DAYMARK ENERGY ADVISORS

CONFIDENTIAL

BENEFITS AND COSTS OF UTILITY SCALE AND BEHIND THE METER SOLAR RESOURCES IN MARYLAND

APRIL 10, 2018

PREPARED FOR
MARYLAND PSC

PREPARED BY
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AC	alternating current
ACP	Alternative Compliance Payment
AEO 2017	U.S. Energy Information Administration's 2017 Annual Energy Outlook
AMI	Advanced Metering Infrastructure
AURORA	AURORAxmp®
BGE	Baltimore Gas & Electric
BLS	Bureau of Labor Statistics
BRA	Base Residual Auction
BTM	Behind the Meter
CETL	Capacity Emergency Transfer Limit
CETO	Capacity Emergency Transfer Objective
Commission	Maryland Public Service Commission
COBRA	U.S. EPA Co-Benefits Risk Assessment
CONE	Cost of New Entry
CPP	Critical Peak Pricing
CSS	Customer Self-Supply
CVaR	Conditional Value at Risk
Daymark	Daymark Energy Advisors
DC	direct current
DER	Distributed Energy Resource
DG	Distributed Generation
DOS	denial-of-service
DPL	Delmarva Power & Light
DRIPE	Demand Reduction Induced Price Effects
DSO	distribution system operators
EIA	U.S. Energy Information Administration
ESS	ESS Group, Inc.
FPR	PJM's Forecast Pool Requirement
GIS	Geographic Information Systems
GW	gigawatt
GWh	gigawatt hours
IA	Incremental Auctions
IAM	Integrated Assessment Model
IOU	Investor Owned Utility
ITC	Investment Tax Credit
IWG	U.S. government's Interagency Working Group
kW	kilowatt
kWh	kilowatt hours

LBL	Lawrence Berkeley National Laboratory
LDA	Locational Deliverability Area
LIDAR	light detection and ranging
LMP	Locational Market Price
LSE	Load Serving Entity
LTC	load tap changers
MD PSC	Maryland Public Service Commission
MD PTC	Maryland Clean Energy Corporate and Personal Production Tax Credit
MMBTU	One Million British Thermal Units
MW	megawatt
MWh	megawatt hour
NARUC	National Association of Regulatory Commissioners
NEM	Net Energy Metering
NERC	North American Electric Reliability Corporation
NITS	Network Integration Transmission Service
NREL	National Renewable Energy Laboratory
NSPL	Network Service Peak Load
NTA	non-transmission-alternative
ODEC	Old Dominion Energy Cooperative
PC44	Public Conference 44
PE	Potomac Edison
PEPCO	Potomac Electric Power Company
PJM	PJM Interconnection
PLC	Peak Load Contribution
PMM	PJM Interconnection Market Model
POI	point of interconnection
PPCA	Purchased Power Cost Adjustment
REC	Renewable Energy Credit
RFP	Request for Proposal
RGGI	Regional Greenhouse Gas Initiative
RLC	RLC Engineering, Inc.
RPM	Reliability Pricing Model
RPS	Renewable Portfolio Standard
RTEP	PJM's Regional Transmission Expansion Plan
RTO	Regional Transmission Organization
RTP	Real Time Pricing
SCANA	supervisory control and data acquisition
SCC	societal cost of carbon
SLG	single line to ground
T&D	Transmission and Distribution

TCIC	Transmission Cost Information Center
TOI	Transmission Owner Identified
TOU	Time of Use
UCAP	Unforced Capacity
VOS	Value of Solar
VRR	Variable Resource Requirement
VSM	virtual synchronous machines

1. EXECUTIVE SUMMARY

On September 26, 2016, the Public Service Commission of Maryland (the "Commission" or "MD PSC") initiated Public Conference 44 ("PC44"), a targeted review to ensure that Maryland's electric distribution systems are customer-centered, affordable, reliable and environmentally sustainable. One topic identified for exploration as part of PC44 was the benefits and costs of distributed solar energy resources in Maryland. This report, developed under the direction of the Commission personnel and with the support and contribution of information from Maryland's four investor owned utilities ("IOU"), documents an independent analysis of the benefits and costs of solar within each IOU's service territory.

This analysis builds up from the components of potential benefits (or costs) that solar brings when interconnected with the electric system. These components are categorized as direct utility and societal, with some components considered in both categories. This analysis presents the benefits and costs as they accrue to or affect (1) the bulk power system, (2) local power distribution systems, and (3) society and the economy.

With all components taken together, Figure 1 depicts the resulting value of solar within each of the four utility service territories, for both behind the meter ("BTM") installations (see dashed lines) and utility scale installations (see solid lines).

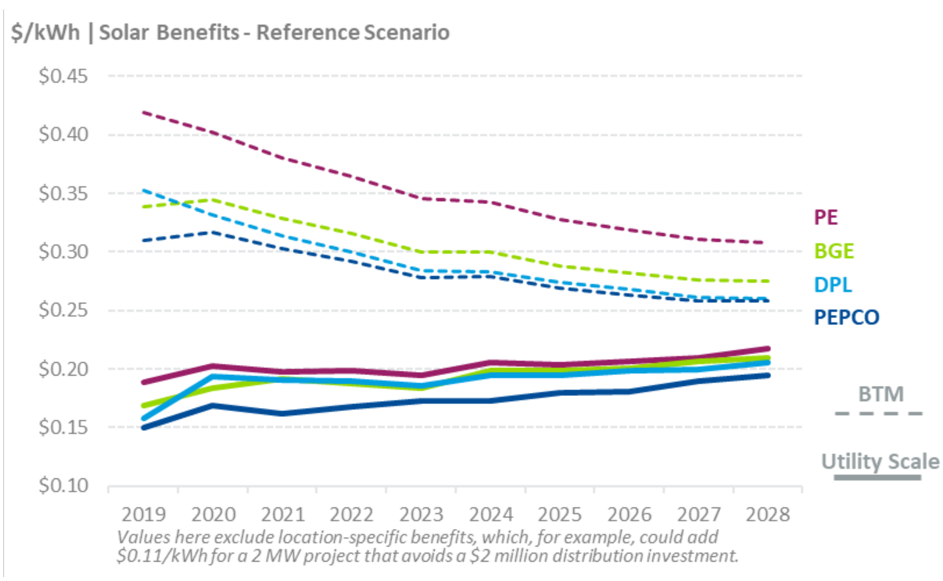

Figure 1: Value of Solar: Utility Scale and BTM by Utility

We developed the value of solar by component for each of the four IOUs. Here we include, as an example, the stacked component value charts for both utility scale BTM and resources in Potomac Edison's service territory. In this service territory (APS zone) for example, the value of utility scale solar (purple solid line in Figure 1) increases from about $0.19 per kilowatt hour in 2019 to about $0.22 per kilowatt hour in 2028. Those same values are represented in Figure 2 by the top of the stacked bars.

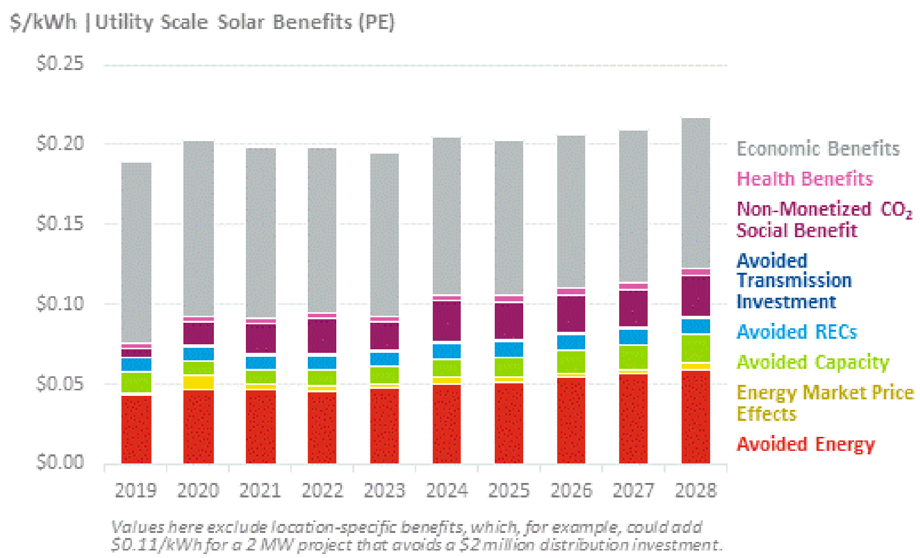

Figure 2: Utility Scale Value of Solar Potomac Edison

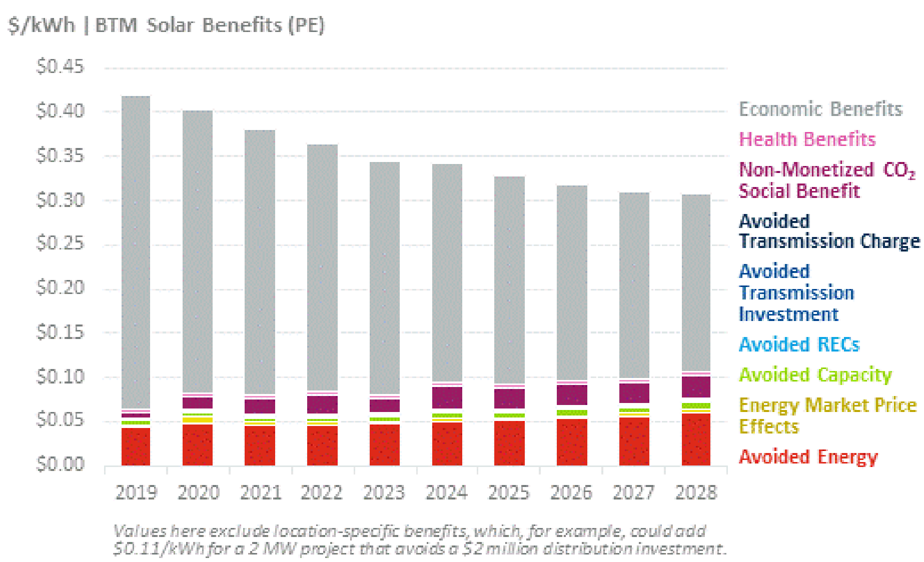

Figure 3: BTM Value of Solar Potomac Edison

Figures 1 through 3 show that the value of solar is significant when considering broader considerations of value. For both BTM and utility scale resources, economic benefits to the state make up a large portion of the benefit, but the benefits to the bulk power system, which include Avoided Energy, Energy Market Price Effects, Avoided Capacity, Avoided RECs, and Avoided Transmission Costs are also significant. Distribution system benefits are not included on Figures 1 through 3 as they are location specific, but these benefits could add significantly to the value of solar if projects are sited appropriately. For example, a 2 MW project that avoids a $2M distribution investment, could add $0.11/kWh in additional locational benefits.

This study also analyzed the potential for future solar development in Maryland. BTM potential was evaluated by looking at available rooftop sites, utility scale potential was evaluated by looking at available land, and both types of potential were analyzed within the context of the amount of hosting capacity the distribution systems could absorb. The results of this analysis are shown below in Table 1. This analysis indicates that Maryland has significant potential for additional solar development.

Table 1: Solar Technical Potential

Utility	BTM-Scale Area Potential (MW)	Utility-Scale Area Potential (MW)[1]	Hosting Capacity (MW)
BGE	16,177	39,413	19,863
DPL	2,310	46,266	2,751
PEPCO	4,433	3,974	7,307
PE	2,823	26,075	2,044
Total	**25,743**	**115,729**	**31,965**

The large potential for additional BTM and utility scale solar development shown in Table 1 and the significant value that solar can bring to the bulk power system, distribution system, and to the residents of Maryland through economic and health benefits represent a considerable opportunity for the state. The state and investor owned utilities should be developing policies and enhancing utility system planning processes to encourage additional cost-effective solar development.

[1] Utility-scale area potential analyzed at the county level. Aggregation to the utility-level provided here simply for reference purposes based on which utilities serve which county; for counties served by multiple utilities, area potential divided evenly among serving utilities.

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2. INTRODUCTION

On September 26, 2016, the Public Service Commission of Maryland (the "Commission" or "MD PSC") initiated Public Conference 44 ("PC44"), a targeted review to ensure that Maryland's electric distribution systems are customer-centered, affordable, reliable and environmentally sustainable. One topic identified to be explored as part of PC44 included the benefits and costs of distributed solar energy resources in Maryland.

This report, developed under the direction of the Commission personnel and with the support and contribution of information from Maryland's four investor owned utilities ("IOU"), documents an independent analysis of the benefits and costs of solar within each IOU's territory, as envisioned by PC44. In addition, this report describes the current level of solar installations, estimates the potential for new solar additions, and introduces a hosting analysis approach that addresses circuit-level capabilities, as well as their potential benefits and costs. Finally, this report's analysis offers insights on land use, solar suitability, health impacts, and economic impacts of solar development within the state of Maryland. We would like to thank the four IOU's for their contribution of data and valuable insight to this effort include Baltimore Gas & Electric ("BGE"), Delmarva Power & Light ("DPL"), Potomac Electric Power Company ("PEPCO"), and Potomac Edison ("PE") as well as the Maryland Energy Administration, Office of Peoples Counsel, MDV-SEIA Branch, Vote Solar and the Pace Energy and Climate Center for sharing their perspectives and input through a series of stakeholder interviews that were conducted over the course of the study.

Prior to the commencement of PC44, the Commission initiated two proceedings to explore topics that could transform the ways in which Marylanders produce and consume electricity. In October 2015, the Commission held a technical conference to investigate the technical and financial barriers to deploying small distributed energy resources in Maryland; the Commission anticipated this would explore rate-related issues affecting distributed energy resources. Nine months later, in July 2016, the Commission held a public conference to explore the regulatory, technical, and financial barriers to deploying electric vehicles in Maryland; the objective of this second conference was to explore strategies, opportunities and barriers to EV deployment, consistent with the legislative directive to increase the efficiency and reliability of the electric system and lower electricity use at times of high demand. This report adds to the Commission's ongoing conversation and investigation regarding efficient, customer centric, affordable, reliable, and environmentally-sustainable electric service.

Daymark Energy Advisors ("Daymark") was selected to lead the development of this independent analysis of the benefits and costs of solar in Maryland based on our response to a Request for Proposal ("RFP") issued by Exelon in April 2017. The Daymark team includes RLC Engineering, Inc.("RLC") and ESS Group, Inc. ("ESS").

1.1 Value of Solar Components

Understanding and valuing solar generation's contribution to the electricity system is a widely discussed topic across the country. This value of solar analysis is built from the components of potential benefits (or costs) that solar brings when interconnected with the system. These components are categorized as direct utility benefits and societal benefits, with some components providing benefits in both categories. In addition, this analysis categorizes the benefits and costs into those accrue to (1) the bulk power system, (2) local power distribution systems, and (3) those that are social and economic.

This assessment looks at all of these elements and how they differ across the following four categories of solar:

- Residential Rooftop
- Small Commercial/Industrial Rooftop
- Large Commercial/Industrial Rooftop
- Utility Scale Solar

The first three categories represent Behind the Meter ("BTM") resources, while utility scale resources are those resources that connect directly to the grid. Table 2 shows the parameters of each category studied.

Table 2: Categories of Solar Projects

CATEGORY	PROJECT SIZE	ROOFTOP?	BTM or GRID TIED
Residential	Small	Yes	BTM
Small Commercial/Industrial	0-500 kW	Yes	BTM
Large Commercial/Industrial	500 kW – 2MW	Mostly Rooftop	BTM
Utility Scale	> 2MW	No	Grid Tied

The bulk power system components considered in this assessment are summarized in Table 3, below.

Table 3: Bulk Power System Benefits and Costs of Solar Development

COMPONENT	DESCRIPTION
Avoided Energy	Market energy purchases avoided due to distributed solar
Energy Market Price Effect	Indirect effects of solar on market prices for energy and capacity
Avoided Capacity	Market capacity purchases avoided due to distributed solar
Avoided Transmission Costs	Avoidances, deferrals, and reductions in transmission investments and transmission charges due to reduction in peak load
Ancillary Services Avoided	Impact of solar on ancillary services costs
Fuel Price Hedge Savings	Reductions in exposure to volatile fuel prices due to solar generation reducing energy needs
Avoided REC Purchases	Reductions in an entity's requirements to comply with RPS policies

Our partner, RLC Engineering, developed an extensive analysis of the impacts of solar development on the distribution system by investigating circuit-specific operational needs and assessing feeder-level hosting capacity, considering advancements in distribution planning and investment. The distribution system components considered in this assessment are described in Table 4.

Table 4: Distribution System Benefits and Costs of Solar Development

COMPONENT	DESCRIPTION
Grid Location	Considers location on a distribution line and relative to electrical geography
Deferral of Distribution Investments	Impacts of solar additions on distribution system investment
Reductions in Losses and Wear and Tear as well as Improvements to Grid Security	Where solar resources offset peak loading, which exacerbates these factors, they can result in system savings
Avoided Distribution Outages	Avoided outages associated with overloaded facilities during peak loads if solar is coincident with peak hours on a distribution line

COMPONENT	DESCRIPTION
Benefits of Controllable Solar	Distributed automation and smart inverter use can positively impact voltage flicker, voltage regulation, and ride-through during system perturbations
Benefits of Solar paired with Storage and Demand Response	Storage complements solar by smoothing out the intermittency; adds value during peak. Adding demand response provides an additional tool for managing load on the distribution system.

To address social benefit and cost considerations, ESS Group, Inc. provided an assessment of the environmental impact, land use impacts, and health impacts of solar development and Daymark provided the economic implications. The economic and social components of solar development are described in Table 5.

Table 5: Economic and Social Benefits and Costs of Solar Development

COMPONENT	DESCRIPTION
Health Benefits	Health and mortality benefits of reduced emissions
Environmental Benefits	Value of reductions in air pollutant emissions
Water Benefits	Value of reduction in water use
Loss of Open Space and Agricultural Use	Impact of solar on agricultural, forested and vegetated lands
Impact on Planning and Zoning	Review of zoning and planning requirements and policies that could impact solar development

1.2 Approach and Results

This report documents the current level of solar development in Maryland's four IOU service territories, referenced herein as the Baseline, projects the potential amount of solar that could be installed going forward from a solar suitability perspective, and identifies, analyzes, and values the costs and benefits of solar additions to the grid. These assessments are provided for each of the utilities and in aggregate. Here we introduce the approach to, and highlight the results for, each area identified above.

1.2.1 Solar Baseline

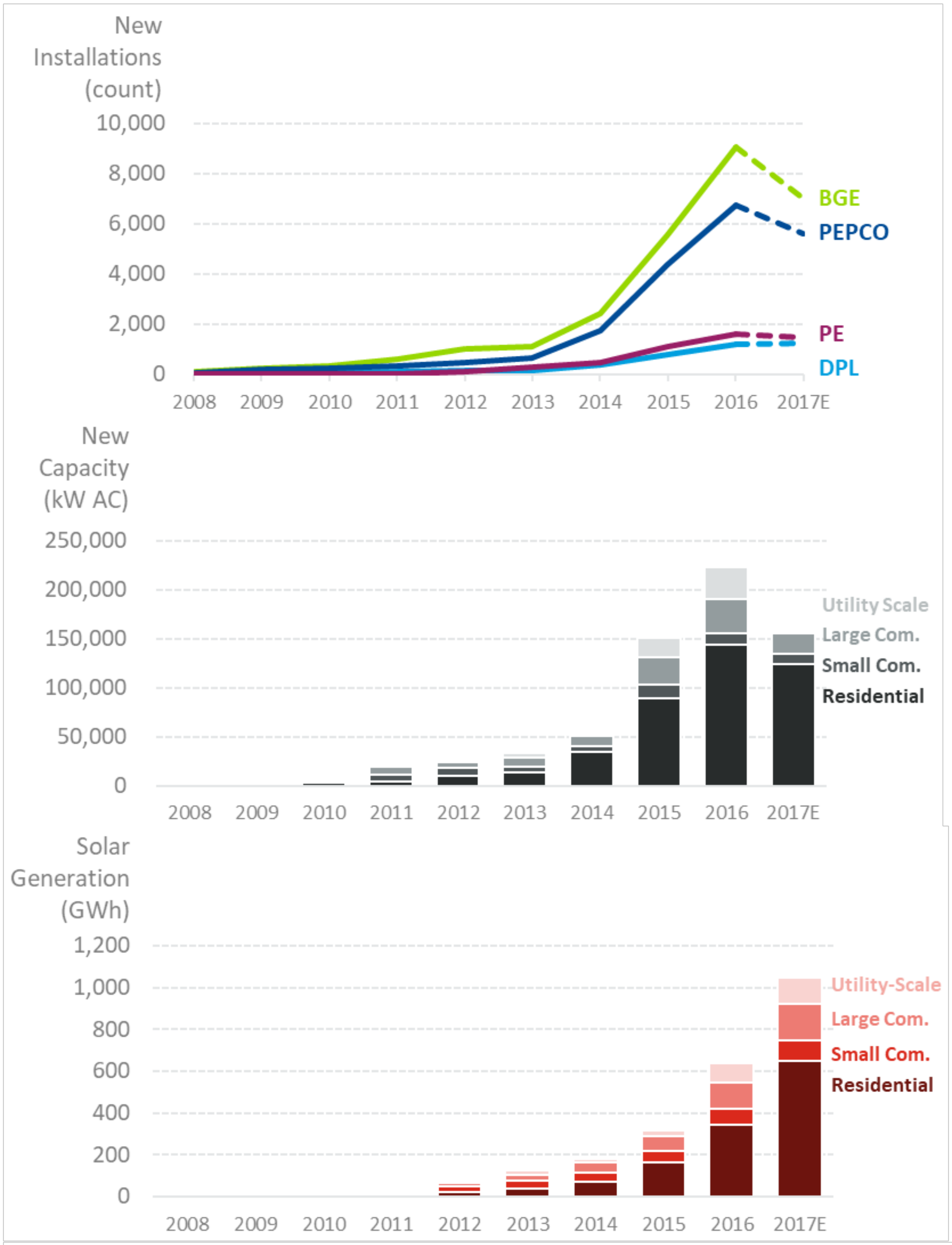
Establishing the current baseline of installed solar relies on reports from each utility relative to historical customer interconnections by year and known utility scale installations. With this information and using a tool to estimate production of solar systems based on their system characteristics, weather, and location, we generated usage profiles for residential, commercial and industrial, and utility scale systems for each utility, on a monthly and annual basis from 2001 to 2017. Currently installed solar within the four utilities' Maryland-based service territories is summarized from 2008 thorough 2017 in Figure 4 on the next page. In 2005, Maryland instituted a Renewable Portfolio Standard ("RPS") of 20% by 2022, which was updated in 2017 to a larger percentage by an earlier deadline. Maryland offers a production tax credit for electricity generated by wind, solar energy, hydropower, hydrokinetic, municipal solid waste and biomass resources The Maryland production tax credit became effective on January 1, 2006, and was initially set to expire on December 31, 2015, but was extended through December 31, 2018.

Due to the timing of this report, 2017 solar installation data reflected a partial year (through June 30, 2017). This half-year data was doubled in order to estimate data as of year-end 2017, which is shown in Figure 4. Residential customers were early adopters of solar, but commercial and industrial customers have increased their levels of installation recently. Note, commercial and industrial system installations are typically larger, so though they are fewer in number, they make up a significantly greater portion of the installed MW in later years.

1.2.2 Solar Potential

The technical potential for future solar development considered both the Electrical Hosting Capacity (potential electrical capability across the distribution system to interconnect solar) and the available real estate (rooftop and land) that is suitable for solar development.

Electrical Hosting Capacity was determined based on a feeder- and substation-level evaluation of distribution system data provided by the four IOUs. High level Electrical Hosting Capacity estimates were determined for each feeder, taking into account factors that are likely to impact the estimates, such as existing generation, thermal capacities, and protection schemes. As a result of this analysis, our team concluded that the distribution systems across Maryland's investor owned utility service territories can support significant additions of solar energy without the need for major upgrades, such as the rebuilding of lines or substations. The approximate aggregate Electrical Hosting Capacity for each utility is shown in Table 6. This represents the nameplate solar capacity that could be added to the distribution circuits in each utility without significant upgrade investments.



2017E data is estimated based on a partial year of data in 2017. Actual data is as of June 30, 2017 - the half-way point in the year; full-year 2017E data is estimated by doubling the partial year actuals.

Figure 4: Aggregate Solar Installations, Nameplate Capacity, and Generation Output

Table 6: Electrical Hosting Capacity by Company

COMPANY	ESTIMATED TOTAL ELECTRICAL HOSTING CAPACITY
Baltimore Gas & Electric	19.9 GW
Delmarva Power and Light	2.8 GW
Potomac Electric Power Company	7.3 GW
Potomac Edison	2.0 GW

Electrical Hosting Capacity is one element of determining solar technical potential; available real estate (rooftop and land) suitable for solar development must also be considered. We analyze the rooftop and land real estate suitable for solar to determine the behind the meter potential (MW) and utility scale potential (MW), respectively, and then compared these with the Electrical Hosting Capacity to determine the total technical solar potential across all 4 utilities. The potential based on area is compared to the potential based on hosting capacity to determine the technical solar potential. The smaller of those two values represents solar technical potential. Table 7 provides a summary of the area-based potential for BTM-scale and utility-scale solar, as well as the Electrical Hosting Capacity, by utility. For more information about how these values compare to one another, please see Section 2.4.

Table 7: Solar Technical Potential

Utility	BTM-Scale Area Potential (MW)	Utility-Scale Area Potential (MW)[2]	Hosting Capacity (MW)
BGE	16,177	39,413	19,863
DPL	2,310	46,266	2,751
PEPCO	4,433	3,974	7,307
PE	2,823	26,075	2,044
Total	**25,743**	**115,729**	**31,965**

1.2.3 Valuing Solar

As described earlier, there are many components to the value of solar – how each of those were valued in this analysis is described generally here and in greater detail in later sections of this report. With all of these components taken together, Figure 5

[2] Utility-scale area potential analyzed at the county level. Aggregation to the utility-level provided here simply for reference purposes based on which utilities serve which county; for counties served by multiple utilities, area potential divided evenly among serving utilities.

depicts the resulting value of solar for each of the four utilities for both behind the meter installations (see dashed lines) and utility scale installations (see solid lines).

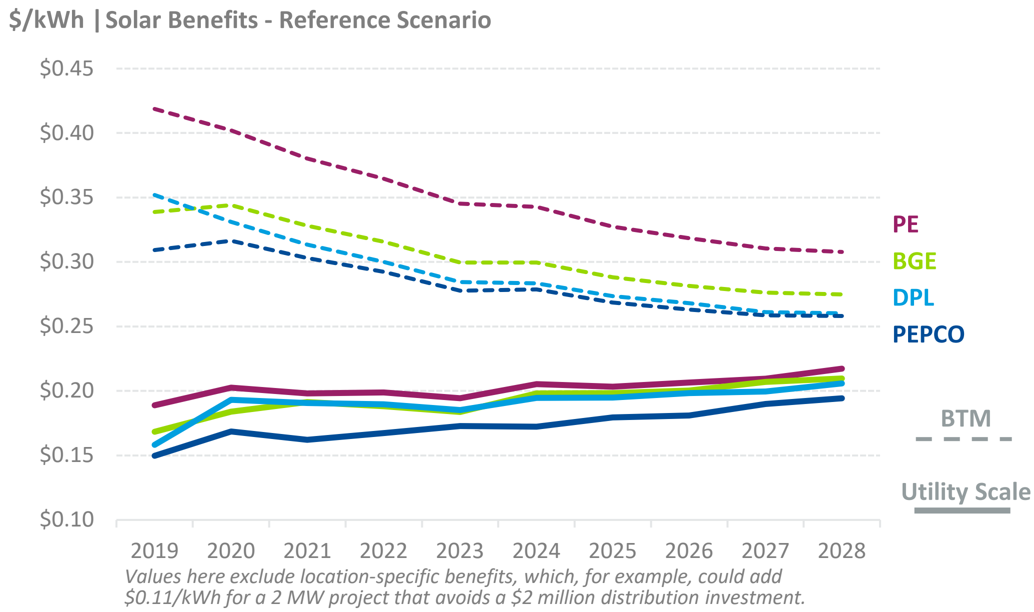


Figure 5: Value of Solar Utility Scale and BTM by Utility

We calculated the value of solar for each utility in this analysis and Figures 3 through 6 provide the value of solar developed for BTM installations for DPL, PE, BGE and PEPCO, respectively. As is seen in the summary in Figure 2 above, the value of solar for BGE, DPL, and PEPCO are quite similar while PE is higher, reflecting slight differences in the components of value for each service area. The underlying differences are better understood when comparing Figures 3 through 6 and understanding the differing characteristics of their service territories. The categories evidencing differences are avoided energy, avoided capacity, and avoided transmission charges and investment. The differences in these benefits between IOU territories are not large and are due to slight differences in the market dynamics in the territories.

The value of solar by component, in the PE service territory (APS zone) for example, is shown in Figure 7. In looking at Figure 5, one can see that the value of BTM solar in PE's service territory (purple dashed line) decreases from about $0.53 per kilowatt hour in 2019 to about $0.45 per kilowatt hour in 2028. Those same values are represented in Figure 7 by the top of the stacked bars.

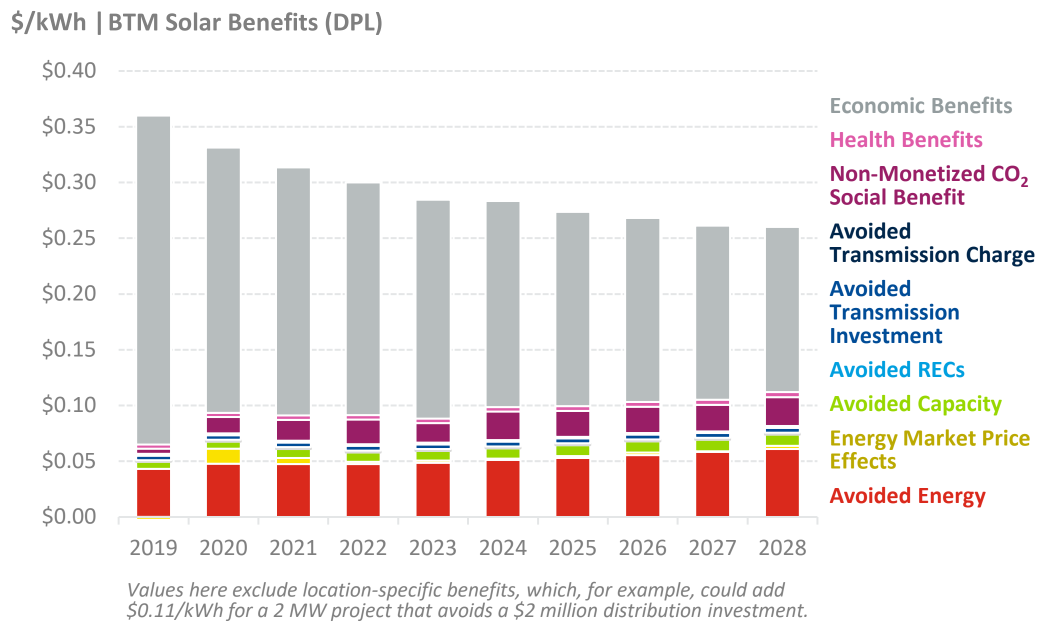


Figure 6: BTM Value of Solar DPL

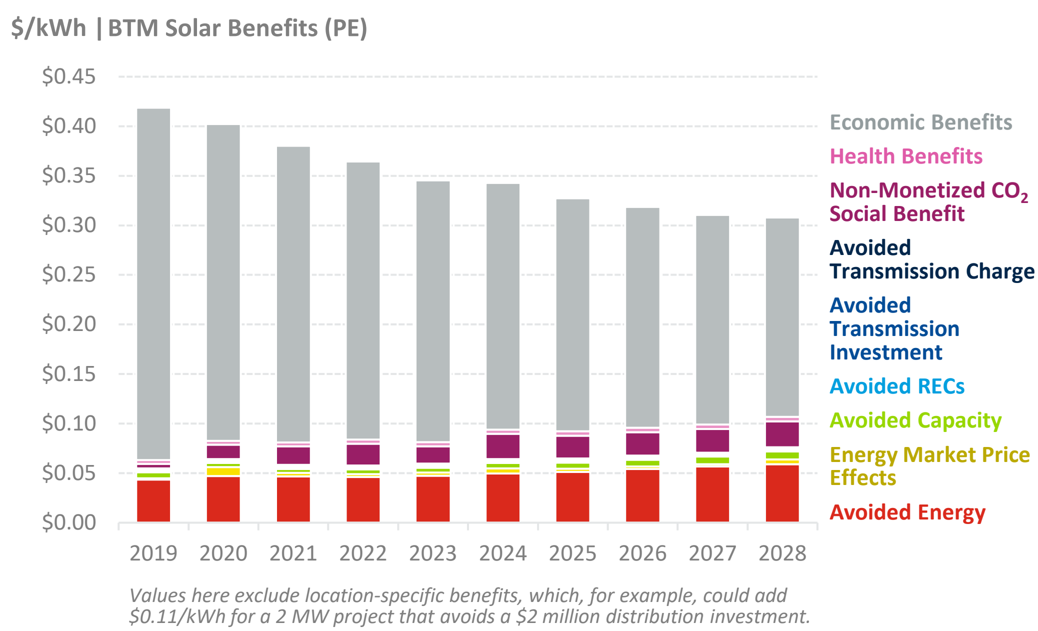


Figure 7: BTM Value of Solar Potomac Edison

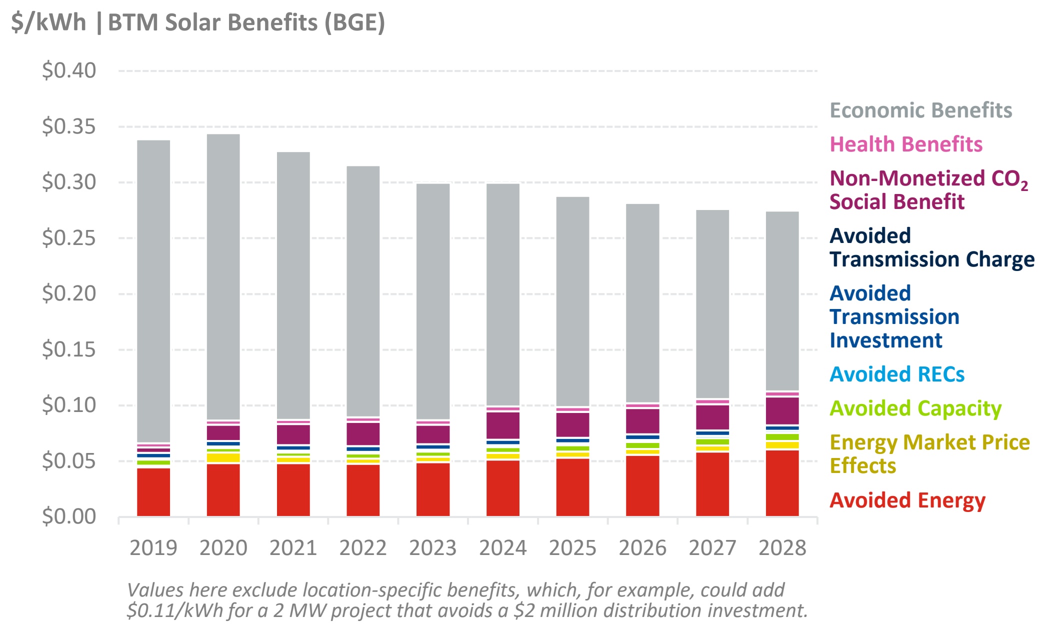


Figure 8: BTM Value of Solar Baltimore Gas & Electric

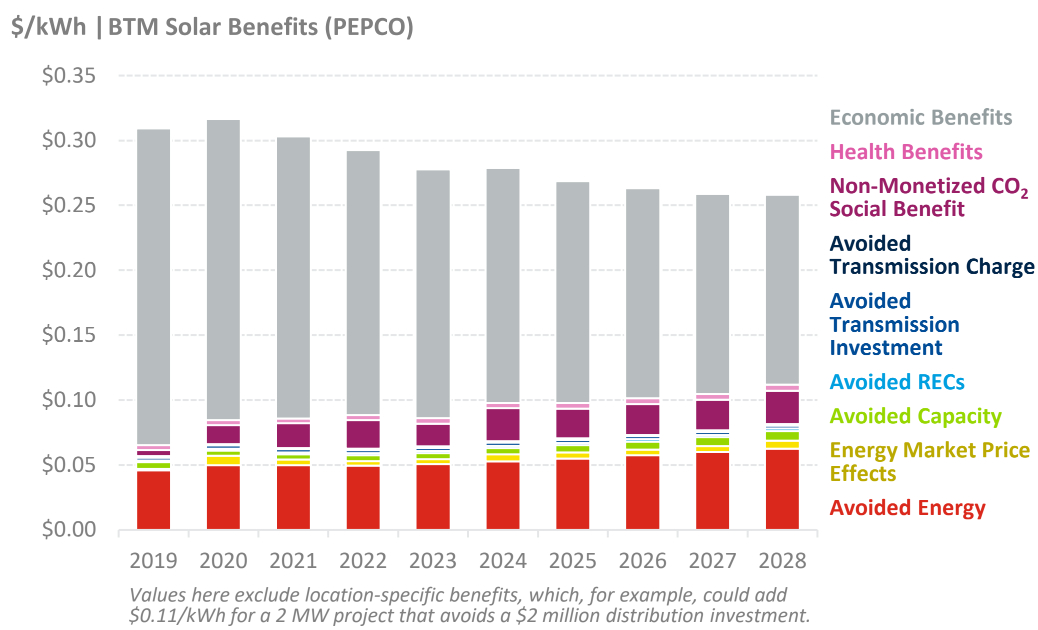


Figure 9: BTM Value of Solar PEPCO

The benefits of solar on the distribution system with the exception of losses are not directly monetized in the stack in the figures above because these benefits are location, and therefore circuit-specific; however, based on our analysis of the utility data provided, these values can be substantial if solar is strategically located to avoid or defer distribution upgrades; these values would be additive to the value of solar summary provided in the figures above. For example, a 2 MW project that results in the avoidance of a distribution system upgrade would translate to an additional average system benefit of $0.13/kWh or higher considering other non-quantifiable system benefits associated with reduced wear and tear and outage avoidance.

The development of each benefit and cost component is described briefly below.

Energy Benefits. Solar has two energy market benefits valued in this report. The energy value of solar differs depending on whether the solar energy is generated behind the meter or by a utility scale project that sells power directly to the grid. For behind the meter solar, the energy generated reduces the amount of energy that the Load Serving Entity ("LSE") must purchase from the PJM market to satisfy customer demand. The grid-connected utility-scale project's energy value is the price at which the project can sell its power in the PJM market. The second energy benefit is the dampening effect that this energy has on the market price for energy. Solar energy has a dampening effect because of its marginal cost of zero – adding a large amount of zero marginal cost power to the electric system shifts the clearing price to a lower-cost resource as the marginal resource in the supply stack. We refer to the added supply (utility scale) or reduced demand (BTM) solar impacts interchangeably as market price effects.

The energy market benefits of solar within the state of Maryland were derived from an analysis using Daymark's PJM Interconnection Market Model ("PMM"). PMM is an hourly chronologic electric market simulation model built on the AURORAxmp® software platform ("AURORA"), developed by EPIS, Inc. AURORA realistically approximates the formation of hourly energy market clearing prices on a zonal basis throughout PJM and neighboring regions, accounting for all key market drivers. The market simulation, relying on a difference analysis,[3] provides estimates of both avoided energy and market price response benefits.

[3] A difference analysis here establishes a base model case without solar additions and a difference case with solar additions so that one can assess the resulting system implications with the addition of solar by investigating the different results between the two cases.

PJM's Locational Marginal Prices ("LMPs") are comprised of three components – an energy component (representing the dispatch cost of the marginal generator needed to serve load), a transmission congestion component (representing the economic price of constraints that limit delivery between generation and load), and a marginal line loss component (representing the physical losses that occur as power flows over transmission and distribution lines between source and sink). The market clearing price in the PIMM are used to estimate the LMPs and are depicted as the avoided energy cost in Figures 7 through 9. Figure 10 depicts the market price impacts by utility zone.

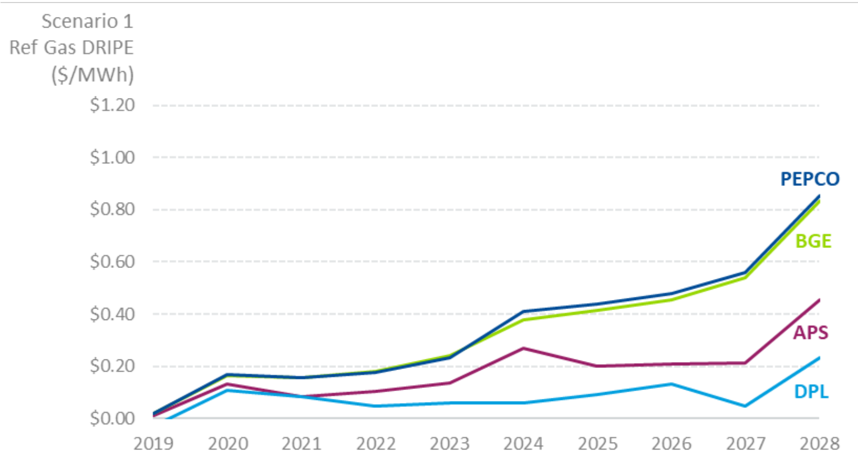


Figure 10: Solar-driven Market Price Reduction, in $/MWh

Capacity Price Benefits or Costs. In PJM, a consequence of the forward market structure is that capacity prices are set and known for the current delivery year, as well as the next three delivery years. The delivery year runs from June through May; capacity prices today are a known value through 2021. We model capacity market prices beyond that period using an economic analysis of PJM's annual capacity auctions after incorporating capacity demand and supply curves. The capacity model also accounts for transmission constraints between PJM modeled zones to fully reflect the actual market behavior. The avoided capacity calculation for BTM and Utility Scale both depend on the PJM capacity market price but are calculated differently because of the different ways these resources impact the market. A BTM resource effectively reduces load, while a utility scale resource can participate as a resource in the capacity market. Avoided capacity costs range from $0.004 per kWh to $0.023 per kWh between 2019 and 2028.

Transmission Costs and Benefits. The avoided transmission cost component attributable to solar additions considers 1) the potential for avoiding or deferring construction and maintenance of new transmission infrastructure, and 2) the impact on transmission charges that are the responsibility of the Maryland IOUs due to load reduction realized in Maryland versus the rest of PJM. Both BTM and utility scale resources have the potential to avoid new transmission infrastructure, but only BTM resources reduce load and provide opportunity for potential transmission cost shifts to out of state customers. Avoided transmission investment costs range from $0.001 per kWh to $0.005 per kWh between 2019 and 2028. Avoided transmission charged range from$0 .0011 to $0.0020 per KWh.

Ancillary Services Benefits and Costs. PJM's Renewable Integration Study concluded that both wind and solar projects are too small to have impacts on ancillary services, mirroring the rationale provided by NREL justifying current industry practice, which is that of assuming solar has no impact on ancillary services. Grid support services represent a small element of the value of solar calculation, with little to no effect at low solar penetration levels. At higher penetration levels, benefits may also be negligible with the potential of additional system costs. Daymark recommends not including benefits or costs for ancillary services in this evaluation.

Fuel Price Hedging Costs and Benefits. While it is a widely accepted concept that adding fixed price resources, such as solar, to a utility's supply portfolio reduces exposure to fuel price volatility, there is no standard method for calculating the hedge value of adding solar to a portfolio. For this assessment Daymark recognizes that a solar project essentially operates like a 25-year hedge or forward contract. If these types of contracts were available in the market place, we could use them as an indication of the fuel price hedging benefit of solar, but there is no market for hedges or forward contracts of that duration. Therefore, the value of the hedge is assessed in three ways: 1) change in the mean and standard deviation of the per MWh cost of the market portion of the portfolio,2) change in exposure to tail risk (the fixed solar piece adds no tail risk) as measure by Conditional Value at Risk (CVaR), and 3) change in the shape of market exposure as measured by exposure to outcomes above or below a target market portfolio cost. While a natural hedging benefit is clear from the introduction of solar and the benefit is real, it is difficult to quantify, but we have presented one way to look at it. However, we have not included the value in the stack. The results of the analysis are described fully in Section 4.6 demonstrating the benefits of solar to the system.

REC Benefits and Costs. The benefit to load serving entities of having behind the meter resources on the system is the avoided RPS compliance costs for the level of the avoided generation purchases. We have assumed that utility scale projects would be able to sell the renewable attributes for the SREC price throughout the study period. The value of RECs range from $0.001 per kWh to $0.002 per kWh for BTM resources and $0.009 per kWh to $0.013 per kWh for utility scale resources between 2019 to 2028. If we were to be in a supply constrained situation due to changes in policy or changes in the cost of solar, the avoided REC value could be as high as $0.01 per kWh for BTM resources and $0.05 per kWh for utility scale resources.

Distribution System Benefits and Costs. Potential distribution system benefits and costs considered include locational impacts, possible deferred investment in infrastructure, system losses, reduced wear and tear, reduced outages, land impacts, and smart inverter benefits. The requirements for and benefits of interconnecting a particular solar installation to the distribution system can be determined only by studying that specific installation, therefore the value of solar figures shown here exclude distribution benefits. However, installation of a relatively large aggregate amount of solar energy to the distribution system has the potential to produce benefits including 1) reduced distribution system losses - this could have a value of up to 0.6 cents per kWh of solar produced and 2) offsetting the need for load driven construction of new lines and substations, which could have a value from a few cents to tens of cents per kWh of solar energy produced.

Health and Environmental Benefits. The US EPA Co-Benefits Risk Assessment (“COBRA”) tool was used to evaluate the potential health benefits from the emission reductions associated with increased solar installations for Maryland. COBRA is a screening tool that estimates air quality, human health, and associated economic impacts of emission reduction scenarios by county and state. Emissions of NO_X, SO_2, and CO_2 are output directly from the Aurora model analysis. For Maryland, the health benefits ranged from $9 to $32 million dollars (2010 $), or $0.002 to $0.006/kWh, with mortality reductions estimated to range from 1 – 4 people.

Non-monetized benefits. The U.S. government’s Interagency Working Group (“IWG”) on Social Cost of Greenhouse Gases estimates the social benefits of reducing CO_2 emissions for the purposes of evaluating benefits and costs of proposed regulatory actions. The IWG updated its social cost of carbon values in August 2016 based on the same methodology used since 2010.[4] The monetized damages associated with CO_2 emissions include (but are not limited to):

- Changes in net agricultural productivity;
- Human health;
- Property damages from increased flood risk; and
- Value of ecosystem services due to climate change.[5]

Some portion of the social benefit of carbon reduction is already captured in the avoided CO_2 emission allowance costs discussed above. However, the cost of allowances calculated in our analysis never reaches the full social cost of carbon as estimated by the IWG. We define the non-monetized social value of CO_2 to be the social benefit of avoided CO_2 emissions as estimated by the IWG, net of CO_2 allowance costs assumed in the energy modeling performed here. These values are added to the stacks for each utility.

Jobs and Economics Impact: To calculate the economic and job impacts of incremental investment in distributed solar resources in the territories of the four Maryland IOUs, the IMPLAN model was used. IMPLAN is an input-output model that combines a set of databases of economic factors, multipliers, and demographic statistics to measure the economic impacts caused by investment or other actions that cause an increase in sales to local industries. Users can define regions to analyze from the national level down to specific geographies within states. For this study, Maryland-specific data with details included down to the county level was modeled for each region (utility service territory in Maryland) and for each year (2018-2028).

The installation of utility-scale and BTM solar projects will provide multiple economic benefits to the state of Maryland, and more specifically the utility service territories. Daymark's analysis demonstrates that the construction/installation and subsequent operation and maintenance of the collective installed solar projects will generate additional jobs, labor income, and tax revenue for the state of Maryland. These benefits are described here, and are added to the value of solar stacks above.[6]

[4] EPA 2016 RIA and Addendum 2020, 3% discount rate https://www.epa.gov/sites/production/files/2016-12/documents/sc_co2_tsd_august_2016.pdf

[5] Ibid.

[5] Ibid.

[6] IMPLAN results are included in the solar stacks above using the value added impacts in terms of $/kWh each year by utility and type of solar installed. As explained by the Bureau of Economic Analysis, "Value added is the difference between gross output and intermediate inputs and

In total, the forecasted solar projects are estimated to generate 22,563 job-years, over $1.34 billion in labor income, over $2.03 billion in value added or Gross Domestic Product, and more than $3.97 billion in incremental local industrial production/output for the state of Maryland. The economic impacts are broken into three categories: direct, indirect, and induced. The total value of each impact is shown in Table 8.

When interpreting the economic impacts for each category, it is important to consider the following:

- Job-years, which are totaled over the study period, refer to jobs created each year due to investment. When interpreting job created from investment, jobs should not be considered cumulatively, but instead on average. The average jobs created over the study period will be the jobs needed to directly install and then operate and maintain the solar projects. The workers needed are declining over the study period as costs of installation go down.
- Indirect jobs are created due to jobs being added to industries that support the installation process and should be also interpreted on average; that average should be considered an upper bound on job creation, since there is more likely to be an increase in production and wages and not necessarily an increase on jobs added.
- Induced jobs are jobs created by spending in the economy from the newly employed workers. These jobs should be interpreted on average and that average should be considered an upper bound on job creation, since the addition of that many retail-type workers (e.g. restaurants, banks, and box stores) is less likely to occur and instead these establishments are more likely going to increase wages and expand in value – although this will lead to some additional job growth.

Table 8: Total Maryland-Specific Economic Impacts

	Employment (Job-Years)	Labor Income (dollars)	Value Added (dollars)	Output (dollars)
Direct	13,517	$796,441,652	$1,120,558,798	$2,516,560,776
Indirect	4,824	$329,581,035	$514,811,689	$831,141,254
Induced	5,493	$290,794,492	$512,472,678	$846,188,424
Total	**22,563**	**$1,340,052,852**	**$2,028,064,404**	**$3,972,715,479**

represents the value of labor and capital used in producing gross output. The sum of value added across all industries is equal to gross domestic product for the economy."
https://www.bea.gov/faq/index.cfm?faq_id=1034

The forecasted solar projects are estimated to generate approximately $146.2 million in tax revenue for Maryland. This tax revenue, shown in Table 9 below, is generated through sales tax, income tax, and property tax.

Table 9: Total Maryland Tax Revenue Generated by All Solar Projects

Tax Category	BGE	DPL	PEPCO	Potomac Edison	Maryland
Sales Tax	$22,114,674	$5,702,243	$12,298,395	$7,169,210	$47,284,522
Income Tax	$24,361,378	$3,996,304	$12,978,936	$7,886,201	$49,222,819
Property Tax	$23,401,630	$5,745,892	$12,915,957	$7,586,293	$49,649,772
Total	**$69,877,682**	**$15,444,439**	**$38,193,288**	**$22,641,704**	**$146,157,113**

1.3 Limitations of Value of Solar Results

The value of solar estimated in this report should be used in such a manner that the limitations of an analysis of this magnitude requires. Several limiting factors or considerations are highlighted here for readers and users of the information provided here.

First and foremost, this is a snapshot in time for four IOUs within a much larger regional system. Our models represent that larger system, and our team has worked diligently to make reasonable assumptions as we developed the implications per utility and in aggregate. Also, while these four IOUs make up a significant portion of the state of Maryland but there are additional utilities in the state that are not reflected in this report.

The requirements for and benefits or costs of interconnecting a particular solar installation to each of the IOUs distribution systems can be determined only by studying that specific installation. The analyses provided in this report are intended to provide insight into the potential costs and benefits on average.

Confidentiality concerns of the IOUs with respect to individual circuit data are important to consider with regard to the information in this report. We are not divulging any IOUs specific circuit information here but we recognize that such information is important to a more detailed identification of benefits and costs.

Air emissions are facility dependent and vary substantially based on fuel type, air pollution control devices and facility design. As the AURORA model projects emissions based on individual facility dispatch, the impact of solar injection into the grid varies substantially for the three modeled scenarios. NOx, SO2 and PM2.5 emissions are particularly sensitive to the facilities being dispatched resulting in the variation noted in the emissions curves above.

The COBRA model used to estimate health benefits offers only two options for analysis year, 2017 and 2025. We used 2025 as the best representation of the time frame of interest for this report.

1.4 Conclusions

From the research and analysis summarized above and discussed in detail in the remainder of the report, we draw conclusions relative to the benefits of solar development in Maryland and the potential policy considerations for such development.

Implications for Utility Planning. One particular policy example is the locational nature of distribution system benefits limited the ability of this team to specify a value for this category, but the conclusions here indicate that there is indeed great value (up to $0.13 per kWh depending on the circuit and its current characteristics). Policymakers may investigate changes to the utility's distribution system planning processes to include increased transparency relative to where solar offers the greatest local benefits. Security issues are of great concern for good reason and utilities were reluctant to share such information with this team. However, in California utilities are now increasing the transparency of their distribution plans and seeking competitive alternatives to traditional distribution investment to maintain and improve reliability and resilience of the system. To that end utilities, rather than policymakers, might also consider offering incentive programs to encourage siting solar projects in the optimal distribution system locations.

Current Solar Deployment is Low. Solar development in these four utility service areas remains very light and there is significant potential for development. At this point, utilities, regulators and legislators have the opportunity to shape the adoption of solar to address planning and operational needs, encourage economic adoption of solar, and ensure investment is targeted at development to benefit the electric system and the state economy.

Potential for Solar Development. There is significant potential for additional solar development in Maryland. While the real estate, including rooftops and open space, generally exceeds distribution capacity, we found that the distribution systems in Maryland can support significant additions of solar energy without the need for major upgrades such as the rebuilding of lines or substations. Based on our analysis and land constraints, the following approximate aggregate potentials for nameplate capacity may be realized from a distribution standpoint:

- Baltimore Gas & Electric = 19.9 GW
- Delmarva Power and Light = 2.8 GW
- Potomac Electric Power Company = 7.3 GW
- Potomac Edison = 2.0 GW

Differentiation of Benefits Based on Category of Solar. Throughout the study, we examined the costs and benefits of solar through the lens of the four categories of solar discussed above. We found the most important distinction between the categories was whether the project was BTM or Utility Scale. While we looked at three different categories of BTM solar, we did not find that there was a different in per unit value that these three categories provided.

Differentiation of Benefits in IOU Territories. There is some difference in some categories of benefits provided by solar installed in the different IOU territories. These categories are avoided energy, avoided capacity, and avoided transmission charges and investment. The differences in these benefits between IOU territories are not large and are due to slight differences in the market dynamics in the territories.

Relative value of benefit categories. Avoided Energy is the most significant contributor to the value of solar. Avoided Capacity and Avoided RECs make up the next biggest contribution

Distribution System Benefits. The addition of solar resources in the proper locations can significantly reduce thermal losses on the distribution system. The marginal distribution loss rate for additional solar can be as high as 10% to 12% of the offset energy.

