EXECUTIVE SUMMARY

co-written by OPC and Synapse

Addressing Barriers to Distributed Solar

Beginning in 2007, Washington DC established renewable portfolio standard (RPS) requirements for electricity suppliers.[1] 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. Solar has grown quickly in recent years, yet current solar capacity falls far short of the District's target of 70 megawatts (MW) for 2016.

The District currently offers numerous incentives to encourage the adoption of distributed solar. These include net metering, community solar, and Solar Renewable Energy Credits (SRECs). Further, the District has undertaken numerous 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. The District has also begun to procure solar for many of its municipal buildings, entering into a power purchase agreement for more than 11 MW.

While 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.

Part I of this report analyzes the barriers that customers in the District of Columbia face, provides case studies of jurisdictions that have implemented policies to overcome such barriers, and provides recommendations for the District of Columbia.

Common Barriers to Distributed Solar in the District of Columbia

The primary barriers to distributed solar that customers in the District face 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,

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

which is significant for distributed generation (DG) development, as renters 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 the past, the time required for Pepco to process and approve interconnection of small solar systems has generally exceeded that of peer utilities. In 2015, the District ranked 33rd out of 34 utilities in terms of time required for interconnecting small-scale solar.[2]

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 uncertainty 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

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[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.

customers. Since instituting full retail rate compensation for community solar, however, applications for such projects have increased rapidly.

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 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.

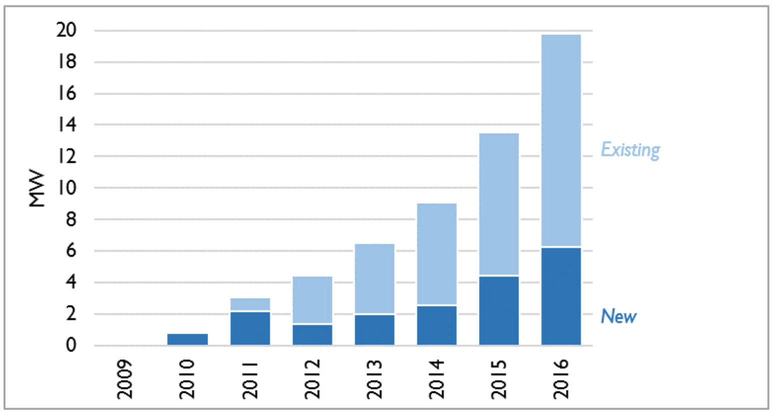
Table ES-2. Recommendations for the District of Columbia

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 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

Technical and Economic Potential Estimates

In order to evaluate the value of distributed generation in the District, this study included an analysis of the distributed technologies available and an assessment of the feasibility of these technologies in Washington DC The overview of available technologies was diverse, 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). This assessment found that a combination of technical feasibility and policy incentives have led to a rapid growth in solar PV capacity in the District in recent years (Figure ES-1) and that these factors indicate the promise for such growth to continue in the near term.

Figure ES-1. Potential distributed solar costs and benefits



The next step of the assessment included an analysis of the technical and economic potential of rooftop solar PV in the District. The technical potential analysis distinguished between small residential and other building types. Both analyses were based on geographical information systems (GIS) data pertaining to the District. Buildings were parsed by zoning districts and the total number of buildings or total roof area calculated per building type. These building stock data were then de-rated using a number of factors and translated into an equivalent capacity of solar PV to arrive at estimates of technical potential.

The technical potential of solar PV on small residential buildings was estimated based on 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.

A similar analysis was conducted for large buildings, including commercial, industrial, government, and multifamily buildings. This analysis was based on roof area instead of the number of buildings as much greater variation in system sizes was found for existing non-residential systems. 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 potential by building type in the District.

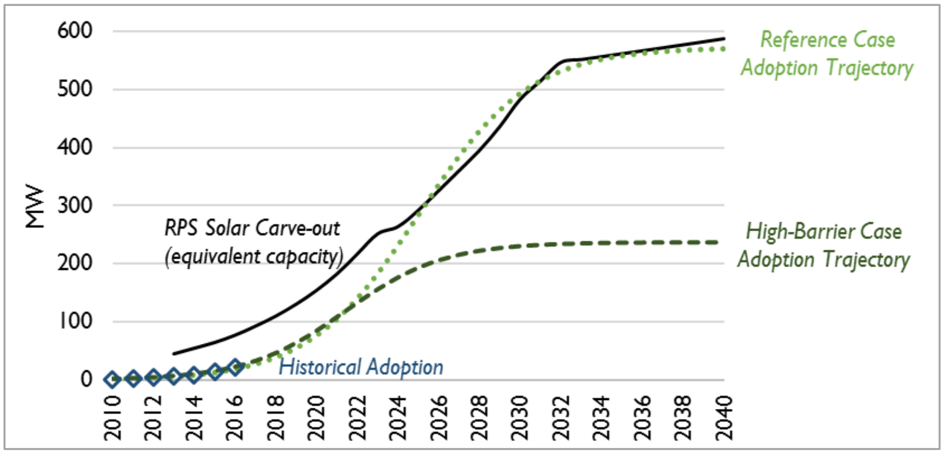
Table ES-3.

