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November 30, 2016

FILED VIA DELAFILE
Donna Nickerson, Secretary
Delaware Public Service Commission
Cannon Building, Suite 100
861 Silver Lake Boulevard
Dover, DE 19904

Re: Delmarva Power & Light Company
2016 Integrated Resource Plan

Dear Secretary Nickerson:

Enclosed is the public version of the Delmarva Power & Light Company Integrated Resource Plan for 2016 which is being filed pursuant to the provisions of 26 *Del. C.* §1007(c)(1). A confidential version of this document is being filed simultaneously herewith under separate cover.

Should you have any questions or require any additional information, please do not hesitate to contact me.

Very truly yours,

Pamela J. Scott

Enclosures
cc: Mario Giovannini (w/enclosures)
Jack Barrar (w/enclosures)
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DELMARVA POWER & LIGHT COMPANY

2016 INTEGRATED RESOURCE PLAN

NOVEMBER 30, 2016

PUBLIC VERSION

2016 Delmarva Power

Integrated Resource Plan

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SECTION 1

Section 1
IRP EXECUTIVE SUMMARY

Delmarva Power & Light Company (Delmarva Power or Company) prepares and submits an Integrated Resource Plan (IRP) every two years as required by Delaware law[1], and in compliance with regulations adopted by the Delaware Public Service Commission ("Commission")[2].

On October 6, 2015, the Commission issued Order No. 8779, in Docket No. 14-0559, which ratified the IRP submitted by Delmarva Power on December 2, 2014. The 2016 IRP incorporates the guidance provided by the Commission in Order No. 8779, as well as other changes suggested by the parties through their comments submitted in response to the 2014 IRP and through a working group meeting held on April 14, 2016. As with the 2014 IRP, the drafting of the 2016 IRP has greatly benefitted from the input received through the collaborative IRP Working Group process.

A. Summary of Integrated Resource Plan Findings

Retail energy supply prices for Delmarva Power's Standard Offer Service ("SOS") customers include the cost of electric energy, capacity and ancillary services. Retail supply prices have been stable and mostly decreasing since the current SOS energy procurement process was approved by the Commission and initiated in 2006. The effectiveness of the current SOS procurement process to provide relatively stable energy prices over time is shown in Figure 1 below.

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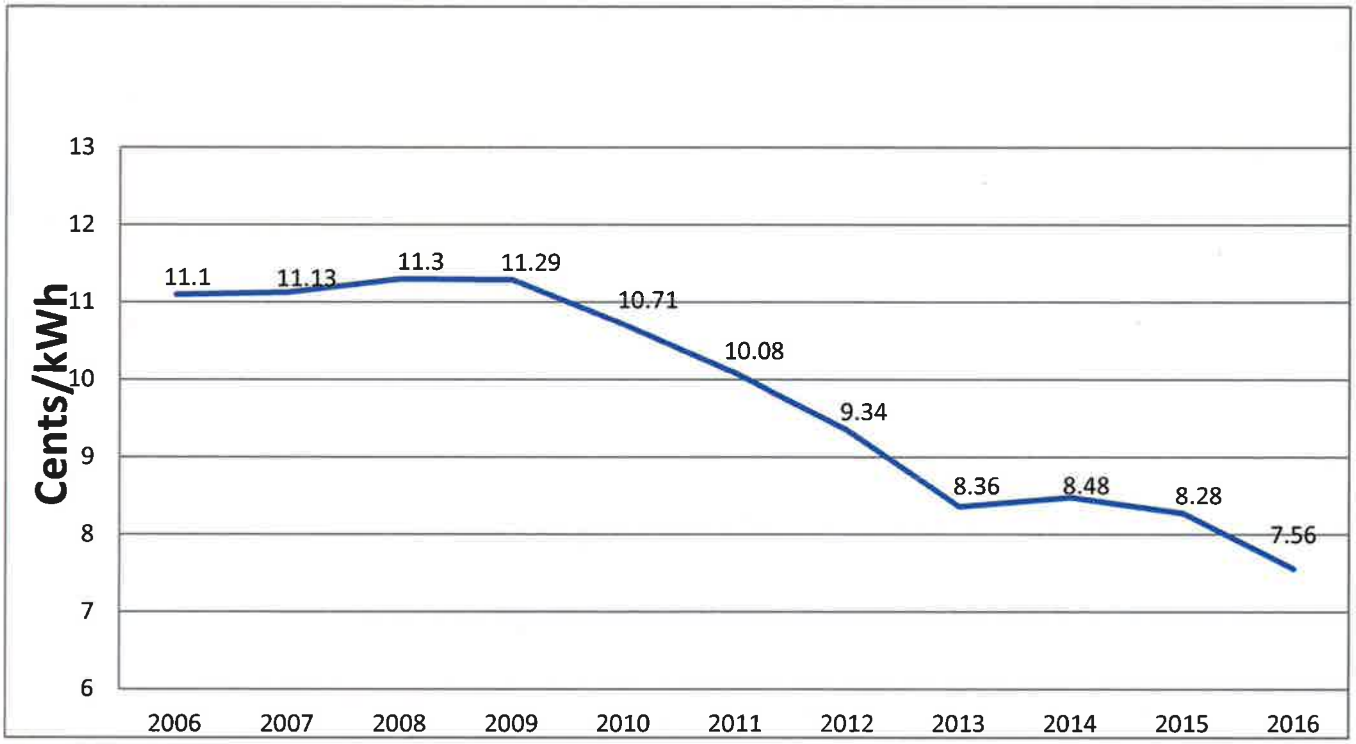
[1] 26 *Del. C.* §1007(c)(1).
[2] 26 *Del. Admin. C.* 3010.

Figure 1

Typical Delaware SOS Residential Customer Supply Price

2006-2016



As seen in Figure 1, since 2009 residential SOS customer supply prices have fallen from 11.29 cents/kwh to 7.56 cents/kwh, a decrease of approximately 33%.

It is also expected that the combination of available generation resources within the PJM DPL Zone, along with the capability of the transmission system to import electricity into the DPL Zone from outside Zone under PJM base case assumptions, will be sufficient to meet PJM reliability requirements through 2026. This result is made more certain by the implementation of demand response programs designed to reduce customer demand during peak load periods. The Commission approved Dynamic Pricing and Residential Direct Load Control Programs adopted in Commission Docket No. 09-311_and Commission Docket No. 11-330continue to support this planning objective[3].

Over the IRP Planning Period air emissions from power plants in Delaware, including carbon dioxide ("CO_2"), sulfur dioxide ("SO_2"), and nitrogen oxide ("NO_x"), are expected to generally decrease over the period 2017/18-2022/23 and then rise through 2026/27 and then reduce back to levels similar to 2017/18. The expected changes in the level of power plant emissions reflect a number of competing market driven forces including changes in relative fuel prices, environmental regulations, the increased use of natural gas fired power generation, energy efficiency and the increased penetration of renewable generation resources.

Delmarva Power has continued to manage a diverse portfolio of eligible renewable resources in order to comply with the State's Renewable Energy Portfolio Standard Act ("REPSA")[4]. Delmarva Power's renewable resource portfolio includes contracts with several wind generators, a large solar generation facility, multiple contracts with smaller distributed solar facilities and spot market purchases. The Company has agreed, as part of the Amended Settlement Agreement in the Delmarva Power/Exelon Merger, Docket No. 14-193, approved by Order No. 8746 dated June 2, 2015, to issue requests for proposals to purchase wind Renewable Energy Credits ("RECs") on commercially reasonable terms in three tranches: (1) the first, for RECs from one or more renewable generating facilities with an aggregate capacity of up to 40 mW (nameplate) beginning in compliance years 2017-2018 for a term of 10 to 15 years; (2) the second, for RECs from one or more renewable generating facilities with an aggregate capacity of up to 40 mW (nameplate) beginning in compliance years 2019-2020 for a term of 10 to 15 years; and (3) the third, for RECs from one or more renewable generating facilities with an aggregate capacity of up to 40 mW (nameplate) beginning in compliance years 2023-2024 for a term of 10 to 15 years.

Delmarva Power's renewable energy portfolio is also managed to take advantage of the REC and solar REC ("SREC") offsets provided by Qualified Fuel Cell Providers ("QFCP").

[3] See Order No. 8105, approved 1/31/12 and Order No. 8253, approved 12/18/12.

[4] 26 *Del. C.* §351, et. seq.

The projected impact on average SOS residential customer bills of meeting the REPSA standards over the IRP Planning Period ranges from $8.48/month in 2017/18 to a high of $9.03 in 2019/20, and to $8.75/month in 2026/27. It should be noted, however, that these amounts do not include other benefits associated with renewable generation (such as improved air quality due to avoided power plant emissions) that the Delaware Department of Natural Resources and Environmental Control ("DNREC") include in their official assessment of the costs of compliance with RESPA.[5]

B. Background

The 2016 IRP describes the Company's plan to procure the electrical energy requirements for its SOS customers for the IRP Planning Period. This IRP is filed pursuant to Title 26, Section 1007 (c) (1) of the Delaware Code, which provides, in part:

> [Delmarva Power] is required to conduct integrated resource planning. ….In its IRP, [Delmarva Power] shall systematically evaluate all available supply options during a 10-year planning period in order to acquire sufficient, efficient and reliable resources over time to meet its customers' needs at a minimal cost. The IRP shall set forth [Delmarva Power's] supply and demand forecast for the next 10-year period, and shall set forth the resource mix with which [Delmarva Power] proposes to meet its supply obligations for that 10-year period….

The statutory provisions make clear that while the IRP must investigate all potential opportunities for a diverse and reliable electric supply, including those that would create environmental benefits for Delaware, it must do so with a careful eye on costs. Delaware law specifically provides that in developing the IRP, the Company must seek to meet its customer's energy supply needs "at the lowest reasonable cost"[6] and "at a minimal cost"[7]. As such, the principal objectives of the IRP are to secure for SOS customers a reliable energy supply at a

[5]DNREC issued Secretary's Order No: 2015-EC-0047 Implementation of Renewable Energy Portfolio Standards Cost Cap Provisions on December 15, 2015.
[6] 26 *Del.C.*§1007(c)(1)(b).
[7] 26 *Del.C.*§1007(c)(1).

reasonable cost, maintain price stability and, at the same time, provide environmental benefits consistent with reasonable cost and price stability.

C. Delmarva Power

Delmarva Power is a regulated public utility company serving electric and gas customers in Delaware and portions of Maryland. In Delaware, as of September 30, 2016, the Company serves almost 307,000 electric energy customers, of which about 267,000 are residential customers.

Delmarva Power is an electric delivery company focusing on the transmission and distribution of electricity to its customers. The Company does not generate any electricity or own any generation facilities. Delmarva Power's Delaware operations are managed out of four in-state offices, one each in the City of Wilmington, New Castle County, the City of Millsboro and the City of Harrington. Among the Company's assets in Delaware are almost 890 miles of high voltage (69kV and higher) transmission lines, and 82 distribution and transmission substations.

Under Delaware's electricity deregulation laws, Delaware customers can choose their own electric energy supplier. Those customers who do not choose an alternate, competitive supplier are supplied by Delmarva Power through its SOS offering. As of September 2016, 89.4% of residential customers' electric usage was provided through the SOS offering, and about 81.2% of non-residential usage was provided by competitive suppliers. The 2016 IRP is focused on the procurement of the energy supply requirements of the SOS customers.

The number of customers and the breakdown of energy usage by residential and non-residential customers for both SOS and non- SOS service for the year ending September 2016, are shown in Table 1 and Table 2 below:

Table 1
Delmarva Power Delaware
Number of Customers
as of September 30, 2016

	SOS	Non-SOS	Total Customers
Residential	249,731	28,755	278,486
Non-Residential	23,377	11,710	35,087
Total Customers	273,108	40,465	313,573

Table 2
Delmarva Power Delaware
kWh Sales12 Months Ending September 2016

	SOS	Non-SOS	Total kWh
Residential	2,679,330,292	318,640,892	2,997,971,184
Non-Residential	926,509,702	3,999,394,802	4,925,904,504
Total KWh	3,605,839,994	4,318,035,694	7,923,875,688

D. 2016 Load Forecast

Table 3 and Table 4 below summarize the 2016 Baseline Load Forecast for the IRP Planning Period for all Delmarva Power Delaware customers by Residential ("Res"), Small Commercial ("Small Com"), Large Commercial and Industrial ("LC&I") class, including Hourly Power Service ("HPS"), and Street Lights ("SL") :

Table 3
Baseline Forecast Peak mW
All DPL DE Customers

	Res (mW)	Small Com (mW)	LC&I* (mW)	SL (mW)	Total (mW)
2017	817	34	938	0	1,788
2018	820	34	948	0	1,802
2019	824	34	957	0	1,815
2020	830	35	967	0	1,831
2021	839	35	977	0	1,851
2022	848	35	987	0	1,871
2023	858	36	998	0	1,891
2024	866	36	1,008	0	1,910
2025	875	36	1,018	0	1,930
2026	885	37	1,029	0	1,951

* includes HPS

Table 4
Baseline Forecast mWh
All DPL DE Customers

	RES (mWh)	Sm COM (mWh)	LC&I* (mWh)	SL (mWh)	Total (mWh)
2017	3,060,888	170,982	4,784,977	33,349	8,050,196
2018	3,058,450	172,323	4,822,509	33,399	8,086,681
2019	3,057,512	173,685	4,860,627	33,436	8,125,259
2020	3,062,970	174,933	4,895,567	33,475	8,166,945
2021	3,074,485	176,090	4,927,943	33,511	8,212,028
2022	3,085,019	177,214	4,959,403	33,544	8,255,181
2023	3,094,985	178,334	4,990,727	33,575	8,297,621
2024	3,104,704	179,420	5,021,133	33,604	8,338,862
2025	3,114,159	180,512	5,051,700	33,633	8,380,004
2026	3,123,347	181,612	5,082,479	33,660	8,421,098

* includes HPS

Much of the IRP is focused on Delmarva Power's efforts to supply energy to customers served through SOS. Table 5 below provides the Baseline Forecast mWh for SOS customers over the IRP Planning Period:

Table 5
Baseline Forecast mWh
DPL DE SOS Customers

	SOS RES (mWh)	SOS Sm COM (mWh)	SOS LC&I* (mWh)	SOS SL (mWh)	SOS Total (mWh)
2017	2,804,511	95,532	339,349	25,740	3,265,132
2018	2,802,277	96,282	342,011	25,779	3,266,348
2019	2,801,417	97,043	344,714	25,807	3,268,980
2020	2,806,418	97,740	347,192	25,837	3,277,187
2021	2,816,968	98,387	349,488	25,865	3,290,708
2022	2,826,620	99,015	351,720	25,890	3,303,245
2023	2,835,751	99,640	353,941	25,914	3,315,247
2024	2,844,656	100,247	356,097	25,937	3,326,938
2025	2,853,319	100,857	358,265	25,959	3,338,401
2026	2,861,738	101,472	360,448	25,980	3,349,638

* includes HPS

The Baseline Load Forecast for all Delmarva Power Delaware and SOS customers is described in more detail in Section 4 of the IRP. Appendix 4 provides more detailed documentation of the preparation of the load forecast.

E. Price and Price Stability

Over the IRP Planning Period, more natural gas generation within PJM is expected to come online than any other type of generation. Consequently, for this and other reasons, electricity supply prices within PJM are becoming increasingly sensitive to changes in natural gas prices. To evaluate this sensitivity, the IRP Reference Case, which includes a forecast of natural gas prices for the region over the planning horizon, was compared with a High Gas Price Case. Table 6 below shows the projected supply cost (energy, capacity and ancillary services) for the IRP Reference Case for SOS Residential and Small Commercial ("RSCI") and SOS Large Commercial ("LC") customers compared to the High Gas Price Case over the IRP Planning Period.

Table 6
Expected SOS Supply Costs RSCI and LC Customers
(Confidential Material Omitted*)

Planning Year	Case	RSCI $/MWh	LC $/MWh
2017/18	Reference Case		
	High Gas Case		
2018/19	Reference Case		
	High Gas Case		
2019/20	Reference Case		
	High Gas Case		
2020/21	Reference Case	$62.30	$54.89
	High Gas Case	$72.48	$64.19
2021/22	Reference Case	$65.24	$57.15
	High Gas Case	$77.25	$67.73
2022/23	Reference Case	$70.67	$60.79
	High Gas Case	$84.37	$72.28
2023/24	Reference Case	$75.92	$63.12
	High Gas Case	$90.75	$75.68
2024/25	Reference Case	$80.83	$65.75
	High Gas Case	$94.95	$77.64
2025/26	Reference Case	$84.90	$68.05
	High Gas Case	$99.41	$80.28
2026/27	Reference Case	$86.69	$69.39
	High Gas Case	$101.53	$81.58

*The pricing information provided for the period 2017/2018 – 2019/2020 is confidential until the results of the on-going SOS auction becomes publically available in Spring 2017.

As expected, prices under the High Gas Case are greater than under the IRP Reference Case. The extent of this difference in energy supply costs between the IRP Reference Case and the High Gas Case for RSCI and LC SOS customers is shown in percentage terms in Table 7 below.

Table 7
Percentage Increase in SOS Supply Costs
High Gas Case vs. IRP Reference Case

Planning Year	RSCI	LC
2017/18	2.87%	11.88%
2018/19	7.06%	12.94%
2019/20	13.12%	15.02%
2020/21	16.35%	16.95%
2021/22	18.42%	18.51%
2022/23	19.38%	18.91%
2023/24	19.53%	19.89%
2024/25	17.47%	18.07%
2025/26	17.09%	17.97%
2026/27	17.12%	17.56%

Table 8 below presents a projection of the retail customer energy supply tariff rates which include the cost of energy, capacity, ancillary services and other adjustments for residential customers served under the "R" tariff and commercial customers served under the "MGS-S" tariff for the period 2017 through 2022. The projections are based on the IRP Reference Case.

Table 8: Customer Energy Supply Rate Projections (Confidential Material Omitted)*

Planning Year	Residential Tariff "R" Energy (Cents/kWh)		MGS-S Rates Demand ($/kW)		MGS-S Rates Energy (Cents/kWh)	
	Summer	Winter	Summer	Winter	Summer	Winter
2017/18						
2018/19						
2019/20						
2020/21	6.25	7.94	8.57	6.48	2.95	4.30
2021/22	6.23	7.65	8.72	6.72	3.00	4.45

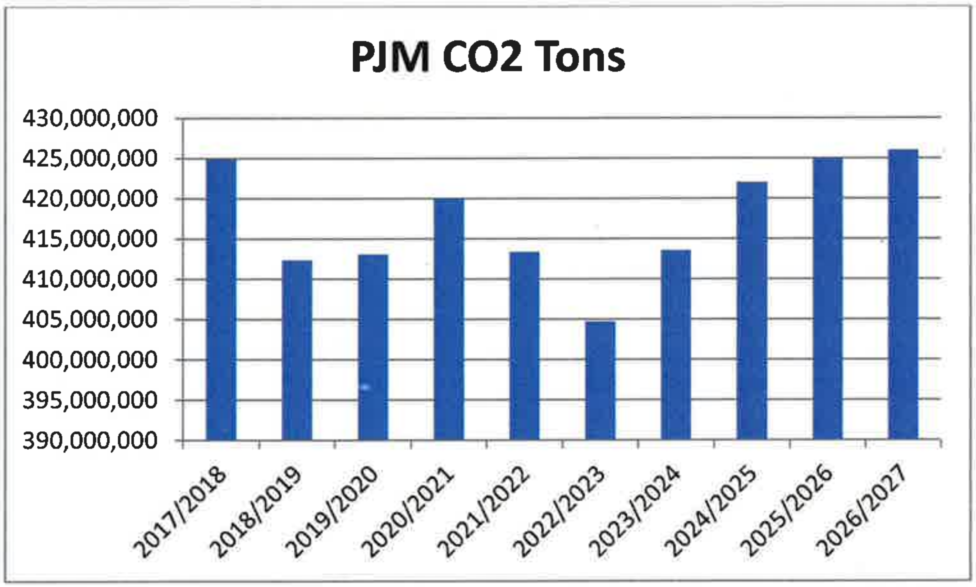
* The pricing information provided for the period 2017/2018 – 2019/2020 is confidential until the results of the on-going SOS auction becomes publically available in Spring 2017.

F. Environmental Issues

- **PJM Emissions**

The following charts show emissions from power plants for the PJM region over the IRP Planning Period. Over this Period, although coal fired capacity is expected to decrease from plant retirements, some nuclear plants are expected to retire and be replaced, in part, with gas fired generation resources. Since nuclear plants do not have any CO_2 emissions, overall CO_2 emissions are expected to increase slightly over this Period with the increase being moderated by increasing levels of wind and solar resources. Expected PJM CO_2 emissions over the IRP Planning Period are shown in Figure 2 below:

Figure 2



For PJM, the emissions for SO_2 are expected to decrease over the IRP Planning Period because of the decrease in coal fired generation. However, in some years of the Planning Period there is an increase in SO_2 emissions in relation to prior years because the improvement in the relative price of coal to natural gas in those years causes modest increases in coal generation in those years. A similar pattern holds for overall PJM NO_x emissions over the Planning Period. These results are shown in Figure 3 and Figure 4 below:

Figure 3

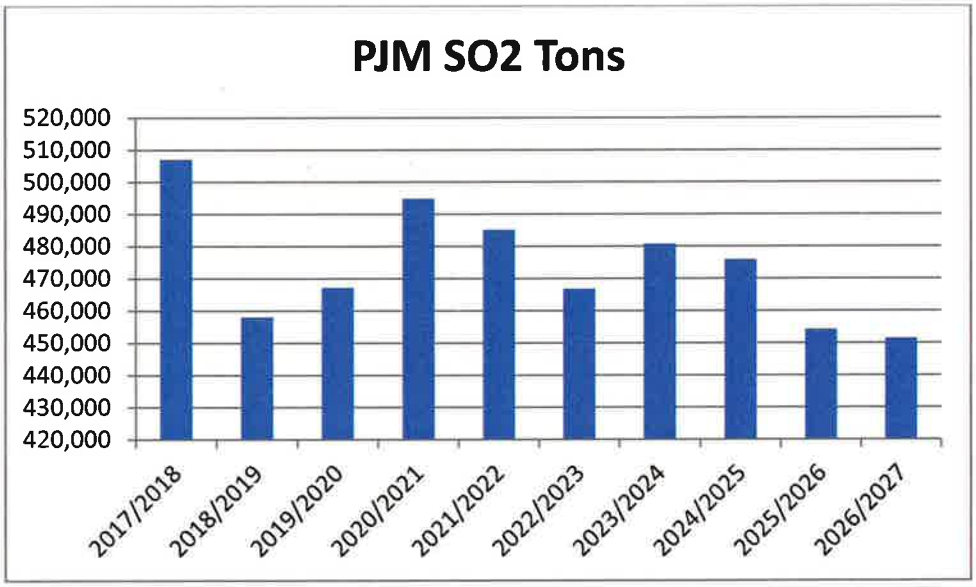
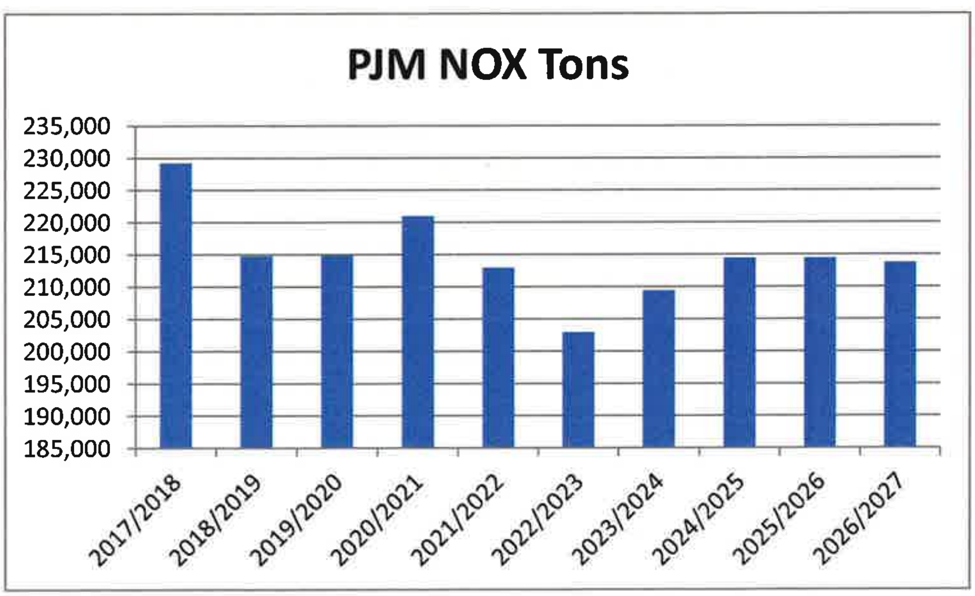


Figure 4



- **Delaware Emissions**

While the State of Delaware is a participant in the Regional Greenhouse Gas Initiative ("RGGI"), a cap and trade program for CO_2, a number of nearby states do not participate in RGGI. Power plants that emit CO_2 in these non-RGGI states enjoy an economic advantage over power plants in RGGI states since they do not have to explicitly pay for CO_2 emissions. Over the IRP Planning Period, this economic advantage is essentially eliminated beginning in 2022 when the IRP assumes that a national carbon tax is implemented. This, in turn, makes fossil-fired generation in Delaware relatively more competitive with the non-RGGI generators, thereby increasing local generation (mWh) in Delaware. Expected power plant emissions in Delaware are shown in Figures 5, 6, and 7 below.

Figure 5

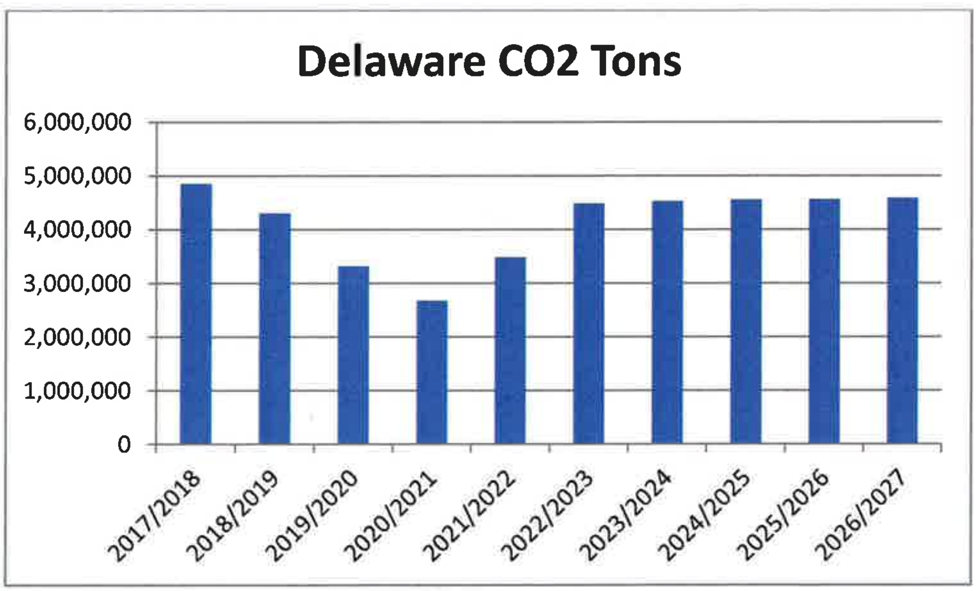
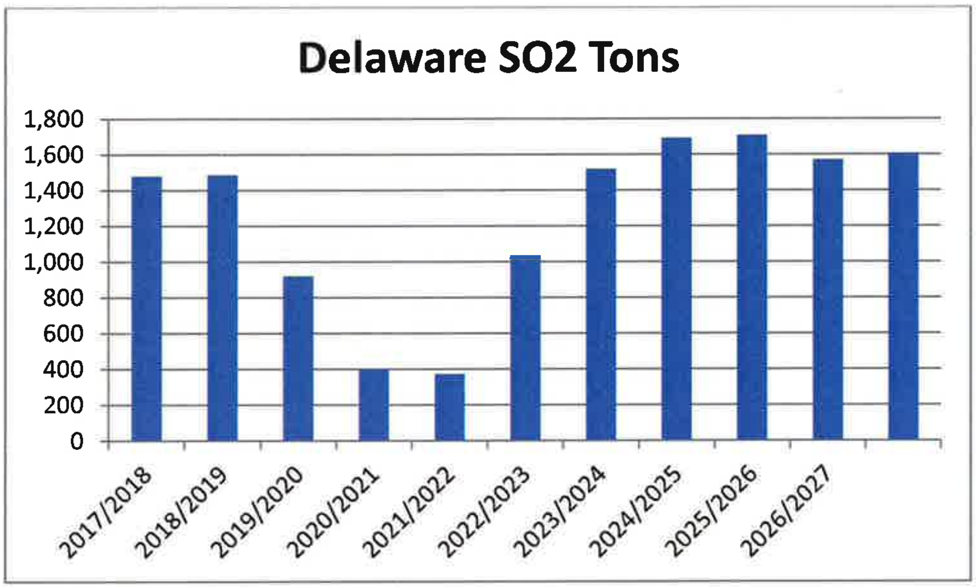
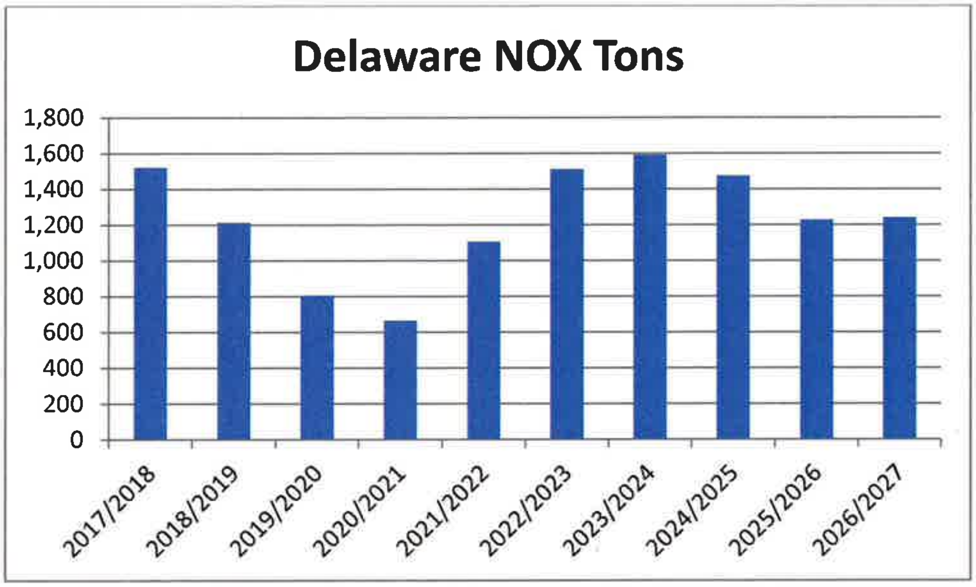


Figure 6



Delaware SO2 Tons
1,800
1,600
1,400
1,200
1,000
800
600
400
200
0
2017/2018
2018/2019
2019/2020
2020/2021
2021/2022
2022/2023
2023/2024
2024/2025
2025/2026
2026/2027

Figure 7



Detailed information on past levels of annual air emissions from power plants in PJM and in Delaware is provided in Appendix 6.

The regulations governing the preparation of Delmarva's IRP require that the Company include an evaluation and give consideration to environmental benefits and externalities associated with specific methods of energy production[8]. On March 15, 2016, DNREC implemented the final rules for estimating the cost caps associated with RPS compliance[9] which prescribed specific values for the benefits of emissions avoided by the RPS. Based on DNREC's prescribed methods and the analysis provided in Section 8 of this IRP, the value of improving air quality resulting from reducing air emissions due to implementation of the RPS is expected to range from about $27.8 million in 2017/18 to a high of $42.7 million in 2025/26.

[8] 26 *Del. Admin. C.* 3010, §6.1.4.

[9] See: **"Director's Determination under 26 Del.C. §354(i) & (j) and 7 DE Admin. Code 104, Implementation of Renewable Energy Portfolio Standards Cost Cap Provisions,"** March 15, 2016.

G. Renewable Energy

In order to comply with the RPS, Delmarva Power manages a portfolio of renewable resources that can be supplemented with RECs and SRECs offsets from the QFCP, as well as spot market purchases. Renewable energy resources in Delmarva Power's existing renewable energy portfolio include:

1. Contracts for the RECs and mWh output of the AES Armenia Mountain, Gestamp Roth Rock, and Gamesa Chestnut Flats wind farms totaling 128 mW;
2. A contract to purchase 70% of the SRECs from the 10 mW Dover Sun Park; and
3. Over 30 mW of SRECs purchased from the Delaware Sustainable Energy Utility (SEU) through the SREC Procurement Pilot Program, the 2013 SREC Procurement Program, the 2014 SREC Procurement Program, the 2015 SREC Procurement Program, and the 2016 SREC Procurement Program.

Securing the RECs, SRECs, and QFCP offsets needed to comply with the State RPS requirements is forecast to increase a typical 1,000 kWh residential monthly bill by $8.48 in compliance year 2017 (June 1, 2017 - May 31, 2018). The impact of RPS compliance on a typical residential customer bill is expected to increase to $9.03 per month in 2019/20 and fall to $8.75 in 2026/27. In December 2015, DNREC finalized rules for calculating the cost caps associated with RPS requirements. These amounts do not include other benefits associated with renewable generation (such as improved air quality due to avoided power plant emissions) that the DNREC include in their official assessment of the costs of compliance with RESPA. This is discussed in more detail in Section 8 of this IRP.

H. IRP Planning Objectives and Action Plans

Delmarva Power follows six planning objectives in preparing this IRP as follows:

1. Reasonable Cost and Price Stability;
2. Meet or Exceed Reliability Standards;
3. Obtaining Renewable Energy through a diverse portfolio at reasonable costs;
4. Implementing cost effective Demand Response Programs;
5. Meeting Energy Efficiency Goals; and
6. Implementing Utility Sponsored Energy Efficiency Programs.

For each of these six objectives, the following tables include objective measures, progress made towards meeting the objectives since the 2014 IRP was filed in December 2014, and action plans for the future.

Planning Objective	Objective Description	Measures	Progress Since 2014 IRP	Action Plan
I. Reasonable Cost and Price Stability	a) Delmarva Power will evaluate generation, transmission and demand side resource options during the IRP Planning Period to ensure that sufficient and reliable resources are acquired at a reasonable cost to meet customer needs. b) Delmarva Power will seek to provide year over year price stability in the prices paid by SOS customers for their total electricity supply.	a) Obtain Commission concurrence that the IRP does not appear unreasonable in meeting these objectives. b) Provide the Commission with information showing changes in rates and procurement cost adjustments.	The Commission issued Order No. 8779 in October 2015 which ratified the 2014 IRP. Delmarva Power has continued to procure Full Requirements Service (FRS) for its SOS customers through the Commission approved reverse auction process. Delmarva Power's strategy is to procure approximately one third of the expected SOS requirements for a three year contract term on an annual basis. The year over year results for Residential and Small Commercial SOS customers since the 2014 IRP are: <u>2015 over 2014</u>: -2.42% <u>2016 over 2015</u>: -9.52%	The following actions are expected to occur in the next five years: a) In accordance with Electric Utility Retail Customer Supply Act, the Company will prepare and file an Integrated Resource Plan every two years. The IRP will include a systematic evaluation of generation, transmission, and demand side resource options. Under this schedule, Delmarva Power will file the next IRP on or before December 1, 2018. b) The IRP will provide an evaluation of the planning Reference Case showing both the expected outcome in terms of average price and potential ranges of outcomes around the expected price.

Planning Objective	Objective Description	Measures	Progress Since 2014 IRP	Action Plan
II. Reliability	Ensure that the electric system serving Delmarva Power's customers meets all NERC, RFC, PJM, PHI and Delaware transmission electrical reliability requirements.	a. Complete PJM approved zonal RTEP projects on schedule as listed on the "RTEP Construction Status" page on the PJM Website www.pjm.com). b. Meet or Exceed Reliability standards in DE PSC Docket 50 "Electric Service Reliability and Quality Standards." From Section 4 of that document, transmission "Reliability and Quality Performance Benchmarks" include: i. Transmission CAIDI & SAIDI (excluding major events) as part of the overall system CAIDI and SAIDI; and, ii. Constrained hours of operation.	A number of major transmission system upgrades, including PJM approved zonal RTEP projects, have been completed by Delmarva Power since the 2014 IRP was filed. Among other projects, this includes the construction of the Wye Mills – Church 138kV line, the re-build of the Glasgow-Cecil 138kV line, installation of 2-15MVAR capacitors at Loretto 69kV, installation of new variable reactors at New Castle 138kV and the reconfiguration of the existing 69kV capacitor position at Sussex. In April 2016, as part of PSC Docket 50, Delmarva provided project updates to the Commission as part of the annual "Reliability Performance Report" which showed that Delmarva Power met the standards established by the Commission.	The following are expected to occur annually for the next five years: a) Complete all approved PJM RTEP Delmarva Zone projects by required in-service dates. b) Provide updates for annual Docket 50 transmission standards targets (in "Reliability Planning and Studies Report" - submitted annually in March for the current calendar year) and performance (in "Reliability Performance Report" - submitted annually in April for the previous calendar year).

Planning Objective	Objective Description	Measures	Progress Since 2014 IRP	Action Plan
III. Renewable Energy	a) Obtain Renewable Energy through a diverse portfolio of renewable energy resources at reasonable cost. b) Prepare a plan to obtain Renewable Energy Credits (RECs) from resources over the IRP Planning Period sufficient to meet the requirements of the Renewable Energy Portfolio Standards Act (REPSA). c) Prepare a plan to obtain sufficient solar resources to meet the State of Delaware's RPS requirements for solar photovoltaic resources. d) Avoid alternative compliance payments under the State RPS. e) Consistent with DREC's final regulations, provide cost of RPS compliance information as needed.	a) Meet the annual RPS requirements for customers through a portfolio of contracted wind and solar resources, offsets from Qualified Fuel Cell Providers, SRECs purchased from the SEU, and balanced with purchases from competitive short-term markets. b) Minimize alternate compliance payment requirements. c) Provide information needed by DNREC to determine the cost of RPS compliance. d.) Submit certified annual RPS Compliance Report with the Commission for each planning year.	On July 21, 2015 the Commission approved the 2015 Delaware SREC Procurement Program. This program secured SRECs from 396 projects that represent 8.2 mW of solar facilities. Filed the June 2014 - May 2015 RPS Compliance Report with the Public Service Commission in September, 2015. No alternate compliance payments were made. On May 3, 2016, the Commission approved the 2016 Delaware SREC Procurement Program. This program secured SRECs from 168 projects that represent 8.2 mW of solar facilities. Filed the June 2015 - May 2016 RPS Compliance Report with the Public Service Commission in September, 2016. No alternate compliance payments were made.	The following are expected to take place over the next five years: 1. Continue to receive energy and RECs through Commission approved contracts with wind generators. 2. Continue to receive SRECs from Commission approved contracts with solar providers. 3. Subject to Commission approval, issue RFP's for up to 40mW worth of RECs from wind generators in 2017/18, 2019/20, and 2023/24. 4. Incorporate REC and SREC offsets derived from the Bloom Energy Project to help meet the State RPS in the most cost-effective manner.

Planning Objective	Objective Description	Measures	Progress Since 2014 IRP	Action Plan
IV. Demand Response (DR)	Implement Commission approved, utility provided, technically feasible, and cost effective demand response programs	Peak demand reduction achievements have been measured each year beginning in 2013. The Energy Wise Rewards program results are filed quarterly with the Delaware Public Service Commission and the Peak Energy Savings Rebate program results are filed annually with the Delaware Public Service Commission.	Demand response programs have been enabled by the deployment of Advanced Meter Infrastructure (AMI) in Delaware. The Peak Energy Savings Rebate program has been initiated for DP&L SOS customers. This program has been in operation since 2014, and will continue to be operated going forward. DP&L also continues to operate the Energy Wise Rewards Direct Load Control Program. There are approximately 50,0000 participating customers in this program. Program results through September 2016 have been filed with the Commission. Future results will be filed quarterly.	**Residential DR Programs** Over the next two years: 1. Continue Peak Energy Savings Rebate and Direct Load Control Program education efforts. 2. Conduct program load reduction events. **Non-Residential DR Programs** 1. Prepare and file testimony seeking Commission authorization to establish a non-residential Direct Load Control Program for air conditioning systems. Delmarva Power will monitor and evaluate the impacts of these Programs and request program revisions and improvements as needed over the next 5 years.

Planning Objective	Objective Description	Measures	Progress Since 2014 IRP	Action Plan
V. Energy Efficiency	Collaborate with key stakeholders of the Energy Efficiency Advisory Council ("EEAC"), as well as Commission Staff and the DPA as enabled by the 2014 revisions to the Energy Efficiency Act of 2009 to successfully implement cost-effective energy efficiency programs on a timely basis for Delmarva Power customers.	On August 6, 2014 Gov. Markell signed SB150, which, among other things, included revisions to the Energy Efficiency Act of 2009 to allow Delmarva Power to implement cost-effective energy efficiency programs. The Company is currently working with the EEAC to develop appropriate measures for its customers.	The SEU has continued to obtain energy efficiency savings through implementation of the programs under its supervision. The Company has put forth a straw proposal to the EEAC that comports with the requirements of SB150.	Delmarva Power will continue to work collaboratively with the other stakeholders to effectively and timely implement energy efficiency programs consistent with the provisions of SB 150.

Planning Objective	Objective Description	Measures	Progress Since 2014 IRP	Action Plan
VI. Utility Provided Energy Efficiency Programs	Implement utility energy efficiency initiatives such as transmission and distribution system improvements and street lighting upgrades.	These programs/initiatives are implemented as available operational opportunities occur. Transmission and distribution improvements follow the processes and procedures as outlined in the PJM RTEP process, while transformer upgraders occur upon failure of existing equipment.	1. Continued installation of high efficiency transformers and replaced transmission conductors. 2. Continued installation of distribution line capacitors, which resulted in lower losses on the system. 3. Continued replacement of Mercury Vapor (MV) streetlights with High Pressure Sodium (HPS) streetlights.	1. Implement transmission and distribution improvement measures as described in the PJM RTEP. 2. Continue installation of high efficiency transformers. 3. Continue streetlight improvement plan. 4. Work with SEU to determine other program utility implementation opportunities.

I. Recommended Path Forward

Upon receipt of this filing, the Delaware Public Service Commission will open a docket for the review and evaluation of the 2016 IRP. Because the IRP Working Group has provided an effective way to share information among stakeholders in a collaborative and transparent manner for the last several IRP's, Delmarva Power recommends that the Commission continue to take advantage of the IRP Working Group process and allow the IRP Working Group to review and evaluate the 2016 IRP. Specifically, Delmarva Power would suggest that the Working Group meet to discuss the 2016 IRP and allow Delmarva Power the ability to answer the parties' questions prior to the parties filing their comments in the appropriate Docket. This will allow for timely and effective sharing of information, allow Delmarva to provide additional clarification as necessary, and provide greater focus on any areas of concern among the parties that may arise.

As the IRP Working Group process proceeds, the Company's current renewable portfolio and SOS procurement strategies, which have been developed and refined with Commission approval on an on-going basis, will continue.

SECTION 2

Section 2.

Events Since the Filing of the 2014 IRP

Pursuant to the Electric Utility Retail Customer Supply Act ("EURCSA") enacted in 2006, Delmarva Power is required to prepare and file an Integrated Resource Plan ("IRP") every two years[1]. The IRP is designed to provide a comprehensive review of Delmarva Power's plans to procure energy for SOS customers over a ten year period[2].

Prior to the 2016 IRP, the most recent IRP prepared by Delmarva Power was filed with the Commission on December 1, 2014 ("2014 IRP"). The 2014 IRP was submitted under the regulations adopted by the Commission on December 8, 2009, pursuant to Order No. 7693, in PSC Regulation Docket No. 60[3]. On October 6, 2015, the Commission issued Order No. 8779 which ratified the 2014 IRP. A copy of Order No 8779 is provided as Appendix 3.

After the issuance of Order No. 8779, Delmarva Power held a working group meeting with interested parties to discuss the planning and development of the 2016 IRP. The topics discussed at the working group meeting included: changes in the PJM capacity pricing model, demand side management, planned sensitivity analyses, and IRP model assumptions. Those parties participating in the working group meeting were Delmarva Power, Commission Staff, DNREC, the Division of the Public Advocate ("DPA"), the Caesar Rodney Institute ("CRI"), the Mid Atlantic Renewable Energy Coalition("MAREC"), NRG and Calpine.

One of the challenges of preparing an IRP is to keep the planning assumptions underlying the resource analysis as current and accurate as can be reasonably expected given the time and resource requirements of developing an IRP. Since the filing of the 2014 IRP on December 1, 2014, a number of events have taken place that impact or may impact the preparation and development of the 2016 IRP. The 2016 IRP incorporates these events into the resource planning analysis to the extent such information was available or known before the analysis for the IRP needed to begin in order to meet the December 1, 2016 filing requirement. Brief descriptions of the more important events that have occurred from a resource planning perspective since the 2014 IRP was filed and ratified are described below.

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[1] 26 *Del. C.* §1007(c)(1).

[2] *Id.*

[3] 26 *Del. Admin. C.* 3010.

RFPs for Renewable Energy Credits

As part of the merger with Exelon, and for the purpose of meeting the renewable portfolio standards under current law, Delmarva Power plans to issue a competitive request for proposals ("RFP(s)") to purchase wind RECs on commercially reasonable terms in three tranches: (1) the first, for RECs from one or more renewable generating facilities with an aggregate capacity of up to 40 mW (nameplate) beginning in compliance years 2017-2018 for a term of 10 to 15 years; (2) the second, for RECs from one or more renewable generating facilities with an aggregate capacity of up to 40 mW (nameplate) beginning in compliance years 2019-2020 for a term of 10 to 15 years; and (3) the third, for RECs from one or more renewable generating facilities with an aggregate capacity of up to 40 mW (nameplate) beginning in compliance years 2023-2024 for a term of 10 to 15 years. If circumstances or conditions change (including but not limited to a material change in the projected load of Delmarva Power such that fewer RECs are required, or there is a substantial change in the cost of RECs through the spot market such that additional spot-market purchases in lieu of long-term contract purchases would be more appropriate), the parties will work in good faith with each other and present any proposed modification to the Commission as may be warranted by those changed conditions.

Energy Efficiency

As part of the IRP, the Company must include a detailed description of its energy efficiency activities. Subsection 1020 of Title 26 of the Delaware Code provides that electricity demand response programs will be implemented by Delmarva Power while demand-side management and other energy efficiency activities are to be implemented by the SEU in collaboration with Delmarva Power. The contributions of these programs are considered in meeting the requirements set forth in the Energy Efficiency Resource Standards Act of 2009 (the "Act")[4] which was enacted by the General Assembly to promote the implementation of cost-effective end-user energy efficiency savings opportunities. The Act established energy efficiency goals to be achieved by the Company by 2015.

In August of 2014, Governor Markell, signed into law Senate Bill 150 ("SB 150") which, among other things, made certain changes to the energy efficiency program requirements by requiring that each affected energy provider implement energy efficiency, energy conservation, and peak demand reduction programs that are cost-effective, reliable and feasible as determined by regulations to be subsequently adopted through DNREC in collaboration with the SEU. To accomplish this, SB 150 established an Energy Efficiency Advisory Council ("EEAC") to be headed by the Secretary of DNREC. The EEAC is charged with assisting affected energy providers in the development of energy efficiency, peak demand reduction and emission-reducing fuel switching programs, and works in collaboration with Commission Staff and the DPA. The EEAC is also tasked with establishing methods to evaluate, measure and verify the energy savings resulting these programs. Based on the recommendations of the EEAC, Delmarva

[4] 26 *Del. C.* §1500, et. seq.

Power will submit three year program implementation plans to the Commission for approval. If the Commission approves the programs, Delmarva Power could proceed with implementation. It is anticipated that this process, by broadening the Company's ability to participate alongside the SEU in pursuing energy efficiency, will greatly expand the effective delivery of energy efficiency savings programs to Delmarva Power's customers.

Since the filing of the 2014 IRP, the EEAC has met regularly, including Council members, stakeholders, subject matter experts and members of the public. The EEAC has put forth statewide goals, worked to develop an Evaluation, Measurement & Verification framework that has been submitted for consideration, and several members have proposed and started the implementation of programs. Delmarva Power has presented several proposals to the EEAC for energy efficiency programs in Delaware. These programs are described in more detail in Section 5 of the 2016 IRP.

Programs to Procure Solar Renewable Energy Credits

On July 21, 2015, the Commission approved Delmarva's proposed 2015 Program for the Procurement of Solar Renewable Energy Credits (the "2015 SREC Program")[5]. The 2015 SREC Program was based on the requirements of the Renewable Energy Portfolio Standards Act ("REPSA")[6], the recommendation of the Renewable Energy Task Force (which is charged with making such recommendation to the Commission), and the prior programs for the Procurement of Solar Renewable Energy Credits which had been approved by the Commission[7]. Under the 2015 SREC Program, the SEU conducted a competitive auction to secure 20 year contracts for SRECs from private solar developers. Contracts accepted by the SEU and approved by the Commission were transferred to Delmarva Power. The 2015 SREC Program resulted in awards for 396 projects for the SRECs produced by 8.2 mW of new solar systems.

On May 3, 2016, the Commission approved the Company's proposed 2016 Program for the Procurement of Solar Renewable Energy Credits (the "2016 SREC Program")[8]. The 2016 Program is similar to the 2015 Program except for some minor revisions. The 2016 SREC Program resulted in awards for 163 projects for the SRECs produced by an additional 8.2 mW of new solar systems.

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[5] PSC Docket No. 14-0560, approved by Order No. 8717 dated 3-3-15 and Order No. 8764 dated 7-21-15.

[6] 26 *Del. C.* §351, et. seq.

[7] PSC Docket No. 11-399, approved by Order No. 8075 dated 11-8-11 and Order No. 8091 dated 12-20-11; and PSC Docket No. 12-526, approved by Order No. 8281 dated 1-22-13 and Order No. 8450 dated 9-10-13; and PSC Docket No. 14-41, approved by Order No. 8551 dated 4-15-14 and Order No. 8629 dated 9-9-14.

[8] See PSC Order No. 8884 in Docket No. 15-1472. Thereafter, the Commission issued final Order No. 8890 dated 9-6-16.

New Combined Cycle Natural Gas Generation

Calpine completed construction of a 309 Mw combined cycle gas-fired generation plant on a 37 acre site in Dover, Delaware in 2015. The facility, referred to as the *Garrison Energy Center*, cleared the relevant PJM RPM capacity auctions and began commercial operation in June 2015. Consequently, the *Garrison Energy Center* is included as a resource in the 2016 IRP. The *Garrison Energy Center* was constructed as a merchant facility without a long term power purchase agreement.

PJM Capacity Market

PJM, the FERC-jurisdictional Regional Transmission Organization covering Delaware, coordinates electric markets, dispatch and transmission planning across thirteen states and the District of Columbia. PJM initiated the Reliability Pricing Model ("RPM") in 2007 to establish a market-based mechanism to procure capacity commitments that assure resource adequacy for a term of one year, secured three-years forward. Historically, RPM has accommodated multiple capacity products. Notably - from inception through the 2017/2018 Delivery Year – PJM rules permitted generation, demand response and energy efficiency resources to offer annual capacity commitments, while also providing demand response and energy efficiency resources the ability to offer commitments for summer peak and extended summer periods, respectively.

Subsequently, in 2015, the FERC approved proposed RPM modifications to institute a single, annual capacity product for all resource technologies, named "Capacity Performance." FERC approved various transition mechanisms for Delivery Years 2016/2017 through 2019/2020, generally accommodating a mix of annual and sub-annual capacity commitments.

Commencing with the 2020/2021 Delivery Year, PJM will only procure Capacity Performance commitments from eligible resources able to provide energy in the subject Delivery Year whenever dispatched, without regard to season, time of day, duration of the dispatch or number of calls. A key feature of the Capacity Performance reforms was to increase performance risk for committed resources. Resources will compete in auctions to supply capacity commitments. Winning resource offers will receive a capacity payment in exchange for a commitment to provide energy whenever called during the relevant Delivery Year. Except for very limited circumstances, resources that fail to provide energy when dispatched will be subject to penalties of several thousands of dollars per Megawatt-hour. Resources that fail repeatedly or for long periods of time could be penalized up to 1.5 times the annual capacity payment.

These reforms will foreclose demand response resources without annual capability from committing as a capacity resource. However, the reforms permit resources with sub-annual capability to aggregate to form a synthetic annual resource and compete for capacity commitments. On November 16, 2016, PJM filed for approval from the FERC for improvements to increase opportunities for seasonal resources to participate in the capacity auctions. The proposal enhances aggregation rules for seasonal resources to satisfy Capacity Performance requirements, such as year-round availability.

Following are the clearing results for each of the last three RPM Base Residual Auctions ("BRA") for the "EMAAC" Locational Deliverability Area in which DPL is priced. These are the clearing results applicable to the DPL service territory. Note that in addition to the BRAs, PJM also hosts three Incremental Auctions ("IA") for each Delivery Year. The purpose of the IAs is to adjust PJM's capacity procurement consistent with changes in the load forecast, and to provide committed resources and opportunity to procure replacement capacity for committed resources. While IA outcomes are integrated with the results of the RPM BRA (typically run annually in May) to establish the total capacity value paid by load, the table below does not reflect the IA results to date since the IAs are not complete and because they typically modify the BRA price by only a small fraction.

EMAAC	2017/18	2018/19	2019/20
Capacity Performance	151.50*	$ 225.42	$ 119.77
Base	n/a	$ 210.63	$ 99.77
Annual	$ 120.00	$ 149.98	$ 119.77
Ext. Summer DR	$ 120.00	n/a	n/a
Limited DR	$ 106.02	n/a	n/a

*Transition Auction

In conjunction with the implementation of the capacity performance reforms, PJM hosted a transitional procurement of capacity performance resources for the 2017/18 Delivery Year ("Transition Auction"). The Transition Auction provided for new and existing resources including resources previously committed to provide the legacy capacity product to commit to provide the new CP product in which nearly all annual performance risk is shifted to the supplier. PJM procured the target volume of Capacity Performance commitments, without locational consideration, equal to 112,194.5 mW (70% of the updated RTO reliability requirement) at a price of $151.50/mW-day. Due to the acquisition of 10,017 mW of capacity commitments from new entrants in this transitional auction procurement, PJM will auction off an excess 10,017 of legacy commitments (i.e., non-Capacity Performance commitments) in the 3rd Incremental Auction scheduled to begin on February 27, 2017.