The installation of a relatively large aggregate amount of solar energy to the distribution system has the potential to produce benefits including:

- Reduced distribution system losses. This could have a value of up to 0.6 cents per kWh of solar produced.
- Offset the need for load driven construction of new lines and substations. This could have a value from a few cents to tens of cents per kWh of solar energy produced.

The integration of solar sources will often require modest upgrades to the distribution system to control voltages and minimize adverse impacts, such as voltage flicker, on other customers. Typical upgrade requirements include grounding banks, voltage regulators, capacitors, reclosers, fault detectors, or capacitor control changes. The costs for these additions are usually borne by the developer and can have a negative impact on the economic viability of a project ranging from nothing to 1.7 cents/kWh. Larger projects might require transformer or line upgrades. Costs for these additions are usually born by the developer and can have a negative impact on the economic viability of a project ranging from 1.7 to 2.3 cents/kWh.

Impact of Smart Inverters. Acceptance and aggressive implementation of the control capabilities of smart inverters by the electric utilities could result in significant reliability improvements to the distribution system. In addition to reactive support, smart inverters can provide voltage and frequency ride through capabilities during system disturbances.

Storage. The installation of storage systems with large solar penetration offers the potential to significantly reduce the peak load that a distribution circuit will experience. This could reduce line construction costs which can be in the millions of dollars per circuit.

Zoning. Specific zoning considerations to encourage development of solar in Maryland include the following:

- Land use types – Open land sites that have little or no competing use value and are compatible with solar development include brownfields, reclaimed surface mines, highway or transmission rights of way and existing power plant sites.   Potential impact on wildlife habitat would generally limit development opportunities in conservation areas. As noted in section 6.2, the value of forested land and cost to develop would preferentially favor agricultural land and other open space.
- Lot Size – A minimum of 20 acres is typically needed to develop a utility solar scale project of 2 MW or greater.
- Setbacks – Three counties specify setbacks to be per the zoning district and four require 50’ setbacks. Setbacks for the other four counties with requirements range from 25’ - 200’ for nonresidential and 100’ – 400’ for residential areas.
- Glare Mitigation – Utility scale solar projects can be designed and sited to reduce glare that could create a nuisance or public safety hazard.
- Screening Buffers – Visual screening to reduce impact on aesthetic and scenic quality of the location can be considered as warranted. In addition, the use of pollinator habitat

can serve a dual function of providing visual screening and enhancing pollination in the surrounding land areas.

- Height – Two counties establish height restrictions consistent with the zoning district. There are nine other counties with height restrictions that vary from 15' – 50'.
- Lighting – Options for reducing the impact of facility lighting can include minimizing the lighting to that required for safety, shielding and downcasting to reduce the impact on the neighborhood and the use of motion sensors.
- Decommissioning – Thirteen counties establish provisions for decommissioning the site including specifying time limits for decommissioning, defining the extent of removal of components, and requiring restoration of the disturbed areas including grading and reseeding. Several counties require a written decommissioning plan and security for the costs of decommissioning.
- Vegetation Removal – Four counties establish limits on tree removal such as requiring approval for tree removal that comprises more than 2% of the parcel being developed.
- Security – Wildlife friendly fence designs are available to allow for wildlife of concern to cross the barriers. [5]
- Dual Land Use – As discussed in section 6.2, utility scale solar facilities may offer opportunities for agricultural use such as shade crops, grazing and pollinator habitat.

1.5 Report Organization

The remainder of this report is organized as outlined below with a number of Appendices providing greater details and reference information.

Section 2 Baseline Solar Data and Trends – Details current installed solar, develops load curves for the categories of solar analyzed, summarizes installed solar capacity and energy, and summarizes the potential for solar relying on electrical hosting capacity and investigating rooftop potential and land-use potential.

Section 3 Bulk Power System Benefits and Costs – Describes the methodologies utilized to monetize, where practical, the benefits and costs of solar on the bulk power grid and details the values.

Section 4 Distribution System Benefits and Costs – Develops and discusses distribution system benefits and costs and investigates circuit specific information to develop electrical hosting analyses to assess potential and costs to the grid of locational solar development; also addresses a variety of equipment interests and addition of storage technology.

Section 5 Economic and Social Benefits and Costs – Addresses environmental, land-use and health considerations of solar development and investigates the economic impact of solar investment in Maryland on jobs and the local economy.

The ***Appendices to this Report*** include:

A. Glossary of Terms

B. Baseline Trends Detail

C. Twenty (20) Year Outlook

D. Energy Modeling Analysis

E. Capacity and Transmission System Analysis

F. Interconnection Process Information

G. Losses Analysis

H. Distribution System Algorithm Analysis

I. Land-use by County Information

J. County Maps

K. County Zoning Information

L. Emission Factor Analysis

3. BASELINE SOLAR DATA AND TRENDS

Daymark Energy Advisors investigated the current state of solar development and the potential for future development in the service territories of the four investor owned utility companies that provide distribution services within Maryland; those companies include, as referenced earlier, BGE, DPL, PEPCO, and PE. Developing this information forms a basis for the characterization of the market potential for solar opportunities within their service territories including consideration of potential new policy proposals or approaches to value solar that may affect adoption.

3.1 Current Solar Policies and Incentives

Maryland's first ever renewable energy procurement policy was put in place in 2001. This executive order mandated that 6% of the electricity consumed by state-owned facilities must be sourced from "green" energy sources such as solar, wind, biomass, and landfill gas[7]. Maryland instated an RPS in 2005 that dictated that the state would get 20% of its electricity from renewable generation by 2022. This standard was updated in February of 2017 to the goal of 25% renewable generation by 2020 with 2.5% of the renewable generation satisfied through solar installations[8]. Additional legislation prohibits the unreasonable limitation on the installation of solar panels on the roof or exterior walls of a property.[9] Each of these renewable energy policies are captured in a timeline in Figure 11.

[7] MD Clean Energy Procurement Policy. Retrieved from: http://programs.dsireusa.org/system/program/detail/568

[8] MD Renewable Portfolio Standards. Retrieved from: http://programs.dsireusa.org/system/program/detail/1085

[9] MD Solar Easements and Rights. Retrieved from: http://programs.dsireusa.org/system/program/detail/3

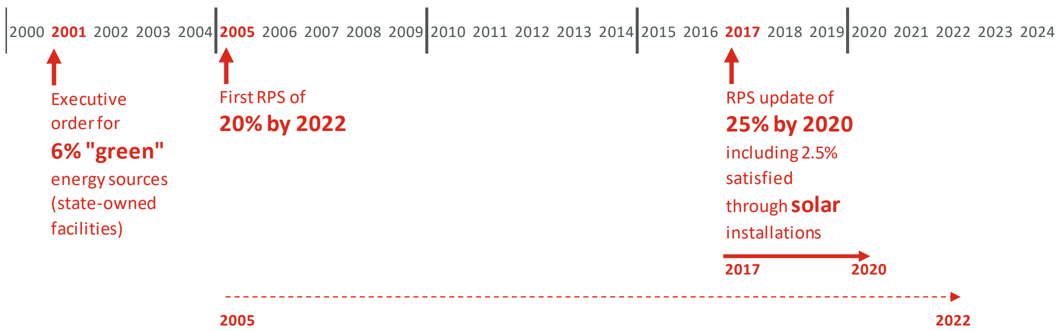


Figure 11: Timeline of Maryland Renewable Energy Policies

In addition to the mandated RPS, Maryland has a number of available incentives for the development of renewable generation, especially solar. Maryland allows total exemptions to the property and sales and use taxes for commercial, residential, industrial, and agricultural solar customers.[10][11] Maryland also offers what they call the Clean Energy Corporate and Personal Production Tax Credit ("MD PTC") which is distinctly different than the Federally-offered Production Tax Credit. An individual or corporation that applied for and received certification from the Maryland Energy Administration may claim a credit equal to 0.85 cents per kilowatt-hour against the state income tax, for a five-year period, for electricity generated by eligible resources including solar, wind, hydropower, and biomass facilities. The most recent amendments to the MD PTC extended the tax credit until December 31, 2018[12].

In addition to state-level policies, there are two major Federal incentives in place to encourage solar deployment. First is the Investment Tax Credit ("ITC"), which has been extended through 2022 with a gradual phase out. As of now the ITC for solar is 30% of the tax liability of an individual residential, commercial, or utility-scale solar investor[13][14]. Additionally, the federal Solar Renewable Energy Credit ("REC") program incentivizes solar deployment by the creation of RECs that can be traded for profit by renewable

[10] MD Property Tax Exemption for Solar and Wind Energy Systems. Retrieved from: http://programs.dsireusa.org/system/program/detail/2542

[11] MD Sales and Use Tax Exemption for Solar and Geothermal. Retrieved from: http://programs.dsireusa.org/system/program/detail/2928

[12] MD Clean Energy Corporate and Personal Production Tax Credit. Retrieved from: http://programs.dsireusa.org/system/program/detail/1687

[13] Federal Investment Tax Credit. Retrieved from: http://programs.dsireusa.org/system/program/detail/658

[14] Solar Investment Tax Credit. Retrieved from: https://www.seia.org/initiatives/solar-investment-tax-credit-itc

electricity generators to electricity suppliers that need them to meet their renewable energy compliance obligations[15].

With the available incentives for solar deployment in mind, the current baseline develops the installed amount of solar and solar production, for each of the four utilities and in aggregate, by relying on information from a variety of sources as described in the methodological summary in the next section (for more details see Appendix B).

3.2 Baseline Methodology

Daymark obtained historical solar installation data from each of the four utilities and used this data, including installation counts and capacities per year, to develop historical solar generation output levels for each utility. This report describes the currently-installed, baseline levels of solar development across all four Maryland IOU service territories. For more information about baseline solar systems on a utility by utility basis, please refer to Appendix B to this report.

Monthly solar generation output profiles were developed using the National Renewable Energy Laboratory's ("NREL's") PVWatts® tool, which estimates the electricity production of customer-sited solar systems based on system characteristics such as location, direct current ("DC") capacity, module type, array type, inverter efficiency, array tilt angle, and array azimuth angle. Characteristics of individual systems within a region will differ based on housing factors like roof angle and orientation, as well as changes to inverter and panel efficiency through time. Given certain assumptions about the general characteristics of a solar installation, PVWatts generates an estimate of that system's alternating current ("AC") output (in kWh) under normal weather conditions.

Daymark then developed three scenarios for monthly generation outputs. These scenarios included an average monthly output through the year, an upper bound output, and a lower bound output. The upper and lower bounds were developed to represent the variability of solar output due to weather and location. The upper bound assumes greater than average production through the year, which could be due to higher instances of sunny weather, while the lower bound represents the opposite. These three generation scenarios were applied to output profiles within each of the four utilities. The four service territories are those covered by BGE, DPL, PEPCO, and PE; these are depicted in Figure 12.

[15] Solar Renewable Energy Credits. Retrieved from: http://programs.dsireusa.org/system/program/detail/5686

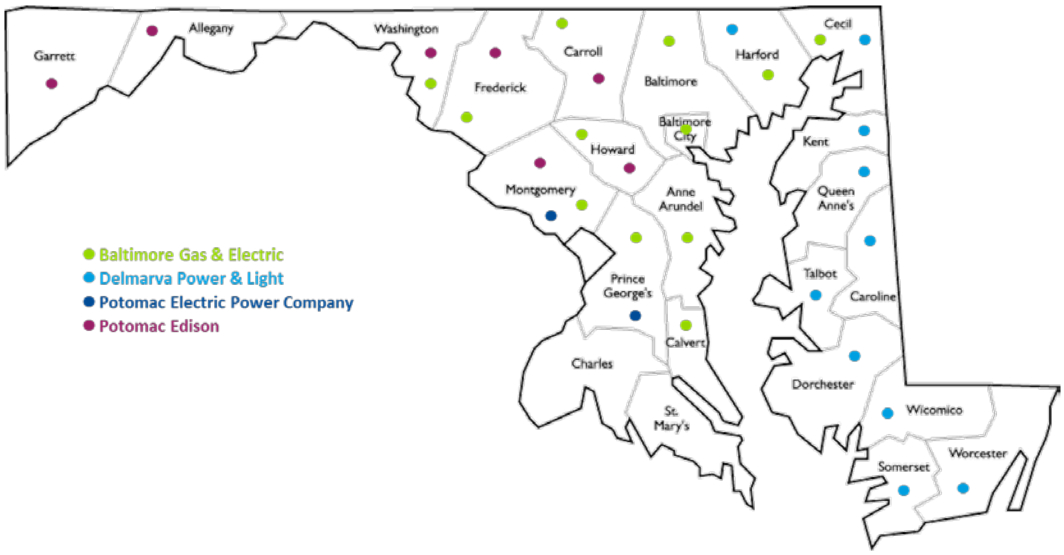


Figure 12: Map Showing Service Individual Service Territories at County Level

3.2.1 Key Production Baseline Assumptions

There are a variety of factors that can affect the output from a solar PV system. Locational differences in geography, latitude, and weather can directly affect the solar radiation available to generate electricity. Additionally, these factors can impact the tracking type that is optimal for a PV system, as well as the optimal panel tilt. Degradation of the systems and line losses in converting the electricity from DC to AC also play an important role in the output of a solar system. To create an accurate output profile within each of the service territories, the NREL PVWatts tool was used. PVWatts accounts for all of the above factors and more, the assumptions for which are discussed in-depth below.

> The *solar radiation and weather data* used by PVWatts is derived from the nearest reporting weather station and accounts for metrics that may impact solar system efficiency such as wind speed, temperature, and cloud cover. While there is some small overlap in the service territories, this does not affect the output profiles for the respective territories.

The *system orientation* assumes a south-facing panel (180-degree azimuth). Optimal panel tilt (see Table 10) was calculated on an individual basis for each service territory[16].

Table 10: Solar System Optimal Tilt for Each Service Territory

BGE	32.86°
DPL	32.55°
PEPCO	32.60°
PE	33.27°

A *fixed-mounted system* was assumed for all installations unless otherwise specified by the utility.

PVWatts was used to simulate the generation output profile (in kWh) for a 1 kW AC system located in each of the four service territories. Generation output was then scaled up to full output based on the actual capacity (in kW AC) of each solar installation.

All other inputs for the PVWatts tool, including system losses, inverter efficiency, and module type, were set to the PVWatts default values, which are based on location, and current data on PV or solar systems. These are assumed reasonable and were not adjusted for the purposes of this study.

3.2.2 Solar Production Results

Average monthly production (in kWh) for a 1 kW AC system in each of the four utility service territories is provided in Figure 13, for comparative purposes. The top part of Figure 13 depicts the output from BTM-scale solar installations, including residential, small commercial, and large commercial-sized installations. The bottom part of Figure 13 depicts the output from a utility-scale installation. The variations in generation levels and the timing of that generation are the result of diversity in location and weather across the utility service territories. We did not rely on statewide assumptions, but rather maintained the local differences in the underlying assumptions data for the solar production estimates.

[16] Solar tilt calculation (38 degrees (latitude) * 0.76 + 3.1 degrees = optimal tilt for fixed rooftop (http://www.solarpaneltilt.com)

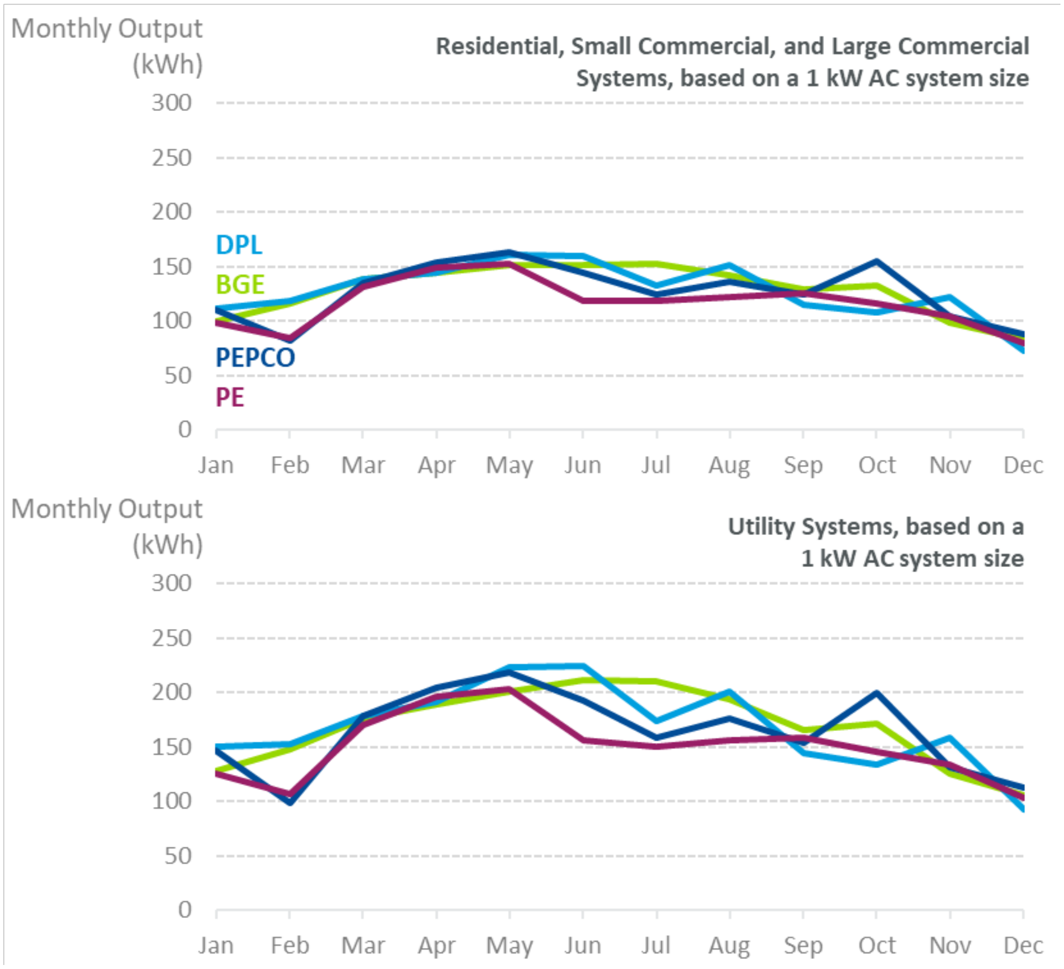


Figure 13: Comparison of Average Monthly Solar Production Between Utilities

All four utilities show peak output for BTM systems in May; from there, both PEPCO and PE decline in output for June while BGE and DPL have June outputs similar to their May outputs. For utility scale systems, BGE peaks in June, whereas the other three utilities peak in May, consistent with their BTM profiles. PEPCO and PE also have dips in output in February that are not present in the BGE and DPL output profiles. This dip in output as well as the general trend of output in PEPCO and PE being generally lower than BGE and DPL throughout the year could be due, in part, to location. PEPCO and PE service territories are located in the north and west of the State which has a lower solar potential than the areas of the state encompassed by BGE and DPL's service territories[17].

[17] Solar Energy Potential Map. Department of Energy. Retrieved from: https://www.energy.gov/maps/solar-energy-potential.

Output from systems within the DPL service territory are at or near the top of the cluster in both parts of Figure 13; this is likely due to the more southern location of DPL's service territory.

The aggregate profile for all of Maryland's IOUS together was generated using a weighted average of the relationship between each service territory's nameplate solar capacity and the total nameplate solar capacity for each category. These weights are shown, for each category of solar, in Figure 14.

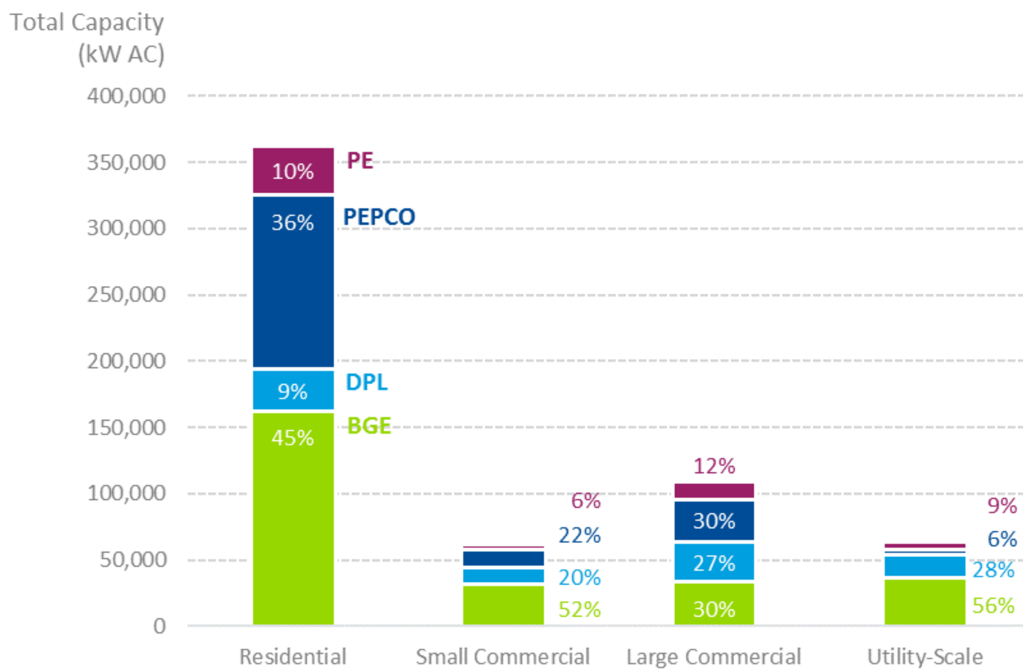


Figure 14: Weighting of Each Service Territory, per Customer Category

Use of the weighted averages to determine the aggregate output shapes for the state of Maryland enhances the ability to visualize the effect that each utility's current PV installations has on output in each tranche size. For example, Figure 15 shows the relative weights of each service territory and each service territory's output shape for the residential category. The aggregate information is shown in red. The aggregate shape is influenced by BGE and PEPCO's shapes most, due to their large weights.

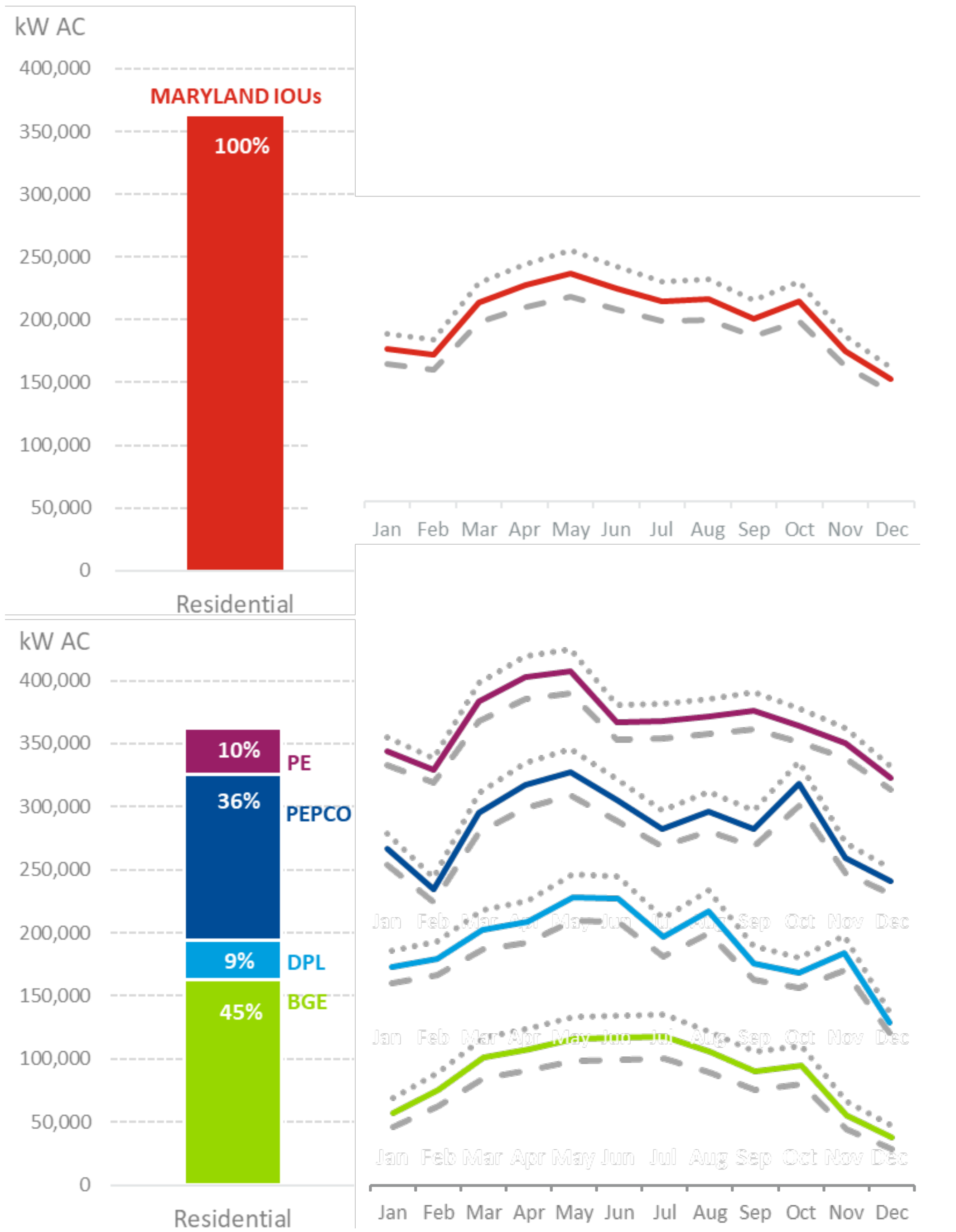


Figure 15: Example Impact of Weighted Average on Aggregate Monthly Output Share

3.2.3 Conclusions

Output from solar installations varies due to many different factors and these factors cause notable differences in the shapes of solar power production throughout the year. Location of the panel has a significant effect on the output and when output peaks throughout the year. We can see this in comparing the output profiles of the individual utilities and the relative locations of the individual service territories.

A weighted average of the output profiles from all service territories provides the best picture of solar output for the state of Maryland because it gives proper weight to the size and volume of solar installations within each service territory. These profiles indicate that solar production in Maryland peaks from May to June and remains highest throughout the summer months. Electricity demand peaks in the summer in PJM, so having the highest solar output align with the peaks in demand helps offset peak demand on the electricity system.

3.3 Current Solar Installations

The amount of solar present in all service territories, both individually and in aggregate, is described in this section from 2002 to the present day. This timeline encompasses the earliest solar installations in the BGE, DPL, PEPCO, and PE service territories. The data includes installations currently under construction as of June 30, 2017 reflecting the most recent information provided by the utilities regarding their PV installations. For the purposes of this study, it is assumed these pending installations will reach commercial operation by 2018.

Analysis of the historical information by utility and in combination represents installed solar capacity for each year as new systems are interconnected. When system installations are combined with the solar production analysis provided in Section 3.2, we provide estimates of the amount of solar system generation that has occurred historically.

3.3.1 Installed Solar Assumptions and Methodology

Customer-sited solar panel systems are interconnected upon approval of the application throughout the calendar year. Solar panel systems have an expected life of 20 to 25 years, at which point their capacity will be between 80-85% of original nameplate[18]. For each year a solar panel is operational the panel is expected to degrade by 0.5% on

[18] At an age of 25 years, solar panels will be between 80 to 85% of original capacity, but panels have the potential to last longer at a reduced capacity. (http://energyinformative.org/lifespansolar-panels/)

average[19]. This is degradation of the panels themselves and their ability to capture sunlight due to exposure to inclement weather. Panels in more extreme climates that are subject to heavy winds, snow loads, sand, and high UV exposure tend to degrade more quickly than those in more moderate climates such as the northern United States.[20] To more accurately model the level of solar online during each historical year, each connection and its respective nameplate capacity was modeled from the month and year of interconnection forward. For example, if a panel was interconnected in March of 2002, the total amount of production for the year 2002 contributed by that system is calculated from March 2002 to year end. For 2003 that panel, and all panels, is given a degradation percentage of 0.5%, for each successive year of production. The result is an estimation of both capacity and output contributions from each solar size tranche to the energy needs of each service territory for a given year.

3.3.2 Summary of Historical Installed Solar Analysis

The residential solar sector shows strong growth in capacity additions over time. Since the first installations in 2002, the residential sector shows the fastest growth in terms of capacity additions year to year, as shown in Figure 16, which depicts annual incremental solar capacity additions by category. The next most rapid growth in capacity additions year to year occurs in the large commercial/industrial category. Both the large commercial/industrial and utility-scale solar make up significant portions of annual capacity additions, especially in recent years, due to system size per installation being considerably greater than the other categories. Small commercial/industrial installations account for the smallest percentage of annual capacity additions. The total solar capacity additions for calendar year 2016 amounted to about 225 MW, a significant increase from 2011 or approximately 35 MW.

[19] 0.5% degradation rate estimate for modern solar panels. Photovoltaic Degradation Rates — An Analytical Review. NREL, June 2012.

[20] What is the Lifespan of a Solar Panel. 2017. Retrieved from: https://www.engineering.com/DesignerEdge/DesignerEdgeArticles/ArticleID/7475/What-Is-the-Lifespan-of-a-Solar-Panel.aspx.

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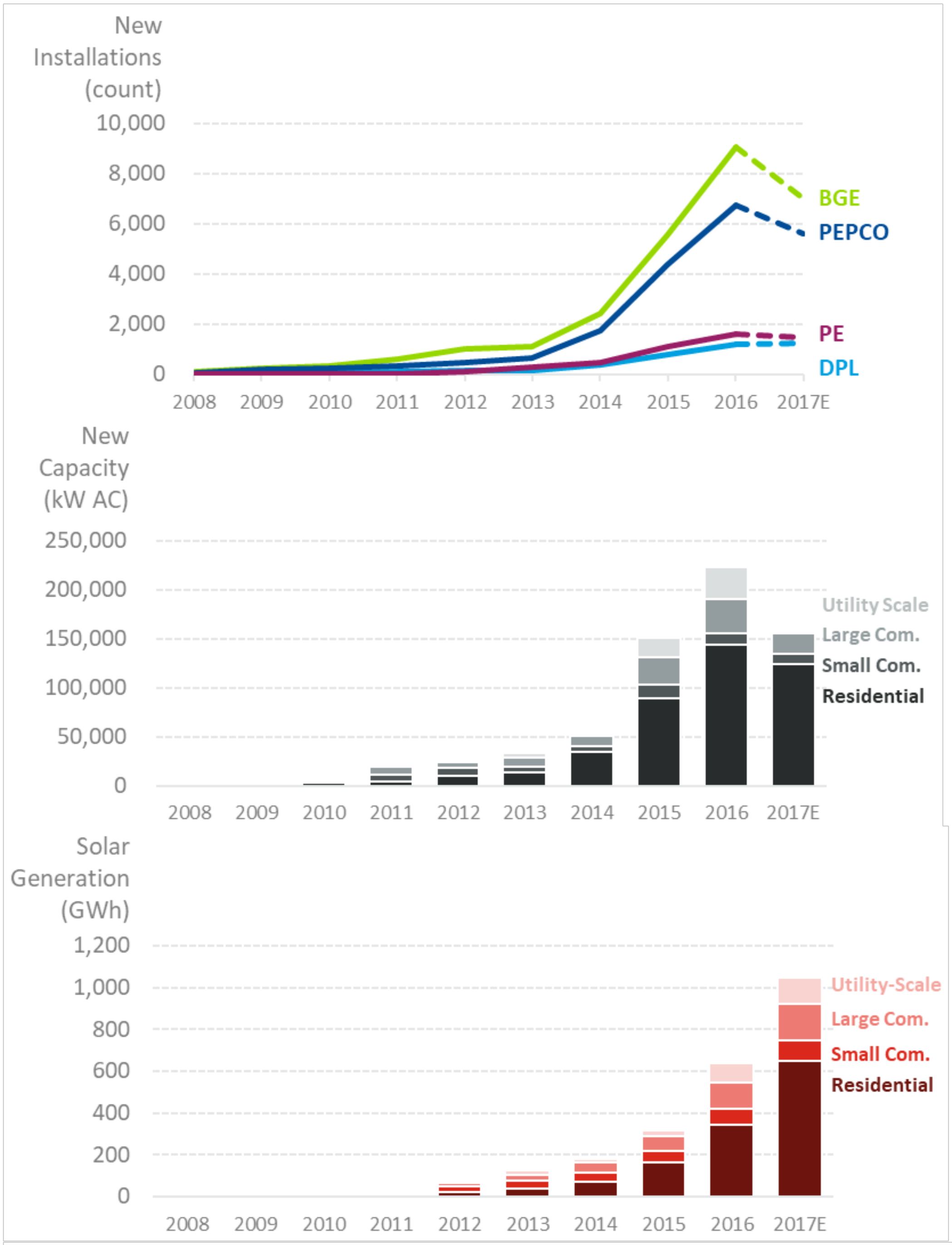

2017E data is estimated based on a partial year of data in 2017. Actual data is as of June 30, 2017 - the half-way point in the year; full-year 2017E data is estimated by doubling the partial year actuals.

Figure 16: Aggregate Installations, Nameplate Capacity, and Generation

Production from all solar installation sizes has increased significantly over time. As demonstrated in Figure 16, from 2003 to 2009, production was low but steadily increasing incrementally for both residential and small commercial/industrial sources. Between 2010 and 2016, large commercial/industrial installations accounted for most of the production with utility-scale generation a close second in output, until 2016 when it surpassed large commercial/industrial output. Residential output began significantly increasing in 2016 when it almost matched utility-scale output and then surpassed it in 2017.

Small commercial/industrial output remains the smallest contributor to combined utility solar production in this analysis. The magnitude of large commercial/industrial and utility-scale generation may be attributed to economies of scale. The individual large commercial/industrial and utility-scale installations are significantly large in capacity such that, regardless of the smaller number of installations, their annual output is significantly large in comparison to the other categories. Total annual production for all customer-sited solar generation in the four utility service areas is estimated at 950,000 GWh as of June 30, 2017.

3.3.2.1 Capacity by Installation Size Tranche

Total installed solar capacity by June 2016 by tranche, which is residential, small commercial/industrial, large commercial/industrial, and utility-scale, is depicted in Figure 17 for the four utility service territories. The residential tranche makes up the majority of the installed capacity. Large commercial/industrial capacity is second to residential, however, residential capacity is about three times that of the large commercial/industrial tranche. Small commercial/industrial capacity and utility-scale capacity are approximately equal. Total installed nameplate capacity to date is slightly less than 600,000 kW (AC). This represents approximately 60 percent of the solar RPS carve out requirement by 2020.

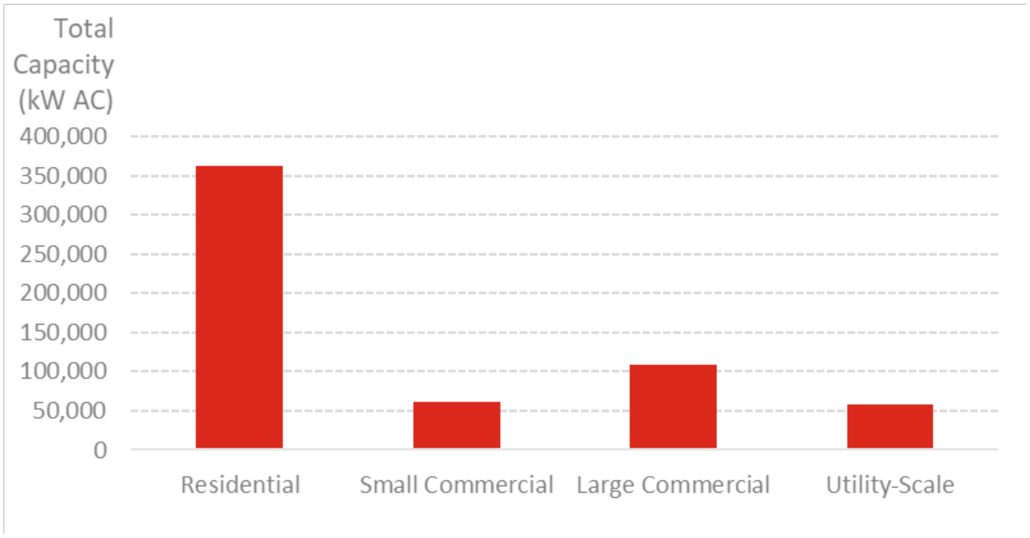

Figure 17. Installed Solar Capacity by Size Tranche for All Service Territories

The average size of residential, small commercial/industrial, and large commercial/industrial installations show increasing trends over time, as shown in Figure 18. While average residential installation size has increased at a fairly steady rate, small and large commercial/industrial installations show higher variability year to year. The average size of utility-scale installations is 2 MW; this trend has stayed constant through time except for in 2016.

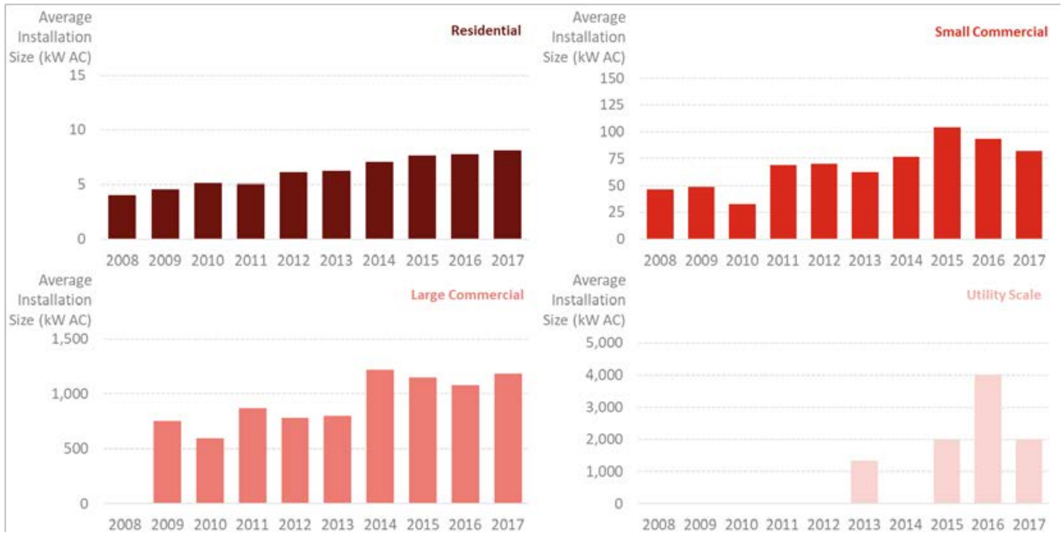

Figure 18. Average Installation Size per Year for Individual Solar Tranches - All Service Territories

3.4 Potential for Future Solar Development

The technical potential for future solar development needs to take into consideration both the Electrical Hosting Capacity[21] as well as available real estate (rooftop and land) suitable for solar development. This section summarizes our analysis of the technical potential for additional solar for each of the investor owned utilities in Maryland.

3.4.1 Electrical Hosting Capacity

Electrical Hosting Capacity was determined based on a feeder- and substation-level evaluation of distribution system data provided by each of the four Maryland IOUs.

Electric Hosting Capacity estimates were then determined for each feeder taking into consideration factors such as existing generation, thermal capacities (other than substation transformers and backbone conductors), and protection schemes that are likely to impact the amount of solar capacity that can be added without major transformer and or distribution line expansion.

[21] Defined, for the purposes of this study, as the available potential electrical capability across the distribution system to interconnect solar without major transformer and or distribution line expansion.

The results, shown below, are valid at a high level for determining the potential level of solar that feeders within each of the territories can accommodate. The full methodology is described in Section 4.6 of this report.

Figure 19 displays feeder hosting capacities for each of the four investor owned utilities in Maryland. In each graph, feeder capacities are sorted from largest to smallest, so for instance, the feeder with the most hosting capacity in BGE's territory is shown at the left, with a hosting capacity of close to 60,000 kVA.

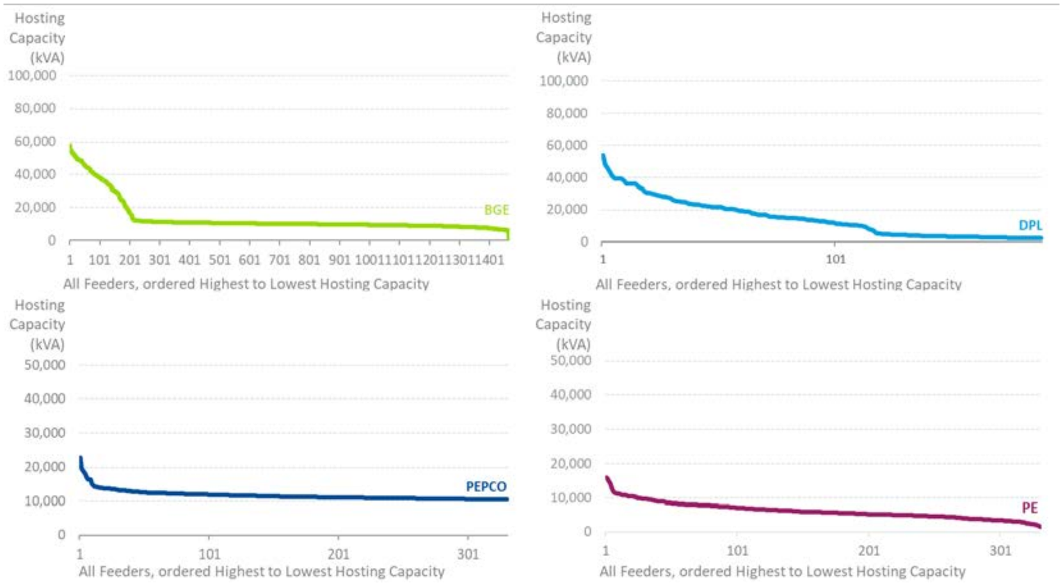

Figure 19: Distribution System Electrical Hosting Capacity by Service Territory

As represented by the area under each curve, the distribution systems across Maryland's investor owned utility service territories can support significant additions of solar energy without the need for major upgrades such as the rebuilding or expansion of lines or substations. The following totals represent the approximate aggregate Electrical Hosting Capacity for nameplate solar capacity that may be realized from a distribution standpoint:

- Baltimore Gas & Electric = 19.9 GW
- Delmarva Power and Light = 2.8 GW
- Potomac Electric Power Company = 7.3 GW
- Potomac Edison = 2.0 GW

As mentioned above, Electrical Hosting Capacity is only one element of determining the solar technical potential. Available real estate (rooftop and land) suitable for solar development must also be considered. The following sections analyze the rooftop and land real estate suitable for solar to determine the rooftop solar potential (MW) and Utility Scale solar potential (MW), respectively. These values are then compared against the Electrical Hosting Capacity to determine the total technical potential across all 4 utilities.

3.4.2 Rooftop Solar Potential

Recent research by NREL was used as the basis for our rooftop solar potential analysis. In a 2016 report entitled, Rooftop Solar Photovoltaic Technical Potential in the United States: A Detailed Assessment, NREL developed a methodology to assess rooftop potential in the United States. The report starts by using light detection and ranging ("LIDAR") and Geographic Information System ("GIS") data to assess potential in 128 cities and then develops two statistical models to extend the potential analysis to small and medium/large buildings in the United States. This report showed a that the solar capacity in Maryland would be 10.9 GW for small buildings[22] and 8.5 GW[23] for medium or large buildings. The NREL research included some more granular data that could be used to allocate the solar capacity to the individual IOU territories. The remainder of this Section 3.4.2 discusses the calculation of the potential available for each category of solar for each IOU territory.

3.4.2.1 Residential and Small Commercial Solar Rooftop Potential Methodology

Residential and small commercial rooftop solar potential was determined for the Maryland IOUs by first collecting customer data from the four IOUs, which provided customer census data outlining the cities, counties, and zip codes for all the customers in their individual IOU service territories.[24] Additionally, forecasted customer data for each IOU in Maryland was taken from a report published by the Maryland Public Service Commission providing a ten-year plan (2016-2025) for the electric companies in

[22] NREL, Rooftop Solar Photovoltaic Technical Potential in the United States: A Detailed Assessment. January 2016, page 26. https://www.nrel.gov/docs/fy16osti/65298.pdf.

[23] Ibid, page 32.

[24] Discovery Responses 1.2 and 1.3 from each IOU.

Maryland.[25] Next, NREL's NSRDB Data Viewer was accessed to download zip code-level data on the suitability of small buildings for rooftop solar.[26]

After collecting all the necessary data, small building suitability was then calculated for each utility through the following process:

1. Suitable building per zip code were calculated by multiplying the number of small buildings by zip code times the percent suitability.[27]
2. Calculate the MW of suitability by zip code by multiplying the total MW of potential (10.9 GW)[28] by the suitable small buildings per zip code divided by the total suitable small buildings in Maryland.
3. Zip codes within each IOU's respective service territories were matched up with the zip code-level small building suitability data.
    a. While assigning zip codes from each IOU to the small building potential data, we needed to address duplicate zip codes that spanned across multiple utilities. Since there is no way to determine percent of a zip code covered by each IOU, we split the small buildings located in zip codes that spanned into multiple IOUs in half, i.e. assigned 50% to one IOU and 50% to the other IOU. This allocation was reasonable because zip codes only ever spanned into one other IOU service territory.
4. Total suitable small buildings and total suitable rooftop capacity MW for each IOU were calculated by summing the totals of each based on zip codes in each of the IOU service territories. These totals are shown in Table 11 below.

[25] Ten-Year Plan (2016-2025) of Electric Companies in Maryland, Prepared for the Maryland Department of Natural Resources, in compliance with Section 7-201 of the Public Utilities Article, *Annotated Code of Maryland*, November 2016, specifically Appendix 1(a) pages 35-36. http://www.psc.state.md.us/wp-content/uploads/Final-2016_2025_TYP-12_8_16.pdf

[26] https://maps.nrel.gov/nsrdb-viewer/?aL=UdPEX9%255Bv%255D%3Dt%268VWYIh%255Bv%255D%3Dt%268VWYIh%255Bd%255D%3D1&bL=clight&cE=0&lR=0&mC=4.740675384778373%2C22.8515625&zL=2

[27] Percent suitability was per zip code was provided by NREL in the downloaded data.

[28] Installed capacity potential converted to MW that was provided by NREL in its report titled "Rooftop Solar Photovoltaic Technical Potential in the United States: A Detailed Assessment", published January 2016, page 27. https://www.nrel.gov/docs/fy16osti/65298.pdf

Table 11: Total Suitable Small Buildings and Capacity MW by IOU

	Total Suitable Small Buildings (count)	Total Small Building PV Capacity (MW)
BGE	1,519,532	8,023
DPL	113,646	600
PEPCO	235,962	1,246
PE	150,013	792
Total	**2,019,152**	**10,662**

Once the total small buildings suitable for solar and associated solar capacity MW for each IOU were determined, the totals of each were allocated between residential and small commercial. This was accomplished by first averaging the number of residential and commercial customers forecasted in the ten-year plan (2016-2025) for the electric companies in Maryland. Then the total small buildings suitable for solar and associated solar capacity MW for each IOU were allocated to residential and small commercial based on percent of average customers of each in each of the IOU service territories.[29] Table 12 below shows the residential and commercial allocations of suitable small buildings and total available potential MW for each IOU.

Table 12: Residential and Commercial Suitable Small Buildings and Available Potential MW by IOU

	Residential Suitable Small Buildings (count)	Residential Available Solar Capacity (MW)	Commercial Suitable Small Buildings (count)	Small Commercial Available Solar Capacity (MW)
BGE	1,384,266	7,309	135,266	714
DPL	98,854	522	14,792	78
PEPCO	215,392	1,137	20,570	109
PE	133,675	706	16,338	86
Total	**1,832,187**	**9,674**	**186,965**	**987**

[29] The allocation based on average forecasted customers was on average about 90% residential to 10% small commercial.

The available solar capacity in MW shown in the table above, does not consider the current residential and small commercial solar installations. Therefore, using the installation data provided by each utility, total installed solar capacity in MW was calculated for each IOU. The current installed MW of residential and small commercial BTM solar in each IOU as of 2017 was subtracted from the total available solar capacity in MW, as shown in the table above, to determine the rooftop potential MW of residential and small commercial BTM solar that could be installed in each IOU service territory. The results are summarized for each IOU in Section 2.4.2.2, below.

3.4.2.2 Large Commercial/Industrial Property Rooftop Solar Potential Methodology

Medium and large commercial/industrial (will be referred to as just large commercial in the rest of this section)[30] rooftop solar potential was determined for the Maryland IOUs by using commercial and industrial customer data from the ten-year plan (2016-2025) for the electric companies in Maryland[31] and the installed capacity potential for Maryland (8.5 GW)[32].

First, the average number of commercial and industrial customers forecasted in the ten-year plan (2016-2025) for the electric companies in Maryland was calculated for each IOU and the cooperatives (in total). Then a percentage weight was determined for each IOU, which was calculated by dividing the total average forecasted commercial and industrial customers in each utility by the total average forecasted commercial and industrial customers in Maryland. Lastly, the available solar capacity in MW by IOU was calculated by multiplying the percentage weight by the installed capacity potential for Maryland (8.5 GW). The available solar capacity in MW for large commercial is shown in Table 13 below.

[30] The main categories of BTM solar are residential, small commercial, and large commercial, so we will refer to medium and large commercial as just large commercial.

[31] Ten-Year Plan (2016-2025) of Electric Companies in Maryland, Prepared for the Maryland Department of Natural Resources, in compliance with Section 7-201 of the Public Utilities Article, *Annotated Code of Maryland*, November 2016, specifically Appendix 1(a) page 36. http://www.psc.state.md.us/wp-content/uploads/Final-2016_2025_TYP-12_8_16.pdf

[32] Installed capacity potential converted to MW that was provided by NREL in its report titled "Rooftop Solar Photovoltaic Technical Potential in the United States: A Detailed Assessment", published January 2016, page 32. https://www.nrel.gov/docs/fy16osti/65298.pdf

Table 13: Large Commercial Total Available Potential MW by IOU

	Total Available Solar Capacity (MW)
BGE	4,191
DPL	892
PEPCO	1,682
PE	1,042
Total	**7,087**

The available solar capacity in MW shown in Table 13 above, do not consider the current large commercial solar installations. Therefore, using the installation data provided by each utility[33], total installed capacity in MW was calculated for each IOU. The current installed MW of large commercial BTM solar in each IOU as of 2017 was subtracted from the available solar capacity in MW, shown in Table 13 above, to determine the available potential MW of large commercial BTM solar that could be installed in each IOU service territory. The results are summarized for each IOU in Section 3.4.2.3, below.

3.4.2.3 Total Rooftop Potential

The residential, small commercial, and large commercial rooftop available potential results based on the methodologies and calculations previously described are provided in the tables below. Figure 20 shows the installed solar versus the potential solar. Table 14 through Table 17 summarize the calculations to estimate total small buildings suitable for solar installations, the existing installed solar, and the resulting small buildings suitable for solar installations on a kW basis. BGE has the greatest available solar potential at 12 GW, while DPL has the lowest available solar potential at 1.5 GW for residential and commercial rooftop solar.

[33] Discovery Response 1.2 from each IOU.

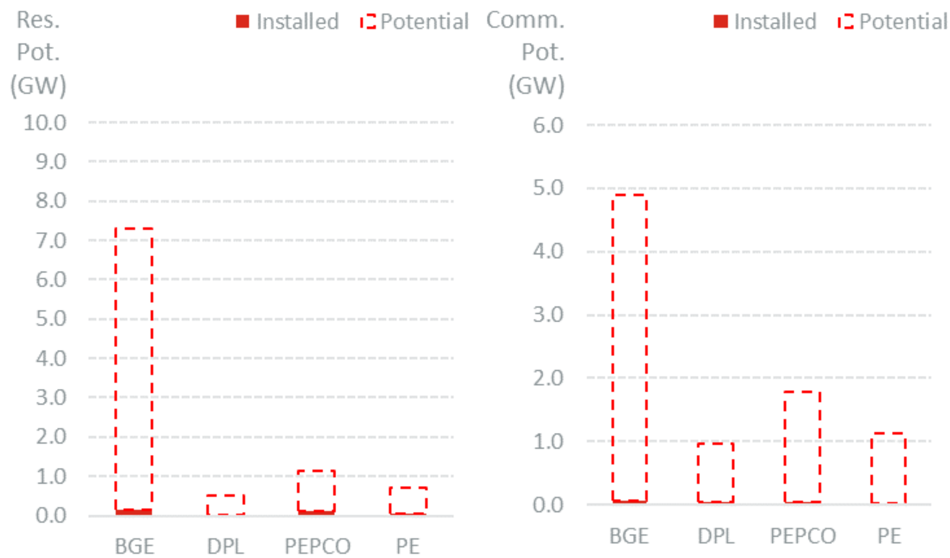

Figure 20: Residential and Commercial Available Capability versus Current Installed Capability

Table 14. BGE Solar Rooftop Potential - Residential and Commercial Properties

	RESIDENTIAL PV CAPACITY MW	SMALL COMMERCIAL PV CAPACITY MW	LARGE COMMERCIAL PV CAPACITY MW
Total Capability (kW)	7,309,208	714,232	4,190,699
Current Installed Solar (kW)	162,588	31,823	33,271
Total Rooftop Potential (kW)	7,146,621	682,408	4,157,428
Total Rooftop Potential (GW)	**7.1**	**0.7**	**4.2**

Table 15. DPL Solar Rooftop Potential - Residential and Commercial Properties

	RESIDENTIAL PROPERTY CAPABILITY	SMALL COMMERCIAL PROPERTY CAPABILITY	LARGE COMMERCIAL PROPERTY CAPABILITY
Total Capability (kW)	521,971	78,106	891,576
Current Installed Solar (kW)	31,100	12,516	30,068
Total Rooftop Potential (kW)	490,870	65,589	861,508
Total Rooftop Potential (GW)	**0.5**	**0.1**	**0.9**

Table 16. PEPCO Solar Rooftop Potential - Residential and Commercial Properties

	RESIDENTIAL PROPERTY CAPABILITY	SMALL COMMERCIAL PROPERTY CAPABILITY	LARGE COMMERCIAL PROPERTY CAPABILITY
Total Capability (kW)	1,137,314	108,611	1,681,928
Current Installed Solar (kW)	131,562	13,184	32,523
Total Rooftop Potential (kW)	1,005,753	95,427	1,649,406
Total Rooftop Potential (GW)	**1.0**	**0.1**	**1.6**

Table 17. PE Solar Rooftop Potential - Residential and Commercial Properties

	RESIDENTIAL PROPERTY CAPABILITY	SMALL COMMERCIAL PROPERTY CAPABILITY	LARGE COMMERCIAL PROPERTY CAPABILITY
Total Capability (kW)	705,832	86,267	1,042,381
Current Installed Solar (kW)	36,933	3,864	13,516
Total Rooftop Potential (kW)	668,900	82,403	1,028,865
Total Rooftop Potential (GW)	**0.7**	**0.1**	**1.0**

The sum of the residential rooftop solar potential for all IOUs is about 9.3 GW and the available commercial rooftop solar potential for all IOUs is about 8.6 GW (see Table 18 below for the summary). The combined available capability is about 17.9 GW of nameplate capacity.

