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An Exelon Company

September 23, 2016

VIA FEDERAL EXPRESS and
ELECTRONIC MAIL
irene.asbury@bpu.nj.gov
board.secretary@bpu.nj.gov

Irene Kim Asbury, Esquire
Secretary of the Board
Board of Public Utilities
44 South Clinton Avenue, 3rd Floor, Suite 314
P.O. Box 350
Trenton, New Jersey 08625-0350

RE: Analysis of Long-Term Effects/Benefits of the Addition of Behind-the-Meter Distributed Generation Attached to Service Territory
In the Matter of the Merger of Exelon Corporation and Pepco Holdings, Inc.
BPU Docket No. EM14060581

Dear Secretary Asbury:

The undersigned is Assistant General Counsel to Atlantic City Electric Company ("ACE") in connection with the above docketed matter.

By letter dated March 24, 2016, Exelon Corporation ("Exelon") and Pepco Holdings, Inc. (now known as Pepco Holdings LLC) ("Pepco Holdings"), as Joint Petitioners, provided notice to the Board of Public Utilities (the "Board") that the merger transaction had been completed.

Enclosed for the Board's review and information is a report by Pepco Holdings, which addresses, among other issues, the long-term effects and benefits of the addition of behind-the-meter distributed generation attached to Pepco Holdings' distribution system within certain of its service territories (the "Report"), including any impacts on reliability and efficiency. The Report is provided pursuant to a Section I. 1. of a written agreement by and among Exelon, PHI, and The Alliance for Solar Choice (the "TASC Agreement), dated November 16, 2015. The TASC Agreement included provisions that Exelon and Pepco Holdings agreed to implement within Pepco Holdings' service territories. The Report contains information and analysis consistent with the commitments outlined in the TASC Agreement.

Three conformed copies of this communication and the Report are attached.[1]

Thank you for your cooperation and courtesies. Feel free to contact me with any questions.

Respectfully submitted,

/jpr
Philip J. Passanante
An Attorney at Law of the
State of New Jersey

Enclosures

cc: Paul Flanagan, Esquire, BPU (electronic mail and overnight courier)
Cynthia Covie, Esquire, BPU (electronic mail and overnight courier)
Jerome May, BPU (electronic mail and overnight courier)
Bethany Rocque-Romaine, Esquire, BPU (electronic mail and overnight courier)
Marisa Slaten, Esquire, BPU (electronic mail and overnight courier)
Stefanie A. Brand, Esquire, Division of Rate Counsel (electronic mail and First Class Mail)
Brian Lipman, Esquire, Division of Rate Counsel (electronic mail and First Class Mail)
Ami Morita, Esquire, Division of Rate Counsel (electronic mail and First Class Mail)
David R. Wooley, Esquire, counsel for TASC (electronic mail)

[1] This filing has been made consistent with the Board's Order Waiving Provisions of N.J.A.C. 14:4-2, N.J.A.C. 14:17-4.2(a), N.J.A.C. 14:1-1.6(c), and N.J.A.C. 14:17-1.6(d), issued on July 29, 2016 in connection with *In the Matter of the Board's E-Filing Program*, BPU Docket No. AX16020100.

Distributed Energy Resources and the Distribution System Planning Process

PEPCO HOLDINGS LLC

September 23, 2016

Pepco Holdings®

An Exelon Company

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1 Background

Distributed Energy Resources ("DERs"), which include Energy Efficiency ("EE"), Demand Response ("DR"), Distributed Generation ("DG"), and Energy Storage are becoming increasingly important considerations for the planning and operation of the PHI[1] power delivery system. Of particular note is that requests for DG interconnections with the power delivery system have greatly increased in all jurisdictions in recent years. This is largely due to customer preferences, decreasing technology costs, and public policy objectives and incentives intended to incorporate greater amounts of renewable energy.

The growth of DERs is a trend not only being observed within the Company's service territories but also within the service territories of electric utilities across the United States. The increasing quantity of DERs creates new challenges for utilities in planning, designing, constructing, and operating the power delivery system while maintaining reliable, safe, and affordable electric service. In addition, customers prefer ever-increasing amounts of control over the way they produce and consume energy. Meeting these evolving customer needs is a challenge for the entire industry that will only be met through increasing levels of transparency and collaboration between utilities, regulators, customers, developers and other stakeholders.

[1] For this report, the terms "PHI" and "the Company" refer to Pepco Holdings LLC or its operating utilities as appropriate. PHI's utility companies are Potomac Electric Power Company (Pepco), Atlantic City Electric Company (Atlantic City Electric or ACE), and Delmarva Power & Light Company (Delmarva Power).

2 Procedural History

On April 30, 2014 Exelon Corporation ("Exelon") announced its intent to merge with Pepco Holdings, Inc., now Pepco Holdings LLC. On March 23, 2016 the merger of Exelon and PHI was completed on the terms and conditions that were agreed to by Exelon and PHI and approved by the relevant Federal and State regulatory bodies. Settlement agreements were also reached with external stakeholders such as the Delaware Sustainable Energy Utility ("DE SEU") and The Alliance for Solar Choice ("TASC"). As a result of the completion of the merger, these conditions are now in effect and compliance with the requirements is the responsibility of Exelon and PHI.

On June 21, 2016, PHI filed a report entitled "Interconnection of Distributed Energy Resources" in each regulatory jurisdiction in its service territory (the "June 21 Report"). This report discussed a subset of the merger commitments, those which pertain to the transparency, efficiency, and clarity of the PHI utilities' interconnection processes and treatment of DERs in general. In addition to providing information as to how PHI is meeting its merger commitments in this subject area, this initial report indicated that PHI would also:

1) Prepare a supplemental report and filing within 6-months of merger closing to provide additional information on the way in which it has incorporated the effects and benefits of actual and anticipated renewable generation penetration into its distribution planning processes:[2]

<table>
<tr><td>DC FC 1119
Order 18148</td><td>Commitment 119</td><td rowspan="2">PHI shall reflect in distribution system planning, actual and anticipated renewable generation penetration. Beginning not later than six months after closing of the merger, Distribution System Planning will include an analysis of the long term effects/benefits of the addition of behind-the-meter distributed generation attached to the distribution system within its service territory, including any impacts on reliability and efficiency. PHI will also work with PJM to evaluate any impacts that the growth in these resources may have on the stability of the distribution system in its service territory.</td></tr>
<tr><td>TASC Amended Settlement Agreement</td><td>Commitment I (1)</td></tr>
</table>

2) Initiate a detailed stakeholder engagement process to review PHI's June 21 Report, take into consideration all comments and recommendations made during this process, and make any additional changes to its plans, policies, or criteria pertaining to DERs as appropriate.[3]

3) Undertake appropriate further study of the issues regarding solar and storage through the aforementioned stakeholder engagement process.[4]

<table>
<tr><td>DE PSC DOCKET NO. 14-193
Amended Settlement Agreement</td><td>Commitment
101 (g)</td><td rowspan="3">In behind-the-meter applications where the battery never exports while in parallel with the grid and both the battery and the solar system share one inverter, no additional metering or monitoring equipment shall be required for a solar plus storage facility than would be required for a solar facility without storage technology. Additionally, the utilities, through a stakeholder/committee process, shall undertake appropriate further study of the issues regarding the</td></tr>
<tr><td>DC FC 1119
Order 18148</td><td>Commitment 124</td></tr>
<tr><td>MD 9361
Order 86990</td><td>Condition 16 (F)</td></tr>
</table>

[2] June 21 Report, p. 40, 52.
[3] June 21 Report, p. 7.
[4] June 21 Report, p. 52.

TASC Amended Settlement Agreement	Commitment I (6)	coupling of solar and storage. As a result of such studies, stakeholders/committee may recommend changes to this protocol to the regulatory bodies. The utilities, in consultation with Board or Commission Staff and interested stakeholders, shall determine an appropriate target completion date for this review within one (1) year after merger closing.
DE PSC DOCKET NO. 14-193 Amended Settlement Agreement	Commitment 101 (f)	With respect to the interconnection process and metering and monitoring requirements, in behind-the-meter applications where the battery and the solar - system share one inverter, the maximum bandwidth of charge to discharge will be used as the capacity for determining the requirement of a Level 1 - Level 4 interconnection study. Where the system will be used for frequency regulation, there may be cases where it will result in a higher-level interconnection study based on the aggregate capacity-following frequency-regulation signals on the respective feeder and/or power transformer. Delmarva Power and the SEU, in conjunction with other stakeholders identified by Delmarva Power and the SEU, through a committee process, may elect to further study the issues regarding the coupling of solar and storage. As a result of such studies, the committee may recommend changes to this protocol to the Commission.

This report has been prepared to demonstrate how PHI has satisfied the first commitment listed above, and to provide an update on the second and third commitments listed above. A more detailed description of the stakeholder process is provided in Section 7.

It is important to note that the aforementioned commitments were not all required by each of the regulatory bodies governing PHI's utilities. However, since the policies and procedures that are discussed in this report apply to all three utilities (Potomac Electric Power Company, Delmarva Power & Light Company and Atlantic City Electric Company) and all four jurisdictions (Delaware, Maryland, New Jersey and the District of Columbia), one report is being prepared.

3 Scope of this Report

This report discusses the manner in which PHI takes into consideration existing and anticipated future distributed energy resources when developing its plans for the modification of and investment in the electric distribution system (consistent with the regulatory obligations to provide safe, reliable electric service to customers). It is important to note that the scope of this report is broader than PHI's merger commitments (i.e., the examination of behind-the-meter distributed generation required by the merger commitments versus the more encompassing definition of DERs discussed in this report). However, in order to improve its practices and shift towards an integrated planning process, PHI is evaluating and determining how to assess and incorporate the benefits of all DERs, inclusive of distributed generation, energy storage, energy efficiency and demand response. This report also discusses the actions that PHI has completed relative to the detailed stakeholder engagement process proposed in its June 21 Report, and provides a status update on the further study of the issues regarding coupled solar and storage.

4 Overview of Distributed Energy Resources in PHI's Service Territories

There are a variety of DERs in operation in PHI's service territories, including distributed generation, energy efficiency programs, demand response programs, and to a limited extent energy storage devices. Collectively, these resources provide customers with the opportunity to reduce energy consumption (kilowatt-hours), reduce their maximum demand (kilowatts), and save money. In addition, some of these resources contribute to an overall reduction in the peak loadings on distribution system feeders, substation transformers, and substations ("distribution system components"). Such peak loading reductions can reduce the level of investment required in the distribution system.[5] An overall summary of the DERs in PHI's service territories is presented as Figure 1.

[5] The degree to which each of these resources provides such a benefit will be discussed in this report in Sections 5 and 6.