Environmental Regulations

Environmental regulations affecting power plants in PJM and elsewhere can impact future costs of electricity in Delaware.

- **The Clean Power Plan and EPA Rule 111(d): Emission Guidelines for Existing Stationary Sources**

On June 2, 2014, the United States Environmental Protection Agency ("EPA") released proposed rules regarding the regulation of emissions of CO_2 from existing Electric Generating Units ("EGU's"). The proposed rules, entitled "Emission Guidelines for Existing Stationary Sources, EGU's", were issued under Sec 111(d) of the Clean Air Act. In the rules, EPA proposed enforceable state-by-state CO_2 performance goals commonly known as the Clean Power Plan ("CPP"). After receiving extensive comments, the U.S. EPA's final CPP rule governing CO_2 emissions from power plants, was issued on October 23, 2015. The CPP sets emission performance standards for fossil fuel-fired power plants, with requirements beginning in 2022 for existing sources. At the same time, the EPA took public comment on model rule options and a potential federal plan that would be implemented in states that elect not to develop their own implementation plan.

In February 2016 the United States Supreme Court, by a vote of 5 to 4, issued a stay of the CPP prior to the completion of litigation underway at the D.C. Circuit Court. Implementation of the CPP is now stayed pending review by the U.S. Supreme Court.

- **EPA Mercury and Toxic Standards**

The EPA released final Mercury and Air Toxics Standards ("MATS") on December 16, 2011 (the "MATS Rule"). The MATS Rule established standards designed to reduce mercury, acid gas and other Hazardous Air Pollutants ("HAP") emissions from coal- and oil-fired power plants. It was upheld in the D.C. Circuit Court and compliance with the MATS Rule was required for most generating units starting April 16, 2015, and for all generating units by April 16, 2016. On appeal, the U.S. Supreme Court decided in May 2015 that the U.S. EPA should have considered costs in determining whether it is appropriate and necessary to regulate HAPs emitted by coal and oil-fired power plants. The U.S. Supreme Court, however, did not vacate the MATS Rule; rather, the case was remanded to the D.C. Circuit Court to resolve (all substantive issues were upheld by the D.C. Circuit Court and not considered by the Supreme Court). As such, the MATS Rule remains in effect.

The MATS Rule, in conjunction with other environmental regulations and recent lower energy prices in markets, has led to the retirement of a significant number of coal-fired power generation plants, with remaining in-service units having installed the necessary pollution control equipment to comply with the MATS Rule.

- **Cross State Air Pollution Rule**

In December 2015, the U.S. EPA proposed to update its Cross-State Air Pollution Rule ("CSAPR") to require additional ozone season NOx emission reductions in the eastern United States to support regional attainment of the 2008 ozone National Ambient Air Quality Standards

("NAAQS"). On September 7, 2016, the EPA finalized the update to CSAPR for the 2008 ozone NAAQS by issuing the final CSAPR Rule Update. Starting in May 2017, CSAPR is intended to reduce summertime (May - September) NO_X emissions from power plants in 22 states in the eastern U.S., aiming to reduce ground-level ozone exposure. The CSAPR will reduce the air quality impacts of ozone pollution that crosses state lines and will help downwind areas meet and maintain the 2008 ozone air quality standard. The final CSAPR includes power sector emission budgets (state level emission limits beginning in 2017) and allowance trading programs for implementation.

- **EPA Clean Water Act Section 316(b)**

On October 14, 2014, the U.S. EPA's final Clean Water Act Section 316(b) rule went into effect ("CWA Rule"). The purpose of the CWA Rule is to minimize the impacts of power plant cooling water intake structures on aquatic life. Under the CWA Rule, operators select from a variety of pre-approved environmentally effective measures to minimize impacts to aquatic life. Alternatively, the operator may develop site-specific technologies or operating practices that need approval by the state permitting director. The CWA Rule also requires that a series of studies and analyses be performed to ensure that selected measures are effective. There is no fixed compliance schedule since the timing for each facility is related to the status of its current National Pollutant Discharge Elimination System ("NPDES") permit, and the subsequent renewal period, but, in general, these measures will be completed within the next decade. Certain parties are pursuing legal challenges to the final CWA Rule through the federal court system.

SECTION 3

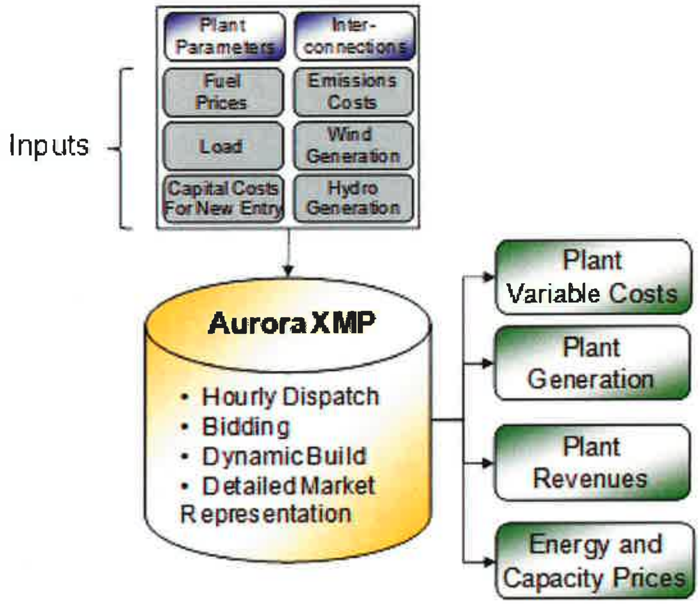
Section 3:
Overview of The IRP Model and Modeling Structure

Pace Global deploys an hourly chronological dispatch model to simulate the economic dispatch of power plants within a competitive framework. Representations of hourly regional demand profiles and plant-level supply characteristics are included, as well as detailed assessments on the fundamental drivers of power plant dispatch within each relevant market area. Key components of the methodology include:

- **Load Forecast:** Pace Global independently develops regional load forecasts based on the historic relationship between economic drivers, weather, and load.
- **Regional Fuel/Emission Projections:** Pace Global develops independent projections of fuel and emission pricing inputs based on the fundamental drivers of each market and a comprehensive review of regulatory environments. Our natural gas market modeling is performed in the Gas Pipeline Competition Model ("GPCM"), which assesses the fundamental relationships between supply and demand across all sectors.
- **Renewable Generation Profiles:** Pace Global analyzes the historic generation of renewable technologies throughout its modeling regions in order to characterize renewable generation profiles.
- **Bidding Function:** Pace Global's market simulations incorporate bidding behavior and scarcity premiums in our dispatch algorithm. Each region's bidding function is based on hourly analyses of the historic relationship between prices and reserve margins
- **Dynamic Capacity Expansion:** Gas-fired, wind, and solar capacity expansions are built dynamically when observed margins reach a specified threshold.

A summary of the methodology with key inputs, algorithms, and outputs is shown in Figure 1 below:

Figure 1
Pace Global Market Analysis Methodology



Source: Pace Global

Dynamic Build Capacity Expansion

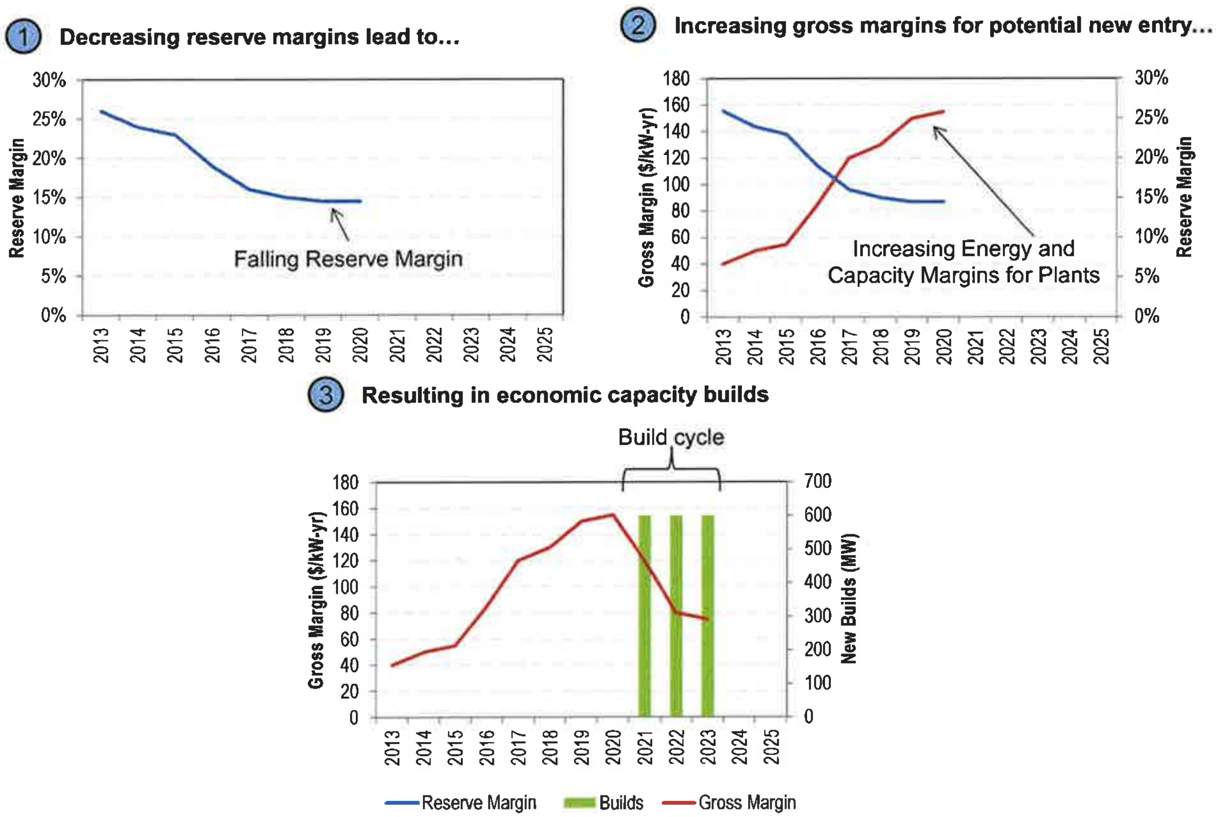
Dynamic simulations of additional economic capacity are incorporated in long term analyses. With this approach, incremental capacity expansion is expected when economic conditions provide a sufficient rate of return for new units. Where net energy and capacity revenues together justify building a new unit on the basis of a historic trend, a new unit is built. Sustained positive returns, generally stimulated by falling reserve margins and rising prices are expected to lead to capacity additions. The magnitude of the capacity expansion depends on the achieved Return on Investment ("ROI") specific to the type of generating plant.

Pace Global's dynamic build logic is illustrated in Figure 2 below. This graphic illustrates how new capacity enters the market according to economic signals. For example, following an expected tightening in system reserve margins over the period to 2013-2017, the system is expected to tighten during the 2018-2020 timeframe. In this example, we project that rising margins in the period 2015-2019 will send a signal causing a new plant to come online around the 2021 timeframe.

The dynamic expansion methodology is currently applied to incremental natural gas-fired combined cycles, natural gas-fired peaking units, wind, and solar builds in the region. This allows all market simulations to incorporate the reactive behavior observed in the market to periods of sustained margins.

Figure 2

Dynamic Build Simulation Logic



Source: Pace Global

Capacity Pricing

Pace Global's capacity price forecast begins with the PJM's annual capacity auction, the RPM, which clears capacity prices three "PJM years" (June 1 through May 30 of the following year) in advance. The last auction occurred in May 2016, meaning prices are known and reported "as-cleared" through the first five months of 2020. Beyond the immediate time period, Pace Global models PJM's capacity market under conditions associated with three major drivers: regional reserve margin, Cost of New Entry ("CONE") (levelized values across technologies are provided in the following section), and revenue opportunities from energy and ancillary services. As an example, low reserve margins and a high CONE are likely to favor the value of existing capacity, driving the capacity price upwards. Conversely, high plant energy margins indicate either low fuel costs or high energy prices, and tend to drive the capacity price down.

REC Pricing

REC pricing curves are developed using a bottom-up approach assuming that renewable capacity will be developed if renewable project revenue including power, capacity and REC value meet investor return requirements. Demand for renewable energy is driven by state RPS requirements that set the parameters for RECs based on existing polices. Due to the significant interstate trading of RECs and the relative continuity of "Tier I" or equivalent requirements in PJM, Tier I/Class I REC prices for these states are modeled as a single region, with demand and supply defined as the aggregate of the region. The REC floor price for both regions is set at a nominal level of a couple of dollars on par with that of the voluntary (Green-e certified) REC market. The Alternative Compliance Payment ("ACP") for the PJM market is assumed at $50 per MWh. Pace Global projects REC value between this defined floor and ceiling by the supply and demand balance differentials between actual supply and demand mandated by the applicable RPS, the more undersupplied the market the higher the REC price drivers. Pace Global calibrates the pricing function based on historic relationship between the relative supply as compared to demand of RPS mandate and demonstrated market pricing.

Although REC pricing varies notably by procurement method and bilateral terms and conditions (i.e. long term vs. spot, bundled vs. unbundled, etc.), it is anticipated that as these markets mature and liquidity and pricing transparency increase that the behavior of market prices will become more highly correlated with actual market supply and demand over the next several years, as the markets emerge out of their infancy.

Escalation Rate

Table 1 below shows Pace Global's annual deflator series. Pace develops its market projections in real terms and converts prices to nominal values as necessary using the market rate implied by the yield on treasury bonds and similar maturity Treasury Inflation Protected Securities ("TIPS"). The yield quoted on treasury bonds is equal to the real yield plus inflation, while the yield quoted for TIPS is the real yield. Subtracting the yield of TIPS from the yield of Treasury bonds arrives at the market's forward implied inflation rate. Beyond 2020, Pace uses a general inflation rate of 2.4%.

Table 1
Pace Global's Annual Deflator Series

Year	Deflator Series
2015	1.000
2016	1.014
2017	1.028
2018	1.042
2019	1.056
2020	1.071
2021	1.087
2022	1.103
2023	1.120
2024	1.137
2025	1.154
2026	1.172

Source: Pace Global and U.S. Treasury Department.

SECTION 4

Section 4

IRP Load Forecast

Delmarva Power's 2016 ten year energy procurement plan to meet the electrical requirements for SOS customers is based on an internally prepared load forecast covering the planning period 2017 through 2026 ("IRP Planning Period"). IRP regulations found at 26 *Del. Admin. C.* 3010§4.0 provide detailed requirements for preparing a range of load forecasts as well as a review of historical load data. Detailed documentation of the Company's load forecasts and its forecasting methods intended to meet these requirements is provided in Appendix 4 to this IRP.

As part of the IRP forecast development, Delmarva Power prepares both a "Baseline Forecast" and a "Reference Case" forecast. The Baseline Forecast is derived from econometric modeling techniques but does not include the effects of future demand side management ("DSM") programs. The expected mWh and mW savings impacts of these future DSM programs are estimated separately from the econometric Baseline Forecast. When the projected DSM savings are subtracted from the Baseline Forecast, the result is termed the Reference Case Forecast. This Section of the IRP provides a summary discussion of the Baseline Forecast and the Reference Case Forecast. Section 5 of the IRP provides detailed information on the expected savings attributable to future DSM programs.

Baseline forecast: all Delmarva DE customers

Table 1 below summarizes the Baseline Forecast for summer peak demand (mW) for all Delmarva Power customers by customer class for 2017 (the initial year of the IRP Planning Period) through 2026 (the last year of the IRP Planning Period). The Delmarva Power Delaware customer classes shown include Res, Small Com, LC&I class, including HPS, and SL.

Table 1
Baseline Forecast Peak mW
All DPL DE Customers

	Res (mW)	Small Com (mW)	LC&I* (mW)	SL (mW)	Total (mW)
2017	817	34	938	0	1,788
2018	820	34	948	0	1,802
2019	824	34	957	0	1,815
2020	830	35	967	0	1,831
2021	839	35	977	0	1,851
2022	848	35	987	0	1,871
2023	858	36	998	0	1,891
2024	866	36	1,008	0	1,910
2025	875	36	1,018	0	1,930
2026	885	37	1,029	0	1,951

* includes HPS

Table 2 below summarizes the Baseline Forecast for energy throughput (mWh) for all Delmarva Power customers by customer class for the IRP Planning Period.

Table 2
Baseline Forecast mWh
All DPL DE Customers

	RES (mWh)	Sm COM (mWh)	LC&I* (mWh)	SL (mWh)	Total (mWh)
2017	3,060,888	170,982	4,784,977	33,349	8,050,196
2018	3,058,450	172,323	4,822,509	33,399	8,086,681
2019	3,057,512	173,685	4,860,627	33,436	8,125,259
2020	3,062,970	174,933	4,895,567	33,475	8,166,945
2021	3,074,485	176,090	4,927,943	33,511	8,212,028
2022	3,085,019	177,214	4,959,403	33,544	8,255,181
2023	3,094,985	178,334	4,990,727	33,575	8,297,621
2024	3,104,704	179,420	5,021,133	33,604	8,338,862
2025	3,114,159	180,512	5,051,700	33,633	8,380,004
2026	3,123,347	181,612	5,082,479	33,660	8,421,098

*includes HPS

Baseline forecast: Delmarva DE SOS customers

Tables 3 and 4 below summarize the Baseline Forecast for peak demand (mW) and energy throughput (mWh) for Delmarva Power Delaware SOS customers by customer class for the IRP Planning Period.

Table 3
Peak mWDPL DE SOS Customers

	SOS Res (mW)	SOS Small Com (mW)	SOS LC&I* (mW)	SOS SL (mW)	SOS Total (mW)
2017	748	19	67	0	834
2018	752	19	67	0	838
2019	755	19	68	0	842
2020	760	19	69	0	848
2021	769	20	69	0	858
2022	777	20	70	0	867
2023	786	20	71	0	877
2024	794	20	71	0	885
2025	802	20	72	0	895
2026	811	21	73	0	905

* includes HPS

Table 4
Energy MWh
DPL DE SOS Customers

	SOS RES (mWh)	SOS Sm COM (mWh)	SOS LC&I* (mWh)	SOS SL (mWh)	SOS Total (mWh)
2017	2,804,511	95,532	339,349	25,740	3,265,132
2018	2,802,277	96,282	342,011	25,779	3,266,348
2019	2,801,417	97,043	344,714	25,807	3,268,980
2020	2,806,418	97,740	347,192	25,837	3,277,187
2021	2,816,968	98,387	349,488	25,865	3,290,708
2022	2,826,620	99,015	351,720	25,890	3,303,245
2023	2,835,751	99,640	353,941	25,914	3,315,247
2024	2,844,656	100,247	356,097	25,937	3,326,938
2025	2,853,319	100,857	358,265	25,959	3,338,401
2026	2,861,738	101,472	360,448	25,980	3,349,638

* includes HPS

Baseline forecast load growth cases

In addition to providing a Baseline Forecast, the IRP regulations require Delmarva Power to prepare a range of load growth forecasts for a number of different assumptions including a High Economic Growth Case, a Low Economic Growth Case, and an Extreme Weather Case (collectively, the "Cases"). The range of forecasts can be used for IRP sensitivity analyses, if needed. Figures 1-3 below present, for the differing Cases, the Company's forecast for the unrestricted summer peak demand, unrestricted winter peak demand and annual MWh for all Delmarva Power Delaware customers for 2016 and through the IRP Planning Period. The details underlying the Cases can be found in Appendix 4.

In Figures 1-3, the green line represents the Baseline Forecast; it is assumed that 50% of the possible future outcomes will be above this forecast and 50% will be below. The red and blue lines represent, respectively, High and Low Economic Growth Cases. It is assumed that 10% of the possible outcomes will lie above the High Economic Forecast and 10% will lie below the Low Economic Forecast.

Finally, the purple line represents the Extreme Weather Case. This case is meant to reflect climate change potential for the region. Extreme Weather is represented by calculating the average and standard deviation of heating and cooling degree days for each month of the year. In the Extreme Weather Case, monthly heating and cooling degree days are set equal to their historical average plus two standard deviations.

Figure 1

DPL Delaware Jurisdictional Summer Peak Demand (mW)

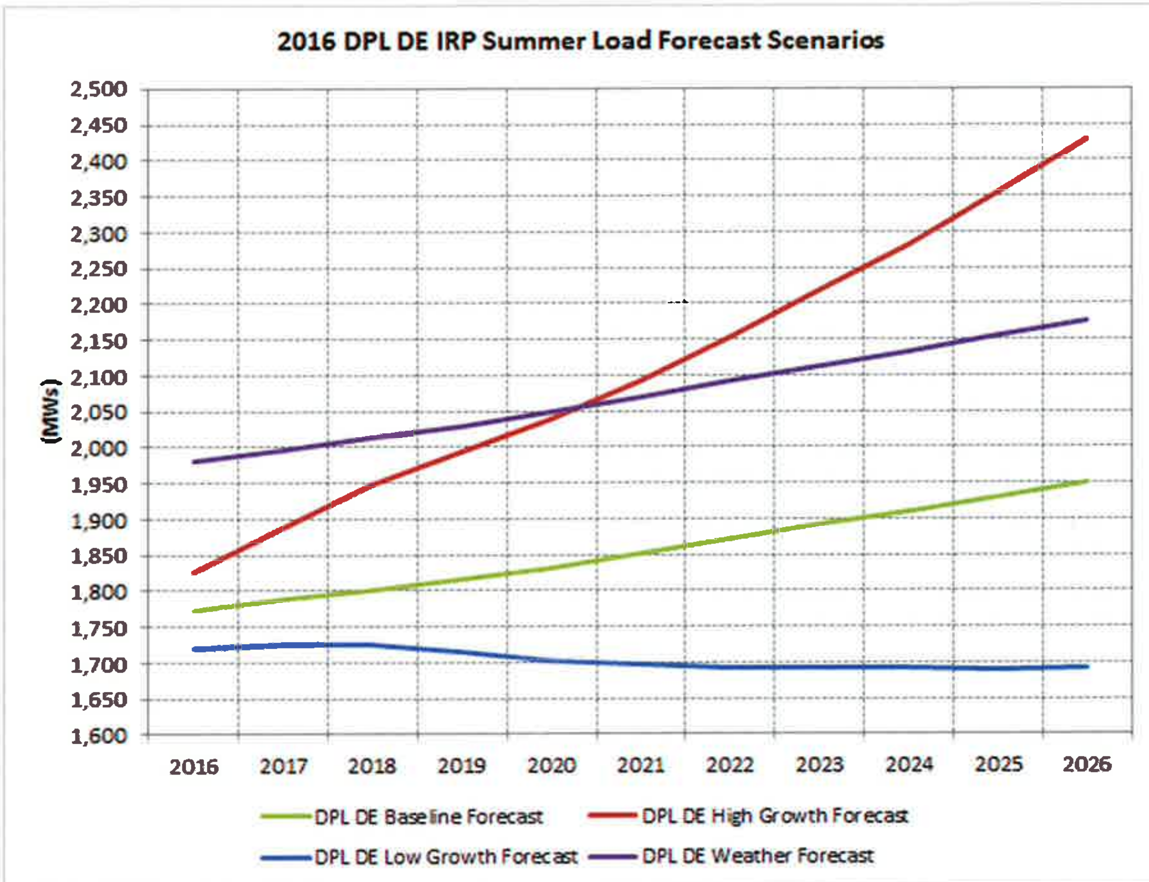


Figure 2

DPL Delaware Jurisdictional Winter Peak Demand (mW)

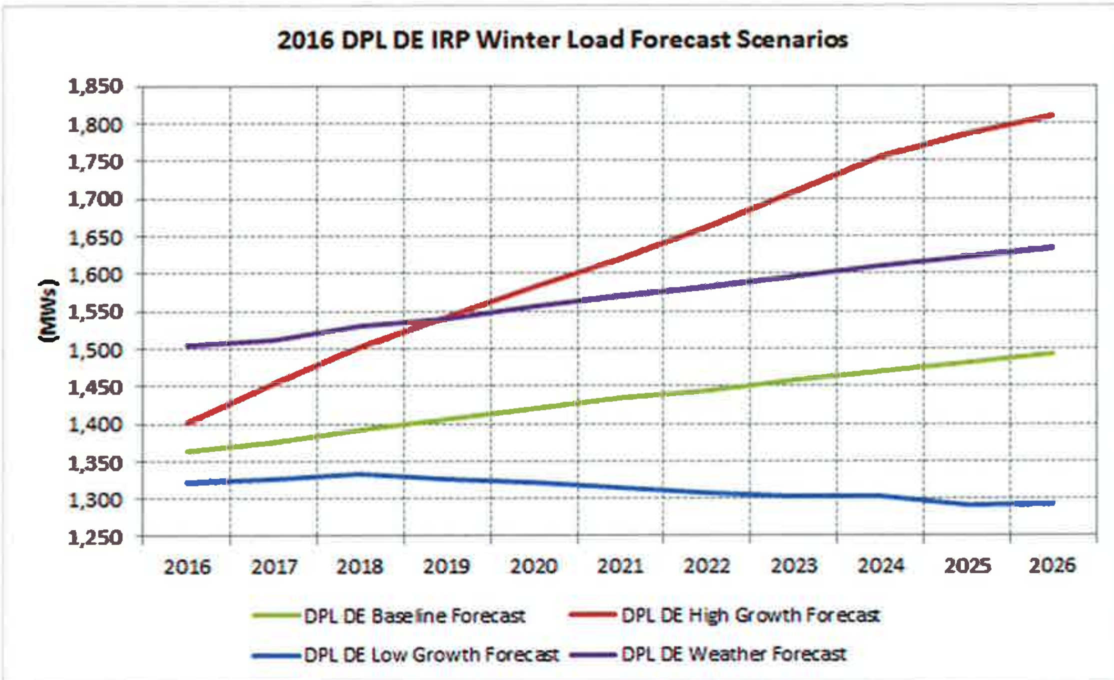
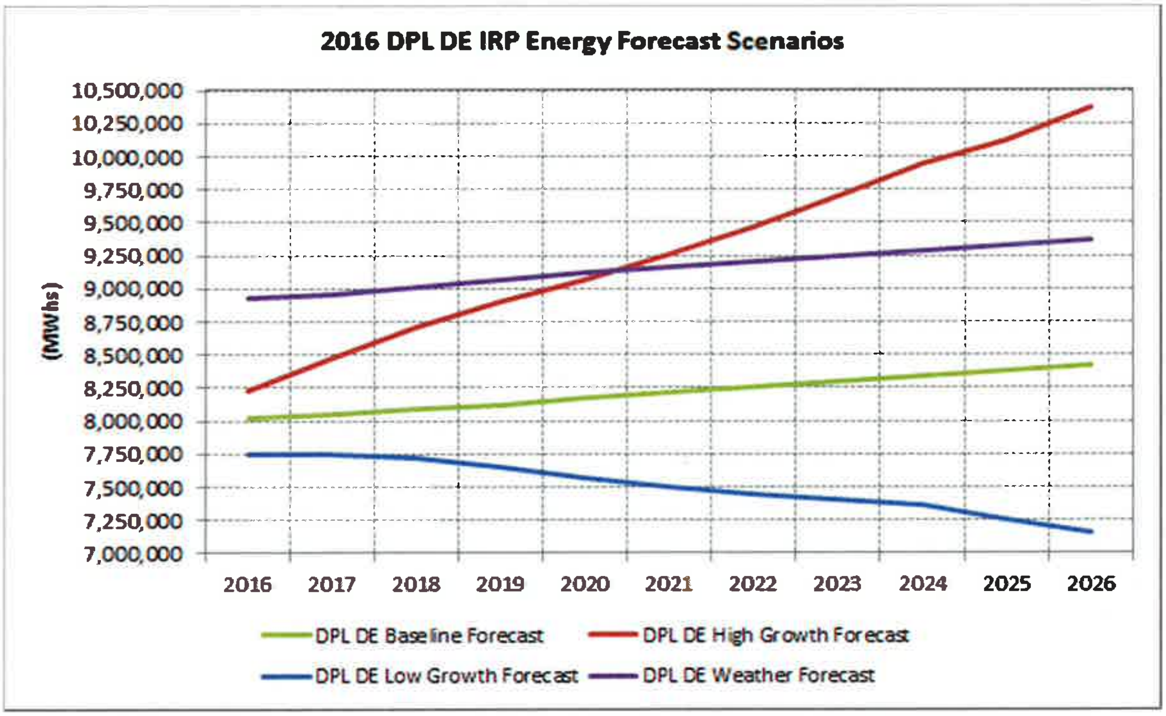


Figure 3

DPL Delaware Jurisdictional Annual Energy (mWh)



IRP Load Forecast Requirements

Appendix 4 also includes a more detailed discussion of the methodology used in developing the Baseline Forecast and the Cases. Additional information is also provided in Appendix 4 including:

- Five year historical loads, current year-end estimates and 10 year weather adjusted forecasts;
- DPL DE and DPL DE SOS load forecasts aggregated and by customer category, including capacity (mW) and energy (mWh) data;
- Winter and summer peak demand for total DPL DE load and DPL DE SOS load by customer class;
- Weather adjustments including consideration of climate change potential; and
- A description of the process used to develop the forecast, probability of occurrence and how well the model predicted past load data for five years.

Reference Case Forecast

As mentioned earlier, the Baseline Forecast described above does not include the effects of future DSM programs on peak demand and energy. The estimates of future savings due to DSM programs are described in the next section of the IRP (Section 5). However, for purposes of procuring a portfolio to provide SOS customer energy requirements and to meet the RPS requirements, the expected energy savings from DSM programs needs to be subtracted from the Baseline Forecast of SOS customer energy. This result is termed the "Reference Case Forecast". The Reference Case Forecast provides the mWh basis for determining the annual amount of RECs needed for RPS compliance, and the amount of annual energy expected to be procured through the Commission approved auction process for SOS customers.

Table 5 below summarizes the calculation of the Reference Case Forecast for all DPL Delaware customers.

Table 5
All DPL Customers

	Baseline Forecast (mWh)	Projected DSM Savings* (mWh)	Reference Case (mWh)
2017	8,050,196	424,019	7,626,177
2018	8,086,681	503,683	7,582,998
2019	8,125,259	577,680	7,547,579
2020	8,166,945	648,142	7,518,803
2021	8,212,028	709,351	7,502,677
2022	8,255,181	770,667	7,484,514
2023	8,297,621	832,068	7,465,552
2024	8,338,862	893,553	7,445,308
2025	8,380,004	955,040	7,424,964
2026	8,421,098	1,016,246	7,404,852

*Adjusted to Retail Sales Level

Similarly, Table 6 below provides the Reference Case Forecast calculation for Delmarva SOS Customers.

Table 6
SOS
Customers

	Baseline Forecast (mWh)	Projected DSM Savings* (mWh)	Reference Case (MWh)
2017	3,265,132	301,945	2,963,187
2018	3,266,348	352,171	2,914,177
2019	3,268,980	400,179	2,868,801
2020	3,277,187	446,737	2,830,450
2021	3,290,708	484,937	2,805,771
2022	3,303,245	523,183	2,780,062
2023	3,315,247	561,456	2,753,791
2024	3,326,938	599,759	2,727,179
2025	3,338,401	638,063	2,700,338
2026	3,349,638	676,111	2,673,527

*Adjusted to Retail Sales Level

SECTION 5

Section 5.

DEMAND SIDE MANAGEMENT

Demand Side Management ("DSM") programs include energy efficiency programs, conservation programs, and demand response ("DR") programs. In contrast to supply side options, such as new generating units, DSM programs reflect potential savings in either, the total consumption of electrical energy, a reduction of system demand during peak periods, or both. In the 2016 IRP, the expected energy and demand savings due to the implementation of future DSM programs are subtracted from the Baseline Forecast prior to running the IRP planning model. In addition, the demand side resources examined herein support compliance with the Delaware Energy Conservation and Efficiency Act of 2009.

Background

The Delaware Energy Conservation and Efficiency Act of 2009[1] ("The Act") designates energy efficiency as the first energy supply resource to be considered before any increase or expansion of traditional energy supplies. The Act created an Energy Efficiency Resource Standard ("EERS") requiring each Affected Electric Energy Provider ("Provider")[2] to achieve, at a minimum, energy savings that are equivalent to 15% of the Provider's 2007 electricity consumption, and a coincident peak demand reduction that is equivalent to 15% of the Provider's 2007 peak demand, by 2015.[3] Pursuant to *29 Del. C.* §8059, the SEU is tasked with coordinating and promoting the sustainable use of energy in Delaware. The Act directed that the SEU be responsible for implementing energy efficiency and conservation programs in Delaware, while Delmarva Power was responsible for implementing DR programs. The Act requires that Delmarva Power achieve the demand and energy reduction goals in coordination with the SEU and the Delaware Weatherization Assistance Program ("WAP").[4] Additionally, the current regulations[5] governing the preparation of this and future IRPs states that it shall include:

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[1] 26 *Del. C.* §§1500-1507.

[2] An "Affected Electric Energy Provider" is defined in the Act as an electric distribution company, rural electric cooperative or municipal electric company serving Energy Customers in Delaware. 26 *Del. C.* §1501(1).

[3] *Id.* at 1502(a)(1).

[4] The Delaware Division of Energy and Climate also offers renewable energy and energy conservation programs for residential and non-residential customers.

[5] In the Matter of the Investigation Into the Adoption of Proposed Rules and Regulations to Accomplish Integrated Resource Planning for the Provision of Standard Offer Service by Delmarva Power & Light Company under 26 *DEL. C.* § 1007(c) & (d) (Opened August 7, 2007). PSC Regulation Docket No. 60.

"...a detailed description of energy efficiency activities in accordance with 26 *Del. C.* §1020."

On August 6, 2014, amendments to 26 *Del. C.* §8059 became effective which allow Delmarva Power , in conjunction with the SEU, to offer energy efficiency programs and obtain cost recovery for such programs through base rates. These amendments also required the creation of a task force/working group to make recommendations as to those Energy Efficiency Programs the Company would provide and how those programs will be implemented. As of the time of this writing, the EEAC and associated working groups have met and developed an Evaluation, Measurement, & Verification ("EM&V") framework for the Energy Efficiency Programs, and have discussed proposed DSM program mixes in detail. Target reductions of 0.4%, 0.7%, and 1.0% incremental energy savings as provided by DNREC (with 1.0% savings held constant beyond the third year) have been adopted by the EEAC on a statewide level. These reductions will be achieved through the combined efforts of the SEU, DNREC, Delmarva Power, and low income services providers located in Delmarva Power's service territory. As these goals are adjusted going forward, future IRPs will take these changes into account.

Estimated Overall DSM Cumulative Impacts

In the IRPs developed prior to 2014, Delmarva assumed that the energy and demand savings achieved by the implementation of SEU sponsored programs would be sufficient to meet the targets set forth in the Act, or that the SEU would be the sole provider of energy efficiency programs in the State. With the implementation of the amendments to the Act, the current 2016 forecast incorporates the Company's experience with the EEAC working group process and the annual goals noted earlier.

The IRP savings targets that the Company has adopted from the EEAC working group were unanimously approved by the EEAC at their August, 2015 meeting. The goals were based upon several factors: 1) the experience of Delmarva Power and its affiliate Pepco in deploying Energy Efficiency Programs in Maryland; 2) the results of a 2014 study to determine the potential for additional energy savings in Delaware performed on behalf of DNREC; and 3) the input from participating stakeholders. The EEAC put forth the 0.4%, 0.7% and 1.0% savings targets with the intention of balancing savings potential and ratepayer impact, while recognizing that due to ever-increasing codes and standards, incremental savings will be harder to achieve now compared to savings associated with past DSM implementations in Delaware and elsewhere.

In addition to these Energy Efficiency Programs, Delmarva Power also implements and operates a number of energy savings programs targeted to the distribution and transmission systems. A summary of the cumulative energy and demand savings from all of these programs for the IRP Planning Period are shown in Table 1 and Table 2 below.

Table 1

Reference Case Energy Savings Estimates

(All Delmarva Power Delaware Distribution Customers)

MWH	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
DSM Initiative										
AMI Enabled Reductions	53,254	53,412	53,594	53,775	53,943	54,104	54,260	54,412	54,564	54,412
Distribution Efficiency Improvements	28,916	33,047	37,177	41,308	45,439	49,570	53,701	57,832	61,962	66,093
Transmission Efficiency Improvements	6,594	6,850	7,110	7,374	7,642	7,914	8,189	8,464	8,739	9,014
Combined Heat & Power	68,063	68,063	68,063	68,063	68,063	68,063	68,063	68,063	68,063	68,063
Street Lighting Improvements	2,896	2,896	2,896	2,896	2,896	2,896	2,896	2,896	2,896	2,896
Delaware Weatherization Assistance Program	6,193	7,078	7,962	8,847	9,732	10,617	11,501	12,386	13,271	14,155
Residential Direct Load Control	2,212	2,166	2,119	2,073	2,073	2,086	2,086	2,086	2,086	2,086
Non-Residential Direct Load Control	0	102	732	1,260	1,289	1,316	1,345	1,367	1,391	1,416
Improved Codes and Standards	257,567	294,363	331,158	367,953	395,125	422,297	449,470	476,642	503,814	530,986
EEAC & SEU Programs	32,245	76,003	113,083	146,444	179,898	213,458	247,123	280,890	314,658	348,425
Total Cumulative Energy Impact (MWh)	457,940	543,978	623,894	699,993	766,099	832,321	898,634	965,038	1,031,444	1,097,546

Table 2

Reference Case Demand Savings Estimates

(All Delmarva Power Delaware Distribution Customers)

MW	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
DSM Initiative										
AMI Enabled Reductions	91	91	91	91	92	93	94	96	97	98
Distribution Efficiency Improvements	3	4	4	5	5	6	6	6	6	6
Transmission Efficiency Improvements	2	2	2	2	2	2	2	2	2	2
Combined Heat & Power	9	9	9	9	9	9	9	9	9	9
Street Lighting Improvements	-	-	-	-	-	-	-	0	0	0
Delaware Weatherization Assistance Program	2	2	2	2	3	3	3	3	3	3
Residential Direct Load Control	46	45	44	43	43	43	43	43	43	43
Non-Residential Direct Load Control	-	2	15	26	27	27	28	28	29	29
Improved Codes and Standards	67	77	87	96	103	110	110	110	110	110
EEAC & SEU Programs	5	11	17	22	27	32	37	42	47	52
Total Cumulative Energy Impact (MW)	225	243	271	297	311	326	333	340	346	353

Descriptions of the individual programs set forth in Tables 1 and 2 are provided below.

1. AMI Enabled Reductions

On March 23, 2011, Delmarva Power filed an Application to Implement an Advanced Metering Enabled Dynamic Pricing Plan and Dynamic Pricing Rider DP. On December 20, 2011, the Commission approved the Settlement Agreement entered into by Delmarva Power, Commission Staff and the DPA, and on January 31, 2012, issued its Final Findings, Opinion and Order (Order No. 8105) approving the proposed phase-in implementation of Delmarva Power's Advanced Metering Infrastructure ("AMI") enabled Dynamic Pricing Program for its SOS customers. The approved rate is structured as a default Critical Peak Rebate ("CPR") rate with the ability for the customer to opt-out of the rate. The program is currently offered to all Delmarva Power residential SOS customers, and is being deployed to all Delmarva Power small and medium non-residential SOS customers. The program is currently titled the "Peak Energy Savings Credit Program."

In June 2013, the second phase of the program began with the remaining Delmarva Power residential SOS customers being defaulted to the dynamic pricing rate. The final phase of program implementation began in June 2015 when all Delmarva residential and small and medium non-residential SOS customers were placed on the dynamic pricing rate.

Delmarva and the Brattle Group performed a detailed study of the projected energy and demand savings attributable to dynamic pricing in the Company's Delaware service territory based upon load reduction impacts from available comparable industry studies. The residential impacts of dynamic pricing programs in Delaware were estimated by adapting the Pricing Impact Simulation Model ("PRISM"). All estimated pricing impacts were adjusted for Delaware load shapes and weather conditions.

The dynamic pricing impact study excluded the load impacts of Delmarva Power's existing and planned direct load control program, the projected energy efficiency and conservation savings expected to be achieved by the SEU, and energy and demand savings from other identified sources. These adjustments lessen the estimated demand savings that will be achieved by dynamic pricing programs; therefore, if reductions from other sources are not achieved, demand reductions from dynamic pricing are expected to be higher. Dynamic pricing is expected to provide over 90 MW of peak demand reduction going forward. In the event that PJM wholesale electricity market conditions for the Delmarva Power Delaware region change, dynamic pricing incentives can be adjusted to reflect those changes. As more operational experience is gained, these forecasts will be updated.

Delmarva Power's AMI deployment has enabled the Company to provide additional detailed electric energy use information to all residential and small commercial customers. The additional energy usage information is now available through Delmarva Power's monthly electricity bills and its "My Account" web portal. Delmarva Power provides energy savings tips through the My Account web portal and via its Call Center through its Energy Advisors. The Company has completed a study which determined that its residential customers reduce their energy consumption by 1.75% annually due to the availability of detailed energy use information. This is expected to remain the case, as the Company continues to offer these energy management tools.

2. Transmission & Distribution System Improvements

Electric distribution transformers are evaluated consistently throughout the PHI utility companies using the minimum efficiency tables contained in the National Electrical Manufacturers Association ("NEMA") standard TP1-2002, Section 4. At the time that the U.S. Department of Energy ("DOE") issued their Final Ruling in 2007 to establish more stringent minimum efficiency levels, Delmarva Power was already investigating methods to increase the minimum efficiency levels. Beginning in 2008, Delmarva Power purchased transformers consistent with DOE's TSL-2 level efficiency criteria. The estimates of energy savings for transmission and distribution system improvements for the 2016 IRP remain unchanged from the 2014 IRP.

3. Combined Heat and Power ("CHP") Potential

CHP offers a potentially efficient and clean approach to generating electricity or mechanical power and supplying useful thermal energy from a single fuel source at the point of use. Instead of purchasing electricity and also burning fuel in an on-site furnace or boiler to produce thermal energy, an industrial or commercial facility can use CHP to provide these energy services in one energy-efficient step. As a result, CHP can provide significant energy efficiency and environmental advantages over separate heat and power supplies. CHP systems are located at or near end-users, and therefore, may lessen or defer the need to construct new transmission and distribution ("T&D") infrastructure. While the traditional method of producing separate heat and power has a typical combined efficiency of 45%, new CHP systems can operate at efficiency levels as high as 80%. CHP's high efficiency results in less fuel use and lower levels of greenhouse gas emissions.

To estimate the savings attributed to CHP in Delmarva Power's Delaware service territory, the Company only included the current CHP systems in operation, or those in the process of being constructed. The estimates of energy savings attributable to CHP for the 2016 IRP remain unchanged from the 2014 IRP.

4. High-Efficiency Streetlamps

As a result of EPACT 2005, the Federal Government banned the manufacture and importation of Mercury Vapor streetlight ballasts, effective January 1, 2008. After a review of options, PHI implemented a plan to proactively replace MV streetlights over a five year period with High Pressure Sodium streetlights throughout its three regional utility companies, including Delmarva Power. These replacements reduce energy consumption, and provide superior lighting performance for Delmarva Power customers. The estimates of energy savings attributable to High Efficiency Streetlamps for the 2016 IRP remain unchanged from the 2014 IRP.

5. The Delaware Weatherization Assistance Program ("WAP")

WAP installs energy efficiency improvements in low-income households. Specifically, WAP provides for the installation of such measures as: air sealing, insulation, window and door replacement, and furnace repair and replacement. Based on an analysis of electrically-heated homes prepared by the University of Delaware's Center for Energy and Environmental Policy, kWh savings associated with improvement through WAP are estimated at 22% on average per household. In program year 2009 (4/1/09 – 3/31/10) WAP served a total of 1,221 homes statewide. WAP plans to serve approximately 1,100 homes during each program year going forward. The estimates of energy savings attributable to WAP for the 2016 IRP remain unchanged from the 2014 IRP.

6. Demand Response Programs

Delmarva Power is responsible for implementing demand response programs within its service territory, although additional demand savings will result from the SEU's energy efficiency and conservation programs, and all other energy savings sources with the exception of street-lighting improvements. The Company has two direct load control programs (residential and non-residential) currently implemented in addition to the Dynamic Pricing program previously discussed. These three combined programs address all customer market segments for Delmarva Power Delaware and have been designed specifically to participate in available demand response market opportunities under the current market rules within the PJM capacity and energy markets. Participation in these current markets provides a revenue stream that offsets a portion of program costs, provides PJ M dispatchers demand response programs that can be used to help maintain system reliability during high load periods, and helps to mitigate high regional electricity market capacity and energy prices. The programs can also be used by Delmarva Power to help manage localized distribution system problems depending upon their location and scale. Demand Response Programs help to defer the need to construct additional generation resources, transmission facilities, and distribution facilities. The programs can also assist with the integration of renewable generation sources, such as wind power, due to its uncertain availability during periods of high electricity demand. Finally, the programs offer consumers a direct method of reducing their monthly electricity bills through both incentives for participating in each program and the reduction of energy consumption during specific periods of time. Going forward, as the direct revenues stream from the PJM capacity market is eliminated for the 2021/22 delivery year, the Company is reviewing options for how to appropriately value demand response assets.

a. Residential Direct Load Control

On December 18, 2012, pursuant to Order No. 8253 in Docket No. 11-330, Delmarva Power received Commission approval for its proposed Residential Direct Load Control Program ("DLC"). The program, titled Energy Wise Rewards™ is a voluntary customer program designed to update, expand, and replace the legacy "Energy For Tomorrow" central air conditioning/heat pump load control program with newer technology. The program provides a voluntary and simple method for residential consumers with central air conditioning or heat pump systems to automatically reduce electricity demand during peak usage periods and to also reduce their overall air conditioning and heating system energy consumption. The program accomplishes this through the installation of either a remotely controllable smart thermostat or direct load control switch. Participating customers have the option of choosing either of the devices. These devices reduce the air conditioner load on the electric system after receipt of a Delmarva Power command signal. The smart thermostats are capable of being programmed to automatically vary temperature settings, thereby providing added energy savings opportunities. This program has been substantially built out, and is not actively marketing to new participants, though any new applications are still accepted.

As shown in Table 3 above, available peak demand reduction capability for the DLC program is projected to be 46 MW during the summer of 2017. Associated energy savings are estimated to exceed 2,020 MWh by year-end 2017.

b. Non-Residential Direct Load Control

The primary objective of the voluntary Non-Residential Load Control Program is to provide a simple method for non-residential consumers with central air conditioning or heat pump systems to automatically reduce electricity demand during peak usage periods and to also reduce their overall electricity consumption. Similar to residential DLC, this program will provide for the installation of either a remotely controllable smart thermostat or a direct load control switch. Participating customers will have the option of choosing either of the devices. The estimates of energy savings attributable to Non-Residential Direct Load Control program for the 2016 IRP remain unchanged from the 2014 IRP, with the exception of the implementation date.

7. Codes & Standard Savings

Delmarva Power has considered the potential savings impact of code and standard improvements in Delaware in calculating the total attainable demand and energy consumption savings. The major impacts from codes and standards that are currently in effect are air conditioning minimum efficiency requirements and Federal lighting efficiency requirements which went into effect beginning in 2011. Since the SEU energy efficiency programs are likely to contain residential and non-residential lighting efforts as part of the Home Performance with Energy Star and other commercial programs that extend through 2017 separately, the codes and standards impacts of the lighting efficiency requirements could result in potential double counting of savings. Therefore, only the impacts of the air conditioning minimum efficiency requirements that are not captured by the identified SEU programs were estimated.

The basis for the analysis is that there are energy savings that are not captured in energy efficiency programs which result from the higher minimum efficiency requirements. When an air conditioner is replaced, the current minimum efficiency is significantly higher than the original unit that was replaced. Since an efficiency program only claims savings that are above the required minimum efficiency, any savings resulting from reaching the minimum efficiency levels are not accounted for in the efficiency program impacts. An analysis was performed to estimate the impacts resulting from the higher minimum efficiencies required for residential and non-residential air conditioning replacement. The estimates of energy savings attributable to Codes and Standards for the 2016 IRP remain unchanged from the 2014 IRP.

8. EEAC and SEU

The savings attributable to EEAC and SEU activities were calculated per the methodology described earlier in the Section titled "Estimated Overall DSM Cumulative Impacts".

SECTION 6

Section 6.
Transmission

Delmarva Power's transmission facilities are part of the PJM Regional Transmission Organization ("RTO"). The Company works with PJM to ensure that reliability standards are met and that the necessary transmission facilities are built to meet the short and long term needs of the Delmarva Peninsula.

PJM, as the RTO, is responsible for ensuring:

- Adequate generation or demand side resources across the entire region; and
- Adequate transmission capacity to reliably and efficiently deliver the generation capacity for the region where it is needed.

PJM meets these objectives by administering competitive markets that encourage generation, transmission and demand-side resources. In addition, PJM, as the regional planner, identifies violations of the PJM planning criteria and works with Delmarva Power's Transmission Planning Department to verify the accuracy of the violations. PJM then works through the Regional Transmission Expansion Plan ("RTEP") process to determine the most appropriate system upgrades to mitigate those violations. The selected upgrades are ultimately included in the documented RTEP.

On July 21, 2011, the FERC issued Order 1000 (the "Order"). The Order required changes to the Transmission Planning and Cost Allocation processes. To comply with the Order, PJM has implemented a competitive solicitation process to address violations of the PJM planning criteria. The Order can be reviewed in its entirety, along with the subsequent FERC Order 1000-A on the FERC website (http://www.ferc.gov/). The Order addresses the following topics: planning requirements inclusive of local, regional and interregional transmission planning processes; public policy requirements advising consideration of transmission needs driven by public policy; the right of first refusal including the development of transmission facilities by non-incumbent developers; and cost allocation requirements specific to transmission cost allocation policies.

The first Request for Proposal ("RFP") issued under FERC Order 1000 to address transmission stability concerns was associated with Artificial Island. This RFP closed in June 2013. In July 2015, the PJM Board approved the project to correct operational voltage and stability problems at the Artificial Island generating complex in southern New Jersey. As part of the project, PJM assigned to LS Power construction of a 230-kilovolt transmission line under the Delaware River. PJM designated Public Service Electric & Gas for the expansion of interconnection facilities at Salem nuclear power station and the installation of reactive support devices at the New Freedom substation. The Board also designated Pepco Holdings for the expansion of interconnection facilities in the Delmarva Power Zone. Most recently, in August 2016, in response to significant pushback from stakeholders, the PJM Board directed PJM Staff to suspend all elements of the project for six months and to perform a comprehensive analysis to address significant cost increases of the previously awarded project and review technical concerns associated with the solution's ability to perform as expected related to the modeling of circuit breaker clearing times. As a result of these actions, and given the uncertainty associated with when this project may be in service, the 2016 IRP does not include Artificial Island in the resource planning analysis.

PJM's planning process is a rigorous 24-month process, which uses a 15-year horizon, as outlined in PJM Manual 14-B, available on the PJM web site. The 24-month planning process is made up of two similar 12-month planning cycles to identify and develop shorter lead-time transmission upgrades, and one 24-month planning cycle to provide sufficient time for the identification and development of longer lead-time transmission upgrades that may be required to satisfy planning criteria. The planning process takes into account the requirement that the future transmission system must meet all applicable reliability criteria including North American Electricity Reliability Council ("NERC"), Reliability First Corporation ("RFC"), PJM and Delmarva Power local planning criteria. PJM tests the system under both expected normal peak conditions and extreme conditions where peak loads are higher than forecasted and there are more generating units out of service than would be expected under normal peak conditions. Based on this analysis, PJM, with support from Delmarva Power, develops a detailed immediate need (less than 3 years out) plan to ensure that the transmission system has sufficient capability to serve the load and that generation resources within PJM are deliverable. PJM develops the near term (4 -5 years out) and long range (15 years out) plans through the FERC Order 1000 competitive solicitation process. The transmission system plans that are developed include upgrades and additions to the transmission system, as well as new reactive sources, to assure adequate transmission system voltages are maintained under all tested conditions. The load flow cases on which the plan is based include all assumptions about the expected load forecasts, the demand response programs, and the proposed generation available.

Table 1 below lists pending individual transmission system upgrades that comprise the RTEP projects for Delmarva Power. A short description of each project as well as the PJM project identification number, expected in-service date and estimated project cost are provided in the Table. PJM will finalize a complete list of projects by the end of the year which will be used as part of the 2016 RTEP report to be issued by February 2017.

Table 1 – Delmarva Power Transmission System Planned Upgrades

Upgrade ID#	Description	In-Service Date	Estimated Cost ($M)
b2695	Rebuild Worcester – Ocean Pines 69 kV Line	12/31/2017	$2.40
b2288	Build a new 138kV line from Piney Grove - Wattsville	6/1/2018	$44.70
b2395	Reconductor the Harmony - Chapel St 138 kV circuit	6/1/2018	$1.62
b2569	Replace Terminal equipment at Silverside 69 kV substation	6/1/2019	$0.04
[redacted]			

Table 2 below shows Delmarva transmission projects by year that were constructed and placed in service since the filing of the 2014 IRP on December 1, 2014. These projects addressed reliability concerns and were identified to resolve violations flagged by PJM in their RTEP process. In addition, these projects helped mitigate economic concerns by lowering congestion hours for all Delaware customers.

