the *gross* reduction in revenues (including pass-through supply revenues) following the addition of distributed solar generation.

TotResSolarGen is the total quantity of solar generation produced by residential customers annually.

Bypassable $Rate_{No\,PV}$ is the portion of the residential retail rate assessed on a per kWh basis that can be offset through net metering.

[418] DC to AC conversion and hourly generation data based on NREL's PV Watts calculator, http://rredc.nrel.gov/solar/calculators/pvwatts/system.html.

[419] Estimated based on the DC PSC Eligible Renewable Generators List, December 9, 2016.

The impact to the total revenue requirement that must be collected from the residential class due to net metering must also include the net avoided costs to the utility system. This can be expressed as the net lost revenues:

$$Net\,Lost\,Revenues = Lost\,Revenues - (NetAC * \; TotResSolarGen)$$

Where:

NetAC is the net avoided cost to the utility system per kWh of solar generation.

The retail rate must then be adjusted to collect the net lost revenues, but it must do so over a reduced number of kilowatt-hours. The change in the retail rate then becomes:

$$Change\;in\;Retail\;Rate = \frac{Net\;Lost\;Revenues}{kWh_{PV}}$$

Where:

kWh_{PV} is the number of kilowatt-hours consumed by the residential class after the addition of distributed solar.

The change in the retail rate can then be multiplied by the average customer energy consumption to determine monthly and annual bill impacts.

17.1. Results of Cost-Shift Analysis

Base Case

Due to variability in avoided costs from year to year, in some years the cost shift from distributed solar customers to non-solar customers is negative while in other years it is positive. On average, over the study period, our analysis shows a modest cost shift of $0.28 per year ($0.02 per month) for the typical non-solar residential customer. These cost-shifting results indicate that, at current penetration levels and the most recent avoided costs, distributed solar results in modest levels of cost-shifting. However, these results may not hold at higher penetrations of distributed solar.

It is important to underscore that this evaluation does not analyze the impacts of larger policy decisions (i.e., the RPS requirements and solar carve-out), but rather the impact of installing distributed generation under the current policy context.

Sensitivity Analysis Overview

In order to analyze how the cost shifting results might change under different assumptions, Synapse analyzed several sensitivities:

1) Distribution System
    a. Lower benefits to the distribution system from distributed solar
    b. Increasing distribution system costs
2) Rate Design
    a. Removal of the inclining block rate
    b. Implementation of a time-of-use rate for both supply and distribution system costs

Distribution System Sensitivities

For the base case, we assumed that the proportion of distribution costs that can be avoided by distributed solar remains constant over time. However, slower load growth coupled with the need to replace aging infrastructure and protect against cyber security may lead to the nature of distribution system investments changing over time. Under such a scenario, the proportion of costs that are avoidable through distributed solar (typically those related to load growth) may decline, rendering solar less valuable over time and increasing cost shifting.

Synapse modeled two distribution system sensitivities. First, we modeled a case in which the avoided distribution capacity value is set to $0 in all years. Such a scenario would significantly increase cost shifting to an average of $0.78 per year ($0.07 per month) per residential customer.

Second, we modeled the impact from rapidly rising distribution system costs (growing at 4 percent per year) while the avoided costs from solar remained constant. This resulted in an average cost shift of $0.83 per year ($0.07 per month) per residential customer.

Rate Design Alternatives

For residential customers, Pepco currently recovers the costs of delivering energy through the distribution system using a combination of a fixed monthly customer charge and an inclining block rate structure. The inclining block rate structure has a low rate ($0.00759/kWh) for the first 400 kWh, and a much higher rate ($0.0216/kWh for the summer months) for any additional kWh. (Other costs, such as taxes and energy assistance, are recovered through riders that cannot be bypassed through net metering. These costs were not changed in our analysis.)

The inclining block rate structure is generally favorable for distributed solar, as net metering credits are applied to the most expensive block first. Because solar generation is often less than a customer's monthly energy consumption, solar generation is credited at the higher rate more than the lower rate. Removing the inclining block rate structure would reduce the credits to solar generators only slightly, however, since the distribution rates are a small portion of a customer's total bill. Cost shifting would be reduced only slightly to an annual total of $0.20 ($0.02 per month) per residential customer.