Figure 1: Summary of DERs in PHI's Service Territories (Demand Response, Energy Efficiency, and Distributed Generation)

Resource	Description	Pepco DC	Pepco MD	DPL MD	DPL DE	ACE
Distributed Generation Resources[6]						
Photovoltaic (PV) Distributed Generation	Solar, inverter-based generation sources which includes systems qualifying under net energy metering "NEM" tariffs, community renewable energy facilities, and generators selling into the PJM market that are interconnected with the distribution system. Such resources in aggregate provide a generally predictable power output during daylight hours.	✓	✓	✓	✓	✓
Other Distributed Generation	Renewable and non-renewable generators that have been deployed by customers for various purposes, including to reduce energy consumption, to reduce maximum demand, or to provide back-up power (e.g., Combined Heat and Power (CHP), Fuel Cells).	✓	✓	✓	✓	✓
Energy Efficiency Resources[7]						
Conservation Voltage Reduction (CVR)[8]	Distribution feeder technologies and equipment used to dynamically lower voltages on distribution feeders to create a reduction in customer energy consumption.		✓	✓		
Energy Management Tools (EMTs)	EMTs allow customers to better understand their energy consumption patterns and provides opportunities to save energy and decrease monthly costs.	✓	✓	✓	✓	
Residential Energy Efficiency & Conservation (EE&C)	Residential EE&C includes a suite of programs including lighting, appliances, home check-up, ENERGY STAR, new construction, HVAC, and low income programs.	✓	✓	✓	✓	✓
Commercial & Industrial Energy Efficiency & Conservation (EE&C)	Commercial and industrial programs include: multi-family, multi-dwelling, small business, existing buildings, new construction, retrocommissioning[9] and combined heat and power (CHP).	✓	✓	✓	✓	✓
Demand Response Programs						
Energy Wise Rewards (EWR)	Direct load control program which allows PHI to cycle customer-level A/C or heat pumps under three cycling options during "peak saving days" to decrease the demand for electricity. The program is dispatched when the wholesale market experiences high prices.	✓	✓	✓	✓	✓
Peak Energy Savings Credit (PESC)[10]	PESC is a form of dynamic pricing where consumers can save money via a rebate for reducing consumption on peak demand days when the wholesale market experiences high prices. PESC requires AMI in order to be implemented.		✓	✓	✓	

[6] PHI broadly defines distributed generation to include the following six categories of resources: 1) Back-up generators, 2) NEM facilities, 3) Community Renewable Energy Facilities, 4) Qualifying Facilities, 5) Generators selling into the PJM wholesale market interconnected with the distribution system 6) Behind-the-meter generators that partially offset the customer's load but are precluded from exporting electricity to the grid.

[7] EE&C programs can be administered by the utility or state approved organization.

[8] Conservation Voltage Reduction programs have been deployed in Pepco Maryland and Delmarva Power Maryland. Moreover, CVR programs are under development in the District of Columbia, and it is anticipated that they will be first deployed in a limited roll-out similar to the program that was deployed in Maryland. Due to the lack of AMI in New Jersey to monitor customer voltages, there are currently no plans to implement Conservation Voltage Reduction in New Jersey. It is important to note that some customers in DC connected to cross-jurisdictional MD feeders have benefitted from CVR.

[9] Retrocommissiong is the application of the commissioning process to existing buildings.

[10] PESC was piloted in DC. To date, the District of Columbia Public Service Commission has not approved the implementation of dynamic pricing.

PJM Demand Response	Programs administered primarily by Energy Service Curtailment providers which have an impact at the system/load zone level and are not directly controlled or dispatched by PHI.	✓	✓	✓	✓	✓

5 Technical Background

5.1 Overview of PHI's Peak Load Planning Process

PHI conducts an ongoing planning process to verify and ensure that each component of the distribution system will meet the capacity needs of customers moving forward. In doing so, PHI seeks to ensure that each distribution system component is adequately sized to reliably serve its maximum electrical power demand under different operating conditions,[11] and at the point in time of maximum annual demand from customers. Commonly referred to as "peak load," this maximum demand[12] is a single value (MVA) that varies in both magnitude and timing for each feeder, substation transformer, and substation on the system.[13]

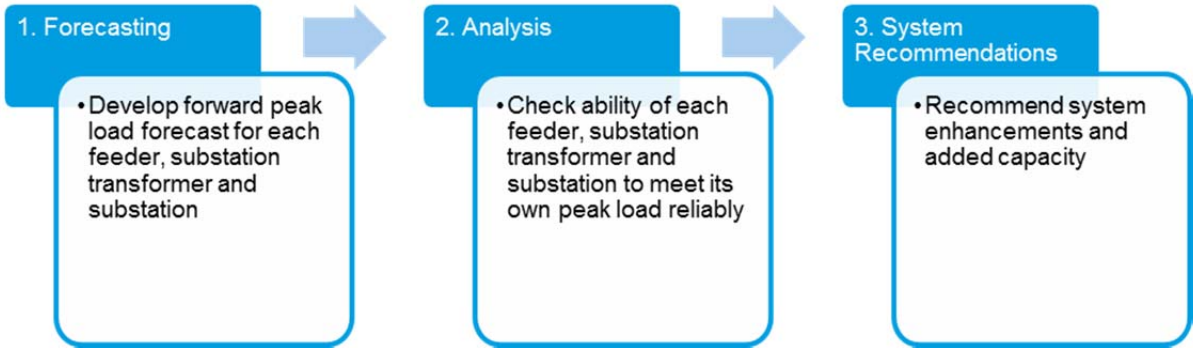
The overall peak load planning process includes the following steps:

1) **Peak Load Forecasting** – A forward-looking 10-year peak load forecast is developed and maintained for each distribution system component in order to plan for longer duration projects. In addition, a short-term forecast is developed in order to address the more frequent changes from new building construction and customer load growth that occurs across the distribution system. The peak load forecasting process also takes into account any reductions in load which may result from DERs.
2) **Analysis** – Each distribution system component is assessed via an engineering process[14] to ensure that it can reliably meet future loading, as projected in the load forecast.
3) **System Recommendations** – When and where PHI identifies the need to relieve load on a distribution system component, system recommendations are developed. These recommendations may consist of operational measures, cost-effective load transfers from one component on the system to another with sufficient capacity to receive that transfer, or more significant system upgrades or construction projects.

[11] Distribution system components must be designed to not only operate under normal day-to-day system configurations, but also to operate with increased loading during contingency or emergency situations, which can arise as a result of outages and equipment failures.
[12] Demand values are measured and recorded by PHI's supervisory control and data acquisition (SCADA) system, and these observed values serve as the foundation for the load forecasting process. The demand data obtained at the substation level are further enhanced by integrating AMI customer data (where deployed) with the SCADA data in order to develop load profiles for each feeder that previously could not be developed with only substation level data.
[13] It is important to note that these individual peak loads are generally in close temporal proximity to each other, whether hours or days apart, or within the same season (i.e., summer or winter). Also, the peak value is identified as the maximum load level that each component experiences within each hour that is being monitored.
[14] The electric distribution system is large, and the analytical processes referenced herein are extensive. For instance, it takes 2-years for PHI to analyze the entirety of the distribution system, which upon completion begins again with new data for the latest seasonal peak loads actually experienced (versus forecasted). Each year a high-level review of major components is performed to identify any significant deviations from the last detailed review.

This peak load planning process is depicted in the following chart:

Figure 2: General Planning Process for Distribution Feeders, Substation Transformers, and Substations



Peak Load Forecasting Process

As described in Figure 2, the development of the peak load forecast is the first step in PHI's distribution system planning process. The development of the forecast is a critical step, because it has an impact on the outcomes of each subsequent step in the process, and ultimately, the timing and magnitude of the investments in the distribution system made by PHI.[15] This section provides additional details on the analytical processes PHI employs to develop its peak load forecast and the way in which DERs are incorporated into these processes.

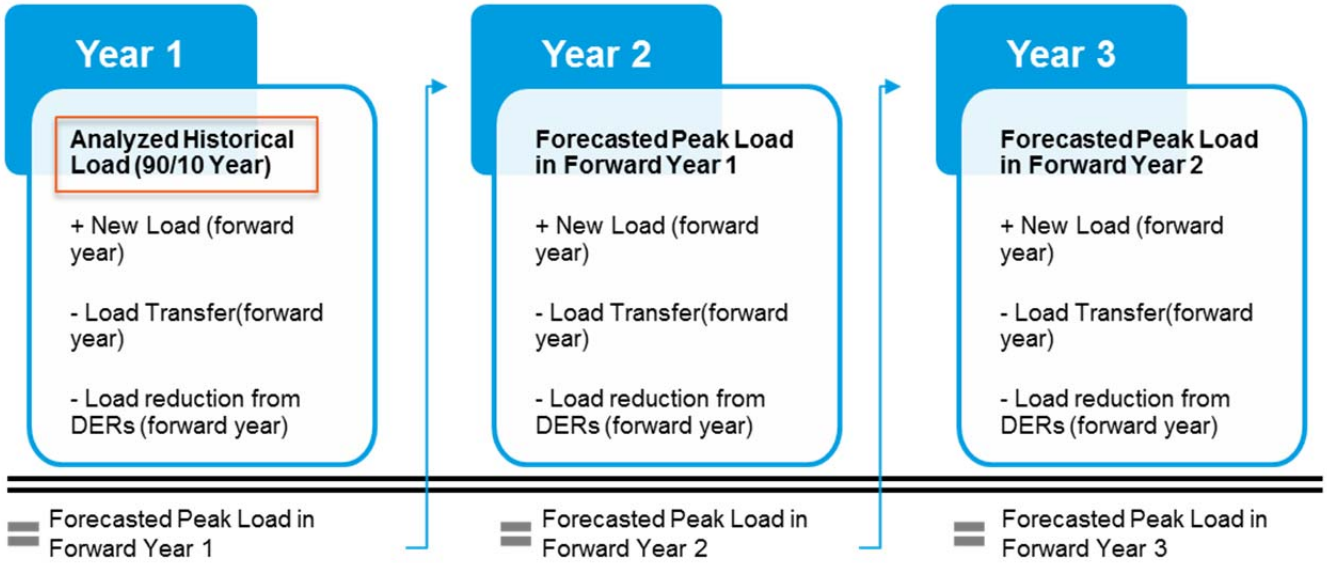
It is important to note that PHI must create more than just one peak load forecast. In fact, it creates many – one for each distribution feeder, individual substation transformer, and substation on its system. The creation of peak load forecasts for each distribution system component is needed to ensure that both individual system components are sized appropriately, and that the system as a whole will perform as it should.

Short-Range and Long-Range Peak Load Forecasts

The peak load forecast is comprised of a short-range forecast for future years 1-3 and a long-range forecast for future years 4-10. This short-term forecast also serves as the basis for the development of the longer term 10-year plan. The former is a detailed, "bottom-up" analysis of historical peak load data, projected new load growth and energy reduction initiatives. The latter is a higher-level and "top-down" trending effort based on the PJM (the regional transmission operator or "RTO" responsible for maintaining the stability of the transmission system) system peak load forecast. The short-range forecast is generally formulated in accordance with the calculation detailed in Figure 3.[16]

[15] Consistent with PHI's regulatory obligations to provide safe, reliable electric service to its customers.
[16] Specific circumstances may merit variations in this calculation process.