Table 18: Available Solar Rooftop Potential for Residential and Commercial Properties for All IOUs

	RESIDENTIAL ROOFTOP POTENTIAL (GW)	COMMERCIAL ROOFTOP POTENTIAL (GW)
BGE	7.1	4.8
DPL	0.5	0.9
PEPCO	1.0	1.7
PE	0.7	1.1
Total	**9.3**	**8.6**

These results for the potential of BTM rooftop solar are based on small buildings per zip code for residential and small commercial and customer allocations for large commercial. Therefore, the results only represent the overall solar potential within the IOU service territories. The technical potential for BTM rooftop solar will be less, due to other factors such as transmission and distribution system constraints. A discussion of the technical potential for BTM solar deployment is addressed in the next section.

3.4.2.4 Total Rooftop Technical Potential

The determination of rooftop PV technical potential is determined by the lesser of the Electrical Hosting Capacity and rooftop solar potential for a given area. Table 19 shows the comparison of rooftop potential and Electrical Hosting Capacity by utility and the resulting rooftop PV technical potential values for each of the IOUs.

Table 19: Rooftop Technical Potential for Residential and Commercial Properties for All IOUs

UTILITY	Total Rooftop Potential (MW)	Electrical Hosting Capacity (MW)	Total Rooftop Technical Potential (MW)
BGE	16,177	19,863	**16,177**
DPL	2,310	2,751	**2,310**
PEPCO	4,433	7,307	**4,433**
PE	2,823	2,044	**2,044**
Total	**25,742**	**31,965**	**24,964**

It is important to note that the electrical hosting capacity included in Table 19, is the electrical hosting capacity available for both rooftop and utility scale projects (described in Section 3.4.3). If utility scale project are built, they will use up some of the electrical hosting capacity and the rooftop potential would be less.

3.4.3 Utility Scale Technical Potential

3.4.3.1 Utility-Scale Solar Potential

Physical land suitable for solar placement is a key factor in determining the potential for large, ground-mounted, utility-scale solar (defined as greater than 2.0 MW), The method of identifying the available acres suitable for solar PV by county in Maryland, is described in Section 6.3. Once this is determined, it is then assumed that each MW of solar requires approximately 7.25 acres of land to determine the Utility Scale land capacity (MW). The chart below summarizes by county the results of this analysis. Note, the counties of Charles and St. Mary's are not listed because they are not located within the territories served by the IOUs included in this study. Furthermore, due to utility service territory geodata limitations in evaluating suitable land by IOU, the "Acres Suitable for Utility-Scale PV" noted in Table 20 are by county, and as a result, may not all be located within the territories served by the IOUs included in this study. For example, the county of Talbot is served by DPL as well as Easton Utilities Commission and Choptank Electric Cooperative, neither of which are analyzed in this study, whereas the county of Baltimore is 100% served by BGE, which is analyzed in this study. A map showing the service territories of all electric utilities in Maryland is included, for reference, in Appendix X.

Table 20: Available Land Capacity for Utility Scale Solar by

COUNTY	AVAILABLE ACRES SUITABLE FOR UTILITY-SCALE SOLAR (acres)	UTILITY-SCALE SOLAR CAPACITY (MW)*
Allegany	22,901	3,159
Anne Arundel	35,466	4,892
Baltimore City	6	1
Baltimore	84,188	11,612
Calvert	51,098	7,048
Caroline	69,836	9,633
Carroll	26,695	3,682
Cecil	81,710	11,270
Dorchester	63,104	8,704
Frederick	109,549	15,110
Garrett	89,235	12,308
Harford	3,652	504
Howard	45,247	6,241
Kent	4,844	668
Montgomery	23,014	3,174
Prince George's	64,138	8,847
Queen Anne's	61,586	8,495
Somerset	34,565	4,768
Talbot	55,881	7,708
Washington	100,404	13,849
Wicomico	69,498	9,586
Worcester	60,670	8,368
Total	**1,157,287**	**159,626**

** 1 MW per 7.25 acres*

As can be seen in more urban counties, like Baltimore City, there is limited suitable land for utility scale solar. However, most of the other counties, particularly in rural areas have significant land available for utility scale solar. These values may be further constrained by electric hosting capacity, which is evaluated in the following section.

3.4.4 Utility Scale Technical Potential

The determination of technical Utility Scale PV potential is determined by the lesser of the Electrical Hosting Capacity and Utility Scale solar potential for a given area. This analysis was performed by county vs. utility due to limitations in the geodata to be able to assign suitable land to a utility service territory. Therefore, for this comparison, the Electrical Hosting Capacity analysis described in Section 2.4.1, above, was assigned to counties based on coordinates provided for substations in the BGE, PEPCO, and DPL territories.[34] Table 21, below, shows the comparison of Utility Scale PV potential and Electrical Hosting Capacity by county and the resulting Utility Scale PV technical potential values for each county.

Table 21: Utility Scale Technical Potential by County within IOU Service Territories

COUNTY	Utility Scale Land Capacity (MW)	Electrical Hosting Capacity (MW)	Utility Scale Technical Potential (MW)
Allegany	2,290	0	0
Anne Arundel	3,547	4,182	3,547
Baltimore City	0.6	3,513	0.6
Baltimore	8,419	5,461	5,461
Calvert	5,110	71	71
Caroline	6,984	83	83
Carroll	2,669	1,032	1,032
Cecil	8,171	807	807
Charles	9,266	0	0
Dorchester	6,310	189	189
Frederick	10,955	0	0
Garrett	8,923	0	0
Harford	365	2,313	365
Howard	4,525	1,689	1,689
Kent	484	116	116
Montgomery	2,301	4,290	2,301
Prince George's	6,414	4,557	4,557
Queen Anne's	6,159	342	342
Somerset	3,456	80	80
St. Mary's	7,899	0	0
Talbot	5,588	81	81
Washington	10,040	0	0
Wicomico	6,950	384	384
Worcester	6,067	519	519
Total	**132,893**	**29,709**	**21,625**

[34] Locational distribution data was not provided by PE.

Counties within the PE territory are grouped together due to lack of data associated with distribution substation locations. The results in this grouping includes PE system-wide data, plus the portion of hosting capacity assigned to these counties from BGE and PEPCO.

Counties that were available for comparison can be seen to be mostly unconstrained by suitable land for Utility Scale solar. However, Baltimore City county appears to be limited by land rather than electrical capacity. Land constraints on solar development in this area may be reduced or even eliminated through the utilization of rooftop installations.

Additional land capacity associated with Commercial Industrial ground mount solar on existing developed properties was not evaluated since the land analysis demonstrated that with the exception of Baltimore City, land is not the constraining factor. It should also be noted that Technical Hosting Capacity absorbed by rooftop solar installations discussed above would serve to reduce the Utility Scale Technical Potential overtime.

3.5 Impact of State Policies and Incentives on Deployment of Renewable Energy and Solar

3.5.1 Qualitative Analysis: Literature Review

There are mixed results within the literature as to the effect of RPS on the deployment of renewable resources. In 2010, Lawrence Berkeley National Laboratory ("LBL") found that an RPS can spur solar energy deployment, though this was most noticeable in states whose RPS included solar carveouts (i.e. specific goals for solar energy as a percentage of the RPS)[35]. In 2012, a national-level quantitative regression analysis submitted to the U.S. Association of Energy Economics found that once other renewable energy incentives and policies are accounted for, the RPS itself is not a significant driver of overall renewable energy deployment, wind deployment, or solar deployment. Instead they found that other policies and incentives have statistically significant impacts[36].

[35] Wiser, R., Barbose, G., & E. Holt. 2010. Supporting Solar Power in Renewables Portfolio Standards: Experience from the United States. Lawrence Berkeley National Laboratory.

[36] Shrimali, G., Jenner, S., Groba, F., Chan, G., & J. Indvik. 2012. Have State Renewable Portfolio Standards Really Worked? Retrieved: http://www.usaee.org/usaee2012/submissions/OnlineProceedings/Shrimali%20Online%20Proceedings%20Paper.pdf

In 2016, NREL, in conjunction with the LBL, published a study on the benefits and impacts of RPS at a national level. In order to estimate the impact of the RPS on renewable deployment, they look at renewable capacity added specifically for RPS compliance as well as fossil fuel generation displacement. NREL and LBL determined that RPS-related capacity additions from 2013-2014 were around 5,600 MW annually, most of which was in the form of utility-scale solar. Contrary to popular belief, the most displaced fossil fuel capacity was in the form of gas turbines. Coal-fired generation was the second most displaced form of fossil fuel generation. The new RPS capacity editions were estimated to have displaced 3.6% reduction in total fossil fuel generation. NREL and LBL determined that the RPS were resulting in an amount of new capacity additions at a national level that succeeded in displacing fossil fuel generation[37].

There is limited literature surrounding the effects of solar-focused incentives on solar deployment. A 2009 study done by the George Washington University Institute of Public Policy looked at the impact of solar incentives in 10 states on two hypothetical solar installations, one residential-scale and one commercial-scale. This study is relevant because it looks at solar incentives in both New Jersey and Delaware, two states bordering Maryland, with similar locations and similar power markets. The study found that New Jersey's policies had been "extremely successful at stimulating solar deployment" because the rebates in addition to the Federal ITC covered almost the entire cost of installation of solar systems. The policies in Delaware, in contrast, do not offer incentives that are nearly as large as those in New Jersey, and have been less effective. When the policies were applied to the hypothetical solar installations, the trend is clear: the greater the value of the incentive, the greater solar deployment is seen[38].

Another quantitative regression analysis done by Shrimali and Jenner in 2012 notes that, with a high degree of confidence, deployment of solar grew faster in the commercial sectors when a cash incentive was in place than when a cash incentive was not. They also noted that, with lower confidence, interconnection standards showed positive

[37] NREL and LBL. 2016. A Retrospective Analysis of the Benefits and Impacts of U.S. Renewable Portfolio Standards.

[38] Sarzynski, A. 2009. The Impact of Solar Incentive Programs in Ten States. George Washington Institute of Public Policy.

effects on solar deployment at the residential level, while property tax incentives showed positive effects on commercial solar deployment[39]

3.5.2 Quantitative Analysis: Regression Modeling

To determine the effect of these policies on renewable deployment and specifically solar deployment in Maryland we performed a regression analysis similar to the one done by Shrimali et al. in which they accounted for the RPS and other state and federal policies.

3.5.2.2 Methodology

For the regression analysis, we employed several different types of independent variables to account for policies and other factors that may affect deployment of renewable energy and specifically solar. For control variables in the regression, we obtained data on average electricity price, median household income, electricity imports, and Maryland's LCV Score[40]. We control for electricity price because high electricity prices are thought to increase deployment of renewable energy. We lag this variable once to avoid reverse causality. Median household income is related to deployment of renewables because it is expected that states with higher incomes may better absorb the additional costs associated with the shift away from conventional fuels. We control for imports to account for the imbalance between domestic sales and out of state power generation. It is supposed that a high import ratio advances domestic renewable energy deployment. Lastly, LCV score is an index created by the League of Conservation Voters that tracks voting behavior at a state level, assigning a score based on how the State's representatives stand with regard to environmental issues. A higher LCV score means that the state and its representatives are in tune with environmental issues and we expect this to correlate with positive renewable deployment[41].

Next, we created policy variables to account for the instatement of state and federal policies that could affect the deployment of renewable energy. We looked to account for the instatement of Maryland's Net Metering policy, the state-level production tax credit, the state-level property tax exemption, and the state-level sales and use tax exemption.

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[39] Shrimali, G. & S. Jenner. 2012. The Impact of State Policy on Deployment and Cost of Solar PV: A Sector-specific Empirical Analysis.

[40] LCV score is an index created by the League of Conservation Voters that tracks voting behavior at a state level, assigning a score based on how the State's representatives stand with regard to environmental issues.

[41] Shrimali, G., Jenner, S., Groba, F., Chan, G., & J. Indvik. 2012. Have State Renewable Portfolio Standards Really Worked? Retrieved: http://www.usaee.org/usaee2012/submissions/OnlineProceedings/Shrimali%20Online%20Proceedings%20Paper.pdf

These policies were accounted for by creating binary variables with the value of 0 when the policy was not in place and the value of 1 when the policy was in place.

In order to account for the RPS specifically and its effect on deployment, state-level data was obtained for generation output and installed nameplate capacity[42]. We employed two different ways of accounting for the RPS. First was to follow the model put forth by Shrimali et al, to represent RPS and policy stringency. This metric, denoted ISI, represents "the mandated increase in renewable generation in terms of the percentage of all generation." The ISI metric is calculated according to the following equation:

$$ISI_{it} = \frac{\eta_{it}^{RES} * \kappa_{it}^{RES} * q_{it}^{total} - Q_{it}^{RES}}{q_{it}^{RES}}$$

Where η_{it}^{RES} is the "RPS yearly fraction;" the ratio of renewable energy generation to total electricity generation. κ_{it}^{RES} represents the percentage of renewable generation capacity that is legally eligible to meet η_{it}^{RES}. Q_{it}^{RES} represents the existing absolute renewable generation, q_{it}^{total} represents the annual total electricity generation, and q_{it}^{RES} represents the annual total renewable generation[43].

The second way we attempted to account for the RPS was to give it binary values as was done above with regard to the other policies we examined in this analysis. These two ways to account for RPS were separately from each other; they were never both used in the same regression.

For the analysis we look at policy effects on two separate dependent variables. First, we look at the annual capacity of renewable energy installed. Second, we look at the capacity ratio of renewables to total annual installed capacity. For the solar-specific regression analysis, the independent variables did not change, however the annual capacity used was only the solar capacity and the capacity ratio was adjusted to reflect the ratio of solar capacity to all other installed capacity. All regressions were run at 90% confidence.

3.5.2.3 Results

Overall Renewable Energy Deployment--We performed two regressions with the renewable energy capacity ratio as the dependent variable and two with overall annual

[42] EIA Electric Power Annual. http://www.eia.gov/electricity/data/state/

[43] Ibid. 2012.

renewable energy capacity as the dependent variable. One of the two regressions used the ISI parameter while the other uses the RPS binary variable.

None of the policy parameters are statistically significant when we use the capacity ratio as the dependent variable. When we use annual renewable energy capacity as the dependent variable, the ISI parameter becomes the only statistically significant policy. The RPS when represented as a binary variable was never significant. This tells us that with respect to total renewable energy deployment in Maryland, the RPS is likely responsible for the increase in overall annual renewable energy capacity.

Solar Deployment-- We performed two regressions with the renewable energy capacity ratio as the dependent variable and two with overall annual renewable energy capacity as the dependent variable. One of the two regressions used the ISI parameter while the other uses the RPS binary variable.

Regardless of the dependent variable (capacity ratio or overall annual capacity), when the ISI parameter is used to represent the RPS, both Net Metering and the Sales and Use Tax exemption become statistically significant. When the RPS Binary is used instead, only the Sales and Use Tax Exemption is statistically significant. Additionally, it should be noted that with use of the RPS Binary, the net metering parameter is very close to significant. This tells us that, with respect to solar deployment in Maryland, it is likely other policies than the RPS, such as Net Metering and Tax exemptions, that are resulting in the increase in the ratio of solar relative to other generation as well as the increase in overall annual solar capacity.

3.5.3 Changes to Policies and Incentives: The Effects of the 2018 Tax Reform and the New Tariffs on Solar Panel Imports

With the passage of the new Tax Reform bill, there was a great amount of uncertainty as to the effects of the legislation especially the effects of the bill on renewable energy technologies. The final version of the bill which became law on January 1, 2018 left all tax credit regimes and their phase-outs in place and untouched. This means that the 30% Investment Tax Credit available to solar projects that begin construction before 2019 is still available and unaltered, as well as the incremental step-down of 26% in 2020, and 22% in 2021. This also means that the decrease of credit to 0 for residential systems after 2021 still applies, as does the perpetual 10% credit for commercial and utility-scale systems after 2021.

Suniva and SolarWorld filed a petition under Section 201 of the 1974 Trade Act stating that cheap imports of solar equipment had made it impossible for the manufacturers to compete in domestic markets. In September 2017, U.S. Trade Commissioners ruled unanimously in favor of Suniva and SolarWorld; that the importation of solar equipment, specifically cells and modules made in Singapore and Canada, had caused "serious injury" to domestic manufactures.

On January 23, 2018, President Trump approved solar tariffs for the next four years including a rate quota. The tariffs will start at 30% and fall to 15% incrementally over the 4-years, with the first 2.5 GW of cells imported annually being exempted from the tariff to help ensure that U.S. module manufacturers will still have access to cheap cells[44]. The tariffs are expected to increase the installed costs of solar projects over the next four years, with the largest impact coming in the first year. Given that panel prices make up a smaller percentage of residential solar installed costs, the impact on residential project costs is expected to be smaller than larger utility scale projects where modules make up a larger portion of the installed cost.

[44] Swanson, A. & B. Palmer. 2017. Trump Slaps Steep Tariffs on Foreign Washing Machines and Solar Products. The New York Times. Retrieved from: https://www.nytimes.com/2018/01/22/business/trump-tariffs-washing-machines-solar-panels.html?hp&action=click&pgtype=Homepage&clickSource=story-heading&module=first-column-region&region=top-news&WT.nav=top-news.

4. BULK POWER SYSTEM BENEFITS AND COSTS

4.1 Introduction

Value of Solar continues to be a widely discussed topic across the country. Multiple jurisdictions have conducted studies to understand the costs and benefits of adding solar to a portfolio of generation resources or as a distribution alternative. Understanding these costs and benefits can inform decisions regarding the fair compensation and positioning for solar.

Daymark's analysis is comprised of components of potential benefits (or costs) that solar brings to the electric system. At the highest level these components can be categorized into direct utility benefits and societal benefits, with some components providing benefits in both categories. The components identified for this analysis are based on prior experience with value of solar in Maryland with two large electric cooperatives, review of other value of solar analyses, our knowledge of the four utilities operating in Maryland, and the PJM marketplace. The bulk power system components considered are provided in Table 22 below.

Table 22: Bulk Power System Costs and Benefits

COMPONENT	DESCRIPTION
Avoided Energy	Market energy purchases avoided due to distributed solar
Avoided Capacity	Market capacity purchases avoided due to distributed solar
Avoided Transmission Costs	Avoids/defers/reduces transmission investment/charges due to reduction in peak load
Ancillary Services Avoided	Impact of solar on Ancillary Services costs
Market Price Response	Indirect effects of solar on market prices for energy and capacity
Fuel Price Hedge Savings	Reduces exposure to volatile prices of fuels due to solar generation reducing energy needs
Avoided REC Purchases	Reduces entity requirement to comply with RPS policies

This section of the report discusses each bulk power system component in detail, methodologies for calculating the impact of both distributed solar and utility scale solar for each component, and the results of the bulk power system benefits and costs analysis.

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4.2 Energy Market Costs and Benefits

Solar has several potential energy market benefits. The first is the energy value of solar and the second is the market price impact benefits of solar. The energy value of solar can be thought of in two ways: both a BTM-scale project or a utility scale project selling power directly to the grid. With a BTM project, solar energy generated reduces the amount of energy that the LSE must purchase from the PJM market to satisfy its demand, thereby reducing energy costs. In the case of a grid connected utility scale project, a solar facility's energy value is the price that the project can sell its power into the PJM market.

The second energy benefit is the market price effect of adding a large amount of zero marginal cost power to the system. In theory adding a large amount of a zero marginal cost resource, such as solar, reduces the cost of energy for the market because its addition allows a lower cost resource to be the marginal price setting resource in the supply stack.

Section 4.2details the methodology and results for the calculation of both energy benefits.

4.2.1 Energy Market Simulation

4.2.1.4 Methodology

The energy market benefit of solar within the state of Maryland is derived from analysis using Daymark's PJM Interconnection Market Model ("PMM"). PMM uses an hourly chronologic electric market simulation model on the AURORAxmp® software platform ("AURORA"), developed by EPIS, Inc. AURORA realistically approximates the formation of hourly energy market clearing prices on a zonal basis throughout PJM and neighboring regions accounting for all key market drivers, including fuel and emission allowance prices, loads, demand-side management, generation unit operating characteristics, unit additions and retirements, and transmission congestion and losses.

The results of the market simulation performed with PMM provides the data to estimate both avoided energy and market price response benefits to LSE's in the state of Maryland under a reference and two alternative market scenarios ("High CO_2, Low Gas"), described further in the following section. These scenarios are designed to test the impact of changes in key market uncertainties driving energy value.

Each of the three scenarios is modeled with a base case run, and a solar case run ("change" or "difference" case). Value of solar estimates are based on the modeled costs and benefits of the incremental solar in the solar case by observing the difference in pricing between the cases.

4.2.1.5 Inputs and Assumptions

Daymark's PMM utilizes a comprehensive database representing the entire Eastern Interconnect, including representations of power generation units, zonal electrical demand and interzonal transmission limits. The database is constructed from several established sources, including an industry-leading default database issued by EPIS, Inc., the developer of AURORA, the U.S. Department of Energy's Energy Information Administration ("EIA"), and PJM. Key model outputs are benchmarked carefully against recent actual market outcomes to ensure reasonable results.

In addition to a reference scenario, we also constructed two scenarios testing alternative assumptions for natural gas prices and carbon allowance pricing. The scenarios and their distinguishing input assumptions are summarized in Table 23.

Table 23: Summary of Energy Market Forecast Scenarios

SCENARIO	NATURAL GAS PRICE	CARBON PRICE
Reference	AEO 2017 Reference	RGGI Price Forecast
High CO_2	AEO 2017 Reference	National Program in 2021 (EPA 5% Price Forecast)
Low Gas	AEO 2017 High oil and gas resource and technology	RGGI Price Forecast

The reference gas price scenario relied on the EIA's 2017 Annual Energy Outlook ("AEO 2017") Reference Case forecast for natural gas prices at Henry Hub. PJM as a market has seen significant increases in natural gas generation in the past five years, with new generation announced and coming online in the next few years to replace older, less efficient and more expensive to run, coal units. The advent of cheap natural gas, along with the continued development of these resources, makes natural gas prices an important variable to consider in valuing solar in the bulk power system. The Low Gas scenario used EIA's AEO 2017 High Oil and Gas Resource and Technology forecast to test the sensitivity of natural gas prices to the value of solar. Figure 21 shows Henry Hub prices for each of the two natural gas scenarios.

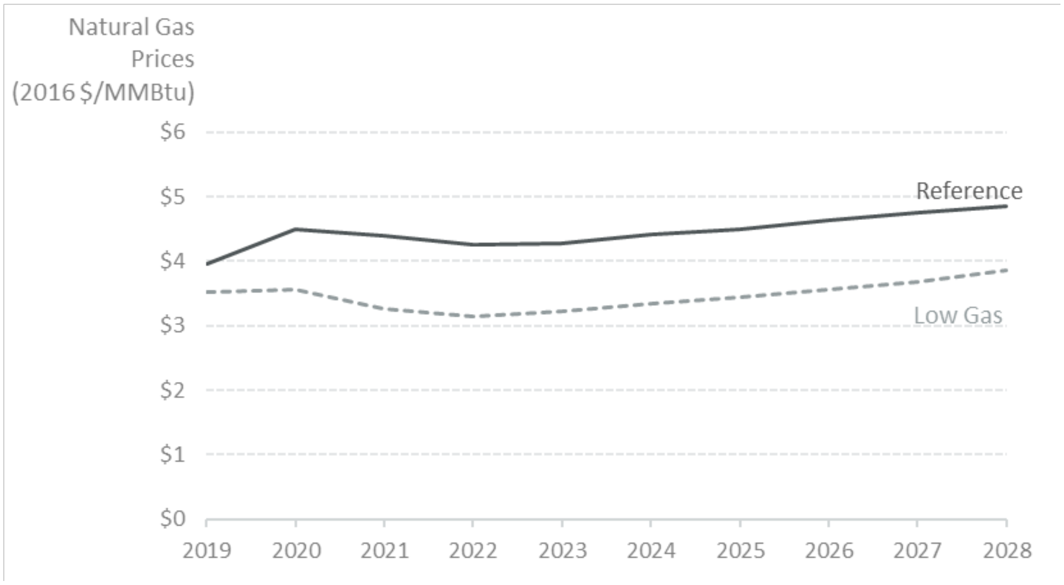


Figure 21: Henry Hub Natural Gas Prices by Scenario.

The reference carbon price forecast relied on a Regional Greenhouse Gas Initiative ("RGGI") CO_2 allowance price forecast and applied to generators located in states that have adopted RGGI. The forecast is derived from analysis completed by RGGI related to the latest the proposed rule update and represents the forecast of RGGI prices under the latest rule update.[45] Maryland and Delaware are the only PJM states currently participating in RGGI.[46] The High CO_2 scenario assumes Reference RGGI prices initially, then implementation of a federal carbon reduction program in 2021 that imposes a price on CO_2 emissions from all generators equivalent to the EPA societal cost of carbon ("SCC") 5% discount rate national carbon price.[47][48] Figure 22 provides a graphical representation of the CO_2 pricing assumed in the PMM cases.

[45] Regional Greenhouse Gas Initiative. DRAFT 2017 Model Rule Policy Scenario Overview. September 25, 2017. Page 14. https://www.rggi.org/sites/default/files/Uploads/Program-Review/9-25-2017/Draft_IPM_Model_Rule_Results_Overview_09_25_17.pdf

[46] On January 29, 2018, New Jersey Governor Phil Murphy signed an executive order to start the process for the state to reenter RGGI. Additionally, Virginia is considering joining RGGI.

[47] The Societal Cost of Carbon represents monetized damages associated with an incremental increase in carbon emissions in a given year. Four scenarios are presented in the report cited in the next footnote. We have chosen the 5 percent discount case, which is the lowest case presented.

[48] 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. https://19january2017snapshot.epa.gov/sites/production/files/2016-12/documents/sc_co2_tsd_august_2016.pdf

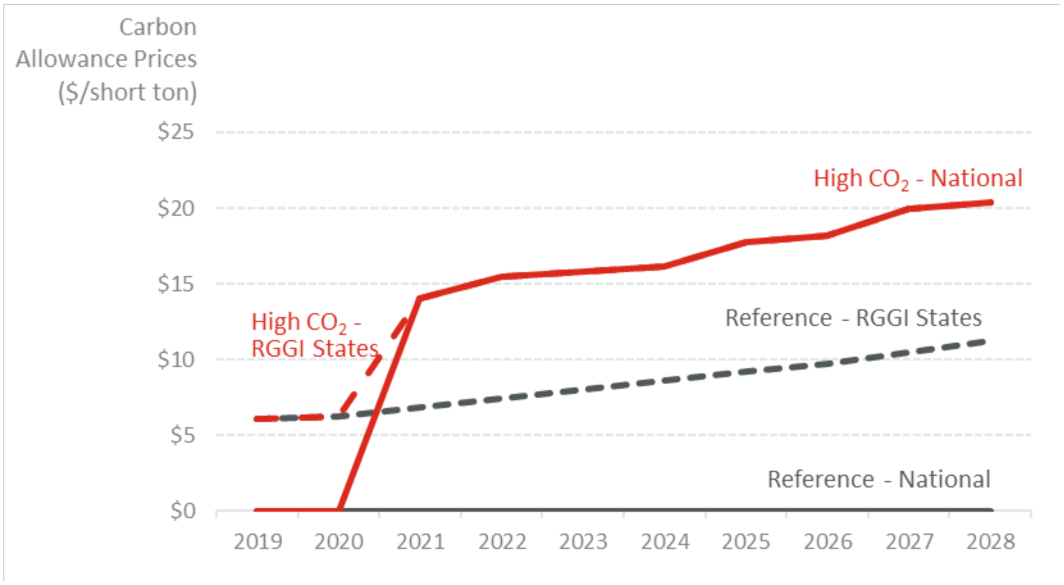


Figure 22: Carbon Pricing Scenarios. Reference (RGGI). High Carbon. (EPA SCC 5%).

The PMM was run twice for each scenario with two cases for Maryland-based solar development: a base case and a difference case for each of the three scenarios – the buildout of solar described below in each of the difference cases is the same – only key assumptions around CO_2 and gas pricing change. The base case assumes no additional utility scale solar is added in Maryland after 2018 and distributed (BTM) solar installations are consistent with the assumptions in PJM's 2017 long-term load forecast. The difference or incremental solar case assumes 2 GW of incremental distributed solar and 2.4 GW of incremental utility scale solar is added over the study period, which was chosen to be consistent with the 30% RPS High Solar case in PJM's Renewable Integration Study.[49] Figure 23 below shows solar installation levels for both cases over the 10-year study period used in PMM.

[49] PJM Renewable Integration Study (March 2014). http://www.pjm.com/committees-and-groups/subcommittees/irs/pris.aspx

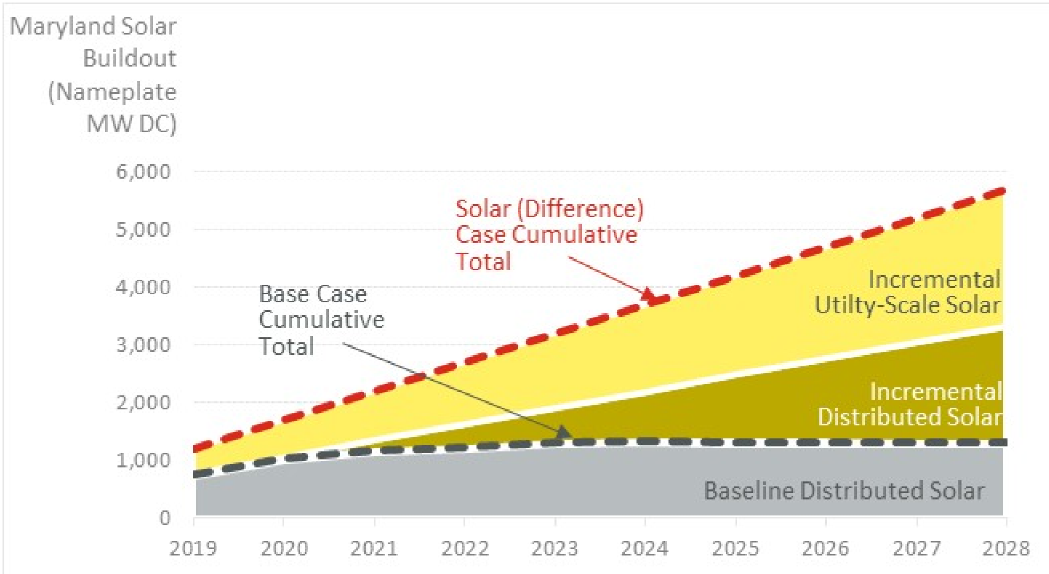


Figure 23: Solar Buildout (Nameplate MW) by Case and Installation Type

Total distributed solar online in Maryland as modeled increases to 3,300 MW nameplate by 2028, while total utility scale solar achieves 2,400 MW nameplate by 2028. Figure 24 and Figure 25 show how statewide solar installations in the difference case, for BTM and utility scale solar respectively, are distributed across the four PJM zones that cover Maryland.[50]

[50] These four Maryland-based zones are Allegheny Power Systems (APS) in which Potomac Edison operates, Baltimore Gas and Electric Company (BGE), Delmarva Power and Light Company (DPL) and Potomac Electric Power Company (PEPCO).

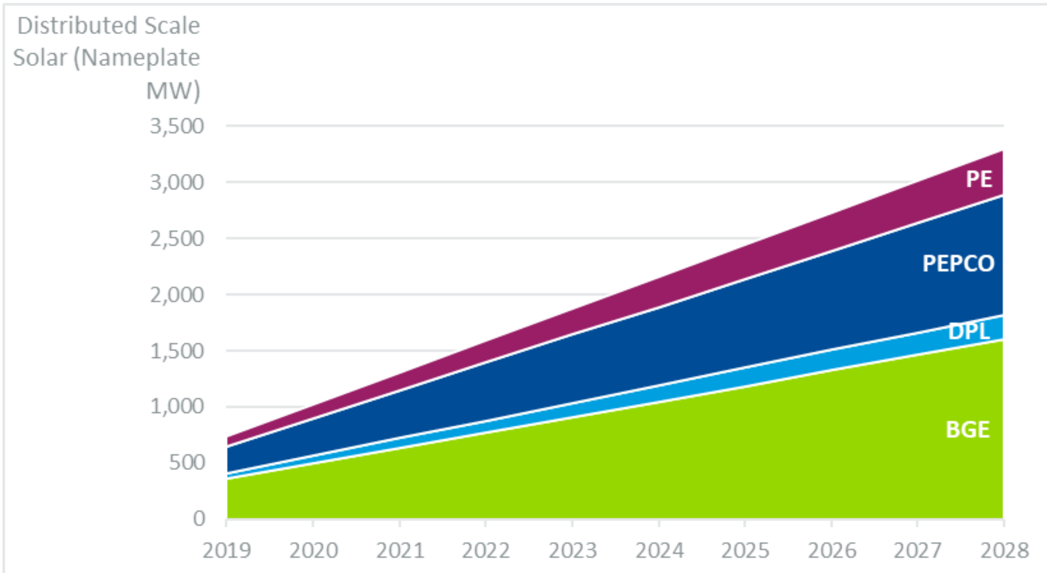


Figure 24: Difference Case Cumulative MW of Maryland-based distributed solar by PJM Zone

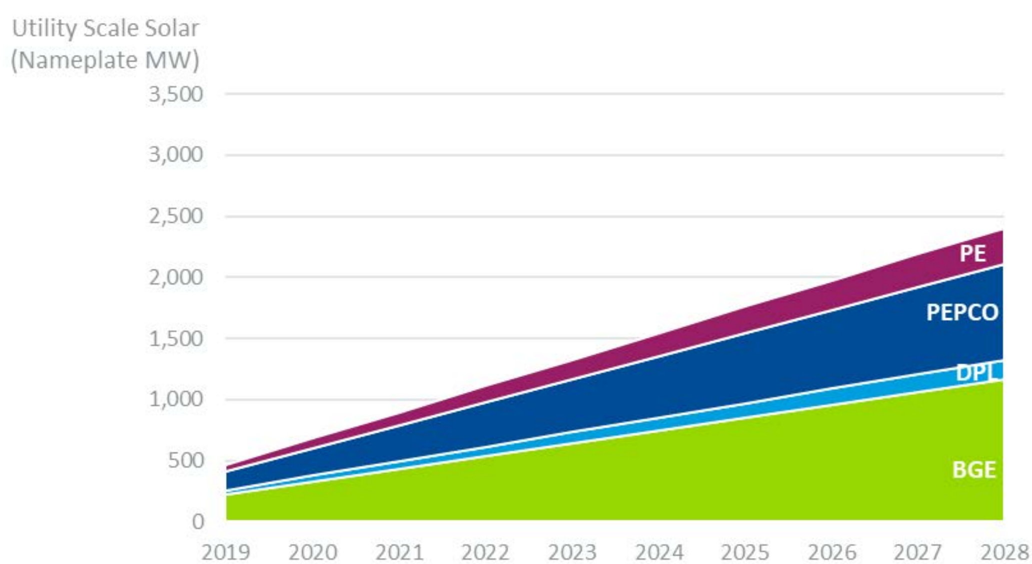


Figure 25: Difference Case Cumulative MW of Maryland-based utility scale solar by PJM Zone

An hourly solar production shape was developed for each solar type (distributed and utility scale) and zone based on the output of NREL's PV Watts[51] which is described in detail in Section 2 of this report.

Based on the solar assumptions in Section 2, we determine the annual average capacity factor for each solar type by each utility. Table 24shows the results of the capacity factor calculations.

Table 24: Annual Average Capacity Factor by Solar Type and Zone.

ZONE	DISTRIBUTED SOLAR	UTILITY SCALE SOLAR
BGE	17.50%	23.14%
DPL	17.43%	22.99%
PEPCO	17.24%	22.42%
APS (PE)	15.92%	20.47%

Appendix D contains additional details on PMM inputs and results.

4.2.2 Avoided Energy Cost

Direct avoided energy costs can be measured at the Locational Marginal Price ("LMP") of either the load that is offset by BTM solar or at the injection node for grid-tied utility scale solar generators. LMPs are comprised of three components – an energy component (representing the dispatch price of the marginal generator needed to serve load), the transmission congestion component (representing the economic price of constraints limiting delivery between generation and load) and the marginal line loss component (representing physical losses that occur as power flows over transmission and distribution lines between source and sink). The LMPs provide important economic signals that fully reflect both system and market operations at a specific time. At each node of the power grid, the LMP - by meeting the power balance equation - embodies the price of the energy from the generators, the impacts of the transmission losses, and the effects of the transmission constraints that result in network congestion.

Hourly zonal clearing prices from Daymark's PMM are used as a proxy for LMPs in our estimates of avoided energy costs associated with incremental solar generation on the system. Due to the variable nature of solar output, the average value of solar energy differs from the annual average (around the clock) price. Solar's peak-heavy production

[51] http://pvwatts.nrel.gov/

shape results in slightly higher solar energy value compared to forecast annual average prices. Table 25 through Table 27 present avoided energy values on a $/MWh basis for each of the three energy market scenarios for each zone in Maryland. The input changes for the scenarios can have slightly varying impacts across zonal avoided energy values for many reasons including different solar production shapes, resource fuel mix within each zone and the resulting competitiveness of energy exchange between neighboring zones.

For a list of annual average zonal prices see Section 1.4 of Appendix D.

Table 25: Avoided Energy Values ($/MWh - Reference Scenario

REFERENCE SCENARIO

ZONE		BGE		DPL		PEPCO		APS (PE)
TYPE	Utility	BTM	Utility	BTM	Utility	BTM	Utility	BTM
YEAR								
2019	44.5	44.5	43.1	43.1	45.8	45.8	43.6	43.6
2020	48.5	48.5	47.9	47.9	49.8	49.8	47.2	47.2
2021	48.3	48.3	47.5	47.5	49.7	49.7	46.7	46.7
2022	47.8	47.8	47.4	47.4	49.4	49.4	46.0	46.0
2023	49.1	49.1	48.7	48.7	50.7	50.7	47.3	47.3
2024	51.5	51.5	51.1	51.1	52.7	52.7	49.6	49.6
2025	53.3	53.3	53.1	53.1	54.8	54.8	51.4	51.4
2026	55.9	55.9	55.6	55.6	57.4	57.4	54.1	54.1
2027	58.7	58.7	58.4	58.4	60.1	60.1	56.7	56.7
2028	60.7	60.7	60.9	60.9	62.6	62.6	59.2	59.2

Table 26: Avoided Energy Values ($/MWh) – High CO_2 Scenario

HIGH CO_2 SCENARIO								
ZONE		BGE		DPL		PEPCO		APS (PE)
TYPE	Utility	BTM	Utility	BTM	Utility	BTM	Utility	BTM
YEAR								
2019	44.5	44.5	43.1	43.1	45.8	45.8	43.6	43.6
2020	48.5	48.5	47.9	47.9	49.8	49.8	47.2	47.2
2021	58.2	58.2	53.1	53.1	59.8	59.8	57.4	57.4
2022	59.1	59.1	53.8	53.8	61.0	61.0	58.2	58.2
2023	60.4	60.4	55.0	55.0	62.4	62.4	59.8	59.8
2024	62.9	62.9	57.2	57.2	64.3	64.3	61.9	61.9
2025	65.7	65.7	60.1	60.1	67.3	67.3	64.6	64.6
2026	68.1	68.1	62.6	62.6	69.8	69.8	67.0	67.0
2027	71.8	71.8	65.9	65.9	73.5	73.5	70.6	70.6
2028	73.9	73.9	68.6	68.6	76.1	76.1	73.3	73.3

Table 27: Avoided Energy Values ($/MWh) – Low Gas Scenario

LOW GAS SCENARIO								
ZONE		BGE		DPL		PEPCO		APS (PE)
TYPE	Utility	BTM	Utility	BTM	Utility	BTM	Utility	BTM
YEAR								
2019	42.3	42.3	39.7	39.7	43.6	43.6	41.5	41.5
2020	42.7	42.7	40.4	40.4	44.2	44.2	41.7	41.7
2021	41.7	41.7	38.7	38.7	43.2	43.2	40.6	40.6
2022	41.3	41.3	38.4	38.4	43.1	43.1	40.1	40.1
2023	42.4	42.4	39.9	39.9	44.2	44.2	41.3	41.3
2024	44.5	44.5	41.9	41.9	45.9	45.9	43.1	43.1
2025	45.9	45.9	43.7	43.7	47.4	47.4	44.3	44.3
2026	47.7	47.7	45.7	45.7	49.3	49.3	46.1	46.1
2027	50.0	50.0	48.2	48.2	51.5	51.5	48.2	48.2
2028	52.1	52.1	51.1	51.1	54.1	54.1	50.7	50.7

4.2.3 Market Price Effect

Adding solar generation at the levels contemplated in this study tends to place downward pressure on LMPs. LMPs are primarily a function of the dispatch cost of the marginal resource, or the most expensive supply resource needed to meet load (demand). Grid-tied utility scale solar adds a resource with negligible dispatch cost at the bottom of the supply stack, theoretically and in practice shifting down to a lower-cost resource as the marginal resource setting the LMP energy component. Distributed solar impacts the other side of the wholesale supply/demand equation, by reducing load and enabling a lower cost supply resource to become the price-setter. We refer to the added supply (utility scale) or reduced demand (distributed) solar impacts interchangeably as market price effects.

As discussed above, solar-driven market price effects benefit consumers of energy by reducing the cost of supplying wholesale load. We measure market price effects in the PMM as the difference in zonal prices between the difference (solar) and the base case for a given scenario. Figure 26 through Figure 28 below show the annual average zonal price reduction over the 10-year period in each PJM zone.

The market price effect is consistently greater in PEPCO and BGE zones compared to APS and DPL. Price effects are relatively modest, never exceeding 1.5% of base case prices for any zone or scenario. There are many factors within the modeling that may explain the differences in price effects between zones, but one of the more significant is the proportion of incremental solar production modeled to total load within each zone. All BGE zone load and the majority of PEPCO zone load is within Maryland. APS and DPL zones have a greater share of load outside of Maryland. Thus, additive Maryland solar in BGE and PEPCO produces a greater market price effect as the ratio of solar additions in Maryland to zonal load is larger and produces relatively more downward pressure on LMPs. For a detailed breakout of load between the four zones in PJM and their respective Maryland loads see section 1.1 of Appendix D.

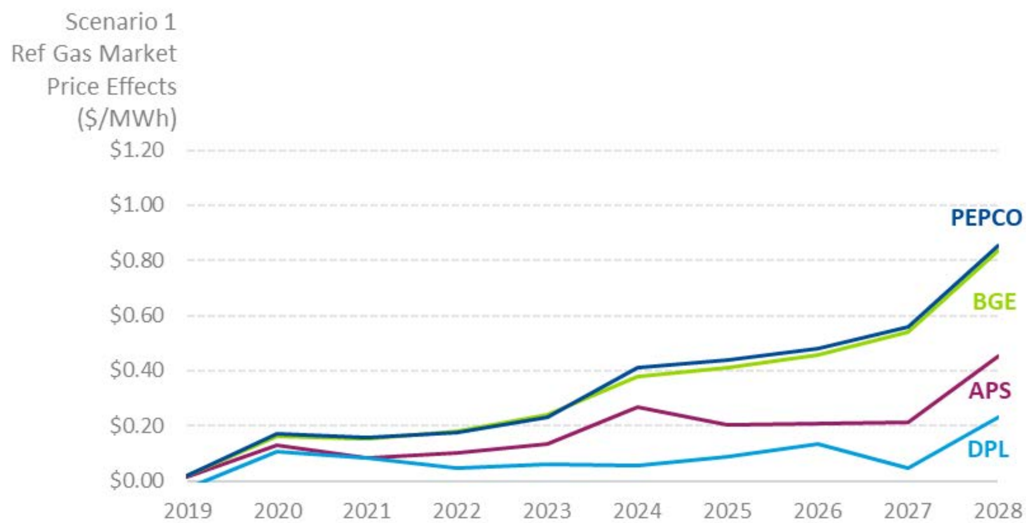


Figure 26: Solar-driven Market Price Reduction, Reference Scenario, in $/MWh.

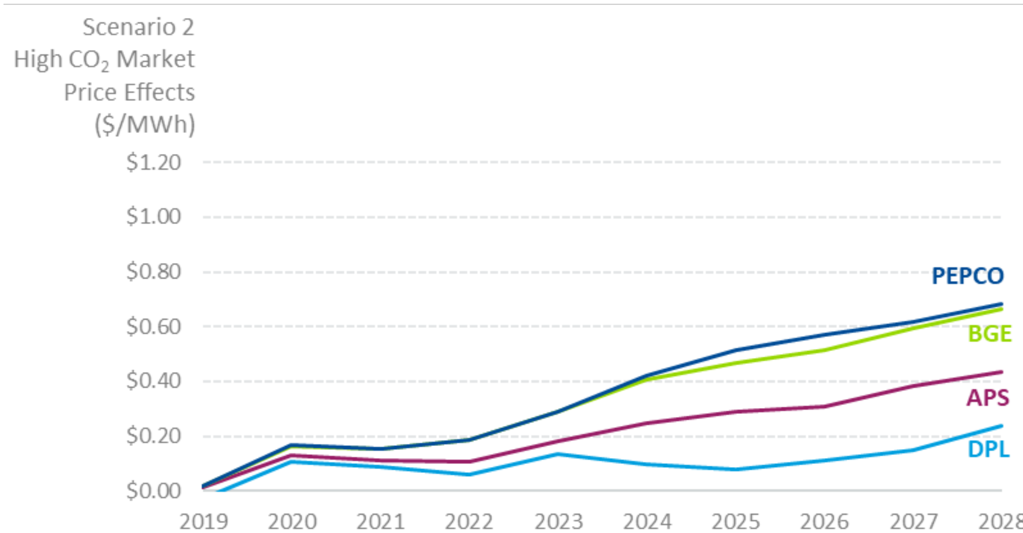


Figure 27: Solar-driven Market Price Reduction, High CO_2 Scenario, in $/MWh.

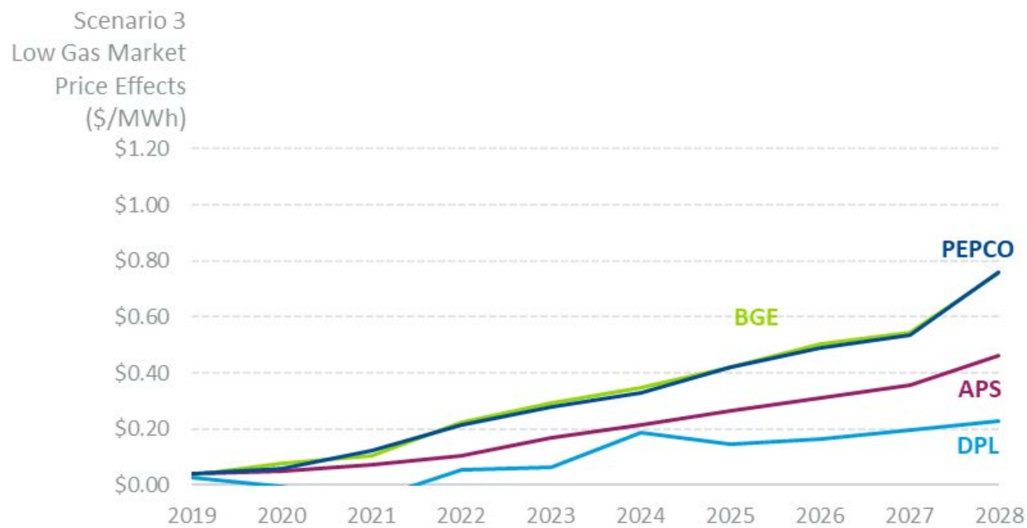


Figure 28: Solar-driven Market Price Reduction, Low Gas Scenario, in $/MWh.

The market price effect benefit of solar was quantified by multiplying these pricing differences by the Maryland load in each corresponding zone, and then dividing by the amount of incremental solar generation in the solar case.

We also looked at the market price reduction that occurs during PJM's standard peak period of non-holiday weekdays, 7:00AM to 11:00PM. Because prices tend to be higher and solar resources generate most of their power during the PJM peak period, the market price reduction is greater during the peak period than during the off peak period. Figure 29 and Figure 30 show the market price reduction during PJM on-peak and off-peak time for the Reference Scenario. Note that the annual average market price reduction for these two graphs is the market price reduction shown in Figure 26.

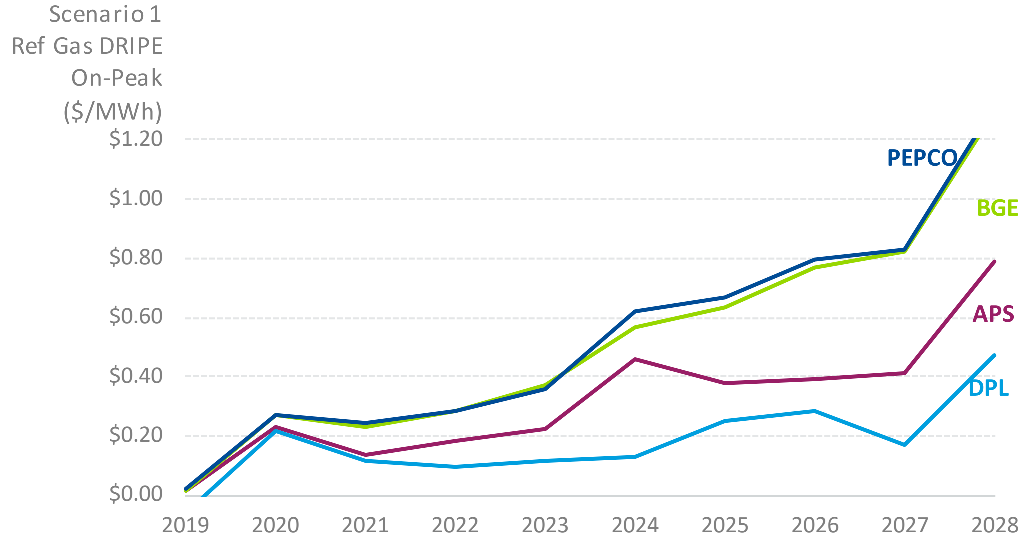


Figure 29: Solar-driven Market Price Reduction, Reference Scenario, On-Peak Hours, in $/MWh.

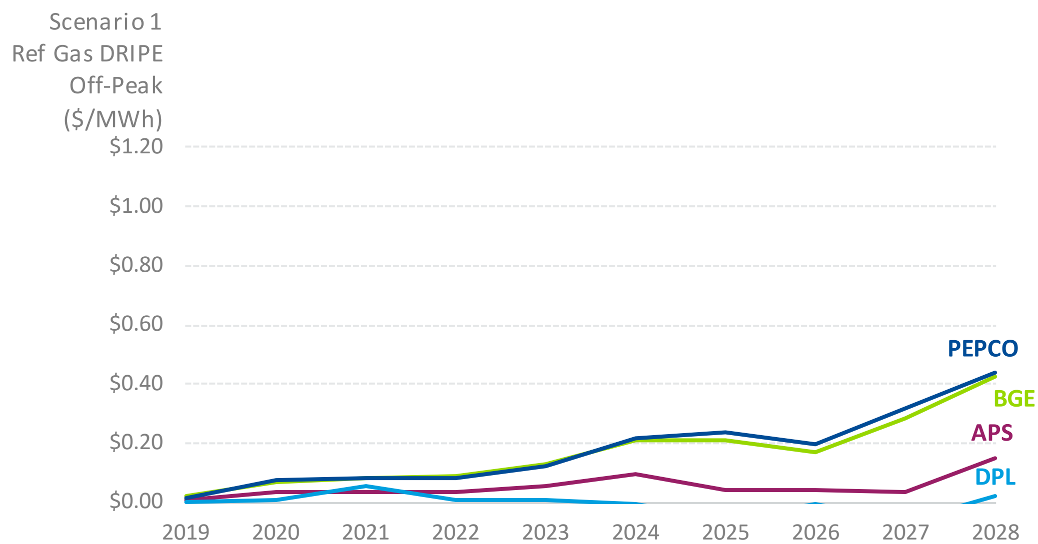


Figure 30: Solar-driven Market Price Reduction, Reference Scenario, On-Peak Hours, in $/MWh.

4.3 Capacity Costs and Benefits

Avoided capacity is measured as the costs associated with acquiring and maintaining the generating capacity required to meet reliability planning requirements that the LSE need not incur because of the inclusion of incremental solar in its supply portfolio.

Solar installations can derive value from the capacity market in two ways: (1) utility scale solar resources act as supply resources – like conventional generation – and are compensated at the established capacity market price; or (2) BTM solar resources act as load reducers, lowering peak demand, and thus reducing the need for capacity at the point of consumption.

The methodology for estimating avoided capacity differs for utility scale and BTM resources because of the different ways they derive value from the market. Utility scale resources will receive revenues from the PJM capacity market based upon the value they provide. BTM resource will reduce the capacity requirement of the utility in whose service territory the resource is located. Both of these methods rely upon a forecast of the capacity price in the applicable PJM zone. Section 3.3 first describes the methodology to forecast PJM capacity market prices by zone and then discusses the analysis and results of the avoided capacity calculation for both BTM and utility scale resources.

4.3.1 Capacity Market in Maryland

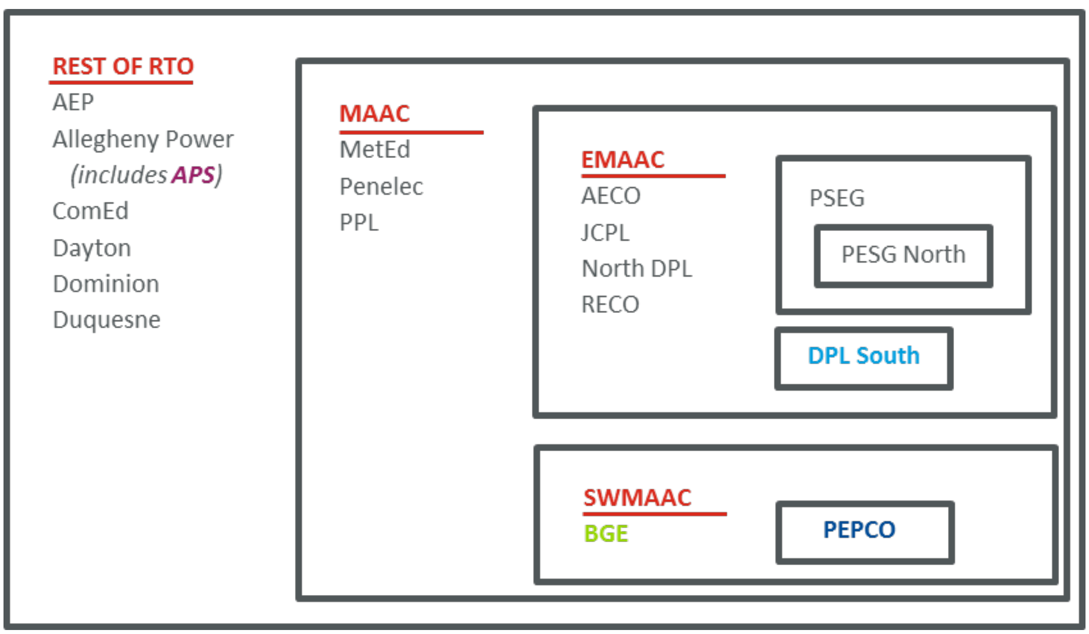
PJM has a structured capacity market where LSEs are required to maintain adequate capacity supply to meet both their peak demand and planning reserves, as governed by the Reliability Assurance Agreements for each reliability region in PJM.[52] PJM has established several means for LSEs to acquire capacity such as through bilateral transactions, long-term self-scheduling, and participation in the Reliability Pricing Model ("RPM") capacity market. The RPM rules require generating resources that participate in the energy market to bid into the capacity market; these rules also require load to purchase capacity from the market (or secure capacity through other means) for one-year commitment periods beginning three years in the future. PJM administers the primary Base Residual Auction ("BRA"), where most of the region's capacity is procured,

[52] PJM Interconnection, L.L.C., Rate Schedule FERC No. 44, "*Reliability Assurance Agreement among Load Serving Entities in the PJM Region*," effective September 17, 2010, available at: https://www.pjm.com/directory/merged-tariffs/raa.pdf

and it administers the subsequent Incremental Auctions ("IA"), where market participants can adjust their positions as necessary.