Table 2

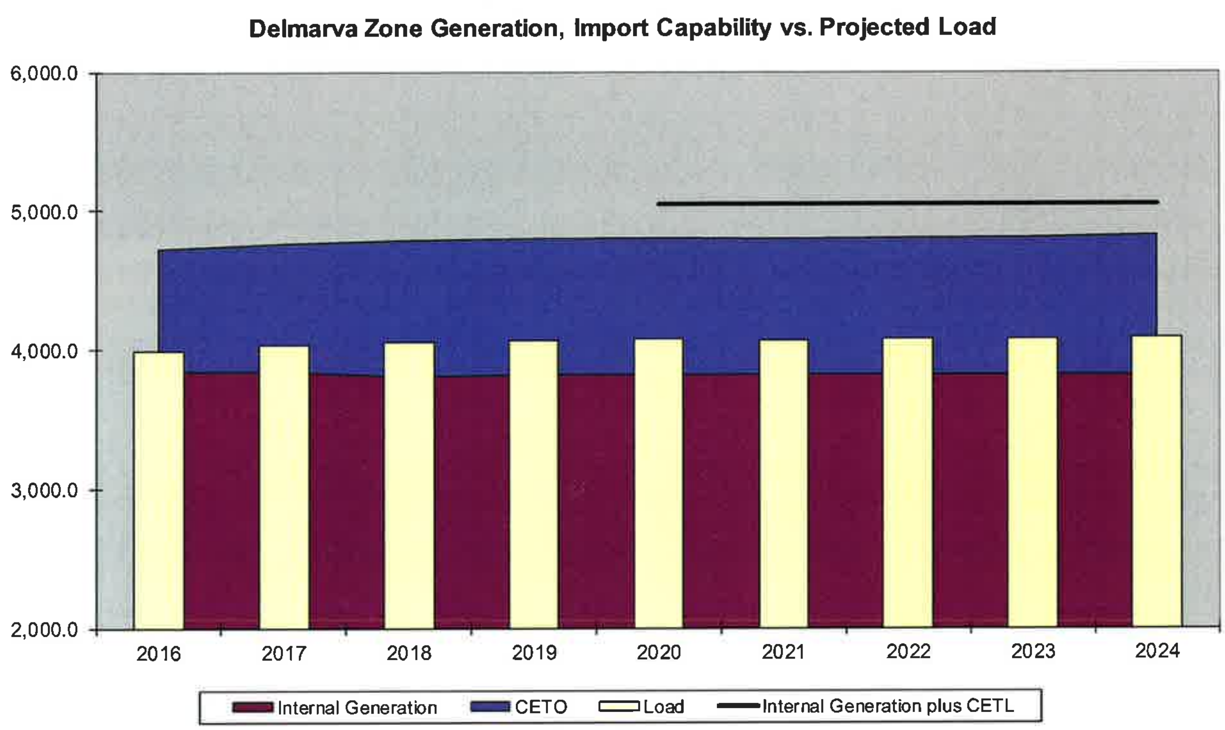
Delmarva Power Transmission System Upgrades Completed since December 2014

Description	In-Service Date	Cost($M)
Install new variable reactors at New Castle 138 kV and Easton 69 kV	12/31/2014	$8.33
[redacted]		
Build a new Wye Mills-Church 138 kV line	6/1/2015	$52.32
Re-build the Glasgow - Cecil 138 kV circuit	6/1/2015	$7.25
Install two 15 MVAR capacitor at Loretto 69 kV	6/1/2015	$2.33
Reconfigure the existing Sussex 69 kV capacitor	6/1/2015	$0.83
[redacted]		

As previously noted, in addition to the detailed plans developed for the next five years, PJM also works with stakeholders, including Delmarva Power, to develop a 15-year plan which addresses the need for new major backbone transmission projects at higher voltages. At this time PHI/Delmarva Power does not have any backbone transmission projects in PJM's 15 year plan, and there are no planned major backbone transmission projects in Delaware.

The graphical data in Figure 1 below shows the import capability into the Delmarva zone with respect to the zonal load. The Capacity Emergency Transfer Objective ("CETO") target was calculated and published by PJM for study year 2019. CETO values for years prior to and after 2019 were extrapolated based on the 2019 value and the yearly change in the forecasted load. The Capacity Emergency Transfer Limit ("CETL") target was calculated and published by PJM for study year 2019. PJM plans for a minimum CETL to CETO ratio of 115%. The chart below conservatively holds CETL values for years 2020 – 2026 constant. Based on PJM's published CETL to CETO value of greater than 115% for Delmarva Power in 2016, it is not anticipated that the CETO value will exceed the CETL value within the Delmarva zone over the planning horizon. The data presented in Figure 1 below illustrates that over the IRP Planning Period, it is expected that there will be sufficient generation and transmission resources to meet projected zonal load and PJM planning objectives.

Figure 1 – Delmarva Zone Generation, Import Capability vs. Projected Load



Capacity Emergency Transfer Objective (CETO) - is the targeted import capability objective into the area to meet established regional reliability margins.
Capacity Emergency Transfer Limit (CETL) - is the estimated/calculated import capability into the area. 2018 CETL values as listed in PJM 2018 RTEP Base Case documentation from 4/10/14 PJM TEAC. CETL conservatively held flat for future years.

Sources: Projected Load: PJM Load Forecast Report dated Jan 2016
Generation Data: 2014 PJM Load, Capacity and Transmission Report dated December 28, 2011,
http://phx.corporate-ir.net/phoenix.zhtml?c=103361&p=irol-newsArticle&ID=1719378&highlight=
Generation includes the retirement of Indian River #3 in 2013, new Calpine generator in 2015, and retirment of McKee Units 1 & 2 in 2017.
Generation additions with signed ISAs submitted through the PJM Queue Generation Interconnection Process have been included.

Contingency Plan

The PJM RTEP considers the immediate, near-term and long-term needs of the regional transmission system and is updated on an annual basis. Delmarva Power actively participates in this process and carefully monitors new developments. As new information becomes available and new decisions are made through the RTEP process, Delmarva Power evaluates and updates its plans, as needed.

SECTION 7

Section 7
IRP Reference Case Supply Side and Environmental Assumptions

This Section of the IRP describes some of the key inputs and parameters used in modeling the IRP Reference Case. This includes the capital costs of new generation resources, expected natural gas fuel prices, environmental regulations and renewable energy credits.

A. Reference Case Capital Cost Projections

In evaluating potential capacity additions for meeting future demand requirements, Pace Global assessed several generation technologies' maturity levels and operating histories. Based on Pace Global's review of available generation technologies and review of other public sources for capital cost data, estimates for new technology costs were developed.

Pace Global's estimates take into account recent trends in commodity price inputs. Pace Global projected trends in technology, materials, and labor costs in order to value early, middle, and late time period cost assumptions. The early time period reflects 2016-2020, the middle time period represents 2021-2025, and the late time period is for 2026-2030.

Table 1 below highlights the national average for new technology parameters, with the relevant regional multipliers shown in Table 2 below.

Table 1
New Resource Technology Parameters

Technology	Early Capital Cost (2016-2020)	Mid Capital Cost (2021-2025)	VOM	FOM	Average Heat Rate	Block Size
	$/kW	*$/kW*	*$/MWh*	*$/kW-yr*	*Btu/kWh*	*MW*
CC (FA)	949	996	3.21	16.29	6,600	623
CT (FA)	617	647	0.90	13.82	9,800	206
Solar PV	1,923	1,633	0.00	14.78	-	7
Wind 1.5 MW	1,724	1,637	0.00	34.49	-	50

Source: Pace Global

Table 2
Regional Multipliers for Capital Costs

Zone	Regional Multiplier
PJM East	1.21
PJM - COMED	1.04
PJM - West	1.00

Source: Pace Global

In assessing the economics of new technology additions over the course of the IRP Planning Period, Pace Global considers revenues from the power markets against levelized recovery targets for new unit construction. The levelized recovery targets for each unit type are derived from capital cost estimates over time, fixed operating and maintenance costs, and financing assumptions. Pace Global assumes a 50:50 debt to equity ratio, with a 15.7 percent required return on equity and a 7.75 percent interest rate on debt. Renewable technologies are evaluated in the context of appropriate tax depreciation schedule benefits and other incentives like the federal Production Tax Credit and Investment Tax Credit. Table 3 below summarizes Pace Global's expected value levelized recovery requirements for new resources. The sharp increase in the recovery requirements for new solar in the 2020-2022 period, and new wind in the 2017-2020 period is driven by rolling off of the Investment Tax Credit and Production Tax Credit, respectively. Pace also applied regional multipliers to represent the differing costs of construction and tax regimes in these regions. This information is also shown graphically in Figure 1 below.

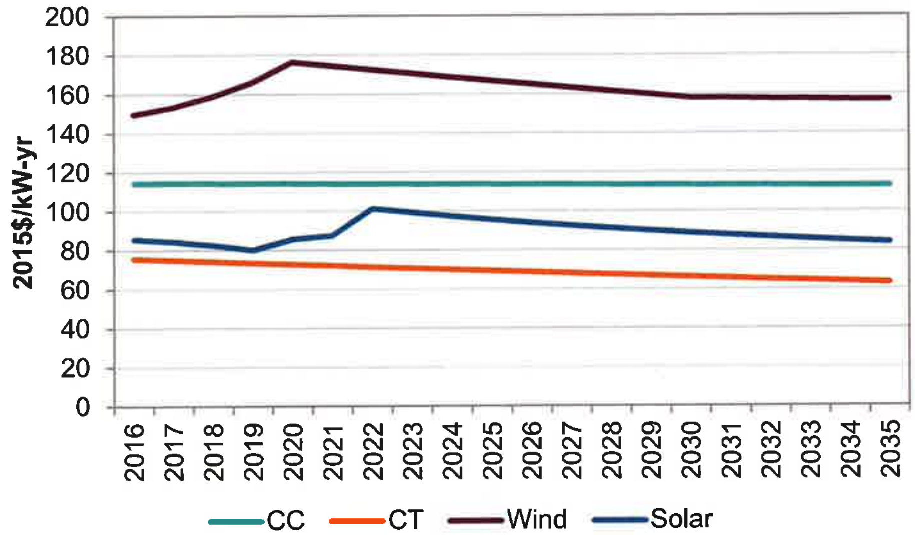
Table 3
Expected Case Recovery Requirements for Various Technologies (2015$)

Technology	Early Capital Cost	Mid Capital Cost	Early Levelized Recovery Requirement	Mid Levelized Recovery Requirement
	(2016-2020)	(2017-2024)	(2016-2020)	(2017-2024)
	$/kW	*$/kW*	*$/kW-yr*	*$/kW-yr*
CC (7FA)	949	996	129	134
CT (FA)	617	647	86	89
Solar PV	1,724	1,637	111	120
Wind 1.5 MW	949	996	150	167

Source: Pace Global.

Figure 1

New Resource Levelized Recovery Requirements ($2015)



Source: Pace Global.

- **Combustion Turbine Based Plants**

Combustion turbine plants include current combined cycle and simple cycle plants, and next generation combined cycle plants represented by the "H" technology. In the near term, industry standard technologies like General Electric ("GE")'s 7FA 1x1 and 2x1 configuration will remain the standard combined cycle configuration. GE's aero-derivative-based LM6000 will likely remain the standard for simple cycle uses and for smaller combined cycle stations (less than 60 MW). As part of the demand curve reset process, NYISO has an F- frame machine as the proxy for the New York City cost of new entry assumptions.

Over the next five years the newest "H" technology is likely to gain market share without supplanting the current 7FA standard model. These machines have lower capital, operations, and operations and maintenance ("O&M") costs and have operating efficiencies over 60 percent.

- **Combustion Boiler Based Plants**

Power plants burning gas, oil, coal, or biomass comprise this category and are not expected to undergo significant technology or cost changes over the next 20 years. Coal-fired power plant overnight costs are expected to fall at a real rate of 0.3 percent per year according to the EIA. The same decline is expected for biomass-fired boiler based plants.

- **Solar-Based Power Plants**

Utility scale solar power plants are either photovoltaic ("PV") or Concentrated Solar Power ("CSP") technology. In either case, the technology is relatively new and, as such, costs are expected to decline over the next few years as the technology matures. When analyzing and determining generic unit additions, Pace Global focuses on large scale solar installations. Nominal equipment prices are expected to decline significantly, while labor increases at 0.5 percent per year.

- **Wind**

Wind turbine technology is fairly mature and, as such, prices are not expected to decline substantially. However, larger wind turbines are becoming more common and should see a reduction in the nominal per unit cost over the next few years. For all wind turbine plants nominal equipment prices are expected to decline 0.5 percent per year, while labor is expected to increase at 0.5 percent per year.

- **Environmental Retrofit Costs**

Environmental retrofit costs represent an area of significant required investment for coal plants looking to comply with EPA regulations. Pace Global's retirement analysis assesses capital expenditures on environmental retrofits when assessing coal plant economics and potential retirement. Table 4 below displays the base capital costs for the three major retrofit installation types used in the analysis.

Table 4
Summary of Environmental Retrofit Capital Costs (2015$)

Technology	Capital Cost
	$/kW
Wet Scrubber	527
SCR	187
Fabric Filter	83

Source: Pace Global, EIA, and EPA

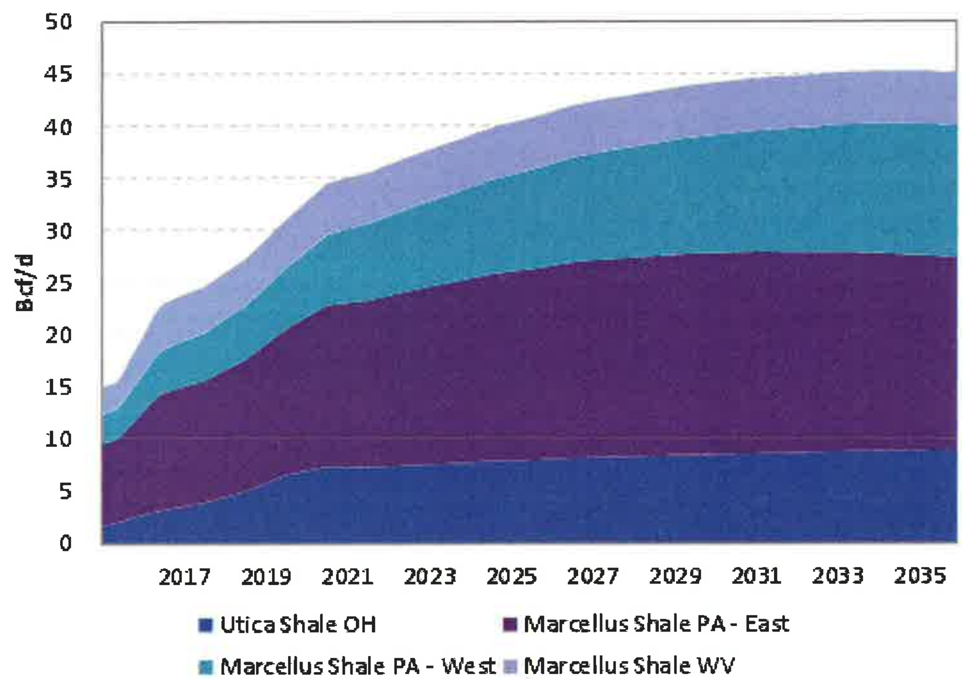
B. Reference Case Natural Gas Price Forecast

The increasing use of natural gas as a power generation fuel in the PJM market makes the forecast of natural gas prices a key component of the IRP Reference Case. The primary components of the natural gas forecast for the PJM region are described below. A more detailed look at generation fuel markets, including natural gas can be found in Appendix 8.

- **Gas Markets in the PJM Region**

Gas production from the Marcellus Shale and now the Utica Shale plays have grown at unprecedented rates in recent years, prompting a dramatic and ongoing reconfiguration of the North American natural gas transmission system. Some 30 Bcf/d of proposed pipeline projects are planned through 2020, which will add significant takeaway capacity (though not 30 Bcf/d worth of takeaway capacity, as some pipeline will only increase intra-regional capacity) from this region to allow supplies to reach demand markets. The rapid expansion of production in this region has slowed somewhat in the face of sustained low prices but has begun to resume its upward trajectory as supplies slowly tighten and the Northeast remains an engine of production growth. Figure 2 below provides Pace Global's view on future production from this region. This outlook is supported in the short- to mid-term by rig counts, well counts, and traded forward contracts that provide an economic view of expected production.

Figure 2: Appalachian Gas Production to 2035



Source: Pace Global and Genscape.

The Utica Shale play is characterized as a liquids-rich play, meaning that the gallons per million cubic feet ("GPM") of natural gas liquids (the "NGLs" known as ethane, propane, butane, iso-butane, and pentane) are higher than in other areas such as the northeastern Pennsylvania Marcellus region. Before the drop in the price of oil, NGLs were fetching roughly twice the value of gas on a per MMBtu basis. Accordingly, drilling activity until recently had been heavily focused on the Utica and the southwestern Pennsylvania Marcellus region. Currently, with prices recovering in the Northeast as new pipeline takeaway capacity comes online, gas production is expected to rise especially in the Northeast Pennsylvania region. Overall, the Marcellus is not expected to experience a downturn in production because there is a large backlog of drilled but uncompleted wells ("DUCs") that can come online at roughly 70% of the cost of a new well, helping to keep operators nimble and production levels elevated.

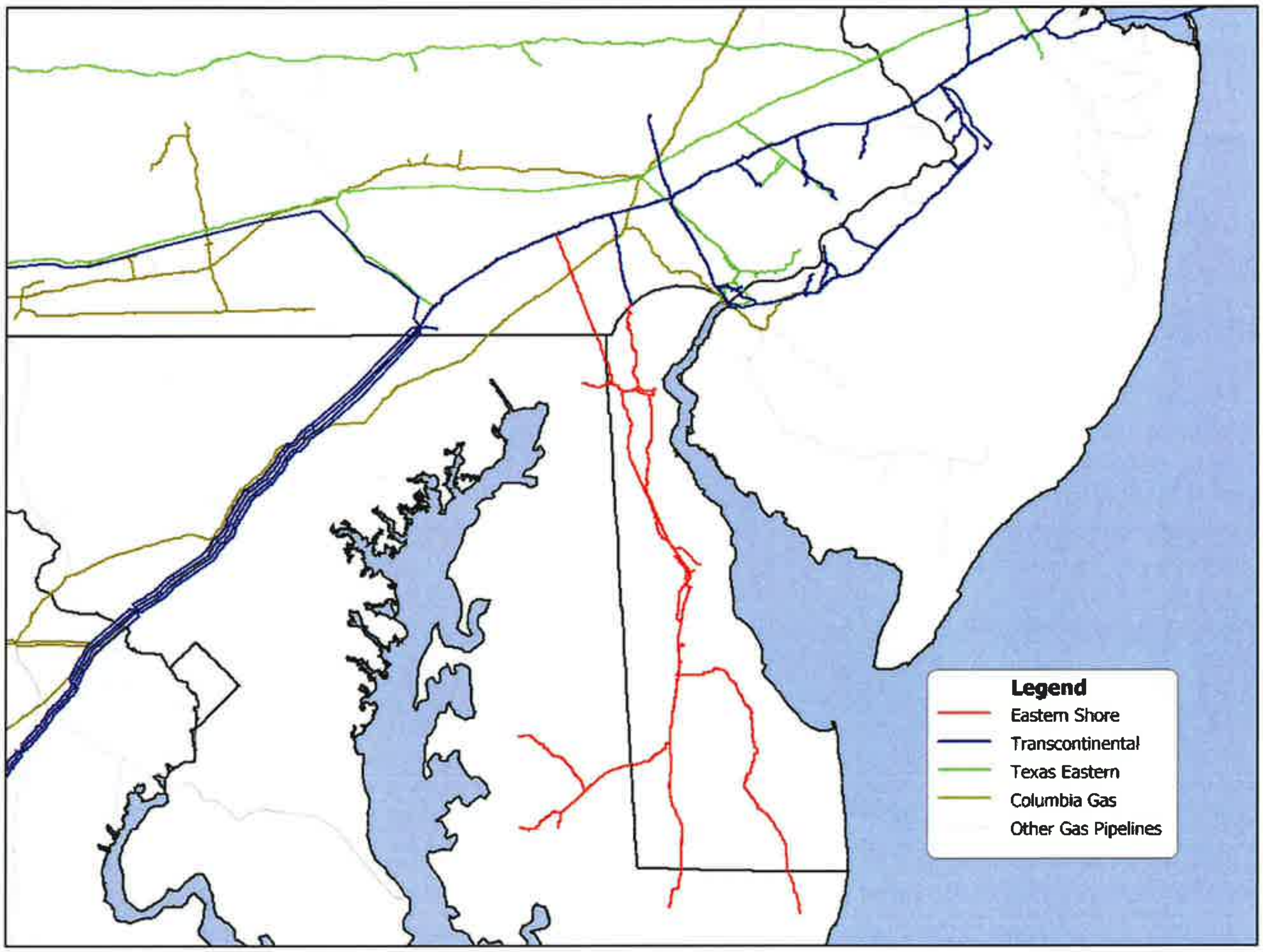
As a result of the prodigious production that has come online and the takeaway capacity constraints that generally lag new supply, gas prices (and basis to Henry Hub) are expected to remain low in the Appalachian basin for the foreseeable future. Effectively, pipeline capacity will be in a persistent lagged state to production, given the expected growth in supply. This situation, coupled with a small but non-negligible revenue uplift provided by NGLs that adds to associated gas production, will help to keep production elevated and put consistent long-term downward pressure on prices in this region.

Although North American gas markets currently remain in a supply-driven environment, significant new demand is expected in the coming few years. On a national level, Pace Global expects the power generation sector to grow robustly as coal-fired plants are retired, gas supply costs remain low, and the need for rapid-ramp generation increases to complement intermittent renewable generation. U.S. LNG exports are expected to reach nearly 7 Bcf/d by 2020, exports to Mexico will exceed 4 Bcf/d by this same year, and industrial demand will add nearly 2 Bcf/d of incremental demand by 2020.

- **Gas Pipelines**

The Eastern Shore pipeline that serves the Delmarva Peninsula is supplied by the Transcontinental (Transco) pipeline with two interconnects at Parkesburg, PA and Hockessin, DE; by the Texas Eastern (TETCO) pipeline with an interconnect at Honey Brook, PA; and the Columbia Gas pipeline with an interconnect at Daleville, PA. There are a few key dynamics at work on the Transco pipeline. These include a partial reversing of south-to-north flows via the Atlantic Sunrise project, which will bring 1,700 MMcf/d of Marcellus gas down from the Northeast PA Transco Leidy line by April 2018. In addition, the Dominion Cove Point LNG export project will add up to 700 MMcf/d of baseload demand on Transco's Zone 5. These two projects will mitigate each other to an extent, but price volatility is likely to increase in any event. Both the Columbia pipeline and Dominion pipelines are also interconnected with the Cove Point LNG project, with access to Marcellus gas from Southwest PA and Utica gas from Ohio and West Virginia. In general, the expansion of these three pipelines and the low-cost Marcellus gas that will push outward on these pipelines is expected to benefit the customers of the Delmarva Peninsula over the long-term. Figure 3 below provides a view of the Peninsula with respect to these pipelines.

Figure 3: Pipelines near the Delmarva Peninsula



Source: Pace Global.

The rapid expansion of shale gas production in the Marcellus and Utica plays has strained pipeline infrastructure in the region. The lack of takeaway capacity to move low-cost gas supply to premium markets in New England, New York, Chicago, and increasingly the Gulf Coast has led to artificially depressed prices in the region. However, many pipeline projects are on the books to alleviate these capacity constraints. A comprehensive list of pipeline projects in the region, including in-service dates, capacities, and flow states is provided in Appendix 8.

- **Natural Gas Price Forecast**

Table 5 below displays Pace Global's expected price projections for natural gas at the Henry Hub as well as gas delivered to the PJM region. The forecast is based on 18 months of current market forwards blended over the next 18 months with Pace Global's fundamental longer term view of market prices, after which the forecast is purely based on the fundamentals-based view.

Table 5
Reference Case Natural Gas Price Forecast

		AEP	APS	Central	ComEd	Delmarva	East	ATSI	PENELEC	South	Dominion	AEP
	Henry Hub	*Lebanon*	*Columbia Gas, Appalachia*	*Tetco M-3*	*Chicago Citygates*	*Tetco M-3*	*Transco Z6 Non-NY*	*Columbia Gas, Appalachia*	*Dominion South. Tetco M-3*	*Tetco M-3*	*Transco Z5*	*Lebanon*
2017	3.09	3.05	2.93	3.13	3.11	3.13	3.62	2.93	2.71	3.13	3.80	3.05
2018	2.96	2.87	2.77	3.15	2.95	3.15	3.45	2.77	2.81	3.15	3.61	2.87
2019	3.18	3.10	3.03	3.39	3.18	3.39	3.37	3.03	3.15	3.39	3.47	3.10
2020	3.78	3.67	3.62	3.91	3.73	3.91	3.78	3.62	3.70	3.91	3.85	3.67
2021	3.95	3.84	3.78	4.07	3.90	4.07	3.93	3.78	3.86	4.07	4.01	3.84
2022	4.08	3.95	3.89	4.17	4.03	4.17	4.02	3.89	3.95	4.17	4.13	3.95
2023	4.12	4.00	3.92	4.18	4.08	4.18	4.01	3.92	3.96	4.18	4.16	4.00
2024	4.19	4.06	3.96	4.19	4.15	4.19	4.03	3.96	3.98	4.19	4.21	4.06
2025	4.29	4.16	4.01	4.22	4.26	4.22	4.08	4.01	4.01	4.22	4.30	4.16
2026	4.38	4.22	4.04	4.24	4.34	4.24	4.10	4.04	4.00	4.24	4.37	4.22
2027	4.38	4.18	3.98	4.20	4.35	4.20	4.05	3.98	3.98	4.20	4.34	4.18

Source: Pace Global

C. Environmental Assumptions

- **Regional Green House Gas Initiative – RGGI**

RGGI was the first operational regional mandatory climate change program active in North America. RGGI regulates the CO_2 emissions of fossil fuel-fired power plants located in participating New England and Mid-Atlantic states. Currently, nine states participate in RGGI: Maine, New Hampshire, Vermont, New York, Massachusetts, Rhode Island, Connecticut, Delaware, and Maryland.

RGGI utilizes a market-based system to reduce CO_2 emissions from the power sector through a cap-and-trade program. All allowances are initially auctioned and then subsequently traded as needed by market participants and speculators. Pricing for RGGI reflects recent auction and over the counter market trading prices in the near-term. Beyond this time, pricing is based on the fundamental drivers, namely the emission cap level through 2020. At this time, carbon goals for

RGGI are not defined beyond 2020. Pace Global assumes that RGGI prices will steadily increase from current pricing levels of around \$4.50/ ton CO_2 in 2016 to \$6/ton CO_2 in 2020 as the regional emission cap declines over this time, but largely the market remains amply supplied. Pace Global's CO_2 allowance price projections under RGGI are presented in Table 6 below.

Table 6: Forecast of RGGI CO_2 Allowance Prices

Year	RGGI
2016	5.00
2017	5.00
2018	5.00
2019	6.00
2020	6.00
2021	6.00
2022	4.00
2023	4.00
2024	3.00
2025	4.00
2026	4.00
2027	5.00

Source: Pace Global.

- **EPA Carbon Regulations**

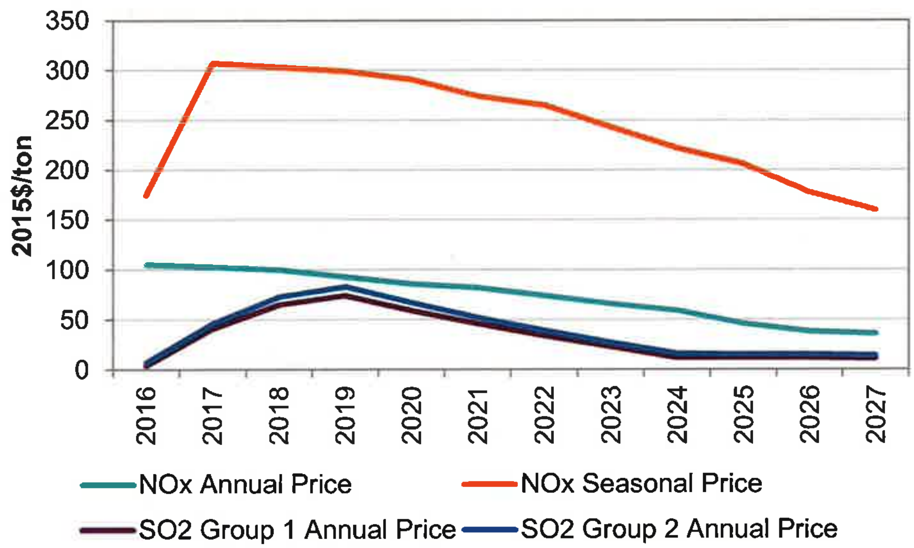
On June 25, 2013 President Obama announced his Climate Action Plan. As part of this announcement, he issued a Presidential Memorandum to the EPA to accelerate greenhouse gas ("GHG") rule-making for both new and existing electric generating units. Subsequently, the EPA released the updated proposed New Source Performance Standards ("NSPS") on September 20, 2013, and on June 2, 2014 the EPA released performance standards under §111(d) of the Clean Air Act ("CAA") for existing plants known as the Clean Power Plan ("CPP"). The final rules for both new (and significantly modified) and existing sources were released on August 3, 2015 and subsequently published in the Federal Register on October 23, 2015. However, in February of 2016 the Supreme Court granted a request to stay the CPP while the courts rule on the legal challenges to the rule, rendering the rule and all associated planning deadlines not in effect until further notice.

Although the implementation schedule of the CPP is currently uncertain, there is the distinct possibility of some form of national carbon policy in the future. To address this, the IRP Reference Case assumes that a national carbon pricing policy will become effective in 2022 with national CO_2 prices equal to the forecasted RGGI prices shown in Table 6 above.

- **SO_2 and NO_x Allowance Prices**

Pace Global's SO_2 and NO_X emission price forecast is based on the current and/or most relevant existing or proposed environmental regulation(s). While there is some pricing transparency from reported over the counter trades of these allowances in the near-term, a fair amount of uncertainty in the longer term as other market factors and regulations have the potential to significantly impact the emissions of SO_2 and NO_X. The allowance price projections for SO_2, NO_X Annual and NO_X Seasonal are contained below in Exhibit 4.

Exhibit 4: IRP Reference Case NO_X and SO_2 Prices



Source: Pace Global.

D. Renewable Energy Credits

RPS, also referred to as Renewable Electricity Standards ("RES") or Alternative Energy Portfolio Standards ("AEPS"), are regulated programs placing an obligation on electricity suppliers that a certain percentage of their electricity sold be derived from alternative or renewable energy resources. At this time, 30 states and the District of Columbia have enacted mandatory state-level RPS requirements.

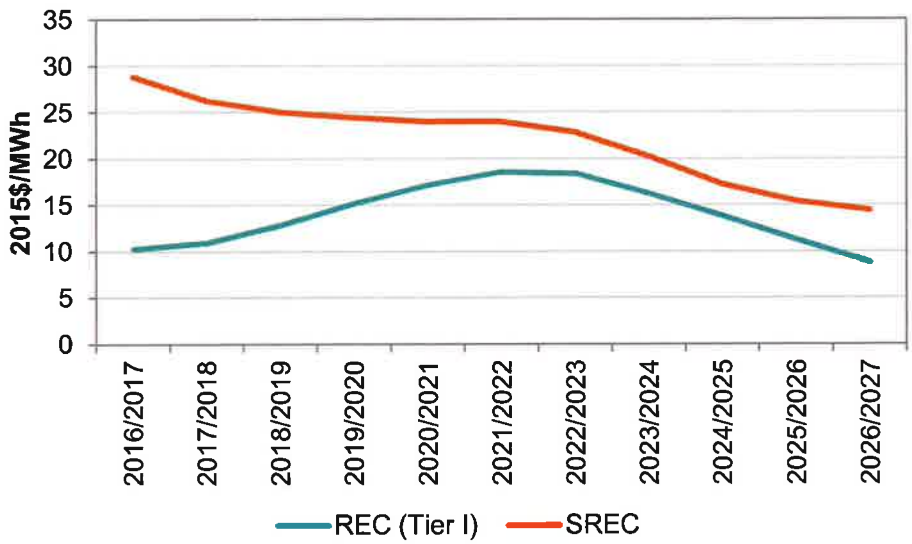
Pace Global projects REC and SREC prices for Delaware through analysis of current market signals, review of the supply-demand balance for renewable generation, and incorporation of other power market fundamentals.

Market pricing for the collective PJM Tier I / Class I markets, including Delaware as well as states like New Jersey and Pennsylvania trend very closely. Due to the supply fungibility between state programs, Pace Global projects REC prices for Delaware Tier I based on the supply, demand and market fundamentals of the broader PJM Tier I/Class I market. The reported pricing for over the counter transactions of RECs eligible for compliance in PJM state Tier I/Class I programs have declined from ~$18/MWh early in 2015 to the $10/MWh to $12/MWh as of September 2016. Much of this decline was due to the extension of the federal tax credits for renewable technologies in December of 2015, adding certainty to this additional financial incentive to new qualifying projects and more supply to the market, as well as the continued decline of renewable technology costs. Upward pressure on REC prices due to increasing RPS requirements between now and the mid-2020s, and the phase out of the federal renewable tax credits, is expected to place upward pressure on REC prices. However, Pace Global's expected recovery in natural gas / power prices and the expected decline in the installed cost of new renewables are expected to moderate this price increase somewhat. Beyond this time, as demand levels out, Pace Global projects a significant drop off in the market price of RECs.

Significant solar development in 2015 and in 2016 has resulted in the significant addition of SREC supply eligible to meet the Delaware solar requirement. PJM data indicates that there are currently 328MW of solar projects eligible to meet Delaware's solar requirements at this time, including in-state and out of state projects. As a result, reported pricing for Delaware SRECs has remained relatively constant in the $30/MWh to $40/MWh range despite significant growth in demand under the RPS. Prices for Delaware SRECs have reached levels well above $200/MWh at the beginning of the program, however, it is not expected that these SREC price levels will return under the current RPS policy. The current volume of eligible supply to meet the Delaware solar requirement is adequate to meet demand growth for the next several years. Competing demand from states like Pennsylvania, and, to a lesser extent the PJM Tier I/ Class I markets, will add incremental demand. Despite the significant increase in demand for SRECs over the forecast period, Pace Global projects relatively flat to declining prices for SRECs in Delaware due to ample current supply levels, declining installed costs for solar and the expected recovery of power markets.

The projections of REC and SREC prices are shown in Figure 4 below.

Figure 4: Reference Case REC and SREC Projections



Source: Pace Global.

SECTION 8

Section 8.
Renewable Energy Resources

A. Overview

As part of REPSA[1], the State of Delaware requires that Delmarva Power purchase an increasing amount of RECs[2] from qualified renewable energy sources through 2025. Compliance with this requirement over the IRP Planning Period (2017 – 2026) is an important focus of the 2016 IRP.

To demonstrate compliance with REPSA, each year Delmarva Power must provide to the State documentation that RECs meeting the annual requirement have been retired. In general, one REC is created for every mWh generated by an eligible renewable energy resource[3]. There is also a requirement for a minimum percentage of RECs to be generated from solar photovoltaic resources. For simplicity purposes, RECs generated by solar facilities are often referred to as "SRECs". Table 1 below shows the minimum percentage of Delmarva Power customer's annual energy supply that must be supplied from renewable sources[4]. The percentages shown in Table 1 below can be applied to Delmarva Power's forecasted annual RPS eligible mWh sales to determine Delmarva Power's expected annual quantity of RECs and SRECs to ensure RPS compliance.

Table 1

Delaware Eligible Renewable Energy Requirements*

* Compliance Year	Minimum Cumulative % from Eligible Resources	Minimum Cumulative % from Solar Resources
2017/18	16.0%	1.50%
2018/19	17.5%	1.75%
2019/20	19.0%	2.00%
2020/21	20.0%	2.25%
2021/22	21.0%	2.50%
2022/23	22.0%	2.75%
2023/24	23.0%	3.00%
2024/25	24.0%	3.25%
2025/26	25.0%	3.50%
2026/27	25.0%	3.50%

* The RPS legislation, as amended, does not extend the REC and SREC requirements beyond Compliance Year 2025. For purposes of the IRP, it is assumed that the 2025 requirements apply for the remaining year of the IRP Planning Period.

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[1] 26 *Del. C.* §351, et. seq.

[2] Defined in REPSA at 26 *Del. C.* §352(18).

[3] Defined in REPSA at 26 *Del. C.* §352(6).

[4] 26 *Del. C.* §351, et. seq.

As indicated in Table 1, in 2017/18, the first year of the 2016 IRP Planning Period, Delmarva Power is required to procure 16% of its electric supply requirements from renewable resources, including at least 1.5% from solar resources. By planning year 2024/25, the percentage increases to 24% for all qualifying resources, with at least 3.25% from solar resources.

To determine the number of RECs and SRECs that Delmarva Power needs to procure and retire in order to comply with REPSA, the percentages shown in Table 1 can be applied to the Reference Case mWh forecast for all Delmarva Power distribution customers, adjusted for large industrial customers that have chosen (as permitted by law) to not participate in the Delaware RPS.

The forecast REC requirements for all distribution customers showing the expected RECs needed for RPS compliance, by year, for both solar and non-solar eligible resources, are shown in Table 2 below.

Table 2

REC and SREC Expected Annual Requirements

Planning Year	RPS Distribution Load (MWh)	REC Requirement	SREC Requirement
2017/18	6,808,186	987,188	102,122
2018/19	6,768,240	1,065,998	118,444
2019/20	6,735,589	1,145,051	134,711
2020/21	6,712,084	1,191,396	151,021
2021/22	6,695,109	1,238,596	167,377
2022/23	6,676,613	1,285,249	183,606
2023/24	6,656,701	1,331,340	199,701
2024/25	6,644,308	1,378,694	215,940
2025/26	6,621,964	1,423,723	231,768
2026/27	6,599,852	1,419,184	231,029

The forecasted REC and SREC requirements shown in Table 2 are equal to the eligible distribution customer mWh forecast multiplied by the appropriate percentage from Table 1. For the non-solar requirement (REC) calculation, the percentage used is the minimum cumulative percentage less the solar carve-out percentage. The results shown in Table 2 will change depending on the load forecast and assumptions used regarding the level of energy efficiency and conservation achieved.

As explained in more detail below, Delmarva Power anticipates securing RECs and SRECs in sufficient quantity to maintain compliance with the REPSA requirements.

B. Contracted Resources

As a result of REPSA, and as approved by the Commission, Delmarva Power has already contracted for a portfolio of wind and solar resources to help meet the renewable energy requirements for eligible distribution customers. The specific resources are described below:

1. AES Armenia Mountain: This 100 mW [nameplate capacity] wind project is located in North Central Pennsylvania. Delmarva Power has entered into a 15-year power purchase agreement with AES to purchase up to half of the wind energy and RECs from this project. The wind farm became operational and contract purchases began in December 2009.

2. Dover Sun Park: Delmarva Power entered into a 20 year contract to purchase 70% of the SRECs created by the 10 mW [nameplate capacity] Solar Park constructed in Dover by White Oak Solar Energy, LLC, an affiliate of LS Power. The Dover Sun Park became commercially operational during the summer of 2011.

3. Gestamp Roth Rock: Delmarva Power has entered into a PPA with Gestamp to provide RECs and energy from a 40 mW [nameplate capacity] wind farm located in Western Maryland. The wind farm became operational and contract purchases began in August 2011.

4. Gamesa Chestnut Flats: Delmarva Power entered into a PPA with Gamesa to provide RECs and energy from a 38 mW wind project located in Central Pennsylvania. The wind farm became operational and contract purchases began in December 2011.

5. Delaware SREC Procurement Programs: To date, Delmarva Power has secured SRECs under six separate Commission approved programs: the SREC Procurement Pilot Program[5], the 2013 SREC Procurement Program[6], and the 2014 SREC Procurement Program[7], the 2015 SREC Procurement Program[8], and the 2016 SREC Procurement Program[9] and a contract with Washington Gas Energy Services (WGES)[10]. For each of these Programs, the SEU conducted a competitive solicitation to award 20 year contracts for the purchase of SRECs from customer sited facilities located in Delaware. Delmarva Power purchases the SRECs acquired under the program from the SEU. The results for each Program solicitation are shown below:

[5] PSC Docket No. 11-399, approved by Order No. 8075 dated 11-8-11 and Order No. 8091 dated 12-20-11.
[6] PSC Docket No. 12-526, approved by Order No. 8281 dated 1-22-13 and Order No. 8450 dated 9-10-13.
[7] PSC Docket No. 14-41, approved by Order No. 8551 dated 4-15-14 and Order No. 8629 dated 9-9-14.
[8] PSC Docket No. 14-0560, approved by Order No. 8717 dated 3-3-15 and Order No. 8764 dated 7-21-15.
[9] PSC Docket No. 15-1472, approved by Order No. 8884 dated 5-3-16 and Order No. 8890 dated 9-6-16.
[10] PSC Docket No. 13-99, approved by Order No. 8396 dated 6-18-13.

a. SREC Procurement Pilot Program: The Pilot program resulted in 165 contracts from Delaware-sited solar systems totaling approximately 8.5 mW of capacity.

b. 2013 SREC Procurement Program: The 2013 SREC Program resulted in awards for 385 projects for the SRECs produced by 5.5 mW of solar systems.

c. 2014 SREC Procurement Program: The 2014 SREC Program resulted in awards for approximately 295 projects for the SRECs produced by an additional 5.5 mW of solar systems.

d. 2015 SREC Procurement Program: The 2015 SREC Program resulted in awards for 396 projects for the SRECs produced by 8.2 mW of solar systems.

e. 2016 SREC Procurement Program: The 2016 SREC Program resulted in awards for 168 projects for the SRECs produced by 8.2 mW of solar systems.

f. WGES: in 2013- Delmarva entered into a contract to purchase SRECs from two solar facilities owned by Washing Gas Energy Services, Inc. totaling 1.8 mW, limited to 2,440 annually, for a period of twenty years at rates approved by the Commission per Order No. 8396, dated June 18, 2013.

In addition to the existing renewable energy contracts outlined above representing 128 mW of wind generation and over 40 mW of solar generation resources, pursuant to a commitment made in the Exelon Merger[11], Delmarva Power plans to issue a competitive request for proposals ("RFP(s)") to purchase wind RECs on commercially reasonable terms in three tranches: (1) the first, for RECs from one or more renewable generating facilities with an aggregate capacity of up to 40 mW (nameplate) beginning in compliance years 2017-2018 for a term of 10 to 15 years; (2) the second, for RECs from one or more renewable generating facilities with an aggregate capacity of up to 40 mW (nameplate) beginning in compliance years 2019-2020 for a term of 10 to 15 years; and (3) the third, for RECs from one or more renewable generating facilities with an aggregate capacity of up to 40 mW (nameplate) beginning in compliance years 2023-2024 for a term of 10 to 15 years[12].

This diverse portfolio of existing and new renewable energy contracts establishes a strong foundation for Delmarva Power's compliance with the Delaware RPS requirements.

[11] PSC Docket No. 14-193, approved by Order No. 8746 dated 6-2-15.

[12] Pursuant to Paragraph 84 of the Amended Settlement Agreement approved by the Commission in Docket No. 14-193, if circumstances or conditions change (including but not limited to a material change in the projected load of Delmarva Power such that fewer RECs are required, or a substantial change in the cost of RECs through the spot market such that additional spot-market purchases in lieu of long-term contract purchases would be prudent), the parties will work in good faith with each other and present any proposed modification to the Commission as may be warranted by those changed conditions.

Over the IRP Planning Period, these projects will create a supply of RECs and SRECs that will help Delmarva Power meet its RPS compliance obligations. Table 3 below shows the projected REC and SREC supply from Delmarva Power's contracted renewable resources over the IRP Planning Period:

Table 3

Delmarva Renewable Portfolio
Contracted Renewable Resources

Planning Year	Existing Wind Contracts	New Wind Contracts	Existing Solar Contracts
2017/18	338,627	112,128	63,168
2018/19	338,627	112,128	62,852
2019/20	338,627	224,256	62,538
2020/21	338,627	224,256	62,225
2021/22	338,627	224,256	61,914
2022/23	338,627	224,256	61,604
2023/24	338,627	336,384	61,296
2024/25	338,627	336,384	60,990
2025/26	283,512	336,384	60,685
2026/27	206,351	336,384	60,382

Table 4 below shows how Delmarva Power's supply of RECs and SRECs obtained from contracted renewable resources are currently expected to match up with the projected RPS requirements over the IRP Planning Period.

Table 4

Contracted Resources Position vs. Projected REPSA Requirement

Planning Year	Non-Solar REC Requirement	Contract Wind Resources	Net REC Positon	Solar SREC Requirement	Contract Solar Resources	Net SREC Position
2017/18	987,188	450,755	-536,433	102,122	63,168	-38,954
2018/19	1,065,998	450,755	-615,243	118,444	62,852	-55,592
2019/20	1,145,051	562,883	-582,168	134,711	62,538	-72,173
2020/21	1,191,396	562,883	-628,513	151,021	62,225	-88,796
2021/22	1,238,596	562,883	-675,713	167,377	61,914	-105,463
2022/23	1,285,249	562,883	-722,366	183,606	61,604	-122,002
2023/24	1,331,340	675,011	-656,330	199,701	61,296	-138,405
2024/25	1,378,694	675,011	-703,683	215,940	60,990	-154,950
2025/26	1,423,723	619,896	-803,827	231,768	60,685	-171,083
2026/27	1,419,184	542,735	-876,449	231,029	60,382	-170,647

As shown in Table 4, Delmarva Power's contracted resources do not meet projected requirements for both RECs and SRECs for the IRP Planning Period. However, as discussed below, additional amendments to REPSA created a provision that allows for the output from qualified fuel cells manufactured and installed in Delaware to offset part of Delmarva Power's RPS obligations[13]. As discussed in more detail below, the output from a QFCP can be used to help offset both solar and non-solar RPS requirements, as needed.

C. Qualified Fuel Cell Provider ("QFCP")

In July 2011, the Governor of the State of Delaware signed legislation establishing that the energy output from fuel cells manufactured in Delaware capable of running on renewable fuels ("Qualified Fuel Cell Provider" or "QFCP") qualify as an eligible resource for RECs under REPSA[14]. The legislation further required that the Commission adopt a tariff under which Delmarva Power would act as the agent for the QFCP to collect payments from its customers and disburse the amounts collected to a QFCP that deploys Delaware-manufactured fuel cells as part of a 30-megawatt generation facility. The payments from customers would be offset by the market revenues received by the QFCP from selling capacity and energy into the wholesale market netted against its cost of fuel. The legislation also provided for a reduction in Delmarva Power's REC and SREC requirements based upon the actual energy output of the 30-megawatt generation facility. On October 18, 2011, pursuant to Order No. 8062 in Docket No. 11-362, the Commission approved the tariff submitted by Delmarva Power in compliance with the legislation.

The State identified Diamond State Generation Partners ("Diamond State" or "Bloom Energy") as the QFCP. Bloom Energy has constructed fuel cell generation facilities at two locations in Delaware. The first site, a 3 mW fuel cell facility adjacent to Delmarva Power's Brookside substation, went into operation in June 2012. The second site, a 27 mW facility located adjacent to Delmarva Power's Red Lion Substation, became fully operational in November 2013.

The amendments to REPSA provide that each mWh produced by a QFCP allows Delmarva Power to offset its RPS obligations. Essentially, the output of the Bloom Energy facilities, as a QFCP Project, reduces the non-solar REC and/or SREC requirements that would otherwise be needed to satisfy REPSA.

The original legislation provided that the output from QFCPs could be used to offset either one REC or 1/6 of a SREC for each mWh generated by the fuel cell. However, during the Commission hearings to approve the QFCP tariff, DNREC testified that an additional multiplier of 2 would be applied to the RECs created by the QFCP. Consequently, the output of the QFCP can

[13] 26 *Del. C.* §352, et. seq.
[14] *Id.*

be used to offset 2 RECs or 1/6 of a SREC. For ease of presentation in this document, these offsets are expressed as equivalent RECs ("ERECs") and equivalent SRECS ("ESRECs"). Delmarva Power allocates the QFCP offsets between RECs and SRECs for RPS compliance in a manner to be most cost-effective for customers. Given the current offset structure and projected market prices for RECs and SRECs, customers will be better off using all of the QFCP offsets as ERECs. Table 5 below shows the projected amount of the non-solar REC and SREC offsets expected to be created from the QFCP that will help offset Delmarva Power's REPSA requirements.

Table 5
Qualified Fuel
Cell Provider

Non Solar and Solar REC Offsets

Year	Projected QFCP Generation (mWh)	REC Offsets	SREC Offsets
2017/18	226,534	453,067	0
2018/19	226,534	453,067	0
2019/20	226,534	453,067	0
2020/21	226,534	453,067	0
2021/22	226,534	453,067	0
2022/23	226,534	453,067	0
2023/24	226,534	453,067	0
2024/25	226,534	453,067	0
2025/26	226,534	453,067	0
2026/27	226,534	453,067	0

Tables 6 and 7 below indicate Delmarva Power's projected net position adjusted to reflect the expected impact of the QFCP on Delmarva Power's RPS obligations. For both tables, a negative net position indicates that Delmarva Power is "short" or will need to purchase more RECs (or SRECs) per the projections. A positive net position indicates that additional RECs are available to be "banked" and used in a future year.

Table 6
QFCP Impact on Delmarva Power's Projected Net Solar Position

Year	SREC Requirement	Bloom ESRECs	Contracted Resources	Net Position
2017/18	102,122	0	63,168	-38,954
2018/19	118,444	0	62,852	-55,592
2019/20	134,711	0	62,538	-72,173
2020/21	151,021	0	62,225	-88,796
2021/22	167,377	0	61,914	-105,463
2022/23	183,606	0	61,604	-122,002
2023/24	199,701	0	61,296	-138,405
2024/25	215,940	0	60,990	-154,950
2025/26	231,768	0	60,685	-171,083
2026/27	231,029	0	60,382	-170,647

Table 7
QFCP Impact on Delmarva Power's Projected Net RPS Position

Year	REC Requirement	Bloom ERECs	Contracted Resources	Net Position
2017/18	987,188	453,067	450,755	-83,366
2018/19	1,065,998	453,067	450,755	-162,176
2019/20	1,145,051	453,067	562,883	-129,101
2020/21	1,191,396	453,067	562,883	-175,446
2021/22	1,238,596	453,067	562,883	-222,646
2022/23	1,285,249	453,067	562,883	-269,299
2023/24	1,331,340	453,067	675,011	-203,262
2024/25	1,378,694	453,067	675,011	-250,616
2025/26	1,423,723	453,067	619,896	-350,760
2026/27	1,419,184	453,067	542,735	-423,382

D. Incremental RPS Requirements

As indicated in Tables 6 and 7, even after the QFCP RPS offsets are taken into account, Delmarva Power projects that it will need RECs and SRECs in excess of currently contracted supply to meet RPS obligations through the IRP Planning Period. As mentioned earlier, both RECs and SRECs can be purchased from the spot market to satisfy these requirements. Given the relatively low spot market prices currently available, Delmarva Power anticipates including a significant level of spot market purchases as part of its renewable supply portfolio to fill the gap.

E. RPS Compliance Costs

The following Tables present the projected costs of RPS compliance given Delmarva Power's contracted resources and the forecast with respect to spot market prices[15]. Consistent with the implementation of the final rules for estimating the cost caps associated with RPS compliance, issued by DNREC in March 2016[16] ("DNREC Rule Implementation")[17], material appearing in the section under the heading of "Non-price Impacts of RPS Compliance" provides additional information related to human health benefits associated with the improvement in air quality that may be quantifiable and attributable to the implementation of the Delaware RPS requirements.

Table 8 below represents the projected cost for Delmarva Power to meet the Solar RPS requirements. The cost of solar compliance is projected to increase from approximately $7.35 million in compliance year 2017/18, to $8.91 million in compliance year 2026/27.

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[15] The cost of the planned but not yet approved REC wind contracts are priced using future annual spot market prices.

[16] See: "Director's Determination under 26 Del.C. §354(i) & (j) and 7 DE Admin. Code 104 Implementation of Renewable Energy Portfolio Standards Cost Cap Provisions", issued March 15, 2016.

[17] Delmarva notes, without prejudice, that the DPA has filed an appeal of the DNREC Rule Implementation which is currently pending in the Delaware Superior Court.

Table 8

Projection of the Cost to Comply with the RPS Solar Requirement

Planning Year	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27
Forcasted Load Obligation GWh	6,669	6,617	6,573	6,540	6,513	6,486	6,456	6,438	6,407	6,376
Projected SREC by Source (SRECs)										
Dover SunPark	13,576	13,508	13,441	13,374	13,307	13,240	13,174	13,108	13,043	12,977
SREC Financing Pilot Program	47,308	47,072	46,836	46,602	46,369	46,137	45,907	45,677	45,449	45,221
QFCP Offsets	0	0	0	0	0	0	0	0	0	0
Spot-Solar	38,954	55,592	72,173	88,796	105,463	122,002	138,405	154,950	171,083	170,647
Total SRECs	99,838	116,172	132,450	148,772	165,139	181,379	197,485	213,735	229,574	228,846
SREC Cost (k$)										
Dover SunPark	$2,468	$2,456	$2,444	$2,432	$2,419	$2,407	$2,395	$2,383	$2,371	$2,360
SREC Financing Pilot Program	$3,832	$3,813	$3,794	$3,775	$3,756	$3,737	$3,718	$3,700	$3,681	$3,663
QFCP Offsets	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Spot-Solar	$1,051	$1,448	$1,862	$2,282	$2,751	$3,073	$3,139	$3,039	$3,045	$2,883
Total Solar Complinace Costs (k$)	$7,351	$7,717	$8,099	$8,489	$8,927	$9,218	$9,253	$9,122	$9,097	$8,905

Table 9 below presents the projected cost to comply with the total RPS requirements. Projected costs increase from $57 million in 2017/18 to $60.8 million in 2019/20, and then fall to $57.7 million by 2026/27.

Table 9

Projection of the Total Cost to Comply with the RPS Requirements

Planning Year	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27
Projected REC by Source (RECs)										
Solar Supply	99,838	116,172	132,450	148,772	165,139	181,379	197,485	213,735	229,574	228,846
Wind Contracts	450,755	450,755	562,883	562,883	562,883	562,883	675,011	675,011	619,896	542,735
QFCP Offsets	453,000	453,000	453,000	453,000	453,000	453,000	453,000	453,000	453,000	453,000
Spot-REC	63,313	162,243	129,168	175,513	222,713	269,366	203,330	250,683	350,827	423,449
Total RECs	1,066,906	1,182,170	1,277,501	1,340,167	1,403,735	1,466,628	1,528,825	1,592,429	1,653,297	1,648,030
REC Costs (k$)										
Solar Supply	$7,351	$7,717	$8,099	$8,489	$8,927	$9,218	$9,253	$9,122	$9,097	$8,905
Wind Contract RECs	$13,853	$13,287	$14,743	$12,463	$12,065	$11,748	$14,584	$14,246	$13,167	$11,562
Wind Contract Net Energy Cost	$3,296	$3,035	$2,468	$1,234	-$1,046	-$1,444	-$1,761	-$1,616	-$1,954	-$1,711
QFCP Offsets	$32,488	$31,656	$33,462	$32,780	$31,919	$32,036	$31,911	$32,082	$32,745	$34,592
Spot-REC	$712	$2,173	$2,069	$3,227	$4,499	$5,473	$3,701	$3,943	$4,556	$4,383
Total RPS Complinace Costs (k$)	$57,700	$57,868	$60,841	$58,192	$56,363	$57,031	$57,688	$57,777	$57,611	$57,731

F. Impact of RPS Compliance

As part of the settlement reached in Docket No 10-2, approved by the Commission in Order No. 8083 dated January 10, 2012, Delmarva Power agreed to estimate the impact of compliance with the Delaware RPS on customer bills as part of the 2012 and future IRPs. As described above, Delmarva Power is employing a three-fold renewable resource compliance plan. First, Delmarva Power has developed a portfolio of renewable resources that includes a mixture of long-term contracts for both wind and solar resources. Second, Delmarva Power is able to use the REC and SREC offsets created by the QFCP to help meet its RPS obligations. The third and final piece of the renewables compliance plan is to purchase RECs and SRECs from the spot market as needed to ensure that the annual compliance requirements are met. In this Section of the IRP, Delmarva Power provides estimates of the annual impact on customer bills, over the IRP Planning Period, for each of these three components of RPS compliance, for both non-solar and solar resources.