Figure 3: General Process for Creating Distribution Feeder, Substation Transformer, and Substation Short-Range Forecasts



For the purposes of this report, terms are defined as follows:

- **Analyzed Historical Peak Load** – This value serves as the base value from which future projections are calculated. This value is most often derived for each distribution system component by taking its actual historical peak load[17] in the hottest year within the last ten years,[18] and adding to it the incremental load changes (i.e., new loads, load transfers and load reductions from DERs) that have occurred between that hottest year and the year prior to the current year.[19]
- **New Load** – This represents additional new load that is anticipated to come online as a result of new building or development activities. At times and in some areas of PHI's service territories, this value may be negative such as when an existing customer facility closes. New loads are added at the anticipated level of load that PHI expects a building of the same size and energy use would add to the distribution system.
- **Load Transfers** – These are projects that PHI conducts to utilize available capacity in one portion of its distribution system to help meet a projected capacity shortfall in another part of

[17] As recorded within the SCADA and AMI systems.

[18] PHI plans to the hottest year in the last 10-years to develop its peak loads for each distribution system component in the short-term load forecast. PHI uses the 90/10 forecast produced by PJM as the basis of its long-range growth forecast in order to ensure that each utility has adequate system capacity to meet area load needs during seasons with extremely hot weather. The 90/10 forecast is produced by PJM to depict peak loading that has a 10 percent probability of occurring in any given year. For capturing peak historical loadings, PHI's methodology uses actual load readings for each component during years of extreme (one in ten year) weather. For years when less than extreme weather occurs, PHI uses the load of the latest extreme summer, making adjustments to the load to account for prospective new businesses (PNBs), load transfers, DERs and other factors. By employing this historical loading methodology, PHI can seamlessly transition from the historical loads used to develop its short-term plan to the long-term forecast using the PJM 90/10 loads as the basis for the trend in growth. This process also assures that no peak load used for future planning is more than 10 years old.

[19] On occasion, this method will result in a value that is less than the peak load encountered in the year prior to the current. This may occur because actual load growth on a feeder is greater than what PHI would arrive at through its calculation (i.e., the addition of new load only from new build). In such cases, PHI will use the actual peak load (i.e., via SCADA and AMI readings) from prior years as the Analyzed Historical Peak Load, to ensure that it is planning the distribution system to meet its maximum load requirement.

the system. Such projects may include rerouting feeders from one substation or another or transferring a portion of one feeder to another feeder. These types of projects occur seasonally on the distribution system and are a way of managing load without undertaking more expensive upgrades or construction. Such projects are planned ahead of time and have an impact on the forecast in future years, and are thus accounted for in the process. It is important to note that these are permanent redistributions of load that must not cause a total projected load to exceed the normal rating of the component, as opposed to the contingency load transfers which occur during outages to help sectionalize and restore customers' service and can result in a component operating up to its emergency rating.

- **Load Reductions from DERs** – Distributed energy resources may, depending on their operation, reduce peak load. Whether or not these resources reduce peak load depends on the coincidence of the resource with the time of peak load on a particular distribution system component. The degree to which a DER contributes to a reduction in peak load depends on its output (which may be variable) and its contribution to total load at the time of peak load.

Long-Range Forecast

Upon completion of the short-range forecast, PHI then completes the long-range forecast for years 4-10. PHI's process for completing the long-range forecast generally occurs via the following steps:

1) PHI first conducts a trending of the short-range forecast beyond its duration (within years 1-3) and into the window of the long-range forecast (years 4-10).
2) PHI then adjusts this trending of peak load for each feeder, substation transformer, and substation for larger-scale system changes and factors that are known to be planned within the long-range forecast window. These changes may include considerations such as major long-term redevelopment initiatives within a geographical area.
3) Finally, PHI adjusts the projected year-by-year long-range peak load growth on each distribution system component such that the growth rate of the system-level peak load of PHI's long-range forecast is reconciled with the rate of growth within the corresponding PJM long-range load forecast.[20] The following paragraphs provide further elaboration on this point.

PHI reconciles the growth rate of its long-range forecast with PJM's 90/10 long-range forecast to ensure consistency across the planning process of the entirety of the power delivery system, inclusive of the distribution system under PHI's purview and the transmission and generation systems under PJM's purview.

PHI must plan for the reliable operation of each feeder, substation transformer, and substation at its individual peak load (MVA). These individual equipment peak loads generally do not coincide with one another, and are thus generally referred to as being "non-coincident" peaks. Moreover, the sum of individual non-coincident equipment peaks generally exceeds the peak load demanded of the collective whole at any given time. In other words, PHI must plan for its "non-coincident" peaks for each component of the distribution system while PJM must plan for the coincident peak that the transmission system is required to serve.

An example of this is presented below, which compares the historical PJM system peak with various PHI operating company peaks, and the non-coincident peaks of a sample of substations – all of which have different hours at which peak loading occurs. Therefore, PHI's non-coincident peak forecast will

[20] In addition, PHI will work with PJM to evaluate any impacts that the growth of DERs may have on the stability of the distribution system in its service territories. PHI will evaluate the impacts of these resources in tandem with other ongoing PJM changes which are expected to affect the PJM markets.

consistently be higher than the PJM coincident peak forecast.

Figure 4: Comparison of PJM Coincident Peak, PHI Company Peaks and PHI Non-Coincident Substation Peaks

PJM Coincident Peak	PHI Coincident Company Peaks	Peak Hour	PHI Non-Coincident Substation Peaks (sample)	Peak Hour
17:00	**Pepco**	**15:00**	**Pepco DC**	
			Northeast #212	12:00
			Harvard #13	18:00
			O Street #2	13:00
			Alabama Ave. #136	16:00
			Pepco MD	
			Montgomery Village Sub. 56	18:00
			Sligo Sub. 9	12:00
			Riverdale Sub. 4	15:00
			Green Meadows Sub. 97	19:00
	DPL	**17:00**	**DPL DE**	
			Darley Rd 12 KV	17:00
			Faulk Rd	14:00
			Christiana	13:00
			Edgemoor	15:00
			DPL MD	
			Bozman	16:00
			Cambridge	15:00
			East New Market	16:00
			Kings Creek	14:00
	ACE	**18:00**	**ACE**	
			Sea Isle	17:00
			Tabernacle	15:00
			Dacosta	16:00
			Churchtown	7:00

Note: ACE and Pepco SCADA data is from 2011, Delmarva SCADA data is from 2012 (2011 data is not available).

Feeder, Substation Transformer, and Substation Analysis Process

Once the peak load forecast is completed, PHI analyzes the capabilities of each distribution system component to ensure that it can reliably meet its forecasted peak loads. Planners use the PNB and DER information gathered in the load forecasting process along with historical AMI customer load data, SCADA and electrical configuration information from PHI's geographic information system (GIS) to model each feeder in its power flow analysis software. From this analysis, predicted system violations such as low voltage and thermal overloads are identified and resolved through the system recommendations process.

System Recommendations Process

Upon completing its analysis process, PHI considers the specific predicted system violations to develop recommended actions, which may consist of:

1) **Operational measures** – Resetting relay limits, conducting phase balancing, or other measures
2) **Load transfers** – Conducting field switching to transfer load from a higher loaded feeder to a lower loaded feeder
3) **Short-range construction projects -** Feeder extensions, installation of capacitors or voltage regulators, reconductoring
4) **Long-range construction projects -** New feeder extensions, new substation transformers or entirely new substations

Once the recommended actions are identified, an area plan containing construction recommendations is issued.

5.2 Factors Guiding the Consideration of DERs in PHI's Peak Load Forecast

DERs are considered in the peak load forecast, and are therefore reflected in the entirety of the distribution planning process which follows. Whether or not a DER is counted as providing a peak load reduction depends on the availability of that resource during the peak load time for the component of the distribution system being assessed. The magnitude of impact of a DER to be counted toward reducing load depends on the level to which that resource can be relied upon to provide a load reduction at that specific point in time when the peak load will occur on the component being assessed.

Availability of a DER at the time of Peak Load

A DER may or may not be available or in operation at the time of distribution feeder, substation transformer, or substation peak load. This is an important factor that has an impact on how the resource is considered in the peak load forecast, and ultimately the entirety of the planning process. The examples below illustrate some of the potential scenarios to be contemplated when incorporating DERs in the planning process:

- A customer completes an energy efficiency upgrade consisting of the installation of a new energy efficient air conditioning unit in place of an old unit – this would result in a permanent load reduction, and thus this DER (the EE upgrade) would be fully available at the time of peak load on the distribution feeder, substation transformer, and substation from which this customer is provided service, and would thus be considered a resource that reduces peak load on these components.
- An industrial customer installs a large diesel generator, which is run on occasion to supplement the customer's energy usage at the time of the customer's maximum energy demand, which occurs seasonally in mid-spring, and not in the summer when the local distribution system experiences a peak load. Therefore, the diesel generator would not be a resource toward reducing peak load on the distribution feeder, transformer, and substation from which this customer is provided service.
- Several customers install small scale residential solar systems on their roofs. In a given area, these DERs would be considered available at the time of peak load on the distribution feeder, substation transformer, and substation from which these customers are provided service. The total percentage of nameplate capacity considered to be available can be determined using a backcasting[21] analysis which relates the hourly capacity factor[22] of the DERs, the hour of the peak load on the component, and the total nameplate capacity on the component.
- A commercial developer installs a utility-scale battery system on a distribution feeder that is discharged during peak load periods on the transmission system. Therefore, most likely this would not be a resource counted toward reducing peak load on the distribution feeder, substation transformer, and substation from which this customer is provided service, because distribution system peaks do not necessarily coincide with the peak load on the transmission system.

In order to be considered as a planning resource, a DER must be "firm." In other words, it must be available at the time of peak load. PHI system planning criteria dictate that a DER is considered firm and is thus a dependable resource for peak planning purposes, if it is available (or coincides) 95% of the time with the peak on whichever component of the distribution system is being evaluated (feeder, substation transformer, or substation).

[21] For additional details on the backcasting process, see Appendix 1.

[22] Capacity Factor is defined as the average power generated for a specified period of time divided by the rated nameplate power of the generating asset.

Planners, however, must also consider the consequences to the system when the DER is not available such as after restoration from a momentary or sustained power outage. For example, current industry standards and local electric codes mandate that all inverter-based systems (e.g., solar PV) automatically disconnect from the utility feeder upon loss of power.[23] When the feeder is reenergized, loading observed on that feeder is now the full load without the reduction from the solar generation until the inverters reconnect the customer PV back to the distribution system, which generally occurs after a minimum of five minutes. For planning purposes, the reduction from solar PV is added back into the loads of each distribution system component and those loads are compared to the emergency capacity ratings of the feeders and substation transformers and to the firm capacity rating of the substation. This ensures that PHI maintains adequate capacity during times when customer generation is unavailable, consistent with its regulatory obligation to provide safe, reliable electric service. Actions to be taken by the planners as a result of this analysis will depend on which component is overloaded and what actions that can be taken to mitigate the overload until the solar PV systems begin to generate and reduce customer net loads. For example if the only overload that exists is at the substation level, then restoration can be performed in stages to mitigate the risk of an overload and no further system enhancements would be needed.