PJM's capacity market also has a locational feature, where capacity price differences may occur between different parts of the system to reflect transmission system limitations. Before each capacity auction, PJM calculates each zone's Capacity Emergency Transfer Limit ("CETL") and Capacity Emergency Transfer Objective ("CETO").[53] A Locational Deliverability Area ("LDA")[54] is modeled in the auction if the CETL is less than 1.15 times the CETO. Price separation is only possible between defined LDAs.

As the market is currently configured, Maryland covers all or portions of five different LDAs, some of which are smaller LDAs nested inside larger LDAs. The LDAs applicable to Maryland are PEPCO, SWMAAC (includes all of PEPCO and BGE), DPL South, EMAAC (includes all of DPL South), and MAAC (includes all of SWMAAC and EMAAC). Potomac Edison is within the Allegheny Power zone that is part of the Rest of RTO. Figure 31, below, provides a schematic of the nested LDAs, focusing on the Eastern Part of PJM. The IOU service territories within Maryland that are the subject of this report are noted in green, blue, and purple text within Figure 31.



[53] Section 4 of PJM's Manual 20 describes the methodology and assumptions used in determining CETO. The CETL is defined to be the actual emergency import capability of the test area (one LDA or multiple LDAs)

[54] The Locational Deliverability Areas for the purposes of determining locational capacity obligations are found in PJM's Manual 18 section 2.3.1

Figure 31: PJM's Nested Locational Deliverability Areas

In PJM, a consequence of the forward market structure is that capacity prices are set and known for the current delivery year, as well as the next three delivery years. A delivery year runs from June through May (e.g., the current delivery year is June 1, 2017 through May 31, 2018). Today, therefore, the market knows the capacity market prices through May 2021.

4.3.1.1 Daymark Capacity Market Forecast

We modeled capacity market prices using an economic analysis of PJM's annual capacity auctions after incorporating capacity demand and supply curves. PJM establishes demand curves for use in the RPM through the application of a tariff-specified, downward-sloping shape that is centered on a reliability-based target quantity and a price that corresponds to the estimated cost of capacity from a new generator entrant. In estimating the model's future demand curves, we adopted PJM's most recent demand curve and shifted it to the right over time, based on PJM's peak load forecast. The capacity model also accounts for transmission constraints between PJM modeled zones to fully reflect the actual market behavior.

The supply curves are structured with quantities and prices at which all existing and potential new resources are willing to provide capacity. Utility solar is included in these supply curves.[55]Actual supply offers are not publicly available data. The Daymark capacity model estimates theses using a combination of unit data that is available through SNL Financial[56], net energy and ancillary resource revenues provided by the AURORA results discussed in Section 3, a risk premium calculated based on generation type and age of units, fixed operating and maintenance costs escalated for inflation and for a general escalator, and a capacity performance premium based on generation type and performance. The supply resources are also categorized by LDA to reflect potential procurement of more expensive capacity to reflect economic capacity import restrictions.

[55] Solar resources considered Capacity Performance resources must be capable of predictable and sustained operation and be available to provide energy and reserves during performance assessment hours throughout the Delivery Year. http://www.pjm.com/~/media/committees-groups/subcommittees/drs/20170407/20170407-item-04a-intermittent-resources-in-rpm-training.ashx

[56] SNL Financial is a licensed data source to which Daymark subscribes. www.snl.com

Daymark's capacity forecast is shown below in Figure 32. Actual capacity prices (associated with auctions that have already occurred) are shown with solid lines for each of the three PJM zone. The Clearing Price result for the SWMAAC was higher by $9.51 MW-Day from the Rest of the RTO and the Clearing Price Results for DPL was higher by $101.83 MW-day due to the EMAAC Locational Price Adder[57], since the EMAAC is nested inside the MAAC and had binding locational constraints in the BRA. The figure also depicts Daymark's capacity forecasts for each of the same three zones, with dashed lines. Maryland's IOUs are noted in the figure in green, blue, and purple text next to the PJM capacity zone that each falls within. We expect the price separation to persist in the upcoming years based on the transmission limitations in the Eastern part of PJM and PJM's capacity market design. For our technical readers, we provide further technical details on this view in Appendix E.

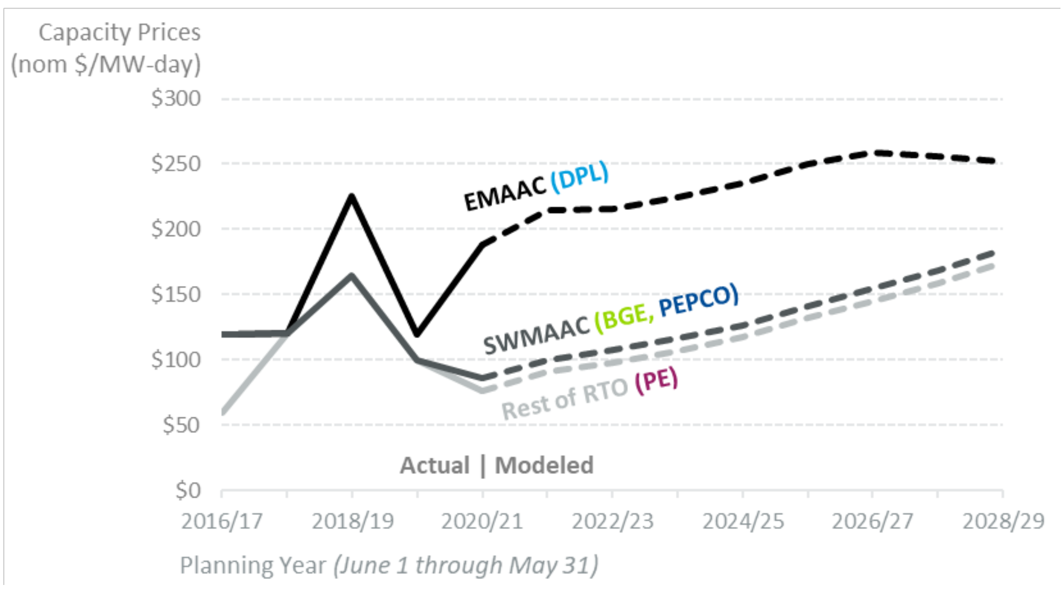


Figure 32: Actual and Modeled Capacity Prices in PJM Zones

4.3.2 Avoided Capacity for Utility Scale Solar

The methodology for estimating the avoided capacity cost of solar has two steps. The first step is the calculation of the capacity credit as a percentage of nameplate capacity

[57] A component of the Capacity Clearing Price that represents the additional price value of capacity resources located in a constrained LDA.

that solar installations would receive.[58] This capacity credit is the amount of capacity requirement otherwise procured from the market that solar can reliably offset. The second step is to estimate the market value of this capacity credit by multiplying the capacity credit by the PJM market price as estimated in Figure 32, above.

PJM relies on an internal study to determine the capacity credit, which is represented by a capacity factor calculation in a percentage, and is then applied to new solar resources when participating in the capacity market to account for their variable output. The internal PJM study assesses actual solar production data during the summer peak hours (Hour Ending 1500-1800) and establishes a generic factor. If a new solar project developer seeks to participate in the capacity market with a capacity factor other than the study's generic value, then proper documentation that justifies the difference must be provided to PJM. Table 28 below summarizes the generic capacity market credit for different types of solar resources in PJM.[59]

Table 28: Generic Capacity Market Credit by Solar Technology

SOLAR TECHNOLOGY	CAPACITY CREDIT
Ground mounted fixed panel	42%
Ground mounted tracking panel	60%
Other than ground mounted	38%

For utility scale solar resources, we assume the capacity credit to be 45% of AC nameplate to reflect the expectation that the vast majority of utility scale resource will be fixed panel systems.

The avoided capacity cost for utility scale solar resources is then calculated by multiplying the capacity credit in Table 28 by the PJM capacity market forecast from Figure 32. The resulting avoided capacity costs attributable to utility scale resources is shown in Table 29 below. The avoided capacity values for the BGE, PEPCO and PE are similar since the capacity prices are mostly similar. Since the EMAAC zone has a significant price separation form the rest of the Eastern zones, the DPL avoided capacity value is modestly higher than the rest.

[58] Capacity credit is measured as a value percentage of nameplate rating [59] http://www.pjm.com/-/media/committees-groups/committees/pc/20170713/20170713-item-10-class-average-wind-and-solar-capacity-factors.ashx

[59] http://www.pjm.com/-/media/committees-groups/committees/pc/20170713/20170713-item-10-class-average-wind-and-solar-capacity-factors.ashx

Table 29: Utility Scale Avoided Capacity ($/kWh)

CALENDAR YEAR	BGE	DPL	PEPCO	PE
2019	$0.011	$0.015	$0.012	$0.013
2020	$0.008	$0.014	$0.008	$0.009
2021	$0.008	$0.018	$0.009	$0.009
2022	$0.009	$0.019	$0.010	$0.010
2023	$0.010	$0.020	$0.010	$0.010
2024	$0.011	$0.021	$0.011	$0.011
2025	$0.012	$0.022	$0.012	$0.013
2026	$0.013	$0.023	$0.014	$0.014
2027	$0.014	$0.023	$0.015	$0.015
2028	$0.016	$0.023	$0.016	$0.017

4.3.3 Avoided Capacity of BTM Resources

To estimate the avoided capacity cost benefits of BTM solar, we made two adjustments to the PJM capacity market forecast presented in Figure 32 above; these include:

1. **Unforced Capacity ("UCAP") requirement.** First, capacity prices are increased by approximately 8.9% to account for PJM's Forecast Pool Requirement ("FPR"), the multiplier converting load values into capacity obligation accounting for UCAP reserve margin requirements for electric generating capacity. In order to ensure resource adequacy, PJM procures excess capacity to accommodate uncertainties around outages and load changes in the region.[60]

2. **Marginal transmission and distribution line losses.** The capacity prices are increased by the losses shown in Table 30 to account for marginal transmission and distribution ("T&D") line losses that are avoided at the end-user level. Estimated transmission losses are based on data from PJM.[61] The methodology for estimating distribution losses is based on the change in losses resulting from the change in net solar production and is discussed in more detail in Section 5.3.2.1.

[60] From PJM 2017 IRM Study, p 42 (http://www.pjm.com/-/media/committees-groups/committees/mrc/20171026/20171026-item-05-2017-irm-study.ashx)

[61] http://www.pjm.com/~/media/training/new-initiatives/ip-ml/marginal-losses-implementation-training.ashx slide 83

Table 30: Marginal Transmission and Distribution Losses

LOSS CATEGORY	BGE	DPL	PEPCO	APS (PE)
Marginal Transmission Losses	3.0%	3.0%	3.0%	3.0%
Marginal Distribution Losses	1.7%	6.8%	10.4%	12.1%
Marginal T&D Losses	**4.7%**	**9.8%**	**13.4%**	**15.1%**

Next, we determine the capacity contribution that BTM solar provides toward reducing each utility's capacity requirement. The capacity contribution[62] of intermittent resources like solar, represented as a percentage of resource capacity, is a measure of the ability of solar to reliably meet demand. We determine this level by projecting solar output during hours typically associated with high system demand as described below.

PJM uses the Peak Load Contribution ("PLC") metric - an entity's share of usage during periods of maximum usage on the electricity grid - to determine each utility's share of consumption. On an annual basis, each LDC is required to calculate and report its PLC to PJM. At the end of a summer season, PJM identifies the five highest peak load hours that occurred on different days during the period from June 1 through September 30. The LDC then determines each customer's specific load during these hours and the customer's PLC will be an average of these five hours' usage. This average is called a Capacity Tag and applies to the next capacity year (June – May).

The five highest peak load hourly observations made by PJM were identified for the years 2012-2017, all of which fell between the hours of 2:00 to 7:00pm (see Table 31). As discussed in Section 3.2, solar shapes were created for each IOU. The average, minimum and maximum solar capacity factors were calculated for the specific peak load hour observations occurring between the months of June to September. The values were calculated for both residential and commercial fixed roof mounted PV and two-axis tracking utility-scale load shapes for each utility. All solar installations were assumed to be south-facing to maximize production.

[62] We consider capacity contribution to reflect the benefit from BTM load reduction while the capacity credit is the benefit from supplying capacity from utility scale solar.

Table 31: Count of Peak Load Contribution hours (5 summer peak hours) by Month and hour, 2012-2017

COUNT OF PEAK HOUR OCCURRENCES	1-2 PM	2-3 PM	3-4 PM	4-5 PM	5-6 PM
June	0	0	0	2	2
July	1	1	2	12	4
August	0	2	1	1	0
September	0	0	1	1	0

The capacity factors from the peak load hour observations gives us an indication of the amount that BTM solar would reduce the Capacity Tags for BGE, PEPCO, DPL and PE. The capacity factor of BTM solar during the peak hours shown in Table 31 ranges from 6.6% to 18.5%. For PEPCO, the capacity factor of BTM solar ranges from 5.8% to 18.7% during the same peak hours. For DPL, the capacity factor of BTM solar ranges from 4.9% to 18.1% during the peak hours shown in Table 31. For Potomac Edison, the capacity factor of BTM solar ranges from 5.6% to 20.4% during the peak hours. Both the average and maximum capacity factor during the peak hours shown in Table 31 are shown in Table 32, below. We note that these using the average capacity factor during the peak hours is probably conservative because the system peak hour is likely to occur on hot, sunny days when solar production would likely be higher than average for the given month. On the other hand, using the maximum capacity factor may overestimate solar production during the peak hour.

Table 32: 2012 – 2017 Potential Capacity Tag Savings of BTM Solar

	ASSUMING AVERAGE CF DURING PEAK	ASSUMING MAX CF DURING PEAK
BGE	13.9%	18.5%
DPL	12.4%	18.1%
PEPCO	12.3%	18.7%
PE	13.2%	20.4%

The BTM avoided capacity value, provided in Table 33, is then the Capacity Tag Savings assuming the average capacity factor during peak shown in Table 32 multiplied by the capacity market forecast shown in Figure 32 adjusted for the UCAP requirement and transmission and distribution losses as described above. Using the Capacity Tag Savings assuming the maximum capacity factor during peak would increase the avoided capacity by 33 to 55 percent.

Table 33: BTM Avoided Capacity Cost ($/kWh)

CALENDAR YEAR	BGE	DPL	PEPCO	PE
2019	$0.005	$0.006	$0.005	$0.006
2020	$0.004	$0.006	$0.004	$0.004
2021	$0.004	$0.008	$0.004	$0.004
2022	$0.004	$0.008	$0.004	$0.005
2023	$0.005	$0.009	$0.005	$0.005
2024	$0.005	$0.009	$0.005	$0.005
2025	$0.006	$0.010	$0.006	$0.006
2026	$0.006	$0.010	$0.006	$0.007
2027	$0.007	$0.010	$0.007	$0.007
2028	$0.007	$0.010	$0.007	$0.008

4.4 Transmission Costs and Benefits

The transmission system is a very complicated network of transmission lines, electrical substations and other peripheral equipment needed to reliably deliver the power produced at the central station power plants to homes and business. Transmission companies are responsible for building and maintaining the transmission system and the cost of these efforts is paid by the electric customers. As the need for power increases, the transmission system may also grow both in size and cost. Due to policy and cost concerns, various actions may be taken to reduce the need to deliver power from a central station power plant across the electric grid to customers. Such actions can include installing energy efficient products, adding building insulation, or installing on-site generation like solar.

In this study, the transmission avoided cost component considers potential avoided costs due to solar installation in two ways 1) the potential for avoiding the construction and maintenance of new transmission infrastructure; and 2) the impact on transmission charges due to the reduction in load realized by the installation of solar resources.

This section first describes Maryland's transmission infrastructure and the PJM transmission planning process and then describes our analysis and results with regard to the two types of avoided transmission costs described above.

4.4.1 Maryland's Transmission Infrastructure

Maryland's power grid is geographically divided into thirteen utility service territories. At the wholesale level, PJM has sectionalized Maryland into sub-regions, known as zones, which generally correspond to IOU service territories. In Maryland, since there are four IOUs; the state is divided into four transmission zones that align with the territory of the IOUs. Figure 33, below, depicts the PJM zones located in Maryland.[63]

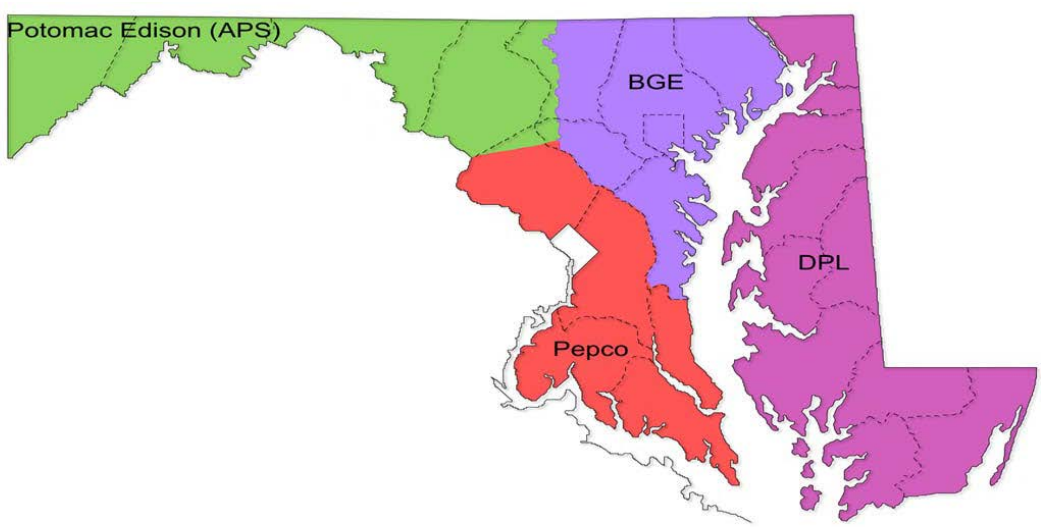


Figure 33: PJM Zones in Maryland

The APS,[64] DPL and PEPCO zones extend into areas outside the state boundaries of Maryland. The table below provides a rough estimate of the Maryland energy consumption as a percentage of each utility's entire energy consumption. For example,

[63] Source: Public Service Commission of Maryland, "*Ten Year Plan (2016-2025) of Electric Companies in Maryland*," prepared for the Maryland Department of Natural Resources, in compliance with Section 7-201 of Public Utilities Article, *Annotated Code of Maryland*, November 2016.

[64] "APS" represents the Allegheny Power Zone, of which Potomac Edison is a sub-zone. Potomac Edison serves customers in western Maryland and the Eastern Panhandle of West Virginia

BGE only serves customers in Maryland, so that is captured as "100%" in the Maryland percentage column.

Table 34: Maryland Energy Consumption, per Utility

UTILITY	MD %
BGE	100%
DPL	30%
PEPCO	58%
APS	17%

4.4.2 Overview of PJM Transmission Planning Process

As the regional system operator, PJM is responsible for managing, planning and operating the transmission system of all the states – including Maryland – within its authority. For planning, the operator has developed a process that assesses the need of new transmission and allocates its costs to the electricity customers.

PJM's Regional Transmission Expansion Plan ("RTEP") process includes both economic and reliability planning for facilities designated as Bulk Electric System and other facilities rated 100 kV and above.[65] PJM also conducts planning and analysis on facilities rated below 100 kV, if those facilities are not part of an individual transmission owner's system. Transmission interconnection planning encompasses generator interconnection requests, merchant transmission interconnection requests, and requests for long-term firm transmission service, and is conducted after an application for interconnection is provided by the affected entity (i.e., generator owner). At the local level, PJM's sub-planning is initiated by individual transmission owners on transmission owner operated facilities less than 100 kV.

The RTEP process identifies necessary transmission infrastructure changes and additions to the grid to ensure that reliability and successful operation of the wholesale markets are maintained. The main criteria that drive transmission planning are reliability and congestion.[66] The RTEP produces a single plan that consists of transmission

[65] NERC and PJM's manual 14B PJM Regional Transmission Planning Process

[66] Reliability refers to transmission contingencies and the ability of the system to respond to such events. Congestion occurs when transmission reliability limitations result in the need to use higher-cost generation than the case without any reliability constraints.

enhancements – called Baseline and Network Transmission Projects – required to meet the above criteria while also considering operational performance requirements. These upgrades formally become part of the RTEP process after the PJM Board approves them.

The RTEP also includes "Supplemental" transmission projects, which are changes to the transmission system that are not required to satisfy reliability, operational performance, or economic criteria like the Baseline and Network Projects. As a result, they are not subject to PJM's Board approval. According to PJM, the Supplemental Projects address the following:

- Replacement, retirement or rebuilding of aging infrastructure;
- Reinforcements to the underlying system to add new distribution substations or delivery points to serve lower voltage systems (e.g., new 230 kV substation);
- Extensions to existing transmission system needed to serve new large customer facilities; and
- Infrastructure resilience (e.g., storm hardening).

Figure 34 below depicts how Baseline Projects and Supplemental Projects costs have trended throughout the past decade, as reported by American Municipal Power, Inc.[67] The Transmission Owner Identified ("TOI")-Supplemental projects have experienced a significant increase over the past few years. The trend for the Supplemental projects shows that transmission companies are investing more on replacement and reinforcement of the transmission system rather than on projects that address reliability and congestion concerns. Increased solar penetration has the ability to defer or avoid a portion of the Supplemental investment since it reduces the need to deliver energy to load and as a result minimize the usage of the regional transmission system.

[67] Ken Rose, "*Survey of PJM Transmission Rates and Charges, Transmission Study for American Municipal Power Inc*.," September 21, 2017.

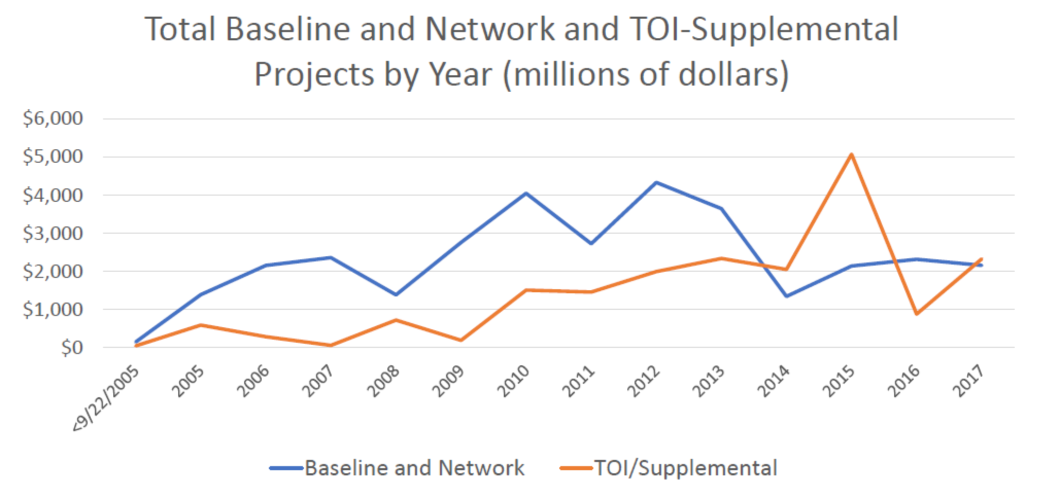


Figure 34: Total Baseline and Network and TOI-Supplemental Projects by Year

4.4.3 Methodology for Estimating Avoided Transmission Costs

Transmission planners estimate the need for transmission enhancements in an area by assessing multiple system characteristics, including load growth, generation, applicable reliability standards and the cost of potential upgrades. BTM solar generation is usually modeled as a load reduction with the potential to defer transmission upgrades needed to accommodate load growth or relieve congestion in an area.

There are multiple methods for assessing the avoided transmission cost from increased solar penetration. The three most commonly used methods are the following:

- Modeling transmission impacts under different solar buildout scenarios;
- Simulation of a co-optimization between transmission upgrades and non-transmission alternatives such as solar; and
- Thorough review of publicly available transmission planning reports to assess to what extent the solar potential will impact the transmission system.

The first and second methods are time consuming and require significant data gathering, advanced transmission modeling techniques and the use of complicated engineering tools. Moreover, the scenario-based evaluation requires a detailed vetting of all scenarios, since each scenario represents a different network topology/solar installation combination. The scope of this study limited applicability of the first and second method, and as a result led to the use of a similar method used in the Value of Solar for Maryland's Electric Cooperative Study.

PJM's RTEP Plan provides significant information regarding a ten-year horizon for transmission investment in Maryland. PJM's recently implemented Transmission Cost Information Center ("TCIC") – further detailed in the section below – includes the RTEP plan information and depicts a reasonable picture of planned transmission investment for all PJM zones. It also provides an estimate of transmission rates, which are based on the planned transmission investment included.

4.4.3.2 PJM's Transmission Cost Information Center

In 2016, PJM established the TCIC to assist its stakeholders in navigating through the complexities of its transmission cost allocation process and reasonably assess the future transmission costs by zone.[68] The TCIC is an Excel-based application that has prepopulated applicable information for each of the RTEP's Baseline and Supplemental Upgrades. This information, together with applicable carrying charges taken from approved Transmission Owner rate filings, is utilized to estimate an Annual Revenue Requirement for each upgrade for the next ten rate years. The TCIC produces cost charges from the estimated Annual Revenue Requirement for each upgrade and summarizes the costs by each PJM zone.

The advantages of TCIC in understanding and estimating future transmission costs outweigh its disadvantages. The inclusion of all known projects (in service and planned), the most recent Transmission Owner formulas, and the most recent project cost estimates for all Baseline and Supplemental Upgrades provide a reasonable picture for how future transmission costs will behave.[69] The avoided transmission analysis utilizes the TCIC as the basis for estimating future costs and assessing the impact of solar realized savings in transmission charges and deferred investment.

4.4.3.3 Forecast of Maryland Transmission Rates

The information included in the TCIC also assisted in the development of future transmission rates for each of the four utilities. The application can forecast future transmission rates by incorporating changes to the peak load for all transmission zones.

[68] http://www.pjm.com/planning/rtep-upgrades-status/cost-allocation-view.aspx

[69] Since the TCIC only uses information known at the time of its posting, it does not capture – similarly to other forecasts - any changes in the future that may occur due to new - unknown at the time - planned projects, deferred transmission investments and other. It is common for planned transmission projects to be delayed, re-configured, or face significant changes in estimated cost.

Therefore, using the TICIC as provided by PJM and incorporating the peak load forecast as provided in PJM's Load Forecast report[70], we concluded in the following transmission rates for the four utilities, as depicted in Table 35.

Table 35: Transmission Rate Forecast by Utility

YEAR	BGE ($/MWh)	DPL ($/MWh)	PEPCO ($/MWh)	APS/PE ($/MWh)
1/1/2018	$4.06	$4.13	$3.33	$3.22
1/1/2019	$4.10	$4.34	$3.67	$3.35
1/1/2020	$4.25	$5.01	$3.79	$3.35
1/1/2021	$4.51	$5.64	$3.89	$3.35
1/1/2022	$4.41	$5.56	$3.81	$3.31
1/1/2023	$4.32	$5.43	$4.40	$3.27
1/1/2024	$4.86	$5.46	$4.98	$3.23
1/1/2025	$4.72	$5.31	$4.94	$3.19
1/1/2026	$4.58	$5.16	$4.80	$3.15
1/1/2027	$4.47	$5.02	$4.66	$3.11

The resulting rates were benchmarked against historical trends and rates to assess their reasonableness. Based on the trends depicted graphically in Figure 35 below, the above rates appear to be a reasonable estimation of future rates, since they are within the historical increase bounds.

[70] http://www.pjm.com/-/media/library/reports-notices/load-forecast/2018-load-forecast-report.ashx?la=en

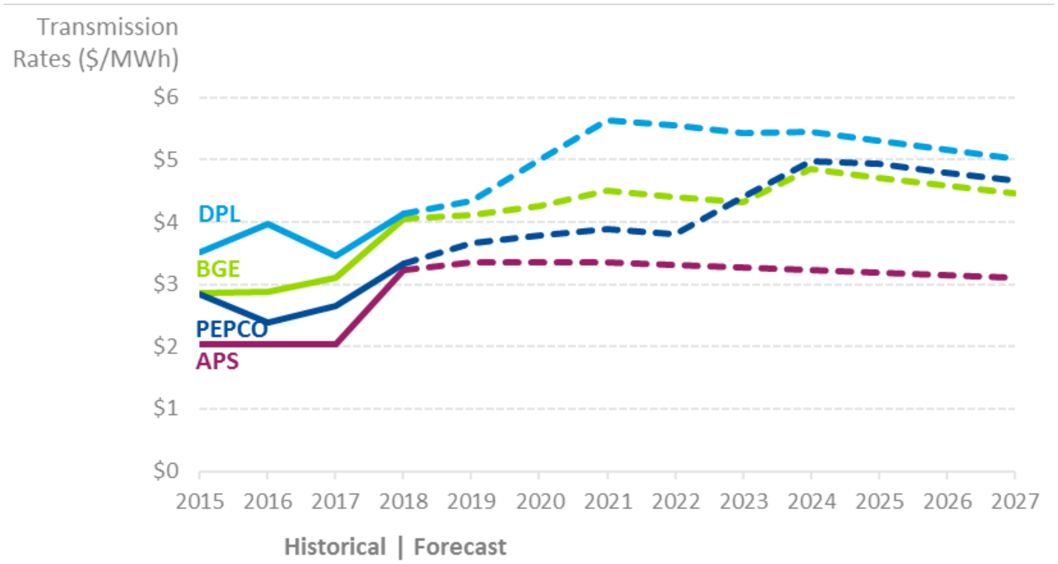


Figure 35: Benchmarking Forecasted Transmission Rates to Historical Trends

4.4.4 Avoided Transmission Charges Analysis

Each utility must obtain Network Integration Transmission Service ("NITS") within its respective PJM transmission zone. If BTM solar decreases a utility's contribution to the zonal peak (by reducing the utility's load at the times when load in the entire zone is highest), then the utility's NITS costs would be reduced, all else equal. These savings are partially (but not fully) offset by the increase in zonal rates that would be required to ensure that the full annual revenue requirement is still collected in the zone. In effect, with BTM solar installations in the utility service territories reducing their load, the utility's NITS costs are shifted to other customers in the same region either within state or to other states.

To estimate NITS savings, we first estimated solar performance during the hours when Network Service Peak Load ("NSPL") is most likely to be determined. Since BGE's service territory does not expand to other states, we focused on PEPCO, DPL and APS to determine NSPL using the previous year's five hours with the highest zonal load occurring on different days (i.e., no two hours from the same day) during the summer (June through September). Reviewing five years of history (2013-2017) for all zones[71], we noted that most transmission peak hours occurred on summer (June or July)

[71] Hourly load data from PJM available via the following link: http://www.pjm.com/markets-and-operations/ops-analysis/historical-load-data.aspx

afternoons between 2:00pm and 7:00pm, with some peaks also occurring on July and August mornings (8:00am – 9:00am) or evenings (7:00pm – 9:00pm). The peak months, number of peak occurrences per month, and hour at which peaks occur for each month can be seen for each zone in Table 36 through Table 39 below.

Table 36: BGE Historical Peak Occurrences by Month

COUNT OF PEAK HOUR OCCURRENCES	8-9 AM	2-3 PM	3-4 PM	4-5 PM	5-6 PM	6-7 PM	7-8 PM	8-9 PM
June	0	0	0	1	2	2	0	0
July	0	0	0	0	5	7	1	0
August	0	0	1	0	2	3	0	0
September	0	0	0	1	0	0	0	0

Table 37: DPL Historical Peak Occurrences by Month

COUNT OF PEAK HOUR OCCURRENCES	8-9 AM	2-3 PM	3-4 PM	4-5 PM	5-6 PM	6-7 PM	7-8 PM	8-9 PM
June	0	0	0	0	1	1	0	0
July	2	1	1	0	4	9	1	0
August	0	0	0	0	1	3	0	1
September	0	0	0	0	0	0	0	0

Table 38: PEPCO Historical Peak Occurrences by Month

COUNT OF PEAK HOUR OCCURRENCES	8-9 AM	2-3 PM	3-4 PM	4-5 PM	5-6 PM	6-7 PM	7-8 PM	8-9 PM
June	0	0	0	0	2	2	0	0
July	0	0	0	5	5	5	1	0
August	1	0	0	0	3	1	0	0
September	0	0	0	0	0	0	0	0

Table 39: APS Historical Peak Occurrences by Month

COUNT OF PEAK HOUR OCCURRENCES	8-9 AM	2-3 PM	3-4 PM	4-5 PM	5-6 PM	6-7 PM	7-8 PM	8-9 PM
June	0	0	0	0	1	2	0	0
July	0	0	1	2	2	7	2	0
August	0	0	1	1	3	0	0	0

September	0	0	0	0	1	2	0	0

Table 40 below shows the average and maximum expected capacity factor of the south-facing solar orientation for BTM projects for the zonal peak summer hours.

Table 40: Nameplate capacity Reduction due to BTM NSPL

	Average	Maximum
BGE	7.8%	10.8%
DPL	8.4%	12.9%
PEPCO	9.9%	14.6%
APS	8.8%	14.1%

Assuming the transmission rates calculated in the previous section, we establish a benefit whereby the short-term savings are given by the NSPL reduction multiplied by the NITS rate. We are using the average reduction from Table 40 in this calculation.[72] However, since we assume that this is a cost shift rather than cost savings at the zonal level, we must account for the change in rate to assure collection of annual transmission revenue requirements. DPL, PEPCO and APS are assumed to absorb a pro-rata share of this re-adjustment based on their share of their respective transmission zonal peaks. Since BGE is 100% within Maryland, there is no cost shifting to other states within the BGE zone. Table 41 shows an example of the calculation of estimated NITS charge savings per kWh of solar generation.

Table 41: Example of Estimated NITS Savings Calculation

LINE	ELEMENT	DPL	PEPCO	PE
(1)	Transmission Zone	DPL	PEPCO	APS
(2)	NITS Rate – 2018 Rates ($/MW-year)	$36,144	$36,179	$28,211
(3)	Utility Share of Zonal Peak (%)	30.3%	57.8%	16.9%
(4)	NSPL Offset (% of DC rating)	8.4%	9.9%	8.8%
(5)	First Year NITS Savings per MW (DC) solar install ($/MW-year) [Line (2) * Line (4)]	$3,032	$3,571	$2,477

[72] The average capacity factor during peak hours may be a conservative estimate as the peak hours likely occur on hot sunny days. However, we felt that using the maximum capacity factor during peak hours may over estimate solar production during those hours. Using the maximum capacity factor would increase the transmission charge benefit by 38 to 60 percent.

(6)	Utility Share of Rate Increase to meet Revenue Requirements ($/MW-year) [Line (3) * Line (5) * -1]	($920)	($2,064)	($419)
(7)	NITS Savings per MW (DC) solar install ($/MW-year) [Line (5) + Line (6)]	$2,113	$1,507	$2,058
(8)	Annual PV Output	1,388	1,373	1,268
(9)	NITS Savings per kWh ($/kWh) [Line (7) / (Line (8) * 1,000)]	**0.0015**	**0.0011**	**0.0017**

After applying the same formulas for the balance of the test period, the NITS savings are provided in Table 42.

Table 42: Transmission Cost shifting benefits for BTM Resources in DPL, PEPCO and APS

YEAR	DPL ($/kWh)	PEPCO ($/kWh)	APS ($/kWh)
2018	$0.0015	$0.0011	$0.0016
2019	$0.0016	$0.0012	$0.0017
2020	$0.0018	$0.0013	$0.0017
2021	$0.0021	$0.0015	$0.0017
2022	$0.0021	$0.0015	$0.0017
2023	$0.0020	$0.0014	$0.0016
2024	$0.0020	$0.0014	$0.0016
2025	$0.0020	$0.0014	$0.0016
2026	$0.0019	$0.0014	$0.0016
2027	$0.0019	$0.0013	$0.0016

4.4.5 Avoided Transmission Investment Analysis

The TCIC includes detailed information for all Baseline and Supplemental projects known at the time. It also includes all the transmission projects already in place with their cost and applicable recovery embedded in the transmission rates by Transmission Owner. For this study, Daymark completed a thorough review of the projects included in the TCIC and other regional transmission planning reports to understand and quantify the impact of solar to the regional transmission system. More specifically, our review focused on how solar can minimize transmission enhancements needed to mitigate congestion or load growth.

All four of the utilities within Maryland have relatively small to negative load growth, therefore, no considerable investment in transmission is needed to mitigate load growth in the state. Furthermore, recently approved transmission upgrades in the region will eventually mitigate most of the congestion issues in the area, once they are in place.[73] As a result, most of the transmission investment deferral due to solar can be attributed to postponement of projects that are related to aging or condition of equipment and materials.

To assess the impact of potential deferred transmission investments, we analyzed the BGE and DPL transmission zones, since they have a relatively small load growth and somewhat stable transmission investment over time. Based on a review of information included in the TCIC, most of the transmission upgrades for these zones are required to maintain reliability or are already approved by the PJM Board, thus they cannot be postponed due to increased solar penetration. However, there are projects that are considered Supplemental and have been proposed by the Transmission Owners to mitigate concerns, such as aging equipment or operational performance. Based on our estimation, the incremental solar build assumed cannot eliminate the need for these projects, but it may postpone them to a later timeframe.

To assess the impact of such deferral, we analyzed the transmission rate impact for BGE and DPL, if the projects in Table 43 could be deferred for two years. The two-year mark is used because it provides a reasonable balance relative to time deferral and a reasonable indication of the impact to transmission rates. A longer postponement of a transmission enhancement may result in additional costs to that project that may significantly alter the project’s cost estimate.

Table 43: Transmission investment assessed projects for BGE and DPL

DESCRIPTION	TCIC PLANNED IN-SERVICE DATE	DAYMARK PLANNED IN-SERVICE DATE	LATEST COST ESTIMATE ($M)	TRANS-MISSION OWNER
Replace the Conaston 230kV '2322 B5' breaker with a 63kA breaker	6/1/2020	6/1/2022	$0.54	BGE

[73] http://pjm.com/~/media/about-pjm/newsroom/2016-releases/20160809-rtep-news-release-market-efficiency-project.ashx

DESCRIPTION	TCIC PLANNED IN-SERVICE DATE	DAYMARK PLANNED IN-SERVICE DATE	LATEST COST ESTIMATE ($M)	TRANS-MISSION OWNER
Replace the Conaston 230kV '2322 B6' breaker with a 63kA breaker	6/1/2020	6/1/2022	$0.54	BGE
Install three 115kV breakers at Westport	12/31/2019	12/31/2021	$2.00	BGE
Rebuild the Hillsboro - Wye Mills 138 kV circuit '13788'	5/31/2019	5/31/2021	$9.15	DPL
A new terminal at Crisfield 69 kV substation for the new Kings Creek - Crisfield 69kV circuit.	12/31/2022	12/31/2024	$4.14	DPL
Rebuild the existing Kings Creek - Crisfield 69kV circuit '6725' and construct a 2nd Kings Creek - Crisfield 69 kV circuit	12/31/2022	12/31/2024	$25.58	DPL
Rebuild 6.16 miles of the Vienna - Nelson 138 kV circuit '13707' (Delaware)	12/31/2022	12/31/2024	$7.21	DPL
Rebuild 7.57 miles of the Vienna - Nelson 138 kV circuit '13707' (Maryland)	12/31/2022	12/31/2024	$8.90	DPL
Rebuild 14.7 miles of the Vienna - N. Salisbury 69 kV circuit '6708'	12/31/2020	12/31/2022	$13.80	DPL
Rebuild the Hebron Substation as a 69/25 kV substation that can accommodate one new 69/25 kV 28 MVA transformer and two new 69 kV high-side breakers	4/30/2019	4/30/2021	$3.30	DPL
Construct a new Beaglin 69/25 kV Substation and tie into circuit 6726 (North Salisbury – Mt. Hermon)	4/29/2020	4/29/2022	$11.50	DPL
Replace Fruitland 69/25 kV transformer with 56 MVA transformer	4/29/2020	4/29/2022	$2.15	DPL

DESCRIPTION	TCIC PLANNED IN-SERVICE DATE	DAYMARK PLANNED IN-SERVICE DATE	LATEST COST ESTIMATE ($M)	TRANS-MISSION OWNER
Replace underground submarine cables portion of the Brandon Shores - Riverside 230 kV circuits #2344 and #2345 with overhead conductors on towers	12/31/2022	12/31/2024	$203.00	BGE

Table 44 and Table 45 provide the impact of deferral on annual transmission charges for the BGE and DPL transmission zones, respectively. Charges are levelized over the period from 2019 to 2027 using a 7% discount rate, which falls within the range of rates of return authorized by the Commission for Maryland's electric utilities in the last three years.

Table 44: Impact on BGE Zone Annual Transmission Charges due to Transmission Project Deferral

YEAR	BGE ($M)	BGE ADJUSTED ($M)	CHANGE ($M)
2019	$237.5	$237.4	($0.1)
2020	$245.9	$245.7	($0.2)
2021	$261.2	$260.5	($0.7)
2022	$255.3	$254.5	($0.8)
2023	$250.0	$248.0	($2.1)
2024	$281.2	$240.9	($40.3)
2025	$273.3	$235.5	($37.8)
2026	$265.5	$266.7	$1.3
2027	$259.0	$260.2	$1.2
Levelized 2019-27	**$257.2**	**$249.3**	($8.0)

Table 45: Impact on DPL Zone Annual Transmission Charges due to Transmission Project Deferral

YEAR	DPL ($M)	DPL ADJUSTED ($M)	CHANGE ($M)
2019	$156.7	$156.6	($0.1)
2020	$180.6	$179.4	($1.2)
2021	$203.2	$200.0	($3.2)
2022	$200.3	$196.0	($4.3)
2023	$195.4	$192.8	($2.6)
2024	$196.0	$189.9	($6.1)
2025	$190.6	$184.9	($5.7)
2026	$185.3	$185.4	$0.1
2027	$180.0	$180.1	$0.1
Levelized 2019-27	**$186.8**	**$184.3**	($2.5)

Levelized transmission charge savings for BGE and DPL zones are equivalent to 3.1% and 4.4%, respectively, of base transmission charges allocated to Maryland. For the two zones that were not studied individually, we assumed the savings related to the solar buildout as a percentage of Maryland-allocated base transmission charges would be the same as the BGE zone or 3.1 %. Table 46 below summarizes the estimation of the transmission savings benefit as a levelized rate per MWh of solar generation in our solar case.

Table 46: Transmission Investment Deferral Benefits Estimation

All figures 2019-2027 levelized $ millions unless noted	BGE	DPL	PEPCO	APS
Base Transmission Charges	257.2	186.8	244.0	253.8
MD Load Share (%)	100.0%	30.3%	57.8%	16.9%
MD-Allocated Base Trans. Charges	257.2	56.7	141.1	43.0
Trans. Savings	8.0	2.5	4.4	1.3
Trans. Zone Savings as % of MD-allocated Charges (%)	3.1%	4.4%	3.1%	3.1%
MD-Allocated Trans. Savings	8.0	0.8	2.5	0.2
Levelized MD Trans. Savings per MWh of Solar Generation ($/MWh)	4.95	4.20	2.29	0.63

4.5 Ancillary Services Costs and Benefits

To ensure system reliability, system operators need reserve capacity to be able to respond to contingencies, such as those caused by unexpected system outages. Solar and other distributed generation can provide grid support services if they have the applicable hardware, software, and the excess capacity to provide these services, as well as an ability to react to signals from a distribution management or supervisory control and data acquisition ("SCADA") system. Since Maryland is part of PJM, solar resources can participate in the established ancillary services market.

4.5.1 Maryland and Ancillary Services

In its Order No. 888, FERC set forth and defined the six different categories of ancillary services: (1) scheduling, (2) system control and dispatch; (3) reactive supply service; (4) regulation and frequency response service; (5) energy imbalance service; and (6) operating reserves. PJM provides the first three services listed on a cost basis, while it provides the remaining services through market mechanisms. Definitions for each service are detailed in Table 47.

Table 47: Ancillary Services Products Overview

ANCILLARY SERVICE	DETAILS[74]
Scheduling System Control & Dispatch	"provides for (i) interchange schedule confirmation and implementation with other control areas, including intermediary control areas that are providing transmission service, and (ii) actions to ensure operational security during the interchange transaction."
Reactive Supply	"reactive supply is necessary to maintain proper transmission line voltage…" specifically the use of generating facilities to supply reactive power
Regulation & Frequency Response	"Supply of extra generating capacity (regulating margin) to follow the moment-to-moment variations in the load located in a control area. This is necessary to maintain the scheduled interconnection frequency of 60 Hz."
Energy Imbalance	Energy Imbalance Service supplies any hourly mismatch between a transmission customer's energy supply and the load being serving in the control area. That is, this service makes up for any net mismatch over an hour between the scheduled delivery of energy and the actual load that the energy serves in the control area."
Operating Reserves	Operating reserve is extra generation available to serve load in case there is an unplanned event such as loss of generation.

PJM allocates costs per MWh of load with the rates calculated using the equation below.

$$Rate_{\left(\$/_{MWh}\right)} = \frac{Total\ Charges\ for\ Specified\ Ancillary\ Service_{(\$)}}{Total\ PJM\ real{-}time\ Load_{(MWh)}}$$

This calculation includes both price changes per MWh of the ancillary service and changes in total load. Ancillary services are broken up into four categories for cost allocation: (1) regulation service; (2) scheduling, dispatch, and system control service; (3) reactive service; and (4) synchronized reserve service which is a subset of operating reserves. The scheduling, dispatch, and system control category includes both PJM scheduling, dispatch and control, owner scheduling, dispatch and control as well as other supporting facilities, back start services, direct assignment facilities and Reliability First corporate charges.

While ancillary services are integral to the functioning of the electrical grid, the costs of providing these services are relatively small compared to the other functions performed

[74] FERC Order No. 888, Retrieved from: https://www.ferc.gov/legal/maj-ord-reg/land-docs/rm95-8-00w.txt

by utilities. Table 48 below is from the PJM market monitoring report which illustrates the historical ancillary services costs in PJM from 1999 through 2016[75].

Table 48: History of Ancillary Services Costs per MWh of Load, 1999 through 2016

YEAR	REGULATION	SCHEDULING, DISPATCH AND SYSTEM CONTROL	REACTIVE	SYNCHRONIZED RESERVE	**TOTAL**
1999	$0.15	$0.23	$0.26	$0.00	**$0.64**
2000	$0.39	$0.26	$0.29	$0.00	**$0.94**
2001	$0.53	$0.71	$0.22	$0.00	**$1.46**
2002	$0.42	$0.86	$0.20	$0.01	**$1.49**
2003	$0.50	$1.05	$0.24	$0.15	**$1.94**
2004	$0.51	$0.93	$0.26	$0.13	**$1.83**
2005	$0.80	$0.72	$0.26	$0.11	**$1.89**
2006	$0.53	$0.74	$0.29	$0.08	**$1.64**
2007	$0.63	$0.72	$0.29	$0.06	**$1.70**
2008	$0.70	$0.38	$0.34	$0.08	**$1.50**
2009	$0.34	$0.29	$0.36	$0.05	**$1.04**
2010	$0.36	$0.35	$0.45	$0.07	**$1.23**
2011	$0.32	$0.34	$0.41	$0.09	**$1.16**
2012	$0.26	$0.40	$0.46	$0.04	$1.16
2013	$0.25	$0.39	$0.76	$0.04	$1.44
2014	$0.33	$0.40	$0.40	$0.12	$1.25
2015	$0.23	$0.41	$0.37	$0.11	$1.12
2016	$0.11	$0.41	$0.39	$0.05	$0.96

Historically, ancillary services costs were less than $2/MWh, which includes all available services and reserves. Additionally, these costs can be hard to pinpoint directly because they are generally not separated from overall energy costs when LMPs are calculated. Daymark issued data requests to each of the four IOUs for any available records of their individual ancillary services costs. All utilities indicated that they do not keep records of

[75] http://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2016/2016-som-pjm-sec10.pdf, p. 395

ancillary services costs themselves and many do not distinguish between these costs and their other energy and capacity costs.[76]

4.5.2 Future impacts to Ancillary Services

According to NREL, solar generation could potentially impact two areas of the ancillary services market, operating reserves and reactive/voltage control services. Operating reserves are a supply requirement and can be broken out into three categories: (1) contingency reserves, (2) regulation reserves, and (3) flexibility reserves.

Solar resources could work to reduce the reserve requirements of contingency reserves if they are based on load. However, contingency reserves would not be impacted by solar resources if they are based on a single-largest contingency. The single-largest contingency is determined by the largest MW loss due to a single contingency.

Regarding regulation reserves, the increased penetration of solar can increase short-term variation in net load and thus increase the reserve requirement. Solar also increases the long-term variation and uncertainty in net load, as well as increasing the reserve requirement for flexibility reserves.

Regarding the impact of solar on voltage control and reactive power services, power injected into the grid from solar resources can cause local voltage fluctuations and in some areas voltage overload. To account for this, solar integration could require increased distribution voltage control. The advent of smart-inverters and other similar inverter technologies has already begun to address this issue by mitigating their own potential voltage impacts. In the future, given proper incentives and improvements to technology, inverters have the potential to exert voltage control beyond what is needed for solar-caused fluctuations and reduce the need for voltage control equipment on a feeder.

Quantifying the costs and benefits of solar on ancillary services is complicated. Attempts have been made to use a simple cost-based approach to value the effects of solar on ancillary services, however this approach is limited in several regards. First, it relies on previous impact estimates on ancillary services. This is problematic because studies that try to quantify changes to reserve requirements due to solar penetration are very few in number and generally system specific, making it difficult to determine if the observed effects are widely applicable. Second, this approach requires assigning dollar values to the impacts. Having a basis for these values is necessary, however market data only

[76] Discovery Response 1.20 from each IOU

exists for some reserve services and only in structured markets; therefore, this data should not be used to evaluate the impact of future changes to grid conditions. NREL explains that a more detailed cost-benefit analysis would be the most effective valuation, however the data available in some regions is scarce and simulation tools are highly complex.[77]

While the potential impacts of solar on ancillary services could be large, the current consensus is to assume there is minimal impact on ancillary services when modeling solar costs and benefits. There are several different rationales for this. First, it is assumed that current solar penetration is too small to have the above-mentioned negative impacts, nor will it, at least in the near-term, be able to provide the above-mentioned reactive service benefits. Second, as the impact on ancillary services is still poorly understood and studies evaluating these impacts are few, it is difficult to employ a simple cost-benefit approach.

PJM's Renewable Integration Study[78] assesses the effect of wind and solar on the ancillary services using statistical analysis. Due to the intermittency of renewable generation, it is thought that PJM would need to increase is reserve margins to respond to the inherent variability. This hypothesis was tested using statistical analysis measuring the effects of wind and solar on the four categories of ancillary services within PJM: (1) Regulation, (2) Reserves, (3) Black Start Services, and (4) Reactive Service. Similar to the conclusion drawn by NREL, the PJM study found that from a contingency perspective, none of the wind or solar projects added to the PJM system were large enough that a loss would require an increase in PJM's level of contingency. Additionally, the study found that the effects of the production variability of wind and solar was significantly dampened by aggregation of resources in the PJM territory as well as through geographic diversity. The PJM Renewable Integration Study concluded that both wind and solar projects are too small to have impacts on ancillary services. This conclusion mirrors the rationale provided by NREL to justify current industry practice - which is the assumption that PV has no impact on ancillary services.

Grid support services represent a relatively minor element of the value of solar calculation, with little to no effect at low solar penetration levels. Even at higher penetration levels, benefits could be negligible with the potential of additional system

[77] Methods for Analyzing the Benefits and Costs of Distributed Photovoltaic Generation to the U.S. Electric Utility System – p. vii

[78] https://www.pjm.com/~/media/committees-groups/subcommittees/irs/postings/pris-executive-summary.ashx

costs, as shown in the PJM study. As such, Daymark recommends not including benefits or costs for ancillary services in this evaluation.

4.6 Fuel Price Hedging Costs and Benefits

The cost structure of solar – with its high upfront capital costs and zero fuel costs – means that once a solar project is constructed, the cost of solar power is largely fixed over the life of the project. This is in sharp contrast to the cost of fossil generation, which, absent contracts to fix fuel prices, is subject to the volatility of fuel prices.

While it is a widely accepted concept that adding fixed price resources, such as solar, to a utility's supply portfolio reduces exposure to fuel price volatility, there is no standard method for calculating the hedge value of adding solar to a portfolio. A solar project essentially operates like a 25-year hedge or forward contract. If these types of contracts were available in the marketplace, we could use them as an indication of the fuel price hedging benefit of solar, but there is no market for hedges or forward contracts of that duration.

Given this constraint, we assess the value of the solar hedge in three ways:

1. Change in the mean and standard deviation of the per MWh cost of the market portion of the portfolio (note that the solar piece is assumed fixed),
2. Change in exposure to tail risk (the fixed solar piece adds no tail risk) as measure by Conditional Value at Risk ("CVaR"), and
3. Change in the shape of market exposure as measured by exposure to outcomes above or below a target market portfolio cost.

We modeled the total spot energy supply portfolio cost in Maryland with and without solar. The logic behind this modeling treatment is twofold. First, utilities will only purchase power from their owned resources to the extent that such purchases cost less than market purchases. Second, the PJM spot energy price reflects the lowest cost fuel in each pricing interval. Because PJM's energy market selects the lowest cost resource in each execution of the market, the market naturally gives the buyer access to the lowest cost spot portfolio, creating something of a natural hedge against high fuel costs. The question here, then, is relative to the lowest cost spot portfolio, what incremental hedge value does the addition of solar offer.