Table 10 below provides a summary of the estimated impact of RPS compliance (including the QFCP) on a typical monthly average Residential customer bill of 1000 kWh for the period June 2017 – May 2027.

Table 10
Impact of RPS Compliance on Average Residential Ciustomer Bill (1000kWh/Month)
Confidential Material Omitted*

Compliance Year	2017/2018	2018/2019	2019/2020	2020/2021	2021/2022	2022/2023	2023/2024	2024/2025	2025/2026	2026/2027
Avg. Residential Customer Bill (1000 kW/Month)										
Supply				$70.89	$68.97	$74.72	$80.27	$85.46	$89.77	$91.66
Transmission	$7.45	$7.45	$7.45	$7.45	$7.45	$7.45	$7.45	$7.45	$7.45	$7.45
Distribution	$30.00	$30.00	$30.00	$30.00	$30.00	$30.00	$30.00	$30.00	$30.00	$30.00
RPS (Includes QFCP)	$8.48	$8.55	$9.03	$8.67	$8.42	$8.54	$8.67	$8.70	$8.70	$8.75
Total				$117.00	$114.84	$120.71	$126.38	$131.60	$135.91	$137.85
Solar Compliance Impact on Typical Customer Bill										
SREC Cost	$1.08	$1.14	$1.20	$1.26	$1.33	$1.38	$1.39	$1.37	$1.37	$1.35
SREC % Impact				1.08%	1.16%	1.14%	1.10%	1.04%	1.01%	0.98%
RPS Compliance Impact on Typical Customer Bill										
Total RPS Cost	$8.48	$8.55	$9.03	$8.67	$8.42	$8.54	$8.67	$8.70	$8.70	$8.75
RPS % Impact				7.41%	7.33%	7.08%	6.86%	6.61%	6.40%	6.34%

*the supply prices for 2017/18 – 2019/20 are confidential until the results of the Spring 2017 SOS auction are publically released.
Note: In Table 10 Transmission and Distribution costs are held constant.

In evaluating the data presented in Table 10, it is important to recognize that the results shown are based upon assumptions embedded in the IRP Reference Case. As future events unfold (e.g., changes in future electricity market prices and/or customer loads) it will impact the results set forth in Table 10.

G. Non-Price Impacts of RPS Compliance

Section 6.1.4 of the regulations governing Delmarva Power in preparing the IRP[18] requires the evaluation of the impact of environmental externalities associated with Delmarva

[18] 26 *Del. Admin. C.*§ 3010.

Power's energy procurement plans on REPSA compliance. REPSA provides, in pertinent part[19]:

> The General Assembly finds and declares that the benefits of electricity from renewable energy resources accrue to the public at large, and that electric suppliers and consumers share an obligation to develop a minimum level of these resources in the electricity supply portfolio of the state. These benefits include improved regional and local air quality, improved public health, increased electric supply diversity, increased protection against price volatility and supply disruption, improved transmission and distribution performance, and new economic development opportunities.

As part of the 2012 IRP, using publically available models, Delmarva prepared a quantitative evaluation of the impact of changes in Air Quality in the Mid-Atlantic Region and Delaware between 2013 and 2022. The results of this evaluation were presented in Section IX and Appendix 8 of the 2012 IRP. In brief, these results (obtained using Delmarva Power data with publically available analysis tools) quantified the human health benefits resulting from improvements in air quality over the period 2013 – 2022 in the range of $980 million to $2.2 billion and $13 to $29 billion, respectively, for Delaware and the Mid-Atlantic Region. These benefits are driven by reductions in air emissions from all sectors of the economy including power generation, industrial production and transportation. Consequently, the externality analysis provided in Appendix 8 of the 2012 IRP did not directly identify the separate contribution of renewable resources to the overall improvement in human health that are part of Delmarva Power's renewable resource compliance portfolio. Because an analysis of the separate contribution of renewable resources to improving air quality would be expensive and overly time-consuming, Delmarva Power has employed a simpler approach as described below.

H. Estimated Impact of Renewables on Air Quality

The wind and solar resources that are part of Delmarva Power's renewable portfolio are considered "intermittent" resources. In other words, they supply energy into the electrical grid whenever the wind is blowing and the sun is shining. In terms of PJM generation dispatch,

[19] 26 *Del. C.* §351(b).

whenever wind and solar resources are producing power, their output is taken into the grid. In general, when wind and solar resources are supplied into the grid, this requires other generation resources that are "dispatchable" to reduce their generation output in order to maintain grid balance and stability. All dispatchable resources, other than nuclear and hydro facilities, produce air emissions such as CO_2, SO_2, and NO_X at varying rates. Accordingly, when wind and solar resources generate power, other sources reduce their output and any air emissions related to that power output.

It is difficult to determine with any precision how much CO_2, SO_2, and NO_X are displaced by wind and solar resources because marginal changes in PJM generation emissions are different for each and every hour during the year, and the specific hourly production of intermittent wind and solar resources during a year's time is hard to predict. Consequently, calculating the exact emissions avoided by intermittent resources can be a complex undertaking. Nevertheless, using some simplifying assumptions, average PJM emission rates[20] for CO_2, SO_2, and NO_X can be combined with the expected annual renewable resource generation (mWh) associated with Delmarva Power's renewable resource portfolio to obtain an estimate of future benefits consistent with the DNREC Rule Implementation.

The Air Quality analyses presented in Section IX and Appendix 8 of the 2012 IRP estimated the potential range of health benefits from air quality improvement between 2013 and 2022 from all sectors, including electric power generation, industry, and transportation. Based on the contribution of electric power generation emissions from the Mid-Atlantic Region, monetized health-related costs in these states was estimated to range from \$36 to \$98 billion (U.S. \$2010) for 2022. This range is based on different epidemiological studies and discount rates (the discount rates account for the time lag between changes in PM2.5 concentration and changes in PM2.5 mortality).

Breaking this down by type of emission and based on the PPTM results, it is estimated that 63% of the overall health cost is attributable to SO_2 emissions, 6% of the overall cost is attributable to NO_x emissions, and 29% of the overall cost is attributable to primary PM2.5 emissions. As reported in the 2012 IRP, the cost per ton for SO_2 and NO_x is estimated to be within the range of \$43,000 – \$110,000 for SO_2, and \$9,500 – \$25,000 for NO_x. Also, as discussed in Appendix 8 of the 2012 IRP, the health cost per ton of CO_2 is estimated to be within the range of \$1 to \$100 per ton. In the DNREC Rule Implementation, DNREC used the following values: \$43,000/ton for SO_2, \$9,500/ton for NO_x, and \$32.19/metric ton[21] for CO_2.

Average annual emission rates (tons/mWh) for CO_2, NO_x and SO_2 can be calculated from the

[20] See Appendix 6 for a more detailed review of recent PJM and Delaware power plant emissions.
[21] The conversion of a \$1/metric ton to \$/ton provides an equivalent price of \$1.10/ton.

Reference Case for PJM resources that create these emissions[22]. This is shown in Table 11 below:

Table 11
PJM Average Emission Rates (ton/mWh)

Planning Year	CO2	NOX	SO2
2017/2018	0.779365	0.000421	0.000930
2018/2019	0.745447	0.000388	0.000828
2019/2020	0.742680	0.000386	0.000840
2020/2021	0.753517	0.000396	0.000888
2021/2022	0.744755	0.000384	0.000874
2022/2023	0.729092	0.000366	0.000841
2023/2024	0.736175	0.000373	0.000856
2024/2025	0.743084	0.000378	0.000838
2025/2026	0.742561	0.000375	0.000794
2026/2027	0.736606	0.000370	0.000781

The total amount of renewable resource generation mWh enabled by Delmarva Power's renewable portfolio for the IRP Planning Period is shown in Table 12 below:

Table 12
Power Delmarva Power Renewable Resource Portfolio
Total Expected Generation (mWh)

Planning Year	Contracted Resources	QFCP	Spot Purchases	Total
2017/18	513,922	226,534	122,320	862,776
2018/19	513,607	226,534	217,768	957,908
2019/20	625,420	226,534	201,274	1,053,228
2020/21	625,108	226,534	264,242	1,115,883
2021/22	624,797	226,534	328,109	1,179,439
2022/23	624,487	226,534	391,301	1,242,321
2023/24	736,307	226,534	341,667	1,304,508
2024/25	736,000	226,534	405,566	1,368,100
2025/26	680,581	226,534	521,843	1,428,957
2026/27	603,116	226,534	594,030	1,423,679

As discussed earlier, when these resources produce power, they displace other resources

[22] Resources that create emissions include coal, gas, oil and other fuel fired generators. Over the last 4 years coal, gas, oil and other generation resources represent the marginal PJM generation unit about 95% of the time. See Appendix 6 for more details on air emissions in PJM and Delaware.

that would have otherwise created air emissions[23]. The DNREC Rule Implementation uses 50% of the average PJM emission rate to estimate the reduction in air emissions resulting from the RPS. Using 50% of the emission rates shown in Table 11 above and the generation mWh in Table 12 above, Table 13 below shows the reduction in air emissions that would otherwise have occurred:

Table 13

Tons of Emissions Avoided by DPL Renewable Portfolio Resources
(50% of PJM average emissions avoided)

Compliance Year	CO2	NOX	SO2
2017/18	247,932	181	401
2018/19	272,601	186	397
2019/20	306,985	203	442
2020/21	335,070	221	495
2021/22	354,841	226	515
2022/23	370,301	227	522
2023/24	396,789	243	558
2024/25	424,140	258	573
2025/26	446,436	268	567
2026/27	440,913	263	556

The estimated tons of emission reductions can be applied to the dollar value per ton as used in the DNREC Rule Implementation to provide an estimate for the total avoided emission costs attributable to Delmarva Power's RPS compliance plan. The DNREC Rule Implementation employed the following dollars per ton valuations:

- CO_2 \$32.19/metric ton (equivalent to \$35.41/ton)
- NO_x \$9,500/ton
- SO_2 \$43,000/ton

These respective dollar values per ton can be multiplied by the estimated avoided emissions shown in Table 13 above to provide a quantitative estimate of the benefits of avoided emissions[24]. The results are shown in Table 14 below:

[23] Over the period 2012 -2015, the marginal generation resource in PJM was coal, gas, other or oil fired approximately 95% of the time. See Appendix 6.

[24] The Caesar Rodney Institute (CRI) provided the following alternative valuations for avoided emissions: CO_2 \$6.10/ton, NO_x \$9,500/ton, SO_2 \$30,000/ton. See "Suggestions for the Delmarva Power 2016 IRP from the Caesar Rodney Institute, 3/30/2016" presented to the IRP Working Group Participants on April 14, 2016.

Table 14

Estimated Benefits of Reduced Air Emissions from Delmarva Power's Compliance with the Delaware RPS
(50% of average PJM emissions avoided)

Compliance Year	CO2	NOX	SO2	Total
2017/18	$8,779,039	$1,723,343	$17,254,759	$27,757,141
2018/19	$9,652,515	$1,766,933	$17,057,005	$28,476,453
2019/20	$10,870,021	$1,932,525	$19,022,369	$31,824,915
2020/21	$11,864,493	$2,101,173	$21,297,146	$35,262,812
2021/22	$12,564,552	$2,149,615	$22,164,187	$36,878,353
2022/23	$13,112,003	$2,157,499	$22,461,958	$37,731,459
2023/24	$14,049,886	$2,309,763	$24,003,506	$40,363,155
2024/25	$15,018,368	$2,453,880	$24,651,803	$42,124,051
2025/26	$15,807,867	$2,543,677	$24,385,176	$42,736,720
2026/27	$15,612,274	$2,499,410	$23,894,487	$42,006,171

SECTION 9

Section 9
Delmarva 2016 IRP Reference Case

In preparing the IRP, Delmarva Power develops a Reference Case to represent the expected view of the future procurement planning environment for the 2017- 2026 period. This case provides a structure for the IRP analysis and evaluations and a point of comparison for varying key assumptions supporting the Reference Case. It is also a dynamic view of the future state of the electric system within Delaware and PJM. The major assumptions underlying this case discussed in previous sections of this document reflect the current state of the overall electric system at the time the IRP modeling analysis was undertaken.

The Reference Case provided in the 2016 IRP provides a detailed look at the results of the Company's expected future energy procurement practices for the period 2017 – 2026. The key data planning assumptions underlying the view of the Company's energy future implied by the Reference Case include the following:

1. The Delmarva Power load forecast (described in Section 4 and Appendix 4);

2. Expected energy and demand response reductions (described in Section 5);

3. PJM approved transmission system upgrades (described in Section 6);

4. The cost and operating characteristics of supply side resource options and the expected implementation and timing of various environmental regulations affecting power generation (described in Section 7); and,

5. Delmarva Power's plan to procure REC's generated by renewable energy resources in sufficient quantities to meet the annual requirements of REPSA (described in Section 8).

The remainder of this Section presents detailed information for the IRP Reference Case and the sensitivity analyses for a high natural gas price scenario.

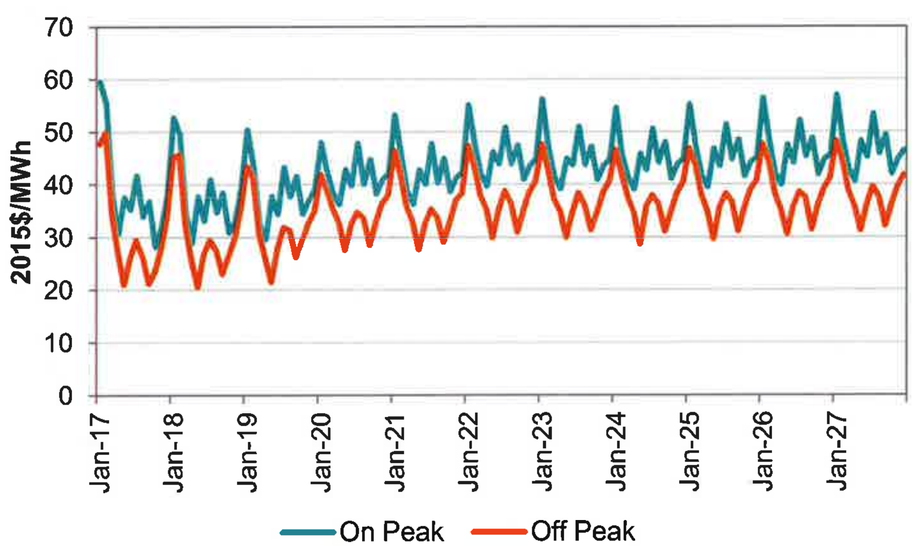
As mentioned earlier, Delmarva Power retained Siemens Industry Inc., for its Pace Global business ("Pace Global") to prepare an independent PJM market assessment to support the modeling effort in preparing the 2016 IRP. Covering the period from 2017 to 2026 ("Study Period"), these analyses include Pace Global's market views for energy, capacity, and environmental markets, as well as the key drivers that reflect these views. In its market analysis, Pace Global has employed proprietary tools to simulate the deregulated power generation markets and to project market clearing prices for energy, capacity, RECs and SRECs. All monetary values in this section are denominated in 2015 U.S. Dollars (2015$) unless otherwise noted.

REFERENCE CASE MARKET PRICE PROJECTIONS

Energy Price

Pace Global's reference case PJM market price projections reflect an integrated market assessment that includes inputs for natural gas prices, coal prices, load growth, environmental compliance costs, and capacity additions and retirements. Figure 1 below summarizes the reference case energy price projections for the DPL zone within PJM. The high price projections during winter months in the early years are driven by expectations for localized gas price spikes due to high demand and pipeline constraints. Over time, those are expected to relax, but natural gas prices at the Henry Hub and across the PJM footprint are expected to rise overall by the end of the current decade, as a result of increased demand from power generation and exports. Rising gas price expectations and coal retirements throughout PJM contribute to expected increases in power prices over time, especially during the summer peak period.

Figure 1: Reference Case PJM DPL Zone Energy Price Projections



Source: Pace Global.

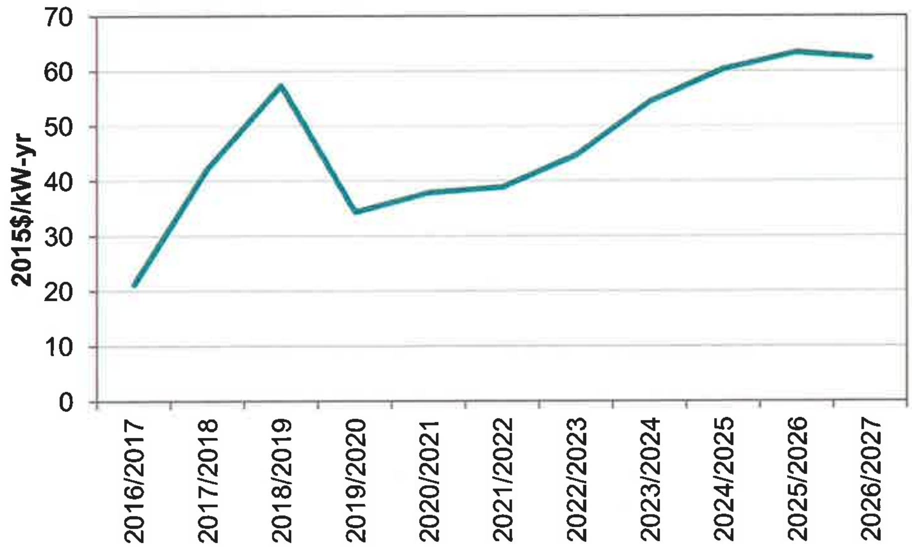
Capacity Price

Figure 2 below shows Pace Global's capacity price projections for the DPL zone, which also corresponds to projections in the Eastern Mid-Atlantic Area Council ("EMAAC") Locational Deliverability Area ("LDA"), over the Study Period in $/kW-yr terms for each auction period. Capacity prices through the 2019/2020 period are based on actual PJM Base Residual Auction ("BRA") clearing prices.[1]

[1] The PJM BRA auction year begins June 1 and ends May 31 of the following year.

Capacity prices for years beyond the auction period are driven by the supply-demand balance (or reserve margin) in the region, the cost of new entry ("CONE"), and the energy revenues that can be realized by plants operating in the market. Pace Global has analyzed the PJM capacity market in an integrated fashion with our energy market projections.

Figure 2: Reference Case DPL Zone Capacity Price Projections



Source: Pace Global.

REC and SREC Price

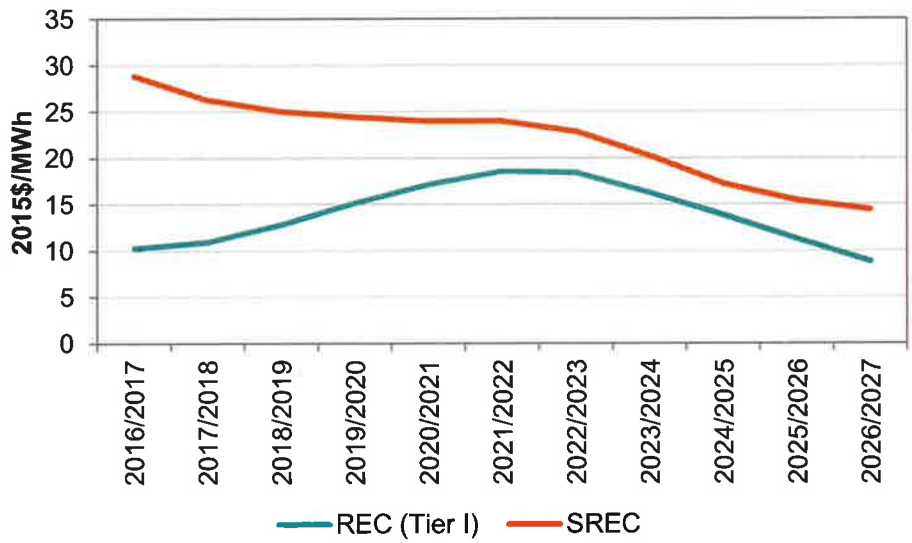
Pace Global projects REC and SREC prices for Delaware and the rest of PJM through analysis of current market signals, review of the supply-demand balance for renewable generation, and incorporation of other power market fundamentals. Figure 3 below presents Pace Global's projections for both REC products in the IRP Reference Case.

Market pricing for the collective PJM Tier I / Class I markets, including Delaware as well as states like New Jersey and Pennsylvania, trend very closely. Due to the supply fungibility between state programs, Pace Global projects REC prices for Delaware Tier I based on the supply, demand and market fundamentals of the broader PJM Tier I/Class I market. The reported pricing for over the counter transactions of RECs eligible for compliance in PJM state Tier I/Class I programs have declined from ~$18/MWh early in 2015 to the $10/MWh to $12/MWh range as of September 2016. Much of this decline was due to the extension of the federal tax credits for renewable technologies in December of 2015, adding certainty to this additional financial incentive to new qualifying projects and more supply to the market as well as the continued decline of renewable technology costs. Upward pressure on REC prices due to increasing RPS requirements between now and the mid-2020s, and the phase out of the federal renewable tax credits, is expected to place upward pressure on REC prices. However, Pace Global's expected recovery in natural gas and power prices, and the expected decline in the installed cost of new renewables are expected to moderate this price increase somewhat. Beyond this time, as demand levels out, Pace Global projects a significant drop of in the market price of RECs.

SREC supply eligible to meet Delaware solar requirement has seen a sharp increase recently, due to significant in-state distributed solar development and out-of-state development of projects that qualify to sell in Delaware. According to PJM's Generation Attribute Tracking System ("GATS"), there are currently 328MW of solar projects eligible to meet Delaware's solar requirements at this time. As a result, reported pricing for Delaware SRECs has remained relatively constant in the \$30/MWh to \$40/MWh range despite significant growth in demand under the RPS. Prices for Delaware SRECs have reached levels close to \$300/MWh at the beginning of the program. The current volume of eligible supply to meet the Delaware solar requirement is adequate to meet demand growth for the next several years. Competing demand from states like Pennsylvania, and, to a lesser extent the PJM Tier 1/ Class 1 markets, will add incremental demand. Despite the significant increase in demand for SRECs over the forecast period, Pace Global projects relatively flat to declining prices for SRECs in Delaware due to ample current supply levels, declining installed costs for solar and the expected recovery of power markets.

Pace Global forecasts fundamental pricing for RECs assessing available market pricing and longer-term supply and demand fundamentals of applicable markets. The near-term price forecasts are largely based on current representative market transactions as the information is available. Pace Global's independent view of market drivers including fuel and power prices, load growth, and technology costs are used to determine the longer-term fundamental drivers of REC pricing in respective markets. No significant policy changes are assumed in the forecasts unless otherwise noted.

Figure 3: **Reference Case REC and SREC Projections**



Source: Pace Global.

REGIONAL GENERATION, CAPACITY EXPANSION, AND EMISSIONS

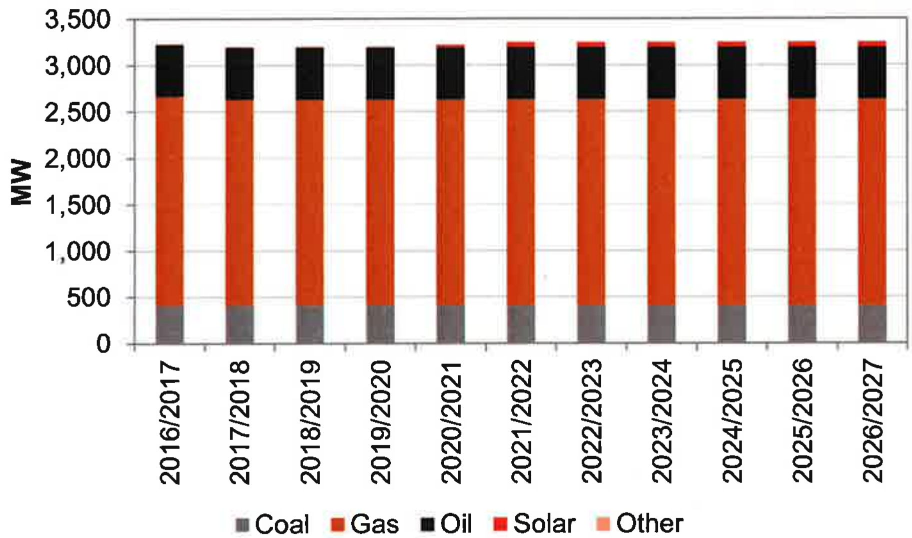
Pace Global's integrated power market analysis produces projections for generation over time as well as capacity additions and retirements.

Delaware

Figure 4 below presents expectations for the installed capacity in the state of Delaware over time, while Figure 5 below summarizes the projected generation by fuel type. By May 2017, two units at the McKee Run gas plant are expected to retire. Beyond that, most capacity changes are expected as a result of solar additions. The generation profile within Delaware is dominated by natural gas, with Indian River as the only remaining operational coal plant. With the rising gas prices in the near term, total in-state MWh generation is expected to decline due to increased imports from new, efficient combined cycle capacity in neighboring states that displaces peaking capacity in Delaware. In addition, fossil-fuel plants over 25 MW in Delaware are bound by the regulations regarding RGGI. This puts them at a disadvantage from a cost standpoint vis-à-vis plants in nearby states that do not participate in RGGI, such as Pennsylvania. However, as a national carbon policy is assumed to take effect in 2022, all plants in the region are affected by an emission adder, which drives Delaware generation to climb back up.

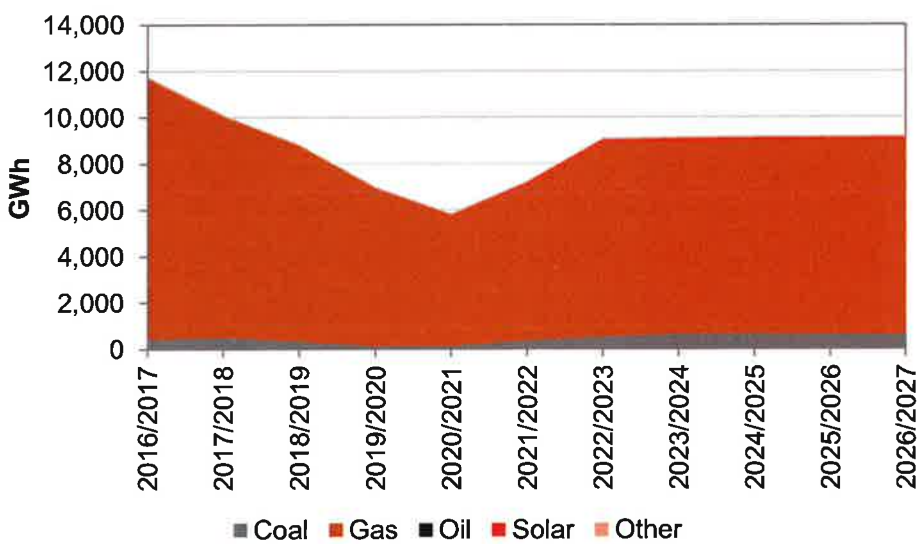
Pace Global's reference case also reports key emissions outputs for CO_2, NO_X, and SO_2. Within Delaware, emissions of all pollutants are expected to fall significantly in the next few years. After 2022, when coal generation is projected to recover modestly, increases in emissions are projected. Figure 6 below summarizes the emission projections for Delaware over time.

Figure 4: Delaware Installed Capacity over Time



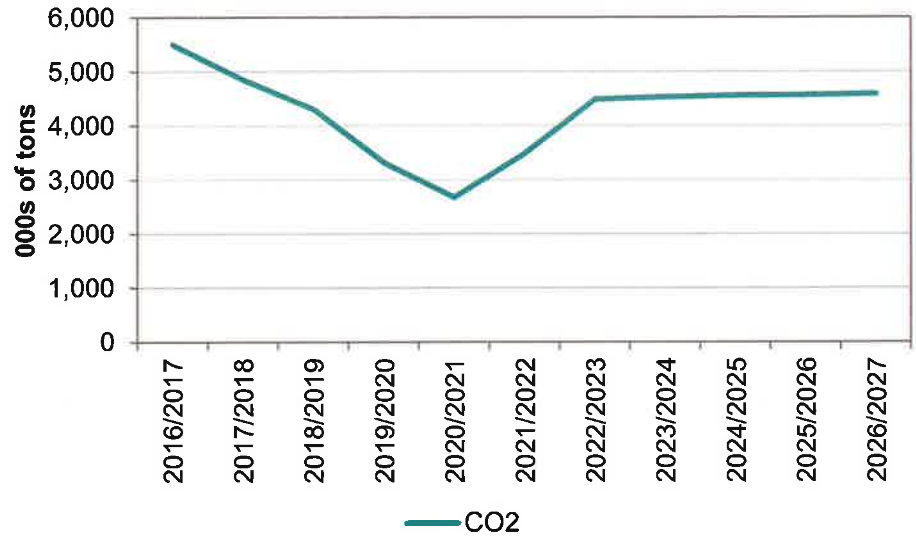
Source: Pace Global.

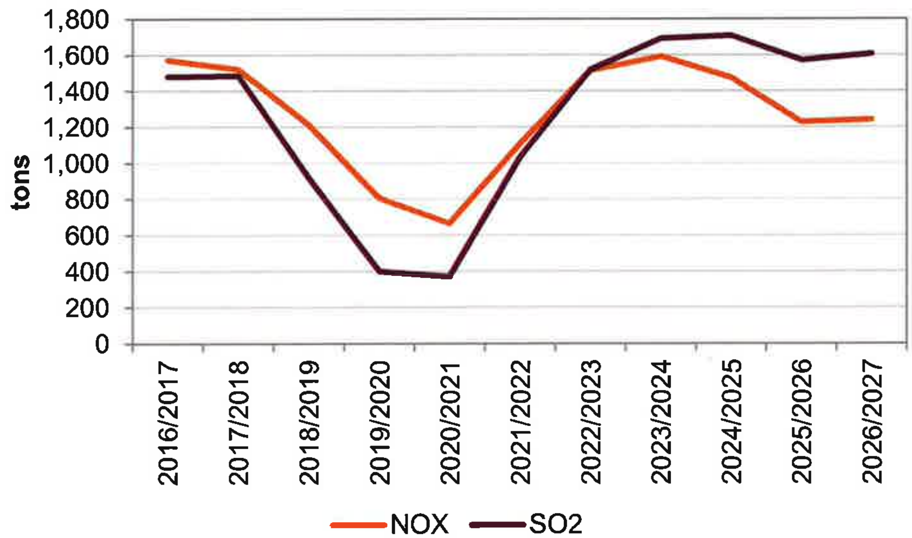
Figure 5: Delaware Generation by Fuel Type over Time



Source: Pace Global.

Figure 6: **Delaware Emission Projections over Time**



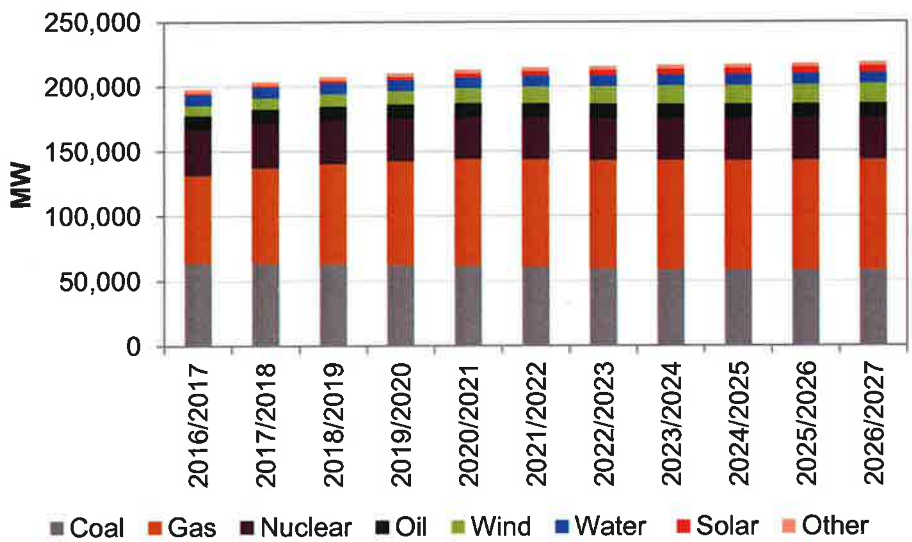


Source: Pace Global.

PJM

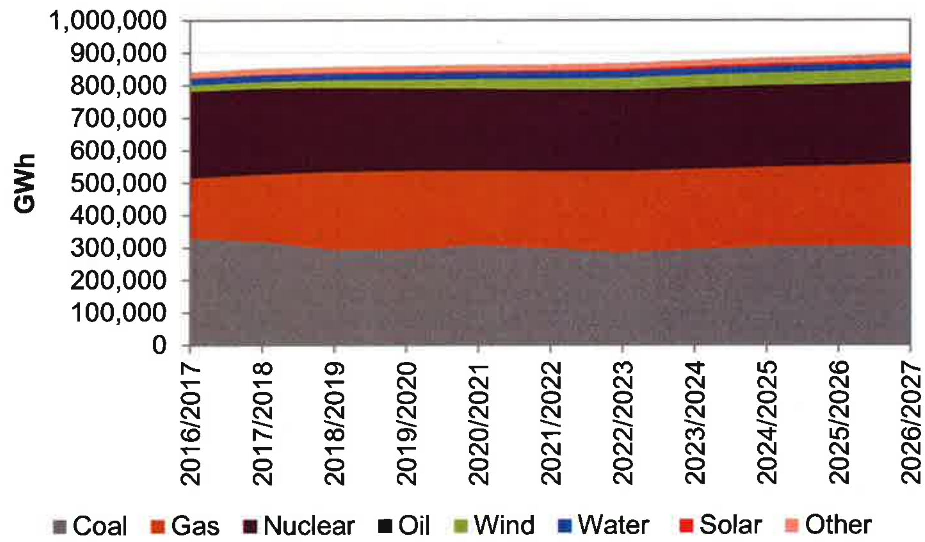
Figure 7 below summarizes the installed capacity projections over time for the entire PJM footprint, while Figure 8 below displays the generation by fuel type. Unlike Delaware, PJM has a considerable amount of nuclear capacity and generation, which is expected to stay relatively constant over time. By the end of the IRP Planning Period, coal capacity is expected to decline by over 5 GW due to retirements as a result of environmental regulations. Renewable and natural gas-fired capacity is expected to dominate new capacity additions through the study period. Figure 9 below summarizes the projected emissions across all of PJM over time.

Figure 7: PJM Installed Capacity over Time



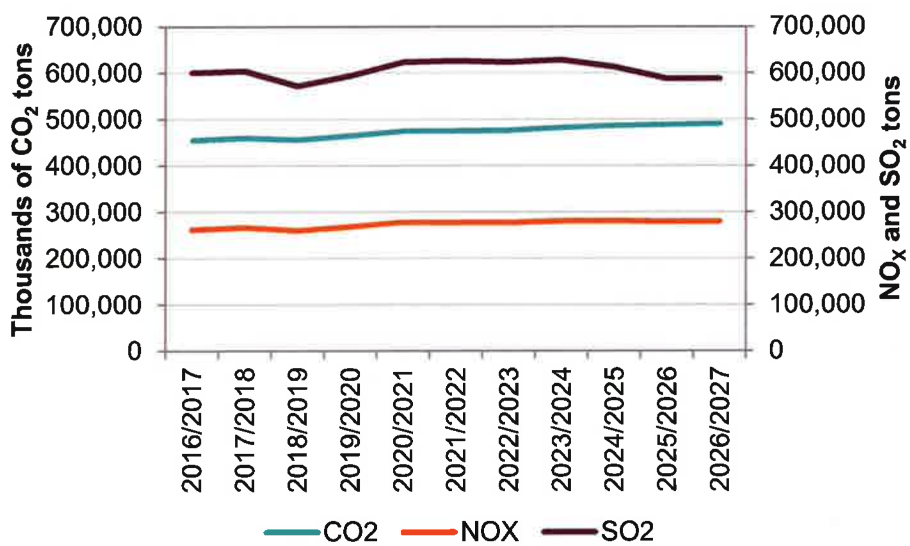
Source: Pace Global.

Figure 8: PJM Generation by Fuel Type over Time



Source: Pace Global.

Figure 9: PJM Emission Projections over Time



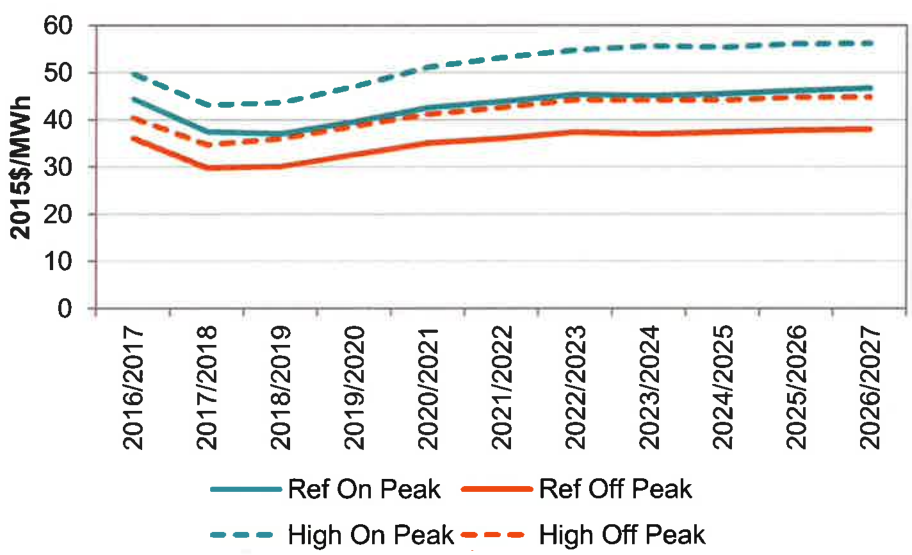
Source: Pace Global.

HIGH NATURAL GAS CASE MARKET PRICE PROJECTIONS

Given significant uncertainty associated with the price of natural gas, Pace Global has assessed the risk of higher natural gas prices on the PJM market. To develop the high natural gas price scenario, Pace Global first analyzed historical natural gas price volatility going back more than a decade. This is because we generally see lower price volatility in the recent past and higher price volatility looking back 10 or more years. Pace then applied different periods of historical price volatility to the forward outlook, per expert judgment and expectations for market supply and demand dynamics. They then ran the IRP Reference Case outlook through a Monte Carlo simulation of 1,000 iterations, from which we produced and analyzed multiple probability bands of possible price formation outcomes. In conclusion, prices at the 75th percentile were deemed reasonable as a high natural gas price scenario due to potential long-term supply and demand factors that may result in tighter markets, as well as observations of historical price movements that are consistent with those observed at the 75th percentile.

Figure 10 below summarizes the impacts of the high gas price scenario on projected DPL zone energy prices. In the 2020s, the average difference between the two cases settles at around \$9.50/MWh for on-peak and \$6.75/MWh for off-peak.

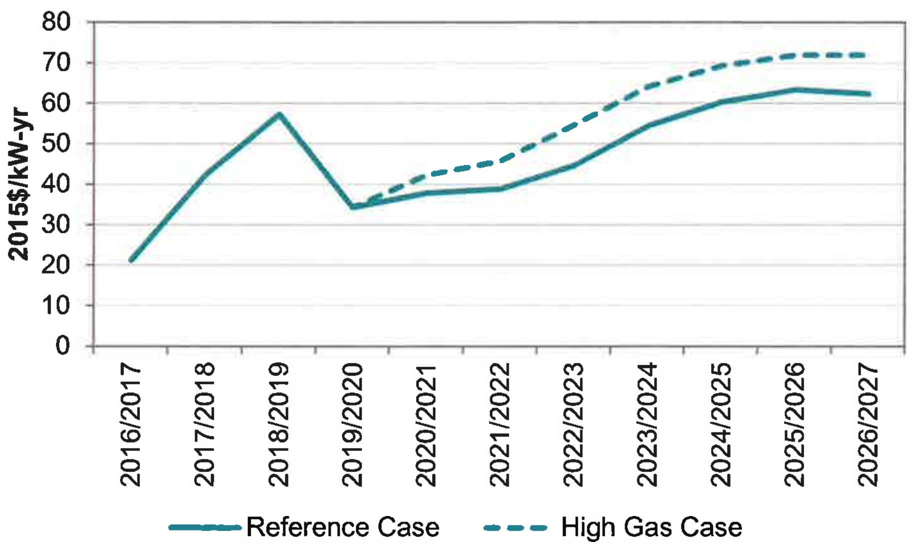
Figure 10: High Natural Gas Price and Reference Case Energy Projections



Source: Pace Global.

Beyond the period of cleared PJM capacity auctions, the high natural gas price case also puts upward pressure on expected capacity prices. Under the high gas price regime, new entry in the form of efficient combined cycles is expected to dispatch less, displacing coal capacity and earning higher energy margins. As a result, the capacity payment requirements for these new entrants are expected to be higher. Figure 11 below shows the difference between the capacity prices for the DPL zone across the two cases, indicating that the increase in capacity prices is projected to be about $5-9/kW-yr.

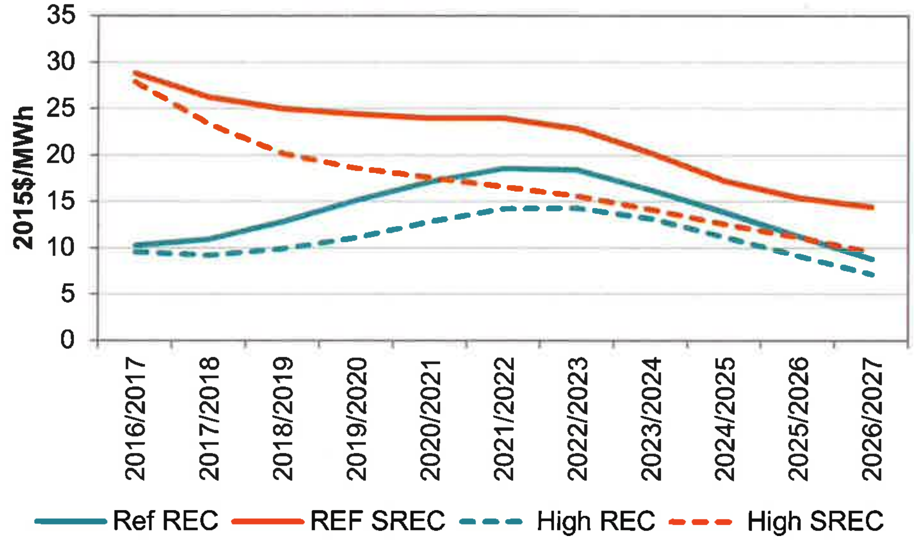
Figure 11: High Natural Gas Price and Reference Case Capacity Price Projections



Source: Pace Global.

On the other hand, REC and SREC prices are lower under a high gas case, as the renewable build out is expected to be slightly greater in PJM and the higher power price provides a larger share of the revenue needed to renewable projects. Similar to the IRP Reference Case, because we build renewables to meet RPS, there is less demand pressure on these markets. Pace Global's analysis indicates that REC and SREC values are likely to decrease by $3-4/MWh in this scenario. This is shown in Figure 12 below.

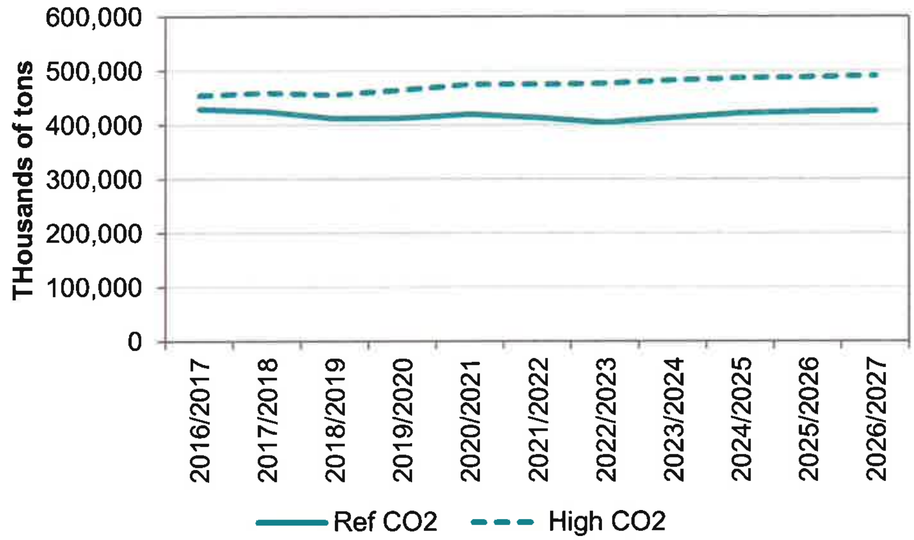
Figure 12: High Natural Gas Price and Reference Case REC and SREC Projections

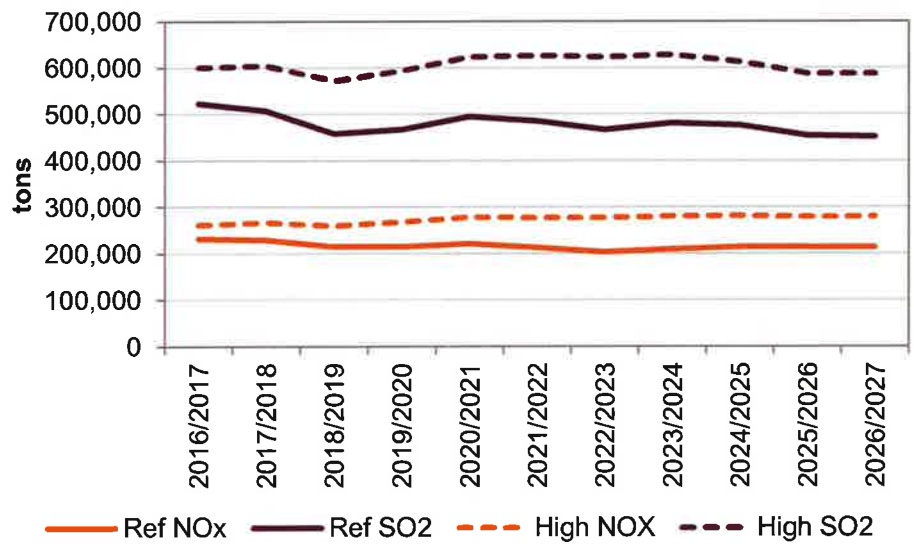


Source: Pace Global.

The high natural gas price environment is also expected to lead to higher emissions across PJM, as there is less coal-to-gas displacement in the generation dispatch stack. Thus, the overall emissions of CO_2, NO_X, and SO_2 are projected to be on average 13 percent higher than they are in the IRP Reference Case throughout the Study Period. This is shown in Figure 13 below.

Figure 13: **High Natural Gas Price and Reference Case PJM Emission Projections**





Source: Pace Global.

APPENDIX 1

Appendix 1

	IRP Regulation No.	Requirement	IRP Section	Comments
1	General 1.3	In accordance with 26 Del. C. 1007, DPL shall file an IRP on Dec 1, 2006 and on the anniversary date of the first filing date every other year thereafter.		The 2016 IRP was filed on Thursday, December 1, 2016.
2	General 1.4	The IRP shall be filed in compliance with normal Commission policies and practices.		The IRP was filed in accordance with all prevailing Commission rules and procedures.
3	General 1.5	The IRP shall identify the year of filing, the individuals responsible for its preparation and those individuals who shall be available to inquiries during the Commission's review of the plan.	Appendix 2	A listing of the individuals responsible for preparing the 2016 IRP and who will be available for responding to inquiries during the Commission's review of the 2016 IRP are provided in Appendix 2 of the 2016 IRP.
4	General 1.6	Confidential utility documents shall be presented under separate seal.		Confidential documents related to the 2016 IRP were presented to the Commission, Staff, DPA and DNREC under separate seal. Due to the timing of the filing of the 2016 IRP with the SOS auction process, Delmarva has filed certain pricing information as confidential so as to not bias the auction bids unfavorably. Upon completion of the auction process, this information will be deemed non-confidential by the Company and made available consistent with prevailing SOS guidelines.
5	General 1.8	The utility shall provide whatever detail and commentary necessary to demonstrate that it has met or exceeded the planning requirements as set forth in this regulation. An effort shall be made to ensure that the IRP is clearly stated and can be readily comprehended by the Commission, State Agencies and other interested parties. The IRP shall include an Executive Summary.	Executive Summary, Technical Appendices 4, 6, 7, and 8	This IRP Regulation Compliance Matrix has been included as Appendix 1 to the IRP. An Executive Summary in the form required by Regulation 3.2.1. is provided in the IRP. Technical information has been set forth in the Appendices in order to keep the text of the IRP clear and straightforward.
6	General 1.9	Compliance with this regulation is a minimum standard for IRP's. The Company needs to exercise its professional judgment based on its systems or customer needs. The Company shall include all information that assists the reader to fully understand the IRP concept and the Company's IRP to meet SOS energy needs.	Executive Summary	Delmarva has provided an Executive Summary consistent with IRP Regulations. Most technical materials related to the IRP have been provided in Appendices. Delmarva has attempted to provide all information needed to assist the reader in understanding the IRP in a clear and starightforward manner.
7	General 1.10	This regulation requires the maintenance and retention of supply resource planning data and the reporting of IRP achievements on an annual basis starting in 2009 to the Commission, Governor and General Assembly. The Company shall retain supply resource planning data, consistent with Federal data retention guidelines and make it available for further review as necessary.		Delmarva will retain IRP information consistent with Federal data retention guidelines. Delmarva has reported on the status of the IRP to the Commission, Governor and General Assembly on an annual basis, since 2009, and will submit a new report on or before December 31, 2016.
8	General 1.11	The Company shall submit 8 copies of the IRP to the Commission, 2 copies to the Controller General's office, 2 copies to the Office of Management and Budget, 2 copies to the Division of Public Advocate and 2 copies to DNREC/Energy Office. The Commission may request up to 6 additional copies for review.		DPL submitted 8 copies of the IRP to the Commission, 2 copies to the Controller General's Office, 2 copies to the Office of Management and Budget, 2 copies to the Division of Public Advocate and 2 copies to DNREC on Thursday, December 1, 2016.
9	General 1.14	The Company shall make the full IRP, including any appendices or other supporting materials, available to the general public on its website and shall update these materials on the Company's website to remain current with all subsequent updates, revisions or other changes made to the IRP.		A copy of the public version of the IRP will be placed on the Company's website after the IRP is filed on December 1, 2016.
10				
11	General 3.1.1	The IRP shall provide a framework for comparing a comprehensive resource mix of supply and demand-side and Transmission Service resource costs and attributes.	IRP Section 3, 5, 6, and 7.	The IRP uses a detailed and comprehensive planning model (AuroraXMP®) to evaluate the optimal combination of demand and supply side resources within PJM, including Delaware. AuroraXMP uses the most recent PJM Regional Transmission Expansion Plan (RTEP) to characterize the expected future transmission grid. Supply side resources are described in Section 7 and AuroraXMP® is described in Section 3. The RTEP is described in Section 6 and demand side resources are described in Section 5.