Moving to time-of-use rates would be more effective at addressing cost shifting, depending on how it is designed. A time-of-use rate assigns each hour of the day to either a peak, off-peak, or shoulder period. The price per kWh is then set to be highest during the peak hours and lowest during off-peak hours to better reflect the actual underlying costs of providing electricity during those hours. The particular design of the rate can either increase or reduce the economic attractiveness of distributed solar, and can increase or decrease the magnitude of cost-shifting.

For our analysis, we used a simple time-of-use rate that would apply only during the summer, and would include both supply and distribution rates. The peak period was set to 3 pm to 8 pm, with a peak rate of $0.12 per kWh, and an off-peak rate of $0.05 per kWh. The winter rates (November – April) were set to $0.104 per kWh for all hours.

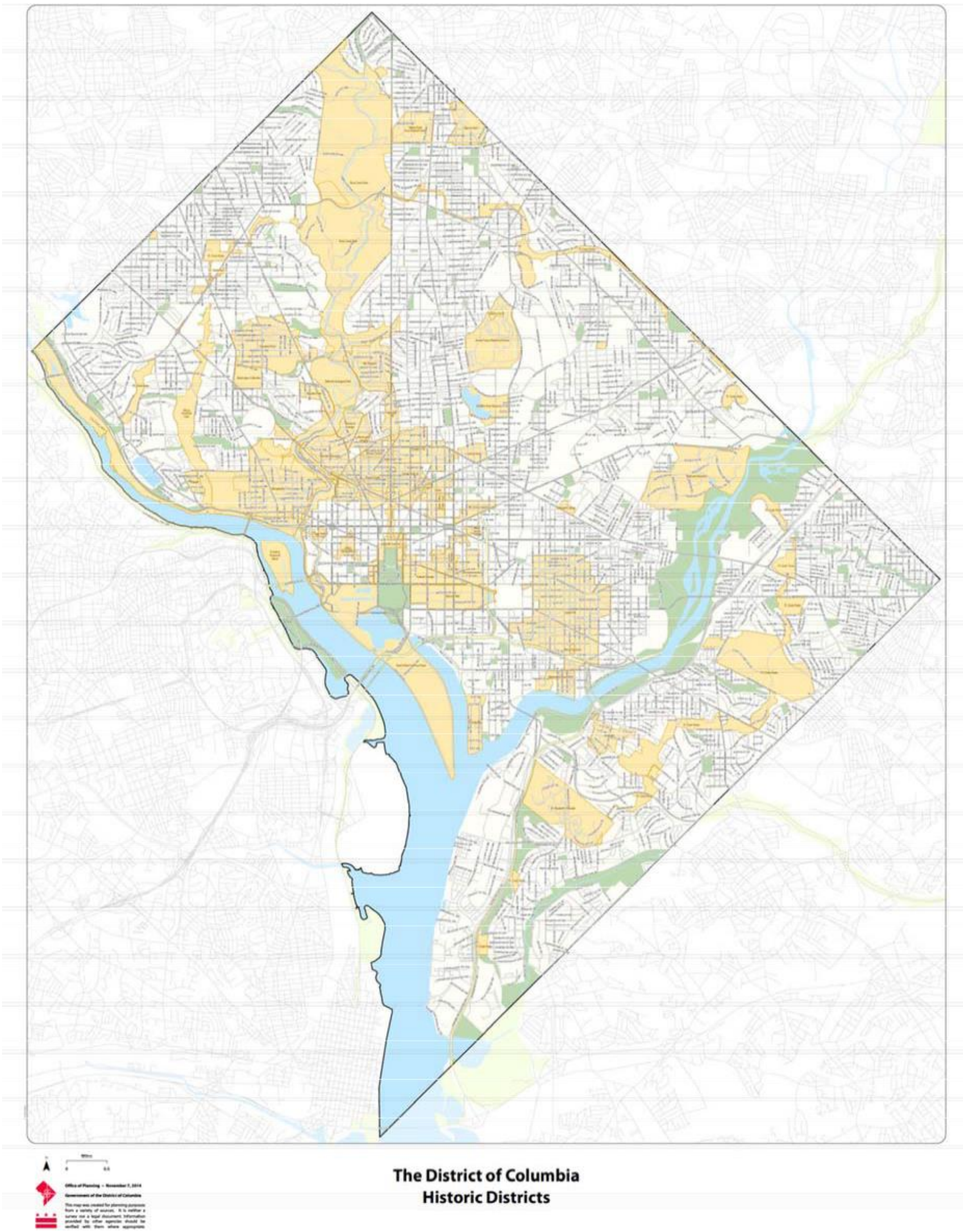
Our analysis shows that a simple time-of-use rate with a late afternoon/evening peak period designed as above would eliminate cost shifting from solar customers to non-solar customers. In fact, the rate design above would reverse cost shifting, resulting in non-solar customers experiencing slight bill reductions of $0.29 per year ($0.02 per month) per residential customer. While this analysis shows that time-of-use rates can be very effective at mitigating cost shifting, they must be designed carefully in order to avoid exacerbating demand during peak hours.