Planners also consider the effects of distributed generation being offline during an outage event when automatic sectionalizing and restoration (ASR) schemes are operated through automated inline and tie switching devices. These ASR schemes are designed to automatically operate in order to isolate a fault during a feeder outage event and restore as many customers as possible. During the outage event, it is anticipated that all distributed generation on the affected feeder will have tripped off due to loss of utility power. Planners must analyze the potential transfers[24] to examine if the receiving feeder/substation transformer/substation can handle the extra load being transferred to it through automated switching. Planners design ASR schemes to maximize the amount of time during the year that there is adequate capacity to back-up an adjacent feeder.

Magnitude of Impact (kW) of a DER at the time of Peak Load

While some resources which meet the firm criteria are considered permanent load reductions (e.g., CVR, EMTs and other programmatic energy efficiency) additional analysis is required for other types of DERs to calculate the magnitude of the impact of the resource. This is particularly evident for variable generation sources such as solar PV. Over the course of a 24 hour period, hourly production of solar PV can range from 0% to 100% of nameplate capacity. Therefore, calculating the magnitude of the impacts requires considering several pieces of related information:

1) Actual or simulated production of the resource (in the case of DG without dedicated metering and telemetry, a backcasting process is used to simulate production based upon conditions in a representative area)
2) The amount of nameplate capacity of the DER interconnected to a distribution system component
3) The hour and magnitude (MVA) of the peak for the distribution system component being evaluated

[23] IEEE 1547.

[24] The total load to be transferred would be equal to the load that existed just prior to the outage plus the total available PV generation on the circuit. Once all load is transferred and customers are restored to service, the solar PV systems will be restored and load will be reduced to pre-outage levels.

Figure 5: Example of Calculating Magnitude of Impact for Solar PV on Select Distribution Feeders

Region	Feeder	Historical Peak (MVA)	Feeder Peak Hour	Nameplate PV Capacity (kW)[25]	PV Capacity Factor for Feeder Peak Hour[26]	PV Impact on Peak (kW)
Pepco MD	1	7.0	15:00	1089	42%	457
Pepco DC	2	8.3	19:00	278	2%	5.6
DPL MD	3	14.4	15:00	119	59%	70
DPL DE	4	24.4	18:00	1263	12%	152
ACE	5	10.4	16:00	2025	48%	972

[25] "Active" PV capacity as of August 1, 2016.
[26] Capacity factors derived from average hourly summer production for June 1, 2015 through August 31, 2015.

6 Consideration of Specific Distributed Energy Resources in PHI's Peak Load Planning Process

6.1 Demand Response Programs

There are four demand response programs which are operated in PHI's service territories. Two of these programs (Economic Demand Response and Load Management) are operated by PJM. Two additional demand response programs are operated by PHI and leverage the communications infrastructure and data provided by AMI[27] to provide customers with opportunities to save money by curtailing usage by either responding to price signals (the Peak Energy Saving Credit program or "PESC") or by allowing PHI to cycle HVAC equipment remotely during periods of high wholesale prices (Energy Wise Rewards or "EWR").[28] While PHI administers the latter two programs, these programs are also enrolled at PJM for emergency calls. Going forward, PHI anticipates that it will refine its processes and operating procedures for the PESC and EWR programs in order to be able to dispatch them to meet distribution system needs during periods of peak demand (in addition to PJM dispatching these programs for emergency reasons).

PJM Demand Response Programs

Background

PJM administers two types of demand response programs which vary according to the mechanism used to compensate the resources (either energy market revenues or capacity market revenues) and how these events are initiated or dispatched. Economic demand response provides an opportunity for those who curtail usage to receive a payment when Locational Marginal Prices (LMPs) are high in PJM's Energy Market. Offers can be submitted as both day-ahead and real-time resources.

The Load Management Demand Resource program is the only program capable of serving as a capacity resource in either the Reliability Pricing Model[29] or to satisfy a Load Serving Entity's Fixed Resource Requirement (FRR) plan.

Load Management Demand Response Program (Emergency and Pre-Emergency Load Management)

PJM administers a Load Management program consisting of both Emergency and Pre-Emergency demand response programs. Additionally, there are three types of products within the Load Management program – each with varying commitments as detailed in Figure 6.

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[27] AMI is not currently deployed in ACE, but DLC is still available using commercial communication systems. In addition since ACE does not have AMI there is no Peak Energy Saving Credit program currently offered. PESC was piloted in DC. To date, the District of Columbia Public Service Commission has not approved the implementation of dynamic pricing.

[27] PHI also has the ability to implement these programs during local system emergencies.

[28] PJM revenues which support the Demand Response programs are expected to end on May 31, 2020. The Company will continue to work within the PJM stakeholder process to ensure programs are appropriately valued in the PJM markets.

[29] The Reliability Pricing Model is PJM's Capacity Market.

Figure 6: Products and Requirements within PJM Load Management Program

Product Types	Description
Limited	Committed to providing up to 10 load reductions of 6 hours duration in the months Jun-Sep
Extended Summer	Committed to providing an unlimited number of interruptions of 10 hours duration during a period of Jun-Oct and the following May
Annual	Committed to providing an unlimited number of interruptions of 10 hours duration

Load Management resources are required to respond to PJM Pre-Emergency or Emergency Load Management events or receive a penalty.[30] Additionally, PJM may test these response capabilities. Revenues for these programs are generated through PJM's capacity market and the majority of participants in these programs are Curtailment Service Providers (CSPs).[31] A summary of the number of locations and total MW registered in PHI's service territories is presented as Figure 7.

Figure 7: PJM Load Management Resources in PHI Areas

State	Load Zone	PHI Utility	Enrolled Locations	MW
DC	PEPCO	PEPCO	308	95.3
DE	DPL	DPL	241	216.0
MD	DPL	DPL	180	115.6
MD	PEPCO	PEPCO	337	404.7
NJ	AECO	AE	252	110.9
Total				**942.5**

Source: PJM 2016 Load Response Activity Report

For energy delivery years 2015/2016 and 2014/2015 there were no events called with mandatory compliance.[32] The last time a PJM Load Management event was called in any of PHI's service territories was in energy delivery year 2013/2014 (See Figure 8).

Distribution Planning Benefits of Resources

PJM maintains transmission system reliability through procurement of four resources types: Generation Capacity, Transmission Upgrades, Load Management (Pre-Emergency and Emergency Demand Resources) and Energy Efficiency. The Load Management program is a demand response program which can be dispatched during both Emergency and Pre-Emergency conditions. However, these PJM system wide conditions do not necessarily coincide with the individual peak loadings of PHI distribution system components. In fact, the last time that a PJM event was dispatched to a PHI load zone was in 2013/2014.

30 PJM Load Management Performance Report 2015-2016.
31 FERC Docket No. ER16-873-000.
32 PJM Load Management Performance Report 2015-2016.

Figure 8: Summary of Recent PJM-Initiated Load Management Events for Recent Years

Event #	Delivery Year	Dates	Year	Start Time	Time Released	Zone(s) Dispatched	Committed/Expected MW
53	2013/2014	3-4	2014	5:30	8:30	AEP, ATSI, COMED, DAYTON, DEOK, DLCO, EKPC zone	1,592
				5:30	8:30	APS, DOM zones	
				5:30	8:30	AE, DPL, JCPL, METED, PECO, PENLC, PL, PS, RECO zones	
				5:30	8:30	BGE, PEPCO zones	
				6:30	8:30	COMED, DAYTON, DEOK, EKPC zones	
				6:30	8:30	AEP, DLCO zones Note: 7th event for Canton portion of AEP zone	
				6:30	8:30	APS zone	
				6:30	8:30	AE, DPL, DOM, JCPL, METED, PENLC, PS, RECO zones	
				6:30	8:30	ATSI, BGE, PEPCO, PL zones	
54[33]	2014/2015	4-21	2015	20:20 19:20 20:20	21:30 21:30 21:30	PENLC	99
55	2014/2015	4-22	2015	7:30 6:30 7:30	12:30 12:30 12:30	PENLC	113

Source: PJM Summary of PJM-Initiated Load Management Events (excerpt)

While PHI and PJM's load forecasts correspond as far as projected load growth rate, planning for PHI's distribution system requires assessing the non-coincident peaks for each substation, substation transformer and feeder. Conversely, PJM's forecast is the sum of the coincident peaks across load zones. PHI must plan to the non-coincident peaks to ensure each component of the distribution system is not overloaded beyond its normal and emergency ratings. Therefore, PJM's demand response programs are not considered in the distribution planning process at the substation, transformer or feeder level.[34]

Resource Growth

Given that PHI relies on PJM demand response resources that are reflected in historical load values, there is no requirement to track the growth of these programs. Should these PJM administered programs be modified to correspond with a distribution system component's peak load, PHI will make the appropriate modifications to its distribution system planning process to reflect these potential benefits.

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[33] Note, beginning with event #54, PJM restructured the Load Management reporting format to reflect new options for Type, Notification Period, and Products. For consistency, these new fields are not reflected in the above table.

[34] PHI's load forecasting methodology may include some amount of load reduction from non-firm DERs. This occurs because there are occasions when such a resource, while not firm, provides a load reduction that is coincident with a facility peak, and as such, is embedded in the historical AMI and SCADA readings that serve as an input to the forecast.

Energy Wise Rewards (Direct Load Control) Program

Background

PHI administers a voluntary direct load control (DLC) program known as Energy Wise Rewards under which a customer allows PHI to install, own, or maintain either a smart thermostat or radio controlled switches in order to cycle the operations of customers' central air conditioner or heat pump.

The Company may exercise cycling for any of the reasons including:

- To test cycling equipment
- In response to a PJM dispatcher request to activate the program
- In response to local utility electric system constraints, or
- In response to regional energy market prices

Customers who choose to participate in the Energy Wise Rewards program are also able to participate in the Peak Energy Saving Credit Dynamic Pricing program (where it is offered). These two programs are also generally initiated together when PJM energy market prices are high.