12	General 3.1.2	The IRP shall utilize a Resource Portfolio approach in achieving the objectives of the IRP, shall incorporate a Portfolio approach to securing resources and incorporating an analysis of risk versus certainty into the planning process, or, absent such a Portfolio approach, the rationale supporting the exclusion.	Executive Summary and IRP Section 8.	The IRP Reference Case employs a Resource Portfolio approach to securing supply resources through the competitive Full Requirements Service (FRS) auction and a portfolio of a diverse mix of renewable resources. The IRP describes the effect on price and price stability of electricity supply prices by evaluating a high gas price forecast in comparison to the Reference Case.
13	General 3.1.3	The IRP shall provide for regulatory, stakeholder, and public input into the development of the IRP in accordance with normal Commission policies and practices.		After the 2014 IRP was filed, DPA, DNREC, and MAREC filed comments concerning in March 2015. Delmarva submitted responsive comments in April 2015. On June 10, 2015 the Parties conducted a technical working group meeting to discuss the issues raised by the Parties (including Staff). The meeting was publically noticed on the Commission's agenda. The working group also met on April 14, 2016 to discuss issues to be addressed in the preparation of the 2016 IRP.
14	General 3.1.4	The IRP shall include provisions for the IRP to be modified from time to time to conform with any subsequent legislative or regulatory directives.		The Commission issued Order No 8779 on October 6, 2015. The Order ratified the IRP filed by Delmarva in December, 2014 and provided guidance for the praparation of the 2016 IRP. A copy of Order No. 8779 is provided as Appendix 3.
15	General 3.2.1	The IRP shall include an Executive Summary with a short description of the utility, its customers, service territory, current facilities, planning objectives, notable areas of departure in the new IRP from the old, citing specific locations within the IRP where the new aspects shall be found, load forecast, proposed IRP and Implementation Plan.	Executive Summary	An Executive Summary of the IRP with the specific information requested under this regulation is provided in the IRP.
16	General 3.2.2	The IRP shall include Established Plan Objectives in quantitative and qualitative terms by which the IRP achievements may be measured and shall not be biased against any particular option. Measures must be ascribed to each objective. The Company must include a summary of the overall process and models used in developing the IRP.	Executive Summary and Section 3	Plan objectives and measures are described in the Executive Summary of the IRP. Each objective has measures ascribed to them. The major model used in developing the 2016 IRP is AuroraXMP®. This model is used to simulate expected generation expansion and long term wholesale prices and provide information to analyze price stability and power plant air emission levels.
17	General 3.2.3	The IRP shall include a description of the load forecast, the assumptions used or implicit in creating the forecast, the range of forecasts examined and the forecast selected for the filing period and a detailed rationale for such selection.	Section 4 and Appendix 4	The load forecast is described in Section 4 of the IRP. The forecast provides a "high growth" and a "low growth" forecast as compared to the "baseline" forecast. The load forecast documentation is provided in Appendix 4.
18	General 3.2.4	The IRP shall include an Integrated Resource Evaluation which shall include a listing of all the options considered to meet the load forecast, identification of those chosen for further evaluation and possible inclusion in the IRP, and a discussion of the rationale for such selections including any key assumptions. The IRP shall include planning information which shall include a ten year planning horizon, starting with the year immediately following the planning year.	Section 3, 4, 5, 6 and 7.	Resource options evaluated by AuroraXMP® model are discussed in Sections 3 and 7 the 2016 IRP. Key assumptions for the Reference Case are provided in Sections 4, 5, 6,and 7 of the IRP. The IRP presents information for the ten year planning period 2017-2026.
19	General 3.2.5	The IRP shall include a Scenario Analysis used to integrate the options into a single resource plan or individual scenarios for further review and analysis to include a listing of the various scenarios considered and any key assumptions.	Executive Summary	The IRP evaluates the potential impact on price and price stability through sensitivity analyses relating to an alternative natural gas price forecast.
20	General 3.2.6	The IRP shall include a description of the process used to develop the proposed IRP, including the assumptions and analysis leading up to the decision and the application of the various criteria as specified in Section 5.0.	Section 3	The process for the development of the IRP is described in Section 3 of the 2016 IRP. Discussions around the IRP process took place at an IRP working group meeting held on April 14, 2016.
21	General 3.2.7	The IRP shall include an analysis of the risk and sensitivity of the proposed IRP in comparison to the other options that were considered and a contingency plan to meet the Plan Objectives should one of the supply, demand, or transmission options be either delayed or not realized.	Executive Summary	The results of various risk and sensitivity analyses around changes in natural gas prices are described in the Executive Summary.
22	General 3.2.8	The IRP shall include plans for the implementation of the IRP, for no less than 5 years, starting with the year immediately following the filing year.	Executive Summary	Implementation Plans for achieving the planning objectives of the IRP are provided in the Executive Summary.
23				

24	Load Forecast 4.1.1	The Company shall consider a range of load growth forecasts that include both historical data and future estimates.	Section 4 and Appendix 4	As part of the 2016 IRP, the Company prepared a High Economic Growth Forecast, a Low Economic Growth Forecast, an Extreme Weather Forecast. These Forecasts are provided in Section 4 and Appendix 4.
25	Load Forecast 4.1.2	The Company's load growth forecasts shall include both winter and summer peak demand for Delmarva Delaware load.	Section 4 and Appendix 4	Summer and Winter Peak forecasts for Delmarva's Delaware customers are provided in Section 4 and Appendix 4 of the 2016 IRP.
26	Load Forecast 4.1.2	The Company's load growth forecasts shall include Delmarva Delaware SOS load by customer class.	Section 4 and Appendix 4	The Baseline Forecast is provided by SOS and customer class.
27	Load Forecast 4.1.3	The Company's load growth forecasts shall include weather adjustments, including consideration of climate change potential.	Section 4 and Appendix 4	The Company has provided a load growth forecast which includes a severe weather case. The severe weather case represents a 90/10 scenario, where the degree days used in the equations are at the 90th percentile for both cooling and heating degree days.
28	Load Forecast 4.1.4	The Company's load growth forecasts shall include 5 year historical loads, current year end estimates and 10 year weather adjusted forecasts showing individually and aggregated Delmarva Delaware and Delmarva SOS load, and both Delmarva Delaware and Delmarva Delaware SOS load disaggregated by customer class including both capacity (MW) and energy requirements (MWh).	Section 4 and Appendix 4	Five (5) year historical loads are shown in Appendix 4. All forecasts except the Extreme Weather Case are weather adjusted
29	Load Forecast 4.1.5	The Company's load growth forecasts shall include analysis of how existing and forecast Conservation, DR, DSM, Customer sited generation, various economic and demographic factors including the price of electricity will affect the consumption of electric services and how customer choice under Retail Competition may affect future loads.	Section 4, Section 5, and Appendix 4	Appendix 4 provides detailed documentation of the process of how economic and demographic variables are included in the Load Forecast. Energy conservation measures and DR program impacts are subtracted from the Baseline Forecast to derive the Reference Case Forecast.
30	Load Forecast 4.1.6	The Company's load growth forecasts shall include a description of the process the Company used to develop these forecasts. Forecasts should include the probability of occurrence. Within the forecasting modeling descriptions, the Company shall demonstrate how well its model predicted load for the past 5 years.	Section 4 and Appendix 4	DPL's IRP Baseline forecast includes a description of the process the Company used to develop the forecasts as shown in Appendix 4. Appendix 4 also includes a review of how well the forecasts have predicted peak load.
31				
32	Resource Portfolio Options 5.1	The Company shall include a description of the overall process and the analytical techniques it used to identify its proposed options. The Company shall not rely exclusively on any particular resource or purchase procurement policy.	Section 3	The IRP process is described in Section 3. Delmarva's Reference Case includes a mix of Full Requirements Service contracts and a diverse mix of renewable resources.
33	Resource Portfolio Options 5.2	The Company shall identify and evaluate all resource options including generation and transmission service, supply contracts, both short and long term procurement DSM, DR, and customer sited generation, even if a particular strategy is not recommended by the Company. The IRP must show an investigation of all reasonable opportunities for a more diverse supply at the lowest reasonable cost including consideration of environmental benefits and externalities. The Company shall also provide any hedging guidelines and shall identify any changes from any existing hedging policy. Cost evaluations shall contain a description of each option and an evaluation that considers the economic and environmental value of the following:	Section 3, 5, 6, 7,and 8.	The IRP considers a full range of transmission, demand side, and supply resources with particular attention to renewable resources and environmental benefits.
34	Resource Portfolio Options 5.2.1	Resources that utilize New or Innovative Base Load Technologies;	Section 3	The AuroraXMP® model used in the IRP considers new and innovative base load technologies within the set of resource options evaluated.
35	Resource Portfolio Options 5.2.2	Resources that provide short or long-term environmental benefits to the citizens of Delaware;		Detailed environmental analyses were filed as part of the 2010 and 2012 IRP's and are incoprporated in this IRP by Reference.
36	Resource Portfolio Options 5.2.3	Facilities that have existing fuel and transmission infrastructure;		As part of the 2010 IRP, Delmarva filed a confidential Generation Siting Study in January 2010. This Document remains relevant for the 2016 IRP.
37	Resource Portfolio Options 5.2.4	Facilities that utilize existing brownfield or industrial sites;		As part of the 2010 IRP, Delmarva filed a confidential Generation Siting Study in January 2010. This Document remains relevant for the 2016 IRP.

38	Resource Portfolio Options 5.2.5	Resources that promote Fuel Diversity;	Section 8	Delmarva manages a portfolio of wind and solar resources.
39	Resource Portfolio Options 5.2.6	Resources or facilities that support or improve reliability; or	Section 6 and 9	The 2016 IRP shows that there are sufficient generation resources to meet the expected load forecast over the IRP Planning Period.
40	Resource Portfolio Options 5.2.7	Resources that support or improve price stability.	Executive Summary	The IRP contains an evaluation of the effects on price and price stability of changing gas prices.
41	Resource Portfolio Options 5.3	Where Transmission Service is identified as a planning option, DPL shall describe the transmission enhancement, the location, and provide PJM's assessment of the impact of the proposed transmission asset when available. The IRP shall reflect the current projects included in PJM's Regional Transmission Plan ("RTEP"). DPL shall file with the Commission any PJM revisions or updates to the RTEP immediately upon receipt.	Executive Summary and Section 6	The IRP includes a description of the transmission investments made since the last IRP and planned transmission investments needed to maintain reliability. Approved RTEP projects under construction are included in the AuroraXMP model.
42	Resource Portfolio Options 5.4	At least 30% of the resource mix shall be acquired through the regional Wholesale Electricity Market via a bid procurement or auction process held by DPL.		The Reference Case portfolio presented in the IRP meets this requirement.
43	Resource Portfolio Options 5.5	The Company shall include a discussion of known plans to reduce existing physical, contractual, or service related portfolio resources during the IRP Planning Period.		The IRP includes all planned retirements at the Indian River generation facility and environmental upgrades to Indian River Unit #4.
44	Resource Portfolio Options 5.6	The Company shall include a detailed description of its energy efficiency activities in accordance with 26 *Del. C.* DPL Section 1020. The Company shall first consider electricity DR and DSM strategies for meeting base load and load growth needs and cost-effective renewable energy resources before considering traditional fossil fuel-based electric supply service to meet their retail electricity supplier obligations as defined in 26 *Del. C.* Section 352.	Section 5	The Delaware Public Service Commission approved the implementation of a Dynamic Pricing Program and a Residential Direct Load Control Program in the Fall of 2012. A description of the Company's energy efficiency efforts is provided in Section 5 of the IRP.
45	Resource Portfolio Options 5.7	The Company shall evaluate all technically feasible and cost effective DR improvements. Where non-Company evaluations of DSM and Conservation are available through the Sustainable Energy Utility ("SEU") (or other organization as requested by the Commission), the Company shall summarize the results and actions taken. The Company shall collaborate and may contract with the SEU to provide services to accomplish the SEU's DSM plans. The Company, using its independent best judgment, may recommend in the IRP any DSM program first offered to the SEU but rejected by the SEU. Where DR programs are new, the Company shall summarize the anticipated benefits with respect to load reductions and provide supporting materials to justify the new program.	Section 5	Delmarva Power continues to collaborate with the SEU. A description of on-going and past SEU activities is provided in Section 5 of the IRP.
46	Resource Portfolio Options 5.8	The Company shall collaborate with the SEU and appropriate State Agencies in its evaluation of Customer Sited Generation resource options. The Company may enter into a contractual relationship with the SEU or other energy service providers to implement a Customer Sited Generation resource option strategy.	Section 5	Under the 2013 and 2014 Solar REC Procurement Programs approved by the Commission, Delmarva entered into contracts to purchase Solar RECs from the SEU.
47	Resource Portfolio Options 5.9	The Company shall assess the Resource Portfolio options against the set of Plan Objectives and criteria.	Section 3, 5, 6, 8 and 9	The Reference Case is evaluated against the major planning criteria and plan objectives.
48				
49	Plan Development 6.1	The Company shall conduct an Integrated Resource Evaluation in formulating its potential plans for supply and demand-side resource scenarios. The Company shall describe the mechanism or process by which the Load Forecast and options have been blended into the various IRP scenarios.	Section 3, 4, 5, 8 and 9	The AuroraXMP® model provides an integrated planning platform. Expected energy efficiency savings are incorporated into the Reference Case load forecast.
50	Plan Development 6.1.1	In integrating its supply and demand side resource, the Company shall prepare an evaluation that takes into consideration the life expectancy of the resource, if the resource provides capacity and/or energy, any improvements to system reliability, the dispatchability of the resource, any lead time requirements, the flexibility of the resource, the Generation Attributes of the resource, the efficiency of the resource and the opportunities for customer participation. The Company shall assess the probability of securing the options according to modeling information used, including any key assumptions. The Company shall provide the estimated energy and capacity impacts for each option and the rationale behind the estimate.	Section 3 and 5.	These factors are considered in the AuroraXMP® model.

51	Plan Development 6.1.2	The Company shall prepare a contingency plan that shall include a discussion of how the Company might alter the proposed IRP in the future if the key planning assumptions used to develop the proposed IRP in the future turn out to be different than what was assumed in preparing the proposed IRP.	Executive Summary	The IRP provides a sensitivity analysis to show the impact of changes in natural gas prices.
52	Plan Development 6.1.3	The Company shall evaluate the cost-effectiveness of the options from the perspectives of the utility and the different classes of ratepayers based on real prices (may also provide an evaluation based upon nominal prices).	Executive Summary	The impact of changing natural gas prices on electric rates for residential and commercial class is shown in the Executive Summary.
53	Plan Development 6.1.4	The Company shall include a current evaluation, detailing and giving consideration to environmental benefits and externalities associated with the utilization of specific methods of energy production (may rely on commonly available published research and not on original research by DPL). To the extent any reliable, relevant peer reviewed published research and scientific and/or medical studies commonly available includes life cycle analyses encompassing energy extraction, transport, generation, and/or use, the Company shall include such research and studies in its evaluation.	Section 8.	The IRP includes an evaluation of the environmental benefits associated with the Reference Case based in part on the analysis provided as part of the 2012 IRP.
54	Plan Development 6.1.4	To the extent that any reliable, relevant peer reviewed published research includes life cycle analyses encompassing energy extraction, transport, generation, and/or use is commonly available, the Company shall include such research and studies in its evaluation.		The 2016 IRP incorporates, by reference, the life-cycle impact analysis completed and filed as part of the 2010 IRP.
55	Plan Development 6.1.5	The IRP shall not include any assumptions that externalities are adequately addressed by either the fact that the IRP meets the RPS, satisfies the EERS, or that the generating units to be utilized comply with existing environmental regulations. This rule does not, however, preclude a potential conclusion that the RPS or EERS in effect at the time adequately address externalities.	Section 8	The IRP includes an evaluation of the environmental benefits associated with the Reference Case based in part on the studies completed in prior IRPs.
56	Plan Development 6.1.6	The Company shall evaluate the financial, competitive, reliability and operational risks associated with the options recommended by the IRP and how these risks may be mitigated over the 10 year planning period. This plan shall include a discussion of the likelihood of the occurrence of such risks.	Executive Summary and Section 6	The IRP provides information on expected energy prices, customer rates, and RPS compliance costs over the IRP Planning Period.
57	Plan Development 6.1.7	For the options included in the proposed plan identified in the IRP, the IRP shall include an analysis of the fuel risk associated with the proposed Resource Portfolio and how such fuel risk will be mitigated when the proposed IRP is implemented.	Executive Summary	The IRP contains a sensitivity analysis of high natural gas prices compared to the Reference Case.
58	Plan Development 6.1.8	The Company shall perform sensitivity analyses on each of the candidate plans to include variations in key assumptions and to assess the likelihood of planned outcomes. These shall include the impact of proposed or existing rules and regulations on a local, regional, or national level related to climate change.	Executive Summary and Section 9	The IRP contains sensitivity analyses of the Reference Case related to changes in the price of natural gas. The analyses also includes an evaluation of the changes in power plant emissions including CO2.
59	Plan Development 6.2	The Company shall forward a copy of the IRP to DNREC and seek input into externalities, including but not limited to, health effects.		DNREC provided comments on the IRP including externalities in March 2015. Delmarva considered DNREC's comments in preparing the externality analysis provided in the 2016 IRP. Delmarva submitted a copy of the 2016 IRP to DNREC on Thursday, December 1, 2016.
60	Plan Development 6.3	In developing candidate plans, special attention shall be given to ensuring consistency between the IRP and typical rate-making processes. In addition to the ultimate consumer price associated with the plan, the stability of rates and other factors discussed in Section 5.2 need to be considered in any candidate plan selection.	Executive Summary, Appendix 5	The IRP provides an evaluation of price stability and a forecast of customer rates.
61				
62	Proposed Plan Selection 7.1	The Company shall select and file the proposed IRP that is the most consistent with the criteria set forth in 26 *Del. C.* Sections 1007 and 1020 and this Regulation. The Company shall provide a description of the options recommended for inclusion in the proposed IRP, including a description of the mechanism or process used for valuing each option. The Company shall describe the rationale behind its selection, including any modeling or methodology used as the basis for selection of the proposed IRP.	Executive Summary, Sections 3, 7, and 9.	These requirements are described in various sections of the IRP and the Appendices.
63	Proposed Plan Selection 7.2	The Company shall provide at a minimum a 5 year forecast of supply rates by customer class that would be anticipated based on the IRP planning assumptions and recommended procurement strategy.	Appendix 5	The forecast of supply rates is provided in Appendix 5. Forecast supply rates for 2017 - 2020 are considered confidential until the completion of the 2017 SOS Auction process.
64				
65	Implementation Plan 8.1	The Company shall file a 5 year action plan outlining the resource decisions intended to implement the IRP.	Executive Summary	Implementation Plans for each planning objective are provided in the Executive Summary.

66	Implementation Plan 8.1.1	This Implementation Plan shall include all actions to be taken in the first 2 years and outline actions anticipated in the last 3 years.	Executive Summary	Implementation Plans for each planning objective are provided in the Executive Summary.
67	Implementation Plan 8.1.2	For IRPs filed on or after December 1, 2010, the Implementation Plan shall include a status report of the specific actions contained in the previous Implementation Plan, including what risk assumptions were made and what actually occurred.	Executive Summary	The Implementation plans for each planning objective include descriptions of relevant milestones that have occurred since the 2014 IRP.
68	Implementation Plan 8.1.3	The Implementation Plan shall include a schedule of key activities related to the IRP implementation.	Executive Summary	The Action plans provide the key milestones expected in the next two years.
69				
70	Review and Comment 9.1	Commencing in 2009 and continuing on an annual bases, the Company shall submit a report to the Commission, the Governor, and the General Assembly detailing its progress in implementing the IRPs.		The Company provided a report on the status of the IRP to the Commission, Governor and General Assembly in December, 2015 and will provide a new report on or before December 31, 2016.
71	Review and Comment 9.2	The Commission, interested State Agencies, interested parties and the general public shall be provided an opportunity for review and comment on the Company's IRP filings. The Commission shall seek input from DNREC on the issues of externalities and environmental benefits due to emissions as a result of the IRP.		It is expected that a schedule for public comment on the IRP will be issued after the IRP is filed on December 1, 2016.
72	Review and Comment 9.3	To the extent that the Commission determines that the IRP is not compliant with the statute or is unlikely to meet the goals of the statute, the Company shall revise its IRP to meet these requirements.		As shown in this Appendix, the IRP is compliant with the provisions of 26 *Del. C.* Sections 1007 and 1020 and accompanying regulations.
73	Review and Comment 9.3	Rate treatment in connection with the treatment of future resource acquisitions shall be addressed in rate or other proceedings as filed by the utility or as initiated by the Commission.		The Company will address rate treatment in rate case or other proceedings as appropriate. The IRP does not request any Commission action on rate treatment.
74	Review and Comment 9.4	DPL must maintain sufficient records to permit a review and confirmation of material contained in all required reports as they are subject to annual review and audit by the Commission and interested State Agencies.		All records related to the IRP will be stored and available for inspection and audit as needed.

APPENDIX 2

Delmarva Power

Appendix 2

Responsible Parties – 2016 Integrated Resource Plan (IRP)

Name	IRP Area of Expertise
Jack Barrar	IRP Process
Jaclyn Cantler	Transmission
David Vermeire	Load Forecast
Pamela Scott	Regulatory and Legal Counsel
Susan DeVito	Customer Rates
Lisa Pfeifer	Environmental
Brian Kwak[i]	AuroraXMP® Model
Wayne Hudders	Demand Side Management
William Swink	Portfolio Design & Renewables Supply

[i] Pace Global

APPENDIX 3

APPENDIX 3

BEFORE THE PUBLIC SERVICE COMMISSION

OF THE STATE OF DELAWARE

IN THE MATTER OF INTEGRATED RESOURCE PLANNING FOR THE PROVISION OF STANDARD OFFER SERVICE BY DELMARVA POWER & LIGHT COMPANY UNDER 26 DEL. C. § 1007 (c) & (d) (OPENED DECEMBER 2, 2014)	)	PSC DOCKET NO. 14-0559

ORDER No. **8779**

AND NOW, this 6th day of October, 2015, the Delaware Public Service Commission ("Commission") determines and orders the following:

WHEREAS, 26 Del. C. § 1007 (c) (1) requires Delmarva Power & Light Company ("Delmarva" or the "Company") to conduct integrated resource planning; and

WHEREAS, pursuant to 26 Del. C. § 1007 (c) (1), Delmarva's Integrated Resource Plan ("IRP") is required to systematically evaluate all available supply options (including procurement, generation, transmission, conservation and load management) over a ten-year planning period, and forecast the appropriate mix of such resources that will be utilized to meet the needs of its Standard Offer Service ("SOS") customers, at minimal cost and without sacrificing adequate reliability; and

WHEREAS, on December 2, 2014, Delmarva filed its IRP pursuant to its statutory obligation; and

WHEREAS, on December 16, 2014, in Order No. 8694 ("Opening Order"), the Commission opened this docket to perform its oversight and review of the IRP, and appointed a Hearing Examiner to make findings on Delmarva's proposed IRP; and

WHEREAS, the Commission Staff ("Staff"), the Division of the Public Advocate (the "DPA"), the Delaware Department of Natural Resources and Environmental Control ("DNREC"), Calpine Mid Atlantic Energy, LLC ("Calpine") and the Mid-Atlantic Renewable Energy Coalition ("MAREC") (collectively, the "Parties") intervened or otherwise participated in the proceedings; and

WHEREAS, pursuant to the Opening Order, on or about March 30, 2015, the Parties (exclusive of Staff) filed their respective comments as to the IRP; and

WHEREAS, also pursuant to the Opening Order, on April 29, 2015, Delmarva filed its responses to the Parties' comments; and

WHEREAS, on June 10, 2015, the Parties conducted a technical working group meeting regarding the issues raised by the Parties (including Staff), which meeting was publically noticed on the Commission's agenda; and

WHEREAS, subsequently, the Hearing Examiner asked Delmarva to provide an update as to the status of the case and to summarize the result of the working group meeting, which was provided to the Hearing Examiner on August 6, 2015; and

WHEREAS, the Parties' filed comments and status update provided by the Parties and Delmarva, were summarized by the Hearing Examiner in his August 24, 2015 Findings; and

WHEREAS, in the status update the Parties and Delmarva recommended that the Hearing Examiner recommend to the Commission, among other things, that it ratify the IRP; and

WHEREAS, on September 1, 2015 the Hearing Examiner issued an Amendment to his Report by including the responses previously filed by Delmarva on April 29, 2015; and

WHEREAS, since no settlement was proposed by the Parties and Delmarva, and the Hearing Examiner assumed that the Parties and Delmarva would make oral argument to the Commission, he stated that he made no specific recommendations concerning the IRP, concluding only that there is ample evidence that the requirements of 26 *Del. C.* § 1007 and 26 *Del. Admin. C.* §3010 have been satisfied, including the public investigation and comment requirements required by 26 *Del. Admin. C.* §3010.9.2; and

WHEREAS, the parties agreed that, prior to the filing of the 2016 IRP in December 2016, most likely in March or April, 2016, the parties would conduct working group meetings to discuss the parties' suggestions as to what Delmarva should include in the 2016 IRP; and

WHEREAS, the parties also agreed that, unless the regulatory provisions are amended, Delmarva Power will continue to include an evaluation of externalities as part of the 2016 IRP; and

WHEREAS, the Commission met in public session on October 6, 2015, to hear oral argument and conduct deliberations on the issues summarized in the Hearing Examiner's Report as amended; and

NOW, THEREFORE, IT IS ORDERED BY THE AFFIRMATIVE VOTE OF NOT FEWER THAN THREE COMMISSIONERS:

1. The Commission ratifies the IRP appended as **Exhibit "A"** to the Hearing Examiner's Report, finding that it was filed in compliance with the requirements of 26 *Del. C.* § 1007 and 26 *Del. Admin. C.* §3010

including the public investigation and comment requirements required by 26 *Del. Admin. C.* §3010.9.2;

2. The Commission reserves the jurisdiction and authority to enter such further Orders in this matter as may be deemed necessary or proper.

BY ORDER OF THE COMMISSION:

Chair

Commissioner

Commissioner

Commissioner

Commissioner

ATTEST:

Secretary

THE DELAWARE PUBLIC SERVICE COMMISSION 1949

APPENDIX 4

Appendix 4

DELMARVA POWER DE IRP
Forecast Documentation

Peak Demand Forecasting

Electric Sales Forecasting

Electric Customer Forecasting

Regional Economics

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I. Introduction

Business Purpose of This Document

This document explains the process used by Delmarva Power and Light Company (Delmarva Power) in preparing the projections of electric energy and power demand submitted as part of the Company's Integrated Resource Plan ("IRP") in Delaware. The purpose of this document is to make those projections transparent, so that any interested reviewer will be able to clearly understand the procedures that were used. Throughout the discussions of forecasting, the goal is to build a consensus that the results are "not unreasonable."

The remainder of this Chapter provides a discussion of business forecasting, focused on how business forecasting practices may differ from textbook treatments of statistics and econometrics. The Chapter then continues with an overview of how the models used in preparing these projections are constructed, and concludes with a discussion of forecast accuracy.

Chapter II discusses the data considerations that influence or limit the range of forecasting techniques available. It also discusses the most important assumptions that are used in the projections.

Chapter III discusses Pepco Holdings ("Pepco")'s coverage of regional economic conditions in the State of Delaware and the Metropolitan Statistical Areas representative of the Delmarva Power footprint.

Chapter IV describes the role of prices in Pepco's forecasting practice and the evidence for price sensitive sales and power demand.

Chapter V discusses Pepco's weather normalization procedures and incorporation of weather into the forecast.

Chapter VI reports the projections of energy requirements by class of customers.

Chapter VII reports the projections of customer formation by class.

Chapter VIII presents the Delmarva Power Baseline forecasts for the Delmarva Zone in the PJM transmission area. This forecast has been prepared by Pepco independent of the forecast published by PJM in their PJM Annual Load Report.

Chapter IX reports alternate scenario projections of power demand and energy requirements. Alternate scenarios include weather, high growth, and low growth scenarios.

A glossary provides data definitions for included energy and demand variables, weather related, economic, and dummy variables.

Brief Overview of Business Forecasting

While statistical analysis is highly mathematical, the discipline of forecasting is most definitely an art. In forecasting we routinely acquire and utilize data as a commodity. Data is not a commodity; instead, every data item requires careful and critical scrutiny. Strictly speaking, there is no such thing as data. Instead, the normal conduct of our business activities generates a flow of documentation—meters are read, bills are printed and mailed, payments are received—and that documentation is then more or less carefully collated and used by the Company as data. The creation of data is strictly the byproduct of unrelated commercial activity.

Take, for example, the economic concept of "employment." It seems unambiguous at first; we're obviously talking about the number of people that have jobs. But it's not that simple. All we know about employment begins with the ES-202 data. ES-202 employment data is the collation of Employment Security Form No. 202, the form that all employers must fill out each month so that their employees will be covered by Unemployment Insurance.

Not all workers are covered by Unemployment Insurance. For example, contractors, farm workers, and several other categories of employees do not qualify. They are not counted in the ES-202 data. To make up for this, the US Bureau of Labor Statistics prepares estimates inclusive of these categories. This augmented data, called the BLS-790 data, has a much longer reporting lag of about 18 months, but does include estimates of these other workers.

Finally, the US Department of Commerce Bureau of Economic Analysis prepares the BEA Personal Income, Population and Employment estimates that incorporate all of the prior information, and also include survey data from the County Business Patterns surveys. The BEA employment data are annual, and are available on an even longer reporting lag of approximately two years.

All of these estimates of employment are treated as data. They are all different, and sometimes they are very different. The right choice of employment estimate depends entirely on the situation faced by the forecaster. And, none of them tell you the "real" level of employment.

At the most basic level, business forecasts must serve the planning needs of the business in an independent, informed and objective manner. At the same time, forecasting is an economic activity. A more involved, more complicated, more expensive forecast is only worthwhile if it creates more value for the business. In many cases, smaller, simpler, more straightforward forecasts provide reasonable results. Our modeling approach does not include an end-use approach for precisely that reason; the costs are not justified. Of course, the most important component in any forecast is the good judgment and expertise of the team of forecasters.

The approach used at Delmarva Power includes the concept of "mutually confirming forecasts." Wherever possible, independently prepared forecasts are used to provide support of the forecast. For example, in preparing the outlook for the Delmarva Zone, independent forecasts of retail sales, the amount of energy throughput for the zone and the peak demand for the zone are prepared. It is expected that forecasts of the load and throughput will provide a consistent view of the future. The reasonableness of the independent components of the forecast increases Delmarva Power's confidence in the forecast.

Forecast Accuracy

Utilities' internal view of forecast accuracy is almost always decided by the credibility of the individual forecasters before their management committee. Rigorous discussions of forecast technique that get down to a critical examination of a forecaster's methods are unusual.

As a result, the quality of these forecasts varies across the board. As hard as it may be to believe, a few utilities are still very proud of the fact that a ruler and logarithmic graph paper provide results suitable to their needs. At the other extreme, there are companies spending several person-years of internal staff time and hundreds of thousands of dollars on consultants during each budget cycle. In reviewing utility forecasts, it is always important to bear in mind that forecasting is itself an economic activity – it is only worthwhile spending more on a forecast if the benefits outweigh the costs – as assessed by senior management.

Delmarva Power's interpretation of forecast accuracy is that there are two considerations. First, forecasts should be unbiased in the sense that errors should be expected to be zero at the time that the forecast is made. Second, forecasts should be risk minimizing, in the sense that the confidence bands around the forecast should be as small as possible.

Forecast risk should be measured as the standard error of the forecast, although that concept is difficult to calculate. In fact, it cannot be calculated directly, although it can be shown that the standard error of the forecast is a function of the standard error of the regression, the number of variables in the regression equation and the distance from the historic mean of the variable being explained.

As shown in Appendix F, the standard error of the regression for the regression relationship used to forecast the peak hour demand in the Delmarva Zone is 178 MW, with a historic average peak demand of 2,870 MW (average of monthly peak demand, 1993:2-2015:12). If the relationship was used to predict the peak hour demand at the mean of the historic data, 95% confidence bands surrounding the forecast would be +/-178*2 or +/-356 MW wide. In other words, the width of the confidence interval is roughly 12% of the underlying series, calculated at the mean of the historical value (which also happens to be its minimum value).

The relationship between the number of explanatory variables and the standard error of the forecast leads to a Principle of Parsimony, that argues that each variable included in the equation must pay its way by way of explanation, because it presents another source of risk to the forecast. The fact that the standard error of the forecast increases as one moves away from the mean of the historical data gives rise to the observation that confidence bands are "trumpet shaped," i.e., the standard error of the forecast gets bigger as the forecast tries to look farther out into the future.

The data in Table I.1, below, are drawn from PJM's annual Load Reports. Table I.1 below illustrates the errors (the difference between expected loads and actual observed loads) for 1-year forecasts, 2-year forecasts, and so on out to 8- year forecasts. Beyond eight years there are not enough data points to estimate a standard error.

Table I.1

Zonal Peak Demand Forecast Accuracy

Delmarva Power Zone	1-Year	2-Year	3-Year	4-Year	5-Year	6-Year	7-Year	8-Year
2015 PJM Unrestricted Forecast	247							
2014 PJM Unrestricted Forecast	11	331						
2013 PJM Unrestricted Forecast	11	48	371					
2012 PJM Unrestricted Forecast	1	36	86	412				
2011 PJM Unrestricted Forecast	78	63	96	108	398			
2010 PJM Unrestricted Forecast	(27)	19	43	89	109	409		
2009 PJM Unrestricted Forecast	12	(48)	68	179	265	313	624	
2008 PJM Unrestricted Forecast	182	318	310	372	412	487	851	851
2007 PJM Unrestricted Forecast	(54)	156	296	294	362	380	447	488
2006 PJM Unrestricted Forecast	(106)	(90)	140	284	263	333	381	457
2005 PJM Unrestricted Forecast	(42)	43	127	362	527	551	646	721
2004 PJM Unrestricted Forecast	105	(46)	37	122	362	535	570	678
2003 PJM Unrestricted Forecast	50	189	72	148	224	460	626	651
2002 PJM Unrestricted Forecast	(35)	81	179	16	66	122	343	461
2001 PJM Unrestricted Forecast	(77)	(100)	15	111	(54)	(6)	49	268
2000 PJM Unrestricted Forecast	19	(112)	(174)	(102)	(46)	(244)	(209)	(168)
1999 PJM Unrestricted Forecast	117	(23)	(132)	(183)	(100)	(35)	(232)	(202)
1998 PJM Unrestricted Forecast	82	115	(23)	(131)	(181)	(96)	(30)	(225)
1997 PJM Unrestricted Forecast	(79)	(176)	(246)	(335)	(455)	(716)	(792)	(770)
1996 PJM Unrestricted Forecast	(6)	(97)	(267)	(283)	(377)	(641)	(704)	(749)
1995 PJM Unrestricted Forecast	(79)	(92)	(174)	(275)	(261)	(352)	(468)	(522)
1994 PJM Unrestricted Forecast	(9)	(80)	(270)	(352)	(415)	(401)	(491)	(607)
1993 PJM Unrestricted Forecast	112	10	97	(48)	(123)	(221)	(208)	(298)
1992 PJM Unrestricted Forecast	(67)	(68)	(180)	(110)	(310)	(405)	(520)	(523)
Mean Error ('92-'15)	18.58	20.74	21.41	32.29	33.30	24.89	49.06	30.06
Standard Error ('92-'15)	88.48	132.46	186.95	240.07	307.80	411.86	523.81	565.70

Based upon our experience, Delmarva Power believes that these data are representative of the results that would be reported for other similar forecasts. It has been Delmarva Power's experience that utility forecasts are usually unbiased. It has also been Delmarva Power's experience that the risk associated with demand forecasts is much higher than most readers of forecasts expect – the future can only be known with great uncertainty. Finally, it has been Delmarva Power's observation that the risk associated with the forecast, or the standard error of the forecast, grows slowly at first as the time horizon of the forecast is extended, but eventually begins to expand at an increasing rate and quickly become very large.

Modeling/Forecasting Philosophy

One of the most vitally important planning tools for energy retailers is the econometric model and forecasting system. Its advanced precision assists in the generation of forecasts that will withstand the scrutiny of regulators and senior executives alike, as well as maintain its credibility over time. In addition, such tools can be helpful in attaining the most important result, which is the prevention of imbalances between energy demand and availability.

The PHI Economics and Forecasting Group has designed, built, tested, and estimated an Electricity and Electricity Peak Load Forecast System (the "Pepco Forecast System"). The Pepco Forecast system incorporates the features of the Pepco Economics and Forecasting Group's basic modeling philosophy. This philosophy recognizes that the ideal econometric features of a model whose purpose is forecasting can often be quite different from the ideal features of a model intended for research purposes.

The most important difference is that a model intended for research purposes is tailored to yield good hypothesis tests on the parameters. This means that the builder of such a model is likely to have searched for explanatory variables that yield high t-statistics, a high priority in variable selection for models of this type.

In contrast, the PHI Economics and Forecasting Group believes that identifying regressors that perform well in t-tests of parameter significance is only one of several objectives that a modeler should try to attain, instead of the most important one. Pepco takes the view that an over-emphasis upon high t-statistics does not necessarily lead to the attainment of the very most important criterion that a forecasting model must meet—a low forecast standard error.

In addition, the emphasis upon high t-statistics could lead the researcher to include among the explanatory variables in the model, equations having lagged dependent variables. Such an inclusion could cause its own distinct set of problems. Models consisting of equations that make use of lagged dependent variables tend not to yield good forecast results. The most important problem is that such models are not really causal models, and thus are generally ineffective at predicting turning points. These models are likely to overstate energy consumption during economic downturns and understate it during economic expansions. In addition, the use of lagged dependent variables in equations is liable to render the model inappropriate for policy or impact analysis because of the resulting biased elasticities.

Intellectually, the use of lagged dependent variables amounts to placing a ruler on the most recent realized observations and making the case that the future will be pretty much like the past, exclusively, because the lagged dependent variable parameter often scores well in tests of parameter significance. For these reasons, an important part of the Delmarva Power Economics and Forecasting Group's modeling philosophy is the sparing use of lagged dependent variables.

As indicated above, the Pepco Economics and Forecasting Group puts a high priority upon attaining a minimum standard error of regression, when selecting equations in the process of model building. This is generally accomplished through three main methods:

- Diagnostic use of summary statistics;
- Correct modeling of seasonal patterns; and
- Including a correction for serial correlation.

The Pepco Economics and Forecasting Group does not use summary statistics as decision rules for selecting an equation, but instead, as diagnostic tools in searching for the smallest possible standard error of regression. Reducing the standard error of the regression generally reduces the standard error of the forecast, and improves the ability of the model to provide "reasonable" forecasts.

Forecasters too frequently either ignore or treat incorrectly the problem of serially correlated residuals. Correcting for serial correlation through the use of something as simple as appropriate differencing, or through the use of a

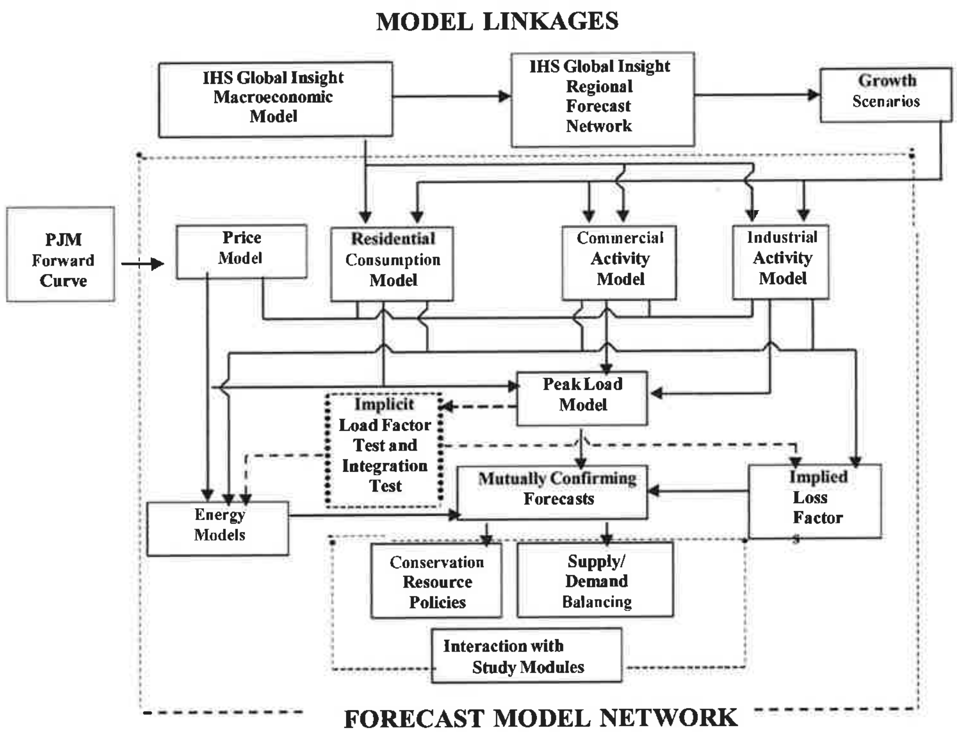
Cochrane-Orcutt or Hildreth-Lu procedure, often serves to reduce the standard error of the regression — and hence the standard error of the forecast — dramatically, providing more efficient forecasts.

Of course, the Pepco Economics and Forecasting Group employed other criteria as well in judging candidate equations in the construction of the Pepco Forecast System. Of central interest was the theoretical and empirical specification of the model as a whole. Estimated coefficients were required to pass rigorous tests of reasonability drawn from the Pepco Economics and Forecasting Group's past experience with other models.

Pepco's modeling approach for energy demand employs a regional economic activity sub-model to economic growth scenarios for the Delmarva Power service areas that drive the customer demographics, sectoral energy consumption and peak load sub-models. Figure I.1, below, illustrates, for the case of electricity demand and peak load components of the model, how the sub- models are related to one another. It also shows how these sub-models are related to their external driver models, such as the IHS-Global Insight Macroeconomic (national) Model and the IHS-Global Insight Regional Forecast Network (which models the individual states and Metropolitan Statistical Areas included in the Delmarva Power service areas).

Figure I.1

The Pepco Load Forecast Model Network



The key economic variables that are drawn from the Global Insight outlook include local employment, local incomes and the rate of inflation. Other exogenous factors include the commodity component of the price of electricity, which is taken as the PJM Forward Curve as posted by the New York Mercantile Exchange (NYMEX). The total all-in retail end-use price of electricity, inclusive of taxes, surcharges and the commodity cost of electricity, is calculated using a deterministic spreadsheet model that replicates the Company's supply portfolio. We anticipate estimated price elasticities to fall within a reasonable range consistent with our expectations given economic theory and industry consensus.

II. Assumptions and Data Considerations

Pepco prepares its forecasts for Delmarva Power DE and the Delmarva Zone utilizing an integrated econometric sales and load modeling network. The forecasting approach relies heavily on the preparation of forecasts for key concepts that are prepared independently, with the expectation that mutually confirming results should raise the confidence that can be placed in the forecast.

The forecasting model uses monthly data that in most cases goes back to 1991. The year 1991 was chosen because there have been two complete business cycles since 1991, and it seems like there has been structural change in our local economies since the 1980s.

The weather data that is used in preparing the forecast for Delmarva Power DE is collected and reported by the National Oceanic and Atmospheric Administration ("NOAA"), reflecting conditions at the New Castle County Regional Airport. Pepco maintains hourly weather data back to 1964, and constructs all of the weather metrics that are used in forecasting from this raw data. For most forecasting exercises, the expected values for each of the weather metrics are their normal, or average, values taken over a rolling 20-year period. For the extreme weather scenario, the normal weather values are defined as their 20-year normal values plus two standard deviations.

Projections of economic and demographic activity in the local economy are purchased from Global Insight ("GI"). GI updates its forecast products monthly, usually during the third week of the month. A narrative discussion of the Mid Atlantic economies prepared by IHS-Global Insight is included as Appendix B.

Projections of the price of electricity are based upon a deterministic spreadsheet model of the Company's supply portfolio. It is believed that households make rational electricity consumption decisions based upon the all-in real cost of electricity, inclusive of all taxes, surcharges, and the commodity component of the electricity price. Since we do not have data on the commodity cost of electricity for choice customers, we have to assume that their commodity costs are the same as for the Standard Offer Service (SOS) customers. It is assumed that costs, taxes and surcharges associated with the wires business will increase with general inflation. It is also assumed that the price of the commodity component will escalate with the PJM forward curve, as posted on the NYMEX.

III. Regional Economic Activity

All three components of the Pepco Forecast System, electricity sales, customers and electric peak load, incorporate the assumption that demand will depend upon economic conditions in the service territory. More specifically, each demand forecast in the system explicitly incorporates local employment for the Metropolitan Statistical Areas (MSA) which is representative of the Delmarva Power service territory. The mapping of economic statistics to the service territory is illustrated in Appendix A (maps were prepared by the U.S. Department of Commerce Census Bureau). The Company's analysis has shown that the Delmarva Power DE service territory is best represented by local economic activity in the Wilmington and Dover MSA. While Delmarva Power DE does not serve the City of Dover, the Company does serve much of the Dover MSA that is outside the City. In addition, activity within the City of Dover spills over into the areas served by the Company outside the City.

Historical and forecast employment and income data for the MSAs are acquired from the Company's economic consultant, IHS Economics, and explicitly incorporated into Pepco's econometric forecasting models. While employment and income are the richest and most important regional economic concepts to model explicitly, the Pepco forecasting team collects economic information on a wide range of concepts to form a comprehensive view of economic conditions in the service territory.

Last, the team makes every effort to analyze the data we receive and produce independent analysis of the economic landscape. As we receive our economic forecast from an external consultant, we spend a significant amount of time understanding the assumptions underpinning the forecast. Provided in Appendix B are write-ups associated with the latest forecast, highlighting key assumptions for their outlook of the Wilmington MSA, Dover MSA and the State of Delaware. These reports are reviewed monthly after the release of each new MSA, state or macroeconomic forecast.

IV. Prices

It's expected that consumers will respond to changes in the price of a commodity by changing their consumption of that commodity. While many different measures of prices are possible, the Company finds that the most useful measure of price in forecasting electricity sales and demand is average revenue per kWh for the rate or revenue class. In the statistical relationships that are estimated, it is assumed that customers respond to the total all-in real price of electricity. The price is real in the sense that it is adjusted for changes in purchasing power as measured by the US Consumer Price Index. The price is all-in when it reflects all of the costs the consumer faces when purchasing electricity, including the commodity cost of electricity, all utility taxes and surcharges, and all base transmission and distribution charges.

Table IV.1, below, shows the sensitivity of electricity consumption to the real all-in price of electricity for Delmarva Power DE customers by revenue class. The real all-in price of electricity is calculated as the sum of all commodity costs, utility taxes and surcharges and base distribution and transmission revenues expressed on a cost per kWh basis and adjusted for the effects of inflation using the US Consumer Price Index.

Table IV.1

Pepco Sales Forecast Model
Estimated Price Elasticitities, August 2010

	DPL DE
Total Residential	
Residential Non Heat	-0.1051
Residential Heat	-0.1294
Commercial	-0.0378
Industrial	-0.1403
Street Light	-0.1137

The price elasticity of electricity measures consumers' response to changing prices as the percentage change in the quantity of electricity consumed when the real price of electricity changes by 1%. For example, if the price elasticity for the residential Non-Space Heat customer class is estimated to be -0.1, as in Table IV.1 above, a 1% increase in the real price of electricity will lead to a -0.1% decrease in the consumption of electricity by that customer class.

For the calculations reported in Table IV.1 above, the price elasticity is calculated as the percent change in quantity related to a percent change in price as of August 2010. The regression coefficient calculated in August 2010 was taken as the best estimate of the change in the amount consumed given a one unit change in price. The regression coefficient was multiplied by the real price prevailing in August 2010 and divided by the amount sold during August 2010 to yield the elasticity.

Figure IV.1, below, illustrates the real and nominal price history for Delmarva Power DE residential customers. The black line represents the nominal price, showing the period of the stipulation against rate increases and the rate increases that occurred when the stipulations came off. The red line represents the real price in 2014 dollars, and clearly shows that the period of falling real prices during the period of the stipulation is almost exactly offset by the price increases that occurred over the last decade, leaving the real price of electricity over the 20 year period almost unchanged.

Figure IV.I

Real and Nominal All-In Price of Electricity

($/kWh, current and 2014$)

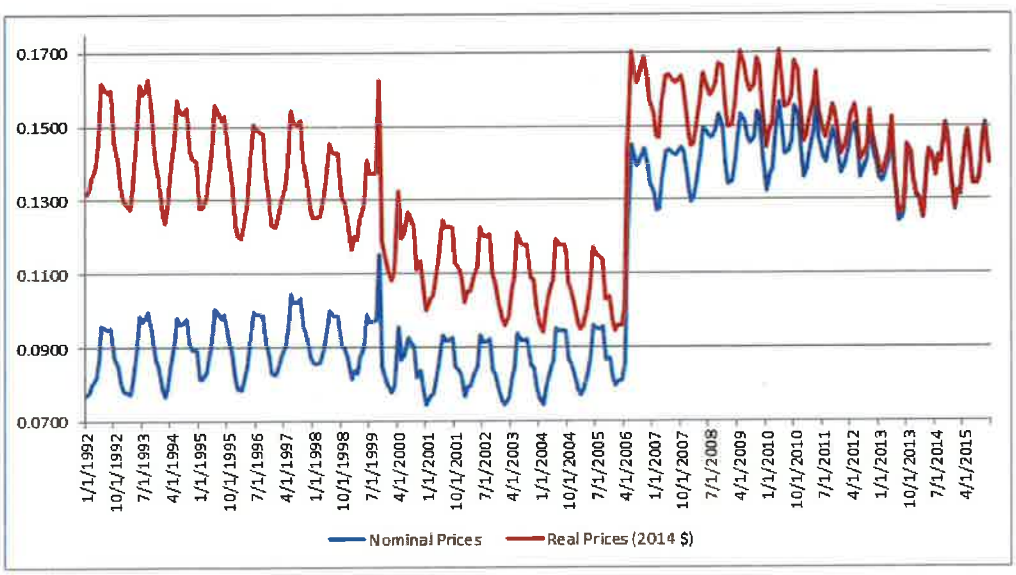


Figure IV.2 below illustrates the forecast of real, all in, electricity prices used in the Delmarva Power DE forecasts. To prepare price projections, the components of the all in price are divided into the commodity portion and the non-commodity portion, consisting of utility taxes, surcharges and base transmission and distribution charges. Nominal prices are converted to real using the U.S. Consumer Price Index, All-Urban, with prices expressed in 2014 dollars.

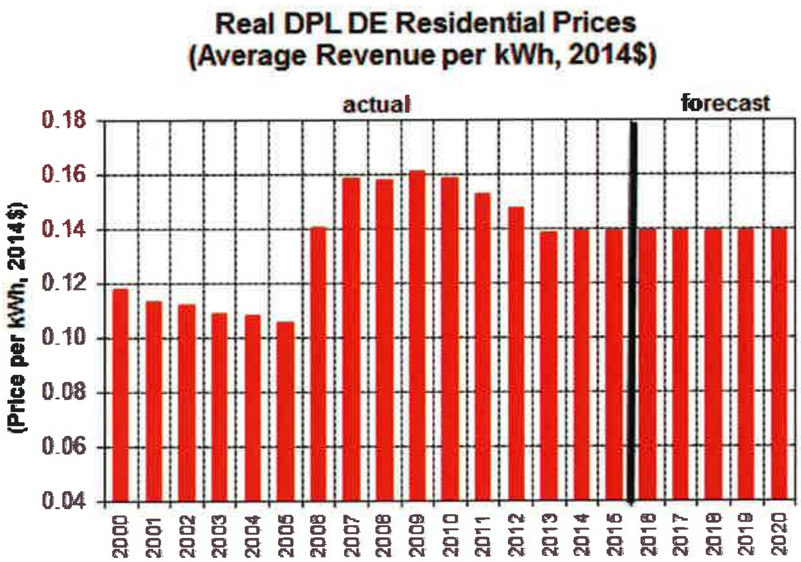
In Figure IV.2, below, the non-commodity portion of prices is assumed to grow with the rate of general inflation. The commodity component of prices is projected by modeling the supply portfolio.

In Delmarva Power DE the supply portfolio is divided into three tranches. The contracts for the supply of one tranche are renewed each year, with all of the contracts renewed after a cycle of three years. Once each year, in November, the prices paid by consumers are updated to reflect changes in the supply portfolio made during the previous June.

In preparing the projected supply portfolio costs, it is assumed that as each tranche of contracts is renewed, the contract price will be the current forward price for the month when the contracts will be renewed, as measured by the NYMEX forward curve for electricity trading at PJM-West.

Figure IV.2

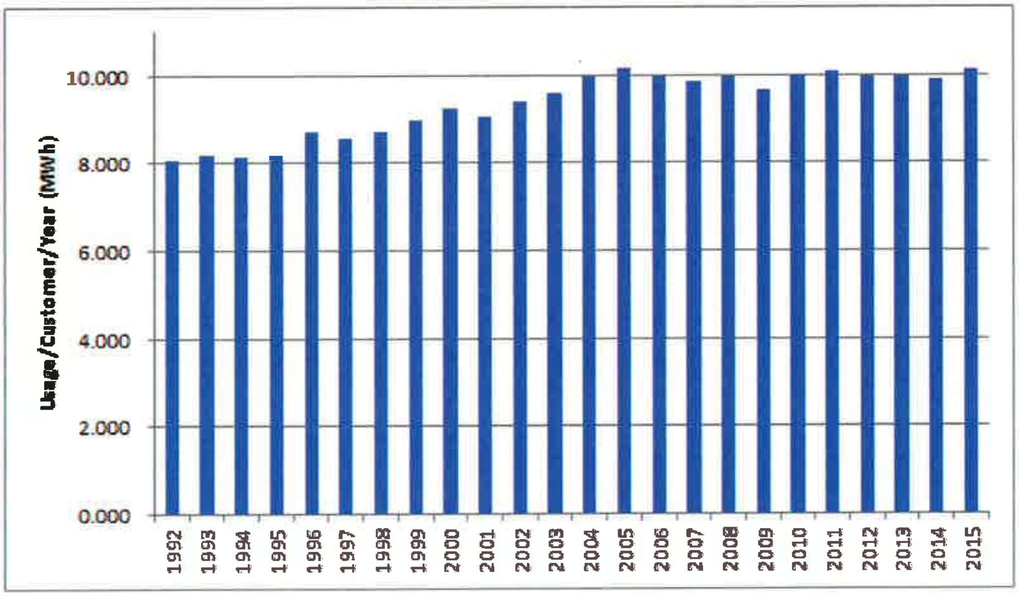
Real Price of Electricity, History and Forecast



By way of comparing historical prices with usage per customer, Figure IV.3, below, illustrates historical usage per customer. Figure IV.3 shows clearly the period of increasing usage per customer following the beginning of the period of price stipulations, and the end of increasing usage when the stipulations ended and the first rate increases were allowed. During the forecast period it is expected that the real all-in price of electricity will be nearly constant – flat real prices – and, as a result, it is expected that usage per customer will remain stable over the forecast time horizon.

Figure IV.3

Usage per Customer (Response to Price)



V. Weather Normalization

The Effects of Weather on the Forecast

Currently, the weather data parameter used in the sales forecasting process is Cooling and Heating Degree Days on a 65° basis. In the peak forecasting process it is Cooling Degrees on a 65° basis and Heating Degrees on a 65° basis. The weather data used in the forecast needs to meet two criteria, it should theoretically relate to geographic sales territory and it should not be biased.

In the forecast, the relationship between historical weather and the historical sales or peaks is modeled using regression analysis. Then, normal monthly weather is calculated and assumed to be the weather in the future. The effect of weather data in the forecast period should be neutral. When normal weather is used, in the unlikely event that the actual weather in a given month happens to be normal, then the weather effect on sales/peaks is zero. Unlike every other independent variable in the model, we do not forecast weather. Once actual sales and actual weather is known for a given month, the variance in actual from budgeted sales caused by the variance in actual from normal weather is determined by, again, performing regression analysis.

The weather data used in the later regression analysis should be that weather data that corresponds closest to the appropriate geographic region and represents the weather that affects the behavior of consumers. Since the variance from actual to normal weather is used to determine the effect on actual sales, it is only logical to use the same data in the former regression analysis.

In the forecasting process, weather normalization is not used *per se*. The current forecast models use approximately 20 years of actual data. This data is not weather normalized; rather, it is the actual historical sales. The forecast period assumes weather will have no effect on sales, i.e., it assumes normal weather.

Weather normalization is a process; that adjusts actual sales/peaks to what they would have been if the actual degree days had been at their historical normal level. This is based on the past relationship between actual degree days and actual sales/peaks.

Weather normalization is an inexact process, degree days are a one variable proxy for a complicated, multivariate phenomena, the weather, that takes into account only one of those variables, the average daily temperature departure from 65 degrees. The relationship between degree days and sales/peaks is not a linear one. The normalization process adjusts sales for weather using a linear model; this makes weather normalization, at best, an approximation.