Appendixes

List of Acronyms

50/50	A load forecast for a typical weather year
ACP	Alternative Compliance Payment
AEO	Annual Energy Outlook
CPP	Clean Power Plan
DER	Distributed energy resource
DG	Distributed generation / distributed generator
EIA	Energy Information Administration
EPA	Environmental Protection Agency
kW	Kilowatt
kWh	Kilowatt-hour
LMP	Locational marginal price
MW	Megawatt
MWh	Megawatt-hour
NREL	National Renewable Energy Laboratory
PJM	The RTO that coordinates the movement of wholesale electricity in all or parts of 13 states and the District of Columbia in the Mid-Atlantic and Eastern Great Lakes regions
PURPA	The Public Utilities Regulatory Policies Act of 1978
PV	Solar photovoltaic
QF	Qualified facility
RAP	Regulatory Assistance Project
RPM	Reliability Pricing Model
RPS	Renewable portfolio standard
RTO	Regional transmission operator

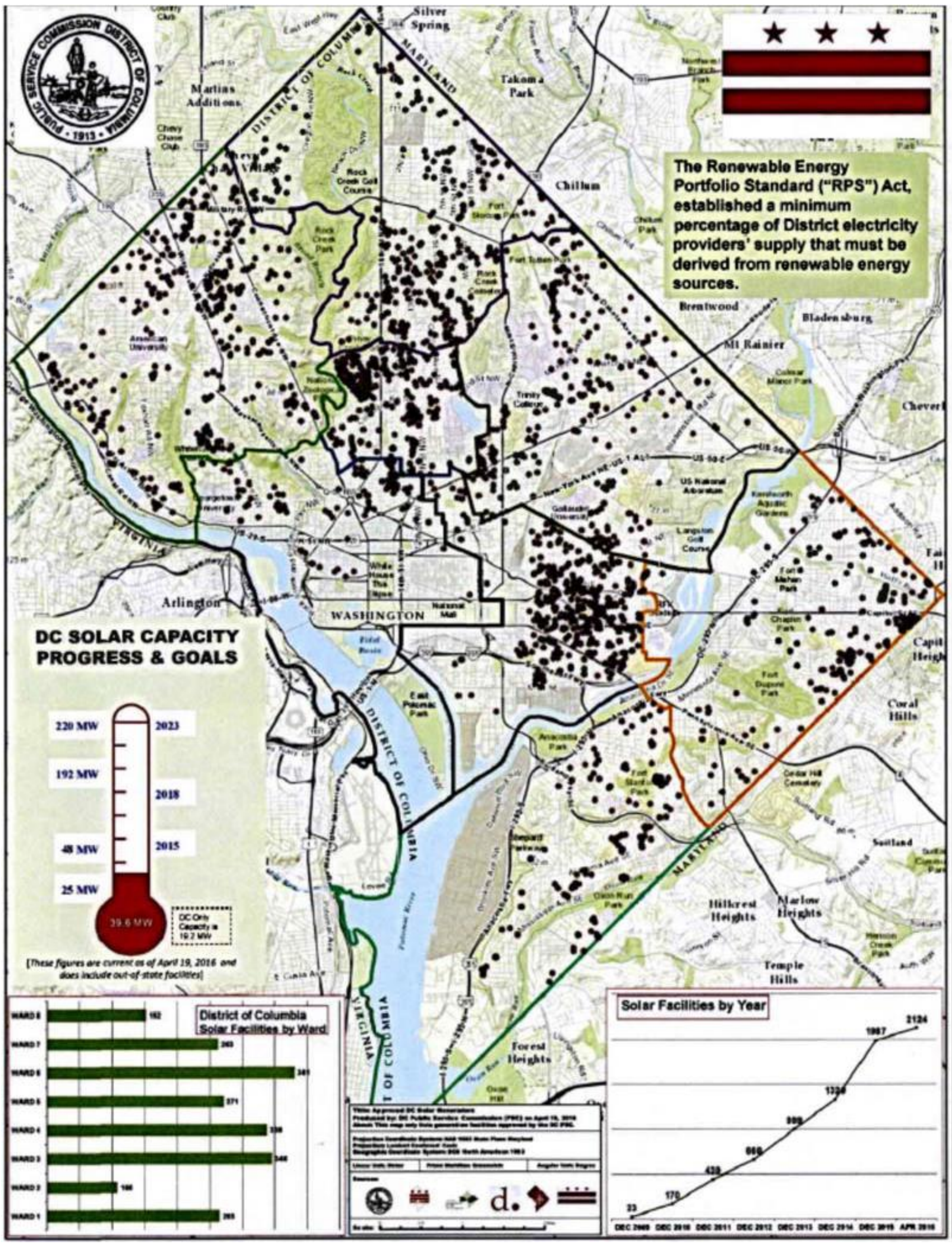
APPENDIX A – MAP OF DC HISTORIC DISTRICTS



Source: DC Office of Planning, DC Historic Map http://planning.dc.gov/publication/dc-historic-district-map.

APPENDIX B – MAP OF CURRENT DC SOLAR INSTALLATIONS

(THROUGH 2015)



Source: DC Public Service Commission, 2015 RPS Compliance Report http://www.dcpsc.org/getmedia/901b3c18-4859-435d-ae1a-ca296584c26b/aharris_542016_831_1_FC_-_945_-_2016_-_E_-_REPORT.aspx.

APPENDIX C – NON-RESIDENTIAL INSTALLATIONS IN 2016

(THROUGH MID-NOVEMBER)

Facility	Approved	Capacity (MW)
Patterson Elementary School Facility	11/8/2016	0.2456
Greater Deliverance Church Facility	11/3/2016	0.0195
New York Ave Presbyterian Facility	11/3/2016	0.0306
Eagle Solutions Facility 2	11/3/2016	0.00204
Eagle Solutions Facility 1	11/3/2016	0.00459
Friendship Public Charter Schools - Collegiate Facility	11/3/2016	0.34155
Big D Corp Facility	11/3/2016	0.00988
Friendship Public Charter Schools - Southeast Elementary Facility	11/3/2016	0.1353