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**

The technical potential analysis was followed by an analysis of the potential economic adoption of rooftop PV across all sectors and building types. Economic adoption of rooftop PV by consumers is understood to be primarily driven by payback period. Because of high SREC prices, solar PV sited in the District has a very low payback period of only four to six years. A payback period of five years was assumed for this analysis. Based on correlations between 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 2030's.

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 solar carve-out in the DC RPS policy—at which point, SREC prices would be set at a market-driven value rather than at the Alternative Compliance Payment value of $300–$500/MWh. This analysis shows that the total amount of solar PV in the District is likely to stay below the solar carve-out limit until at least the mid-2020s, after which point economic adoption is expected to largely track the carve-out 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 carve-out value. 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. Potential distributed solar costs and benefits



Value of Solar in the District of Columbia

To estimate the value of solar for the District of Columbia, 18 categories of potential costs and benefits were considered for this study. Sixteen of those were categorized as "utility system" impacts, meaning that these impacts affect 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 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.

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 $194.40 (2015$). 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

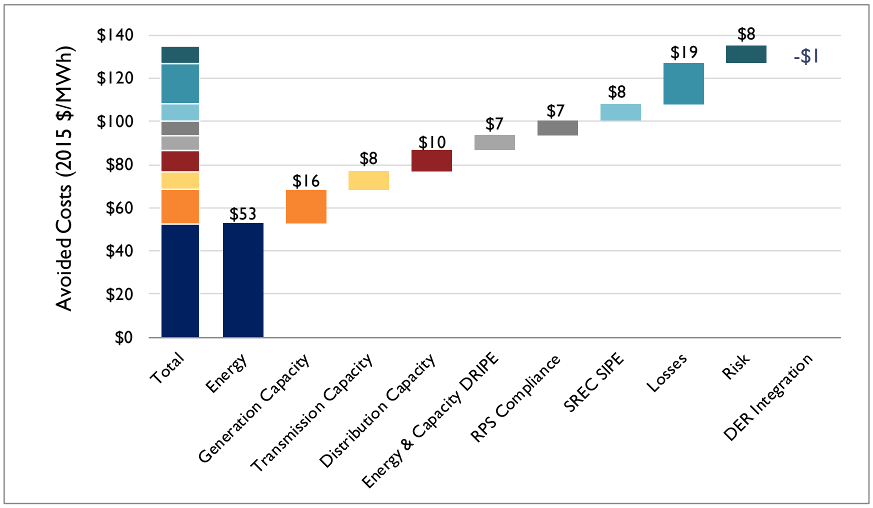
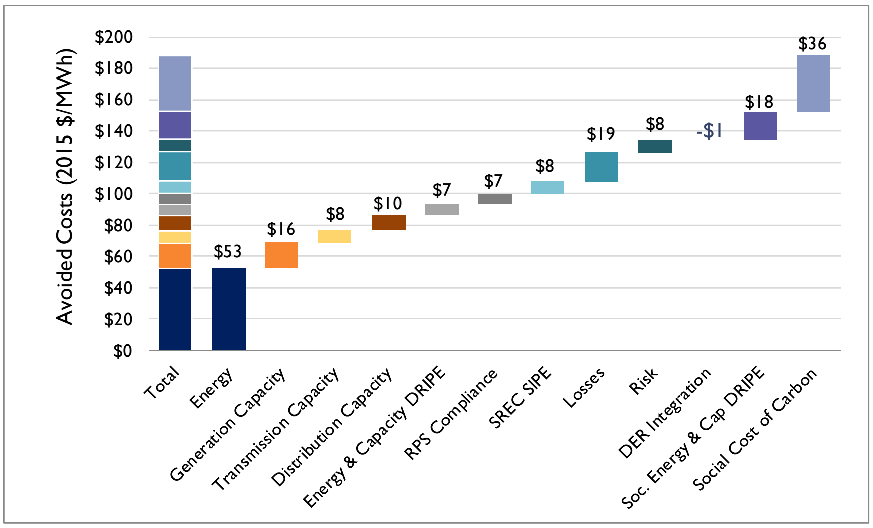


Figure ES-4. Levelized societal value of solar by component



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.

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 solar renewable energy credit supply-induced price effect (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 $44M. Whereas 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 $10M 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.

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 through rate increases that result in higher bills for non-solar customers. In their most simplified form, electricity rates are set by dividing the utility class's revenue requirement by its electricity 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, then 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 costs and distribution system upgrades).

2. Changes in electricity sales: If a utility must 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 costs. Lost revenues should be accounted for in the rate impact analysis, but not in the cost-effectiveness analysis.

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 met 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 impact per residential customer annually. However, higher distribution investments would increase cost shifting to $0.83 per customer, while the inability of distributed solar to reduce distribution system investments would increase cost shifting to $0.78 per customer.

Changes to rate design 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 would 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.