The various revenue classes have different sensitivity to changes in degree-days, residential being most affected, non-space heat being least affected.

However, that does not mean that there is no relationship between weather and the so called non-weather sensitive classes. During near normal weather there is no change, but there is during extreme weather, again these instances being too rare to accurately model.

Finally, there are always other variables at work that will affect sales/peaks. These other variables are generally unknown or known only anecdotally. In either case, these variables are either not measured or not measurable; therefore, they cannot be modeled.

Mapping of Weather Stations to Loads

Currently, Delmarva Power uses weather data measured at the New Castle County Regional Airport (Wilmington Airport.) A weather station needs to provide at least thirty years of continuous hourly data to allow for calculation of normal weather and to support special studies. Wilmington Airport meets this standard. Some alternative Delaware weather stations are shown in Table V.1 below.

Table V.1

Alternative DE Weather Stations

Location	Station ID	Temp. Frequency	Status	2005 Avg. Temp.
Wilm. Porter Reservoir	79605	Daily	Open	54.83
Newark University Farm	76410	Daily	Open	54.47
Dover DELDOT Office	72730	Daily	Open	55.68
Greenwood	73595	Daily	Closed	54.41
Milford	75915	Daily	Closed	55.44

Source: David T. Stevenson, Director, Center for Energy Competitiveness, Caesar Rodney Institute, email to Jack E. Barrar dated 4/13/2012.

How Weather is Modeled

Delmarva Power collects hourly weather data from NOAA. This is used in different ways in the peak and sales model. In the peak model the weather parameter is recorded *at the time of the peak* for each month of history. The 20 year average of this weather parameter is the normal weather for that month. Since, the weather parameter, at the time of the peak, is going to be close to the maximum weather of that day, we characterize this as the extreme normal. In the peak load model, the current weather parameter is Heating Degrees 65° Base and Cooling Degrees 65° Base. This is defined as the amount of the current (at the time of the peak) dry bulb temperature in degrees Fahrenheit over 65 for Cooling Degrees and under 65 for Heating Degrees.

Table V.2

Example of Cooling/Heating Degrees for a given Hour

Current Temperature	Cooling Degrees (65°)	Heating Degrees (65°)
55°	0°	10°
65°	0°	0°
72°	7°	0°

In the sales models, the weather parameter for each hour of each day of each month of history is recorded. The average of the hourly dry bulb temperature for each day is recorded. The monthly sum of the daily averages of the weather parameter is recorded. The 20 year average of this weather parameter is the normal weather for that month. In the sales models, the current weather parameter is Heating Degree Days 65° Base and Cooling Degree Days 65° Base. This is defined as the amount the daily average dry bulb temperature in degrees Fahrenheit is over 65 for Cooling Degree Days and is below 65 for Heating Degree Days. Note the difference between the sales and peak weather parameters. For the peak they are called

Heating/Cooling Degrees, for the sales they are called Heating/Cooling Degree-Days. This is because for the peak, it is a weather parameter for a single hour while for sales it is a weather parameter for a month.

Calendar Month and Billing Month

There is one further step before the sales weather parameter is completed. The Degree Days need to be converted to a Billing Month Basis. This is in recognition of the fact that the sales which are reported in any given calendar month, did not necessary completely occur during that calendar month. This is due to the Billing Cycle and the Meter Reading Schedule. It is beyond the scope of this document to give a complete treatise on these subjects.

A quick example should suffice. A customer has his meter read on the 2nd day of May, because that customer is on a certain Billing Cycle. However, because of the occasional incongruity of the Meter Reading Schedule, the last time this customer's meter was read was on the 30th day of March. The calendar month sales report will show all of this particular customer's usage to have occurred in May. In reality, the vast majority of this customer's usage took place in the month of April. Most customers' usage patterns fall into varying degrees of this example.

To compensate for this result, weather normalization for sales is not done on a calendar month basis, but on what is called a Billing Month Basis. This is done by compiling the daily weather parameters into half month blocks, these blocks are then weighted to approximate average usage patterns. The following formula is used:

For any given calendar month:

- The sum of the first 15 days of Degree Days of the previous calendar month is multiplied by 0.25;
- The remaining Degree days of the previous month is multiplied by 0.75;
- The first 15 days of Degree Days of this calendar month is multiplied by 0.75;
- The remaining Degree Days of this calendar month is multiplied by 0.25; and
- The sum of these four calculations equals this month's Billing Month Degree Days.

Scenarios for 90/10 Weather

The PJM Standard for Weather Sensitivity Analysis is called a 90/10. Using statistical methods, an upper and lower band is set for weather. It is determined what the weather conditions would be so that there is a 90% likelihood that these conditions would not be exceeded. The lower end of the band represents those weather conditions where there is only a 10% possibility that these conditions would not be exceeded.

Weather Normalization Factor Estimation

The procedure for preparing the factors used in weather normalization at Pepco is to regress daily sales by class against daily heating or cooling degrees, and then to use the estimated coefficients on the weather terms as the weather normalization factors.

Daily sales data by revenue class for the study period are used as the dependent variables in regression studies. Each regression equation includes a constant term, weather variables measuring heating and cooling degree days, and two dummy variables for Saturdays and Sundays. Holidays are included as a separate dummy variable for each holiday. All weather data is received from NOAA; weather data is measured at the Wilmington Airport.

A set of regressions is estimated for the summer cooling season, in which the weather metric is Cooling Degree Days measured on a comfort threshold of 65 degrees Fahrenheit. A second set of regressions is estimated for the heating season, in which the weather metrics are Heating Degree Days measured on a comfort threshold of 65 degrees Fahrenheit and Heating Degree Days measured on a comfort threshold of 35 degrees Fahrenheit. In both cases, lagged weather variables are allowed if the current weather variable is significant. Each seasonal set of regressions includes an equation for each rate or revenue class, depending upon the level of detail available from market settlements. Finally, each equation includes an autoregressive correction.

For example, in the 2016 study that was completed in December 2015, the summer period was defined as April 1, 2015 through September 30, 2015, while the winter period was defined as December 1, 2014 through March 31, 2015. Each equation is examined carefully for the reasonableness of the estimated coefficients. Where variables do not pass a Student's t-test for significance, the variable is deleted. When an equation contains more than one insignificant term, insignificant terms are deleted in a reverse stepwise fashion. An exception is made with dummy variables for Saturday and Sunday; these two dummy variables are always included, even if they are insignificant.

Once the regression equations are complete, the coefficients associated with the two heating terms with comfort thresholds of 35 degrees and 65 degrees are designated as the weather normalization factors for the heating season, by class. Similarly, the coefficient in each equation for the cooling degrees term is taken as the weather normalization factor for the summer cooling season, by class. Appendix C reports the weather normalized factors estimated for each year for the period 2012-2016.

How Are Sales (kWh) Weather Normalized?

The Company weather normalizes sales by making an additive weather normalization adjustment to actual sales. The weather normalization adjustment is equal to the amount of sales calculated to be above (or below) the sales that would have occurred if the weather had been normal. The weather normalization adjustment is estimated by multiplying the difference between actual weather and normal weather, measured as degree days, multiplied by a weather normalization factor for each revenue class. Multiplying the weather normalization adjustment to sales by class times the average rate per kWh for that class and for that month yields the weather normalization adjustment to revenue.

VI. Delmarva Power DE Energy Forecast

Introduction

The Pepco Forecast System produces projections of electricity sales using explanatory variables selected according to economic theory. Electricity demand is derived from the demand for the services of a stock of capital goods that use electricity as a primary energy input. As a result, the stock of space-conditioning appliances is an important explanatory variable.

Once the inventory of appliance stocks is known, the rate at which those stocks are used determines energy consumption. This rate might be influenced by the price of electricity or natural gas, weather conditions, and, in the case of industrial customers, the level of manufacturing output.

A substantial share of electricity is sensitive to weather. This dependence is represented in the sales equations by the inclusion of weather variables. This allows the calculation of expected electricity sales over the forecast horizon by inserting hypothetical normal weather and deviations from normal weather into the sales forecasting equations.

Each equation of the Delmarva Power DE Power Delivery Electric Forecast System explains electricity consumption in one of several revenue classes of sales:

- Residential Non-Space Heating Electric Sales (MWh);
- Residential Space Heating Electric Sales (MWh);
- Commercial Electric Sales (MWh); and
- Industrial Electric Sales (MWh).

The inputs of the electricity forecasting model are the forecasts of service territory economic activity, the customer models, future weather and future real prices for electricity. The output of each equation is a monthly forecast of electricity sales corresponding to a revenue class and sub-region.

Table VI.1, below, reports Delmarva Power DE electric sales (MWh) by year from 2001 through 2015. Prior to the beginning of the Great Recession, total residential sales usually grew in excess of 2% annually. Since the end of the recession, residential sales growth has slowed and become more erratic.

Table VI.1

Delmarva Power DE Historical Electric Sales (MWh)

	Residential Non Space Heat Sales (MWh)	Growth (%)	Residential Space Heat Sales (MWh)	Growth (%)	Commercial Sales (MWh)	Growth (%)	Industrial Sales (MWh)	Growth (%)	Public Street Light Sales (MWh)	Growth (%)	Total Sales (MWh)	Growth (%)
2006	1,892,997	-0.7%	1,074,100	-1.2%	3,512,590	1.8%	2,378,548	-5.6%	37,166	1.2%	8,895,422	-1.2%
2007	1,898,039	0.3%	1,040,148	-3.2%	3,558,184	1.3%	2,357,339	-0.9%	37,549	1.0%	8,891,259	0.0%
2008	1,920,777	1.2%	1,036,251	-0.4%	3,550,363	-0.2%	2,240,707	-4.9%	37,945	1.1%	8,786,043	-1.2%
2009	1,864,123	-2.9%	1,018,853	-1.7%	3,463,128	-2.5%	1,935,704	-13.6%	37,933	0.0%	8,319,741	-5.3%
2010	1,927,194	3.4%	1,049,097	3.0%	3,513,428	1.5%	1,707,096	-11.8%	38,122	0.5%	8,234,937	-1.0%
2011	1,944,406	0.9%	1,058,871	0.9%	3,496,919	-0.5%	1,812,838	6.2%	36,773	-3.5%	8,349,807	1.4%
2012	1,920,496	-1.2%	1,031,590	-2.6%	3,440,945	-1.6%	1,906,607	5.2%	36,684	-0.2%	8,336,323	-0.2%
2013	1,930,443	0.5%	1,057,266	2.5%	3,428,955	-0.3%	1,819,938	-4.5%	36,338	-0.9%	8,272,941	-0.8%
2014	1,929,523	0.0%	1,058,501	0.1%	3,412,145	-0.5%	1,629,568	-10.5%	35,248	-3.0%	8,064,985	-2.5%
2015	1,997,332	3.5%	1,091,356	3.1%	3,427,448	0.4%	1,578,469	-3.1%	33,606	-4.7%	8,128,210	0.8%

Estimation Results

Ordinary Least Squares (linear regression) was used to calculate the statistical relationship between electric energy sales to each customer class and a set of explanatory variables. These relationships, in the form of equations, are then used in conjunction with forecasts of the explanatory variables to create the ultimate sales forecasts. Appendix D to this Chapter titled "Estimated Sales Equations" contains the statistical reports for each of the linear regressions that are used as forecasting equations.

A truism of demand theory is that consumers respond to changes in the real price of a commodity by changing the amount of that commodity they consume. Each equation contains a price term, which is explained more completely in the earlier section titled "Prices".

Other terms included in the sales equations are the weather, number of customers, a proxy measure of household income and a number of seasonal and accounting dummy variables.

Weather and number of customers enter the sales equations as an interactive term, degree-days multiplied by customers. Degree days is either heating or cooling degree-days, taken as the positive difference between the average daily temperature and 65 degrees Fahrenheit for a cooling degree-day, and the opposite for a heating degree-day. Using it in the interaction term interprets the degree-days metric as a proxy variable for the probability that any particular space conditioning appliance will be turned on.

Employment is included in the sales equations. In the commercial and industrial equations it serves as a measure of local economic activity. More people employed means that more people will be working in air conditioned or heated spaces, or operating electricity consuming machinery and equipment. In the residential equations employment serves as a proxy for customers. The customer variable was already used in two interaction terms with weather to approximate the cooling and heating loads. Including the employment variable accounts for the growth in non-weather sensitive demand, using a variable that trends with the customer variable but is not so highly correlated with customers.

Real personal disposable income per employee is also included, as a proxy for household income. As household income rises, households will consume more of all normal commodities, including electricity.

The sales equations also contain accounting dummy variables. These variables have names like DEC99 or MAR00, signifying December 1999 or March 2000. These variables are used to remove the effect of outlying data resulting from billing adjustments and similar causes of extreme outlying data. By including a variable coded "1" in that month and zero elsewhere the effect of that month is removed from the analysis while still maintaining the continuity of the data.

The interpretation of the parameter on a dummy variable or additive combination of monthly dummy variables is that the intercept term for the equation being estimated will change by the amount of the parameter estimate for the dummy variable. In other words, if the parameter estimate for JAN is 100, the intercept term for all observations corresponding to the month of January will be 100 higher than just the estimated intercept term.

VII. Delmarva Power DE Customer Forecast

Introduction

One of the most important activities in the Electricity and Electricity Peak Load Forecast System is customer modeling and forecasting. The electric sub models estimate and forecast customers for the commercial and residential classes (residential non-space heating and residential space heating). The customer sub model does not address the industrial customer class because Delmarva Power believes that the number of industrial customers is not helpful to estimate electric because there is so much variation in size among the industrial customers.

The Delmarva Power customer model contains four customer equations:

- Electric Non Space Heat Residential Customers
- Electric Space Heat Residential Customers
- Electric Commercial Customers
- Electric Street Light Customers

Table VII.1, below, reports the number of Delmarva Power DE electric customers by year, from 2001 through 2015.

Table VII.1

Delmarva Power DE Historical Electric Customers

	Residential Non Space Heat Customers	Growth (%)	Residential Space Heat Customers	Growth (%)	Commercial Customers	Growth (%)	Industrial Customers	Growth (%)	Public Street Light Customers	Growth (%)	Total Customers	Growth (%)
2006	191,477	1.2%	71,207	0.8%	31,933	1.9%	270	-0.4%	359	0.3%	295,246	1.2%
2007	193,191	0.9%	71,811	0.8%	32,410	1.5%	261	-3.3%	366	1.9%	298,039	0.9%
2008	192,699	-0.3%	72,541	1.0%	32,702	0.9%	259	-0.8%	367	0.3%	298,568	0.2%
2009	192,578	-0.1%	73,017	0.7%	32,968	0.8%	250	-3.5%	370	0.8%	299,183	0.2%
2010	192,984	0.2%	74,219	1.6%	33,111	0.4%	210	-16.0%	374	1.1%	300,898	0.6%
2011	192,891	0.0%	74,769	0.7%	33,376	0.8%	240	14.3%	370	-1.1%	301,646	0.2%
2012	193,197	0.2%	75,507	1.0%	33,577	0.6%	229	-4.6%	370	0.0%	302,880	0.4%
2013	194,415	0.6%	76,417	1.2%	33,755	0.5%	231	0.9%	367	-0.8%	305,185	0.8%
2014	196,502	1.1%	76,819	0.5%	34,026	0.8%	228	-1.3%	367	0.0%	307,942	0.9%
2015	199,032	1.3%	77,624	1.0%	34,352	1.0%	216	-5.3%	367	0.0%	311,591	1.2%

The model depends upon forecasts of service area economic variables to forecast customers. The approach to customer modeling is to assume that the number of new customers depends upon changes in economic activity in the electric service territories.

Delmarva Power finds that the most significant determinant of customers is nonfarm agricultural employment, published by the U.S. Bureau of Labor Statistics. The relationship exists because both household formation and migration occur more frequently when jobs are available.

Each of the customer equations contains a number of monthly dummy variables, also known as seasonal variables. These variables have names like JAN, FEB, MAR, etc. They are used to account for regularly occurring seasonality in customer formation that is not accounted for by the explanatory variables.

These dummy variables are explanatory variables intended to capture variations in demand that are not already captured by the other explanatory variables in the model. The seasonal dummy variable corresponding to each month takes the form of a monthly variable represented by a column consisting only of ones and zeros. The observations corresponding to the month that the dummy variable represents is always a one, all others are zeros. For example, the dummy variable for the month of January, takes a value of one for every January, and zero for all other months.

Several equations also contain accounting dummy variables. These variables have names like DEC99 or MAR00, signifying December 1999 or March 2000. These variables are used to remove the effect of outlying data resulting from billing adjustments and similar causes of extreme outlying data. By including a variable coded "1" in that month and zero elsewhere the effect of that month is removed from the analysis while still maintaining the continuity of the data.

The interpretation of the parameter on a dummy variable or additive combination of monthly dummy variables is that the intercept term for the equation being estimated will change by the amount of the parameter estimate for the dummy variable. In other words, if the parameter estimate for JAN is 100, the intercept term for all observations corresponding to the month of January will be 100 higher than just the estimated intercept term.

The electricity component of the customer model contains four equations. Each of the four equations corresponds to a revenue class: residential non-space heating, space heating, commercial and street light. As noted above, Delmarva Power does not forecast the number of industrial customers. The results for each of the regression equations appear as Appendix E to this Chapter.

As an example, consider the first equation, RESCUSDE, residential non space heat customers within the Delmarva Power DE jurisdiction. The regression equation is estimated using monthly data from July 1991 through November 2015. The regression contains one economic variable, the sum of total non-farm employment in the metropolitan statistical areas of Wilmington and Dover, lagged 3 months. Employment is the measure of local economic activity that we know with the most precision. Because employers must file Employment Security Form number 202 monthly – their unemployment insurance premium – the monthly employment data that we have is the nearest thing to a monthly census of employed people. The lag of four months indicates the approximate amount of time before new hiring translates into new residential non-space heat customers. Finally, the estimated coefficient of 6.347067 indicates that for every 1,000 new employees hired in the Wilmington and Dover MSAs, Delmarva Power DE will add 6.3 residential non-space heat customers. Note that the second equation, for residential space heat customers, reports that for every 1,000 new jobs Delmarva Power DE also gets 6.9 residential space heat customers. In other words, every 1,000 jobs eventually turns into 13 net new residential customers.

VIII. Delmarva Power DE Load Forecast

Introduction

The following section and tables contain zonal demand forecasts (MW) for the State of Delaware and the Delmarva Power DE retail footprint broken down into class level. Energy forecasts (MWh) are provided for the Delmarva Power DE retail footprint once again by class. The forecast tables represent the output from the Delmarva Power forecasting system described above. Additional detail on further disaggregation of the IRP demand and energy forecasts follows.

Disaggregated Forecasts for SOS and Choice Customers.

Projections of the demand requirements by state or jurisdiction, or by SOS and choice customers, or by rate class, are calculated in a spreadsheet model that uses sharing techniques. Projections of energy requirements broken down by SOS and choice customers or by rate class are also calculated in the same spreadsheet model. Results are presented in Tables VIII.5 – VIII.8, below.

The class sharing methodology first assumes that the DE state and Delmarva Power DE retail load are a constant share of the zonal forecast over the forecast horizon. The share is determined by calculating each respective jurisdiction's contribution to the 2015 Delmarva Zone peak. For further disaggregation to the customer class level, we sum the relevant rate class peaks into the classes required for IRP modeling. After calculating the IRP class contribution to the 2015 Delmarva Power DE peak mentioned above, class forecasts are calculated as a constant share of the Delmarva Power DE forecast over the forecast horizon.

In each class, the number of customers that choose to use competitive suppliers is taken to be a constant percentage of total customers in the class. SOS customers are assumed to represent a constant share of the overall energy and demand forecasts. These shares represent class level energy migration rates consistent with the prior year's peak month. Constant shares are used for forecasting choice customers because even though the fraction of any rate class that chooses choice is extremely volatile, it does not appear to have a trend over time. Logic tells us that if customers could get a better deal by choosing a competitive supplier they would make that choice, with the share quickly going to 100%, however, that is not the case. As a result, since we do not have better information and there is no obvious trend, we assume that shares will remain constant at their current level.

Table VIII.5

Summer Peak Demand Forecast Disaggregated by Rate Class

	DE Forecast (MW)	DPL DE Forecast (MW)	DPL DE Res (MW)	DPL DE Small Com (MW)	DPL DE LC&I (MW)	DPL DE LC&I HPS (MW)	DPL DE SL (MW)
2016	2,569	1,774	813	33	914	14	0
2017	2,582	1,788	817	34	923	14	0
2018	2,596	1,802	820	34	934	14	0
2019	2,609	1,815	824	34	943	15	0
2020	2,630	1,831	830	35	952	15	0
2021	2,658	1,851	839	35	962	15	0
2022	2,688	1,871	848	35	972	15	0
2023	2,717	1,891	858	36	983	15	0
2024	2,744	1,910	866	36	992	15	0
2025	2,773	1,930	875	36	1,002	16	0
2026	2,804	1,951	885	37	1,014	16	0

*DPL DE MW forecast is unrestricted peak non-coincident with PJM Zonal Peak Demand
*DPL DE MW forecast does not include EE/DSM programs
*DPL DE MW forecast includes the impact of reduced load from installed solar

Table VIII.6

Summer Peak Demand Forecast Disaggregated by SOS

	DPL DE SOS Res (MW)	DPL DE SOS Small Com (MW)	DPL DE SOS LC&I (MW)	DPL DE SOS LC&I HPS (MW)	DPL DE SOS SL (MW)	DPL DE Non-SOS Res (MW)	DPL DE Non-SOS Small Com (MW)	DPL DE Non-SOS LC&I (MW)	DPL DE Non-SOS LC&I HPS (MW)	DPL DE Non-SOS SL (MW)
2016	745	19	52	14	0	68	15	862	0	0
2017	748	19	52	14	0	68	15	871	0	0
2018	752	19	53	14	0	69	15	881	0	0
2019	755	19	53	15	0	69	15	889	0	0
2020	760	19	54	15	0	70	15	898	0	0
2021	769	20	54	15	0	70	15	908	0	0
2022	777	20	55	15	0	71	16	917	0	0
2023	786	20	56	15	0	72	16	927	0	0
2024	794	20	56	15	0	73	16	936	0	0
2025	802	20	57	16	0	73	16	946	0	0
2026	811	21	57	16	0	74	16	956	0	0

Table VIII.7

Energy Forecast Disaggregated by Rate Class

	DPL DE RES (MWh)	DPL DE COM (MWh)	DPL DE IND (MWh)	DPL DE Sm COM (MWh)	DPL DE LC&I (MWh)	DPL DE LC&I HPS (MWh)	DPL DE SL (MWh)
2016	3,056,364	3,385,807	1,545,311	170,125	4,688,469	72,524	33,315
2017	3,060,888	3,371,744	1,584,215	170,982	4,712,088	72,889	33,349
2018	3,058,450	3,370,984	1,623,848	172,323	4,749,048	73,461	33,399
2019	3,057,512	3,375,376	1,658,936	173,685	4,786,585	74,042	33,436
2020	3,062,970	3,380,305	1,690,195	174,933	4,820,993	74,574	33,475
2021	3,074,485	3,385,250	1,718,783	176,090	4,852,876	75,067	33,511
2022	3,085,019	3,390,142	1,746,476	177,214	4,883,857	75,546	33,544
2023	3,094,985	3,394,923	1,774,138	178,334	4,914,704	76,023	33,575
2024	3,104,704	3,399,631	1,800,922	179,420	4,944,647	76,487	33,604
2025	3,114,159	3,404,242	1,827,970	180,512	4,974,748	76,952	33,633
2026	3,123,347	3,408,753	1,855,338	181,612	5,005,058	77,421	33,660

*DPL DE MWh forecast does not include EE/DSM programs
*DPL DE MWh forecast includes the impact of reduced load from installed solar

Table VIII.8

Energy Forecast Disaggregated by SOS

	DPL DE SOS RES (MWh)	DPL DE SOS Sm COM (MWh)	DPL DE SOS LC&I (MWh)	DPL DE SOS LC&I HPS (MWh)	DPL DE SOS SL (MWh)	DPL DE Non-SOS RES (MWh)	DPL DE Non-SOS Sm COM (MWh)	DPL DE Non-SOS LC&I (MWh)	DPL DE Non-SOS LC&I HPS (MWh)	DPL DE Non-SOS SL (MWh)
2016	2,800,365	95,053	265,125	72,524	25,714	255,999	75,071	4,423,344	0	7,601
2017	2,804,511	95,532	266,460	72,889	25,740	256,378	75,449	4,445,628	0	7,609
2018	2,802,277	96,282	268,550	73,461	25,779	256,173	76,041	4,480,498	0	7,621
2019	2,801,417	97,043	270,673	74,042	25,807	256,095	76,642	4,515,912	0	7,629
2020	2,806,418	97,740	272,618	74,574	25,837	256,552	77,193	4,548,374	0	7,638
2021	2,816,968	98,387	274,421	75,067	25,865	257,517	77,704	4,578,454	0	7,646
2022	2,826,620	99,015	276,173	75,546	25,890	258,399	78,200	4,607,684	0	7,654
2023	2,835,751	99,640	277,918	76,023	25,914	259,234	78,694	4,636,786	0	7,661
2024	2,844,656	100,247	279,611	76,487	25,937	260,048	79,173	4,665,036	0	7,667
2025	2,853,319	100,857	281,313	76,952	25,959	260,840	79,655	4,693,435	0	7,674
2026	2,861,738	101,472	283,027	77,421	25,980	261,609	80,140	4,722,031	0	7,680

*DPL DE MWh forecast does not include EE/DSM programs
*DPL DE MWh forecast includes the impact of reduced load from installed solar

IX. Delmarva Power DE IRP Forecast Scenarios

Figure IX.1, below, presents the Company's forecast for the unrestricted summer peak demand for the Delmarva Power DE jurisdiction within the Delmarva Zone, including all of the scenarios. The heavy green line is the **Baseline Scenario**; it is assumed that 50% of the possible future outcomes will be above this line and 50% will be below it. The red and blue lines are the **High** and **Low**, respectively, **Economic Scenarios**. It is assumed that 10% of the possible outcomes will lie above the red line, and 10% will lie below the blue line. Finally, the purple line represents the **Extreme Weather Scenario**. Extreme Weather is represented by calculating the average and standard deviation of heating and cooling degree-days for each month of the year. In the forecast, monthly heating and cooling degree-days are set equal to their historical average plus two standard deviations.

Figure IX.1

Delmarva Power Delaware Jurisdictional Summer Peak Demand (MW)

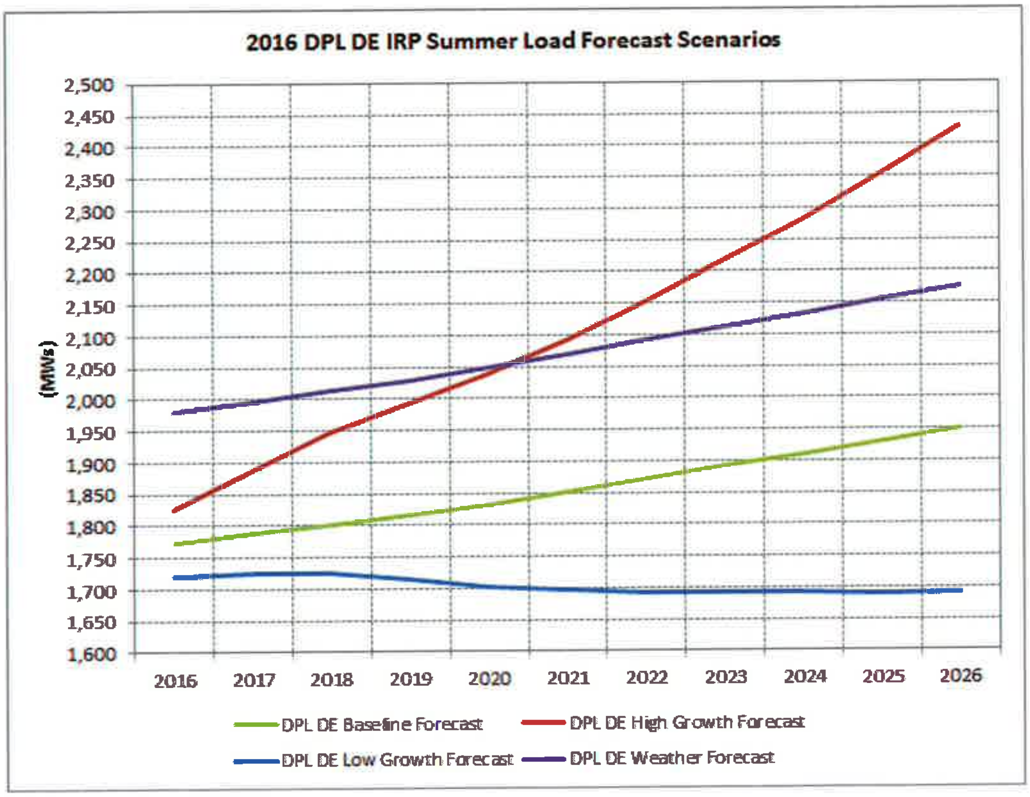
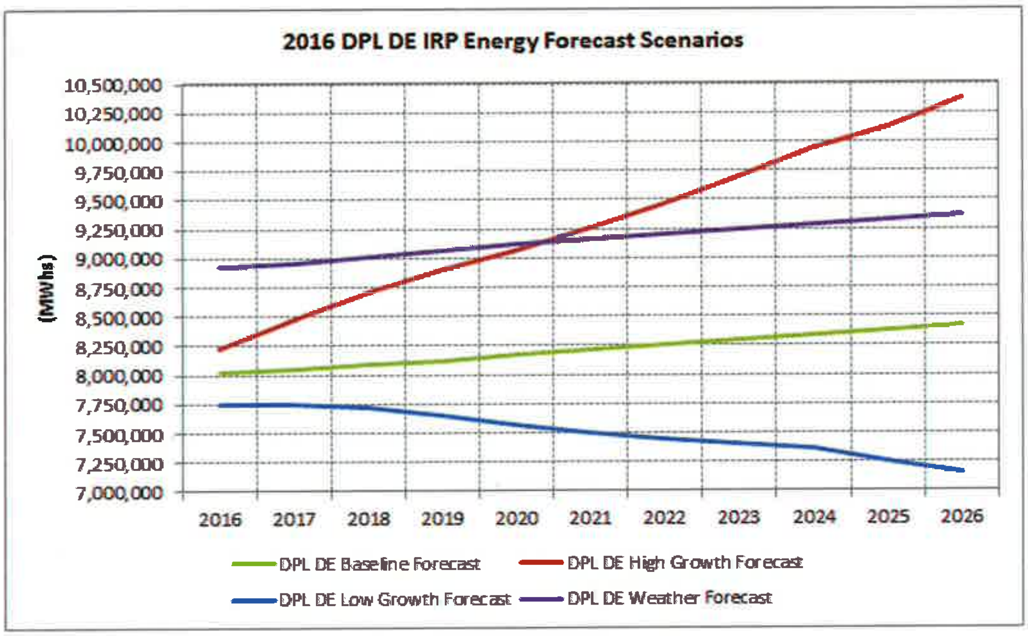


Figure IX.2, below, illustrates energy throughput for the Delmarva Power DE jurisdiction within the Delmarva Zone, the amount of annual energy required to serve all Delmarva Power DE customers, inclusive of all losses and self-use, for these same four scenarios.

Figure IX.2

Delmarva Power DE Jurisdictional Energy Throughput (MWh)

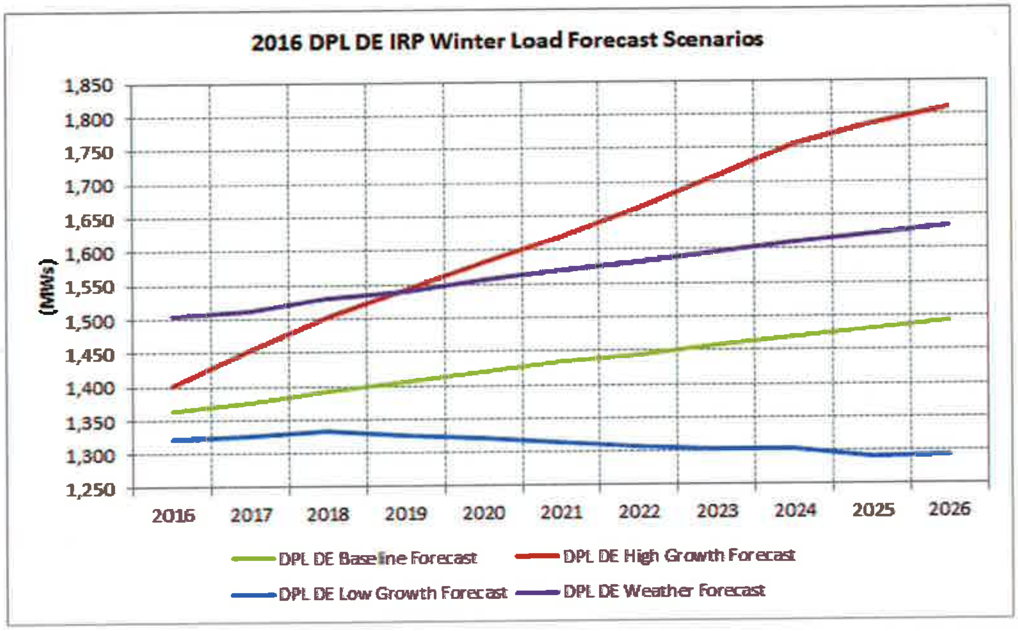


Finally, Figure IX.3, below, displays the Delmarva Power DE unrestricted winter peak forecast for each of the scenarios. These scenarios are constructed symmetrically to the ones provided in Figure IX.1.

Figure IX.3

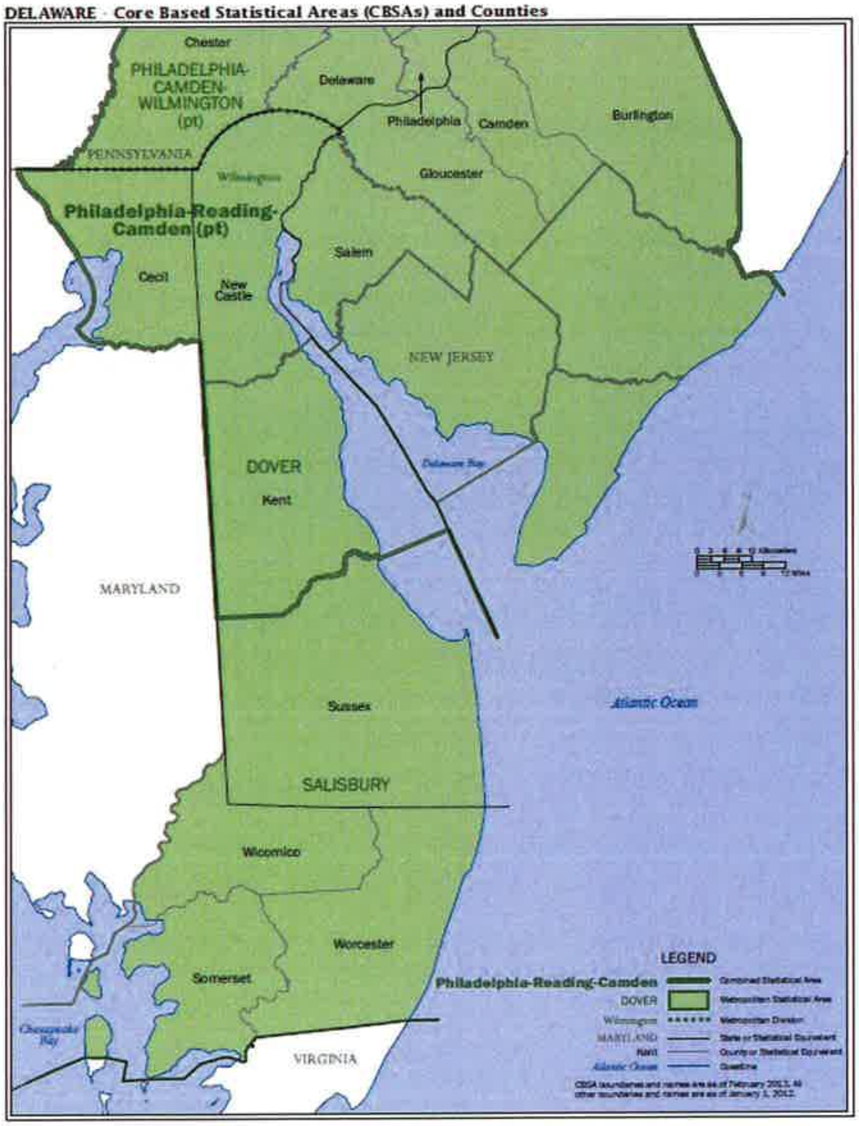
Delmarva Power Delaware Jurisdictional Winter

Peak Demand (MW)



Appendix A: Delaware Metropolitan Statistical Areas Map

DELAWARE - Core Based Statistical Areas (CBSAs) and Counties



U.S. DEPARTMENT OF COMMERCE Economics and Statistics Administration U.S. Census Bureau

Appendix B: IHS Global Insight Delaware Economic

Delaware

Troy Walters, Senior Economist I

At a glance

Employment growth in Delaware continued to accelerate in the early months of 2016. Nonfarm payrolls climbed 2.7% year over year (y/y) in the first quarter, considerably outpacing the nation, which added 1.9%. Much of the pickup came from the professional and business services sector, which added 3.7%, a far bigger increase than recent quarters. The leisure and hospitality services sector, which was already expanding rapidly, sped up again, adding 7.1%. Construction payrolls also accelerated, jumping 5.4%. The factory sector continued its strong run, adding another 3.1%. All told, job gains over the past year have pushed the unemployment rate down to 4.4%, its lowest level since May 2008.

Issues to watch

- DuPont, one of both the state's and the nation's oldest companies, has recently announced that nearly a quarter of employees located within the state will be let go. After confirming its merger with Dow, DuPont has highlighted a restructuring plan for 2016 that will require 10% of its global workforce to be laid off. Specific to Delaware, the company will eliminate 1,700 positions in the beginning of the year.

- AstraZeneca, which has over 2,000 employees in Delaware, recently announced that it will be making reductions to its global workforce. The company has yet to reveal the number and location of those cuts, but they do have the potential to significantly impact its payrolls in Delaware.

Near-term developments

We expect Delaware's good labor market fortunes to continue this year, when payroll gains will be 2.6%, largely in line with the solid performance in 2015. With the exception of wholesale trade and government, all sectors of the state economy will add jobs this year. The services sectors and construction will remain the leaders in job creation. The factory sector will slow from its strong showing last year, but remain solid, adding 2.1%.

Outlook

Although Delaware's pace of payroll expansion will outpace the nation slightly this year, we expect labor market growth in the medium-term to largely mirror the US rate. Over the next five years, nonfarm payroll gains in the state will grow at an average annual pace of 1.3%. Services and construction will remain the main drivers of growth over this period. The sizable finance sector will continue to expand in 2016, but will average only 0.3% gains through 2020.

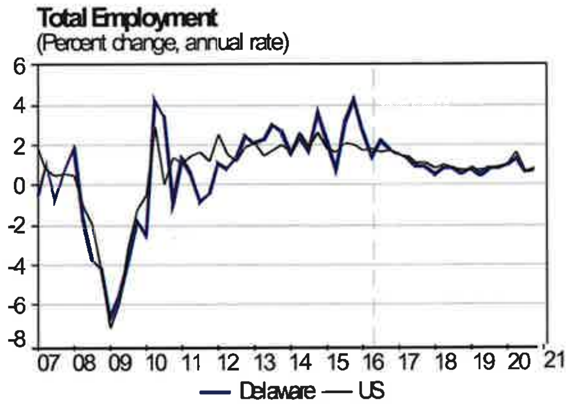
Strengths

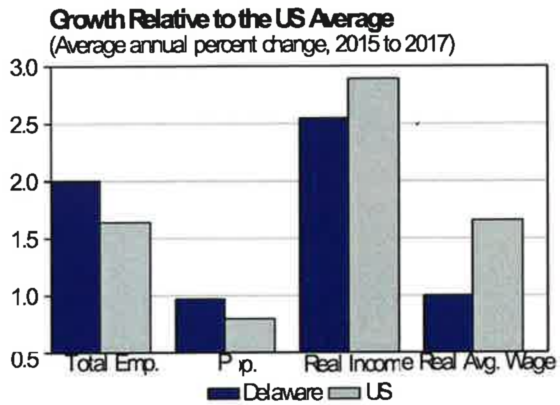
- Although Delaware needs to diversify its economic structure further, the increasing diversification that occurred during the late 1990s buffered the state from the pro-cyclical employment declines that it has suffered in past downturns in the manufacturing sector. The state is less dependent on a few cyclical sectors (autos, chemicals, pharmaceuticals, and

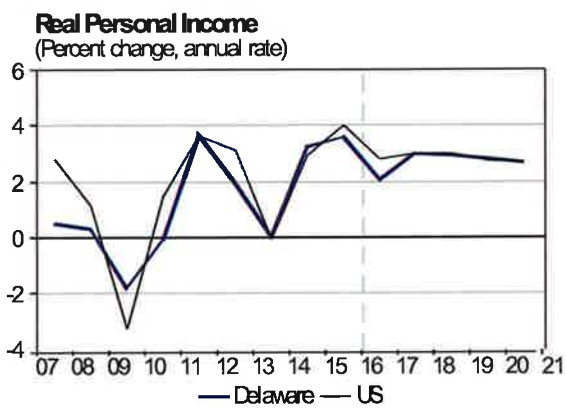
Economic Performance Summary
Delaware

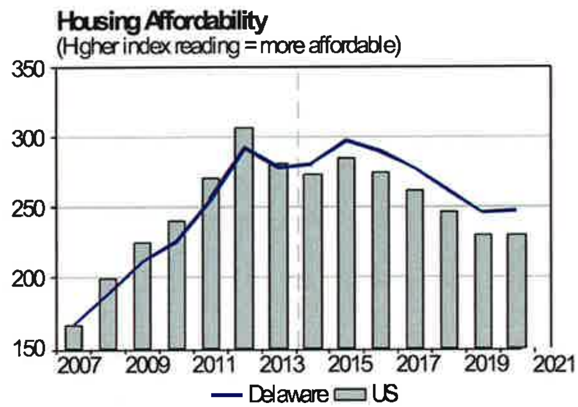
	Level				Annual Percent Change					
	2016	Rank	2021	Rank	2014 - 2016	Rank	2016-2018	Rank	2018 - 2021	Rank
Total Employment (Ths.)	460.3	46	482.9	46	2.4	13	1.1	20	0.8	23
Manufacturing	27.8	44	28.5	44	3.1	2	0.3	27	0.6	29
Non-manufacturing	432.5	46	454.5	46	2.4	14	1.2	21	0.9	22
Population (Ths.)	956.6	45	1001.6	45	1.0	15	0.9	16	0.9	13
Labor Force (Ths.)	480.9	45	512.7	45	3.0	1	1.6	9	1.1	10
Unemployment Rate (%)	4.6	21	5.1	33						
Housing Starts (Ths.)	5.0	38	5.6	39	0.7	40	3.9	42	1.3	36
Personal Income (Billions)	46.4	45	59.2	45	3.5	35	5.0	20	5.0	22
Per Capita Income (Ths.)	48.5	22	59.1	22	2.4	42	4.0	40	4.0	47
Avg. Ann. Wage (Ths.)	53.8	15	64.8	17	0.7	49	3.7	33	3.8	37

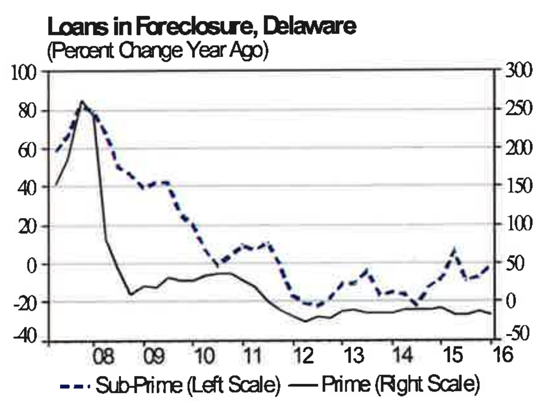
Note: Rankings are out of 50 states and the District of Columbia
Source: IHS


Total Employment
(Percent change, annual rate)
6
4
2
0
-2
-4
-6
-8
07 08 09 10 11 12 13 14 15 16 17 18 19 20 21
Delaware — US


Growth Relative to the US Average
(Average annual percent change, 2015 to 2017)
3.0
2.5
2.0
1.5
1.0
0.5
Total Emp.
Pop.
Real Income
Real Avg. Wage
Delaware US


Real Personal Income
(Percent change, annual rate)
6
4
2
0
-2
-4
07 08 09 10 11 12 13 14 15 16 17 18 19 20 21
Delaware — US


Housing Affordability
(Higher index reading = more affordable)
350
300
250
200
150
2007 2009 2011 2013 2015 2017 2019 2021
Delaware US


Loans in Foreclosure, Delaware
(Percent Change Year Ago)
100
80
60
40
20
0
-20
-40
300
250
200
150
100
50
0
-50
08 09 10 11 12 13 14 15 16
Sub-Prime (Left Scale) — Prime (Right Scale)

financial services) that are affected by a decline in national investment.

Weaknesses

- Delaware had great success during the 1990s in attracting new financial services firms with the passage of several progressive tax and incorporation laws. Nevertheless, because of consolidation in the financial-activities sector, along with continued productivity growth driven by IT investments that are increasing the capital/labor ratio, this sector will not be as big an employment driver going forward as it was during the 1990s.

- Delaware has one of the lowest percentages of native-born residents among US states. Young people continue to flee the state in search of better employment opportunities. Such a brain-drain will make the state a less-attractive location despite the otherwise business-friendly regulatory environment.

Business climate

- As demand continues to increase across the nation for organic poultry, particularly chicken, Perdue has looked to its Milford factory to support the expansion, adding 10,000 square feet and 350 jobs in 2014. The plant currently employs about 1,500 employees and ships out about 600,000 organic chickens a week for sale at supermarkets. This industry is only expected to keep growing.

- JP Morgan Chase announced the purchase of the AstraZeneca 58-acre campus in Wilmington for $44 million. The company plans to move jobs to the location, although it is unclear if they will be additions or relocations. JP Morgan currently owns two buildings in downtown Wilmington and a location in Newark combining for around 8,800 total jobs in Delaware.

- Poultry producer Allen Harim will purchase the former Pinnacle Foods plant in Millboro to expand domestic operations and employ 700 new workers. The expansion, along with the new jobs, will come to Sussex County in November 2014.

- AstraZeneca, the global pharmaceuticals company, is preparing to cut 1,200 jobs from its Wilmington payrolls, half of which are being relocated to Maryland, as the company looks to globally restructure in hopes of building a leaner organization. The company, while now headquartered in Cambridge, England, will retain about 2,000 employees and keep Wilmington as its North American headquarters.

Real estate and construction

While the recession certainly hit the Delaware housing market, the results have been rather modest compared with losses across the country. Housing starts have fallen roughly three-fold since highs in 2004-05, but were relatively stable over 2010-11, ranging from 2,500 to 3,500 annually over that period. In 2014, however, housing starts picked up to average 4,700 for the year—a clear indication of improvement. Housing prices experienced a slow, gradual slide from the third quarter of 2007 through the third quarter of 2010 before shooting up at the end of the year, according to the Federal Housing Finance Agency. Purchase-only prices increased 5.3% year over year in the first quarter of 2015, a boost over a dismal end to 2014, though prices decelerated in the second quarter, only increasing 1.8% y/y. IHS expects prices to climb gradually back to prerecession levels by the end of 2018.

Delaware outlook over the next four quarters

		Baseline Scenario			Pessimistic			Optimistic		
		Level	Percent	Rank	Level	Percent	Rank	Level	Percent	Rank
Year-over-year change (2017Q2)										
	Employment	+7,553	+1.6	15	+3,729	+0.8	11	+9,095	+2.0	16
	Personal income (mil.$)	+2,240	+4.8	17	+2,289	+4.9	17	+2,535	+5.5	17
	Real gross state product (mil. 2009$)	+1,669	+2.8	11	+404	+0.7	9	+2,036	+3.4	14
Level (2017Q2)										
	Unemployment rate (%)	4.5		31	5.2		31	4.2		33
	Housing starts	5,283		39	4,850		39	5,548		39

Source: IHS

Profile

Labor force and demographics

In 2014, Delaware was the 45th-largest state by population. From 2013 to 2014, the state's total population increased 1.0% to 935,700, ahead of the national growth rate (0.8%), making Delaware the 16th-fastest growing state. Delaware experienced a net influx of 2,400 new residents from foreign countries, while net domestic in-migration was just over 3,000 in 2013. Total net in-migration was about 5,400.

Export performance

In 2014, Delaware's export merchandise value slipped by 0.9% from the previous year, totaling nearly $5.3 billion. Chemicals remain, by far, the largest export product category and as of 2014, accounted for 40.3% of total exports, approximately a $2.1-billion value. While chemicals exports increased 16.8% over 2013, computer and electronic products jumped 30.5% over the prior year, yet still only account for 18.3% of total exports. The next leading export industries are transportation equipment ($522 million) and machinery ($292 million), both of which took hits in comparison to 2013 (down 27.9% and 26.0%, respectively). Belgium remains the top destination for Delaware's goods and services, followed by Canada and the United Kingdom.

High tech

The Information Technology & Innovation Foundation has recently ranked Delaware second in its 2014 State New Economy Index, which measures indicators such as knowledge jobs, the digital economy, and innovation capacity. The foundation highlights business-friendly corporate law and industry investment in research and development (R&D) as the main drivers of the ranking. Delaware also offers an R&D tax credit at both the state and federal level, which generally amounts to twice the amount given in other states.

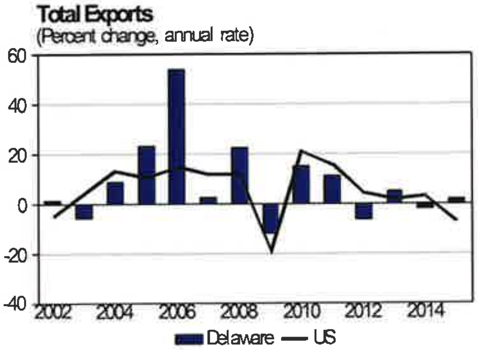
Manufacturing

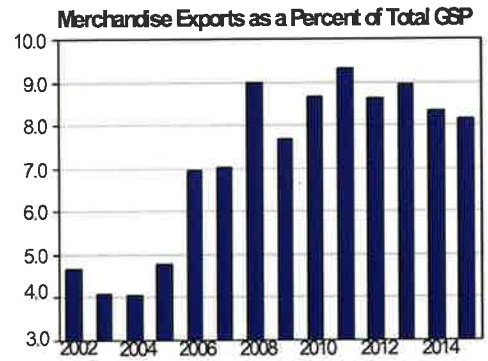
The downfall of automobile manufacturing in Delaware

Delaware's manufacturing sector has suffered a serious setback as a result of the recent troubles in the automobile industry. Initially, higher oil prices in 2005 and 2006 led to a decline in demand for relatively less fuel-efficient cars. Oil prices remained high, and actually rose further in 2007 and 2008. General Motors (GM) and Chrysler lagged behind in developing fuel-efficient new models, and the market response led both companies into financial difficulties. The national economic recession exacerbated the situation. Chrysler implemented major production adjustments in 2006, and announced a restructuring plan in February 2007 that included closing its Newark, Delaware plant by 2009. The Chrysler plant was closed in December 2008. GM emerged from bankruptcy in June 2009 and announced its decision to close its Boxwood Road Assembly plant in Newport, Delaware. That plant was closed in July 2009.

The automobile manufacturing industry was once the second-largest employer in Delaware after DuPont, with 10,000 workers on payroll in 1985. These recent troubles with GM and Chrysler have cost the state's manufacturing sector about 5,000 direct jobs over the past few years. This has induced further losses in other sectors of the economy, resulting in an estimated 3,000 additional jobs lost because of indirect and induced effects. A permanent negative impact is that the state economy has lost more than $350 million in gross state product and about $450 million in personal income annually. While the negative impact is significant, though, it is not substantial enough to derail Delaware's economic growth. Delaware ranks high on the list of knowledge- and-innovation-based state economies, and therefore the state fits well in the modern global economic sphere. The private-services-producing sector will remain buoyant and will help the state maintain above-average economic growth.

Export Trends





Economic Structure

Business Monitor for Delaware

Employment Growth (2016:1-2018:1)	* * *
Per Capita Personal Income (2015)	* * *
Avg. Unemp. Rate (2016:1-2018:1)	* * *
Economic Diversity Index (2015)	* *
High-Tech Concentration (2015)	* * *
Housing Affordability (2015)	* *

Top (* * * * *)
Above Average (* * * *)
Average (* * *)
Below Average (* *)
Bottom (*)

Note: For definitions, please see appendix at back of book.
Source: IHS

Key Industries in Delaware (Employment, Thousands)

	2015 Level	2015 Share (%)**
Total Manufacturing	27.2	6.1
Food	9.2	34.0
Chemicals	3.8	13.9
Transportation Equip	0.6	2.1
Trade, Transp, & Util	81.3	18.1
Educational & Health	75.3	16.8
Government	65.4	14.6
Professional & Business	59.8	13.3
Leisure & Hospitality	49.0	10.9
Financial Activities	46.6	10.4

** The Manufacturing sector shares are of Total Manufacturing
** All other shares are of Total Employment
Source: IHS

Economic structure

The main sectors driving the Delaware economy are food processing, chemicals (including pharmaceuticals), financial services, and professional and business services. Manufacturing accounted for 5.8% of Delaware's total employment in 2014, down from 10.0% as recently as 2000, and is projected to gradually decline, remaining below 6.0% through 2020.

Since the founding of the DuPont Company in Wilmington during the early 1800s, chemicals have dominated Delaware's industrial production. Biotechnology and pharmaceuticals are today's growth industries; however, global competition and industry restructuring are diminishing chemicals' role in the state economy. The Port of Wilmington supports transportation and distribution services, aiding development of various manufacturing industries. Kraft-General Foods is one of Delaware's leading employers, and the state has also become a center for international fruit and vegetable trade and poultry production.