The modeling approach relies on Monte Carlo analysis to simulate LMP and load variability with the average daily LMP and loads modeled as distributions fit to historical data. The model applies a daily shape to winter and summer loads for Maryland and to the daily average energy prices output from the Aurora model described above. We ran two simulations: one without solar and one with the same amount of solar added as we that assumed in our high solar case from the Aurora analysis. The simulations used 10,000 draws to generate a distribution of portfolio cost outcomes. The distribution of energy supply cost results was used to measure Maryland's aggregate risk exposure to variations in wholesale electricity prices.

In the no-solar case all of the energy was assumed to be purchased from the PJM market at average energy price from the Aurora output and a distribution based on the typical seasonal price shape in PJM. In the solar case, the amount of energy purchased from the market was reduced by an amount equal to the energy supply assumed to come from the solar resources. In this way, solar is treated as a net reduction to the load that needs to be served.

The output of the simulation is the total annual energy costs of the supply portfolio with and without solar. Not surprisingly, we found that there was a reduction in the total portfolio cost for the solar case as is shown in Table 49 below. The total supply costs are lower because less energy is purchased from the market. This total does not include the carrying cost of the solar plant. Additionally, we found that there is a reduction in the volatility of supply costs as measured by the change in variance between the without and with solar cases.

Table 49: Change in the Mean and Standard Deviation of Portfolio Cost

	NO SOLAR	WITH SOLAR
Mean	\$61.86	\$57.07
Standard Deviation	\$7.69	\$7.22
% Δ Mean		-7.74%
% Δ Variance		-11.93%

To characterize Maryland's aggregate risk exposure, we also looked at the CVaR of the portfolio with and without solar. CVaR (also called expected shortfall) is a metric used to quantify an entity's dollar-exposure to extreme market outcomes (i.e., those that would lie at the tail-end of the distribution). CVaR (see Figure 36) is calculated as the weighted average of all power supply costs (output from the Monte Carlo simulation) which are greater or equal to VaR in the worst 5% of simulated outcomes. This approach is particularly useful when considering long-tailed distributions, such as found in power costs, where a lot of cost exposure can be bound up in relatively few hours with extreme prices. We use CVaR, therefore, as a proxy for the extreme power supply cost scenarios against which state's utilities would seek a hedge.

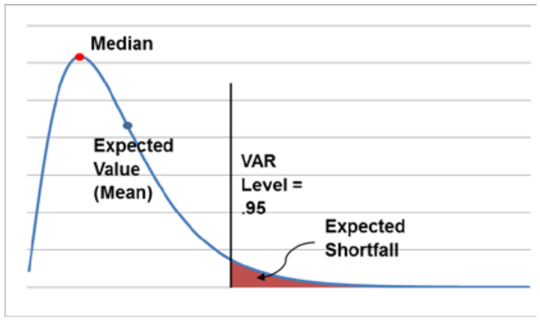


Figure 36: Conditional Value at Risk

CVaR is calculated for both the without and with solar cases. We found that adding solar to the portfolio reduced the CVaR. The results of this analysis for Winter, Summer and Annually are shown in Table 50 below for 2028.

Table 50: Conditional Value at Risk, 2028

	SUMMER		WINTER	
	no solar	w/ solar	no solar	w/ solar
CVaR (90)	5,584,118,377	5,098,835,241	6,984,374,874	6,550,406,919
CVaR (95)	6,048,424,615	5,527,055,970	7,562,117,895	7,097,665,942
CVaR (99)	7,181,957,010	6,572,423,413	8,921,511,352	8,386,578,607
Change in Tail Exposure				
CVaR (90)				
CVaR (95)		485,283,136		433,967,955
CVaR (99)		521,368,645		464,451,953
Percentage Change in Tail Exposure				
CVaR (90)		-8.69%		-6.21%
CVaR (95)		-8.62%		-6.14%
CVaR (99)		-8.49%		-6.00%

	TOTAL	
	no solar	w/ solar

CVaR (90)	11,354,369,575	10,517,008,803
CVaR (95)	11,984,492,689	11,109,269,278
CVaR (99)	13,363,975,815	12,406,917,294
Change in Tail Exposure		
CVaR (90)		
CVaR (95)		837,360,772
CVaR (99)		875,223,411
Percentage Change in Tail Exposure		
CVaR (90)		-7.37%
CVaR (95)		-7.30%
CVaR (99)		-7.16%

The last way we looked at the hedge value of solar was to estimate the change in exposure to supply cost outcomes above or below a target market portfolio cost. This analysis assumed that the target portfolio cost was the same in both the without and with solar cases. The net impact on the supply costs is the difference between the change in the expected upside and downside exposure as a consequence of adding solar into the portfolio. Because the effect of adding solar is realized as a reduction in the dispersion of the distribution of power supply cost outcomes, in summer and winter we find that the potential upside increases (i.e., the expected value of the set of outcomes with a lower cost than target) and the potential downside decreases (i.e., the expected value of the set of outcomes with an expected value higher than target). Table 51 summarizes the results of this analysis.

Table 51: Change in Exposure due to Solar Additions

		SUMMER		WINTER
	no solar	w/ solar	no solar	w/ solar
Mean (Expected) Case Value	3,892,300,779	3,892,300,779	4,820,957,011	4,820,957,011
avg below	3,366,938,598	3,200,070,817	4,140,990,424	4,007,726,585
avg above	4,597,294,992	4,515,775,738	5,719,738,014	5,652,775,838
Upside	525,362,180	692,229,961	679,966,587	813,230,426
(Downside)	(704,994,214)	(623,474,959)	(898,781,003)	(831,818,827)
Net Exposure	(179,632,033)	68,755,002	(218,814,416)	(18,588,401)

Change in Net Exposure	248,387,036	200,226,015

		TOTAL
	no solar	w/ solar
Mean (Expected) Case Value	8,713,257,789	8,713,257,789
avg below	7,816,884,360	7,499,718,348
avg above	9,843,044,915	9,673,687,469
Upside	896,373,429	1,213,539,442
(Downside)	(1,129,787,125)	(960,429,679)
Net Exposure	(233,413,696)	253,109,763
Change in Net Exposure		486,523,459

4.7 REC Market Costs and Benefits

Load serving entities in Maryland are required to provide a certain percentage of renewable energy to customers to comply with Maryland's RPS. The RPS requirements are divided into two Tiers with carve-outs for solar and offshore wind included in Tier I. The offshore wind carve-out is yet to be determined by the PSC. Tier II includes hydropower and pumped storage. Tier II requirements are phased out in 2019, so there are no Tier II requirements during the study period.

The Maryland RPS requirements for the study period are shown in Table 52 below.

Table 52: Maryland RPS Requirements

YEAR	2018	2019	2020+
Solar (Tier I)	1.50%	1.95%	2.50%
Other Tier I	14.30%	18.45%	22.50%
Tier I (Total)	**15.80%**	**20.40%**	**25.00%**

The net metering rules in Maryland allow customers to retain the renewable attributes of the power they produce. This means that the benefit to load serving entities of having BTM resources on the system is the avoided RPS compliance for the level of the avoided generation purchases. For each kWh of distributed solar that is generated, the avoided RPS compliance costs are the percentage requirement of each tier times the REC cost for that tier. For example, in 2019 the avoided RPS compliance cost would be 1.95% times the SREC price plus 18.45% times the Tier I REC price.

The benefit for utility scale projects is the value at which the utility scale project can sell the renewable attributes on the market. We have assumed that utility scale projects would be able to sell the renewable attributes for the SREC price throughout the study period.

To determine the REC price for this analysis, we looked at the currently traded REC price and escalated these prices by inflation of 2 percent. While Maryland has aggressive carbon reduction goals that require a 40 percent reduction in carbon emissions by 2030 and the RPS is a likely mechanism by which to achieve these goals, we assumed that REC prices would remain close to their current levels even if there was greater demand for renewables, because the cost to construct renewables is coming down over time. The REC Prices and Avoided Compliance Costs are shown in Table 53 below.

Table 53: REC Prices and REC Benefits

	REC PRICES		**BTM REC BENEFIT**	**UTILITY SCALE REC BENEFIT**
YEAR	*Tier1*	*Solar*	*(Avoided REC Purchases)*	
2019	$6.00	$9.00	$1.28	$9.00
2020	$6.12	$9.18	$1.61	$9.18
2021	$6.24	$9.36	$1.64	$9.36
2022	$6.37	$9.55	$1.67	$9.55
2023	$6.49	$9.74	$1.70	$9.74
2024	$6.62	$9.94	$1.74	$9.94
2025	$6.76	$10.14	$1.77	$10.14
2026	$6.89	$10.34	$1.81	$10.34
2027	$7.03	$10.54	$1.85	$10.54
2028	$7.17	$10.76	$1.88	$10.76

It is possible that REC prices could be higher than those shown in Table 53 because of increased demand for solar due to policy changes, supply constraints, and/or increases in the cost of solar. In a constrained market the REC benefit for utility scale solar could be as high as the ACP value of $50/MWh. The REC benefit of BTM resources could be as high as $10/MWh assuming current RPS requirements and ACP levels or even higher depending on policy changes.

4.8 Bulk Power System Conclusions

The bulk power system analysis shows that there are significant benefits from adding both BTM and utility scale solar to the Maryland electric grid. The largest benefit comes from the energy value of solar, with the avoided capacity and avoided RECs making up the next largest benefits.

Throughout the study, we examined the costs and benefits of solar through the lens of the three categories of BTM (residential, small commercial, large commercial/industrial) and utility scale solar. While we did find differences in bulk power system benefits between BTM and utility scale projects, we did not find a difference in per unit value of benefit between the three categories of BTM solar that we studied. The differences between BTM and utility scale solar were largely because BTM behaves as a load reducer and utility scale projects behave as market participants.

There is some difference in some categories of benefits provided by solar installed in the different IOU territories. These categories are avoided energy, avoided capacity, and avoided transmission charges and investment. The differences in these benefits between IOU territories are not large and are due to slight differences in the market dynamics in the territories.

5. DISTRIBUTION SYSTEM BENEFITS AND COSTS

5.1 Introduction

Benefits and costs of solar projects on the bulk transmission grid have been presented in Section 4. While potential benefits at the bulk transmission level would generally be most significant, considering that many solar projects are located at the distribution level, distribution benefits and costs must also be factored into a comprehensive value assessment. Table 54 summarizes the benefits and costs that may be realized from the introduction of solar considered in this analysis.

Table 54: Distribution System Benefits and Costs of Solar Development

COMPONENT	DESCRIPTION
Grid Location	Considers location on a distribution line and relative to electrical geography
Deferral of Distribution Investments	Impacts of solar additions on distribution system investment
Reductions in Losses and Wear and Tear as well as Improvements to Grid Security	Where solar resources offset peak loading, which exacerbates these factors, they can result in system savings
Avoided Distribution Outages	Avoided outages associated with overloaded facilities during peak loads if solar is coincident with peak hours on a distribution line
Benefits of Controllable Solar	Distributed automation and smart inverter use can positively impact voltage flicker, voltage regulation, and ride-through during system perturbations
Benefits of Solar paired with Storage and Demand Response	Storage complements solar by smoothing out the intermittency; adds value during peak. Adding demand response provides an additional tool for managing load on the distribution system.

This section includes a discussion of potential distribution system benefits and costs including locational impacts, possible deferred investment in infrastructure, system losses, reduced wear and tear, reduced outages, land impacts, and smart inverter benefits. Also included is an assessment of the electrical capability of the existing Maryland distribution system to accommodate more solar resources.

5.2 Feeder Location Impacts on Benefits and Costs

The economic benefits and costs of distributed solar projects interconnected to the distribution system vary significantly depending on two critical factors: the project location (geographical and electrical) and the project size.

In regard to its location, installation of a distributed solar project closer to a substation could incur less costs due to its contribution to the system strength and system Stiffness Ratio. On the other hand, installation of the project along a feeder farther from the substation could be more cost effective, if such a feeder is facing current or forecasted overloads and is in need of system upgrades. The addition of a solar project along this feeder could potentially eliminate or postpone the need for expensive distribution system upgrades, resulting in a net system benefit when avoided costs exceed any added project costs. This benefit is typically retained by the utility and not passed on to the developer. See Section 5.4.3 below for a discussion of possible savings.

For Residential and Small Commercial/Industrial projects, installations are typically fast tracked for interconnection approval without need for a specific study. Although, at larger penetration rates, these projects could have similar impact as large Commercial/Industrial projects and may need to be studied for aggregate impact across a particular feeder or substation. Please refer to Appendix F for a discussion on project interconnection process methodologies.

For larger Commercial/Industrial and Utility Scale solar projects each installation typically requires a specific study to determine system interconnection needs. System reinforcements that are often required to accommodate solar integration include grounding transformers, voltage regulators, capacitors, substation expansion and distribution line rebuild. The costs associated with the solar project interconnection are typically born by the developer and thus can impact the economic viability of the project.

Based on our experience, grounding bank, voltage regulator, capacitor, and control system changes that might be required to support a project's interconnection are typically $300,000 or less and could increase cost of a project up to $0.017 per kWh for a 2 MW Large Commercial/Industrial or small Utility Scale project. The cost of substation expansions or distribution line rebuilds can be relatively high (typically around $1,000,000 or more) and thus can only be supported by larger Utility Scale distributed solar projects. This translates to a cost of $0.023 per kWh for a 5 MW Utility Scale project. As shown here, the interconnection costs associated with system interconnection requirements can significantly vary depending on the size of the project and magnitude of required system improvements.

The addition of solar projects at sub-transmission or transmission voltage levels (above 23 kV) could have negligible impact on the distribution system but could either increase or decrease the need for system improvements at those higher system voltage levels. This is discussed in more detail in the Section 4.4.

5.3 Avoided Distribution Costs

This section presents the potential benefit streams associated with solar projects sited on the distribution system. These benefits can include:

- Distribution asset addition deferrals
- Distribution loss reductions
- Reduced distribution system equipment wear and tear (increased equipment life)
- Reduced distribution system outages (improved reliability), and
- Avoided land associated with avoided distribution system expansion

5.3.1 Distribution Asset Addition Deferrals

Customer load growth and peak overload related issues can justify the need for costly substation expansions and/or distribution line rebuilds.

However, the need for these upgrades can potentially be deferred and/or eliminated through the aggregation of various distribution level solar sites ranging from rooftop to Utility Scale solar projects. As demonstrated through a number of pilot programs such as Brooklyn Queens Demand Management Program from Consolidated Edison[79] and the Boothbay Sub-Region Smart Grid Reliability Pilot Project[80] as well as non-transmission alternatives studies[81], the addition of demand side management resources including a

[79] file:///C:/Users/dnallan/Downloads/%7BEA551051-F5C8-4E51-9B83-F77017F0ED0D%7D.pdf

[80] http://www.neep.org/sites/default/files/resources/FINAL_Boothbay%20Pilot%20Report_20160119.pdf

[81] https://www.iso-ne.com/static-assets/documents/2015/01/a2_sema_ri_mra_non_ceii_version.pdf

wide-range of solar projects could aid in deferment and/or elimination of these types of upgrades.

The Boothbay Pilot suggested that the addition of 2 MW of non-transmission-alternatives (NTAs) could offset the need for the rebuild of a 34.5-kV sub-transmission line from Newcastle to Boothbay Harbor, Maine, at a construction cost savings of about $18 million. The need was established by projected peak load conditions and the implemented NTAs included 308 kW of photovoltaic solar arrays.

As another example, BGE deferred the reconductoring project consisting of two 34 kV circuits supplied out of its Lippins Corner station. The project was deferred by two years from its initial service date based on the impact of BGE's demand response program. Furthermore, BGE's transmission and distribution expansion plans in the Loch Raven area was considered for deferral as result of demand response. While these programs are specific to demand response, deferrals like these are also possible considering the suitable placement of solar projects to offset customer load[82].

Given the expectation of continued growth in distributed solar in Maryland supported by Renewable Portfolio Standards and other renewable energy policies, it is likely that significant distribution improvements that would be historically driven by load growth will be displaced. The amount, and hence value, of distribution improvements that can be displaced by solar is circuit and location dependent. Typical circuit improvements such as substation transformer replacements or distribution line rebuilds that might be avoided by the installation of solar can vary from several hundred thousand dollars to a few million dollars. Locational demand management programs, like those described above, can enhance the value of energy and environmental policy supported distributed solar growth.

Figure 37 shows the value, expressed in dollars per kilowatt hour of the solar energy produced, of varying capital investment required and varying amounts of solar installation required to offset that investment. The basic assumptions underlying this figure are that the average annual capacity factor for solar is approximately 16% and that the annual carrying charges for capital investment are approximately 16%.[83] Referring to the figure, as an example a 2 MW project that results in the avoidance of a $2 million distribution system upgrade translates to an average system benefit of approximately $0.114/kWh. To step through the math, offsetting a $2 million

[82] Baltimore Gas and Electric – Distribution Investment Plan, Case No. 9406, June 2017

[83] These assumptions are based on RLC's experience over a range of solar projects.

investment at a 16% annual carrying charge rate would result in an annual revenue requirement savings of $320,000. A 2 MW solar installation producing energy at a 16% capacity factor would produce 2,803,200 kWh per year. Dividing the savings by the energy yields $0.114 saved for each kWh of solar energy produced. As shown, a smaller project, 1 MW for example, that results in avoidance of the same $2 million distribution system upgrade will provide a larger benefit on a cost per kWh basis. However, potential benefits from all solar site sizes can contribute to long-term RPS goals, provided a suitable and progressive framework is in place.

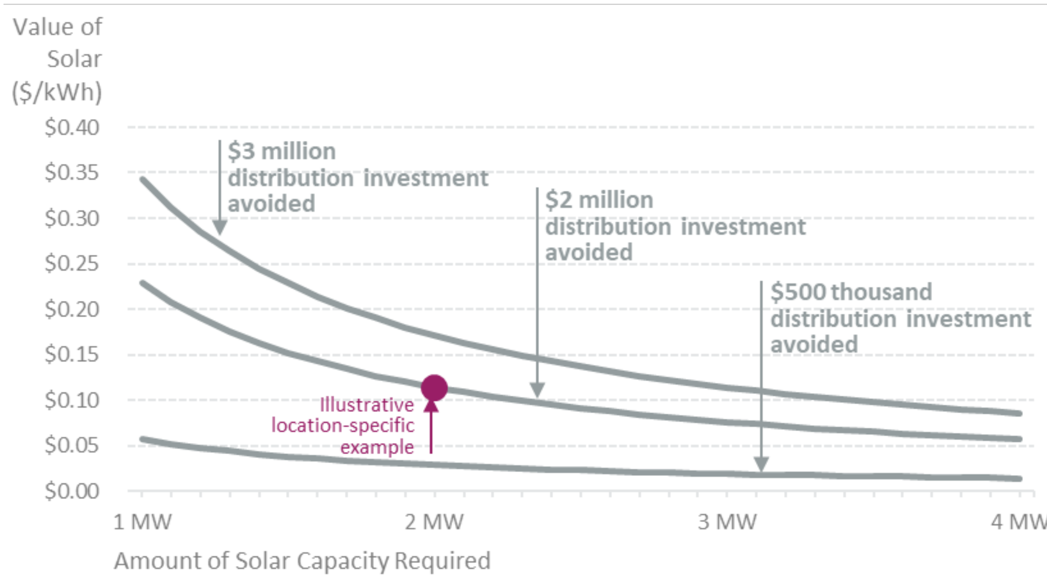


Figure 37: Value of Solar in Avoiding Distribution Investment

Figure 38 through Figure 45 take this illustrative example one step further by combining the location-specific value with the system-wide value in each of the four utility territories, for both behind the meter and utility scale projects. For example, by adding the system-wide value of behind-the-meter solar in Potomac Edison's service territory in the year 2020 ($0.402/kWh) to the value of this illustrative 2 MW example ($0.114/kWh), Figure 45 shows a total value of solar on this hypothetical circuit of over $0.50 per kWh of solar energy produced.

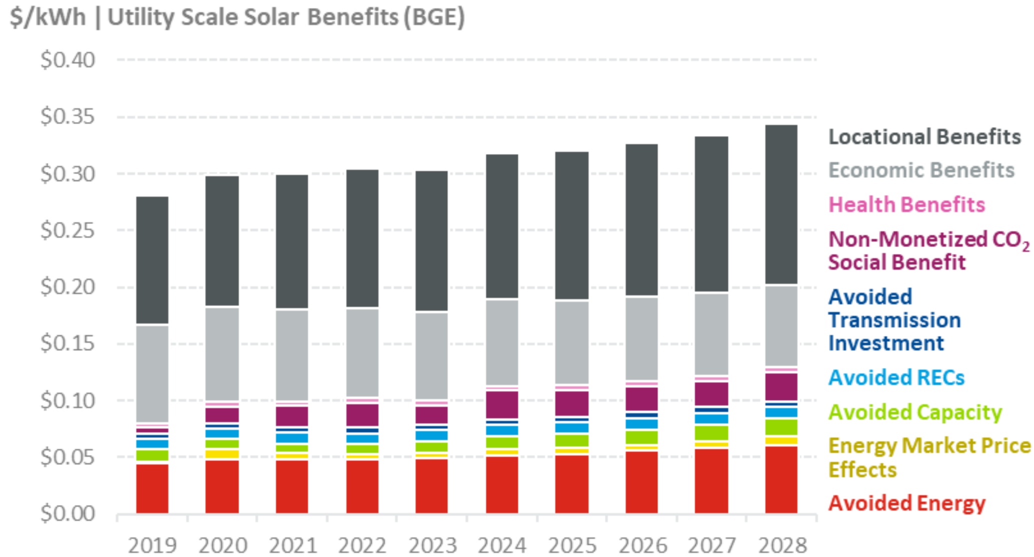


Figure 38: BGE Utility Scale Value of Solar for an Illustrative Location-Specific Example

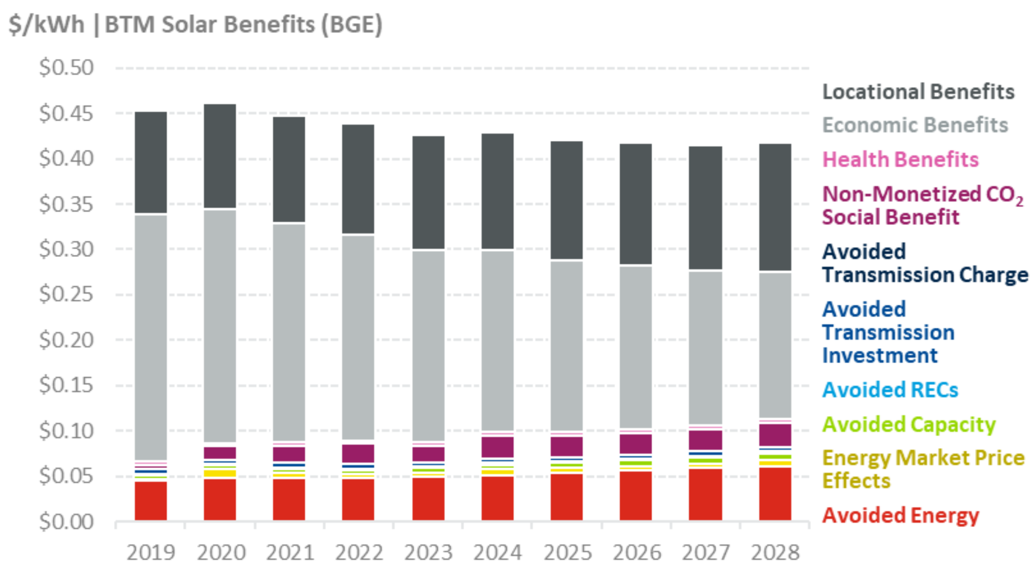


Figure 39: BGE BTM Value of Solar for an Illustrative Location-Specific Example

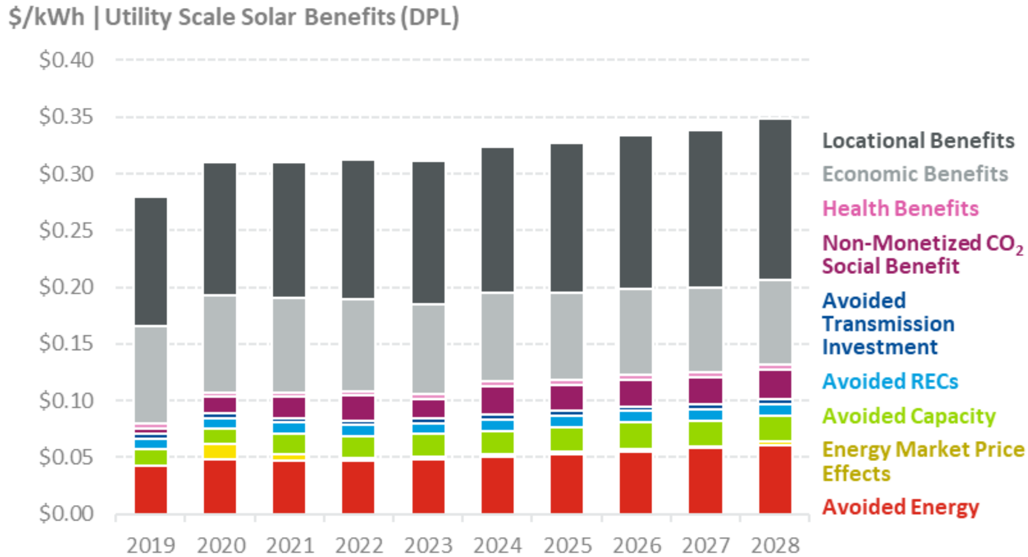


Figure 40: DPL Utility Scale Value of Solar for an Illustrative Location-Specific Example

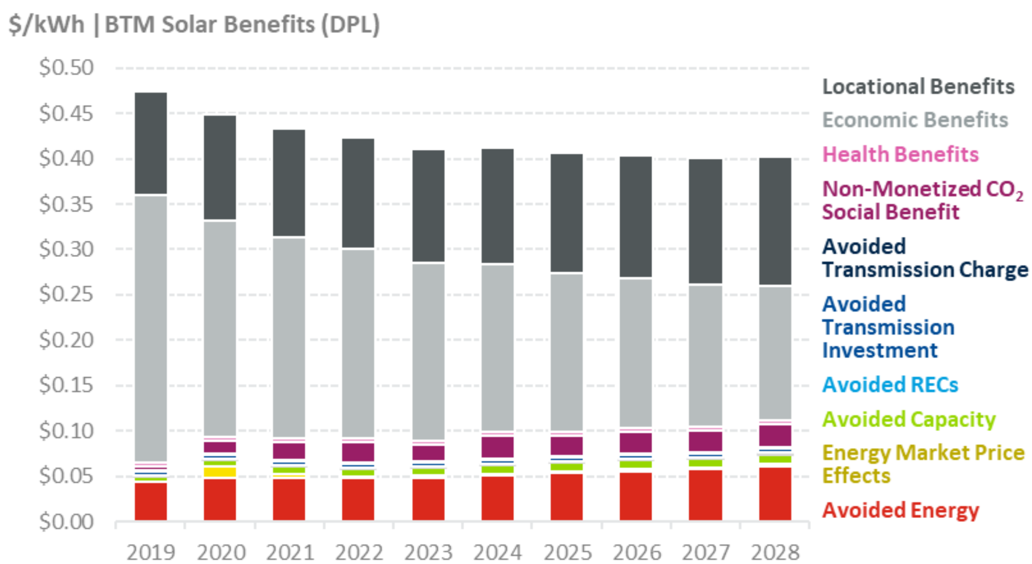


Figure 41: DPL BTM Value of Solar for an Illustrative Location-Specific Example

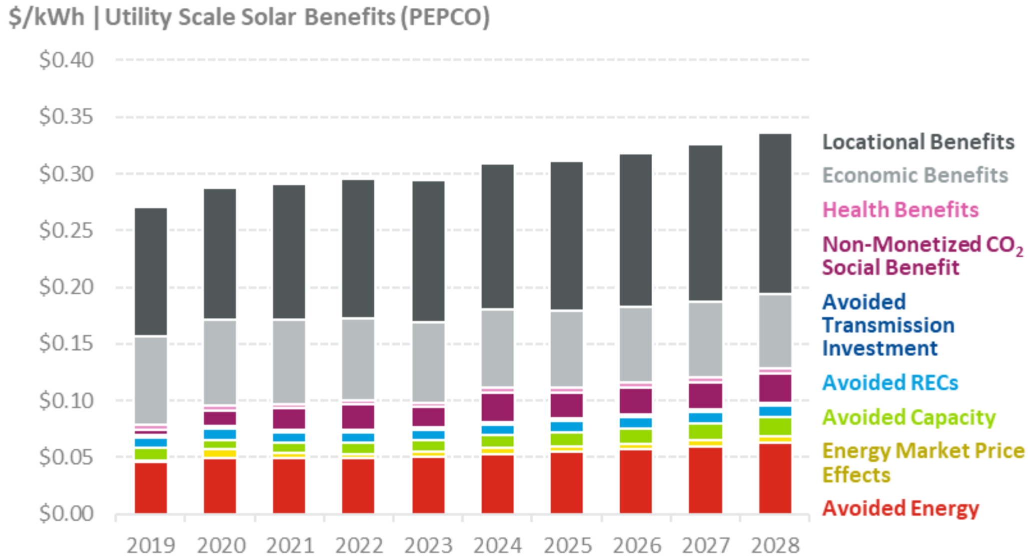


Figure 42: PEPCO Utility Scale Value of Solar for an Illustrative Location-Specific Example

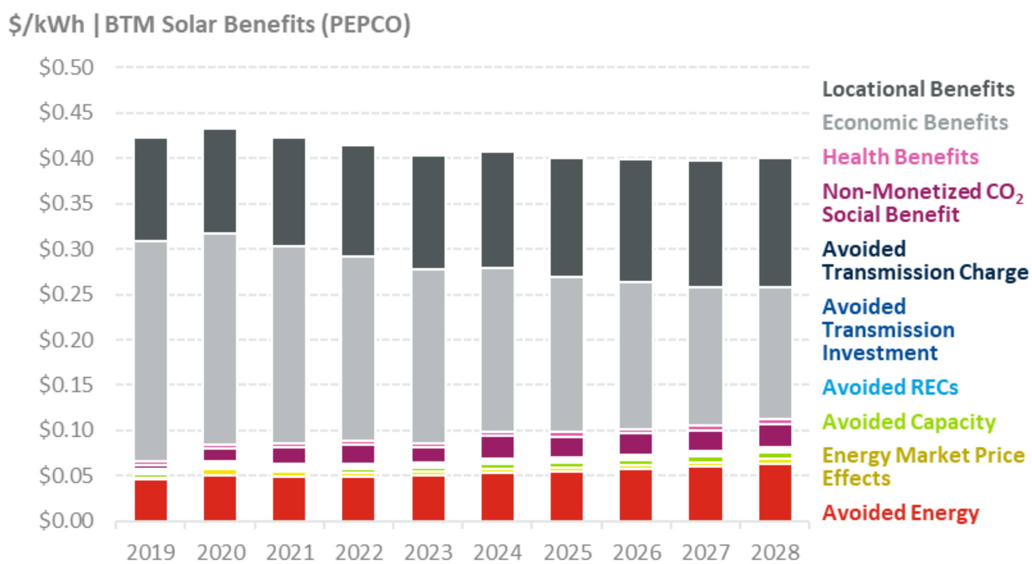


Figure 43: PEPCO BTM Value of Solar for an Illustrative Location-Specific Example

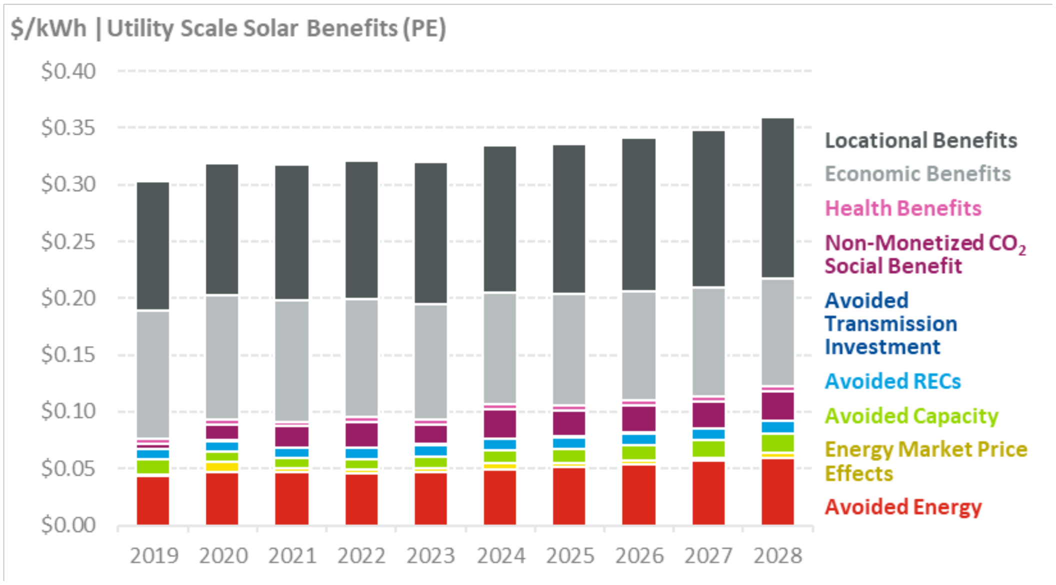


Figure 44: PE Utility Scale Value of Solar for an Illustrative Location-Specific Example

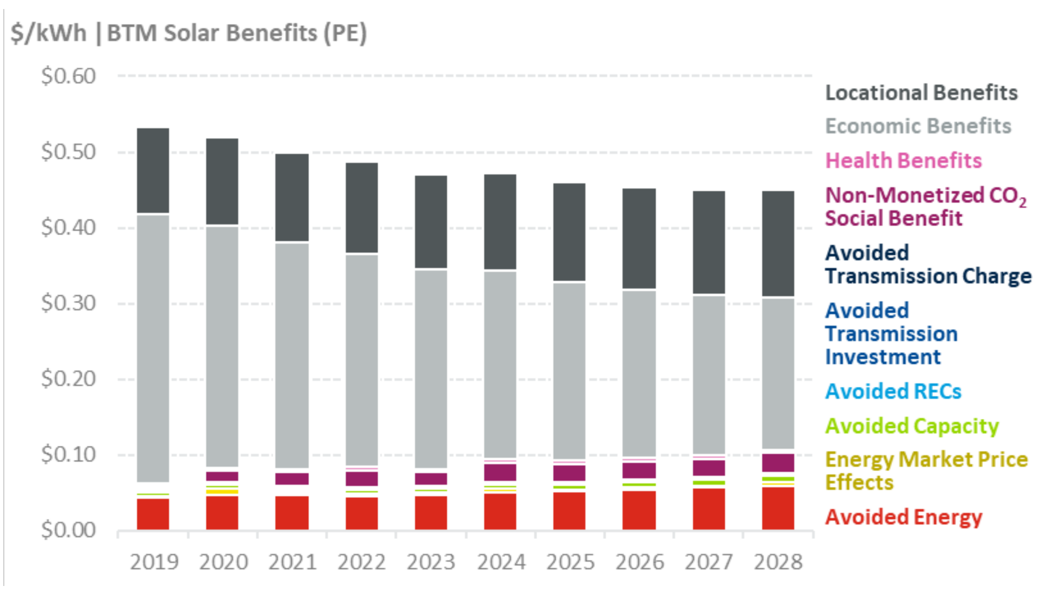


Figure 45: PE BTM Value of Solar for an Illustrative Location-Specific Example

5.3.1.1 Potential for Deferment of Distribution Projects in Maryland

Based on the information provided to Daymark in response to data requests, distribution projects in the planning phase can be classified into:

- Small distribution projects: projects involving smaller upgrades to the distribution system such as relay upgrades or customer interconnections (typically less than $1,000,000); and
- Large distribution projects: generally involving construction of new substations, transformers and/or associated feeder lines (typically above $1,000,000)

The following Table 55 summarizes those projects that fall within the study period for each of three of the four utilities:

Table 55: Large and Small Distribution Projects Summary

UTILITY	NUMBER OF SMALL DISTRIBUTION PROJECTS	NUMBER OF LARGE DISTRIBUTION PROJECTS
DLP	27	20
PEPCO	41	42
PE	13	5

Based on a high-level review of these projects, about one-third appear to be related to load-growth, with the potential to be deferred or avoided by strategically placed distributed or utility scale solar installations. A detailed study of each project would be necessary to determine if commercial solar, utility solar, solar combined with storage or other distributed resources could offset the need for the project.

BGE did not provide a list of distribution projects. However, their Distribution Investment Plan stated that they have over 23,000 Distributed Energy Resources ("DER") System Net Metering installations in their system. They also discuss the benefits of their Advanced Metering Infrastructure ("AMI") that will allow for the control of DER resources to help shape net load to avoid capital expenditures on the T&D system.

5.3.2 System Loss Reduction

Strategically placed solar also has the potential to reduce line losses by injecting power and offsetting power flow to serve load. Counteracting of power flow by siting solar units close to the system loads can be an effective measure to reduce current and therefore reduce overall transmission and distribution system losses. Refer to Appendix G for additional technical information on system losses.

For example, a large commercial load could be located towards the end of a distribution feeder's main backbone, which would create potential for large losses across the entire circuit. Through the use of a nearby placed solar facility that has a generating capacity in the same magnitude as the load, these losses could be greatly decreased, especially if the generation were controlled to shave the peaks of the loading profile.

Another example would be a radial tap off the main backbone of the distribution feeder that has numerous customers, thus equating to large load aggregation. Losses on the main backbone could again be reduced if the generation were optimally placed, which in this case would be somewhere along the distribution feeder tap.

Though it is evident that locating generation close to loads reduces losses when compared with power being provided from large generation stations located further away, other factors must be taken into account to fully evaluate the best locational placements; thus, full feeder impact studies are recommended when making these determinations. Analyses such as voltage profile, flicker, short circuit, effective grounding, thermal, and reactive should all be examined using power flow software before finalizing project placement decisions.

It should be recognized in the planning and interconnection process, however, that increasing solar penetration can eventually result in exacerbated losses in the reverse direction (power flow from the solar project(s) toward the substation), particularly along the distribution feeder under off-peak load conditions. Again, power flow studies are recommended when making final PV solar size and placement decisions.

5.3.2.1 Loss Testing

As part of this study, testing was performed with solar penetration at the high level assumed in Section 5.6 of this report to determine the potential impact of solar development on distribution system losses. Distribution system simulations were performed on the Potomac Electric system with the utility's CYME model representing the full distribution network at different levels of load[84]. Multiple reduced net load level scenarios, representing different levels of solar penetration across the distribution system, were modeled together with typical load shapes to provide a full spectrum of loss scenarios. The change in feeder losses were summed across all hours of the year to

[84] Detailed models required for this loss analysis were not made available by the other distribution companies.

arrive at annual estimates of loss savings for the four service areas. The resulting marginal loss savings are shown in Table 56 below with a range from 1.7% to 12.1%.

Table 56: Estimated Loss Savings with High Penetration of Solar

Utility	Annual Losses			Annual Solar Energy (GWh)	Marginal Loss Savings (%)
	Pre-Solar (MWh)	Post-Solar (MWh)	Delta (MWh)		
BGE	651,134	572,809	78,325	4,489	1.7
DPL	405,727	295,347	110,380	1,627	6.8
PEPCO	1,774,454	1,441,205	333,249	3,208	10.7
PE	741,017	581,476	159,541	1,323	12.1

Note that BGE average loss savings are lower than PE's because most of the distribution circuits are at a higher nominal voltage level. Similarly, some of PEPCO's and DPL's distribution circuits are at higher voltage levels.

A byproduct of reducing line losses is an increase in distribution equipment life by relieving heavily loaded devices, conductors, etc. during peak loading scenarios. As a result, component replacement and/or maintenance can be pushed out and required less often as discussed further in the next section.

5.3.3 Reduced Equipment Wear and Tear

Significant swings in daily loading profiles can translate directly to large voltage variations, which in-turn, can lead to an increase in tap and switching operations per day on substation transformer load tap changers ("LTC"), stepdown transformer LTCs, feeder voltage regulators, and capacitor banks. In more simple terms, this means an increase in mechanical operation of certain distribution equipment is required to maintain the distribution system to within acceptable limits as load levels change throughout the day. Since these equipment operations require physical movement by a device and inherent electrical arcing takes place[85], loss of life occurs at a faster rate with more frequent device operations.

As with overload related issues, reductions in frequent tap operations and capacitor switching can be seen through strategic placement and operation of solar generation.

[85] An electrical arc is a high intensity spark that is produced when a current jumps a gap between contacts. Arching can lead to loss of life due to heating, and deterioration of contact materials and insulation.

However, increased voltage fluctuations resulting from high solar penetration could also result in accelerated loss of life[86]. Solutions that provide for real time dispatch through a combination of smart invertors and ESS technology can provide for a more consistent daily load profile, thus producing fewer daily tap and switching operations and increasing equipment life as discussed in more detail in Section 5.3.3.

On top of device loss of life due to physical operations, wear and tear also occurs as more power flows through devices and/or conductors. Heavier flows equate to more losses, which are directly related to heat increases. Device and conductor lifespans can be increased not only by peak shaving, but by dispatching Utility Scale solar sites in accordance with distribution feeder load profiles with the intent of lowering load levels altogether, thus lowering heat dissipation. Again, if high rates of solar penetration are left undispatched/uncontrolled, devices and conductors can end up with adverse impacts due to high power flows in the reverse direction. Therefore, in the distribution planning process, it is important that priorities are balanced between device life impacts and power serving needs.

5.3.4 Avoided Outages

Recent data has shown that Maryland does not suffer from excessive electrical outages[87]. However, it is typical for rural areas such as those within the Potomac Edison territory to contain lengthy distribution feeders of 100 miles or more. Outages in areas such as these may take days to relieve. Therefore, it is important to consider the resulting benefits of high solar penetration to the reliability of distribution feeders.

An increase in customer load demand or in the number of customers tied into the distribution feeders can result in large load increases that can render the initial substation and/or feeder designs insufficient, which can subsequently lead to degraded reliability (increased outages). Frequent outage occurrences can justify expensive upgrades such as new substation transformers, rebuilding/reconductoring existing lines, and new non-renewable generation facilities.

[86] Increased voltage fluctuations can occur due to solar project intermittency characteristics and the potential for bi-directly power flow during a daily load cycle when non-dispatchable solar is applied.

[87] https://www.delmarva.com/News/Pages/DelmarvaPowerCustomersinDelawareExperienceRecordElectricityReliabilityin2017.aspx
https://content.govdelivery.com/accounts/MDCARROLL/bulletins/16ff295

Based on the information provided by each utility as part of a data request response, approximately 142,108 outages events were observed collectively between 2014 and 2016 across their territories. The outage events have been separated into two categories: Equipment & Load Outage Events, and Non-Equipment & Load Outage Events[88] and are presented in Figure 46 along with the total number of outage events.

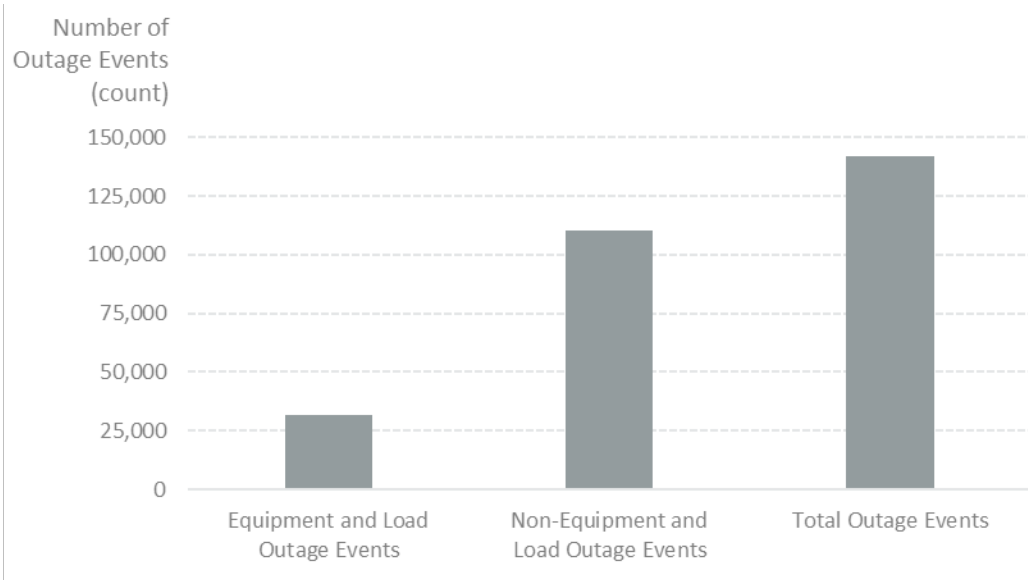


Figure 46: Maryland Investor Owned Utility Distribution Outage Events between 2014 and 2016

As observed from Figure 46, the Equipment & Load Outage Events make up approximately 22% of the total outage events.

Strategically placed solar along distribution feeders could potentially address some of these Equipment & Load related outages, remove the need for expensive upgrades, and help maintain system reliability.

5.3.5 Avoided Land for Distribution

Most distribution lines are located either underground or roadside. Therefore, there is minimal land needed for the linear sections. However, if more capacity is required to serve increasing load, then distribution substation expansion might be required. The

[88] Non-Equipment & Load Outage Events are due to animals, vehicles, tree contact, foreign contact, weather, vandalism, etc., and also includes planned/scheduled outages and outages for unknown cause.

amount of land required for a typical substation expansion consisting of one transformer and three additional distribution circuits is approximately 1/4 acre.

As discussed above, a benefit of strategically placed solar may serve to eliminate or postpone the need for a substation expansion that would otherwise be needed to serve load growth in a particular area. In this case, the land use and associated cost of land would be avoided or postponed in addition of equipment costs.

5.4 Benefits of Non-Dispatchable Solar

5.4.1 Non-Dispatched Solar

As discussed earlier, strategically placed solar projects interconnected along the distribution system can offset and potentially eliminate the need for load related distribution feeder upgrades. An example of this would be on a feeder primarily constructed of overhead lines during a hot summer day. A primary issue in this scenario is that overhead lines are thermally rated for less Ampacity[89] than they would be under a colder weather scenario. In practical terms, the lower Ampacity rating reduces the amount of load the system can reliability serve on a hot summer day. At the same time, customers are likely increasing their use of air conditioning in their homes or offices, which results in higher than average loading. These two factors among others can result in overloaded lines and increased outages.[90] A potential solution to issues like these can be found in interconnecting solar sites on the aforementioned feeder. Whether it be large utility scale generation or an aggregation of residential and/or commercial/industrial rooftop units, solar generation can aid in relieving overloads by injecting power close to the load at the time during the day when it is most needed. Figure 47 presents a plot of a distribution feeder load profile with solar (see the pink line labeled "Peak Shifted Load") and without solar production (see the dark blue line labeled "Normal Load") over a period of seven days. The Peak Shifted Load profile has a lower peak value than the Normal Load peak value when the peak occurs at approximately 4 PM (16:00) each day. This is due to the solar offsetting the load.

[89] Ampacity is the maximum amount of electric current a conductor or device can carry before sustaining immediate or progressive deterioration.

[90] This situation can also result in increased losses and wear & tear as discussed in Section 5.3.2 and 5.3.3 above.

Another result is that the peak load of the Peak Shifted Load profile occurs later in the day at around 6 PM (18:00) each day.

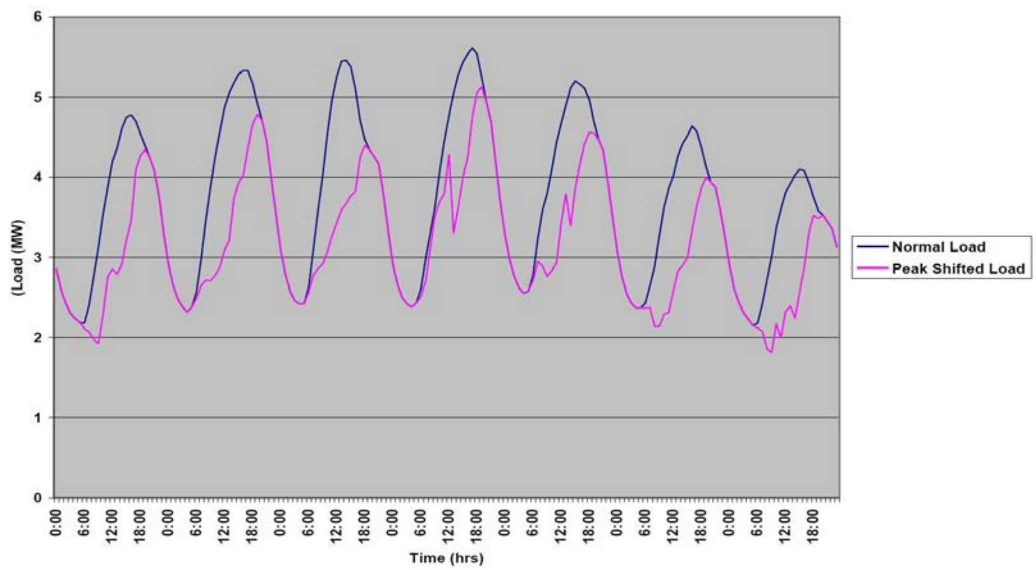


Figure 47: PV Production Offsetting Peak Load (Source: PEPCO)

Consequently, the siting and operation of solar facilities can be a viable option in offsetting or eliminating the need for costly distribution upgrades and/or alternative circuit schemes that have traditionally been required to safely and reliably serve customer load.

Depending on interconnection location, a solar facility could also result in power flow in the reverse direction which can lead to increased losses or even the potential for system upgrades to mitigate equipment overloads, voltage violations, and/or system protection impacts. Although this scenario is less likely to occur with low levels of Residential and small Commercial/Industrial rooftop solar, the likelihood increases at higher penetration levels and with larger solar projects. Currently, Utility Scale solar interconnections typically undergo impact studies to determine whether adverse impacts will be probable before the project is approved for interconnection.

Furthermore, the interconnection standards in many states dictate that solar sites will not be permitted to regulate voltage and/or reactive power; rather, they will only be allowed to operate at a unity power factor and in some special cases, an off unity fixed power factor. In this restricted mode of operation, there is potential for an equal and opposite problem of overloaded equipment in the reverse direction, especially under off peak conditions with high solar penetration which can limit the ability of the feeder to host non-dispatchable solar projects in the absence of system upgrades. This condition is illustrated in Figure 48[91]. The solar generation at mid-day exceeds the load level shown by the dashed line and as a result power flow is reversed toward the transmission grid. The distribution feeder experiences bi-directional power flow over the 24-hour period shown.

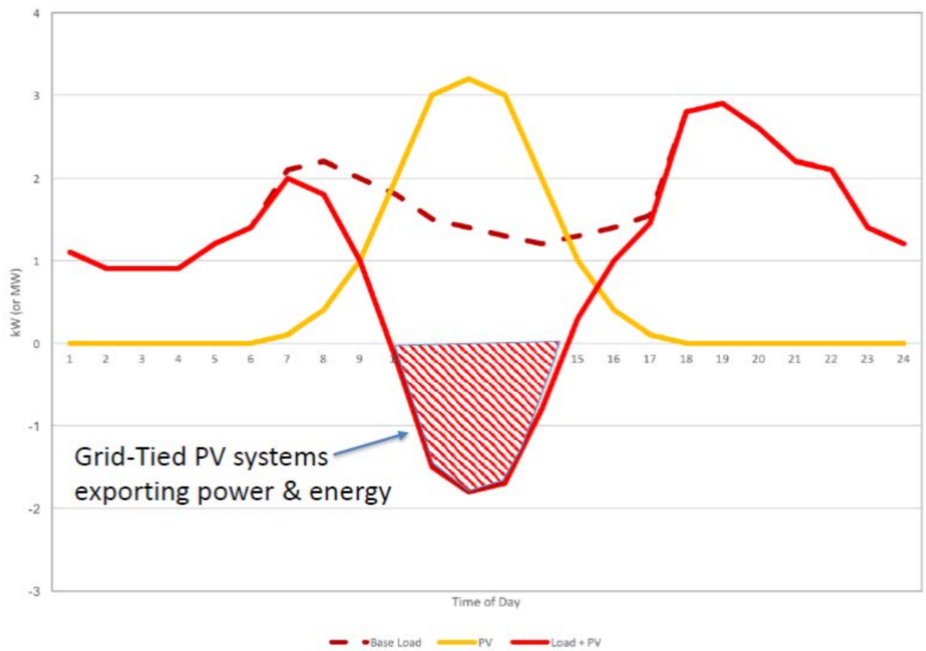


Figure 48: Distribution Feeder Load Profile with Solar PV (Source: NREL)

Nevertheless, the likeliness of a distribution feeder experiencing peak loading during peak solar output is relatively high as it is common for peak loading to occur during hot, sunny days. Therefore, large solar interconnections without any sort of voltage/reactive regulation or dispatch capabilities can be effective for the portions of the day where the feeder loading and solar output curves coincide. However, as peak loads increasingly move towards evening and night, the advantages of non-dispatched and unregulated solar appears to diminish. See Figure 49 for a graphical representation of this.

[91] Distributed Energy Resources (DER), Distribution Systems and Planning Training for Midwest PUCs, Jan 2018

5.4.2 Benefits of Controllable Solar

The potential benefits due to the application of solar projects can be further enhanced by taking advantage for advanced inverter function including real-time control of the output power.

New IEEE Standard 1547 revisions propose a heavier utilization of inverter control capabilities compared to the current practice of interconnecting utility scale solar sites with the requirements of static power factor operation and tripping offline during abnormal events92. Inverter capabilities include, but are not limited to:

- Voltage Regulation at the point of interconnection (“POI”)
- Voltage Ride Through
- Frequency Ride Through

Another key aspect complimenting these changes is real time dispatch. Though the exact coordination between solar site owners, transmission/distribution owners, and a potential third-party dispatcher has not been officially determined, the strategy would be to intelligently monitor and control the dispatch, curtailment, and regulation points of the individual solar sites (likely Utility Scale only). The intent of these methods is to increase distribution system stability, thus reducing outages and deterring the need for expensive distribution system upgrades. This is further discussed in Section 5.4.8.5.

5.4.3 Automated Control, Monitoring, and Protection

Inverters are primarily comprised of solid-state components, computer processors, and multiple protection schemes. Accordingly, they have the potential to allow a solar installation to react faster, more flexibly and intelligently than traditional generation. Potential grid improvements are numerous as inverter integration through multiple solar installations can lead to improved real-time monitoring, faster control and dispatch, and improved anti-islanding protection.