Distribution Planning Benefits of Resource

Because PHI does not dispatch the direct load control program specifically to mitigate loading or capacity constraints on the distribution system components, in order to determine whether this resource should be considered in the planning process, PHI evaluates the coincidence of historical DLC events with substation peak loading. As Figure 9 indicates, the highest count of instantaneous substation peak loading falling within the DLC call log window, expressed as a percentage of all substations for a jurisdiction in a year, is approximately 47%. Given that this resource has historically had a service factor of less than 95%, the full amount of MW enrolled in the DLC program has not historically been considered in the planning process, except to the extent that any coincident load reductions are embedded in the historical AMI and SCADA readings that serve as an input to the forecast.[35]

Figure 9: Average DLC % Coincident with Substation Peaks

Jurisdiction	State	2011	2012	2013	2014	2015
Pepco	DC	47.1%	37.3%	0.0%	5.9%	0.0%
Pepco	MD	41.3%	17.5%	0.0%	0.0%	0.0%
Delmarva Power	DE	N/A	0.0%	18.4%	0.0%	0.0%
Delmarva Power	MD	N/A	19.0%	0.0%	4.8%	0.0%
Atlantic City Electric[36]	NJ	33.3%	14.7%	2.0%	0.0%	0.0%

Moving forward, PHI anticipates that it will count the full amount of MW enrolled in EWR as a firm resource since it is within PHI's operational control and because PHI recognizes the value of utilizing such a resource to manage peak load on distribution system components. However, in order to utilize the program in this manner, PHI will need to refine its process and operating procedures to be able to dispatch EWR to meet distribution system needs during periods of peak demand.

[35] PHI's load forecasting methodology includes some amount of load reduction from non-firm DERs. This occurs because there are occasions when such a resource, while not firm, provides a load reduction that is coincident with a facility peak, and as such, is embedded in the historical AMI and SCADA readings that serve as an input to the forecast.

[36] The analysis for ACE is based upon substation transformer SCADA data.

Resource Growth

The direct load control program is generally considered to be fully deployed and PHI does not anticipate any significant growth of the program moving forward.

Peak Energy Savings Credit Program

Background

PHI administers an AMI-enabled dynamic pricing (DP) program known as Peak Energy Savings Credit in certain jurisdictions. In Pepco MD, approximately 5,000 customers were involved in 2012 to test operational readiness. In 2013, all Pepco MD residential customers with activated AMI meters were placed on the PESC rate. In Delmarva Power DE, PESC was made available to 6,800 customers with activated AMI meters beginning in the summer of 2012 and the program was fully deployed to all Standard Offering Service (SOS) customers with activated AMI meters during the summer of 2013. In Delmarva Power MD, beginning in the summer of 2014, a limited number of residential customers with activated AMI meters were placed on PESC DP rate. Enrollment was subsequently expanded jurisdiction-wide in 2015. The PESC program has not been approved in the District of Columbia for Pepco DC customers. Due to the lack of AMI in ACE's service territory, the PESC program is not currently available.

The PESC Program provides a residential customer bill credit of $1.25 per kWh reduced during PESC event periods. A residential customer receives a credit calculated by applying the bill credit amount of $1.25 to the difference between actual kWh consumption and a Customer Base Line (CBL) level of consumption during each PESC event designated by the Company. Customers who also participate in the EWR program are eligible for PESC credits in excess of the monthly EWR reward credits. There is no penalty if a customer's usage is above the CBL. All energy use, including the kWh actually consumed during PESC events, is priced at the normally applicable distribution, transmission, and generation rates.

Distribution Planning Benefits of Resource

Because PHI does not dispatch the PESC program specifically to mitigate loading or capacity constraints on the distribution system components, in order to determine whether this resource should be considered in the planning process, PHI evaluates the coincidence of historical PESC events with substation peak loading. As Figure 10 indicates, the highest count of instantaneous substation peak loading falling within the PESC call window, expressed a percentage of all substations for a jurisdiction in a year, is approximately 18.4%.

Figure 10: Average PESC Call % Coincident with Substation Peaks[37]

Jurisdiction	State	2011	2012	2013	2014	2015
Pepco	DC	No Program				
Pepco	MD	No Program	Pilot	0.0%	0.0%	0.0%
Delmarva	DE	No Program	Pilot	18.4%	0.0%	0.0%
Delmarva	MD	No Program	No Program	No Program	Pilot	0.0%
Atlantic City Electric[38]	NJ	No Program				

Given that this resource has a service factor of less than 95%, the full amount of MW enrolled in the PESC program has not been considered in the planning process historically, except to the extent that any coincident load reductions are embedded in the historical AMI and SCADA readings that serve as an

[37] PHI typically activates the EWR and PESC programs concurrently. This analysis assumes activations occurred at the same time for the specified periods.
[38] The analysis for ACE is based upon substation transformer SCADA data.

input to the forecast.[39] Moving forward, PHI anticipates that it will count the full amount of MW enrolled in PESC as a firm resource since it is within PHI's operational control and because PHI recognizes the value of utilizing such a resource to manage peak load on distribution system components. However, in order to utilize the program in this manner, PHI will need to refine its process and operating procedures to be able to dispatch PESC to meet distribution system needs during periods of peak demand.

Resource Growth

The Peak Energy Savings Credit program is generally considered to be near full deployment within the areas where it has been implemented and PHI does not anticipate any significant growth of the program moving forward unless deployment of AMI in the Atlantic City Electric area occurs or the District of Columbia approves a similar program, which would allow the same PESC credit to be offered through AMI functionality.

[39] PHI's load forecasting methodology includes some amount of load reduction from non-firm DERs. This occurs because there are occasions when such a resource, while not firm, provides a load reduction that is coincident with a facility peak, and as such, is embedded in the historical AMI and SCADA readings that serve as an input to the forecast.

6.2 Energy Efficiency Programs

Energy efficiency programs designed to lower overall energy consumption and reduce peak demand are available to all PHI customers. Some of these programs (e.g., Energy Management Tools, EmPOWER MD) are administered entirely by PHI, while other programs are administered by agencies like DC SEU and DE SEU. It is important to note that all types of energy efficiency are considered to be permanent load reductions and the reductions from these programs are therefore factored into the distribution system planning process for all components of the distribution system.

Energy Management Tools (EMTs)

Background

PHI is providing customers with detailed electricity use information available through AMI and supporting ongoing customer education through a variety of formats. EMTs refer to a range of AMI information available to help customers understand their energy use and to raise their awareness of ways to save energy and reduce costs:

1. Communications reminding customers to save energy and the impact of saving energy on the environment and lowering energy costs.
2. Daily energy use charts and historical energy use charts on bills.
3. Online tools available through My Account, including energy use analysis, bill-to-date information, hourly energy usage charts and historical data, and calculators to identify ways to save energy. Paper energy use reports that provide data similar to My Account for non-My Account users are available upon request. Detailed energy use information that customer service representatives and Energy Advisors can access when discussing monthly bills with customers.
4. A mobile application with similar functionality also is available. Customers can use PHI's mobile application to receive notifications for high-usage levels, view seven days of hourly usage data (where AMI is deployed), compare the current bill to the same period last year, and receive energy saving tips.

Distribution Planning Benefits of Resource

PHI considers EMTs to be permanent load reductions and these reductions are counted at the substation, substation transformer, and feeder levels.

Resource Growth

EMTs are generally considered to be fully deployed within the areas where they have been implemented and PHI does not anticipate any significant growth of the program moving forward unless deployment of AMI in the Atlantic City Electric area occurs or the District of Columbia approves a similar program, which would allow the same roll out of these tools customers who otherwise previously would not have access to them.

Conservation Voltage Reduction (CVR)

Background

CVR is used to reduce electric energy use and electric peak demand by lowering voltage on the distribution system, but only to a level that remains within the voltage range specified by corresponding regulations (e.g., COMAR 20.50.07.02.) and industry standards (e.g., ANSI C84.1). Studies have demonstrated that the implementation of CVR decreases customer energy consumption without any action by a customer. The voltage reduction is undetectable to customers and it does not damage electric end-uses. There are numerous customer benefits which are provided by CVR which include:

- Avoided energy
- Capacity price mitigation
- Energy price mitigation
- Avoided transmission losses
- Avoided distribution losses
- Avoided air emissions

The availability of AMI data enabled PHI to carefully monitor a sampling of individual customer voltage levels to maximize CVR enabled reductions, while limiting the possibility of delivered voltage levels lower than allowed ranges. AMI-enabled grid monitoring of customer voltages is essential for maintaining electric distribution service quality and maximizing CVR energy and demand reduction capability while maintaining delivered voltage levels within required standards.

CVR was initiated in August 2013 in Maryland and has subsequently been expanded to 18 substations in Pepco MD and 12 substations in Delmarva MD with plans for further, continued expansion through the 2023/2024 timeframe. CVR is not currently deployed in New Jersey or Delaware. Within the District of Columbia, CVR will be deployed in a phased implementation as was performed in Maryland. Once a limited number of stations have had CVR installed it is expected that CVR will be rolled out to an increased number of substations. Also due to the fact that circuits supply both Maryland and District customers there are some customers in the District supplied by Maryland circuits that have CVR installed.

Distribution Planning Benefits of Resource

The energy and peak load reductions resulting from CVR are considered to be permanent load reductions since once PHI lowers the voltage on a feeder, it does not re-adjust or raise voltage settings. Therefore, CVR is considered a firm resource. PHI retained the Brattle Group to quantify the impact of the application of CVR. Brattle determined that a 1.5% voltage reduction is expected to provide a 1.1% residential summer peak demand reduction and a 0.9% non-residential summer peak demand reduction. These values are used to account for historical impacts of CVR as well as forecasted expansion and PHI will apply the reductions that were determined through Brattle's analysis to any substations which in the future are selected for CVR implementation.

Resource Growth

PHI plans to implement CVR at additional substations throughout its service territories through the 2023/2024 timeframe. The contributions of additional CVR deployments will be reflected in future iterations of the load forecast accordingly.

Residential Energy Efficiency & Conservation Programs

Background

There are a number of residential energy efficiency programs available to all PHI customers. However, not all of these programs are administered by PHI. PHI administers programs in Maryland and is working on implementing programs in Delaware and New Jersey (where programs are currently administered by third-parties). The suite of residential energy efficiency programs could include the following: lighting, appliances (rebates, recycling), home energy check-ups, home performance with ENERGY STAR, new construction, HVAC, low income programs, and other behavior based programs. These programs are administered by varying agencies/groups for each jurisdiction as indicated by Figure 11.

Figure 11: PHI Energy Efficiency Programs and Administrators

Operating Company and Jurisdiction	Program Administrator
Pepco (DC)	DC Sustainable Energy Utility (SEU)
Pepco (MD)	Pepco MD
Delmarva Power (MD)	Delmarva Power MD
Atlantic City Electric Company (NJ)	NJCEP, ACE[40]
Delmarva Power (DE)	DE Sustainable Energy Utility (SEU)

The energy (MWh) savings as well as the peak (MW) savings are estimated by each program administrator and generally summarized in annual reports. The results of many of these programs are also independently measured and verified. The DC SEU releases annual reports in the District of Columbia; the EmPOWER MD annual reports cover both Pepco MD and Delmarva MD; DE SEU has not released a comprehensive annual report yet as of mid-2016 and the preliminary program-level savings (below) were obtained from the executive director at DE SEU; NJ BPU releases the NJ Clean Energy Plan (CEP) program reports, covering all of NJ. The figure below summarizes the residential energy efficiency MW savings by year for each PHI jurisdiction.