In the 1980s, Delaware passed legislation that continues to attract numerous financial services companies to the state, particularly banks and credit card companies; the resulting emergence of a financial services cluster is shown in the figure below, where the bar for the Financial Activities sector is well above 150. In fact, it has the highest concentration of employment in the financial activities sector among the 50 states, at 10.5% of all nonfarm jobs, compared with the national share of less than 6.0%. Connecticut and New York trail behind Delaware, each accounting for 7.6% of their state's economy. About 60% of Delaware financial activities sector employment was found in the credit card sector. The first- and third-largest U.S. credit card issuers—JPMorgan Chase and MBNA (now Bank of America)—which together control more than 30% of the U.S. market (with 140 million credit cards in circulation) are located in Wilmington. Other companies with credit card operations in Wilmington include Discover and Juniper.

Short Term Outlook for Delaware
May 2016 Forecast

	2015:2	2015:3	2015:4	2016:1	2016:2	2016:3	2016:4	2015	2016	2017	2018	2019
Establishment Employment (Place of Work, Thousands)												
Total Non-Agricultural	446.3	449.7	454.4	457.3	458.9	461.4	463.4	448.9	460.3	467.1	470.8	474.2
Pct. Ch. Ann. Rate	0.7	3.1	4.2	2.6	1.4	2.2	1.8	2.4	2.5	1.5	0.8	0.7
Manufacturing	27.1	27.3	27.5	27.8	27.8	27.8	27.8	27.2	27.8	27.9	28.0	28.1
Pct. Ch. Ann. Rate	1.5	3.0	2.5	5.4	-1.1	0.1	0.8	4.1	2.1	0.4	0.3	0.6
Durables	9.3	9.4	9.4	9.5	9.5	9.5	9.5	9.4	9.5	9.6	9.6	9.7
Transportation Equip.	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.7
Nondurables	17.8	17.9	18.1	18.4	18.3	18.3	18.3	17.9	18.3	18.3	18.4	18.4
Food Manufacturing	9.1	9.2	9.4	9.5	9.5	9.5	9.6	9.2	9.5	9.7	9.8	9.9
Non-Manufacturing	419.2	422.4	426.9	429.5	431.1	433.7	435.6	421.7	432.5	439.2	442.9	446.1
Pct. Ch. Ann. Rate	0.7	3.1	4.4	2.5	1.5	2.4	1.8	2.3	2.6	1.6	0.8	0.7
Construction & Mining	20.8	21.2	21.6	21.6	22.0	22.4	22.7	21.0	22.2	23.4	24.1	24.7
Pct. Ch. Ann. Rate	6.0	7.2	8.5	0.0	7.1	7.6	6.2	2.8	5.5	5.6	3.1	2.1
Trade, Trans., & Utilities	81.0	81.7	81.9	82.2	82.6	82.9	83.2	81.3	82.7	83.6	83.2	83.0
Pct. Ch. Ann. Rate	1.7	3.2	1.3	1.1	1.9	1.9	1.4	2.1	1.7	1.0	-0.4	-0.3
Wholesale Trade	11.9	11.8	11.8	11.8	11.8	11.8	11.9	11.8	11.8	11.9	12.0	12.2
Retail Trade	52.7	52.8	52.9	53.2	53.6	53.9	54.1	52.8	53.7	54.2	53.4	52.8
Trans. & Warehousing	14.3	14.9	15.0	15.0	15.0	15.0	15.1	14.5	15.0	15.3	15.6	15.8
Utilities	2.2	2.1	2.3	2.2	2.2	2.2	2.2	2.2	2.2	2.1	2.1	2.1
Information	4.7	4.7	4.8	4.8	4.9	4.9	4.9	4.7	4.9	4.8	4.8	4.8
Pct. Ch. Ann. Rate	-2.1	-4.5	8.2	5.0	4.7	3.0	-0.7	-3.9	3.2	-1.6	-0.4	1.4
Financial Activities	46.4	46.9	47.0	46.7	46.9	47.2	47.1	46.6	47.0	47.1	47.1	47.1
Pct. Ch. Ann. Rate	1.2	4.1	0.9	-2.6	2.1	2.3	-0.7	3.6	0.7	0.3	0.0	0.1
Finance & Insurance	41.1	41.6	41.6	41.3	41.5	41.7	41.6	41.3	41.5	41.6	41.5	41.5
Real Estate & Rental	5.3	5.3	5.4	5.4	5.4	5.5	5.5	5.4	5.4	5.5	5.6	5.6
Prof. & Business Svcs.	58.8	59.2	61.1	62.1	61.9	62.4	63.1	59.8	62.4	64.9	66.7	67.6
Pct. Ch. Ann. Rate	-6.9	2.7	13.7	6.5	-1.4	3.7	4.6	0.9	4.4	4.0	2.7	1.3
Prof, Scientific, & Tech	28.5	28.4	28.6	28.6	28.2	28.3	28.3	28.5	28.3	28.2	28.2	28.4
Management	4.7	4.8	4.7	4.7	4.7	4.8	4.8	4.8	4.8	4.9	5.1	5.2
Admin & Waste Svcs	25.6	26.0	27.8	28.8	29.0	29.3	30.0	26.5	29.3	31.8	33.5	34.0
Educ & Health Services	75.3	75.6	76.0	76.9	77.2	77.6	78.4	75.3	77.5	79.1	79.9	81.1
Pct. Ch. Ann. Rate	4.6	1.6	2.1	5.0	1.5	2.4	3.7	3.5	2.9	2.0	1.1	1.5
Educational Services	8.0	8.1	8.3	8.4	8.4	8.4	8.4	8.1	8.4	8.3	8.3	8.2
Health Care	67.3	67.5	67.7	68.5	68.8	69.2	70.0	67.2	69.1	70.8	71.7	72.9
Leisure & Hospitality	48.5	49.1	50.2	51.4	52.0	52.3	52.3	49.0	52.0	52.7	53.0	53.4
Pct. Ch. Ann. Rate	4.3	5.3	9.3	9.6	4.4	2.4	0.2	4.1	6.1	1.4	0.7	0.7
Arts, Entrtnmnt, & Rec	10.1	10.1	10.4	10.5	10.7	10.8	10.8	10.1	10.7	10.8	10.8	10.9
Accom & Food Svcs	38.4	39.0	39.9	40.9	41.3	41.5	41.5	38.8	41.3	41.9	42.2	42.5
Other Services	18.7	18.6	18.5	18.6	18.7	18.7	18.7	18.6	18.7	18.5	18.5	18.5
Pct. Ch. Ann. Rate	2.2	-0.7	-2.1	1.4	1.4	1.0	-0.6	0.1	0.3	-0.6	-0.1	0.0
Government	65.0	65.5	65.8	65.3	65.2	65.2	65.2	65.4	65.2	65.2	65.5	65.9
Pct. Ch. Ann. Rate	-2.6	3.1	1.9	-3.0	-0.7	0.3	0.0	0.9	-0.3	0.0	0.4	0.7
Federal	5.4	5.7	5.5	5.7	5.7	5.7	5.7	5.5	5.7	5.7	5.6	5.5
State & Local	59.6	59.8	60.2	59.6	59.5	59.5	59.5	59.9	59.5	59.5	59.9	60.5
Resident Employment & Unemployment (Thousands)												
Total Employment	442.7	446.1	449.6	455.8	458.3	460.1	461.8	444.4	459.0	466.1	472.5	477.6
Pct. Ch. Ann. Rate	3.3	3.2	3.2	5.6	2.2	1.6	1.5	3.9	3.3	1.6	1.4	1.1
Labor Force	465.4	469.1	472.6	477.6	479.6	482.1	484.2	467.3	480.9	489.0	496.2	502.4
Labor Force Partic Rate	61.0	61.2	61.5	62.0	62.1	62.2	62.4	61.1	62.2	62.6	62.8	63.0
Number Unemployed	22.7	22.9	23.0	21.8	21.3	22.0	22.4	22.9	21.9	22.9	23.7	24.8
Unemployment Rate	4.9	4.9	4.9	4.6	4.4	4.6	4.6	4.9	4.6	4.7	4.8	4.9
Other Economic Indicators												
CPI (Pct. Ch. Ann. Rate)	3.9	-0.9	0.4	-1.4	1.6	2.0	3.5	-0.6	0.6	2.6	2.7	2.9
Retail Sales (Bil $)	16.1	16.2	16.2	16.1	16.4	16.6	16.8	16.1	16.5	17.3	18.2	19.0
Personal Cons Exp (Bil $)	40.3	40.7	41.1	41.3	41.8	42.2	42.8	40.5	42.1	44.1	46.3	48.7
New Car Regis. (Ths)	54.2	57.0	52.4	51.5	53.6	54.2	54.2	53.1	53.3	54.9	55.4	54.6
Mfg. Ship. (Bil 82$)	10.8	10.9	10.9	10.8	10.8	10.8	10.9	10.8	10.8	11.0	11.1	11.3

Source: IHS

Short Term Outlook for Delaware
May 2016 Forecast

	2015:2	2015:3	2015:4	2016:1	2016:2	2016:3	2016:4	2015	2016	2017	2018	2019
Personal Income (Billions $)												
Total Personal Income	45.1	45.3	45.6	45.8	46.2	46.6	47.2	45.1	46.4	48.7	51.2	53.8
Pct. Ch. Ann. Rate	6.0	1.5	3.0	1.6	4.0	3.3	5.0	3.9	3.0	4.8	5.1	5.1
Real Personal Income	40.8	40.8	41.1	41.2	41.5	41.8	42.0	40.8	41.6	42.9	44.2	45.4
Pct. Ch. Ann. Rate	3.8	0.2	2.6	1.3	2.6	2.6	2.6	3.6	2.1	3.0	3.0	2.8
Real Disposable Income	36.1	36.1	36.4	36.4	36.7	36.9	37.2	36.1	36.8	37.9	39.2	40.3
Real Per Capita Income (Ths)	43.1	43.0	43.2	43.3	43.4	43.6	43.8	43.1	43.5	44.4	45.3	46.2
Med. Household Income (Ths)	61.1	61.4	61.8	62.0	62.5	62.9	63.4	61.1	62.7	64.9	67.2	69.6
Avg. Annual Wage (Ths)	53.7	53.1	53.1	53.3	53.5	53.9	54.4	53.2	53.8	55.7	57.9	60.1
By Place of Work												
Wages and Salaries	24.4	24.3	24.5	24.8	25.0	25.3	25.6	24.3	25.2	26.4	27.7	28.9
Manufacturing	1.8	1.7	1.7	1.8	1.8	1.8	1.8	1.7	1.8	1.8	1.9	2.0
Construction & Mining	1.2	1.2	1.2	1.3	1.3	1.3	1.4	1.2	1.3	1.4	1.5	1.6
Trade, Trans., & Utilities	3.3	3.4	3.4	3.4	3.4	3.5	3.5	3.3	3.5	3.6	3.8	4.0
Information	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3
Financial Activities	4.2	4.2	4.2	4.2	4.2	4.3	4.4	4.1	4.3	4.5	4.7	4.9
Prof & Business Svcs.	4.5	4.3	4.4	4.5	4.5	4.5	4.6	4.4	4.5	4.8	5.1	5.4
Educ & Health Services	3.7	3.7	3.8	3.8	3.9	3.9	4.0	3.7	3.9	4.1	4.4	4.6
Leisure & Hospitality	1.0	1.1	1.1	1.1	1.1	1.2	1.2	1.1	1.1	1.2	1.3	1.3
Other Services	0.6	0.6	0.6	0.6	0.7	0.7	0.7	0.6	0.7	0.7	0.7	0.7
Government	3.4	3.4	3.4	3.4	3.4	3.4	3.4	3.4	3.4	3.5	3.6	3.7
Other Labor Income	6.1	6.0	6.1	6.1	6.2	6.3	6.3	6.1	6.2	6.5	6.8	7.1
Less: Social Insurance	3.8	3.8	3.8	3.8	3.9	3.9	3.9	3.8	3.9	4.1	4.3	4.5
By Place of Residence												
Residence Adjustment	-2.4	-2.3	-2.4	-2.4	-2.4	-2.5	-2.5	-2.4	-2.4	-2.6	-2.7	-2.8
Property Income	7.5	7.6	7.6	7.7	7.7	7.7	7.7	7.5	7.7	7.9	8.4	9.0
Proprietor's Income	4.5	4.5	4.4	4.3	4.3	4.3	4.4	4.5	4.3	4.5	4.7	4.9
Farm Proprietor	0.6	0.5	0.5	0.3	0.3	0.2	0.2	0.6	0.2	0.2	0.2	0.2
Business Proprietor	3.9	3.9	4.0	4.0	4.1	4.1	4.2	3.9	4.1	4.3	4.5	4.7
Transfer Payments	8.8	9.0	9.0	9.1	9.3	9.4	9.6	8.9	9.4	9.9	10.5	11.1
Real Gross State Product, NAICS Based (Billions 2009$)												
Total GSP	58.2	58.3	58.6	58.6	58.9	59.4	59.9	58.1	59.2	60.8	62.1	63.3
Pct. Ch. Ann. Rate	5.7	1.0	2.0	-0.1	1.7	3.4	3.4	2.2	1.8	2.8	2.1	1.9
Agriculture	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.7
Manufacturing	4.0	4.1	4.1	4.0	4.1	4.1	4.1	4.1	4.1	4.3	4.4	4.5
Mining	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Construction	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.8	1.8	1.8
Trade, Trans., & Util.	6.4	6.4	6.4	6.4	6.5	6.5	6.5	6.4	6.5	6.6	6.7	6.9
Information	2.2	2.2	2.2	2.3	2.3	2.3	2.4	2.2	2.3	2.4	2.6	2.8
Financial Activities	23.3	23.2	23.4	23.5	23.7	24.0	24.2	23.2	23.8	24.7	25.3	25.7
Prof. & Business Svcs.	6.8	6.9	6.9	6.9	6.9	7.0	7.0	6.8	6.9	7.2	7.5	7.7
Educ & Health Services	4.6	4.7	4.7	4.7	4.7	4.8	4.8	4.6	4.8	4.9	4.9	4.9
Leisure & Hospitality	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7
Other Services	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8
State & Local Govt.	4.8	4.8	4.8	4.7	4.7	4.6	4.6	4.8	4.7	4.6	4.5	4.5
Federal Govt.	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7
Housing												
Total Housing Starts (Ths)	4.9	5.8	5.1	5.7	4.7	4.7	4.9	5.2	5.0	5.2	5.4	5.5
Single-Family (Ths)	4.2	4.6	4.5	5.0	4.3	4.3	4.5	4.3	4.5	4.6	4.8	4.9
Multi-Family (Ths)	0.7	1.2	0.6	0.7	0.4	0.4	0.4	0.9	0.5	0.5	0.6	0.6
New Median Price ($)	368302	393001	366173	389971	380774	378272	375221	375365	381060	382391	373851	366357
Unit Sales, Existing (Ths)	12.7	13.4	12.5	12.5	12.7	13.0	13.1	12.6	12.8	13.1	13.1	12.9
Existing Median Price ($)	235683	241136	237859	237985	244289	249589	246585	237185	244612	252310	258056	263644
Population (Thousands)												
Total Population	945.9	948.4	950.8	953.2	955.5	957.8	960.0	947.1	956.6	965.7	974.7	983.8
Pct. Ch. Ann. Rate	1.1	1.0	1.0	1.0	1.0	1.0	0.9	1.1	1.0	0.9	0.9	0.9
Under 14 years	170.4	170.5	170.6	170.7	170.9	171.0	171.2	170.5	171.0	171.7	172.6	173.5
15 to 24 years	123.1	123.1	123.2	123.3	123.5	123.6	123.7	123.1	123.5	124.0	124.6	125.3
25 to 44 years	237.3	238.0	238.6	239.2	239.9	240.5	241.1	237.6	240.2	242.5	244.7	246.9
45 to 64 years	254.9	255.0	255.1	255.1	255.1	255.1	255.1	254.9	255.1	255.0	254.8	254.6
65 years and over	160.3	161.8	163.3	164.7	166.1	167.6	169.0	161.0	166.9	172.5	178.0	183.5
Net Migration	1.9	1.8	1.8	1.7	1.7	1.6	1.5	7.3	6.5	6.2	6.3	6.3
Households	366.7	367.7	368.8	369.8	370.9	371.9	372.9	367.3	371.4	375.7	380.8	386.1

Source: IHS

Wilmington, DE-MD-NJ

David Iaia, Director, Economics

At a glance

Services bolstering Wilmington payrolls

Wilmington payrolls expanded modestly through 2015, yet finished strongly, growing 1.6% year over year (y/y) in the fourth quarter; this is on the heels of 2.3% and 1.8% growth in 2013 and 2014, respectively. Professional and business services led the charge, tacking on 3.9% to payrolls, while financial services, traditionally a major part of the Wilmington economy due to its prevalence in the area and typically high salaries, added a negligible 0.2% y/y. Education and health services, also a leader in payroll growth, expanded 2.3% y/y. After a mediocre year in 2014, the construction sector finished 2015 quite robustly, tacking on nearly 8.0% to payrolls. Manufacturing continued to drag on the economy, posting another consecutive quarter of loss (down 1.5% y/y), while information remained even over the prior year. The jobless rate fell to 4.9% in December, just below Delaware and the nation, both reporting 5.0% unemployment in December.

Issue to watch

- DuPont, one of both the state's and nation's oldest companies, has recently announced that nearly one-quarter of employees located within the state will be let go. After confirming its merger with Dow, DuPont has highlighted a restructuring plan for 2016 that will require 10% of its global workforce to be laid off. Specific to Delaware, the company will eliminate 1,700 positions in the beginning of the year. Many of the noted jobs are located in the Wilmington metropolitan area.

Near-term developments

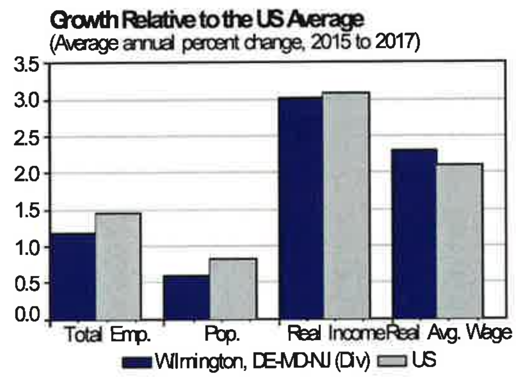
Wilmington's job growth will keep pace through 2016, adding between 0.8% and 2.0% each quarter, year over year. Professional/business services, as well as construction, will provide a boost to payrolls, but manufacturing will continue to decelerate. As a result, 2016 is expected to finish the year with about 1.6% payroll growth overall.

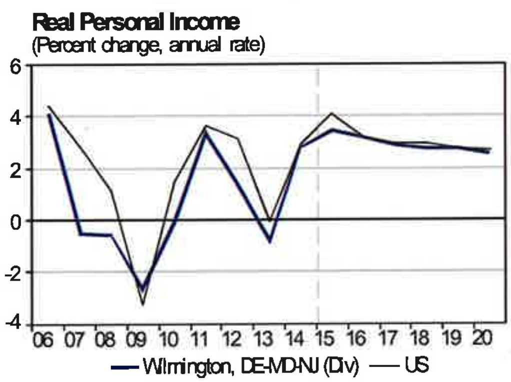
Outlook

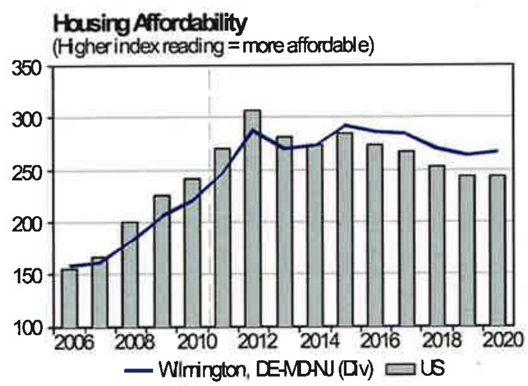
Average annual growth rate drops below 1%

The Wilmington economy will see quite modest job growth over the 2016-21 forecast period, averaging just 0.8% growth each year. The small construction sector will register the most robust gains thanks to pent-up demand, averaging 3.1% annual job growth. Services will be pillars of growth over the same period, with professional/business services and education/health services leading the charge.


Total Employment
(Percent change, annual rate)
4
2
0
-2
-4
-6
06 07 08 09 10 11 12 13 14 15 16 17 18 19 20
Wilmington, DE-MD-NJ (Div) — US


Growth Relative to the US Average
(Average annual percent change, 2015 to 2017)
3.5
3.0
2.5
2.0
1.5
1.0
0.5
0.0
Total Emp.
Pop.
Real Income
Real Avg. Wage
Wilmington, DE-MD-NJ (Div)
US


Real Personal Income
(Percent change, annual rate)
6
4
2
0
-2
-4
06 07 08 09 10 11 12 13 14 15 16 17 18 19 20
Wilmington, DE-MD-NJ (Div) — US


Housing Affordability
(Higher index reading = more affordable)
350
300
250
200
150
100
2006 2008 2010 2012 2014 2016 2018 2020
Wilmington, DE-MD-NJ (Div)
US

Age Distribution
(Percent of population, 2014)

	Wilmington	Delaware	United States	Average Annual Percent Change 2010-14	Average Annual Percent Change 2015-19
0-24	32.8	31.9	33.2	-0.5	-0.2
25-34	13.4	13.0	13.6	1.8	0.8
35-44	12.7	12.0	12.8	-1.7	0.6
45-54	15.1	14.2	13.8	-0.2	-0.3
55-64	12.6	13.1	12.4	2.3	1.2
65+	13.5	15.9	14.1	2.7	
	2.6				

Source: IHS Economics

Population Characteristics
(Percent of total population, 2014)

	Wilmington	Delaware	United States
High School Diploma *	88.7	88.3	86.6
Higher Education **	36.7	37.4	37.7
Foreign-Born	8.7	8.3	13.1
Non-U.S. Citizen	4.8	4.6	7.0
Median Household Income	62,139	57,846	52,250

*Population over 25 years of age
** Associate's, Bachelor's, or Advanced Degree
Source: American Community Survey

Key employers

The largest Wilmington employers include:

Bank of America (MBNA) (Financial Services)
The DuPont Company (Chemicals Manufacturing)
Christiana Health Care System (Health Care)
JPMorgan Chase & Co. (financial services)
University of Delaware (Educational Services)
AstraZeneca (bio-chemical mfg. and pharmaceuticals)
First USA/Bank One Corp. (Financial Services)
Christiana School District (Education)
DaimlerChrysler (Automotive Manufacturing)
Citigroup (Financial Services)
Alfred I. DuPont Hospital for Children (healthcare)
General Motors (Automotive Manufacturing)
Wilmington Trust (Financial Services)
PNC Financial Services (Financial Services)
Red Clay Consolidated School District (Education)
First USA Bank (Financial Services)

Wilmington, DE-MD-NJ Metropolitan Division - Employment Structure						
	2006		2016		2026	
	Share of Total	Location Quotient (U.S. Avg = 100)	Share of Total	Location Quotient (U.S. Avg = 100)	Share of Total	Location Quotient (U.S. Avg = 100)
Construction, Natural Resources, and Mining	5.9%	102	4.4%	89	5.8%	97
Manufacturing	7.2%	66	5.8%	65	5.4%	66
Trade, Transportation, and Utilities	18.9%	97	17.7%	93	16.2%	90
Information	1.8%	78	1.4%	70	1.6%	73
Financial Activities	11.3%	184	11.7%	205	11.0%	214
Professional and Business Services	16.6%	135	15.6%	114	17.8%	111
Education and Health	12.7%	98	16.8%	110	17.3%	113
Leisure and Hospitality	8.2%	85	8.7%	82	8.2%	82
Other Services	4.2%	104	4.5%	116	4.1%	118
Government	13.2%	79	13.3%	83	12.6%	80

Source: IHS

Economic structure

Since the founding of the DuPont Company in Wilmington in 1802, local manufacturing activity has centered on chemicals and pharmaceuticals. After General Motors and Chrysler shut down their automobile plants in the Wilmington area, manufacturing's share of the local economy's job base declined from 9.0% in 2000 to 5.4% in 2010. Chemicals remain the major component in manufacturing. The prominent sectors in the Wilmington MSA economy are trade, transportation, and utilities (18.2% share), education and health services (17.1% share), professional and business services (15.1%), government (13.4%), and financial activities (12.1%).

In recent years, a number of biomedical firms have been attracted into the metropolitan statistical area (MSA) largely because of the region's existing cluster of medical and chemical facilities, the high share of the labor force possessing scientific training, and the research and development (R&D) capabilities of both local businesses and academic institutions. The importance of R&D activities to the state and Wilmington's economy is revealed by the fact that, according the Delaware Development Office, Delaware ranks first in the nation in number of patents granted per 100,000 residents and in R&D spending per capita.

Because of its location, especially its close proximity to the New York, Baltimore, Philadelphia, and Washington DC metro markets, along with its excellent transportation connections, Wilmington is becoming increasing desirable as a location for regional distribution centers. The added Wal-Mart distribution facility in Newark confirms this competitive advantage.

The state's fiscal conservatism has created a business climate with one of the lowest tax burdens in the nation, no sales tax, and no property tax on machinery and equipment. This has been particularly attractive to financial service providers, notably banks and credit card companies, who have flocked to the area.

Short Term Outlook for Wilmington, DE-MD-NJ
February 2016 Forecast

	2014:4	2015:1	2015:2	2015:3	2015:4	2016:1	2016:2	2016:3	2016:4	2017:1	2017:2
Personal Income (Billions $)											
Total Personal Income	35.5	35.7	36.2	36.6	37.1	37.3	37.6	37.9	38.3	38.8	39.3
Pct Chg Year Ago	0.4	0.5	1.4	1.2	1.1	0.6	0.8	0.9	1.0	1.3	1.3
Wages and Salaries	20.8	20.7	21.1	21.3	21.8	22.0	22.2	22.4	22.6	22.9	23.2
Nonwage Income	14.6	14.9	15.1	15.3	15.3	15.3	15.4	15.5	15.7	15.9	16.1
Real Personal Income (09$)	31.5	31.8	32.1	32.4	32.8	33.0	33.2	33.4	33.5	33.9	34.1
Pct Chg Year Ago	0.5	1.0	0.8	1.0	1.1	0.8	0.6	0.5	0.4	1.0	0.8
Per Capita Income (Ths.)	49.2	49.4	50.0	50.5	51.0	51.3	51.6	52.0	52.4	53.0	53.6
Real Per Capita Income (09$)	43.6	44.0	44.3	44.7	45.1	45.4	45.6	45.8	45.9	46.3	46.6
Median Household Income (Ths)	63.6	62.7	63.8	64.6	65.4	65.7	66.1	66.7	67.2	67.8	68.6
Pct Chg Year Ago	0.0	-1.3	1.7	1.3	1.1	0.5	0.6	0.8	0.8	1.0	1.1
Establishment Employment (Place of Work, Thousands, SA)											
Total Employment	350.7	350.6	351.2	352.1	356.4	356.1	357.3	358.6	359.1	359.9	360.6
Pct Chg Year Ago	0.6	0.0	0.2	0.3	1.2	-0.1	0.3	0.4	0.1	0.2	0.2
Manufacturing	17.9	17.8	17.5	17.5	17.6	17.5	17.5	17.5	17.5	17.5	17.5
Pct Chg Year Ago	-0.5	-0.5	-1.6	-0.2	0.8	-0.9	-0.1	0.0	0.3	0.2	0.0
Nonmanufacturing	332.8	332.8	333.7	334.6	338.8	338.6	339.9	341.2	341.6	342.3	343.0
Pct Chg Year Ago	0.7	0.0	0.3	0.3	1.2	0.0	0.4	0.4	0.1	0.2	0.2
Construction & Mining	16.0	16.1	16.1	16.6	17.2	17.4	17.7	18.0	18.3	18.5	18.8
Pct Chg Year Ago	1.6	1.0	-0.4	3.6	3.3	1.2	1.5	2.1	1.5	1.3	1.2
Trade, Trans, & Utilities	63.6	63.5	64.0	64.3	64.3	64.3	64.4	64.6	64.6	64.6	64.6
Pct Chg Year Ago	-0.5	-0.1	0.7	0.5	0.1	-0.1	0.2	0.2	0.1	0.0	0.0
Wholesale Trade	10.1	9.9	9.7	9.6	9.6	9.6	9.6	9.7	9.7	9.7	9.7
Retail Trade	36.1	35.9	36.5	36.2	36.0	36.0	36.0	36.1	36.1	36.0	35.9
Trans, Whsng, & Util	17.5	17.7	17.8	18.5	18.7	18.7	18.7	18.8	18.9	18.9	19.0
Information	4.1	4.0	4.0	3.9	4.1	4.1	4.1	4.1	4.1	4.2	4.1
Pct Chg Year Ago	-1.5	-2.6	0.2	-1.2	3.7	0.2	0.3	1.1	-0.4	2.1	-2.5
Financial Activities	42.4	42.7	42.4	42.1	42.4	42.7	42.9	42.8	42.7	42.6	42.5
Pct Chg Year Ago	1.2	0.7	-0.7	-0.7	0.8	0.5	0.5	-0.1	-0.3	-0.3	-0.1
Prof & Business Services	53.5	53.5	53.2	53.6	55.6	54.8	54.9	55.3	55.8	56.3	56.7
Pct Chg Year Ago	1.3	-0.1	-0.5	0.7	3.8	-1.5	0.1	0.8	0.9	0.9	0.6
Educ & Health Services	59.4	59.4	59.9	59.6	60.8	61.0	61.3	61.7	61.9	62.0	62.3
Pct Chg Year Ago	0.7	0.0	0.9	-0.6	2.0	0.5	0.4	0.6	0.3	0.3	0.4
Leisure & Hospitality	33.1	33.1	33.4	34.1	33.7	33.8	34.1	34.1	34.1	34.1	34.2
Pct Chg Year Ago	1.8	0.1	0.7	2.1	-1.0	0.1	1.0	0.1	0.0	0.0	0.3
Other Services	13.8	13.6	13.8	13.5	13.3	13.3	13.4	13.3	13.3	13.2	13.2
Pct Chg Year Ago	-0.7	-1.3	0.8	-1.8	-1.3	0.2	0.1	-0.4	-0.2	-0.4	-0.2
Federal Government	5.2	5.3	5.3	5.3	5.3	5.3	5.2	5.2	4.7	4.7	4.7
Pct Chg Year Ago	-0.1	1.3	1.5	-1.6	0.7	-0.5	-0.6	-0.5	-10.0	0.2	0.1
State & Local Government	41.8	41.6	41.7	41.7	42.0	41.9	42.0	42.0	42.0	41.9	41.9
Pct Chg Year Ago	0.7	-0.5	0.4	0.0	0.7	-0.1	0.0	0.0	0.0	-0.1	-0.1
Other Economic Indicators											
Gross Metro Product (09$ Mil)	51026.6	51089.2	51799.5	51993.2	52298.3	52500.8	52965.7	53518.8	53917.5	54239.3	54616.2
Population (Ths)	721.9	723.0	724.0	725.2	726.3	727.4	728.4	729.6	730.6	731.8	732.9
Pct Chg Year Ago	0.1	0.1	0.1	0.2	0.2	0.2	0.1	0.2	0.1	0.2	0.1
Labor Force (Ths)	368.8	370.8	373.4	374.2	379.4	382.0	383.7	385.4	386.8	388.0	389.1
Percent Change, Year Ago	0.3	0.5	0.7	0.2	1.4	0.7	0.5	0.4	0.4	0.3	0.3
Unemployment Rate (%)	5.5	5.0	5.1	5.1	5.2	5.1	5.1	5.1	5.1	5.2	5.2
Total Housing Starts	2180.1	1838.0	1933.9	2337.3	1589.1	1619.1	1676.5	1841.5	2081.3	2254.0	2423.6
Single-Family	1589.0	1404.4	1491.2	1439.4	1361.3	1404.5	1457.7	1615.7	1835.7	1979.1	2114.1
Multifamily	591.0	433.7	442.7	897.9	227.7	214.6	218.8	225.8	245.6	274.9	309.6
Retail Sales	11348.2	11198.4	11402.6	11553.7	11521.5	11492.6	11628.3	11840.8	12076.7	12179.5	12339.4

Source: IHS

Long Term Outlook for Wilmington, DE-MD-NJ
February 2016 Forecast

	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Personal Income (Billions $)											
Total Personal Income	33.6	33.7	35.1	36.4	37.8	39.5	41.5	43.5	45.6	47.7	49.9
Pct Chg Year Ago	3.2	0.2	4.2	3.7	3.8	4.7	4.9	4.9	4.8	4.6	4.5
Wages and Salaries	19.3	19.8	20.6	21.2	22.3	23.3	24.3	25.4	26.6	27.8	29.0
Nonwage Income	14.2	13.9	14.5	15.1	15.5	16.2	17.1	18.1	19.0	19.9	20.9
Real Personal Income (09$)	30.6	30.3	31.2	32.3	33.3	34.2	35.2	36.2	37.1	38.0	38.8
Pct Chg Year Ago	1.4	-0.8	2.8	3.4	3.2	2.9	2.8	2.7	2.6	2.4	2.3
Per Capita Income (Ths.)	47.1	47.0	48.7	50.2	51.8	53.9	56.2	58.6	61.0	63.4	65.9
Real Per Capita Income (09$)	42.9	42.3	43.3	44.5	45.7	46.7	47.7	48.7	49.6	50.5	51.3
Median Household Income (Ths)	62.1	63.4	63.4	64.1	66.4	68.9	71.5	74.1	76.8	79.6	82.6
Pct Chg Year Ago	-0.1	2.1	0.1	1.1	3.6	3.7	3.8	3.7	3.6	3.7	3.8
Establishment Employment (Place of Work, Thousands, SA)											
Total Employment	334.2	341.9	348.0	352.6	357.8	360.9	363.5	366.2	369.4	371.9	374.4
Pct Chg Year Ago	0.8	2.3	1.8	1.3	1.5	0.9	0.7	0.8	0.9	0.7	0.7
Manufacturing	18.6	18.4	18.0	17.6	17.5	17.5	17.6	17.7	17.8	17.8	17.8
Pct Chg Year Ago	0.9	-1.4	-2.0	-2.2	-0.8	0.4	0.3	0.4	0.4	0.4	-0.1
Nonmanufacturing	315.6	323.5	330.0	335.0	340.3	343.4	345.9	348.5	351.6	354.1	356.6
Pct Chg Year Ago	0.8	2.5	2.0	1.5	1.6	0.9	0.7	0.8	0.9	0.7	0.7
Construction & Mining	15.0	15.5	15.7	16.5	17.8	18.8	19.5	20.1	20.5	20.9	21.1
Pct Chg Year Ago	-2.6	2.9	1.7	5.0	8.2	5.6	3.6	2.7	2.3	1.7	1.2
Trade, Trans, & Utilities	60.3	62.0	63.5	64.0	64.5	64.6	64.3	64.2	64.1	63.9	63.7
Pct Chg Year Ago	1.9	2.8	2.4	0.8	0.7	0.2	-0.5	-0.2	-0.2	-0.2	-0.3
Wholesale Trade	10.7	10.5	10.3	9.7	9.7	9.7	9.8	9.9	10.0	10.1	10.2
Retail Trade	35.4	36.0	36.3	36.1	36.0	35.9	35.2	34.9	34.7	34.6	34.4
Trans, Whsng, & Util	14.1	15.6	17.0	18.2	18.8	19.0	19.3	19.3	19.3	19.2	19.1
Information	4.7	4.4	4.1	4.0	4.1	4.1	4.1	4.2	4.3	4.4	4.5
Pct Chg Year Ago	-4.1	-6.7	-6.5	-3.9	3.1	-0.5	0.1	2.8	1.9	2.8	2.3
Financial Activities	38.8	40.4	41.6	42.4	42.8	42.5	42.2	42.0	42.2	42.3	42.4
Pct Chg Year Ago	0.1	3.9	3.2	1.8	0.9	-0.6	-0.8	-0.3	0.3	0.3	0.3
Prof & Business Services	50.6	51.9	52.8	54.0	55.2	56.9	58.3	59.3	60.7	61.9	63.3
Pct Chg Year Ago	1.9	2.6	1.8	2.3	2.3	3.0	2.5	1.8	2.3	1.9	2.3
Educ & Health Services	55.2	57.2	58.9	59.9	61.5	62.3	62.9	63.8	64.6	65.4	66.1
Pct Chg Year Ago	2.3	3.8	3.0	1.7	2.6	1.3	1.0	1.5	1.3	1.2	1.1
Leisure & Hospitality	31.3	32.2	32.6	33.6	34.0	34.3	34.6	34.9	35.0	35.3	35.3
Pct Chg Year Ago	-0.2	2.8	1.4	2.9	1.4	0.7	1.0	0.7	0.5	0.6	0.2
Other Services	13.9	13.9	13.9	13.6	13.3	13.2	13.2	13.2	13.1	13.1	13.0
Pct Chg Year Ago	-0.1	0.4	-0.6	-2.2	-1.7	-0.9	-0.1	-0.1	-0.4	-0.5	-0.6
Federal Government	4.8	5.0	5.2	5.3	5.1	4.7	4.7	4.6	4.8	4.6	4.6
Pct Chg Year Ago	-1.4	4.3	3.6	1.7	-3.6	-7.7	-0.5	-0.9	3.1	-3.2	-0.1
State & Local Government	40.9	41.0	41.6	41.7	42.0	41.9	42.1	42.3	42.3	42.5	42.6
Pct Chg Year Ago	-0.5	0.2	1.3	0.4	0.5	-0.1	0.4	0.4	0.2	0.4	0.3
Other Economic Indicators											
Gross Metro Product (09$ Mil)	50008.2	49470.7	50952.3	51795.0	53225.7	54755.2	55936.5	57086.1	58350.7	59645.2	61004.4
Population (Ths)	713.9	716.9	720.5	724.6	729.0	733.4	737.9	742.8	747.8	752.5	756.7
Pct Chg Year Ago	0.5	0.4	0.5	0.6	0.6	0.6	0.6	0.7	0.7	0.6	0.6
Labor Force (Ths)	362.2	360.4	366.3	374.5	384.5	389.6	393.7	397.5	401.1	403.2	405.2
Percent Change, Year Ago	0.2	-0.5	1.6	2.2	2.7	1.3	1.1	1.0	0.9	0.5	0.5
Unemployment Rate (%)	7.6	7.0	5.9	5.1	5.1	5.2	5.3	5.4	5.4	5.5	5.5
Total Housing Starts	1421.2	1685.1	1950.6	1924.6	1804.6	2520.4	3020.7	3186.8	3376.5	3344.9	3370.8
Single-Family	1030.8	1169.0	1434.1	1424.1	1578.4	2200.9	2598.9	2732.4	2887.1	2865.5	2902.6
Multifamily	390.4	516.1	516.5	500.5	226.2	319.4	421.9	454.4	489.4	479.4	468.3
Retail Sales	10512.4	10843.8	11258.8	11419.1	11759.6	12411.8	13011.5	13592.2	14162.4	14732.0	15334.6

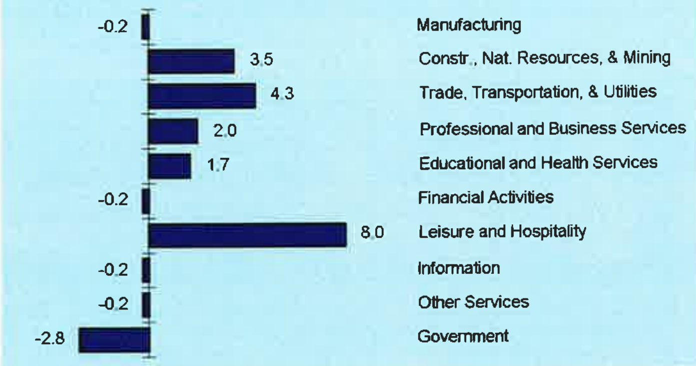
Source: IHS

22 Aug 2016 IHS Economics and Country Risk

Analysis: At a glance

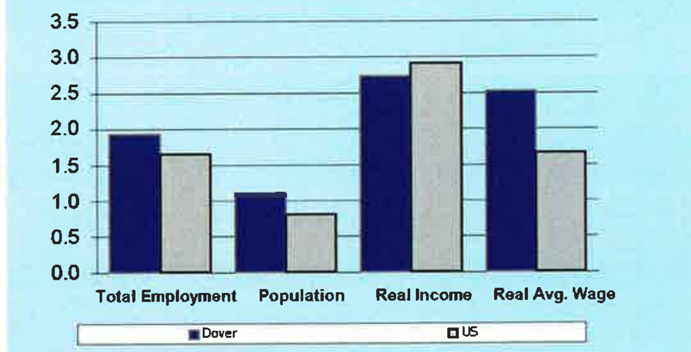
Employment by sector

(Percent change from a year earlier, June 2016)



Growth relative to the US average

(Average annual percent, 2015 to 2017)

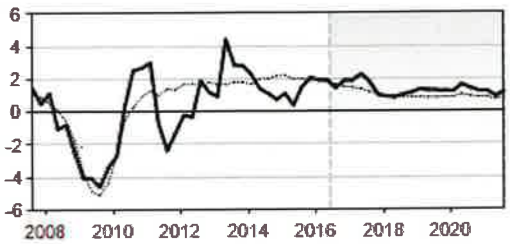


Personal Income Indicators

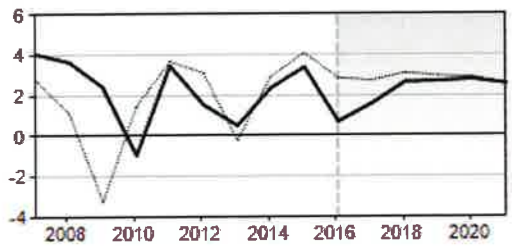
	2012	2013	2014	2015	2016	2017	2018	2019
Per Capita Personal Income (Thous . $)	36.7	36.8	38.1	39.2	39.5	40.4	41.8	43.2
Per Capita Personal Income (% change)	1.6	0.5	3.5	2.9	0.7	2.4	3.3	3.5
Average Annual Wage (Thous. $)	39.5	39.6	40.9	41.7	41.9	42.9	44.4	45.8
Average Annual Wage (% change)	3.8	0.3	3.4	1.8	0.5	2.3	3.6	3.2
Total Personal Income (Mil. $)	6,154	6,254	6,555	6,813	6,933	7,173	7,505	7,864
Total Personal Income (% change)	3.0	1.6	4.8	3.9	1.8	3.5	4.6	4.8
Wage Disbursements (Mil. $)	2,728	2,810	2,936	3,023	3,090	3,213	3,361	3,509
Wage Disbursements (% change)	4.5	3.0	4.5	3.0	2.2	4.0	4.6	4.4
Nonwage Income (Mil. $)	3,426	3,444	3,619	3,790	3,842	3,960	4,144	4,355
Nonwage Income (% change)	1.8	0.5	5.1	4.7	1.4	3.1	4.7	5.1

Outlook

Total Employment
(Quarterly change, compound annual rate)



Real Personal Income
(Percent change, annual rate)

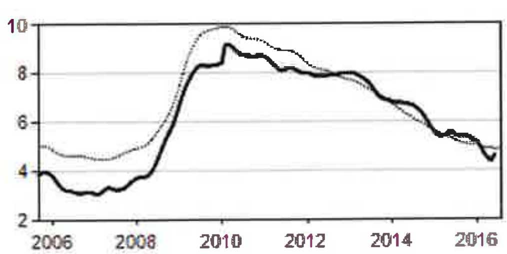


Economic Key Indicators

	2012	2013	2014	2015	2016	2017	2018	2019
Real Gross Metro Product (Mil. 2009 $)	5,983	5,951	6,046	6,205	6,299	6,427	6,512	6,643
Real Gross Metro Product (% change)	-1.8	-0.5	1.6	2.6	1.5	2.0	1.3	2.0
Total Employment (Thous.)	64.6	66.4	67.3	68.2	69.4	70.6	71.3	72.2
Total Employment (% change)	0.6	2.7	1.4	1.3	1.8	1.7	1.0	1.3
Manufacturing Employment (Thous.)	4.5	4.7	4.7	4.8	4.8	4.8	4.8	4.9
Nonmanufacturing Employment (Thous.)	60.2	61.7	62.6	63.4	64.6	65.8	66.5	67.3
Population (Thous.)	167.8	169.7	172.0	173.8	175.6	177.5	179.7	181.9
Population (% change)	1.4	1.1	1.3	1.1	1.0	1.1	1.3	1.2
Unemployment Rate (%)	7.9	7.4	6.4	5.4	4.8	4.9	4.9	4.8
Personal Income (% change)	3.0	1.6	4.8	3.9	1.8	3.5	4.6	4.8
U.S. ECONOMY								
Real Gross Domestic Product (% change)	2.2	1.7	2.4	2.6	1.6	2.4	2.4	2.2
Employment (% change)	1.7	1.6	1.9	2.1	1.7	1.2	0.8	0.8

Business climate

Unemployment Rate
(Percent)

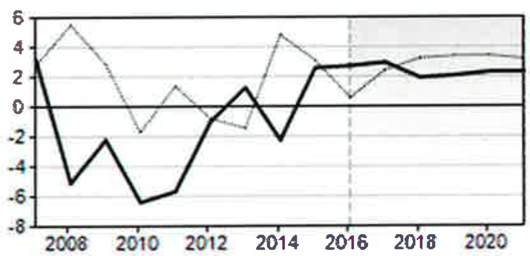


Real estate and construction

Real Estate Key Indicators

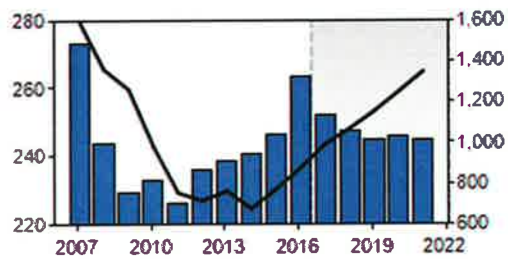
	2012	2013	2014	2015	2016	2017	2018	2019
CONSTRUCTION ACTIVITY								
Housing Starts, Total Private	863	911	946	1,036	1,326	1,135	1,056	1,009
Housing Starts, Total Private (% change)	22.2	5.5	3.8	9.5	28.0	-14.4	-7.0	-4.4
Single-Family Units	685	815	905	856	1,222	1,061	922	857
Multi-Family Units	179	96	40	180	104	73	133	153
PRICES AND SALES								
Home Price, Existing Average ($)	226,890	229,724	224,535	230,284	236,505	243,437	248,083	253,164
Home Sales, Existing Single-Family Units (Thous.)	1.9	2.2	2.1	2.3	2.4	2.4	2.5	2.5
Home Sales, Existing Single-Family Units (% change)	11.4	13.6	-2.3	8.0	3.2	1.6	2.0	-0.5

Home Prices vs. Average Household Income
(Percent change, annual rate)



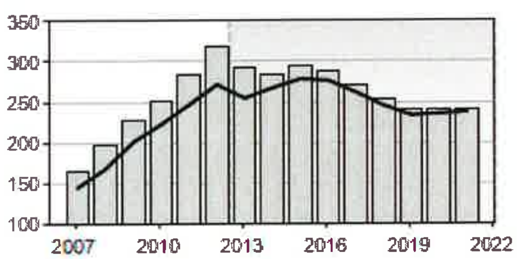
— Existing Home. Average Price
······ Average Houshold Income

Home Prices vs. Housing Starts
(Thousands)



Total Housing Starts (Right scale, units)
— Avg. Existing Home Price (Left scale, thous. $)

Housing Affordability
(Higher index reading = more affordable)



U.S. — Dover, DE

Profile: Economic structure

Dover - Employment structure

	2006		2016		2026	
	Share of total	Location quotient (US avg = 100)	Share of total	Location quotient (US avg = 100)	Share of total	Location quotient (US avg = 100)
Construction, Natural Resources, and Mining	5.6%	92	4.7%	91	5.2%	86
Manufacturing	7.2%	70	6.9%	81	6.5%	81
Trade, Transportation, and Utilities	21.1%	110	19.9%	106	22.2%	125
Information	1.1%	47	0.6%	30	0.6%	28
Financial Activities	4.3%	71	2.4%	42	2.3%	46
Professional and Business Services	5.9%	46	6.0%	43	6.2%	38
Education and Health	12.5%	94	14.7%	93	14.9%	94
Leisure and Hospitality	11.1%	115	12.4%	116	12.7%	123
Other Services	3.6%	91	3.9%	99	3.4%	95
Government	27.6%	170	28.6%	184	26.1%	172

Labor force and demographics

Personal Income Indicators

	2012	2013	2014	2015	2016	2017	2018	2019
Per Capita Personal Income (Thous. $)	36.7	36.8	38.1	39.2	39.5	40.4	41.8	43.2
Per Capita Personal Income (% change)	1.6	0.5	3.5	2.9	0.7	2.4	3.3	3.5
Average Annual Wage (Thous. $)	39.5	39.6	40.9	41.7	41.9	42.9	44.4	45.8
Average Annual Wage (% change)	3.8	0.3	3.4	1.8	0.5	2.3	3.6	3.2
Total Personal Income (Mil. $)	6,154	6,254	6,555	6,813	6,933	7,173	7,505	7,864
Total Personal Income (% change)	3.0	1.6	4.8	3.9	1.8	3.5	4.6	4.8
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Wage Disbursements (% change)	4.5	3.0	4.5	3.0	2.2	4.0	4.6	4.4
Nonwage Income (Mil. $)	3,426	3,444	3,619	3,790	3,842	3,960	4,144	4,355
Nonwage Income (% change)	1.8	0.5	5.1	4.7	1.4	3.1	4.7	5.1

Age distribution

	Percent of population, 2014			Average annual percent change	
	Dover	Delaware	United States	2010-14	2015-19
0-24	34.1	31.4	32.9	0.1	0.9
25-34	13.2	13.2	13.6	2.9	0.8
35-44	11.6	11.8	12.7	-0.6	2.1
45-54	13.2	13.9	13.6	-0.6	-0.5
55-64	12.3	13.3	12.6	3.0	1.3
65+	15.6	16.4	14.5	4.8	3.9

Source: IHS Economics

Population characteristics (percent of total population, 2014)

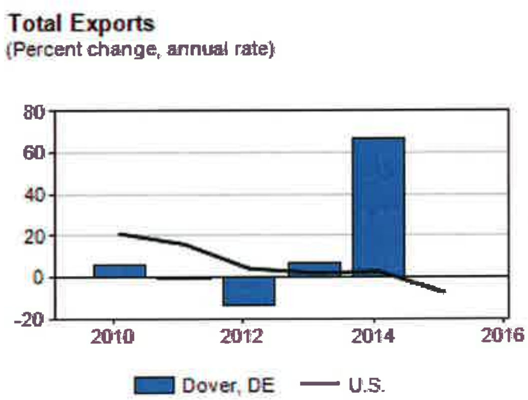
	Dover	Delaware	United States
High school diploma *	88.1	89.0	86.9
Higher education **	33.1	38.5	38.2
Foreign-born	5.0	8.6	13.3
Non-US citizen	1.8	4.4	7.0
Median household income	55,227	59,716	53,657

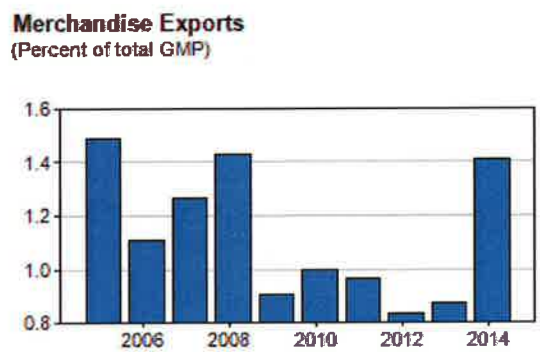
*Population over 25 years of age

** Associate's, Bachelor's, or Advanced Degree

Source: American Community Survey

Export performance





High-tech

Dover: High-tech employment

NAICS	2006	Employment level (Total jobs) 2016	2026	Average annual Percent change 2006-16	2016-26
3254 Pharmaceutical & medicine mfg.	-	17	18	--	0.6
3336 Turbine & power transmission Eq.	-	-	-	--	--
3341 Computer & peripheral eq. mfg.	-	-	-	--	--
3342 Communications eq. mfg.	2	2	4	0.0	7.2
3343 Audio & video eq. mfg.	-	-	-	--	--
3344 Semiconductor & comp. mfg.	-	-	-	--	--
3345 Electronic instrument mfg.	-	-	-	--	--
3346 Magnetic media mfg.	-	-	-	--	--
3353 Electrical equipment	27	-	-	--	--
3363 Motor vehicle parts mfg.	-	-	-	--	--
3364 Aerospace product & parts mfg.	-	-	-	--	--
3391 Medical eq. & supplies mfg.	291	554	776	6.7	3.4
5112 Software publishers	12	11	18	-0.9	5.0
5121 Motion picture & video industries	26	44	58	5.4	2.8
5122 Sound recording industries	1	1	5	0.0	17.5
5182 Data processing and hosting	7	19	27	10.5	3.6
5413 Architectural, engin. & related svcs.	263	527	681	7.2	2.6
5414 Specialized design services	5	6	13	1.8	8.0
5415 Computer systems design & svcs.	194	232	176	1.8	-2.7
5416 Management consulting services	131	136	143	0.4	0.5
5417 Scientific research & dev. svcs.	6	113	103	34.1	-0.9
8112 Elec. & precision eq. repair & maint.	10	9	13	-1.0	3.7
Metro Total	**975**	**1,671**	**2,035**	**5.5**	**2.0**
Delaware Total	**23,999**	**25,655**	**28,986**	**0.7**	**1.2**
US Total	**8,356,834**	**9,403,480**	**10,947,747**	**1.2**	**1.5**

Note: 50% of motor vehicle parts is used in the analysis.
Source: US Business Markets Insights, IHS Economics

Forecast Data: Quarterly Data

Annual Data

Core Summary Tables

Analyst Contact Details: Troy Walters

Appendix C: WN Factor Table

	2016	2015	CDD65 2014	2013	2012
RES	199,959.45	193,774.98	214,279.94	233,613.40	228,962.80
RSH	60,029.71	59,997.20	65,983.25	83,928.59	75,754.91
COM	132,584.35	141,199.64	147,008.58	151,503.70	145,881.80
DPL DE Total	392,573.51	394,971.83	427,271.78	469,045.69	450,599.51

	2016	2015	HDD65 2014	2013	2012
RES	54,245.06	54,319.71	48,028.90	45,654.50	31,500.99
RSH	83,930.48	73,563.58	90,561.99	63,060.85	67,575.75
COM	35,440.19	33,154.29	39,793.43	11,576.28	46,865.77
DPL DE Total	173,615.74	161,037.58	178,384.31	120,291.63	145,942.51

	2016	2015	HDD35 2014	2013	2012
RES	0.00	0.00	0.00	0.00	0.00
RSH	64,004.61	72,525.29	24,026.38	55,804.64	44,834.13
COM	35,667.34	29,239.75	17,480.38	80,748.22	0.00
DPL DE Total	99,671.95	101,765.04	41,506.76	136,552.86	44,834.13

Appendix D: Estimated Sales Equations

The following regressions were estimated using the EViews econometrics software package.