Distributed solar sites with automated inverter capabilities can improve overall resiliency of the electric power service. With appropriate islanding logic and equipment, loss of power supply can be reduced as customers can run directly off solar generation during grid outages, or in an islanded, off-grid operation. There is potential for automated solar, combined with other resources such as battery-based storage, to provide backup supply

[92] http://sites.ieee.org/gms-pes/files/2017/02/IEEE-1547-Vermont-Chapter.pdf

to serve multiple customers in a local area during an outage of the associated electrical grid. This type of automated back-up system can focus supply to critical locations such as emergency dispatch centers and communication towers during disaster events to support electric power resiliency. This may be referred to as a Microgrid configuration. There is also potential for this backup to be in the form of single customers running off their own solar generation based system, as can be seen in many global instances presently.

Furthermore, inverters have potential to aid in system restoration following a black-out condition. In addition to inverters having the capability to support Microgrids, they also have the capability to manage a Cold Load Pickup scenario as customers come back online following a blackout. Complex algorithms utilizing sets of rules and conditions can be used to offer the smoothest Microgrid restoration process while avoiding the necessity for non-renewable generation to operate distribution networks in an islanded fashion[93].

According to research conducted and reported by NREL, solar PV has proven to be a viable option for increasing electric power resiliency during grid outages for more than two decades. PV technologies have provided emergency electric power in the aftermath of major disasters, including[94]:

- The Northridge Earthquake of 1994—PV kept some communications links operating and supplied power to Southern California residents that had installed systems in their homes.
- Hurricane Andrew in 1992—PV systems were used at shelters and medical clinics to power street lights and to power communications systems.
- Hurricane Hugo in 1989—A portable solar PV generator powered a community center for six weeks following the storm.

NREL also listed the following examples of incorporating solar PV into electrical systems designed to improve resiliency in residential communities and private sectors[94]:

- A neighborhood in the California desert city of Borrego Springs is utilizing community energy storage and 700 kW of distributed rooftop solar PV to improve electrical supply reliability and resiliency. This system is comprised of distributed generation, energy

[93] http://citeseerx.ist.psu.edu/viewdoc/download?doi=10.1.1.330.8186&rep=rep1&type=pdf

[94] https://www.nrel.gov/technical-assistance/blog/posts/how-solar-pv-can-support-disaster-resiliency.html

storage units, and island-enabling control technologies. It has demonstrated successful islanding and provided power during scheduled and weather-related outages.

- Rutland, Vermont, which experienced power outages during Hurricane Sandy, decided to take matters into its own hands by implementing a solar-powered Microgrid. The project includes 2.5 MW of solar capacity, along with 4 MW of battery storage, which can supply electricity to approximately 365 homes.

T-Mobile is improving the resiliency of their communications services by installing solar PV to provide backup power at cell towers across the nation.

Smart inverter designs present challenges, however, including an increase in opportunity for targeted cyberattacks. It is common for smaller Commercial/Industrial and Residential solar sites to be monitored and controlled through the customer's personal network. One such example of a vulnerability would be a hacker creating a denial-of-service ("DOS") attack, thus severing the customer's communication link to their device. From here, the hacker could turn offline or even damage the solar equipment[95]. For a large-scale attack, this could create issues for grids with high solar penetration. Therefore, it is vital that utility cyber security programs mature as advanced communication and control technologies are introduced to the system.

5.4.4 Benefits of Smart Inverters Paired with Energy Storage and Demand Response

Distribution feeder hosting capacity for solar-based DER can be potentially increased by taking advantage of several advanced technologies including:

- Smart inverters,
- Energy Storage Systems, and
- Load Demand Management.

By pairing and coordinating the operation of solar with the above, loadings on a distribution feeder can be managed to limit necessary distribution system upgrades and minimize potential curtailment of the solar under off-peak load periods. This leads to a more flexibility, optimized use of solar, and potential cost-benefits.

The key to integrating solar is that it must be available to supply energy and capacity when needed. Solar can provide energy during the day when the sun is shining;

[95] http://prod.sandia.gov/techlib/access-control.cgi/2017/170794.pdf

however, their intermittent characteristics (from cloud cover) limit the amount of capacity that can be counted on to reliably serve load.

An increase in capacity value can be achieved though coordination with energy storage systems to effectively shift and flatten out the feeder load profile.

5.4.4.1 Smart Inverters

Advanced inverter functionality can play a role in increasing the reliable integration of solar on the distribution system. When coupled with fast and reliable communications and control these advanced functions can offer new sources of grid flexibility to support the higher penetration of solar. These functions can include:

- Voltage and VAR control
    - In many cases the capacity of the distribution feeder to support the integration of solar is limited by the voltage constraints especially during light load conditions. The solar inverters with AC voltage control capability can be used to help regulate the feeder voltage and relieve this constraint. Careful coordination of the AC voltage set points and control characteristics with voltage control devices on the feeder such as regulators, main substation transformer LTC, and other resources is required. Often distribution system operators ("DSO") do permit inverters to control voltage due to the potential coordination issues. Providing the DSO with visibility and direct control of this inverter function could alleviate concerns and unleash this capability and this potential benefit.
- Voltage and frequency ride-through
    - The capability of solar inverters to ride-through voltage and frequency excursions following network disturbances is necessary to support a high level of solar penetration on the system.
    - This need was exemplified during operation of the electrical system on the Hawaiian island of Oahu under a condition of high solar dispatch[96]. In 2013 a trip of a 180 MW thermal unit caused a frequency deviation that subsequently resulted in tripping several solar units with legacy frequency protection set at 59.3 Hz limit (a level below the load

[96] IEEE power & energy magazine, The Power of Small, page 52, Volume 15, Nov/Dec 2017

shedding frequency protective thresholds). In this case, because of the high level of solar penetration, conventional island generation that would have traditionally responded with frequency control was de-committed and therefore unable to respond to the fast decline of system frequency following the contingency.

The tripping of solar due to low frequency protection, in turn, caused the frequency response to dip further, which led to three blocks of load shedding response before the system frequency began to recover. The UFLS protection disconnected both load and solar, thus it was less effective than originally designed for a pre-solar system. Approximately 76,000 customers were disconnected from service during this event.

As a result of this particular event, new inverter under-frequency ride through requirements were standardized in Hawaii's Rule 14H which requires solar to ride through frequencies as low as 57 Hz – well below all UFLS protection settings. Voltage ride-through requirements were also standardized. The 2014 standard was a result of collaboration between equipment suppliers, utility members, regulators and customers. These lessons learned and others have been used in the evolution the IEEE 1547 standard that is the interconnection standard for DERs in the United States.

- Frequency control
    - Voltage and frequency must be controlled and maintained to preserve the secure and reliable operation of interconnected electrical network including the distribution systems. Historically, system frequency control has been provided by the large, traditional thermal generators connected to the network. With increased solar and other inverter-based resources, the frequency response of the network can become compromised, particularly under light load conditions when traditional power plants are offline. This was discussed above corresponding to the contingency event in Oahu, Hawaii.
    - As solar becomes more and more prevalent, the need to control frequency through means other than by traditional thermal units will become necessary. The ability for inverters equipped with special

functions to enable the control of frequency is one way to address this need. These advanced inverters are termed “grid-forming” inverters. One method of control is the implementation of droop control based on the method used with traditional generation governor action, however, this has limitations in the speed of frequency response. Other control strategies have been researched and studied through simulation software to create what are named “virtual synchronous machines” (“VSM”).[97] These VSM can emulate the inherent physical response of a synchronous machine including mechanical (inertia) and electrical characteristics by appropriately programming the inverter control.

- In general, the controls of modern inverters are very fast and flexible, limited only by the characteristics of the control software and associated communications, allowing various control objectives and strategies to be implemented. Through careful analysis, simulation and testing, this flexibility can be exploited to meet some of the challenges associated with the integration of higher levels of solar.
- There is still research to be conducted to determine the appropriate level of smart inverters to introduce into the system as it evolves from a conventional generator dominated system toward a system dominated with inverter-based resources. The evolution process needs to consider the co-existence of traditional resources and control strategies, current inverter technology (i.e., non-dispatchable, grid-following inverters) with advanced inverter technologies.

- Bi-directional control (when paired with energy storage system batteries)
    - As will be discussed in the subsequent subsection, the use of solar and battery-based energy storage systems can be complementary. Battery-based energy storage systems can be co-located with solar installations on the DC bus and share the same inverter and interconnection facilities to minimize costs. The inverter must have the capability to control power flow into and out of the distribution system support this arrangement and realize the fully benefits.

[97] IEEE power & energy magazine, Paving the Way, page 64, Volume 15, Nov/Dec 2017

A key aspect complimenting these capabilities is real time dispatch. The strategy would be to intelligently monitor and control the dispatch, curtailment, and regulation points of the individual solar sites with the intent of increasing distribution system stability, thus reducing outages and deterring the need for expensive distribution system upgrades.

Furthermore, real time dispatch effectiveness is significantly dependent on energy resource availability. For example, if a feeder's peak load occurred at 8 PM, solar energy alone would not be able to aid in load reduction as irradiance from the sun is minimal, if not zero. On the other hand, excessive mid-day generation caused by heavy solar penetration can also present issues. The load profile surrounding these issues is known as the "Duck Curve" and has been analyzed extensively. A large-scale instance from California can be seen in Figure 49:

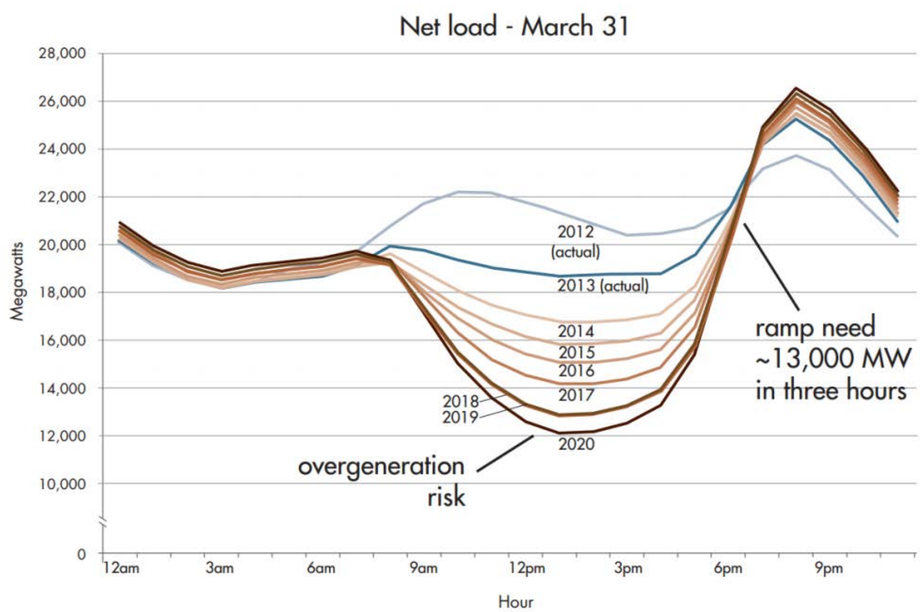


Figure 49: California ISO Duck Curve[98]

Note that though this is on a statewide scale, this same curve can be scaled down to a smaller region or a distribution system level where heavy solar penetration is present or expected.

[98] https://www.nrel.gov/docs/fy16osti/65023.pdf

Use of energy storage systems paired with solar generation can remedy issues such as the "Duck Curve" and improve the overall usefulness of real time dispatch. Rather than posing an over-generation risk during the middle of the day, extra solar energy generated during these times can be stored and used later for evening peaks with the overall effect of a smoothed out daily load profile.

Large scale solar implementation will undeniably change the electrical grid at both transmission and distribution levels when compared to more traditional generation due to the evolving nature of inverter-based generation and smart grid innovations. Increased sophistication in design and implementation of advanced technologies can lead to certain challenges; however, through proper planning, their application has strong potential to improve system reliability, and security aspects.

5.4.4.2 Energy Storage Systems

The use of energy storage systems, particularly battery-based systems, can complement solar installations to smooth out the intermittent nature of these resources. Figure 50 illustrates how an energy storage system can be paired with solar to fill in the supply of energy during periods of cloud cover.[99]

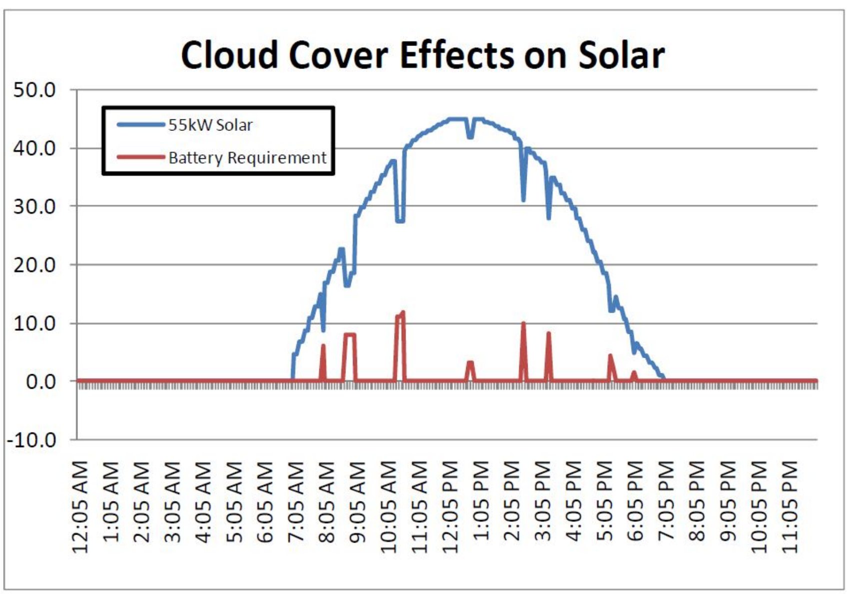


Figure 50: Energy Storage System Smoothing of Cloud Cover Effects on Solar

[99] Virginia Solar Pathways Project Training Session, Module III, Slide 33, April 2015

The energy storage systems can be charged by the solar during light-load conditions when the sun is available or they can be charged by other DERs and/or conventional base-load units. During periods of cloud cover or non-daylight hours, energy stored in the batteries can be used to supply the local load and potentially back-feed the supply substation up to distribution feeder's available capacity. In short, energy storage systems can be used to balance periods of high solar penetration on sunny days with periods of low solar penetration on cloudy days.

It should be recognized that energy storage systems energy margins (reserves) needs to be maintained during operation to accommodate load and solar balancing requirements, especially short-term variability of solar and loads.

Alternatively, the energy storage system can be applied with solar to arbitrage variations in energy prices as shown in Figure 51.[100] In this example, the energy storage system is used during the late-day, peak period where energy prices are highest. The energy storage system would be charged by the solar in the off-peak, daytime hours, and possibly from other resources during the overnight hours.

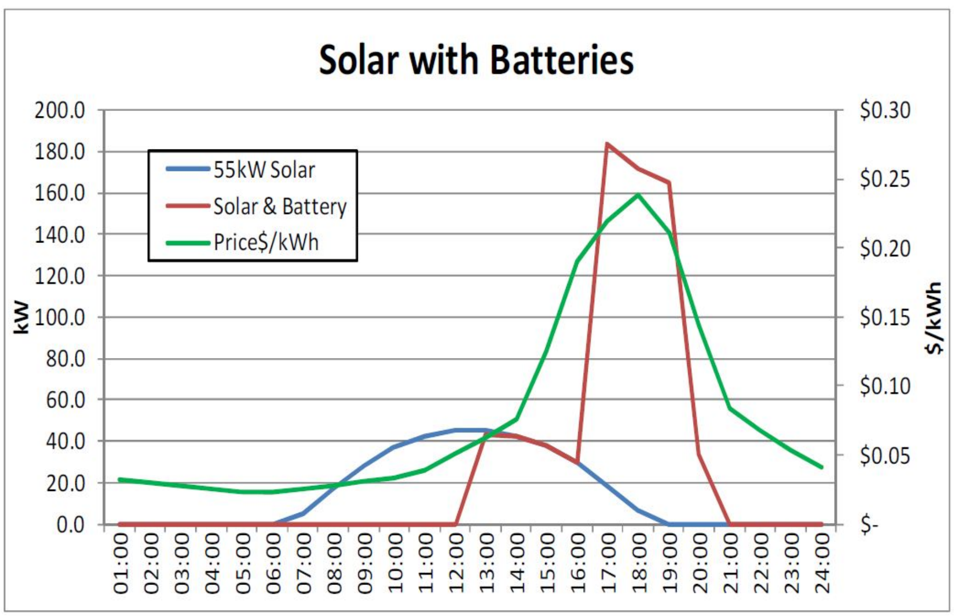


Figure 51: Solar with Energy Storage System to Arbitrage Energy Price

[100] Virginia Solar Pathways Project Training Session, Module III, Slide 33, April 2015

The combination of solar and energy storage systems offers potential operational flexibility to increase the overall hosting capacity of the distribution feeder. Figure 52 shows the how this combination can reduce peaks in the feeder load curve while taking full advantage of the peak solar power output, which exceeds the load curve at hour 12.[101]

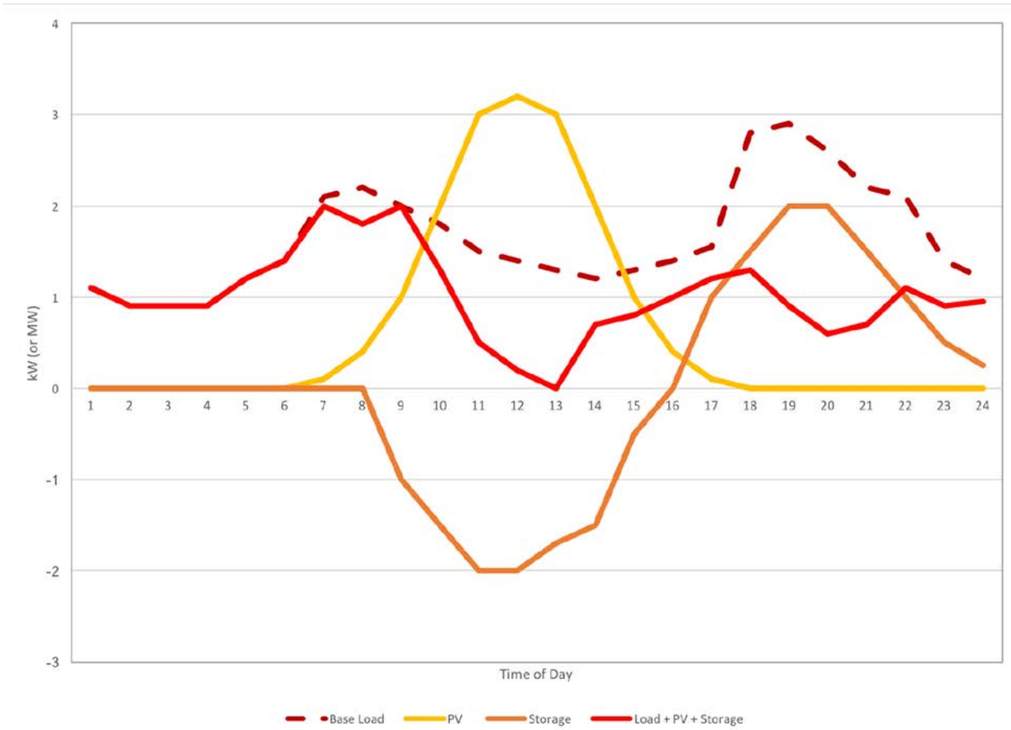


Figure 52: Feeder load profile changes due to solar and Energy Storage System (source: NREL)

Battery-based energy storage systems are of specific relevance considering their ability to provide fast response power ramping. Like most solar, battery-based systems are inverter-based, so these can also be utilized to provide other ancillary services such as voltage support, frequency regulation, and other support provided an aligned market framework is established.

The appropriate sizing of energy storage systems, including discharging times and charging times, will need to consider load profiles, solar profiles, and other factors that

[101] Distributed Energy Resources (DER), Distribution Systems and Planning Training for Midwest PUCs, Jan 2018

impact feeder loading and available feeder capacity. In general, the integration of solar onto distribution feeders will make the load profile “peakier”, which is ideal for the application of short-term duration battery-based energy storage system to peak shave.[102]

Battery-based energy storage systems can also be designed and installed to be easily scalable, and even transportable, to accommodate future changes in solar and/or feeder loading. The cost of batteries used in battery-based energy storage systems and electric vehicles are trending down as shown in Figure 53, which will likely increase their application in the future.[103]

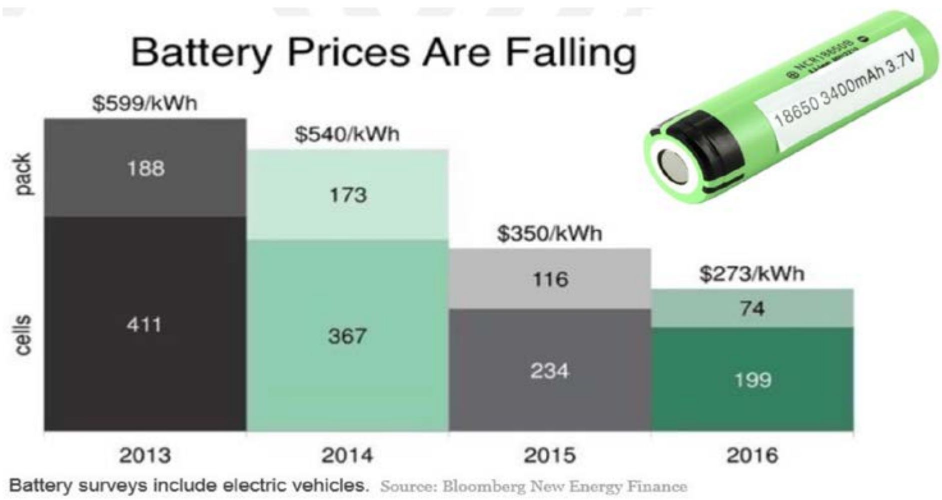


Figure 53: Battery-Based Energy Storage System Capital Cost Trend (Battery System Only)

5.4.4.3 Load Demand Responsiveness

In addition to energy storage systems, load demand response could also be coupled with solar to smooth out the distribution feeder loading under periods of low solar irradiance. Many loads today are electronic based which allow for remote control and scheduling. For example, electrical vehicle charging stations could be curtailed during periods of intermittent cloud cover over solar arrays that are located along a common

[102] IEEE power & energy magazine, Maintaining Balance, page 36, Volume 15, Nov/Dec 2017

[103] Distributed Energy Resources (DER), Distribution Systems and Planning Training for Midwest PUCs, Jan 2018

distribution feeder. Please refer to Figure 50 above and consider that energy storage systems can be replaced with a reduction in local load demand to achieve a similar smoothing influence.

5.5 Fundamental Enabling Requirements

The following fundamental requirements are necessary to support the potential increase in distribution feeder Electrical Hosting Capacity from the advances discussed in this Section 5.5.

- Sound feeder load profiles and characteristics including available demand response,
- Software programs and other tools for advanced planning to effectively analyzed the benefits and risks of an integrated application for planning and operations, including net locational benefits,
- Increased visibility of load levels and solar projects though more granular system monitoring,
- Progressive forecasting tools that can capture and predict changes to load and available solar and energy storage system levels, and
- Advanced control functions and intelligent energy management systems at the distribution feeder level complying with appropriate cyber security measures,
- Additional pilot programs to test and fine-tune the process and integrated system,
- Business, regulatory, and market framework and transparency of process to provide proper opportunities and incentives to developers, utilities, customers and other stakeholders,
- Revisions to utility planning process/models that consider the system and societal benefits and costs of solar projects, demand response, and energy storage systems,
- A skilled workforce to operate and maintain this supporting infrastructure.

The overall the framework and integrated system must achieve high availability, safety, reliability and resiliency.

5.6 Capabilities of Existing Circuits

Once full benefits to reliability, device life, loss reductions, cost savings, and overall system improvements from solar generation are understood, the next key step is to analyze how much available Electrical Hosting Capacity exists on each system's distribution feeders. For the purpose of this study Electrical Hosting Capacity is defined as the amount of solar PV that can be accommodated on a distribution feeder without the need for extensive infrastructure upgrades (i.e., no substation transformer, main feeder backbone or other major equipment upgrades). Theoretical limits to individual feeder capacities can be determined by a number of metrics with a varying emphasis on the importance of each. Existing loading, substation transformer ratings, overhead and underground conductor Ampacity ratings, and individual system strengths all play a role in determining feasibility of solar interconnections at various locations. Limits to these metrics, however, will vary from utility to utility and additional costs may be incurred depending on utility standards.

With electrical capabilities taken into account, physical land constraints also need to be considered. Each territory should, at the very least, be analyzed for available acreage and rooftops that are suitable for solar panels. Further insight can then be given to limiting factors in a territory's solar placement.

Full distribution impact studies for proposed solar locations over a certain capacity (typically 250 kW and above) are a necessity in determining whether or not the interconnecting generation will result in adverse impact. If adverse impact occurs or additional feeder side protection is needed, the cost is typically the responsibility of the project developer. However, the way this cost is allocated may depend on the interconnection approval methodology being employed.

5.6.1 Electrical Hosting Capacity

5.6.1.1 General Methodology

Maryland investor owned utility electrical hosting capacity was determined based on an evaluation of the following distribution system data provided by Potomac Edison, Baltimore Gas and Electric, Pepco, and Delmarva:

- Substations
    - Transformer feed schemes and ratings (all utilities)s

    - Low side fault currents (Potomac Edison and BGE only)[104]
- Feeders
    - Nominal voltages (all utilities)
    - Peak daytime loading (all utilities)
    - Minimum daytime loading (all utilities)
    - Primary backbone conductor types and ratings (all utilities)

High level hosting capacity estimates were then determined for each feeder across multiple scenarios. Since interconnection costs vary depending on a number of factors, it is important to consider a spectrum of capacity limits. For example, a large solar facility would be more likely to incur the cost of installing voltage and/or reactive support devices on a feeder than a smaller project that causes voltages to barely exceed feeder ratings. Also, utility policies may vary from company to company for criteria such as effective grounding, anti-islanding, and acceptable voltage levels as well as corresponding remedies to meeting these criteria.

Much of this data is confidential to the utilities or their customers. Therefore, the results are generally presented as averages or hypotheticals rather than for specific circuits.

5.6.1.2 Algorithms

Nine separate algorithms were tested on the four utility distribution systems to provide hosting capacities using a range of metrics. These are discussed in Table 57.

[104104] Note that low side fault currents were used to determine the likelihood of feeders experiencing voltage related issues. Therefore, this analysis could not be completed for Pepco and Delmarva.

Table 57: Algorithms Used to Determine Electrical Hosting Capacity

Name	Key Factors	Summary	Notes/Disclaimers
Algorithm 1	Minimum Daytime Loading	Assumes that net export on feeders is not allowed. Aggregate generation can only export up to minimum loading values.	Not allowing feeder export may not be realistic with high solar penetration.
Algorithm 2	Loading Based on Real Time Dispatch	Assumes that net export on feeders is not allowed. Aggregate generation can only export up to loading values based on real time dispatch estimates.	Not allowing feeder export may not be realistic with high solar penetration.
Algorithm 3	Transformer Ratings Minimum Daytime Loading	Allows generation to be added up to the substation transformer rating. Uses minimum loading values as negative generation values.	Applied on a feeder-by-feeder bases. DOES NOT consider generation on adjacent feeders. May result in exceeded backbone conductor ratings.
Algorithm 4	Transformer Ratings Loading Based on Real Time Dispatch	Allows generation to be added up to the substation transformer rating. Uses loading values based on real time dispatch estimates as negative generation values.	Applied on a feeder-by-feeder bases. DOES NOT consider generation on adjacent feeders. May result in exceeded backbone conductor ratings.
Algorithm 5	Transformer Ratings	Allows generation to be added up to 95% of the substation transformer rating. Does not consider loading.	Applied on a feeder-by-feeder bases. DOES NOT consider generation on adjacent feeders. May not be realistic, but this standard has existed for some utilities historically.
Algorithm 6	Backbone Conductor Ratings Minimum Daytime Loading	Allows generation to be added up to the feeder backbone conductor rating. Uses minimum loading values as negative generation values.	Applied on a feeder-by-feeder bases. DOES NOT consider generation on adjacent feeders. May result in exceeded transformer ratings.
Algorithm 7	Fault Currents Feeder Nominal Voltages	Allows generation to be added up to the number that would likely cause voltage and/or flicker issues.	Based on interconnections within a mile of the substation. Results may vary depending on location along feeder.
Algorithm 8	Fault Currents Feeder Nominal Voltages	Determines feeder suitability based on system strength. The result is a non-numerical value indicative of whether a feeder is "Very Weak" or "Very Strong" with multiple steps in between.	Should be used strictly as a rule of thumb to get a general feel for feeder suitability.
Algorithm 9 Thermal Max	**Transformer Ratings Minimum Daytime Loading Backbone Conductor Ratings**	**Allows generation to be added up to the substation transformer rating OR the backbone conductor rating. Uses minimum loading values as negative generation values.**	**DOES consider generation on adjacent feeders. This algorithm presents the most realistic scenarios.**

The practical use of each algorithm is as follows:

- **Algorithm 1**: Used to determine hosting capacity under the assumption that reverse power flow is not allowed on feeders and real-time dispatch of solar is also not allowed. This algorithm should only be used under these limited conditions and will therefore tend to underestimate Electrical Hosting Capacity.

- **Algorithm 2:** Nearly identical to Algorithm 1, except it assumes that real time dispatch of solar is permitted. This algorithm should only be used under this limited condition and will therefore will tend to underestimate Electrical Hosting Capacity even with the consideration of dispatchable solar.
- **Algorithm 3:** Used to determine hosting capacity under the assumption that feeders can have a net export up to the level of the substation transformer power rating and assumes real time dispatch of solar is not allowed. This algorithm should be used under these conditions; however, existing generation on adjacent feeders must be considered to avoid overestimation of the available Electrical Hosting Capacity.
- **Algorithm 4:** Nearly identical to Algorithm 3, except it assumes that real time dispatch of solar is permitted. This algorithm should only be used under these conditions and the same disclaimer about considering existing generation still applies to avoid overestimation of the available Electrical Hosting Capacity.
- **Algorithm 5:** Used to determine hosting capacity under the assumption that feeder generation can aggregate up to the level of 95% of the substation transformer power rating and assumes real time dispatch of solar is not allowed. This algorithm is likely not practical and is not recommended for use as it does not consider loading; although, this criteria has been used by utilities in the past, it is likely not practical as it does not consider loading and will tend to overestimate the Electrical Hosting Capacity.
- **Algorithm 6:** Used to determine hosting capacity under the assumption that feeders can have a net export up to the level of a feeder's primary backbone conductor. This algorithm should be used under these conditions; however existing generation on adjacent feeders as well as smaller conductors in a project's path should be considered to avoid overestimating the available Electrical Hosting Capacity.
- **Algorithm 7:** Used to determine electrical hosting capacity based on the most probable amount of generation that can be added to each feeder without experiencing major voltage issues. Although this algorithm is suitable to be used in determining the potential for voltage issues, voltage issues do not typically impact the interconnection feasibility of solar projects as the cost of associated

upgrades are required by each project to mitigate the voltage issues. As a result, this algorithm will tend to underestimate Electrical Hosting.

- **Algorithm 8:** Used to determine a feeder's suitability for large solar projects or evaluating the impact of a high penetration of smaller rooftop projects on a feeder based on system strength. This algorithm should only be used as a rule of thumb to evaluate the impact of large solar projects or a high penetration of smaller rooftop projects on a feeder as it does not yield numeric results.
- **Algorithm 9:** This algorithm was used to determine the Electrical Hosting Capacity used in this study. It is based on thermal limits of both substation transformers and primary backbone conductors while simultaneously considering generation on adjacent feeders. In the absence of detailed feeder power flow analysis, this algorithm provides a reasonable estimate of a feeder's potential for solar generation Electrical Hosting Capacity.

Note that all algorithms except Algorithms 1 and 2 assume that reverse power flow at the substation level is acceptable. Further elaboration and sample calculations for each algorithm including a functional flowchart describing Algorithm 9 can be found in Appendix H.. It should be noted that these algorithms may be used across a variety of criteria to give a general idea of individual feeder hosting capacity. However, full distribution impact studies should be conducted in order to fully evaluate adverse impact caused by Utility Scale solar interconnections.

5.6.1.3 Results

For comparative purposes only, individual Maryland utility feeders were tested against all of the aforementioned algorithms. Large variances can be seen based on the key factors discussed above, which is expected. Other economic factors are likely to impact electrical hosting capacity such as existing generation, thermal capacities other than substation transformers and backbone conductors, and protection schemes. However, the results shown for Algorithm 9-Max Thermal Rating are valid at a high level for determining potential solar that feeders can accommodate within each utility territory.

Figure 57 through Figure 55 display the feeder hosting capacities results sorted from largest to smallest for each of the four utilities. Note that each algorithm is sorted individually as they do not necessarily correlate.

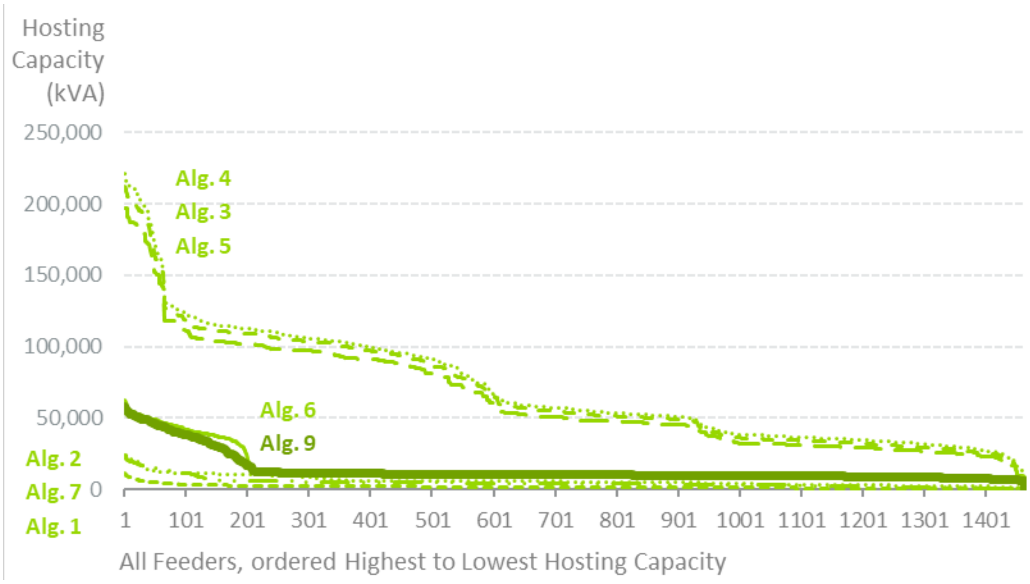


Figure 54: BGE Hosting Capacity

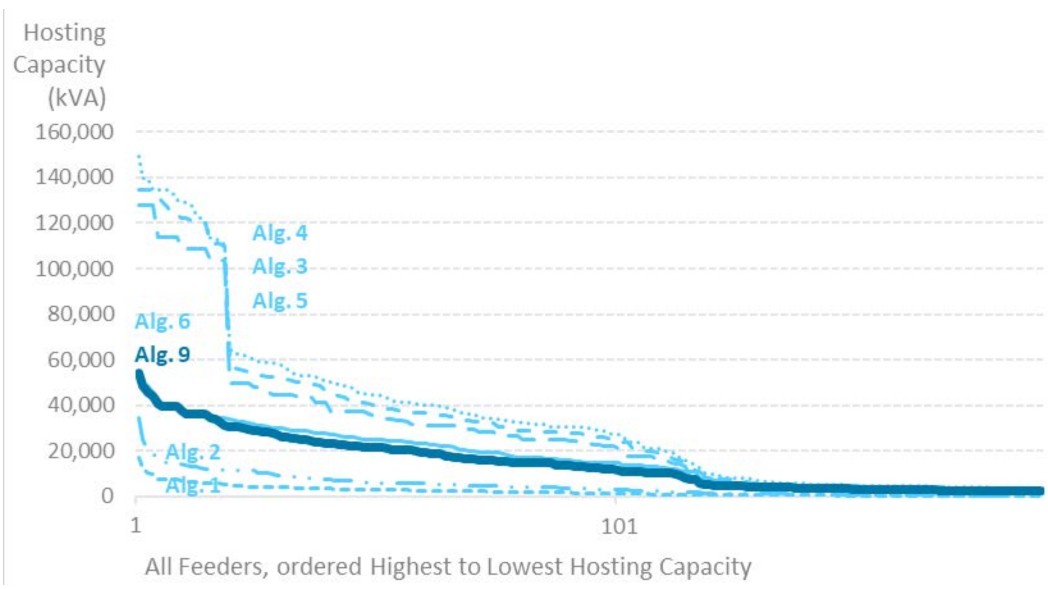


Figure 55: DPL Hosting Capacity

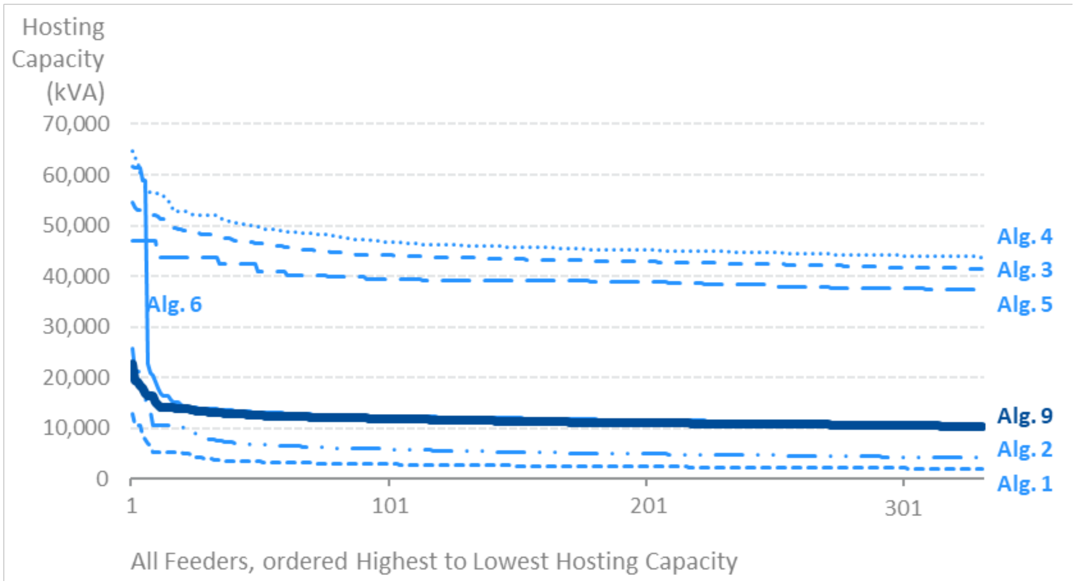


Figure 56: PEPCO Hosting Capacity

Figure 57: PE Hosting Capacity

Note that low side fault current values were not provided for PEPCO and DPL, so Algorithm 7 could not be completed in their cases.

Each algorithm applied has outliers for each case. It can also be seen that some values are particularly high with respect to expected distribution feeder interconnections, particularly in BGE and DPL territories. This is due to the fact that the feeders in these voltage classes have much larger transformer ratings than typical distribution feeders since they are essentially subtransmission voltage level, or 34.5 kV in this case. However, Algorithm 9 takes this into account and presents more realistic values than those seen for algorithms that only consider transformer ratings and no other generation on adjacent feeders.

Note that even for Algorithm 9, some values are still quite high with respect to distribution feeders. These values may be realizable without exceeding thermal limits, but voltage, reactive, and protective solutions among many others may be needed and will likely drive up the cost of interconnections as corresponding constraints are approached.

A final thought to consider when evaluating the feasibility of large solar penetration at any given substation is the transmission system configuration at that location. It is very common to have substation transformer windings configured as delta on the transmission side and grounded wye on the distribution side. This configuration was originally intended to serve load on the distribution level as opposed to generation on the distribution level. With the increase of DER penetration, reverse power flows through distribution substation transformers are very possible and can result in the substation becoming an ungrounded source. During periods of net export, less generation from traditional, large-scale facilities is required, which could leave these sites offline. However, this form of generation was typically designed to provide effective grounding to the transmission system through their interconnections to the grid. This type of bulk generation is known as a grounded source. Hence, the more DER penetration trends increase, the more transmission systems can see ungrounded sources.

From a protection and power quality perspective, effective grounding reduces the amount of neutral shift in phase voltages during a single line to ground (SLG) fault. If extreme neutral shift occurs (e.g. all generation interconnections are ungrounded sources), the unfaulted phases can experience up to a 173% increase in voltage while the fault current can be reduced to almost zero. The protective relaying scheme of the transmission line would require a grounded wye – broken delta voltage transformer configuration to detect this condition and cause an overvoltage (59G) relay function to trip the SLG fault during this event. An overcurrent (51G) relay function using current transformers that was originally intended to sense this type of fault would likely not detect the fault and thus, would not trip. This same condition may occur on distribution systems not possessing effective grounding.

In anticipation of increased DER penetration resulting in reverse power flow from ungrounded interconnections, utilities should review their existing protection schemes to ensure timely removal of SLG faults. Additionally, a transfer trip scheme from the transmission to the distribution may be used to trip off large commercial and utility scale DER sites during periods of extreme overvoltage to alleviate these issues. Note that these protection scheme variations are not cost prohibitive for large solar projects and are therefore unlikely to result in a project cancellation.

In summary, increased DER penetration resulting in reverse power flow through ungrounded interconnections should promote the review of existing protection schemes by the utility to ensure timely removal of SLG faults by transmission side equipment. Subsequently anti-islanding protection schemes may be used to trip off Large Commercial & Industrial, Utility Scale, and BTM DER sites during periods of extreme overvoltage to alleviate issues caused by the islanding of distribution systems when the transmission source is lost during these events. Note that these protection schemes variations are not cost prohibitive for large solar projects and are therefore unlikely to result in a project cancellation. Also, the implementation of local anti-islanding protection schemes are relatively inexpensive for BTM level DER sites.

5.7 Conclusions

This portion of the study addresses the impacts of adding more solar resources to the Maryland power system at the distribution level. It includes both general observations based on literature searches and studies performed in other jurisdictions as well as conclusions based on conditions specific to four companies in Maryland: PE, BGE, PEPCO, and DPL. The primary conclusions are:

- The distribution systems in Maryland can support significant additions of solar energy without the need for major upgrades such as the rebuilding of lines or substations. Based on Algorithm 9 and land constraints, the following approximate aggregate potentials for nameplate capacity may be realized from a distribution standpoint:
  - BGE = 19.9 GW
  - DLP = 2.8 GW

- PEPCO = 7.3GW
- PE = 2.0 GW

- The available places to install solar systems, such as rooftops and open space, generally exceed the electrical capability of the system.
- The integration of solar sources will often require modest upgrades to the distribution system to control voltages and minimize adverse impacts, such as voltage flicker, on other customers. Typical requirements are grounding banks, voltage regulators, capacitors, reclosers, fault detectors, or capacitor control changes. Costs for these additions are usually born by the developer and can have a negative impact on the economic viability of a project ranging from nothing to 1.7 cents/kWh.
- Larger projects might require transformer or line upgrades. Costs for these additions are usually born by the developer and can have a negative impact on the economic viability of a project and typically ranging from 1.7 to 2.3 cents/kWh, but can be higher or lower depending the size of the project and the upgrade required.
- The addition of solar resources in the proper locations can significantly reduce thermal losses on the distribution system. The marginal distribution loss rate for additional solar can be as high as 10% to 12% of the offset energy.
- The installation of a relatively large aggregate amount of solar energy to the distribution system has the potential to produce benefits including:
  - Reduced distribution system losses. This could have a value of up to 0.6 cents per kWh of solar produced.
  - Offset the need for load driven construction of new lines and substations. This could have a value from a few cents to tens of cents per kWh of solar energy produced.
- Acceptance and aggressive implementation of the control capabilities of smart inverters by the electric utilities could result in significant reliability improvements to the distribution system. In addition to reactive support, smart inverters can provide voltage and frequency ride through capabilities during system disturbances.

- The installation of storage systems with large solar penetration offers the potential to significantly reduce the peak load that a distribution circuit will experience. This could reduce line construction costs which can be in the millions of dollars per circuit.
- The requirements for and benefits of interconnecting a particular solar installation to the distribution system can be determined only by studying that specific installation.
- Utilities should consider offering incentive programs to encourage siting solar projects in the optimal locations.
- In anticipation of increased DER penetration resulting in reverse power flow from ungrounded interconnections, utilities should review their existing protection schemes to ensure timely removal of SLG faults. Note that protection scheme variations to address reverse power flow are not cost prohibitive for large solar projects and are therefore unlikely to result in a project cancellation.

6. ECONOMIC AND SOCIAL BENEFITS AND COSTS

This report addresses a number of economic and social benefits and costs that may be considered in the policy development relative to solar. These are described generally in Table 58.

Table 58: Economic and Social Benefits and Costs of Solar Development

COMPONENT	DESCRIPTION
Health Benefits	Health and mortality benefits of reduced emissions
Environmental Benefits	Value of reductions in air pollutant emissions
Water Benefits	Value of reduction in water use
Loss of Open Space and Agricultural Use	Impact of solar on agricultural, forested and vegetated lands
Impact on Planning and Zoning	Review of zoning and planning requirements and policies that could impact solar development

6.1 Health and Environmental Benefits

An increase in solar generation may result in a reduction in air pollutant emissions when the solar generation offsets or results in reduced utilization of fossil-fuel fired facilities. As noted in the National Renewable Energy Laboratory Treatment of Solar Generation in Electric Utility Resource Planning document, output from solar developments can overlap during times of peak electricity demand and it may also offset or result in decreased use of marginal peaking units, typically fueled by oil or natural gas.[105] The reductions achieved occur for nitrogen oxides (NOx), sulfur dioxide (SO_2), particulate matter (PM2.5) and carbon dioxide (CO_2) which are the emissions of concern in this evaluation.

The United States Department of Energy (USDOE) SunShot Vision Study[106] identifies the following environmental and health benefits and impacts of solar energy:

- Solar energy reduces greenhouse gas emissions as compared to most other sources of energy across entire technology life cycles;
- Electricity generating facilities emit higher levels of air pollutants than solar installations which are essentially emission free;
- NOx emissions from fossil fuel and refuse fired power plants can cause respiratory ailments, acid rain, deterioration of water quality, ground-level ozone (smog) and PM;
- SO_2 emission from coal fired power plants can cause acid rain and PM and aggravate respiratory illness, heart and lung disease; and
- Particulate matter, particularly PM2.5, causes health problems including premature death, reduced lung function, asthma, bronchitis and cardiovascular diseases[107].

[105] NREL Treatment of Solar Generation in Electric Utility Resource Planning, October 2013 https://www.nrel.gov/docs/fy14osti/60047.pdf

[106] United States Department of Energy (USDOE) SunShot Vision Study, February 2012 https://www1.eere.energy.gov/solar/pdfs/47927.pdf

[107] DOE Sun Shot Vision Study February 2012 https://www.energy.gov/sites/prod/files/2014/01/f7/47927_executive_summary.pdf

6.1.1 Methodology

To evaluate the cost and benefits of potential pollutant emissions reduction as the result of increased solar generation, emissions output from the AURORA model for the base and difference (solar) cases described in Section 4.2.1.5 were used. The modeling quantified the potential emission reductions of NOx, SO_2 and CO_2 throughout the PJM service area associated with solar development in the State of Maryland over the study period (2019-2028). The model was used to evaluate the impact of solar implementation for three scenarios, a reference scenario, a high carbon dioxide price scenario and a low natural gas price scenario as discussed in Section 4.2. The difference (solar) case included both BTM and utility scale solar additions.

Emissions of NOx, SO_2 and CO_2 are output directly from the model. Emissions for PM2.5 for natural gas and distillate fuel fired electric generating utility facilities were estimated using United States Environmental Protection Agency AP-42 emission factors. PM2.5 emission factors for coal and refuse fired facilities are based on particulate emission limits from air permits for representative facilities. To account for variability in emissions from coal fired facilities, the average of the emissions factors for the top five energy producing plants in this study was used to represent emissions from all coal fired facilities. These emission factors were converted to tons per MWh using representative AP- 42 heat capacities and United States Energy Information Administration heat rates. These emission factors were then multiplied by energy output to estimate emissions. Emission factor calculations are provided as Appendix D.

6.1.2 Results

Overall emissions reductions are summarized in Table 59 and Figure 58 through Figure 61 below.

Table 59: Emissions Reductions Results for All Three Scenarios (tons)

REFERENCE SCENARIO				
TYPE	**CO_2**	**SO_2**	**NO_X**	**PM 2.5**
YEAR				
2019	109,841	476	320	18
2020	338,244	652	-198	40
2021	713,248	638	168	63
2022	1,150,435	175	776	111
2023	1,167,845	682	523	90

REFERENCE SCENARIO				
TYPE	CO_2	SO_2	NO_X	PM 2.5
YEAR				
2024	2,010,593	2,348	1,846	257
2025	2,074,388	1,862	1,287	241
2026	2,336,508	918	915	223
2027	2,608,488	1,199	1,215	250
2028	3,084,234	1,235	1,867	280

HIGH CO_2 SCENARIO				
TYPE	CO_2	SO_2	NO_X	PM 2.5
YEAR				
2019	109,841	476	320	18
2020	338,244	652	-198	40
2021	999,873	1,062	660	152
2022	1,188,250	767	682	171
2023	869,693	1,157	653	101
2024	2,299,067	2,332	1,361	352
2025	2,409,517	5,238	1,926	416
2026	2,576,429	2,804	1,768	343
2027	3,248,459	6,401	3,086	521
2028	3,406,911	3,768	2,561	482

LOW GAS SCENARIO				
TYPE	CO_2	SO_2	NO_X	PM 2.5
YEAR				
2019	-70,018	-326	-215	-22
2020	554,964	435	560	89
2021	631,554	-33	406	40
2022	1,088,221	808	896	142
2023	1,601,838	2,298	794	222
2024	1,773,184	2,263	1,113	241
2025	2,521,247	4,002	2,672	405
2026	2,736,670	2,722	2,154	374
2027	3,631,165	5,151	2,945	535

LOW GAS SCENARIO				
TYPE	**CO_2**	**SO_2**	**NO_X**	**PM 2.5**
YEAR				
2028	3,919,998	5,271	3,798	591

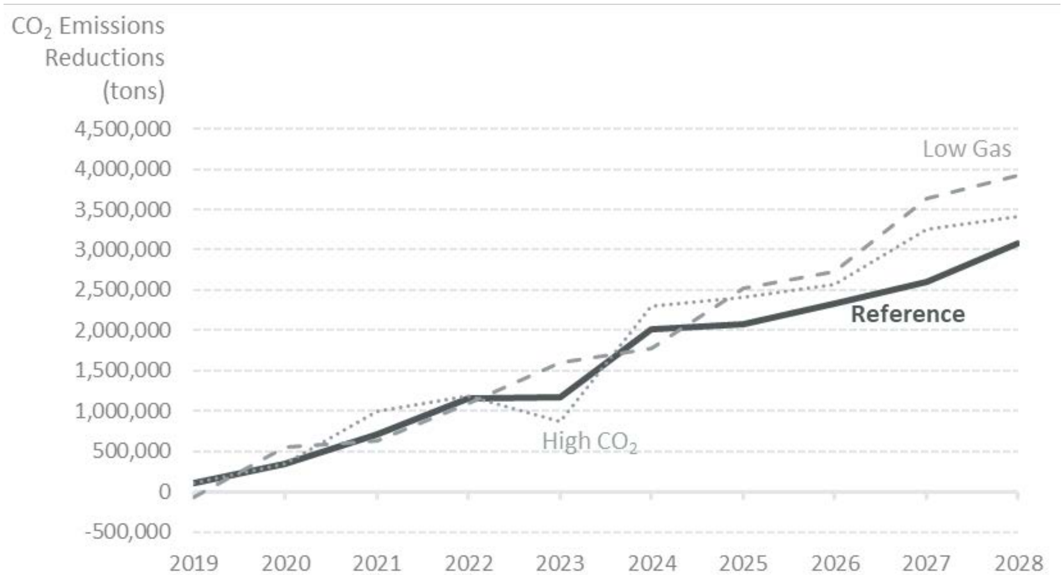


Figure 58: CO_2 Emissions Reduction Results

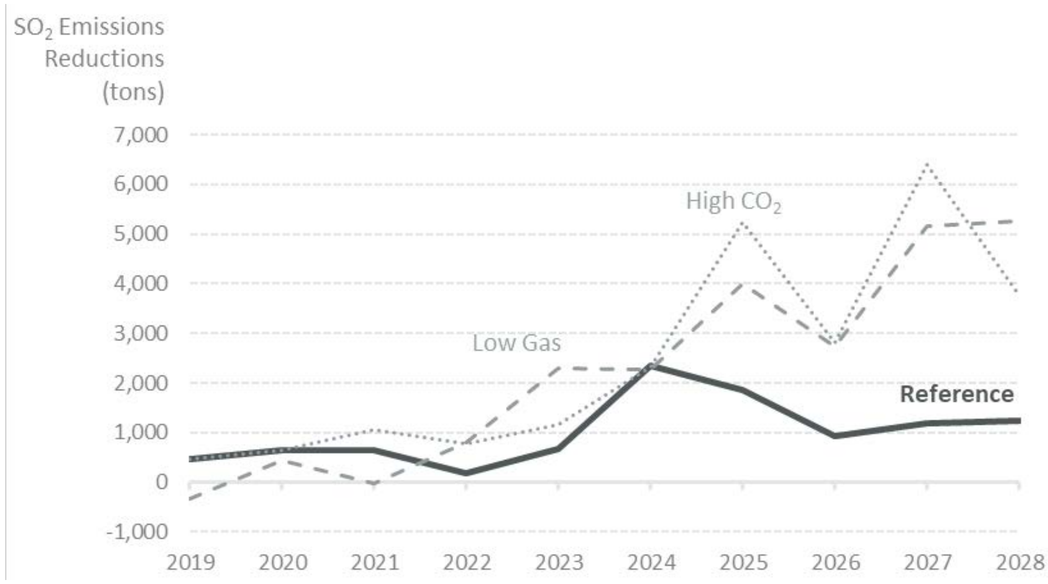


Figure 59: SO_2 Emissions Reductions Results

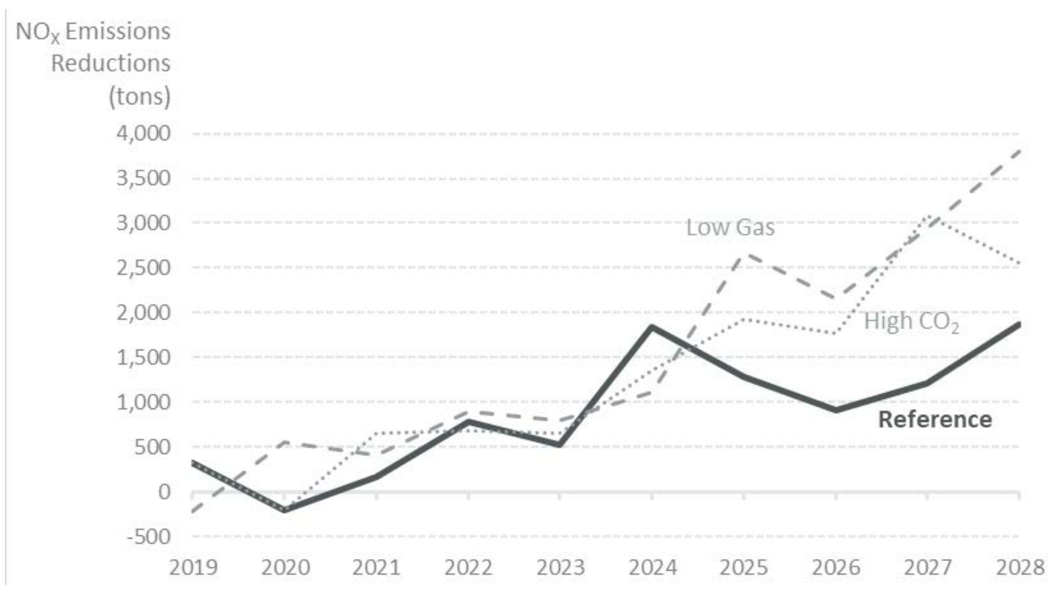


Figure 60: NO_X Emissions Reduction Results

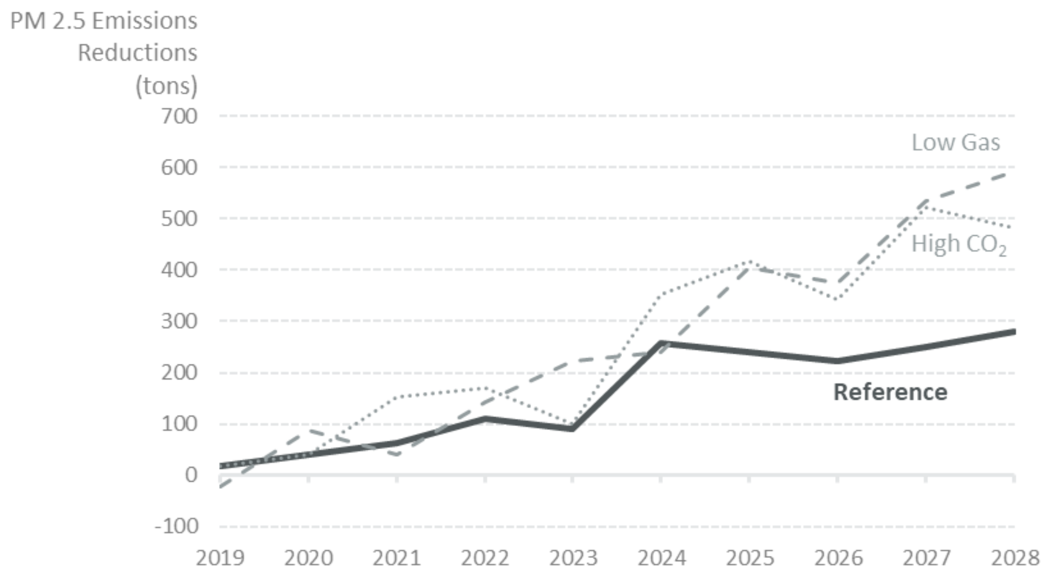


Figure 61: PM 2.5 Emissions Reduction Results

Air emissions are facility dependent and vary substantially based on fuel type, air pollution control devices and facility design. As the AURORA model projects emissions based on individual facility dispatch, the impact of solar injection into the grid varies substantially for the three modeled scenarios. NOx, SO_2 and PM2.5 emissions are particularly sensitive to the facilities being dispatched resulting in the variation noted in the emissions curves above.