Figure 12: Yearly Incremental Peak Demand Savings for Residential Energy Efficiency by Jurisdiction

Measured & Verified Residential EE: Yearly Incremental Peak Demand Savings					
Year	**PEPCO DC**	**PEPCO MD**	**DPL MD**	**DPL DE**	**ACE NJ**
2011	0.00	5.17	1.03	0.00	4.42
2012	0.96	15.02	3.00	0.00	3.33
2013	2.40	25.35	5.97	0.01	3.33
2014	2.37	23.42	5.99	0.12	3.69
2015	2.39	19.00	4.37	0.22	6.04
2011-2015 Total	8.13	87.96	20.35	0.36	20.81

Distribution Planning Benefits of Resource

These resources are considered permanent load reductions and these reductions are counted at the substation, substation transformer, and feeder level.

Resource Growth

For programs which PHI does not directly administer, growth and subsequent impacts will be informed by updates and budgets from program administrators. For programs which are administered directly by PHI, PHI will take into consideration Commission directives, various stakeholder agreements, or specific service territory characteristics and considerations. If information or program updates are made available

[40] Comfort Partners is administered by New Jersey utilities, including ACE

which significantly impact forecasted load reductions from energy efficiency, PHI will consider these updates in its load forecasting and planning processes.

Commercial & Industrial Energy Efficiency & Conservation Programs.

Background

Commercial and industrial (C&I) energy efficiency programs also vary by jurisdiction. The suite of C&I programs could include the following: multi-family or multi-dwelling appliances and HVAC, small business, prescriptive/existing buildings, new construction, retrofits, pay-for-performance, direct install, and CHP programs.

These programs are similarly administered by varying agencies/groups for each jurisdiction. Pepco DC's jurisdiction is administered by DC SEU. Pepco MD and Delmarva MD's jurisdictions are administered by Pepco and Delmarva. Delmarva DE's jurisdiction is administered by DE SEU. ACE NJ's jurisdiction is administered by NJ BPU/NJ CEP. The figure below summarizes the C&I energy efficiency MW savings by year for each jurisdiction.

Figure 13: Yearly Incremental Peak Demand Savings for C&I Energy Efficiency by Jurisdiction

Measured & Verified C&I EE: Yearly Incremental Peak Demand Savings					
Year	**PEPCO DC**	**PEPCO MD**	**DPL MD**	**DPL DE**	**ACE NJ**
2011	0.00	4.96	1.24	0.00	8.54
2012	1.93	11.67	1.78	0.00	2.61
2013	4.81	48.26	4.67	0.00	2.61
2014	4.75	40.71	12.84	0.12	4.33
2015	4.77	32.97	7.88	1.08	5.31
2011-2015 Total	16.26	138.57	28.40	1.20	23.40

Distribution Planning Benefits of Resource

These resources are considered permanent load reductions and these reductions are counted at the substation, substation transformer, and feeder level.

Resource Growth

For programs which PHI does not directly administer, growth and subsequent impacts will be informed by updates and budgets from program administrators. For programs which are administered directly by PHI, PHI will take into consideration Commission directives, various stakeholder agreements, or specific service territory characteristics and considerations. If information or program updates are made available which significantly impact forecasted load reductions from energy efficiency, PHI will consider these updates in its load forecasting and planning processes.

6.3 Distributed Generation

Background

Customers in PHI's service territories own, lease, or operate a variety of distributed generation sources which are interconnected with the distribution system. These technologies are typically behind the customer's meter and include inverter-based technologies like solar PV and synchronous generation like CHP and methane gas digesters.

PHI has experienced a significant increase in the number of interconnection applications over the past six years for distributed energy resources. In particular, solar PV composes the majority of interconnections in both number of applications and aggregate customer system capacity (MW). While the majority of this growth can be attributed to policy measures including state incentives, tariffs like retail net energy metering (NEM) and the federal investment tax credit (ITC) – PHI cannot predict with certainty the impact of these policy measures on future growth, short of the technical considerations which may constrain growth on an individual feeder. The impact of state level policies has been particularly evident in states where the revenue from solar renewable energy credits (SRECs) has proven to be lucrative such as New Jersey, the District of Columbia, and Maryland. Similarly, PHI witnessed a significant increase in the number of interconnection applications for distributed PV in 2015, likely in anticipation of the expiration of the 30% federal investment tax credit that has since been extended by Congress.

Net Energy Metered (NEM) PV

Net energy metering, which provides compensation or a credit for excess generation exported back to the grid at the full retail rate is available in all of the states in which PHI has operations. This tariff also applies to community solar arrangements and aggregated arrangements (ANEM). To date, PHI has received more than 40,000 interconnection applications across its three operating companies. The eligibility of resources for net energy metering tariffs is presented as Figure 14. It is important to note that current NEM tariffs do not place a premium or provide an incentive for solar arrays where PV may provide greater benefits to the distribution system (e.g., a large amount of solar interconnected to a feeder with an early afternoon peak). Inversely, systems which are interconnected in less than optimal locations also receive full retail credits, dependent upon production.

Figure 14: Net Energy Metering System Size Caps and Corresponding Statute or Regulation

	System Size Cap (kW) and Corresponding Statute, Regulation			
	Residential, Non-Residential		**Community or Aggregated Net Metering**	
D.C.	1000, 1000 (DC systems cannot exceed 100% of baseline usage)	C.B. 17-492	5000	C.B. 20-0057
NJ	Theoretical NJ limit is 10 MW for all systems (NJ systems cannot exceed 100% of baseline usage	N.J. Stat. § 48:3-87, N.J.A.C. § 14:8-4.1 et seq.	Only applies to public entities (100% of aggregated accounts - No existing Rider yet)	S.B. 1925
DE	25, 2000 (DE systems cannot exceed 110% of baseline usage)	(Del. C. § 1014(d), CDR § 26-3000-3001)	Allows for up to 110% of expected consumption of aggregated accounts	S.B. 267
MD	2000, 2000 (systems cannot exceed 200% of baseline usage), Micro-CHP cannot exceed 30 kW	Md. Public Utility Companies Code § 7-306, COMAR 20.50.10, H.B. 1057	2000	H.B. 1087, S.B. 398)

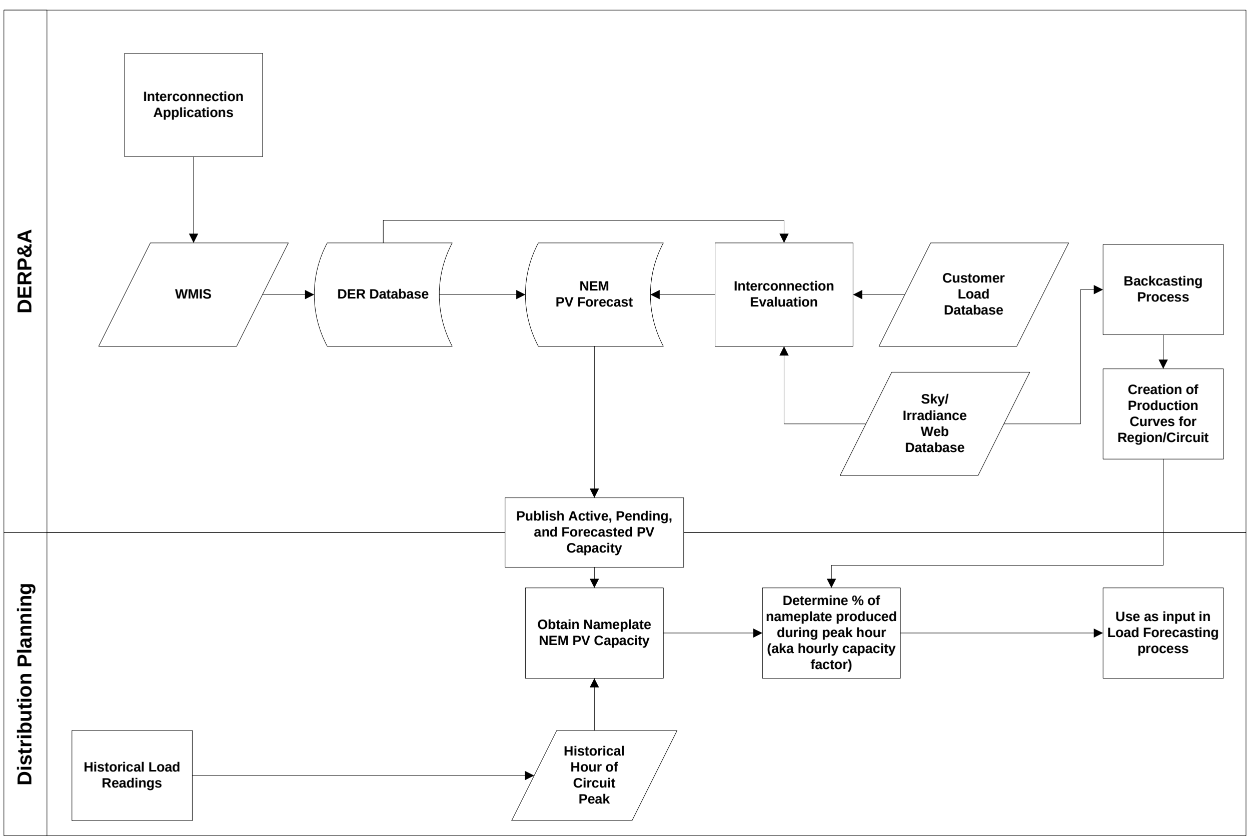
Distribution Planning Benefits of Resource

The benefits of solar PV to the distribution system depend upon a confluence of factors which includes the production characteristics of the resource, the attributes of the power delivery system component with which the PV system is interconnected, and temporality of the resource's production as it pertains to peak loading conditions on each component of the distribution system.

Calculating these impacts is particularly challenging as it pertains to distributed solar since 98% of the distributed PV systems installed in PHI's service territory do not have dedicated metering and telemetry which would allow PHI to monitor the operational parameters of the resources. Given this lack of visibility, PHI employs advanced modelling software to conduct an industry-leading backcasting process which leverages a database of historical sky conditions (e.g., cloud cover and corresponding fluctuation in solar irradiance) for a given period of time and the configuration of the PV systems to simulate what the actual production of the PV systems would have been over a specified period. The backcasting process allows PHI to determine hourly capacity factors for PV systems in aggregate at the feeder level which can subsequently be used to calculate the percentage of nameplate PV capacity which should be considered a load reduction on the distribution system component during peak loading conditions. This level of production is the amount of generation that the planners use to perform their analysis and to forecast future loads and system enhancements. In certain instances, PV may not provide any benefit as a peak load reduction resource, as some feeders peak in the winter morning, prior to sunrise and any solar production.