Clearview Family Partners Facility (BP Gas Station 6300) Facility	11/3/2016	0.03689
Menick's Market Facility	11/1/2016	0.00988
Bowen Discount Liquor Facility	11/1/2016	0.00988
Cap City 412 Facility	11/1/2016	0.00468
First Trinity Lutheran Church Facility	10/26/2016	0.03009
Friendship Public Charter Schools - Tech Prep II Facility	10/20/2016	0.1122
Thos. Somerville Co. Facility	10/12/2016	0.09576
Ballou Senior High School Facility	10/12/2016	0.5192
Metermik Othordox-DC0PV-13.73434kw Facility	9/28/2016	0.013734
Foundry United Methodist Church-DC-PV-20.5kw Facility	9/28/2016	0.0205
Off the Beaten Track Warehouse Facility	9/28/2016	0.052
Carlyle Condominiums Facility 2	9/19/2016	0.00546
Carlyle Condominiums Facility 1	9/19/2016	0.00988
Howard University - College Hall South Facility	9/19/2016	0.20768
Anacostia High School Facility	9/19/2016	0.0924
Miner Elementary School Facility	9/19/2016	0.16808
Turner Elementary School Facility	9/19/2016	0.143
Burrville Elementary School Facility	9/19/2016	0.28996
Evangelical Lutheran Church of Our Redeemer Facility	9/19/2016	0.05304
Righteous Church of God Facility	9/19/2016	0.03354
Trinity Landholding Facility 4 (house)	9/15/2016	0.00408
Kramer Middle School Facility	8/24/2016	0.07568
Nalle Elementary School Facility	8/18/2016	0.0968
Evidence Control Branch Facility	8/18/2016	0.1386
C.W. Harris Elementary School Facility	8/18/2016	0.15136
Horning Brothers Facility	8/16/2016	0.20982
Stoddert Elementary School Facility	7/29/2016	0.11352
Savoy Elementary School Facility	7/29/2016	0.12584
Brookland Middle School Facility	7/29/2016	0.07964
Trinity Landholding Corp Facility 3 (house)	7/20/2016	0.009945
Contee AME Zion Church Facility	7/20/2016	0.02193
Trinity Landholding Corp Facility 2 (boiler)	7/20/2016	0.00714
Trinity Landholding Corp Facility (boiler)	7/20/2016	0.00306
Friendship Public Charter Schools - Woodridge Facility	7/19/2016	0.1485