6.1.3 Health Benefits

The United States Environmental Protection Agency (USEPA) Co-Benefits Risk Assessment (COBRA) tool was used to evaluate the potential health benefits from the emission reductions associated with increased solar installations for Maryland. COBRA is a screening tool that estimates air quality, human health and associated economic impacts of emission reduction scenarios by county and state. COBRA uses a simple air quality model to estimate the effects of changes on ambient particulate matter. The model uses databases of emissions, population and disease incidence to project estimated health effects for the years 2017 and 2025 at discount rates of 3% or 7%.[108]

The following assumptions were used when running the COBRA model:

- Analysis Year – 2025

[108] USEPA – How COBRA Works September 2017

- Location – State level for all counties in the state with emissions
- Emission Tier – Fuel combustion electrical utility
- Discount Rate – 3%, used to project the impact of the lag in health impact.

Emissions changes due to solar installation projected by AURORA were totaled for all fuel types and input by state into the COBRA model. As noted in Section 4.2, the base case assumes Maryland does not add any additional solar to their system past 2018, while the difference (solar) case assumes solar buildout within Maryland on both utility scale and residential scale. Solar buildout for all of PJM remains the same for each of the three scenarios. The emissions changes projected by the AURORA modeling occur throughout the PJM region and air quality is impacted in surrounding states. The results of the modeling are provided below in Table 60 and

Table 61, and provided visually in Figure 62 and Figure 63.

The total estimated health benefits for the PJM region in 2025 range from $101 million to$480 million dollars (2010 $), or $0.020 per kWh to $0.093 per kWh for the three scenarios. Mortality reductions were estimated to range from 11 to 53 people. For Maryland, the health benefits ranged from $9 million to $32 million dollars (2010 $) or $0.002 per kWh to $0.006 per kWh, with mortality reductions estimated to range from 1 to 4 people.

Table 60: Health Benefits of Difference (Solar) Case (PJM Region, 2025)

	PJM REGION		
	Reference	**High CO_2**	**Low Gas**
Health Benefits (2010 $) - Low Estimate	$100,888,590	$212,295,233	$192,195,227
Health Benefits (2010 $) - High Estimate	$227,847,920	$479,559,829	$434,094,097
Health Benefits (2010$) - Average	$164,368,255	$345,927,531	$313,144,662
Health Benefits ($/kWh) - Low Estimate	$0.020	$0.041	$0.037
Health Benefits ($/kWh) - High Estimate	$0.044	$0.093	$0.084
Health Benefits ($/kWh) - Average	$0.032	$0.067	$0.061
Mortality (lives) - Low Estimate	11	24	21
Mortality (lives) - High Estimate	25	53	48
Mortality (lives) - Average	18	39	35

Table 61: Health Benefits of Difference (Solar) Case (Maryland, 2025)

	MARYLAND		
	Reference	High CO_2	Low Gas
Health Benefits (2010 $) - Low Estimate	$9,420,111	$14,151,104	$13,823,177
Health Benefits (2010 $) - High Estimate	$21,273,813	$31,952,447	$31,213,678
Health Benefits (2010$) - Average	$15,346,962	$23,051,775	$22,518,427
Health Benefits ($/kWh) - Low Estimate	$0.002	$0.003	$0.003
Health Benefits ($/kWh) - High Estimate	$0.004	$0.006	$0.006
Health Benefits ($/kWh) - Average	$0.003	$0.004	$0.004
Mortality (lives) - Low Estimate	1	2	2
Mortality (lives) - High Estimate	2	4	3
Mortality (lives) - Average	2	3	3

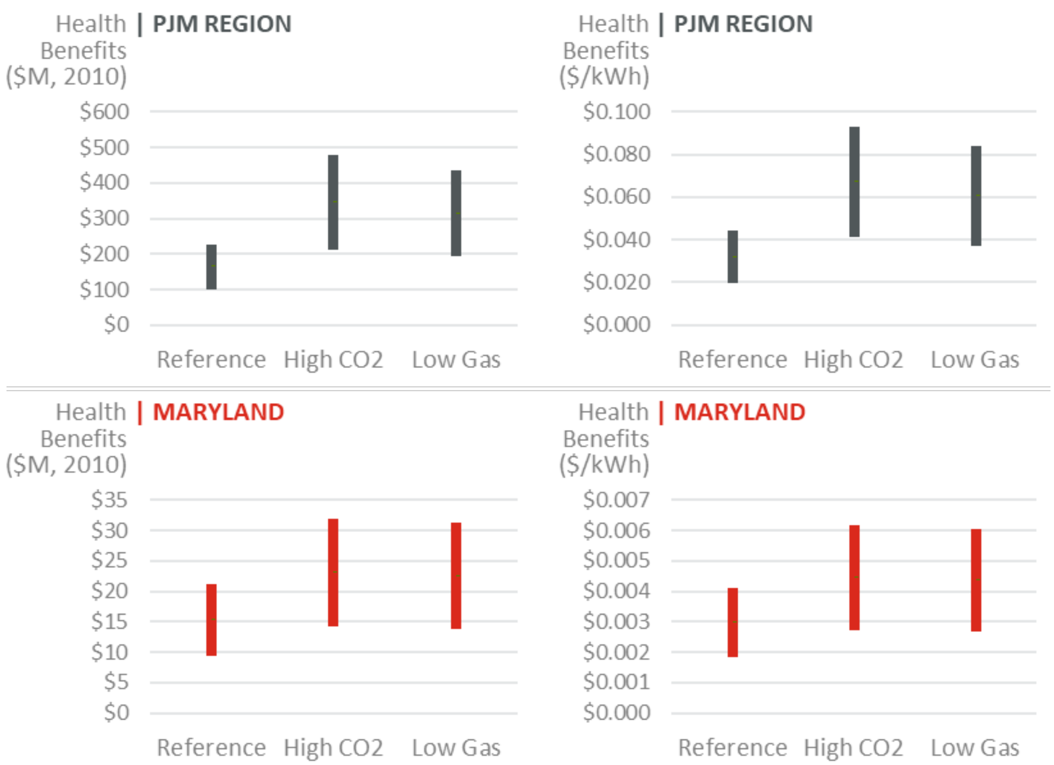


Figure 62: Health Benefits

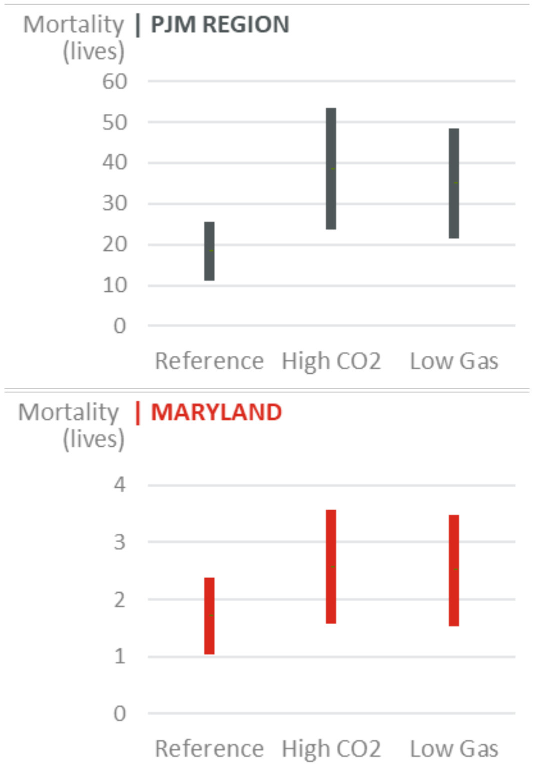


Figure 63: Mortality

6.1.4 Compliance Market Value Benefits

The CO_2, NOx and SO_2 emissions avoided due to modeled solar generation can be valued directly based on the forecast value of tradeable allowance certificates for each type. Current policies and programs that create markets for tradeable emission allowances include RGGI for CO_2 and the EPA Cross-State Air Pollution Rule ("CSAPR") and the Acid Rain Program for NOx and SO_2.

Our AURORA analysis incorporates compliance market value based on unit-specific emission rates and emission program assignments, as well as program-based allowance price forecasts. The CO_2 allowance price forecasts vary by scenario, as discussed in Section 4.2 above. Daymark's PMM contains NOx and SO_2 prices for units in PJM based on the CSAPR program. Total emission allowance savings values were then divided by the solar output for each case to develop a \$/MWh value. CO_2 and NOx savings by scenario are shown in the charts below. SO_2 cost savings were de minimis, with savings never exceeding \$0.01/MWh for any scenario.

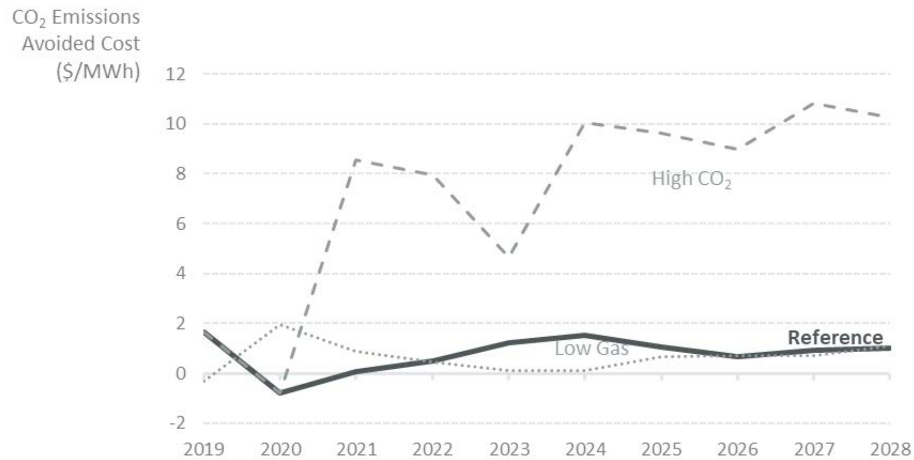


Figure 64. CO_2 Compliance Market Value Embedded in Energy Benefits of Solar ($/MWh)

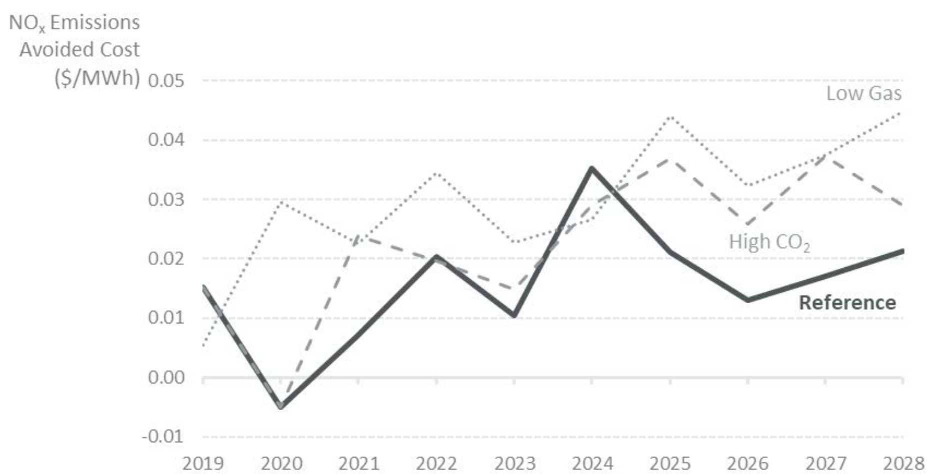


Figure 65. NO_x Compliance Market Value Embedded in Energy Benefits of Solar ($/MWh)

Though generators bear responsibility for obtaining allowances, the cost of allowances is passed to consumers through variable cost bids into the energy market (and thus market prices). Compliance market value benefits of emissions reduction are therefore embedded entirely in the energy benefits and energy market price effects discussed in Section 4.2above. The value of benefits shown in the Figure 64 and Figure 65 is a subset of -- not additive to -- the energy benefits estimated in Section 4.2.

6.1.5 Social Value of CO_2

The U.S. Government's Interagency Working Group ("IWG") on Social Cost of Greenhouse Gases estimates the social benefits of reducing CO_2 emissions for the purpose of evaluating benefits and costs of proposed regulatory actions. The IWG updated its social cost of carbon values in August 2016 based on the same methodology used since 2010.[109] The monetized damages associated with CO_2 emissions include (but is not limited to):

- Changes in net agricultural productivity;
- Human health;
- Property damages from increased flood risk; and
- Value of ecosystem services due to climate change.[110]

The IWG presents a distribution of cost estimates based on a variety of quantified sources of uncertainty, including discount rate. The IWG considers the central value, or the best point estimate, to be the average of estimates using a 3% discount rate. This average estimate ranges from $42 per metric ton (2007$) of CO_2 in 2020 to $50 per metric ton (2007$) in 2030.

Some portion of the social benefit of carbon reduction is already captured in the avoided CO_2 emission allowance costs discussed above. However, even in our High CO_2 energy market scenario, the cost of allowances never reaches the full social cost of carbon as estimated by the IWG. We define the non-monetized social value of CO_2 to be the social benefit of avoided CO_2 emissions as estimated by the IWG, net of CO_2 allowance costs assumed in the energy modeling. These non-monetized benefits are shown by scenario in Figure 66.

[109] EPA 2016 RIA and Addendum 2020, 3% discount rate, available at: https://www.epa.gov/sites/production/files/2016-12/documents/sc_co2_tsd_august_2016.pdf

[110] Ibid.

[110] Ibid.

Figure 66. Non-Monetized Social Benefit of CO2 Reduction by Scenario ($/MWh)

6.1.6 Carbon Sequestration

A study was prepared for the United States Department of Energy in 2007, Terrestrial Carbon Sequestration in the Northeast: Quantities and Costs - Part 6, that provides data for carbon sequestration by various land types. Area weighted average carbon dioxide sequestration/emissions reduction equivalence for 20-year time period for afforestation of agricultural land with non-cultivated crops (similar to solar facility land cover) in Maryland is 12 tons of CO_2e/acre.[111] Conversion of forested land to a solar facility would result in a loss of carbon dioxide sequestration of a similar amount.

As discussed in Section 6.2.3, there are multiple land use options for solar installation on agricultural and vegetated land that reduce the potential for loss of carbon dioxide sequestration.

6.1.7 Water Consumption

The US DOE Sun Shot study provides comparisons of water usage intensity for various types of electrical utility facilities. Photovoltaic (PV) solar technologies use little, if any, water during operation (minimal amounts may be needed occasionally to wash the panels). Concentrating solar technologies do require significant amounts of water, however this type of technology is not generally feasible for the solar irradiance levels in

[111] "*Terrestrial Carbon Sequestration in the Northeast: Quantities and Costs - Part 6. Comparison of terrestrial carbon mitigation options in the northeast United States*," 2007, available at: https://www.winrock.org/wp-content/uploads/2016/03/Comparison_of_terrestrial_carbon_migitation_options_in_the_Northeast_USA.pdf

Maryland. Water consumption for fossil fuel fired power plants are substantial, particularly for coal fired facilities. Estimated water consumption for various fuel sources is provided in Table 62. [112]

Table 62: Water Consumption by Generation Technology

GENERATION TECHNOLOGY	WATER CONSUMED FOR COOLING (gal/MWh)	OTHER WATER CONSUMED IN GENERATION (gal/MWh)
PV Solar	0	0-5
Pulverized Coal	360-590	60-120
Natural Gas Combined Cycle	180-280	2

The BGE 2018-2020 EmPower MD Program Filing estimates a water benefit of \$0.00794338 per gallon saved through the use of solar.[113-] Using this estimate, water reduction cost benefits were calculated for the three cases; these are provided in Table 63. The average water consumption figures from the Sun Shot study were used and the contribution from oil and refuse fuel facilities was assumed to be negligible.

Table 63: Estimated Water Benefits of Solar

2025	MWh REDUCTION COAL AND NATURAL GAS	WATER BENEFIT TOTAL	WATER BENEFIT (\$/MWh)[114]
Reference	3,797,387	\$9,074,862	\$1.76
High CO_2	3,086,274	\$11,025,602	\$2.13
Low Gas	3,572,501	\$11,488,758	\$2.22

[112] DOE Sun Shot Vision Study February 2012
https://www.energy.gov/sites/prod/files/2014/01/f7/47927_executive_summary.pdf

[113] BGE 2018-2020 EmPOWER MD Program Filing (Case No. 9154) September 2017

[114] Water benefit is show in dollars per MWh of incremental solar generation in 2025 compared to the base case.

6.2 Loss of Open Space and Agricultural and Ecological Services

Solar energy can potentially have a land benefit if conventional generation sources are replaced with roof-mounted distributed solar generation (DSG) systems. However, larger ground-based solar arrays typical of utility scale installations can have negative land impacts, given that they require much more land per MW of power generation as compared to a conventional power facility. Open land sites may be available that have little or no competing use value or are compatible with solar development such as highway or transmission rights of way, brownfield sites or existing power plant sites. The use of green field sites such as agricultural or forested land for ground based solar photovoltaic (PV) installations may have a potentially negative impact on land use.

Depending on the location of the solar development, conversion of agricultural land could result. Existing vegetation or forest may also be lost due to development of solar resources and impacts could occur to any existing wetland, waterbodies or rivers and streams. Soil erosion and storm water management at these sites also needs to be considered. Options for multiple land use combining solar installations and agricultural operations or wildlife habitat can mitigate negative impacts.

As noted in Section 4.2, this study estimated that 2.4 GW of utility scale solar installations would be installed from 2018 – 2028. The DOE Sunshot Vision Study estimates that 4.4 – 10.1 acres of direct land use are required per MW of solar energy produced by solar with 1-axis tracking.[115] Using an average estimate of 7.25 acres needed per MW of solar energy, 17,400 acres of land would be required to site these facilities. A land use analysis was conducted to identify the amount of land that would hypothetically be available for solar development.

6.2.1 Methodology

Available geographic information system (GIS) data base information was used to conduct a land use analysis for various land types including agricultural land, vegetated land and forested land. The data provided below in Table 64 summarizes a geospatial analysis of land use data from the National Land Cover Database (NCLD) for the State of Maryland. This NCLD data is current as of 2014 and has a spatial resolution of 30-meters. Acreage information derived from NLCD land use types within the State has

[115] DOE Sun Shot Vision Study February 2012
https://www.energy.gov/sites/prod/files/2014/01/f7/47927_executive_summary.pdf

been generalized through the analysis as Agriculture, Forest and Vegetated types as noted below.

Table 64: Land Use in Maryland

LAND USE	TOTAL ACRES	NLCD LAND USE
Agriculture	1,970,235	Cultivated Crops, Pasture/Hay
Forest	2,068,306	Deciduous Forest, Evergreen Forest, Mixed Forest
Vegetated	138,330	Grassland/Herbaceous, Shrub/Scrub

Land use types that were not conducive to development were designated as constraints and removed as noted below in Table 65Table 65. These constraints are similar to the assumptions made in the PJM Renewable Integration Study for areas to be excluded from the utility solar development site selection process such as open water, developed areas, wetlands, parks, Federal lands, airport buffers and slopes greater than 10%.[116]

[116] PJM Renewable Integration Study, February 17, 2012
http://www.pjm.com/-/media/committees-groups/subcommittees/irs/postings/pris-task-1-wind-and-solar-power-profiles-final-report.ashx?la=en

Table 65: Land Use Types not Suitable for Solar Development

CONSTRAINT	SOURCE
Water bodies (Lakes & Ponds)	Maryland GIS Data Catalog, 2005
Land use classified as 'Open Water'	National Land Cover Database, 2014
Wetlands	National Wetlands Inventory, 2017
Wetlands of Special State Concern	Maryland GIS Data Catalog, 1998
Rivers and streams	Maryland GIS Data Catalog, 2017
Protected areas	USGS Protected Areas Database of the United States, 2017
Airport Buffer (10,000 ft)	Airport point locations (MD GIS Data Catalog, 2017) with 10,000 foot buffer (20,000 foot buffer for BWI due to size) (ESS)
Road buffer (500 meter)	State-wide road centerlines (MD GIS Data Catalog, 2017) areas outside 500 meters (surrogate for distribution system access) (ESS)
Developed, High Intensity	NLCD land cover type
Developed, Medium Intensity	NLCD land cover type
Developed, Low Intensity	NLCD land cover type
Developed, Open Space	NLCD land cover type
Terrain Slope > 10%	LiDAR from Maryland GIS Data Catalog (years vary by county)
Natural Heritage Areas	Maryland GIS Data Catalog, 2010
Area < 25 Acres	Contiguous area of 25 acres assumed minimally necessary for a utility scale solar installation (approximately 2 MW)

Additional land was removed from counties that had zoning restrictions for utility scale solar installations for agricultural and/or forested land; these are summarized in Table 66.

Table 66: Counties with Zoning Restrictions Relative to Solar on Specific Land Types

LAND USE	COUNTIES WITH ZONING RESTRICTIONS
Agriculture	Carroll, Harford, Kent, Montgomery
Forest	Frederick, Harford

6.2.2 Results

Statewide acreage totals for each generalized land use type after removal of any associated constraint acreage are summarized in Table 67 below. Acreage totals for generalized land use after constraints for each county are provided in Appendix I and summarized for the state of Maryland in Table 66 .

Table 67: Statewide Land by Generalized Land Use Type

LAND USE	AVAILABLE ACRES	% TOTAL
Agriculture	757,031	57%
Forest	518,532	39%
Vegetated	53,229	4%

Figure 67 and Table 68 present the hypothetical or suitable land availability for utility scale solar installations in the state of Maryland by generalized land use type. Figures for each county are provided in Appendix J.

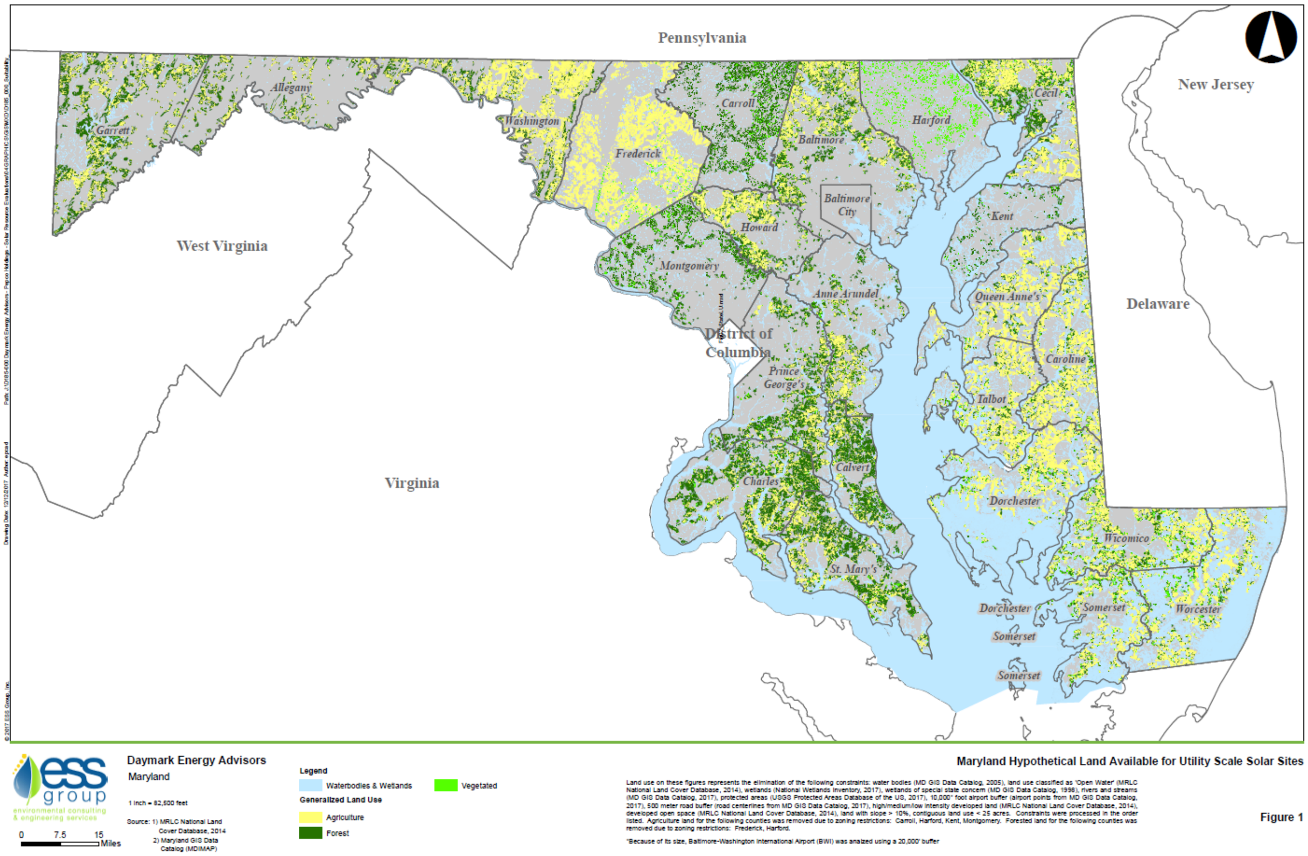


Figure 67: Suitable Land Availability for Utility Scale Solar in Maryland

For the purposes of this land use evaluation, it was assumed that areas with the greatest potential for utility scale solar installations to cause adverse ecological effects on wildlife and threatened or endangered species would not be considered for development and were set as a constraint. The land use constraints included wetlands, protected areas and Maryland Natural Heritage areas. However, there would still be the potential for sensitive species project review areas to be impacted by potential solar installations as noted in the areas below. These would have to be evaluated on an individual project basis.

Table 68: Suitable Acres of Land Availability for Utility Scale Solar in Maryland

LAND USE	ACRES	ACRES WITHIN SENSITIVE SPECIES PROJECT REVIEW AREAS	% OF ACREAGE WITHIN SENSITIVE SPECIES PROJECT REVIEW AREAS
Agriculture	757,031	94,027	12%
Forest	518,532	90,490	17%
Vegetated	53,229	9,281	17%

For the purposes of this land use evaluation, it was assumed that areas with the greatest potential for utility scale solar installations to cause adverse ecological effects on wildlife and threatened or endangered species would not be considered for development and were set as a constraint. The land use constraints included wetlands, protected areas and Maryland Natural Heritage areas. However, there would still be the potential for sensitive species project review areas to be impacted by potential solar installations as noted in the areas below. These would have to be evaluated on an individual project basis.

6.2.3 Integrating Solar with Agricultural and Vegetated Land Use

Agricultural and vegetated land are well-suited for utility scale solar installations and can be installed with a minimum of disruption to existing land cover as well as the potential introduction of new habitat. Research by the National Renewable Energy Lab (NREL) provides guidance on options for multiple use include agriculture, ranching and grazing, and pollination.[117] They note that site preparation techniques that remove all vegetation can be avoided and that there have been successful examples of solar facilities co-located with agricultural operations or native vegetation. Solar installation that have integrated vegetation may have potential cost and performance benefits resulting from decreased site preparation costs, reduced operational costs, maintenance and/or creation of environmental habitat, agricultural revenue and community acceptance.

In a webinar on co-location of solar and agriculture, NREL provides guidance on low-impact site preparation to minimize impact on vegetation while meeting the needs of

[117] NREL Overview of Opportunities for Co-Location of Solar Energy Technologies and Vegetation, December 2013
https://www.nrel.gov/docs/fy14osti/60240.pdf

the solar installation. [118] Examples provided include, keeping existing vegetation intact or replacing with low growing native vegetation or crops, minimizing the land footprint needed for foundations, encouraging vegetation that supports habitat and minimizing operation and maintenance activities through the use of low-growing native vegetation and livestock grazing. Potential benefits include control of soil erosion, protection of natural habitat, shade and cover for livestock, improved habitat for pollinator species, reductions in site preparation costs, reduction in environmental mitigation investments, reduced risk of frost heaves, increased stormwater infiltration and reduced need for dust suppression.

Maryland law SB 1158 Department of Natural Resources - Solar Generation Facilities - Pollinator-Friendly Designation establishes a standard for ground mounted solar generation facilities of at least one acre in size to be designated as pollinator-friendly. The land on which the solar generation facility is located must be planted and managed in accordance with a pollinator-friendly vegetation management standard or pollinator habitat plan.[119]

For example, Baker Point solar is a 9 MW solar installation located on 60 acres of a 7,000acre farm in Frederick County. The site was designed to include pollinator habitat including nine different species of native long-stemmed and short-growing flowers and warm-season grasses planted between the rows of solar panels. Forty bee colonies were established in beehives located on the site that each produce 30 pounds of honey per year. [120,121]

6.2.4 Forest Habitat

Forest habitat has the potential to be impacted by development of utility scale solar projects. However, due to the added cost to clear forested land and the availability of

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[118] NREL Co-Location of Solar and Agriculture: Benefits and Tradeoffs of Low-Impact Solar Development, January 2017

https://www.youtube.com/watch?v=VVapBZUCiw8

[119] MD Senate Bill 1158 – Solar Generation Facilities – Pollinator-Friendly Designation, May 2017

http://mgaleg.maryland.gov/webmga/frmMain.aspx?id=sb1158&stab=01&pid=billpage&tab=subject3&ys=2017RS

[120] One Energy Renewables – Baker Point Solar November 2017

http://www.oneenergyrenewables.com/news/announcement-marylands-first-solar-array-inspired-marylands-pollinator-friendly-solar-legislation/

[121] One Energy Renewables – Baker Point Solar – The Frederick News-Post November 2017

http://www.oneenergyrenewables.com/news/baker-point-solar-lights-holidays/

agricultural and vegetated land, it is unlikely that there would be interest in installing solar facilities on existing forested land.

6.2.5 Stormwater Management

The Maryland Department of Environment Stormwater Design Guidance – Solar Panel Installations outlines factors to be considered for stormwater management to minimize the impact of land development on water resources. This applies to solar facility installations when more than 5,000 square feet of land area is disturbed. For solar panels, stormwater management may be provided in a cost-effective manner by disconnecting each row of panels and directing runoff over vegetated areas between rows.[122]

6.3 Impact on Local Comprehensive Plans, Zoning and Planning Requirements

The ability to develop solar projects can be influenced by local comprehensive plans and zoning ordinance. Comprehensive plans and zoning can provide specific policies or requirements for siting which can affect the development of solar energy systems on public or private land. These can cover such things as setbacks, access, street and building orientation, or preferred locations for new solar energy systems such as overlay district. Factors such as the type of system, location size and capacity of systems may be appropriate factors for consideration under the comprehensive plans, zoning, and planning requirements.

6.3.1 Methodology

To address the potential impact to comprehensive plans, zoning, and planning requirements, we reviewed existing comprehensive plans and zoning ordinances for each Maryland county and evaluated the level to which solar project development is addressed. For the purposes of this report, we focused on the requirements for utility scale solar development due to the scale and land use impacts.

[122] Maryland Department of Environment Stormwater Design Guidance – Solar Panel Installations http://mde.maryland.gov/programs/water/StormwaterManagementProgram/Documents/ESDMEP%20Design%20Guidance%20Solar%20Panels.pdf

6.3.2 Results

6.3.2.1 Moratoriums

Many counties have expressed concerns about the rapid pace of utility scale solar development in their communities and have instituted moratoriums to allow for time to evaluate their current zoning requirements. The majority of those moratoriums have expired and the zoning ordinance updated to reflect community concerns. A summary of the moratorium status is provided in Table 69.

Table 69: Utility Scale Moratorium Status

COUNTY	UTILITY SERVICE TERRITORY	MORATORIUM STATUS
Anne Arundel	BGE	Moratorium set to expire August 2018
Baltimore County	BGE	Moratorium expired, zoning ordinance updated June 2017
Caroline	BGE/PE	Moratorium expired, zoning ordinance updated December 2017
Frederick	BGE/PE	Moratorium expired, zoning ordinance updated May 2017
Talbot	DPL	Moratorium expired, zoning ordinance updated February 2017

6.3.2.2 Zoning Ordinance

The primary mechanism for addressing solar development is zoning ordinance and we found only generalized statements in the comprehensive plans. Most counties have zoning ordinance for utility scale solar development with only four counties (Baltimore City, Garret, Prince George's and Somerset) that do not have specific requirements. Most define utility scale systems by functionality (power generating facility, utility, commercial) or size (> 2 – 2.5 MW). Land use restrictions include prohibitions on installation in specific zoning districts and lot size restrictions. For example, four counties restrict development of utility scale solar on agricultural land (Carroll, Harford, Kent and Montgomery) and two restrict development on forested land (Frederick and Harford). Other district types such as conservation, residential, commercial and industrial are typically not suitable for utility scale solar development as noted in the land use analysis in Section 6.2. Installation of utility scale solar facilities is generally subject to special exemption or conditional use.

Figure 68 depicts the counties that have zoning requirements and restrictions on the use of agricultural land for utility scale solar development.

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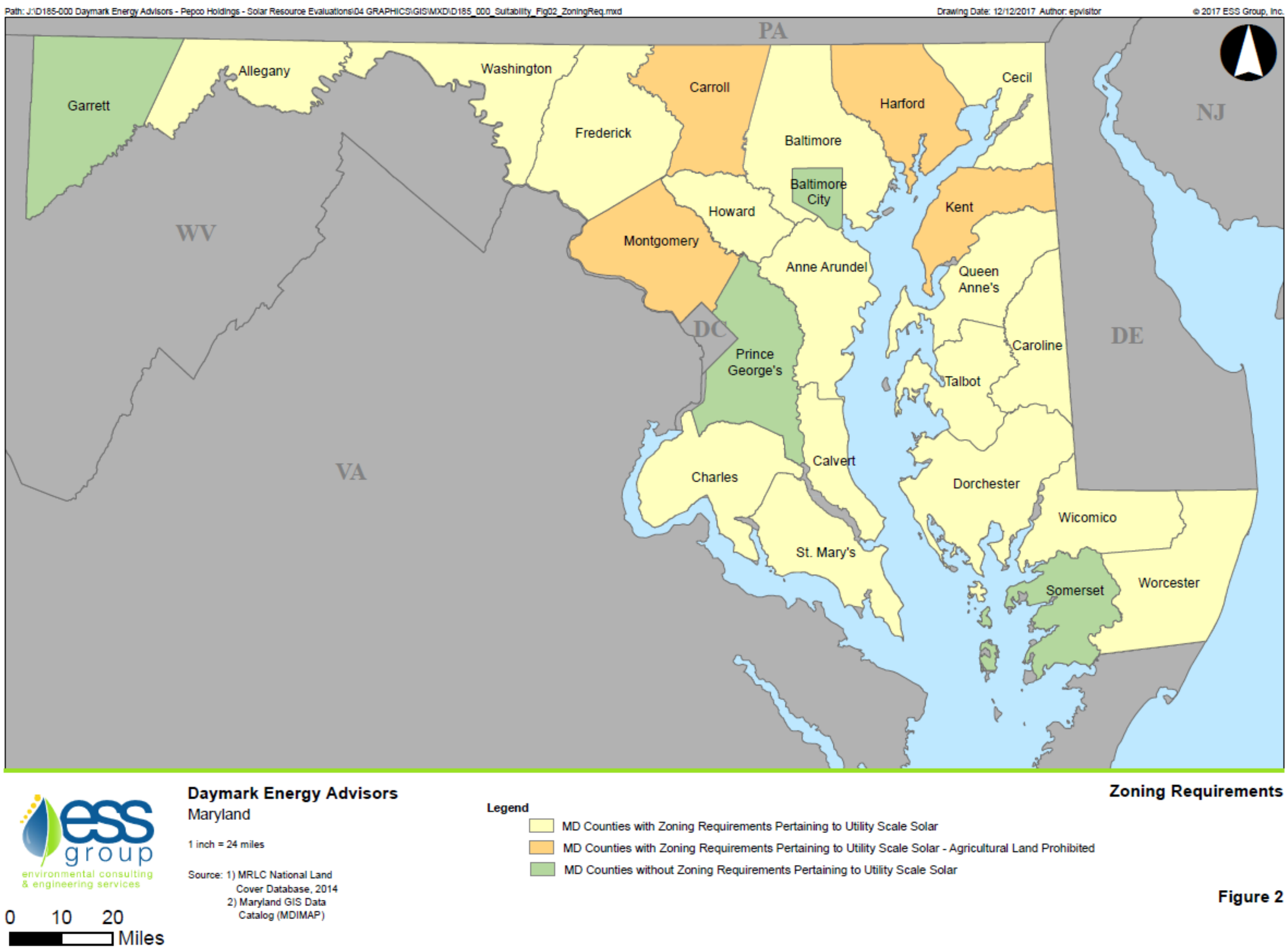

Figure 68: County Level Zoning Requirements

Six counties have minimum lot size restrictions varying from 10 to 50 acres while four counties have maximum lot size restrictions ranging from 5 to 750 acres. Other requirements address aesthetic and community concerns such as glare mitigation, screening buffers, setback distances, fencing and lighting. Eleven counties establish minimum setbacks ranging from 25 to 400 feet for different zoning districts. Ten counties establish glare mitigation requirements such as the use of glare mitigating technology and siting to reduce glare on nearby roadways and structures or that cause a safety hazard. Thirteen counties have landscape screening buffer requirements. Eleven counties set height restrictions that range from 15 to 45 feet. Five counties address security requirements related to fencing and lighting. A summary of the local zoning ordinances for utility scale solar development is provided as Appendix K.

6.3.2.3 Conclusions

Factors that can be considered when developing a zoning ordinance for utility scale solar development include:

- **Land use types** – Open land sites that have little or no competing use value and are compatible with solar development include brownfields, reclaimed surface mines, highway or transmission rights of way and existing power plant sites. Potential impact on wildlife habitat would generally limit development opportunities in conservation areas. As noted in section 6.2, the value of forested land and cost to develop would preferentially favor agricultural land and other open space.
- **Lot Size** – A minimum of 20 acres is typically needed to develop a utility solar scale project of 2 MW or greater.
- **Setbacks** – Three counties specify setbacks to be per the zoning district and four require 50’ setbacks. Setbacks for the other four counties with requirements range from 25’ - 200’ for nonresidential and 100’ – 400’ for residential areas.
- **Glare Mitigation** – Utility scale solar projects can be designed and sited to reduce glare that could create a nuisance or public safety hazard.
- **Screening Buffers** – Visual screening to reduce impact on aesthetic and scenic quality of the location can be considered as warranted. In addition, the use of pollinator habitat can serve a dual function of providing visual screening and enhancing pollination in the surrounding land areas.
- **Height** – Two counties establish height restrictions consistent with the zoning district. There are nine other counties with height restrictions that vary from 15’ – 50’.
- **Lighting** – Options for reducing the impact of facility lighting can include minimizing the lighting to that required for safety, shielding and downcasting to reduce the impact on the neighborhood and the use of motion sensors.
- **Decommissioning** – Thirteen counties establish provisions for decommissioning the site including specifying time limits for decommissioning, defining the extent of removal of components, and requiring restoration of the disturbed areas including grading and reseeding. Several counties require a written decommissioning plan and security for the costs of decommissioning.

- **Vegetation Removal** – Four counties establish limits on tree removal such as requiring approval for tree removal that comprises more than 2% of the parcel being developed.
- **Security** – Wildlife friendly fence designs are available to allow for wildlife of concern to cross the barriers.
- **Dual Land Use** – As discussed in section 6.2, utility scale solar facilities may offer opportunities for agricultural use such as shade crops, grazing and pollinator habitat.

6.4 Jobs and Local Economic Impact & Inflation

To calculate the economic and job impacts of incremental investment in distributed solar resources in the territories of the four Maryland IOUs, the IMPLAN model was used. IMPLAN is an input-output model that combines a set of databases of economic factors, multipliers, and demographic statistics to measure the economic impacts caused by investment or other actions that cause an increase in sales to local industries. Users can define regions to analyze from the national level down to specific geographies within states. While investments in technology occur over time, IMPLAN assumes a fixed technology over a study period. IMPLAN is a single-year and one-region model, although each region can include various sub-regions (e.g. counties), so it must be run for each region for each year in a study period. It is important to note that IMPLAN is a deterministic model not a probabilistic model, so the margin of error is not measurable. Like other input-output models, IMPLAN relies on supporting data and general assumptions.[123]

Using IMPLAN, a user can estimate impacts to a specified region "by identifying direct impacts by sector, then developing a set of indirect and induced impacts by sector through the use of industry-specific multipliers, local purchase coefficients, income-to-output ratios, and other factors and relationships".[124] For this study, Maryland-specific data with details included down to the county level was modeled for each region (IOU service territory in Maryland) and for each year of the study period (2018-2028).

After selecting the state level of input data to use in IMPLAN, four regional (or IOU) models were created by first aggregating county data specific to each utility. Then, industry codes for products and services associated with solar, which are key inputs to each model, had to be selected for both utility-scale solar and BTM solar (residential and commercial). Industrial codes, or more specifically North American Industry Classification System ("NAICs") codes, are used by federal statistical agencies to classify businesses into industrial sectors for purposes of statistical analysis and reporting. Solar NAICs codes are based on the supply

[123] For more documentation about input data and input-output models, refer to the following: http://implan.com/index.php?option=com_content&view=article&id=414&Itemid=1878 and http://implan.com/index.php?option=com_content&view=article&id=377:377&catid=222:222.

[124] http://cier.umd.edu/RGGI/documents/IMPLAN.pdf

chain utilized to develop and install solar. A picture of the supply chain for BTM solar is provided in Figure 69 below.[125]

Figure 69: Solar PV Supply Chain

Research into the supply chain components reveals that most solar panels for either BTM or utility-scale installations are not manufactured in the United States. Thus, only parts of the supply chain that focus on is the installation of the solar panels were considered in the analysis. After reviewing all the possible NAICs codes and industries that could be involved in the installation process, the most applicable NAICs codes were selected for each type of solar installation. Since the utility-scale panels in the study are assumed to be two-axis tracking, the installation process involves mostly different NAICs codes than for the BTM panels, which are assumed to be rooftop mounted. Utility-scale projects require construction (includes materials, labor/construction services, and financing) and maintenance and operation (includes production payroll, fixed production costs, maintenance, general and administration costs, and capital costs) components. BTM projects require construction (materials, labor/construction services, sales and marketing, and financing) and maintenance and operation (includes only maintenance) components.

The other key input for the IOU models is the investment or spend projection for each of the selected industries. For both utility-scale and BTM solar projects, the investment each year is equated to the capital costs (only those applicable to the part of the supply chain analyzed) multiplied by the incremental solar installations, and for utility-scale solar it also includes multiplying cumulative solar installations by operating and maintenance costs.

For both types of solar projects, capital costs were analyzed by reviewing recent reports[126] detailing both installation and capital costs. A report published by NREL that provided a system cost benchmark for different size and type solar projects in the U.S., was ultimately

[125] https://www.solarworld-usa.com/about-solarworld/value-chain

[126] https://emp.lbl.gov/publications/utility-scale-solar-2016-empirical; https://emp.lbl.gov/publications/tracking-sun-10-installed-price/;and https://www.nrel.gov/docs/fy16osti/67142.pdf

used to forecast capital costs for different supply chain components over the study period (2018-2028).[127] The NREL report analyzed residential rooftop systems in the 3 kW to 10 kW range, commercial rooftop systems in the 10 kW to 2 MW range, and utility-scale ground-mounted systems greater than 2 MW.[128] Capital cost data was shown in real 2016 dollars per watt DC for each type of solar project described was looked at over time (2009-2016) and by cost category (inverter, module, hardware – structural and electrical components, installation labor, and other soft costs – inspection, land acquisition, sales tax, developer overhead, and net profit).[129]

Daymark analyzed the trends in cost over the last seven years (2014 data not provided in the study) and determined reasonable cost trends to apply to each cost category over the study period for each type of solar project. Most of the cost trends were based on the last few years of cost data, as costs have decreased rapidly since 2009, but are unlikely to continue falling at the same rate going forward. There will likely be advancements in technology that will cause the hardware components to see more of a cost decline over time. However, these costs were not part of the analysis, as they are not produced in Maryland, or most of the U.S. – for that matter.

Labor costs were held constant over the study period, since they have fell rapidly between 2009 and 2013, but have stabilized since then – most likely due to the installers becoming more efficient and going forward the installation industry and installer costs are likely to grow with more solar penetration. After reviewing the projected costs over the study period for the specific cost categories, Daymark determined that small and large commercial projects should be treated the same when determining costs.[130]

Additionally, for utility-scale projects, operating and maintenance costs were initially set at $17.8/kW-AC (2016$), and then kept flat for the study period, since these costs do not fluctuate much and may even decrease over time with technology innovation.[131]

After determining the costs for each type of solar project over the study period, the incremental buildouts were multiplied by the costs to determine the capital costs for each type of solar project. Incremental additions of BTM solar projects were allocated to

[127] https://www.nrel.gov/docs/fy16osti/67142.pdf

[128] *Id*., slide 6.

[129] *Id*., slide 8.

[130] The determination was made based on the comparing hardware costs, which are the main driver in increased installation costs. These costs tracked closely to utility-scale hardware costs and therefore represented a reasonable estimate for all commercial project sizes.

[131] https://emp.lbl.gov/publications/utility-scale-solar-2016-empirical

residential, small commercial, and large commercial size categories for each IOU, based on the percentage of historical additions of each category.[132]

Table 70: Allocation factor for Incremental Nameplate Capacity (MW) for BTM Solar Projects

	Residential	Small Commercial	Large Commercial
BGE	74%	13%	13%
DPL	42%	19%	39%
PEPCO	74%	8%	18%
PE	68%	7%	25%

The last step in determining the total investment each year for both utility-scale and BTM solar projects involved allocation of county level investment across the IOUs, specifically to address possible double counting of county level investment for counties served by multiple IOUs. This allocation was completed by performing a zip codes served analysis by county by IOU. Based on percentage of zip codes served by each IOU, costs proportioned to the counties were reallocated to better represent IOU service territories.

The tables below show the incremental MW additions[133] and the total investment in each utility's territory of utility-scale and BTM solar projects forecasted each year of the study period (2017 is included in the tables, but not used in the analysis).

Table 71: Incremental Nameplate Capacity (MW) of Utility-Scale Solar Projects[134]

	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
BGE	-	99	99	99	99	99	99	99	99	99	99	99
DPL	6	23	23	23	23	23	23	23	23	23	23	23
PEPCO	-	64	64	64	64	64	64	64	64	64	64	64
PE	-	28	29	29	29	29	29	29	29	29	29	29

[132] Using the data provided by each IOU in Discovery Response 1.1, the percentage allocation was determined by summing each category of solar project installed through 2017 in each IOU, except for utility-scale, and then calculating the percent of the total BTM solar installations were residential, small commercial, and large commercial. Daymark acknowledges this is an imperfect percent allocation, since the installs of each type of BTM solar can change year to year, it was a reasonable way to assign percentage breakdowns.

[133] Incremental MW additions were determined from the cumulative solar additions in the Solar Case analyzed in Aurora.

[134] Incremental nameplate capacity is the difference between the cumulative nameplate capacity each year for the Change Case.

Table 72: Incremental Nameplate Capacity (MW) of BTM Solar Projects[135]

	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
BGE	90	127	104	104	104	104	104	104	104	104	104	104
DPL	12	17	25	25	25	25	25	25	25	25	25	25
PEPCO	60	85	67	67	67	67	67	67	67	67	67	67
PE	23	32	30	30	30	30	30	30	30	30	30	30

Table 73: Total Investment ($M) of Utility-Scale Solar Projects[136]

	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
BGE	$1	$129	$123	$119	$116	$113	$110	$108	$106	$105	$103	$102
DPL	$7	$32	$32	$31	$30	$29	$28	$28	$27	$27	$27	$26
PEPCO	$0	$77	$74	$71	$69	$68	$66	$65	$64	$63	$62	$61
PE	$0	$42	$41	$39	$38	$37	$36	$36	$35	$34	$34	$33

Table 74: Total Investment ($M) of BTM Solar Projects[137]

	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
BGE	$224	$293	$226	$211	$198	$186	$175	$165	$156	$148	$141	$134
DPL	$36	$46	$54	$51	$48	$45	$42	$40	$37	$35	$34	$32
PEPCO	$138	$181	$135	$127	$119	$112	$105	$99	$94	$89	$84	$80
PE	$67	$87	$74	$69	$65	$61	$57	$54	$51	$48	$46	$44

The total incremental investment each year was then proportioned over the industries related to the installation of solar based on general industry knowledge, expected business creation resulting from the investment, the strengths of each of the industries in Maryland relative to other states, and use of the NREL report[138] that benchmarked solar system costs as a guide.

[135] *Id.*

[136] Calculated by multiplying the capital cost each year by the incremental nameplate capacity plus the operations and maintenance cost times the cumulative nameplate capacity.

[137] Calculated by multiplying the capital cost each year by the incremental nameplate capacity by the percent allocation of incremental nameplate capacity for each residential, small commercial, and large commercial. All three were then totaled.

[138] https://www.nrel.gov/docs/fy16osti/67142.pdf, specifically slides 27 and 33.

6.4.1 Results of IMPLAN Analysis

The installation of utility-scale and BTM solar projects will provide multiple economic benefits to the state of Maryland, and more specifically the IOU service territories. Daymark's analysis demonstrates that the construction/installation and subsequent operation and maintenance of the collective installed solar projects will generate additional jobs, labor income, and tax revenue for the state of Maryland.

In total, the forecasted solar projects are estimated to generate 22,563 job-years, over $1.34 billion in labor income, over $2.03 billion in value added[139] or Gross Domestic Product, and more than $3.97 billion in incremental local industrial production/output[140] for the state of Maryland. The economic impacts are broken into three categories: direct, indirect, and induced. The total value of each impact is shown in Table 75 below. When interpreting the economic impacts for each category, it is important to consider the following:

- Job-years, which are totaled over the study period, refer to jobs created each year due to investment. When interpreting job created from investment, jobs should not be considered cumulatively, but instead on average. The average jobs created over the study period will be the jobs needed to directly install and then operate and maintain the solar projects. The workers needed are declining over the study period as costs of installation go down.
- Indirect jobs are created due to jobs being added to industries that support the installation process, and should be also interpreted on average and that average should considered an upper bound on job creation, since there is more likely to be an increase in production and wages and not necessarily an increase on jobs added.
- Induced jobs are jobs created by spending in the economy from the newly employed workers. These jobs should be interpreted on average and that average should be considered an upper bound on job creation, since the addition of that many retail-type workers (e.g. restaurants, banks, and box stores) is less likely to occur and instead these establishments are more likely going to increase wages and expand in value – although this will lead to some additional job growth.

[139] Value added is explained by the Bureau of Economic Analysis as, "the difference between gross output and intermediate inputs and represents the value of labor and capital used in producing gross output. The sum of value added across all industries is equal to gross domestic product for the economy." Intermediate inputs are explained by the Bureau of Economic Analysis as, "the foreign and domestically-produced goods and services used up by an industry in the process of producing its gross output". https://www.bea.gov/faq/index.cfm?faq_id=1034

[140] Gross output is explained by the Bureau of Economic Analysis as, "the total value of goods and services produced by an industry". https://www.bea.gov/faq/index.cfm?faq_id=1034

Table 75: Total Maryland-specific economic impacts

	Employment (Job-Years)	Labor Income (dollars)	Value Added (dollars)	Output (dollars)
Direct	13,517	$796,441,652	$1,120,558,798	$2,516,560,776
Indirect	4,824	$329,581,035	$514,811,689	$831,141,254
Induced	5,493	$290,794,492	$512,472,678	$846,188,424
Total	22,563	$1,340,052,852	$2,028,064,404	$3,972,715,479

For the utility-scale solar projects, the direct impacts include facility construction (construction, materials, and labor) and facility upkeep (workers, materials, and supplies). Indirect impacts for utility-scale solar projects include downstream activity in other industries that supply the materials needed to build, maintain, and run the solar projects. Induced impacts include business activities created by the spending of job income by the solar projects' and solar industry employees in the local Maryland economy (also referred to as multiplier effects). The values of each impact are shown in the table below.