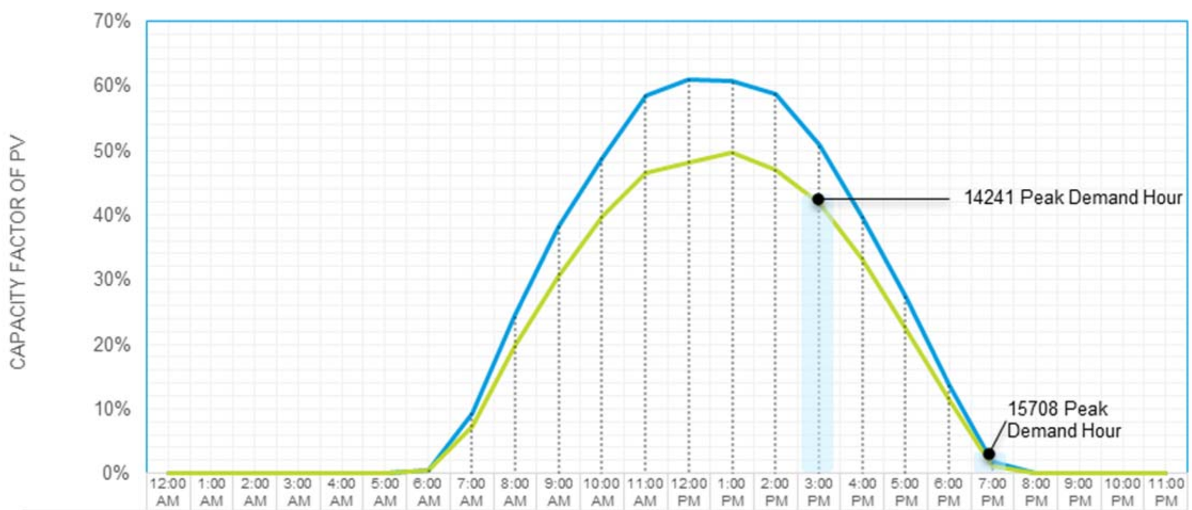
The end-to-end process of calculating these impacts is depicted as Figure 15. It is important to note that PHI must apply this same process for each component of the distribution as each component may experience peak loading at different hours of the day.

Figure 15: Process Flow for Calculating Peak Impact of Distributed PV



A depiction of the hourly capacity factor curves are illustrated as Figure 16. The production curves displayed below are created using average hourly production data derived from historical sky conditions and corresponding solar irradiance for June 1, 2015 through August 31, 2015. Summer months are typically modeled given that this is when PHI typically experiences peak loading on the components which comprise the distribution system. However, PHI has the ability to model multiple years of data. The shaded blue areas indicate the historical hour of peak loading for the feeders 14241 (Pepco MD) and 15708 (Pepco DC). Therefore, for feeder 15708, which has a historical peak hour of 7:00 PM, a Planner would count 2% of nameplate PV capacity installed on that feeder when calculating the load reduction impact from PV. On feeder 14241, which has a historical peak hour of 3:00 PM, a Planner would count 42% of the nameplate PV capacity installed on that feeder when calculating the load reduction impact from PV. Both of these impacts would then be incorporated into the short-term load forecasting process.

Figure 16: Average Hourly Summer (Jun-Aug) PV Capacity Factors for Summer 2015



	12:00 AM	1:00 AM	2:00 AM	3:00 AM	4:00 AM	5:00 AM	6:00 AM	7:00 AM	8:00 AM	9:00 AM	10:00 AM	11:00 AM	12:00 PM	1:00 PM	2:00 PM	3:00 PM	4:00 PM	5:00 PM	6:00 PM	7:00 PM	8:00 PM	9:00 PM	10:00 PM	11:00 PM
15708	0%	0%	0%	0%	0%	0%	1%	9%	24%	38%	49%	59%	61%	61%	59%	51%	40%	27%	14%	2%	0%	0%	0%	0%
14241	0%	0%	0%	0%	0%	0%	0%	7%	20%	30%	40%	47%	48%	50%	47%	42%	33%	22%	11%	1%	0%	0%	0%	0%

HOUR OF DAY AND CORRESPONDING CAPACITY FACTORS

Note: Actual hourly production capacity will rarely achieve 100% of nameplate rating due to factors which include cloud cover, panel efficiency loss due to temperature, panel tilt and orientation, and shading

Resource Growth

PHI maintains a database ("DER Database") of all active and pending interconnection applications which serves as the foundation for PHI's growth projections. The database contains more than 40,000 applications, of which approximately 30,000 are in service.

PHI forecasts additional growth of NEM PV using a dynamic average over the number of years since a PV system was first installed on a feeder (beginning in 2010), to the present date in order to determine the incremental PV system capacity additions for future years. The base values used to calculate the forecast begin in 2010 since there was not significant growth prior to 2010. The numerator of the dynamic average is the sum of the AC inverter rating for all PV installed on that feeder, and the denominator is the count of the number of years from the first year a system was installed (beginning in 2010) to the present. For the current year, the incremental value is composed of the systems currently in service and pending applications from the previous 12 months. The 2016 value is also averaged into the forecasted incremental values for 2017 and all future years. Growth is assumed to continue until the strict penetration limit[41] of the feeder is reached. An example of this calculation is depicted in Figure 17. The yellow highlighting indicates the total number of years PV has been installed on a feeder, and subsequently serves as the denominator for calculating the average (which is used as the incremental forecasted value). The sum of the values inside the shaded boxes (nameplate AC capacity) serves as the numerator.

Figure 17: Dynamic Average Used to Calculate Incremental NEM PV Growth

	Incremental (kW)							Forecast (kW)			
Circuit	**2010 and Prior**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017E**	**2018E**	**2019E**	**2020E**
NJ0694	50.6	7.5	11.4	11.2	23.8	23.2	58.4	26.6	26.6	26.6	26.6
NJ0696	0.0	0.0	0.0	11.8	0.0	0.0	3.0	3.7	3.7	3.7	3.7
NJ0698	556.4	0.0	0.0	3.0	21.6	16.6	21.1	88.4	88.4	88.4	88.4
NJ0741	0.0	5.0	366.8	8.6	16.0	56.0	22.8	79.2	79.2	79.2	79.2
NJ0744	4.0	0.0	24.0	0.0	3.8	40.8	18.0	12.9	12.9	12.9	12.9
NJ0745	121.3	69.2	91.8	53.8	145.8	114.6	161.4	108.3	108.3	108.3	108.3
NJ0746	29.0	26.6	46.1	15.8	53.0	59.1	102.3	47.4	47.4	47.4	47.4
NJ0747	211.6	94.7	62.6	47.2	95.2	313.5	132.0	136.7	136.7	136.7	136.7

For example, in order to calculate the forecasted incremental values for feeder NJ0694, the following steps are followed:

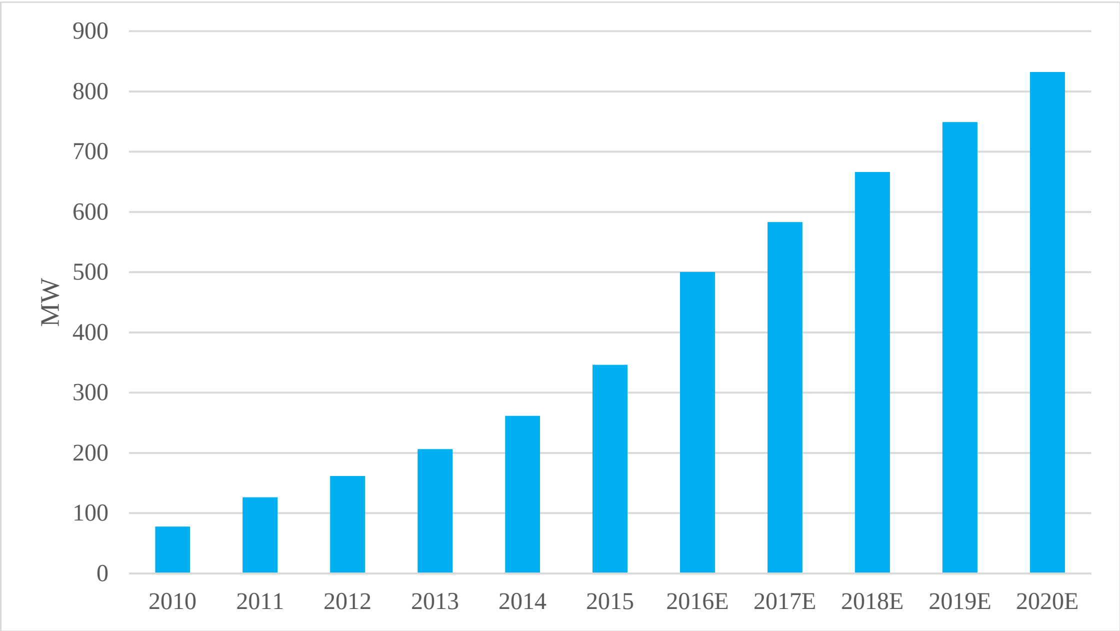
1. Determine the first year a PV system was interconnected on the feeder. In this example, the first PV system was interconnected in 2010 or Prior. Therefore, the denominator of the dynamic average is the count of the number of years since 2010 and Prior. In this example, the count is seven years (2010 and Prior, 2011, 2012, 2013, 2014, 2015, and 2016) and therefore seven is used as the denominator.
2. For each year which is counted in the denominator, sum the aggregate nameplate AC capacity interconnected in those years. In this example, the sum is equal to (50.6+7.5+11.4+11.2+23.8+23.2+58.4) = 186.1 kW

[41] The strict penetration limit is the amount of capacity known with certainty to be available to host interconnecting DERs, which can be added anywhere in the feeder up to this level without creating an adverse impact on the system or other customers.

3. To determine the incremental forecast value for future years, divide the resulting value in step 2 (186.1 kW) by the value in step 1 (7).
4. Therefore, the Incremental Forecast Value $=$ (186.1 kW)/(7 years) = 26.6 kW

A PHI-wide, cumulative roll-up of this forecast is presented as Figure 18.

Figure 18: PHI-Wide Cumulative NEM PV Capacity 2010-2020 as of May 2016



Non-NEM PV

Distributed solar resources that choose not to participate in NEM tariffs or are ineligible due to system size or other system attributes may still be interconnected with the distribution system.

Distribution Planning Benefits of Resource

Similar to the process for calculating the benefits of NEM PV, PV production curves (which illustrate hourly capacity factor) will be established that are indicative of the solar production in each respective service territory. The relationship between solar production and peak loading hour shall be used to determine the appropriate amount of nameplate PV capacity which is applied as a load reduction. If the system has its own metering and telemetry, historical production data will be used to calculate the impact of an individual facility.