Dominion Church Facility 2	6/21/2016	0.03774
Dominion Church Facility 1	6/21/2016	0.014535
Emes, Fabrizio and Fabrizio Facility	6/21/2016	0.0325
Dean Avenue Cleaners Facility	6/21/2016	0.0306
PEAR Commercial Projects I, LLC-DC-PV-13.5kw (St. Columbs Episcopal	6/21/2016	0.0135
GCP-Nextility 1, LLC-DC-ST-24.81kw (Bader Condominiums) Facility	6/21/2016	0.02481
GCP - Nextility 1, LLC -DC-ST-116.667kw (Essex Condominiums) Facility	6/21/2016	0.116667
GCP-Nextility 1, LLC-DC-ST-8.208kw (Weinberg Commons) Facility-2	6/21/2016	0.008208
GCP-Nextility 1, LLC-DC-ST-8.208kw (Weinberg Commons) Facility	6/21/2016	0.008208
Maret School Facility	6/21/2016	0.06448
GCP-Nextility 1, LLC-DC-ST-8.208kw (Weinberg Commons) Facility-3	6/21/2016	0.008208
East Capitol St Church Facility	6/21/2016	0.02754
Lock 7 Facility 2 (Thomas D Walsh Inc.)	6/21/2016	0.005355
Bryan School Lofts and Condos Facility	6/21/2016	0.02075
KIPP II Facility	6/7/2016	0.28224
1754 Lanier, LLC Facility	6/6/2016	0.05148
Friendship Public Charter Schools - Chamberlain Facility	6/6/2016	0.1518
Friendship Public Charter Schools - Blow Pierce Facility	6/6/2016	0.2112
G&S V Street Facility	6/6/2016	0.10736
1600-1608 28th Place Facility	5/24/2016	0.02728
Latin American Youth Center 3	5/24/2016	0.02805
Jubilee Ontario Apartments Facility	5/24/2016	0.0325
Garden Memorial Presbyterian Church Facility	5/24/2016	0.02958
Hart Senate Office Building	5/24/2016	0.1485
Takoma Village Cohousing Condominium Facility 2	5/24/2016	0.0605
Takoma Village Cohousing Condominium Facility 1	5/24/2016	0.004675
Defense Intelligence Agency Facility	5/18/2016	0.611325
Lock 7 Facility (Thomas D Walsh Inc.)	5/11/2016	0.02346
Latin American Youth Center Facility 2	5/11/2016	0.00408
Latin American Youth Center Facility 1	5/11/2016	0.00612
E&K Real - NIDO Facility	5/5/2016	0.00624
Bright Future Center Facility	5/5/2016	0.0045
Latin American Youth Center Facility	5/5/2016	0.0102
Phyllis Wheatley DP YWCA Facility	4/19/2016	0.030084
Henry S Washington and Sons Funeral Home Facility	4/13/2016	0.0102
GA Ave Garages Facility	1/29/2016	0.007125
Rosedale Development LLC-DC-PV-4.8kw Facility-9	1/29/2016	0.0048
Rosedale Development LLC-DC-PV-4.8kw Facility-8	1/29/2016	0.0048
Rosedale Development LLC-DC-PV-4.8kw Facility-7	1/29/2016	0.0048
Rosedale Development LLC-DC-PV-4.8kw Facility-6	1/29/2016	0.0048
Rosedale Development LLC-DC-PV-4.8kw Facility-5	1/29/2016	0.0048
Rosedale Development LLC-DC-PV-4.8kw Facility-4	1/29/2016	0.0048
Rosedale Development LLC-DC-PV-4.8kw Facility-3	1/29/2016	0.0048
Rosedale Development LLC-DC-PV-4.8kw Facility-2	1/29/2016	0.0048
Rosedale Development LLC-DC-PV-4.8kw Facility 1	1/29/2016	0.0048
St. Stephen and the Incarnation Episcopal Church Facility	1/29/2016	0.03425
City Vista Condominium Facility	1/29/2016	0.02365