Table 76: Total Maryland-specific economic impacts from utility-scale solar projects

	Employment (Job-Years)	Labor Income (dollars)	Value Added (dollars)	Output (dollars)
BGE				
Direct	2,166	$130,822,985	$170,278,570	$343,123,108
Indirect	507	$38,977,883	$62,464,747	$100,042,532
Induced	709	$37,944,143	$68,561,802	$108,049,855
Total	3,382	$207,745,010	$301,305,121	$551,215,496
DPL				
Direct	634	$30,475,390	$40,191,827	$88,306,156
Indirect	144	$7,113,189	$11,696,909	$22,052,766
Induced	167	$6,559,978	$12,394,872	$21,529,218
Total	945	$44,148,557	$64,283,608	$131,888,138
PEPCO				
Direct	1,225	$68,987,397	$91,171,277	$191,457,454
Indirect	302	$21,889,417	$34,985,638	$56,473,367
Induced	530	$28,770,265	$48,527,356	$81,663,014
Total	1,812	$105,249,699	$152,843,948	$290,040,880

	Employment (Job-Years)	Labor Income (dollars)	Value Added (dollars)	Output (dollars)
PE				
Direct	661	$40,162,115	$52,624,357	$105,273,430
Indirect	172	$12,756,228	$20,674,639	$33,061,954
Induced	313	$17,531,594	$29,460,960	$48,729,219
Total	1,008	$61,924,397	$89,810,715	$164,298,248
Maryland				
Direct	4,686	$270,447,887	$354,266,031	$728,160,148
Indirect	1,124	$80,736,717	$129,821,933	$211,630,619
Induced	1,719	$90,805,980	$158,944,990	$259,971,306
Total	7,146	$419,067,663	$608,243,392	$1,137,442,762

For BTM solar projects, direct impacts only include the installation of the solar panels (materials and labor). Indirect impacts include the incremental activity in other industries that supply the installation materials that are made in Maryland. Induced impacts include business activities created the by the spending of job income of solar industry employees in the local Maryland economy. The values of each impact are shown in the table below.

Table 77: Total Maryland-specific economic impacts from BTM solar projects

	Employment (Job-Years)	Labor Income (dollars)	Value Added (dollars)	Output (dollars)
BGE				
Direct	4,151	$257,292,906	$371,095,108	$853,216,629
Indirect	1,720	$123,859,698	$191,594,008	$302,470,801
Induced	1,593	$84,941,737	$153,516,790	$242,023,830
Total	7,464	$466,094,342	$716,205,905	$1,397,711,259
DPL				
Direct	1,043	$53,840,264	$77,666,310	$194,634,261
Indirect	445	$18,899,988	$29,341,405	$55,809,633
Induced	324	$12,695,799	$23,993,033	$41,683,489
Total	1,812	$85,436,048	$131,000,752	$292,127,384
PEPCO				
Direct	2,375	$136,034,478	$203,456,295	$482,377,502

	Employment (Job-Years)	Labor Income (dollars)	Value Added (dollars)	Output (dollars)
Indirect	985	$67,386,276	$103,534,486	$165,698,372
Induced	1,169	$63,666,043	$109,858,139	$190,190,923
Total	3,962	$233,343,854	$363,466,964	$737,291,424
PE				
Direct	1,263	$78,826,117	$114,075,054	$258,172,236
Indirect	550	$38,698,356	$60,519,857	$95,531,829
Induced	688	$38,684,933	$66,159,726	$112,318,876
Total	2,179	$136,110,945	$209,147,391	$408,142,650
Maryland				
Direct	8,831	$525,993,765	$766,292,767	$1,788,400,628
Indirect	3,699	$248,844,318	$384,989,756	$619,510,635
Induced	3,774	$199,988,512	$353,527,688	$586,217,118
Total	15,417	$920,985,189	$1,419,821,012	$2,835,272,717

The forecasted solar projects are estimated to generate approximately $146.2 million in tax revenue for Maryland. This tax revenue, as shown in the tables below, is generated through sales tax, income tax, and property tax.

Table 78: Total tax revenue for Maryland generated by all solar projects

Tax Category	BGE	DPL	PEPCO	PE	Maryland
Sales Tax	$22,114,674	$5,702,243	$12,298,395	$7,169,210	$47,284,522
Income Tax	$24,361,378	$3,996,304	$12,978,936	$7,886,201	$49,222,819
Property Tax	$23,401,630	$5,745,892	$12,915,957	$7,586,293	$49,649,772
Total	$69,877,682	$15,444,439	$38,193,288	$22,641,704	$146,157,113

Table 79: Total tax revenue for Maryland generated by utility-scale solar projects

Tax Category	BGE	DPL	PEPCO	PE	Maryland
Sales Tax	$8,549,238	$2,407,041	$4,858,175	$2,803,743	$18,618,197
Income Tax	$7,493,817	$1,359,167	$4,029,199	$2,458,159	$15,340,342

Property Tax	$9,024,893	$2,420,936	$5,089,576	$2,959,741	$19,495,146
Total	$25,067,948	$6,187,144	$13,976,950	$8,221,643	$53,453,685

Table 80: Total tax revenue for Maryland generated by BTM solar projects

Tax Category	BGE	DPL	PEPCO	PE	Maryland
Sales Tax	$13,565,436	$3,295,202	$7,440,220	$4,365,467	$28,666,325
Income Tax	$16,867,561	$2,637,137	$8,949,737	$5,428,042	$33,882,477
Property Tax	$14,376,737	$3,324,956	$7,826,381	$4,626,552	$30,154,626
Total	$44,809,734	$9,257,295	$24,216,338	$14,420,061	$92,703,428

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7. VALUE OF SOLAR

Sections 4, 5, and 6 of this report discuss the bulk power system, distribution system and economic and social benefits and costs of solar. This section brings those benefits together, to show the total value adding solar to the Maryland power grid can create.

The benefits and costs of solar included in the charts in this section are shown in the Table 81 below. Note that distribution costs and benefits are not included in the chart because these can be negative or positive depending on location. Additionally, some of the emission costs savings discussed in Section 6 are included in the Avoided Energy Benefit, so not included here.

Table 81: Components included in Value of Solar Benefits Charts

COMPONENT	DESCRIPTION	REPORT SECTION DISCUSSED
Avoided Energy	Market energy purchases avoided due to distributed solar	4.2.2
Energy Market Price Effect	Indirect effects of solar on market prices for energy and capacity	4.2.3
Avoided Capacity	Market capacity purchases avoided due to distributed solar	4.3
Avoided Transmission Costs	Avoidances, deferrals, and reductions in transmission investments and transmission charges due to reduction in peak load	4.4
Avoided REC Purchases	Reductions in an entity's requirements to comply with RPS policies	4.7
Non-Monetized CO_2 Social Benefit	Social benefit of avoided CO_2 emissions, net of CO_2 allowance costs assumed in the energy modeling	6.1.5
Health Benefits	Health benefits of reduced emissions	6.1.3
Economic Benefits	Benefits to Maryland's economy of solar development	6.4

Section 7.1 and 7.2 show the build up of all categories of benefits for BTM and Utility Scale Solar respectively for each of the three scenarios discussed in Section 4.2.

7.1 Behind the Meter Benefits

7.1.1 BTM Benefits Reference Scenario

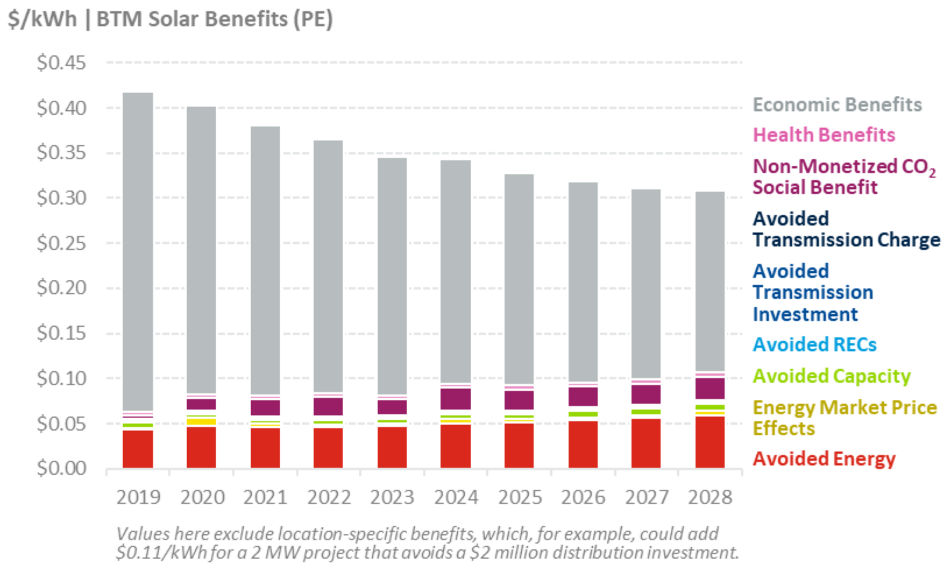

Figure 70: Benefits of BTM Solar in PE Service Territory: Reference Scenario

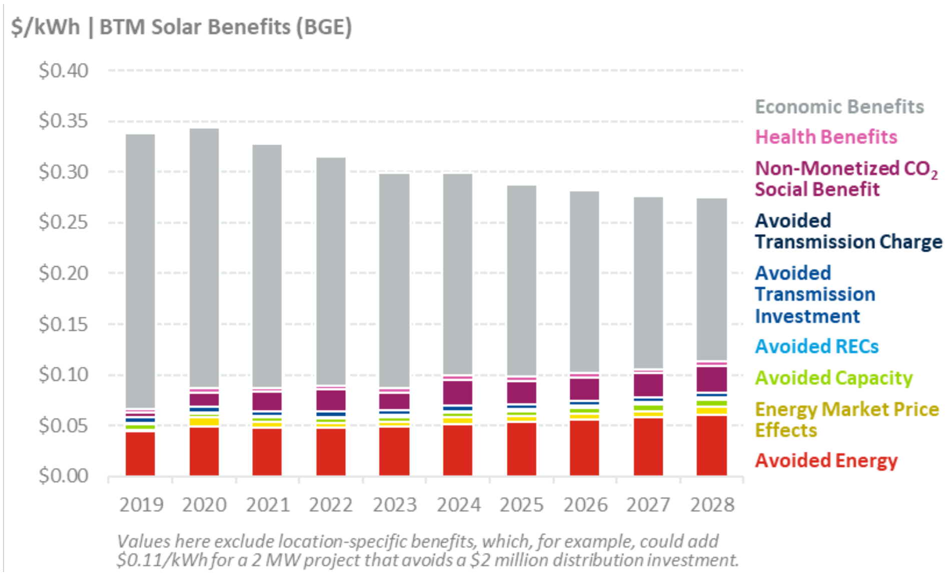

Figure 71: Benefits of BTM Solar in BGE Service Territory: Reference Scenario

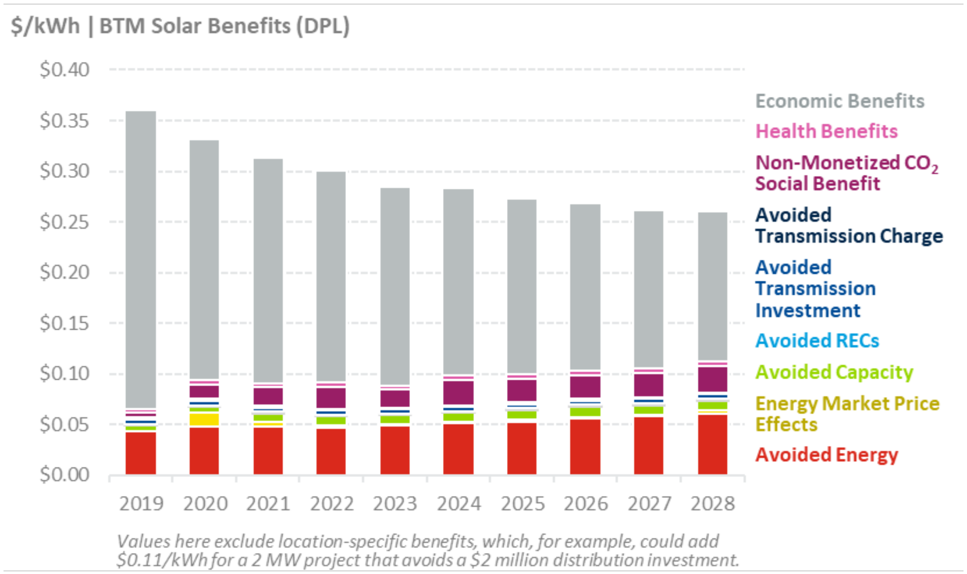

Figure 72: Benefits of BTM Solar in DPL Service Territory: Reference Scenario

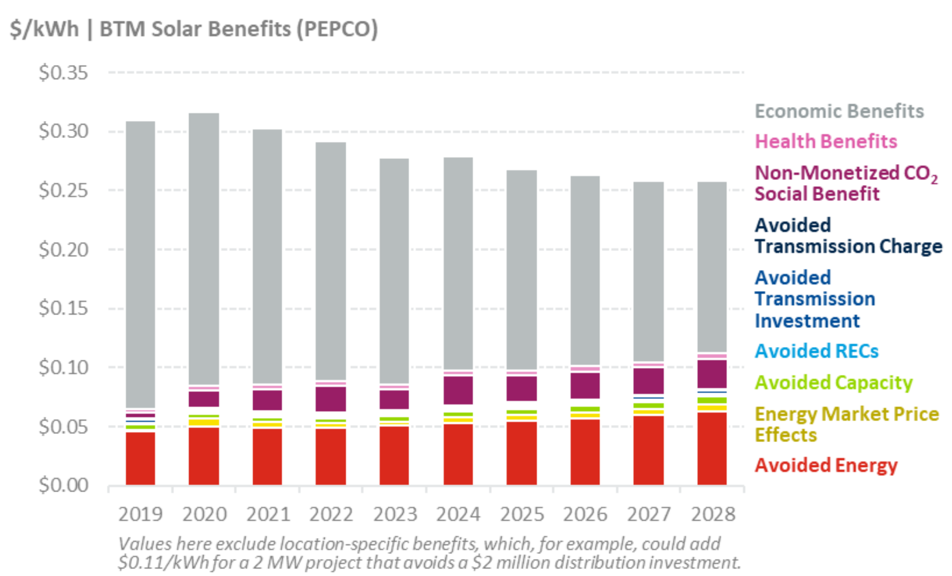

Figure 73: Benefits of BTM Solar in PEPCO Service Territory: Reference Scenario

7.1.2 BTM Benefits High CO_2 Scenario

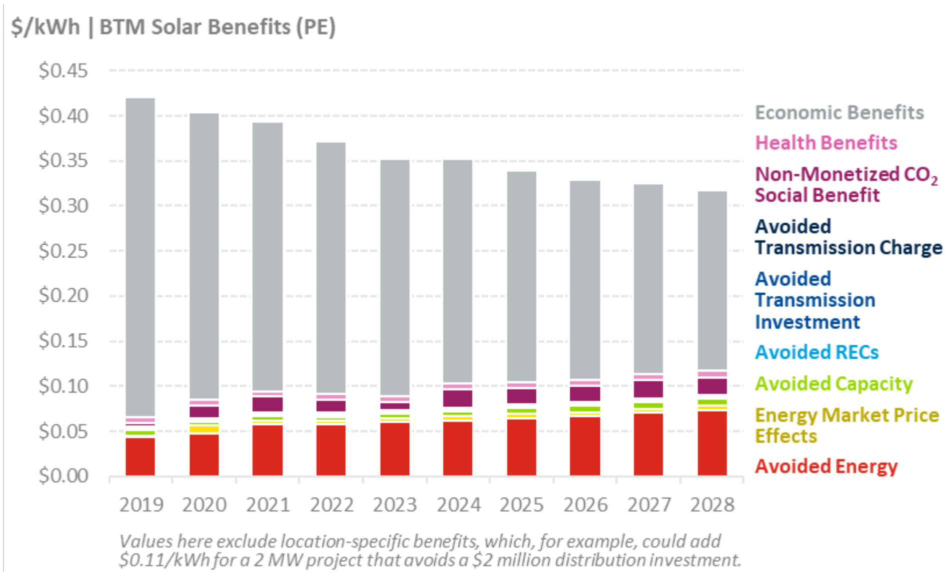

Figure 74: Benefits of BTM Solar in PE Service Territory: High CO_2 Scenario

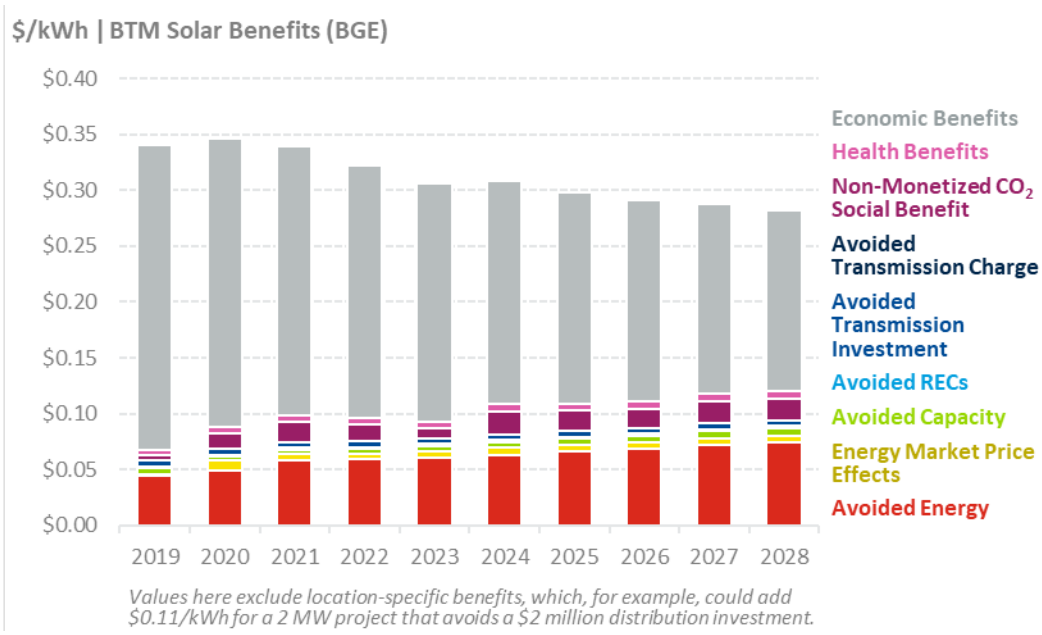

Figure 75: Benefits of BTM Solar in BGE Service Territory: High CO_2 Scenario

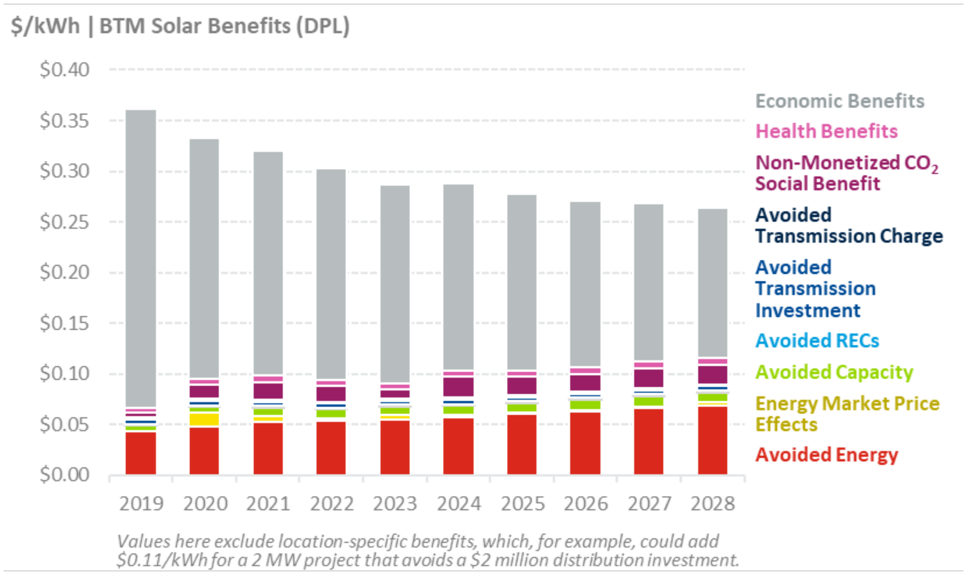

Figure 76: Benefits of BTM Solar in DPL Service Territory: High CO_2 Scenario

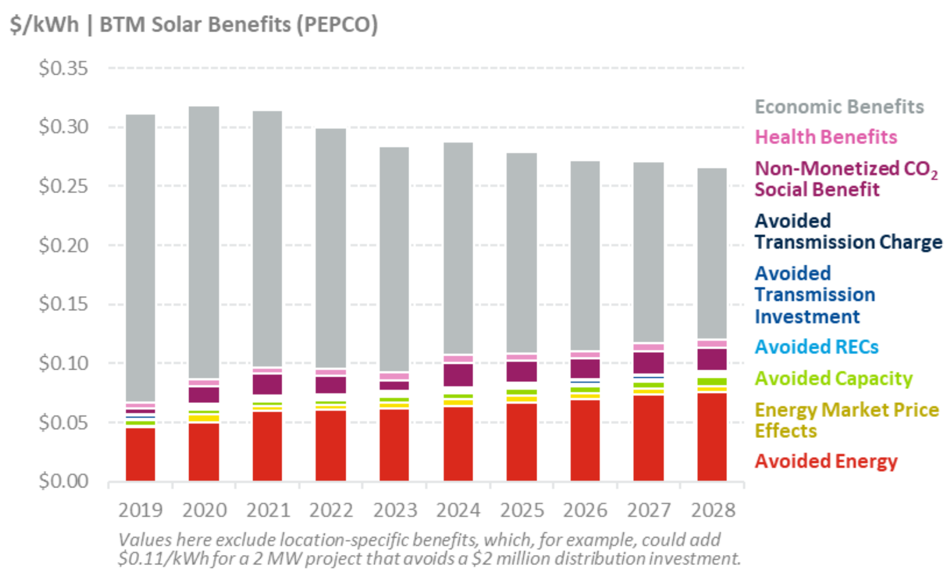

Figure 77: Benefits of BTM Solar in PEPCO Service Territory: High CO_2 Scenario

7.1.3 BTM Benefits Low Gas Scenario

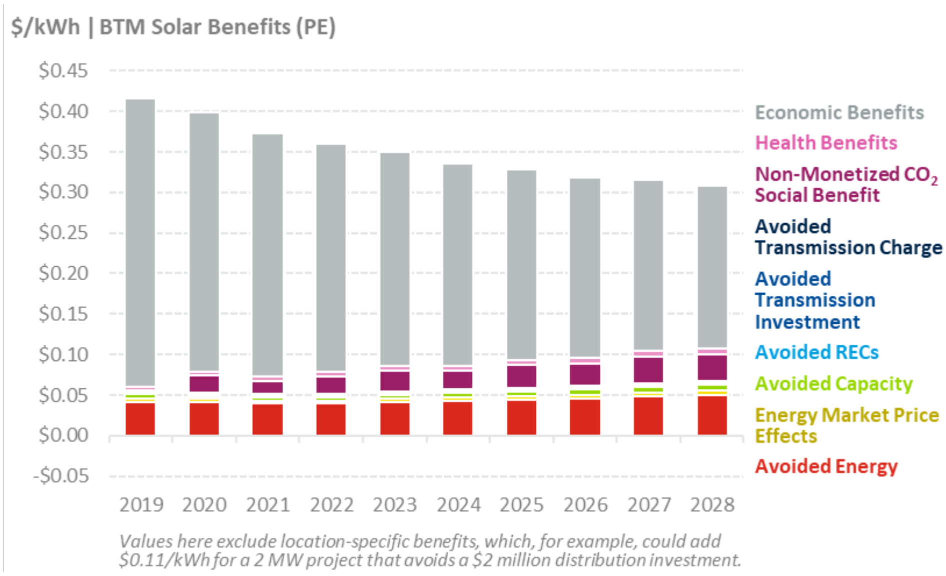

Figure 78: Benefits of BTM Solar in PE Service Territory: Low Gas Scenario

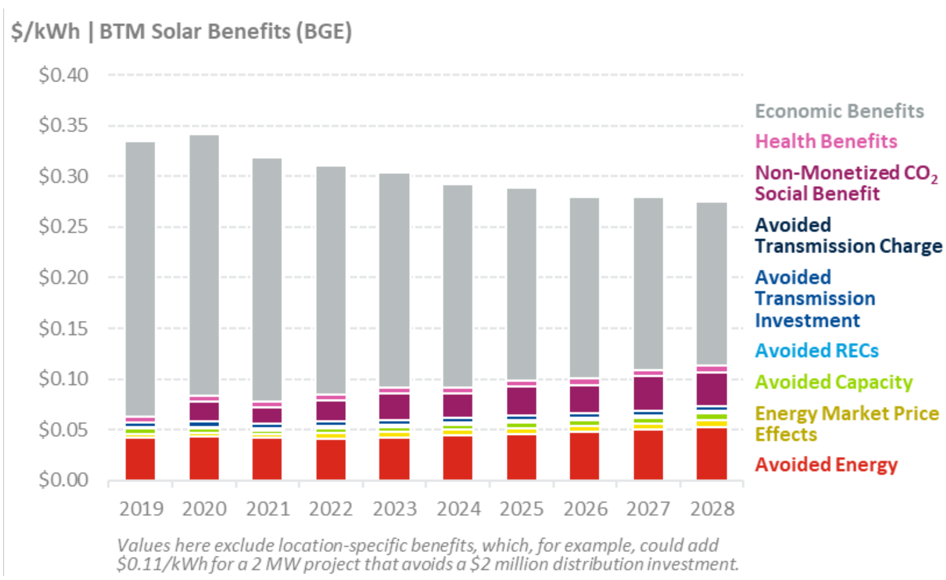

Figure 79: Benefits of BTM Solar in BGE Service Territory: Low Gas Scenario

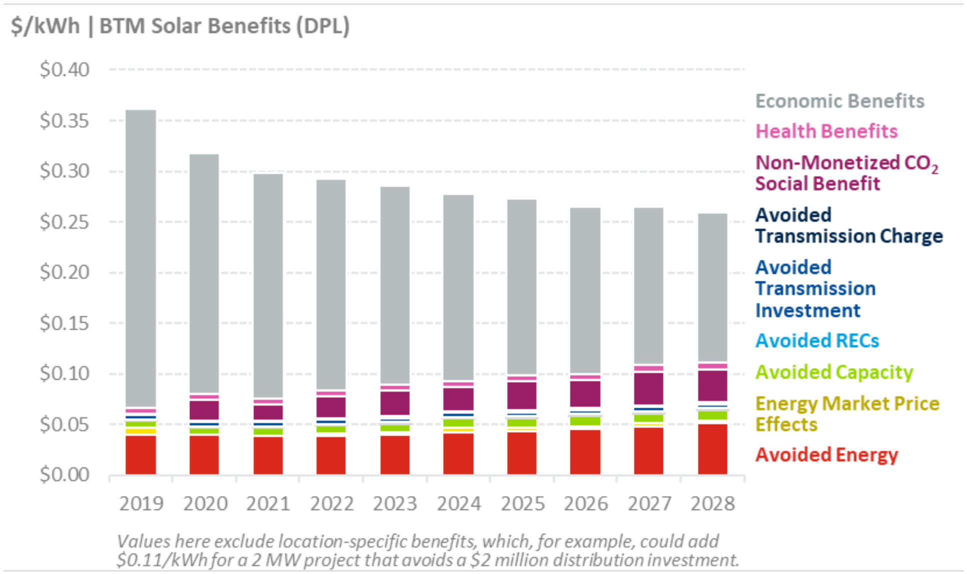

Figure 80: Benefits of BTM Solar in DPL Service Territory: Low Gas Scenario

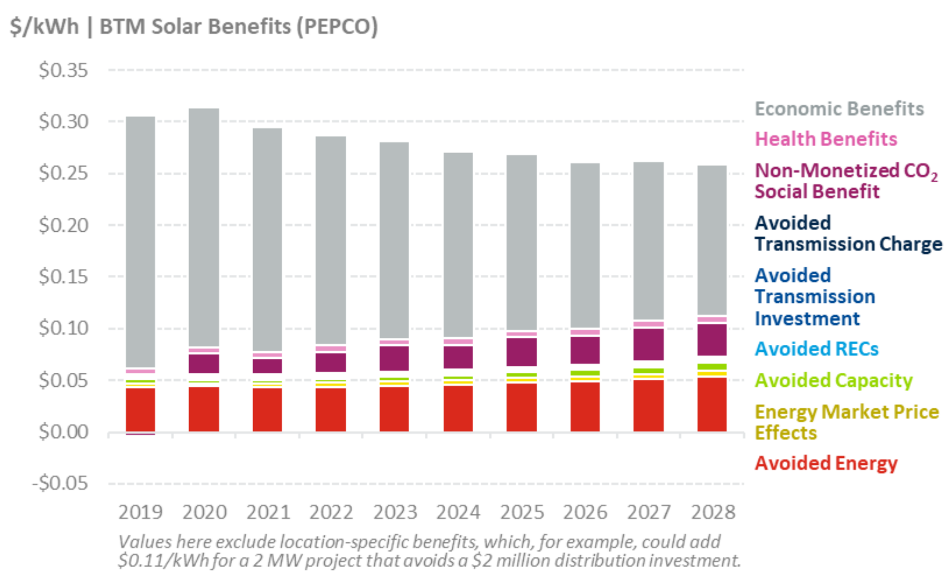

Figure 81: Benefits of BTM Solar in PEPCO Service Territory: Low Gas Scenario

7.2 Utility Scale Benefits

7.2.1 Utility Scale Benefits Reference Scenario

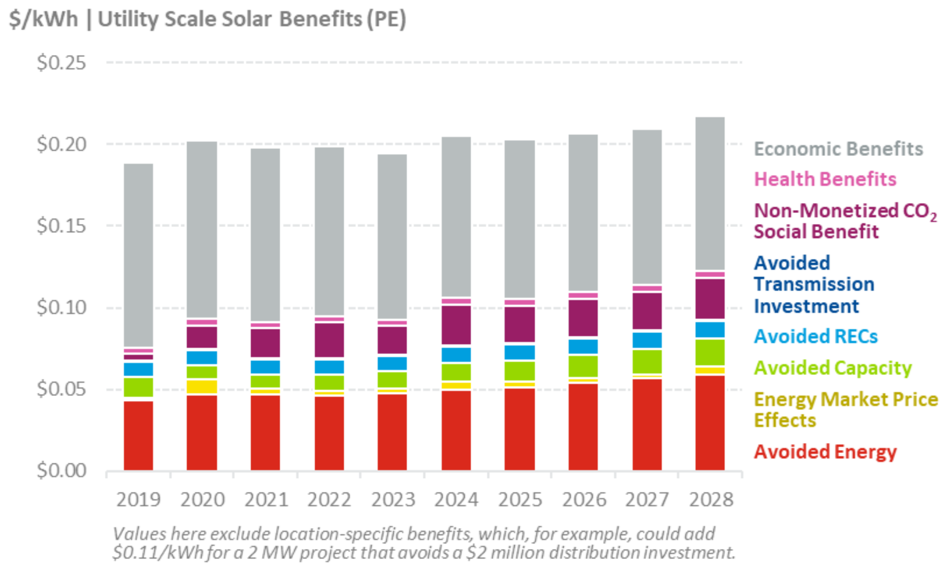

Figure 82: Benefits of Utility Scale Solar in PE Service Territory: Reference Scenario

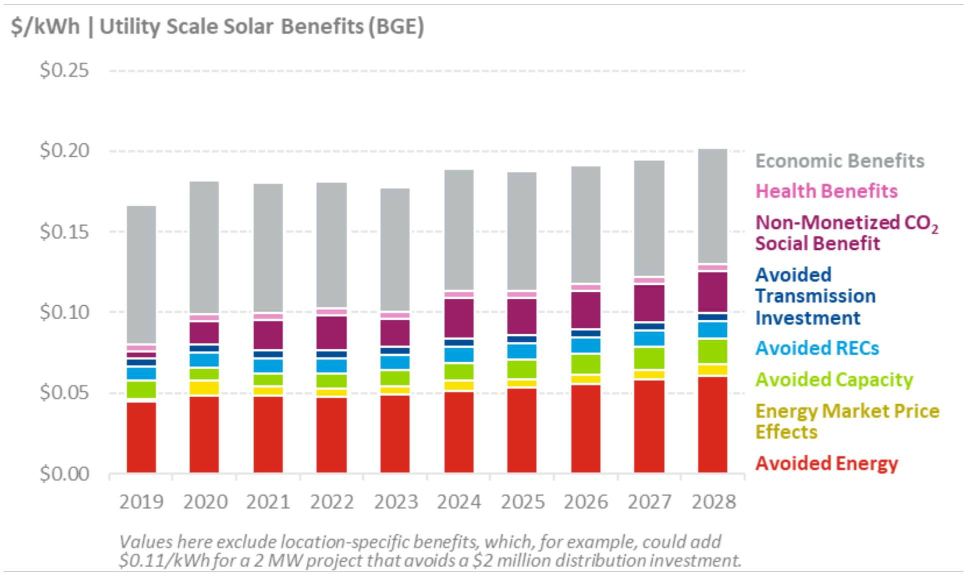

Figure 83: Benefits of Utility Scale Solar in BGE Service Territory: Reference Scenario

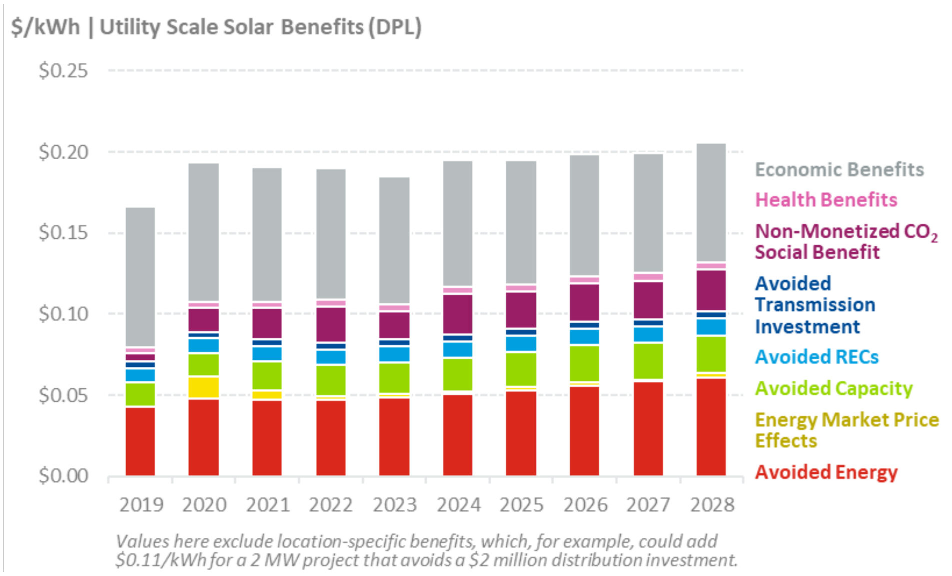

Figure 84: Benefits of Utility Scale Solar in DPL Service Territory: Reference Scenario

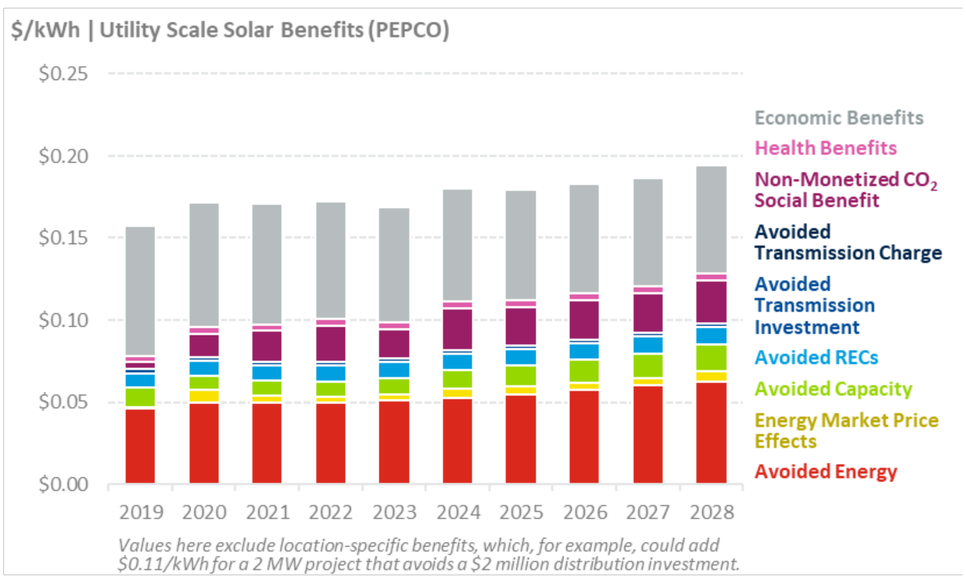

Figure 85: Benefits of Utility Scale Solar in PEPCO Service Territory: Reference Scenario

7.2.2 Utility Scale Benefits High CO_2 Scenario

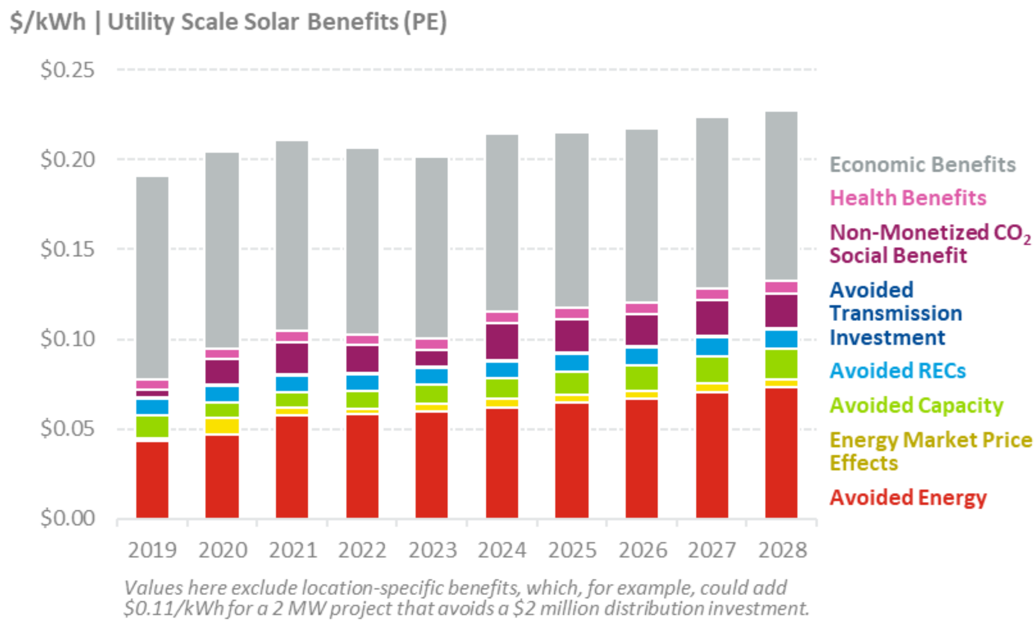

Figure 86: Benefits of Utility Scale Solar in PE Service Territory: High CO_2 Scenario

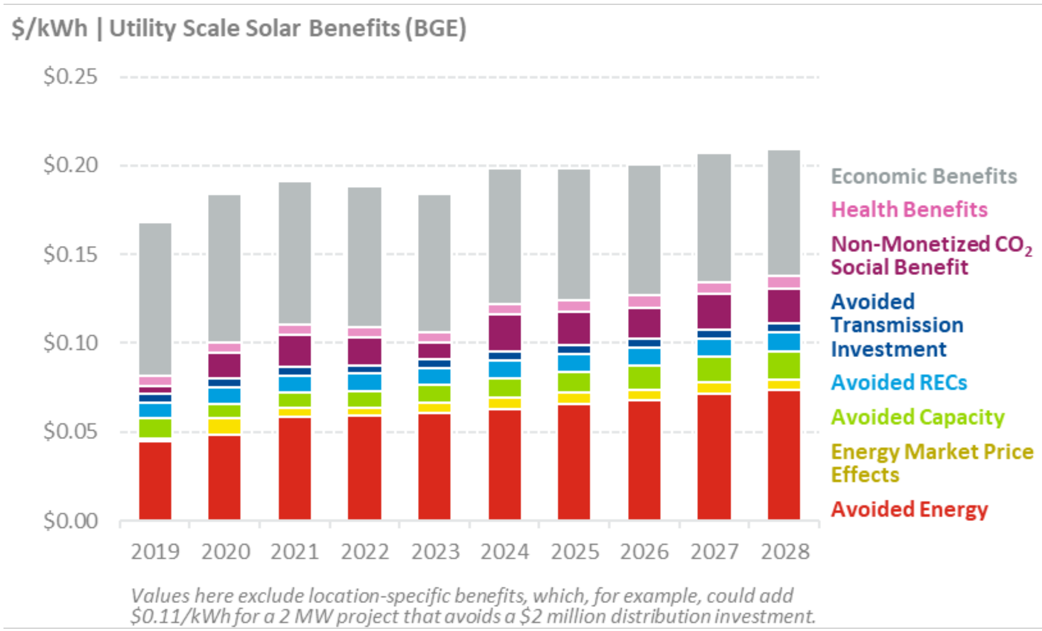

Figure 87: Benefits of Utility Scale Solar in BGE Service Territory: High CO_2 Scenario

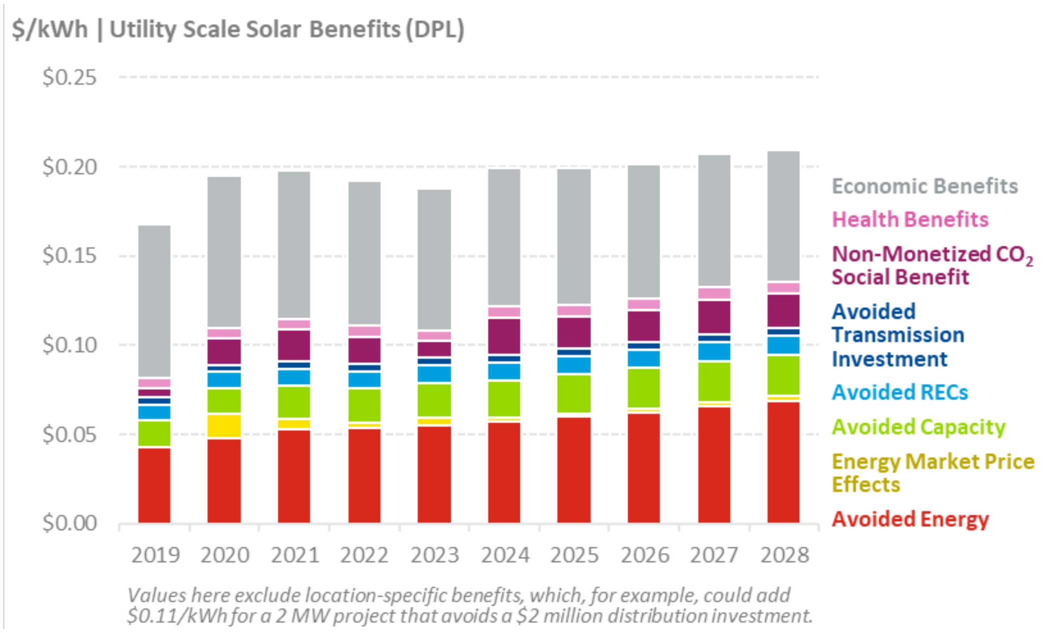

Figure 88: Benefits of Utility Scale Solar in DPL Service Territory: High CO_2 Scenario

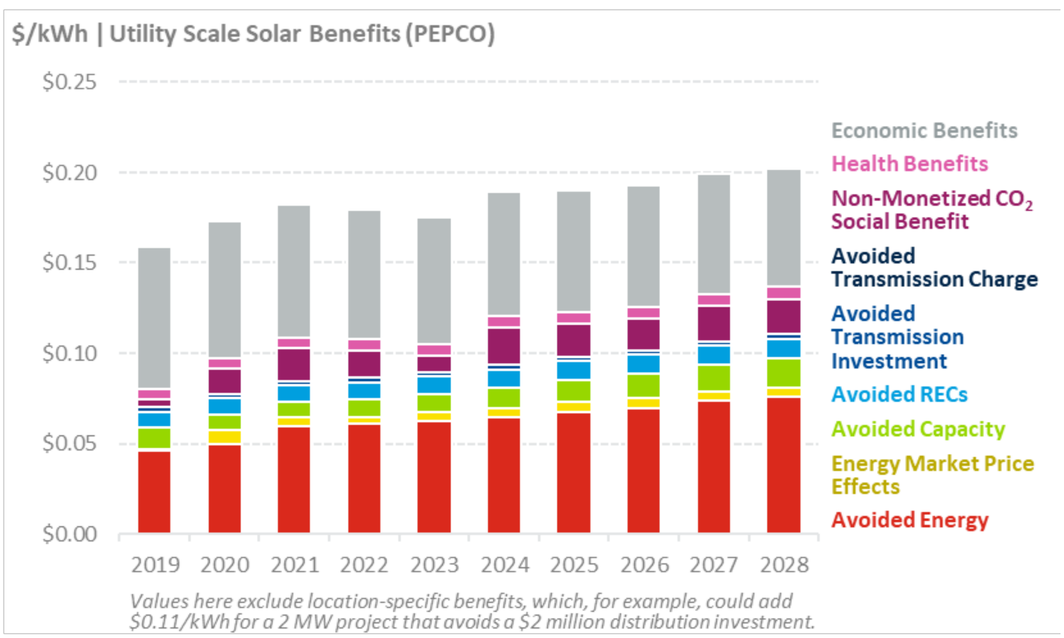

Figure 89: Benefits of Utility Scale Solar in PEPCO Service Territory: High CO_2 Scenario

7.2.3 Utility Scale Benefits Low Gas Scenario

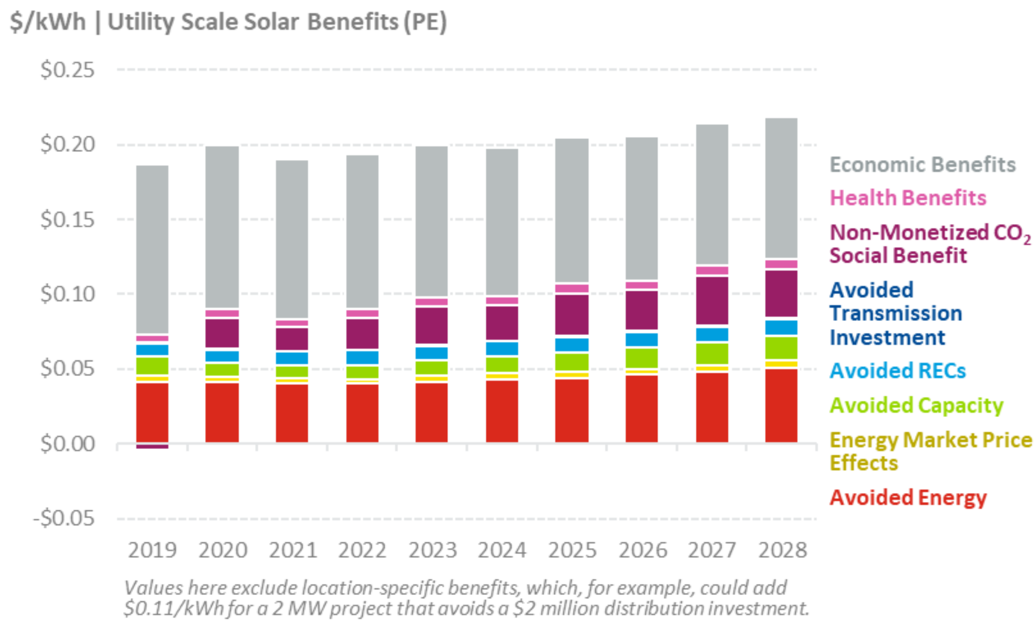

Figure 90: Benefits of Utility Scale Solar in PE Service Territory: Low Gas Scenario

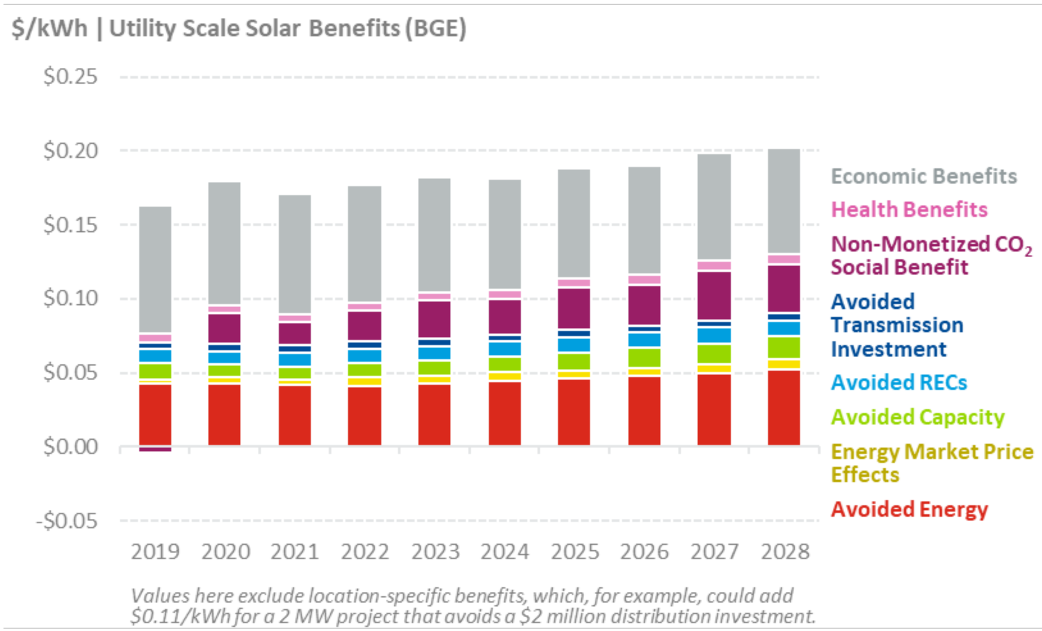

Figure 91: Benefits of Utility Scale Solar in BGE Service Territory: Low Gas Scenario

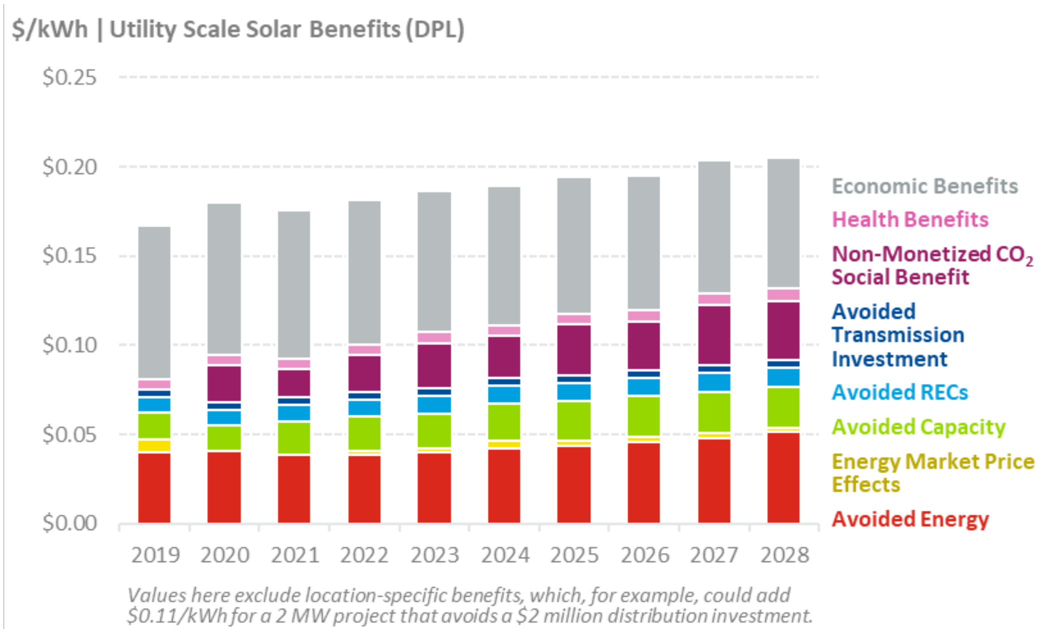

Figure 92: Benefits of Utility Scale Solar in DPL Service Territory: Low Gas Scenario

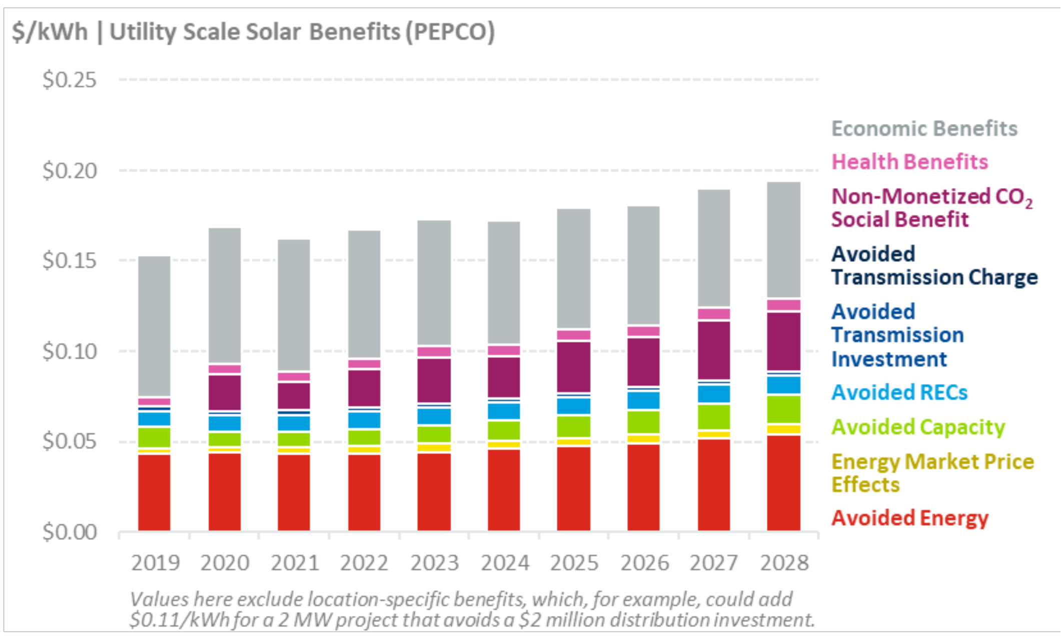

Figure 93: Benefits of Utility Scale Solar in PEPCO Service Territory: Low Gas Scenario