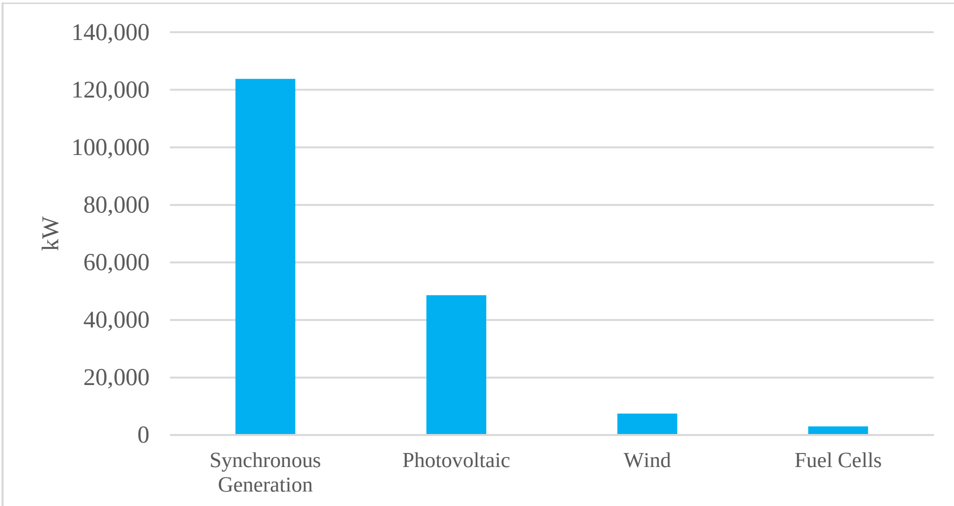
Resource Growth

Given the uncertain nature of many of these projects, PHI only considers the impacts of these projects when they are either "Under Construction" or "In Service."

Other Distributed Generation

Other distributed generation operating in PHI's service territories include fuel cells, methane gas digesters, CHP, and distributed wind. These generators are typically assessed on a one-off basis and may or may not meet the criteria to be considered firm resources. The majority of this capacity participates in the PJM markets as detailed in Figure 19.

Figure 19: PJM Distributed Generation in PHI's Jurisdictions (Active)



7 Update on DER Stakeholder Engagement Process

PHI indicated that it would initiate a detailed stakeholder engagement process to review its June 21, 2016 report on "Interconnection of Distributed Energy Resources", take into consideration all comments and recommendations made during this process, and make any additional changes to its plans, policies, or criteria pertaining to DERs as appropriate.

Following the issuance of its report, PHI distributed invitations to stakeholders to a 1-Day session for each jurisdiction (Figure 20). Locations were selected that were convenient and accessible for stakeholders.

Figure 20: PHI Stakeholder Invitation for Pepco DC and MD

As of the filing of this report, PHI has conducted the following stakeholder meetings:

Jurisdiction	**Dates**
Pepco – District of Columbia	August 30, 2016
Pepco – Maryland	September 6, 2016

The dates of the remaining stakeholder meetings are listed below:

Jurisdiction	**Dates**
Delmarva – Delaware	September 29, 2016
ACE – New Jersey	October 4, 2016
Delmarva – Maryland	October 6, 2016

The stakeholder meetings were a forum for discussing PHI's enhanced communications plan for proactively promoting installation of behind-the-meter solar generation as well as discussing opportunities and challenges for other DERs. In addition, PHI will continue to solicit stakeholder feedback and questions regarding several key topics which include:

- Benefits of solar generation
- Information that PHI can help communicate through its communications activities
- Solar grant opportunities
- PHI bill inserts and topics stakeholders would like to see PHI promote to customers

A consolidated list of frequently asked questions and answers will be posted, and the corresponding PHI presentations will be made available at the following hyperlinks:

- Pepco D.C. - http://www.pepco.com/nem-education.aspx
- Pepco MD - http://www.pepco.com/my-home/save-money-and-conserve-energy/renewable-energy/green-power-connection/md/webcasts,-education-and-publications/
- Delmarva DE - http://www.delmarva.com/my-home/save-money-and-conserve-energy/renewable-energy/green-power-connections/delaware/net-energy-metering-education/
- Delmarva MD - http://www.delmarva.com/my-home/save-money-and-conserve-energy/renewable-energy/green-power-connections/maryland/webcasts,-education-and-publications/
- ACE - http://www.atlanticcityelectric.com/NEM-Education.aspx

Additionally, PHI's enhanced communication plan will be shared at each collaborative and shared with interested stakeholders. In addition, a separate discussion was dedicated to discussing and asking questions on the technical processes PHI uses to evaluate the interconnection of DERs.

8 Update on Further Study of Solar and Storage

Background

PHI has undertaken discussion of issues regarding solar and storage through the aforementioned stakeholder engagement process. Energy storage is being considered for numerous use cases both on the utility and customer side of the meter and there may be potential to incorporate the flexible characteristics of storage into the planning process, contingent upon device operations and the visibility PHI has into those operations. Pursuant to its merger commitments, the PHI utilities, in consultation with Board or Commission Staff and interested stakeholders, shall determine an appropriate target completion date for this review within one (1) year after merger closing.

Distribution Planning Benefits of Resource

PHI is still in the early stages of evaluating how energy storage can be used to the benefit of the distribution system. Because there are multiple configurations for energy storage systems (both-standalone and interconnected with other DERs), it is critical that PHI evaluate the impacts of these configurations both during the interconnection process and during observed operations.

The evaluation follows a similar review/screening/study process as DG, based on size, with a few added items:

- If the energy storage system shares an inverter with the generation, such as a PV system, then the maximum power flow fluctuation would be the import to export range of the inverter. For example, a 10 kW inverter system that can import or export 10 kW will be evaluated for the scenario where the power flow may fluctuate by 20 kW.
- If the energy storage has a separate inverter from the generator, such as PV, then the aggregate impact of the power flow fluctuation of the battery and generation will be evaluated.
- If there are multiple energy storage systems on a feeder that will be used for frequency regulation (FR), then the aggregate operation will be studied as acting simultaneously. PHI may require different time delays for systems responding to PJM's FR signals.
- If a battery can only be used for back-up purposes, then it will only be evaluated as a load.

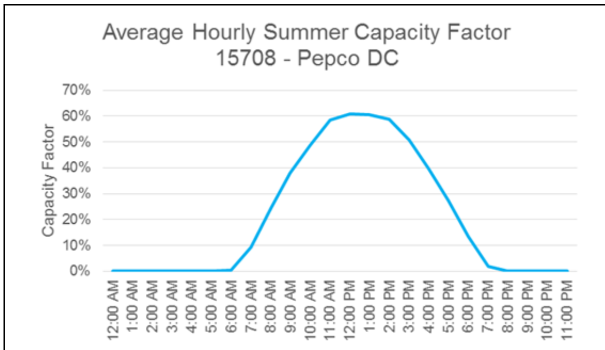
Resource Growth

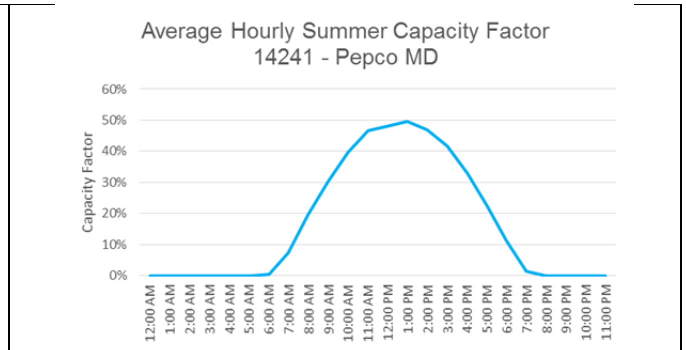
Given the handful of applications PHI has received for energy storage, it does not currently plan to implement a forecasting process. However, should the volume of applications increase, PHI will implement a forecasting process as appropriate. A related item that may require further study in the future relates to the rate at which battery storage degrades. This may become a factor in the inclusion of this resource category in the distribution peak load planning process.

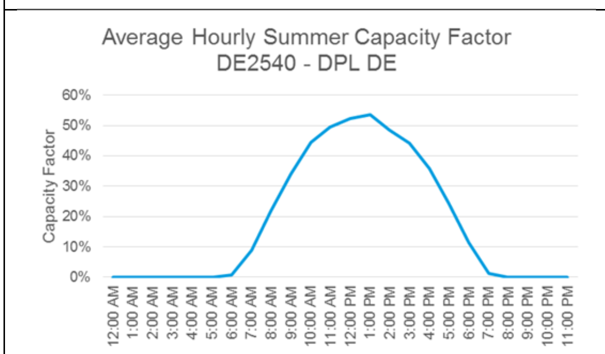
Additional Stakeholder Discussion Regarding Coupling of Behind-the-Meter Solar and Storage

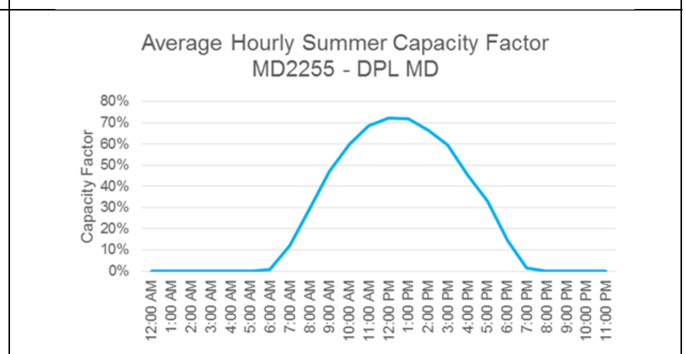
It is PHI's intent to continue the discussion and study of energy storage with stakeholders in each of its jurisdictions. The Company will request this subject as an agenda topic in the Maryland Net Metering Working Group and either the Net Metering and Interconnection Standards Working Group or the Renewable Energy Committee in New Jersey. The Company will also consult with the Delaware Sustainable Energy Utility and the District of Columbia Public Service Commission Staff to determine the appropriate forum for this topic in their respective jurisdictions.

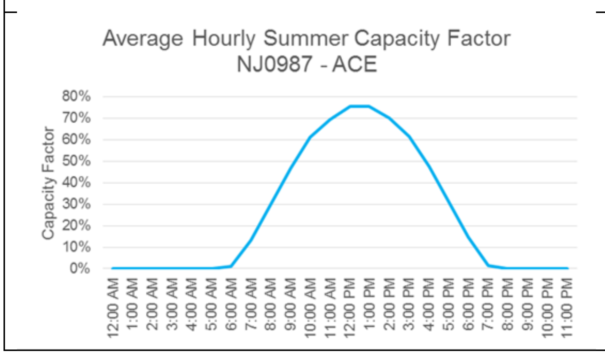
Appendix 1 – Representative Backcasting Results and Average Hourly Summer Capacity Factors











Backcasting

To backcast solar output, PHI utilizes historical sky-based data. A third party parses the historical sky data and predicts how much output there is for each hour based on the installed PV capacity. That output data is used to predict each customer's solar system output. For this study, the aggregate amount of active solar system capacity on each feeder, was backcasted using the location of the substation sourcing that feeder, for the period of June 1, 2015 through August 31, 2015. The average output of each hour for that period of time is plotted. That output can be expressed as a percent of the installed capacity (represented on the Y axis). This percentage can then be used to approximate how much existing or future solar installations are or will reduce the peak.