2016 Delmarva Power DE IRP Forecast

Delmarva Power DE Residential Non Space Heat Electric Sales

Dependent Variable: RESKWHDE

Method: Least Squares

Date: 08/23/16 Time: 16:59

Sample (adjusted): 1992M08 2015M11

Included observations: 280 after adjustments

Convergence achieved after 15 iterations

Variable	Coefficient	Std. Error	t-Statistic	Prob.
C	140429.1	14765.05	9.510916	0.0000
@MOVAV(RESPRIDE(-6)/(CPIU(-6)/CPI14)	-341976.7	98932.67	-3.456661	0.0006
BILLWFORTCDD65WLM*RESCUSDE	0.001757	4.79E-05	36.68046	0.0000
BILLWFORTHDD65WLM*RESCUSDE	0.000307	2.29E-05	13.41596	0.0000
JAN	11583.12	2123.016	5.455975	0.0000
FEB	-7379.312	2185.576	-3.376369	0.0008
APR	-3446.979	2005.037	-1.719160	0.0867
MAY	-4935.465	2088.709	-2.362926	0.0188
NOV	-5139.180	1689.867	-3.041174	0.0026
AR(1)	0.810196	0.035638	22.73399	0.0000

R-squared	0.930489	Mean dependent var	144386.6

Adjusted R-squared	0.928172	S.D. dependent var	38880.96
S.E. of regression	10420.41	Akaike info criteri	21.37598
Sum squared resid	2.93E+10	Schwarz criterion	21.50580
Log likelihood	-2982.637	Hannan-Quinn criter	21.42805
F-statistic	401.5846	Durbin-Watson stat	2.688251
Prob(F-statistic)	0.000000		

Inverted AR Roots	.81

Delmarva Power DE Residential Space Heat Electric Sales

Dependent Variable: RSHKWHDE

Method: Least Squares

Date: 08/23/16 Time: 16:59

Sample (adjusted): 1992M02 2015M11

Included observations: 286 after adjustments

Convergence achieved after 14 iterations

Variable	Coefficient	Std. Error	t-Statistic	Prob.
C	39494.05	3459.355	11.41659	0.0000

2016 Delmarva Power DE IRP Forecast

@MOVAV(RSHPRIDE/(CPIU/CPI14),1)	-110884.5	24368.85	-4.550253	0.0000
BILLWFORTCDD65WLM*RSHCUSDE	0.002007	0.000154	13.05152	0.0000
BILLWFORTHDD65WLM*RSHCUSDE	0.001404	4.16E-05	33.77406	0.0000
JAN	13532.61	1516.739	8.922174	0.0000
FEB	5117.275	1763.041	2.902527	0.0040
MAR	9565.938	1352.204	7.074331	0.0000
JUN	7761.635	1903.041	4.078543	0.0001
JUL	13011.87	3295.098	3.948857	0.0001
AUG	10990.12	3780.967	2.906697	0.0040
SEP	16361.94	2797.978	5.847772	0.0000
OCT	5223.594	1713.112	3.049185	0.0025
NOV	-4903.402	1271.220	-3.857241	0.0001
FEB00	-24129.84	5241.668	-4.603466	0.0000
AR(1)	0.352706	0.058176	6.062765	0.0000

R-squared	0.964171	Mean dependent var	82598.56
Adjusted R-squared	0.962320	S.D. dependent var	27556.80
S.E. of regression	5349.123	Akaike info criteri	20.05827
Sum squared resid	7.75E+09	Schwarz criterion	20.25002
Log likelihood	-2853.333	Hannan-Quinn criter	20.13513
F-statistic	520.9110	Durbin-Watson stat	2.102896
Prob(F-statistic)	0.000000		

Inverted AR Roots .35

Delmarva Power DE Commercial Electric Sales

Dependent Variable: COMKWHDE

Method: Least Squares

Date: 08/23/16 Time: 16:59

Sample (adjusted): 1992M05 2015M11

Included observations: 283 after adjustments

Convergence achieved after 13 iterations

Variable	Coefficient	Std. Error	t-Statistic	Prob.
C	236794.7	16826.33	14.07287	0.0000
@MOVAV(COMPRIDE(-3)/(CPIU(-3)/CPI14)	-170601.3	129711.8	-1.315233	0.1896
BILLWFORTCDD65WLM*COMCUSDE	0.006802	0.000420	16.21385	0.0000
BILLWFORTHDD65WLM*COMCUSDE	0.001385	0.000191	7.237536	0.0000
MAR00	-85158.85	11866.29	-7.176535	0.0000
MAY00	73380.05	11912.42	6.159963	0.0000
AUG00	-41271.31	13840.77	-2.981865	0.0031
OCT00	-80746.48	12418.60	-6.502060	0.0000
JUL00	66693.89	13722.20	4.860291	0.0000
JAN	13526.32	2464.090	5.489377	0.0000

MAR	4549.724	2471.430	1.840928	0.0667
JUN	11532.22	2806.230	4.109508	0.0001
JUL	11574.96	2857.011	4.051423	0.0001
SEP	22227.48	3146.272	7.064705	0.0000
OCT	17913.04	3063.341	5.847551	0.0000
AR(1)	0.902248	0.025484	35.40482	0.0000

R-squared	0.892682	Mean dependent var	259318.1
Adjusted R-squared	0.886653	S.D. dependent var	46300.96
S.E. of regression	15588.17	Akaike info criteri	22.20129
Sum squared resid	6.49E+10	Schwarz criterion	22.40739
Log likelihood	-3125.482	Hannan-Quinn criter	22.28393
F-statistic	148.0623	Durbin-Watson stat	2.795501
Prob(F-statistic)	0.000000		

Inverted AR Roots .90

Delmarva Power DE Industrial Electric Sales

Dependent Variable: INDKWHDE

Method: Least Squares

Date: 08/23/16 Time: 16:59

Sample (adjusted): 2005M02 2015M11

Included observations: 130 after adjustments

Convergence achieved after 8 iterations

Variable	Coefficient	Std. Error	t-Statistic	Prob.
C	-53333.10	16668.89	-3.199559	0.0017
@MOVAV(INDPRIDE(-1)/(CPIU/CPI14),	-59205.52	26042.98	-2.273377	0.0247
@MOVAV(MMFDE,1)	8756.720	654.6174	13.37685	0.0000
CDD65WLM*DPLDEIP	0.344988	0.109312	3.155991	0.0020
AR(1)	0.325310	0.087286	3.726929	0.0003

R-squared	0.778786	Mean dependent var	165360.0
Adjusted R-squared	0.771707	S.D. dependent var	30186.26
S.E. of regression	14423.01	Akaike info criteri	22.02874
Sum squared resid	2.60E+10	Schwarz criterion	22.13903
Log likelihood	-1426.868	Hannan-Quinn criter	22.07355
F-statistic	110.0156	Durbin-Watson stat	2.037996
Prob(F-statistic)	0.000000		

Inverted AR Roots	.33

Delmarva Power DE Public Street Light Electric Sales

2016 Delmarva Power DE IRP Forecast

Dependent Variable: PSLKWHDE

Method: Least Squares

Date: 08/23/16 Time: 16:59

Sample (adjusted): 1992M07 2015M11

Included observations: 236 after adjustments

Convergence achieved after 12 iterations

Variable	Coefficient	Std. Error	t-Statistic	Prob.
C	3026.546	331.9265	9.118121	0.0000
@MOVAV(PSLPRIDE(-3)/(CPIU(-3)/CPI14)	-1500.165	1058.881	-1.416745	0.1579
@MOVAV(PSLCUSDE(-3),3)	1.091752	1.178470	0.926415	0.3552
MAR00	1461.617	326.2046	4.480676	0.0000
FEB01	1235.803	327.2172	3.776706	0.0002
AR(1)	0.279909	0.062141	4.504392	0.0000

R-squared	0.238434	Mean dependent var	3082.076
Adjusted R-squared	0.221878	S.D. dependent var	377.9262
S.E. of regression	333.3732	Akaike info criteri	14.48150
Sum squared resid	25561674	Schwarz criterion	14.56956
Log likelihood	-1702.817	Hannan-Quinn criter	14.51700
F-statistic	14.40187	Durbin-Watson stat	2.050055
Prob(F-statistic)	0.000000		

2016 Delmarva Power DE IRP Forecast

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Inverted AR Roots .28

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Appendix E: Customer Sub-Model Econometric Equations

Residential Non-Space Heat Electric Customers

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Dependent Variable: RESCUSDE

Method: Least Squares

Date: 08/23/16   Time: 16:59

Sample (adjusted): 1991M07 2015M11

Included observations: 293 after adjustments

Convergence achieved after 9 iterations

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Variable	Coefficient	Std. Error	t-Statistic	Prob.
C	233085.1	19474.27	11.96887	0.0000
@MOVAV(METDE(-4),2)	6.347067	3.424273	1.853552	0.0649
MAR00	7164.902	228.6823	31.33125	0.0000
FEB00	-15643.45	181.9481	-85.97756	0.0000
MAY00	-5558.353	226.9081	-24.49605	0.0000
JUN00	-590.8872	179.3926	-3.293823	0.0011
APR00	-15944.42	241.0934	-66.13377	0.0000
SEP00	-1548.951	162.9784	-9.504026	0.0000
OCT00	-717.3142	162.9680	-4.401564	0.0000

JAN	148.1661	35.50491	4.173116	0.0000
FEB	114.1987	42.35940	2.695946	0.0075
MAR	93.86183	35.88066	2.615945	0.0094
SEP	-89.37056	34.93439	-2.558240	0.0111
OCT	-168.9157	40.13333	-4.208862	0.0000
NOV	-176.1614	34.42357	-5.117464	0.0000
JAN15	-3730.413	163.2524	-22.85059	0.0000
FEB15	-7657.341	163.4113	-46.85932	0.0000
JUN15	632.4667	138.8986	4.553441	0.0000
AR(1)	0.997385	0.000904	1103.783	0.0000

==

R-squared	0.999783	Mean dependent var	180670.5
Adjusted R-squared	0.999769	S.D. dependent var	12844.42
S.E. of regression	195.2775	Akaike info criteri	13.44937
Sum squared resid	10448525	Schwarz criterion	13.68801
Log likelihood	-1951.333	Hannan-Quinn criter	13.54495
F-statistic	70168.30	Durbin-Watson stat	1.478620
Prob(F-statistic)	0.000000		

==

Inverted AR Roots 1.00

==

2016 Delmarva Power DE IRP Forecast

Residential Space Heat Electric Customers

==

Dependent Variable: RSHCUSDE

Method: Least Squares

Date: 08/23/16   Time: 16:59

Sample (adjusted): 1992M02 2015M11

Included observations: 286 after adjustments

Convergence achieved after 9 iterations

==

Variable	Coefficient	Std. Error	t-Statistic	Prob.
C	91603.94	6150.869	14.89285	0.0000
@MOVAV(METDE,6)	6.936355	5.797765	1.196384	0.2326
@MOVAV(RSHPRIDE/GRSHPRICE,1)	-17847.26	6801.163	-2.624148	0.0092
FEB00	15255.99	67.12211	227.2872	0.0000
APR00	-5311.875	67.54328	-78.64402	0.0000
MAY00	-1816.931	67.55517	-26.89551	0.0000
JAN00	-488.8606	67.37209	-7.256130	0.0000
JAN15	-1429.679	67.11212	-21.30284	0.0000
FEB15	-692.2304	67.09257	-10.31754	0.0000
JUL15	-116.3670	56.84758	-2.046999	0.0416
JAN	64.49201	15.63161	4.125743	0.0000
FEB	98.65660	18.67610	5.282506	0.0000

MAR	107.3545	18.19644	5.899752	0.0000
APR	35.53903	15.04795	2.361719	0.0189
SEP	-69.37642	14.40165	-4.817255	0.0000
OCT	-72.96019	16.92096	-4.311823	0.0000
NOV	-62.60589	14.53403	-4.307537	0.0000
AR(1)	0.996832	0.000670	1487.486	0.0000

R-squared	0.999889	Mean dependent var	66966.45
Adjusted R-squared	0.999882	S.D. dependent var	7385.402
S.E. of regression	80.20068	Akaike info criteri	11.66781
Sum squared resid	1723816.	Schwarz criterion	11.89791
Log likelihood	-1650.497	Hannan-Quinn criter	11.76004
F-statistic	142147.7	Durbin-Watson stat	2.369289
Prob(F-statistic)	0.000000		

Inverted AR Roots	1.00

Commercial Electric Customers

Dependent Variable: COMCUSDE

Method: Least Squares

2016 Delmarva Power DE IRP Forecast

Date: 08/23/16 Time: 16:59

Sample (adjusted): 1991M06 2015M11

Included observations: 294 after adjustments

Convergence achieved after 8 iterations

Variable	Coefficient	Std. Error	t-Statistic	Prob.
C	47286.61	7701.422	6.139985	0.0000
@MOVAV(METDE(-2),3)	2.343197	1.104171	2.122132	0.0347
MAR00	3978.518	45.56214	87.32070	0.0000
MAY00	2419.035	63.99766	37.79881	0.0000
JUN00	2683.814	63.86480	42.02337	0.0000
JUL00	3078.375	58.28707	52.81404	0.0000
AUG00	3171.219	45.18002	70.19074	0.0000
APR00	497.6185	58.63363	8.486913	0.0000
JAN15	-713.5442	44.74843	-15.94568	0.0000
FEB15	-1240.908	56.82882	-21.83589	0.0000
MAR15	588.7501	59.90524	9.828023	0.0000
APR15	574.8856	56.30755	10.20974	0.0000
MAY15	602.8119	44.58256	13.52125	0.0000
AR(1)	0.998014	0.000799	1249.129	0.0000

R-squared	0.999826	Mean dependent var	29451.53

Adjusted R-squared	0.999818	S.D. dependent var	3613.080
S.E. of regression	48.71305	Akaike info criteri	10.65622
Sum squared resid	664429.2	Schwarz criterion	10.83163
Log likelihood	-1552.464	Hannan-Quinn criter	10.72646
F-statistic	123969.0	Durbin-Watson stat	2.220075
Prob(F-statistic)	0.000000		

==

Inverted AR Roots 1.00

==

Industrial Electric Customers

==

Dependent Variable: INDCUSDE

Method: Least Squares

Date: 08/23/16 Time: 16:59

Sample (adjusted): 1998M05 2015M11

Included observations: 211 after adjustments

Convergence achieved after 8 iterations

==

Variable	Coefficient	Std. Error	t-Statistic	Prob.
C	131.8651	5.517973	23.89738	0.0000

@MOVAV(MMFDE(-2),5)	4.543977	0.183903	24.70849	0.0000
SEP00	-17.04670	7.339140	-2.322711	0.0212
AUG00	34.70988	7.371869	4.708423	0.0000
MAR15	-26.07970	7.468627	-3.491900	0.0006
APR15	-23.73410	8.232526	-2.882967	0.0044
MAY15	-18.51047	7.461742	-2.480716	0.0139
AR(1)	0.541741	0.060520	8.951438	0.0000

==

R-squared	0.940744	Mean dependent var	265.5592
Adjusted R-squared	0.938700	S.D. dependent var	30.30244
S.E. of regression	7.502512	Akaike info criteri	6.905530
Sum squared resid	11426.40	Schwarz criterion	7.032615
Log likelihood	-720.5334	Hannan-Quinn criter	6.956900
F-statistic	460.3991	Durbin-Watson stat	2.630324
Prob(F-statistic)	0.000000		

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Inverted AR Roots .54

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Street Light Electric Customers

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Dependent Variable: PSLCUSDE

2016 Delmarva Power DE IRP Forecast

Method: Least Squares

Date: 08/23/16 Time: 16:59

Sample (adjusted): 1992M02 2015M11

Included observations: 243 after adjustments

Convergence achieved after 6 iterations

Variable	Coefficient	Std. Error	t-Statistic	Prob.
C	331.0169	35.30985	9.374633	0.0000
@MOVAV(METDE(-4),5)	0.127981	0.071824	1.781871	0.0761
JAN15	-56.49416	1.022293	-55.26220	0.0000
MAR15	-34.34254	1.253063	-27.40688	0.0000
APR15	-33.79407	1.454963	-23.22675	0.0000
MAY15	-32.93987	1.256476	-26.21607	0.0000
AR(1)	0.991585	0.002965	334.4287	0.0000

R-squared	0.998071	Mean dependent var	338.4074
Adjusted R-squared	0.998022	S.D. dependent var	32.37210
S.E. of regression	1.439659	Akaike info criteri	3.595073
Sum squared resid	489.1379	Schwarz criterion	3.695696
Log likelihood	-429.8014	Hannan-Quinn criter	3.635603
F-statistic	20353.93	Durbin-Watson stat	1.624593
Prob(F-statistic)	0.000000		

2016 Delmarva Power DE IRP Forecast

Inverted AR Roots	.99

Appendix F: Delmarva Power Zonal Load Model Equations

The following regressions were estimated using the EViews econometrics software package.

Delmarva Zonal Peak Demand (MW)

Dependent Variable: MWDPL

Method: Least Squares

Date: 08/23/16 Time: 16:59

Sample (adjusted): 1993M02 2015M12

Included observations: 251 after adjustments

Convergence achieved after 6 iterations

Variable	Coefficient	Std. Error	t-Statistic	Prob.
C	-1510.419	262.1356	-5.761976	0.0000
(METDE+METMD)*MWHDWIL	0.027963	0.002410	11.60464	0.0000
(METDE+METMD)*MWCDWIL	0.049948	0.004726	10.56914	0.0000
@MOVAV(JPRIDPL(-3)/(CPIU(-3)/CPI14),	-1803.796	951.1651	-1.896407	0.0591
@MOVAV((METDE(-4)+METMD(-4)),6)	4.894084	0.671560	7.287630	0.0000
@MOVAV(((PDINCDE(-2)+PDINCSAL(-2))/(C16.77765CPI2.444731TDE6.8627823)				0.0000
MAR	-177.4868	43.27209	-4.101647	0.0001

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APR	-318.8445	45.03840	-7.079393	0.0000
JUN	572.3783	51.50648	11.11274	0.0000
JUL	706.2739	58.35206	12.10367	0.0000
AUG	696.6013	57.23944	12.16995	0.0000
SEP	409.8160	53.76229	7.622741	0.0000
OCT	-89.18129	54.04136	-1.650241	0.1002
NOV	-199.6419	45.29139	-4.407943	0.0000
AR(1)	0.209583	0.064217	3.263696	0.0013

R-squared	0.909088	Mean dependent var	2870.012
Adjusted R-squared	0.903695	S.D. dependent var	572.6060
S.E. of regression	177.6973	Akaike info criteri	13.25594
Sum squared resid	7452012.	Schwarz criterion	13.46663
Log likelihood	-1648.621	Hannan-Quinn criter	13.34073
F-statistic	168.5653	Durbin-Watson stat	1.991837
Prob(F-statistic)	0.000000		

Inverted AR Roots	.21

Appendix G: Delmarva Zone Peak Demand By Rate Class

2016 Delmarva Power DE IRP Forecast

Delmarva Zone Summer Peak Demand By Rate Class
(Non-Coincident With PJM System Peak, July 20, 2015, 3:00 PM)

CUSTCLASSCODE	CUSTCLASSNAME (Description)	kWh at 07/20/15-15:00
DE_DEMECT	DE_DEMECTRANS	415349.457
DE_GSPTOU	Delaware General Service Primary Tou	398168.065
DE_GSPTOUH	Delaware General Service Primary Tou Hourly	12815.517
DE_GSPTOUMIN	Delaware General Service Primary Tou	5248.183
DE_GSSPHTG	Delaware General Service Space Heating	5465.409
DE_GSTTOU	Delaware General Service Transmission Tou	78871.143
DE_GSWTRHTG	Delaware General Service Water Heating	111.967
DE_LGSTOU	Delaware Large General Service	119435.209
DE_LGSTOUH	Delaware Large General Service Hourly	594.521
DE_MGSOPS	Delaware Medium General Service Off Peak	5834.499
DE_MGSSBASIC	Delaware Medium General Service	253787.931
DE_ODECPRI	Delaware ODEC Primary	10712.565
DE_ODECT	DE_ODECTRANS	334320.818
DE_OLBASIC25	Delaware Outdoor Lighting Rate 25	9.355
DE_OLBASIC30	Delaware Outdoor Lighting Rate 30	0
DE_ORLBASIC	Delaware Outdoor Recreational Lighting	29.689
DE_RSBASIC	Delaware Residential Service	562135.708
DE_RSHEATING	Delaware Residential Heating	213673.952
DE_RSTOUND	Delaware Residential Tou Non Demand	360.573
DE_SGSBASIC	Delaware Small General Service	31456.909
MD_BERLINT	MD_Berlin Trans	2800.946
MD_GSP3TOU	Maryland General Service Primary Tou 3	100146.681
MD_GSPTOU	Maryland General Service Primary	25472.748
MD_LGS3TOU	Maryland Large General Service Tou 3	27564.506
MD_LGSTOU	Maryland Large General Service	56948.181
MD_ODECPRI	Maryland ODEC Primary	60900.597
MD_ODECT	MD_ODECTRANS	178095.006
MD_OLBASIC25	Maryland Outdoor Lighting Rate 25	0
MD_OLBASIC30	Maryland Outdoor Lighting Rate 30	0
MD_ORLBASIC	Maryland Outdoor Recreational Lighting	64.119
MD_RSBASIC	Maryland Residential Service	495860.992
MD_RSTOUND	Maryland Residential Tou Non Demand	243.631
MD_SG2BASIC	Maryland Small General Service 2	139164.273
MD_SG2OPS	Maryland Small General Service Off Peak 2	1654.524
MD_SGSBASIC	Maryland Small General Service	44459.04
MD_SGSCON	MD_SGSCONOWINGO	4351.697
MD_SGSOPS	Maryland Small General Service Off Peak	27.73
MD_SGSSPHTG	Maryland Small General Service Space Htg	20971.119
MD_SGSTN	Maryland TELECOM NETWORK	437.803
MD_SGSWH	MD_SGSWWTRHTG	23.213
VA_ODECT	VA_ODECTRANS	154385.726

2016 Delmarva Power DE IRP Forecast

Delmarva Zone Winter Peak Demand By Rate Class

(Non-Coincident With PJM System Peak, February 22, 2015, 8:00 AM)

CUSTCLASSCODE	CUSTCLASSNAME (Description)	kWh at 02/22/15-08:00
DE_DEMECT	DE_DEMECTRANS	338469.176
DE_GSPTOU	Delaware General Service Primary Tou	334462.553
DE_GSPTOUH	Delaware General Service Primary Tou Hourly	6660.727
DE_GSPTOUMIN	Delaware General Service Primary Tou	5731.392
DE_GSSPHTG	Delaware General Service Space Heating	9172.532
DE_GSTTOU	Delaware General Service Transmission Tou	76049.261
DE_GSWTRHTG	Delaware General Service Water Heating	212.832
DE_LGSTOU	Delaware Large General Service	99409.543
DE_LGSTOUH	Delaware Large General Service Hourly	437.419
DE_MGSOPS	Delaware Medium General Service Off Peak	3029.922
DE_MGSSBASIC	Delaware Medium General Service	197131.727
DE_ODECPRI	Delaware ODEC Primary	11703.779
DE_ODECT	DE_ODECTRANS	369759.508
DE_OLBASIC25	Delaware Outdoor Lighting Rate 25	4.174
DE_OLBASIC30	Delaware Outdoor Lighting Rate 30	0
DE_ORLBASIC	Delaware Outdoor Recreational Lighting	8.281
DE_RSBASIC	Delaware Residential Service	367214.892
DE_RSHEATING	Delaware Residential Heating	505979.579
DE_RSTOUND	Delaware Residential Tou Non Demand	360.037
DE_SGSBASIC	Delaware Small General Service	31102.638
MD_BERLINT	MD_Berlin Trans	14973.435
MD_GSP3TOU	Maryland General Service Primary Tou 3	69807.151
MD_GSPTOU	Maryland General Service Primary	24056.662
MD_LGS3TOU	Maryland Large General Service Tou 3	15838.634
MD_LGSTOU	Maryland Large General Service	53258.406
MD_ODECPRI	Maryland ODEC Primary	81664.061
MD_ODECT	MD_ODECTRANS	228960.532
MD_OLBASIC25	Maryland Outdoor Lighting Rate 25	0
MD_OLBASIC30	Maryland Outdoor Lighting Rate 30	0
MD_ORLBASIC	Maryland Outdoor Recreational Lighting	49.556
MD_RSBASIC	Maryland Residential Service	806589.921
MD_RSTOUND	Maryland Residential Tou Non Demand	380.67
MD_SG2BASIC	Maryland Small General Service 2	111488.296
MD_SG2OPS	Maryland Small General Service Off Peak 2	842.992
MD_SGSBASIC	Maryland Small General Service	47926.327
MD_SGSCON	MD_SGSCONOWINGO	5020.506
MD_SGSOPS	Maryland Small General Service Off Peak	19.052
MD_SGSSPHTG	Maryland Small General Service Space Htg	35595.918
MD_SGSTN	Maryland TELECOM NETWORK	439.696
MD_SGSWH	MD_SGSWWTRHTG	59.519
VA_ODECT	VA_ODECTRANS	187999.687

Glossary: Data Dictionary

Demand Variables

MWDPL – The monthly peak hour metered demand observed on the Delmarva Zone, non-coincident with the PJM peak demand measured in MW.

Weather Related Variables

CDD65WLM – Monthly cooling degree days measured on a comfort threshold of 65 degrees Fahrenheit, based upon NOAA weather data collected at the New Castle County Regional Airport.

HDD65WLM – Monthly heating degree days measured on a comfort threshold of 65 degrees Fahrenheit, based upon NOAA weather data collected at the New Castle County Regional Airport.

MWCDWIL – Cooling degrees at the time of the Delmarva Zonal peak demand (non-coincident with the PJM peak system demand) measured on a comfort threshold of 65 degrees Fahrenheit, based upon NOAA weather data collected at the New Castle County Regional Airport.

MWHDWIL – Heating degrees at the time of the Delmarva Zonal peak demand (non-coincident with the PJM peak system demand) measured on a comfort threshold of 65 degrees Fahrenheit, based upon NOAA weather data collected at the New Castle County Regional Airport.

Economic Variables

CPI14 – A factor used to rebase CPIU so that it is expressed with a base year of 2008=100.

CPIU – The Consumer Price Index, All Urban, with a base period of 1982-84=100. The Consumer Price Index is published by the Bureau of Labor Statistics, US Department of Commerce.

METDE – Total Non-Agricultural Payroll Employment for the State of Delaware. Published by the Bureau of Labor Statistics, US Department of Commerce.

METSAL – Total Non-Agricultural Payroll Employment for the Salisbury, MD Metropolitan Statistical Area. Published by the Bureau of Labor Statistics, US Department of Commerce.

PDINCDE – Total Personal Disposable Income for the State of Delaware. Published by the Bureau of Economic Analysis.

PDINCSAL – Total Personal Disposable Income for the Salisbury, MD Metropolitan Statistical Area. Published by the Bureau of Economic Analysis.

JPRIDE – The total all-in price of electricity, measured in $/kWh, for retail sales within the Delmarva Power DE jurisdiction, inclusive of all taxes, surcharges and the commodity component. The cost of electricity provided is estimated for choice customers by assuming that cost is equal to the cost experienced by Delmarva Power in serving Standard Offer Service customers within the DE jurisdiction.

JPRIDPL – The total all-in price of electricity, measured in $/kWh, for sales within the Delmarva Power service areas, inclusive of all taxes, surcharges and the commodity component. The cost of electricity provided is estimated for choice customers by assuming that cost is equal to the cost experienced by Delmarva Power in serving Standard Offer Service customers.

Dummy Variables

JAN – A categorical variable coded 1 during the month of January and zero otherwise.

FEB – A categorical variable coded 1 during the month of February and zero otherwise.

MAR – A categorical variable coded 1 during the month of March and zero otherwise.

APR – A categorical variable coded 1 during the month of April and zero otherwise.

MAY – A categorical variable coded 1 during the month of May and zero otherwise.

JUN – A categorical variable coded 1 during the month of June and zero otherwise.

JUL – A categorical variable coded 1 during the month of July and zero otherwise.

AUG – A categorical variable coded 1 during the month of August and zero otherwise.

SEP – A categorical variable coded 1 during the month of September and zero otherwise.

OCT – A categorical variable coded 1 during the month of October and zero otherwise.

NOV – A categorical variable coded 1 during the month of November and zero otherwise.

DEC – A categorical variable coded 1 during the month of December and zero otherwise.

FEB00 – A categorical variable coded 1 during the month of February 2000 and zero otherwise.

JUN00 – A categorical variable coded 1 during the month of June 2000 and zero otherwise.

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MAR00 – A categorical variable coded 1 during the month of March 2000 and zero otherwise.

MAY00 – A categorical variable coded 1 during the month of May 2000 and zero otherwise.

AUG00 – A categorical variable coded 1 during the month of August 2000 and zero otherwise.

OCT00 – A categorical variable coded 1 during the month of October 2000 and zero otherwise.

JUL00 – A categorical variable coded 1 during the month of July 2000 and zero otherwise.

APR00 – A categorical variable coded 1 during the month of July 2000 and zero otherwise.

SEP00 – A categorical variable coded 1 during the month of September 2000 and zero otherwise.

JAN00 – A categorical variable coded 1 during the month of January 2000 and zero otherwise.

OCT04 – A categorical variable coded 1 during the month of October 2004 and zero otherwise.

DEC99 – A categorical variable coded 1 during the month of December 1999 and zero otherwise.

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FEB07 – A categorical variable coded 1 during the month of October 2004 and zero otherwise.

FEB01 – A categorical variable coded 1 during the month of February 2001 and zero otherwise.

JAN15 – A categorical variable coded 1 during the month of January 2015 and zero otherwise.

FEB15 – A categorical variable coded 1 during the month of February 2015 and zero otherwise.

MAR15 – A categorical variable coded 1 during the month of March 2015 and zero otherwise.

APR15 – A categorical variable coded 1 during the month of April 2015 and zero otherwise.

MAY15 – A categorical variable coded 1 during the month of May 2015 and zero otherwise.

JUN15 – A categorical variable coded 1 during the month of June 2015 and zero otherwise.

JUL15 – A categorical variable coded 1 during the month of July 2015 and zero otherwise.

APPENDIX 5

Appendix 5 - CONFIDENTIAL MATERIAL OMITTED

Forecast of Residential and Small Commercial Fixed Price SOS and large Commercial and Industrial Rates

2017-18	R	RTOU-ND	RSH	SGS-S	GS-SH	GS-WH	OL	ORL	MGS-S	LGS-S	GS-P
Demand ($/kW)											
Summer											
Winter											
Energy ($/MWH)											
Summer - all hrs											
DP&L On pk											
DP&L Off pk											
Winter - all hrs											
DP&L On pk											
DP&L Off pk											

Forecast of Residential and Small Commercial Fixed Price SOS and large Commercial and Industrial Rates

2018-19	R	RTOU-ND	RSH	SGS-S	GS-SH	GS-WH	OL	ORL	MGS-S	LGS-S	GS-P
Demand ($/kW)											
Summer											
Winter											
Energy ($/MWH)											
Summer - all hrs											
DP&L On pk											
DP&L Off pk											
Winter - all hrs											
DP&L On pk											
DP&L Off pk											

Forecast of Residential and Small Commercial Fixed Price SOS and large Commercial and Industrial Rates

2019-20	R	RTOU-ND	RSH	SGS-S	GS-SH	GS-WH	OL	ORL	MGS-S	LGS-S	GS-P
Demand ($/kW)											
Summer											
Winter											
Energy ($/MWH)											
Summer - all hrs											
DP&L On pk											
DP&L Off pk											
Winter - all hrs											
DP&L On pk											
DP&L Off pk											

Forecast of Residential and Small Commercial Fixed Price SOS and large Commercial and Industrial Rates

2020-21	R	RTOU-ND	RSH	SGS-S	GS-SH	GS-WH	OL	ORL	MGS-S	LGS-S	GS-P
Demand ($/kW)											
Summer									$ 8.565929	$ 9.777782	$ 9.569337
Winter									$ 6.481791	$ 7.843880	$ 7.552952
Energy ($/MWH)											
Summer - all hrs	$ 0.062526		$ 0.061659	$ 0.061696	$ 0.062420	$ 0.059461	$ 0.034648	$ 0.045940	$ 0.029502		
DP&L On pk		$ 0.098033								$ 0.039659	$ 0.043825
DP&L Off pk		$ 0.031938								$ 0.028555	$ 0.035805
Winter - all hrs	$ 0.079372		$ 0.070265	$ 0.073480	$ 0.075572	$ 0.064591	$ 0.046060	$ 0.057277	$ 0.042963		
DP&L On pk		$ 0.121165								$ 0.052452	$ 0.055630
DP&L Off pk		$ 0.046200								$ 0.037482	$ 0.045188

Forecast of Residential and Small Commercial Fixed Price SOS and large Commercial and Industrial Rates

2021-22	R	RTOU-ND	RSH	SGS-S	GS-SH	GS-WH	OL	ORL	MGS-S	LGS-S	GS-P
Demand ($/kW)											
Summer									$ 8.721974	$ 9.955484	$ 9.743225
Winter									$ 6.721257	$ 8.133249	$ 7.831992
Energy ($/MWH)											
Summer - all hrs	$ 0.062266		$ 0.061400	$ 0.061437	$ 0.062161	$ 0.059202	$ 0.034506	$ 0.045681	$ 0.029997		
DP&L On pk		$ 0.097561								$ 0.040326	$ 0.044535
DP&L Off pk		$ 0.031794								$ 0.029021	$ 0.036369
Winter - all hrs	$ 0.076514		$ 0.067408	$ 0.070623	$ 0.072715	$ 0.061733	$ 0.044342	$ 0.054420	$ 0.044464		
DP&L On pk		$ 0.116081								$ 0.054278	$ 0.057511
DP&L Off pk		$ 0.044327								$ 0.038757	$ 0.046682

APPENDIX 6

Appendix 6

PJM and Delaware Generation by Fuel Type and Power Plant Emissions

This Appendix provides information on the generation (mWh) by type of fuel for the PJM System over the period January 2012 through December 2015, and for Delaware for the period January 2012 through December 2014[1]. Annual power plant emissions for Carbon Dioxide (CO_2), Sulphur Dioxide (SO_2), and Nitrous Oxide (NO_x) are also presented. PJM information was obtained from publically available data located on the PJM-EIS website: (https://gats.pjm-eis.com/gats2/PublicReports/PJMSystemMix). The Delaware information was obtained from the report, "1990 -2014 U.S. Electric Power Industry Estimated Emissions by State (EIA-767, EIA-906, EIA-920, and EIA-923," available on the following website: www.eia.gov/electricity/data/state .

Table 1 below indicates PJM system generation by fuel type for calendar years 2012 - 2015.

Table 1: PJM Generation mWh by Fuel Type

Fuel type	**2012**	**2013**	**2014**	**2015**
Coal*	321,127,748	337,480,528	334,230,605	274,726,041
Natural gas	148,998,647	129,388,223	140,126,655	179,283,802
Oil**	2,571,028	1,534,638	2,019,910	2,208,785
Nuclear	273,137,947	277,081,534	277,463,058	278,935,869
Hydro	6,414,553	7,638,864	7,598,909	8,167,296
Wind	12,633,476	14,815,490	15,550,177	16,599,653
Solar	234,424	357,071	403,713	535,123
Other***	16,946,322	20,699,191	21,838,126	19,261,077
Total certificates (MWH)	782,064,145	788,995,539	799,231,153	779,717,646

*includes anthracite, bituminous and sub-bituminous
** includes distillate fuel oil, jet fuel, kerosene, petroleum coke and residual fuel oil
***includes biomass, coal waste, other gas, propane, solid waste, wood, and other

[1] The U.S. Energy Information Administration (EIA) is not scheduled to release the 2015 data for Delaware until after the 2016 IRP has been filed.

The data in Table 1 above indicates that the large majority of mWh generated in PJM are produced by coal, nuclear and natural gas facilities. The mWh generated by wind and solar facilities has been increasing since 2012, but it still accounts for a relatively small percentage of the total PJM generation mWh.

Tables 2, 3 and 4 below show the amount (tons) of CO_2, SO_2, and NO_x produced by various generation fuels in the PJM system for the period 2012-2015:

Table 2: PJM CO_2 Emissions (Tons) by Fuel Type 2012 - 2015

Fuel type	**2012**	**2013**	**2014**	**2015**
Coal*	332,026,662	352,284,891	348,718,379	283,773,910
Natural gas	72,613,092	60,819,406	66,704,232	86,577,469
Oil**	2,427,253	1,935,169	2,624,995	2,208,785
Nuclear	0	0	0	0
hydro	0	0	0	0
Wind	0	0	0	0
Solar	0	0	0	0
other***	19,816,450	23,562,366	24,634,782	22,868,377
Total tons	426,883,457	438,601,831	442,682,387	395,428,541

*includes anthracite, bituminous and sub-bituminous
** includes distillate fuel oil, jet fuel, kerosene, petroleum coke and residual fuel oil
***includes biomass, coal waste, other gas, propane, solid waste, wood, and other

Table 3: PJM NOx Emissions (Tons) by Fuel Type 2012 - 2015

Fuel type	2012	2013	2014	2015
Coal*	321,272	339,781	321,491	257,853
Natural gas	18,613	26,747	15,545	22,222
Oil**	3,871	2,406	3,077	2,885
Nuclear	0	0	0	0
Hydro	0	0	0	0
Wind	0	0	0	0
Solar	0	0	0	0
Other***	26,473	7,140	21,379	19,493
Total tons	370,229	376,075	361,492	302,452

*includes anthracite, bituminous and sub-bituminous
** includes distillate fuel oil, jet fuel, kerosene, petroleum coke and residual fuel oil
***includes biomass, coal waste, other gas, propane, solid waste, wood, and other

Table 4: PJM SO_2 Emissions (Tons) by Fuel Type 2012 - 2015

Fuel type	2012	2013	2014	2015
Coal*	853,427	822,843	847,585	583,580
Natural gas	2,346	750	1,039	2,144
Oil**	4,653	6,823	5,754	6,823
Nuclear	0	0	0	0
Hydro	0	0	0	0
Wind	0	0	0	0
Solar	0	0	0	0
Other***	76,134	106,145	38,523	35,555
Total tons	936,561	936,561	892,901	628,102

*includes anthracite, bituminous and sub-bituminous
** includes distillate fuel oil, jet fuel, kerosene, petroleum coke and residual fuel oil
***includes biomass, coal waste, other gas, propane, solid waste, wood, and other

Since the last IRP was filed in December 2014, PJM has begun releasing some information on the system emission rates for CO_2, SO_2, and NO_x (see: "2012-2015 CO_2, SO_2, and NO_x Emission Rates, March 18, 2016" ("PJM March 2016 Report"), publically available on the PJM website at http://www.pjm.com/~/media/documents/reports/20160318-2015-emissions-report.ashx. The information provided in the PJM March 2016 Report provides average emission rates for these pollutants by month for the period Jan 2012 - December 2015.

Table 5 below is taken from the PJM March 2016 Report and indicates the percentage of time which generating units, by fuel source, are the marginal unit on the PJM System. As indicated by the data in Table 5, on an annual basis for the last four years the marginal generating units for the majority of time on the PJM system have either been coal, gas or oil fired.

Table 5: PJM Marginal Units By Fuel

Fuel Type	2012	2013	2014	2015
Coal	58.84%	56.94%	52.90%	51.74%
Gas	30.35%	34.72%	35.80%	35.32%
Oil	6.00%	3.27%	7.45%	8.99%
Wind	4.19%	4.76%	3.29%	3.27%
Other	0.47%	0.20%	0.43%	0.39%
Municipal Waste	0.13%	0.07%	0.05%	0.06%
Uranium	0.02%	0.02%	0.04%	0.03%
Demand Response	0.00%	0.02%	0.04%	0.00%
Interface	0.00%	0.00%	0.00%	0.00%

Source: 2012-2015 CO_2, SO_2, and NOx Emission Rates, March 18, 2016

As indicated by the data contained in Table 5 above, generation produced by coal, gas, oil, and other fuel over the last four years represent the PJM marginal generating units roughly 95% of the time. The 2016 IRP and previous IRPs that estimated the emissions avoided due to renewable generation resources used a percentage of the average emission rate of generating resources that produced emissions to determine avoided emissions. Generating resources that produce emissions include coal, gas, oil and other.

Table 6 below shows the statewide mWh and tons of CO_2, SO_2, and NO_x for Delaware:

Table 6: Delaware Power Plant Emissions 2012-2014

	2012	2013	2014
CO_2 Tons	5,479,157	5,193,918	4,704,057
SO_2 Tons	2,670	2,235	824
NO_x Tons	3,124	2,581	2,831
Net Generation MWH	8,633,694	7,760,861	7,703,584

APPENDIX 7

Appendix 7

PJM Market Overview and Historical Prices

MARKET STRUCTURE

The electric power pool encompassing the Pennsylvania, New Jersey and Maryland service territories was named the PJM Interconnect in 1956. PJM was designated a Regional Transmission Organization ("RTO") by the Federal Energy Regulatory Commission ("FERC") in 2001. Since then, PJM's service territory has grown to include all or parts of Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia and the District of Columbia.

The PJM Independent System Operator ("PJM ISO") is tasked with administering the world's largest electric wholesale market and operating the world's largest centrally dispatched transmission grid. The PJM ISO dispatches over 200,000 megawatts ("MW") of generating capacity over more than 60,000 miles of transmission lines, and ensures electric reliability to 60 million customers. The majority of PJM's territory is also part of the Reliability First Corporation ("RFC"), one of the regional organizations of the North American Electric Reliability Corporation ("NERC").

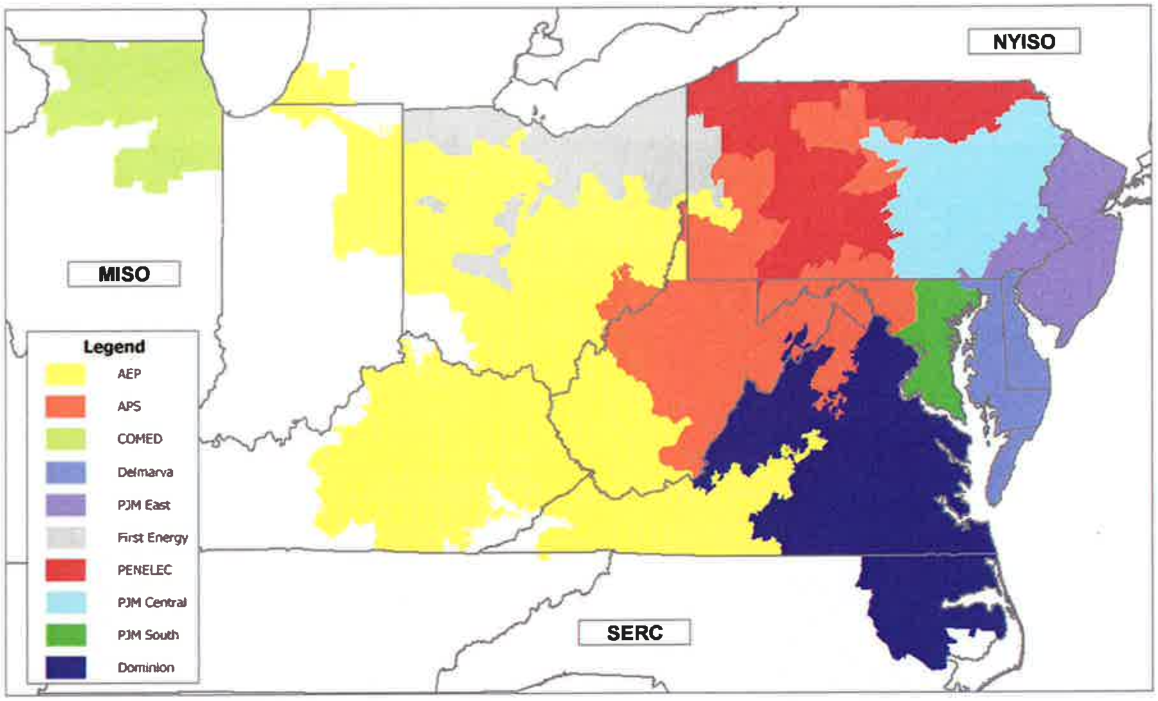
The classic footprint of the PJM Interconnection represents a zonal designation used by PJM and corresponds to the former Mid-Atlantic Area Council ("MAAC") NERC region. Within the PJM Mid-Atlantic area, Pace Global has identified four sub-regions that represent areas of persistent congestion and distinct pricing; these areas are referred to as PJM West, PJM Central, PJM East and PJM South.

The PJM ISO administers the wholesale electric market by providing the following primary functions:

- Performs continuous real-time operation of the bulk power system including generation dispatch and scheduling transmission flow;
- Maintains reliability in response to power system events;
- Provides coordinated transmission planning; and
- Administers wholesale markets for trading electricity-related commodities.

Across PJM, there are several areas of significant and persistence price divergences, which are individually represented in Pace Global's modeling approach. In our assessment, we have examined power pricing across ten distinct zones, with transfer capabilities modeled across each zone and with neighboring ISOs. Figure 1 below shows the footprint of PJM, including the ten distinct zones simulated in Pace Global's market assessment.

Figure 1: PJM Footprint



Source: Pace Global.

The PJM ISO administers a multi-settlement system for buying and selling electricity-related products including energy, capacity and ancillary services. As an independent entity, it facilitates the unbiased financial settlement of these products, and continually monitors the market for anti-competitive behavior. The PJM energy market exchange consists of two settlements: one for the day-ahead market and another for the real-time market. The day-ahead market produces financially binding schedules for the supply and consumption of energy for the upcoming operating day. The real-time market is a spot market that accounts for deviations from the day-ahead market schedules.

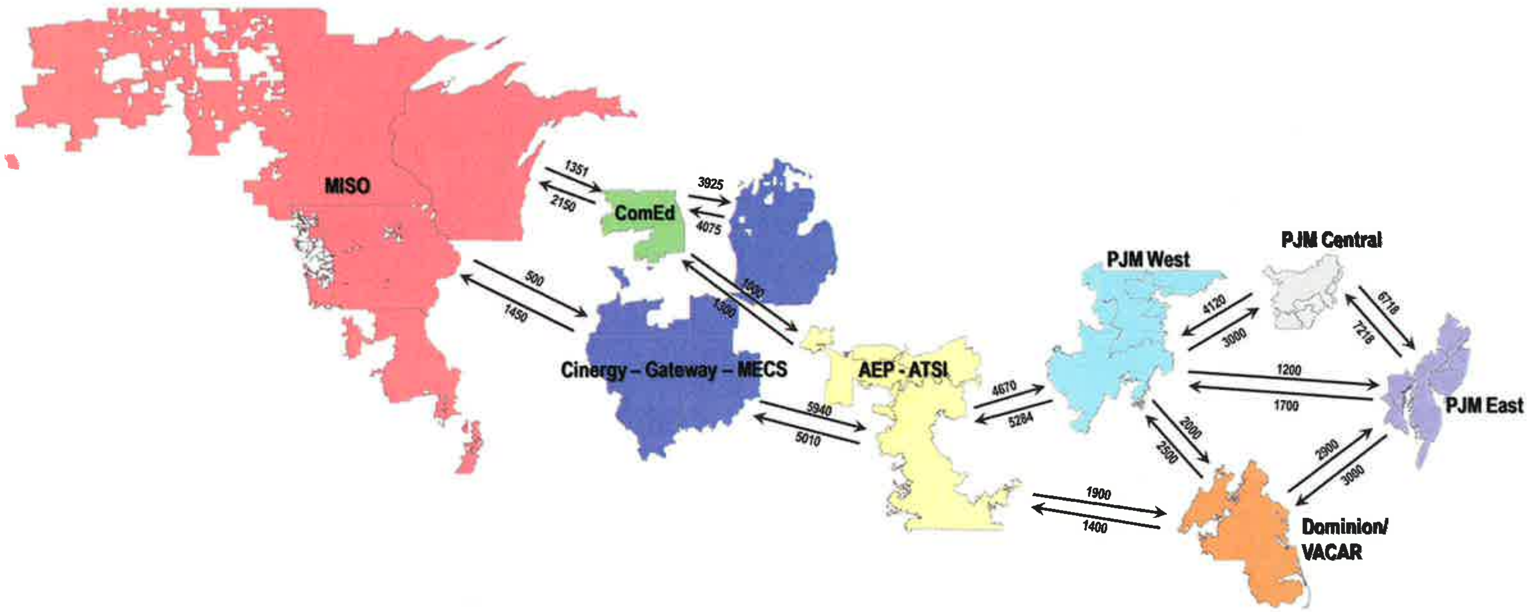
TRANSMISSION

Figure 2 below displays the transmission capabilities (in MW) between relevant PJM zones and between neighboring regions. Pace Global analyzes the PJM market area in accordance with transmission constraints across zones with significant and persistent congestion. In order to assess potential transmission upgrades, Pace Global assesses PJM's Regional Transmission Expansion Plan ("RTEP") process, which is responsible for planning transmission systems in the PJM territory. The latest load forecast outlook, published in January 2014 by PJM, projects lower summer and winter peak demand in all regions compared to the 2013 load forecast. This expectation, combined with slower economic recovery and increased energy conservation participation, contributed to less demand for transmission upgrades for the region in the near-term when compared to earlier assessments.

Within PJM, there are several major transmission projects aimed at bringing low cost power from the West and Central regions to the load centers in the East. Notable expansion plans are described below:

- PJM is targeting transmission projects in Pennsylvania and New Jersey. PSEG and PPLS are collaborating on the 500kV Susquehanna to Roseland project, which was approved for construction in 2012 and completed in 2015. This project is included in our analysis.
- The Mt. Storm- Doubs 500 kV line has been upgraded by APS and Dominion and went into service during the second quarter of 2014. This project is included in our analysis.

Figure 2: PJM Transfer Capability (MW)



Source: Pace Global

PJM coordinates the continuous buying, selling and delivery of wholesale electricity through open, competitive markets. PJM balances the needs of suppliers, wholesale customers and other market participants. PJM oversees day-ahead and real-time energy markets as well as the Base Residual Auction ("BRA") for procurement of capacity and clearing of capacity prices.

RELIABILITY PRICING MODEL

The PJM Reliability Pricing Model ("RPM") was implemented on June 1, 2007. It is designed to provide generators, demand response resources, and transmission owners with the economic incentives necessary to maintain system reliability and to ensure that sufficient generation capacity is available to reliably meet the region's electricity demands. The RPM allows facilities to sell capacity for a 12-month period on a three-year forward basis through an auction process, creating a construct with greater transparency and cash flow stability than a bilateral capacity market.

The key characteristics of the RPM are:

- Three-year forward commitment of capacity delivery;
- Predetermined downward sloping Variable Resource Requirement ("VRR") demand curve;
- Locational value of capacity;
- Integration with the energy markets of the PJM-ISO; and
- Load Serving Entities ("LSE") have the ability to opt out of the RPM at the discretion of the authorities of an applicable state, but must keep a higher reserve margin than the participating LSE.

Load Deliverability Areas

The RPM establishes clear regulations as to what PJM-ISO zones will become load deliverability areas ("LDAs"). The RPM has defined the following LDAs:

1. Western PJM
2. ComEd
3. AEP
4. Dayton
5. DLCO
6. APS
7. VAP/Dominion
8. MAAC
9. WMAAC
10. MetEd
11. PPL
12. Penelec
13. EMAAC (includes RECO)
14. SWMAAC

15. AE
16. PSEG
17. PS-NORTH
18. PECO
19. JCPL
20. DPL
21. DPL-SOUTH
22. BGE
23. PEPCO
24. ATSI
25. CLEVELAND

VRR Curve

The VRR curve determines the price at which given supply bids will clear. The VRR curve is tied to the Cost of New Entry ("CONE") within the applicable LDA. The RPM-defined CONE (nominal $) was modified in FERC's January 31, 2013 ruling on PJM's CONE values. The Settlement CONE was then adjusted by the Handy Whitman Index. The CONE for the 2017-2018 delivery period was $393/MW-day ($143/kW-year) for the RTO, up 3.4 percent from the 2016-2017 auction. CONE area 1, which includes AE, DPL, JCPL, PECO, PS, and RECO, had the highest CONE at $430/MW-day ($157/kW-year), while CONE area 3, which includes AEP, APS, ComEd, Dayton, and Duquesne, was set at $393/MW-day ($144/kW-year).

In order to integrate the RPM with the energy markets of the PJM, the energy and ancillary services ("E&AS") gross margins for a hypothetical peaking unit are used to offset the CONE. The RTO's current calculated value for E&AS is $22.4/kW-year ($61.4/MW-day) (nominal $).

To calculate the VRR curve, the following equation is used:

$$VRR = \frac{Multiple * (CONE - E\&AS)}{EFORd^1}$$

[1]where EFORd is the average system-wide equivalent forced outage rate of demand for the LDA

The multiple is the feature of the VRR curve that gives the curve its downward sloping shape. The RPM has a price cap through the use of a 1.5 multiple for all reserve margins below the Installed Reserve Margin ("IRM"), minus 3 percent (for the 2017-2018 auction, this is 12.7 percent). The IRM, last specified as 15.7 percent, is the equilibrium point of the RPM with a multiple of 1. The multiple falls to 0.2 at the IRM plus 5 percent (20.3 percent). The PJM system-wide EFORd rate is 5.65 percent.

Auctions in the Reliability Pricing Model

A BRA is held three years and one month before the beginning of the delivery year. Three incremental auctions are held between the BRA and delivery year to facilitate market condition adjustments and provide added liquidity. Parties' ownership rights must offer their capacities into the RPM auctions at the desired price. New generators may choose to fix their initial capacity payment for an additional two years beyond the initial delivery period, under certain circumstances.

The first and third incremental auctions are held in order to allow market participants to satisfy their commitment due to:

- Changes in the LSE peak load forecast;
- Cancellations or delays of a planned resource;
- Deratings, retirements, or forced outage rating increases of an existing resource;
- Transmission upgrades; or
- Variations in the value of a demand resource.

The second incremental auction is held only if the peak load forecast for the entire PJM-ISO changes by more than 100 MW. The PJM-ISO buys the necessary capacity on behalf of all LSE during the second auction. No VRR curves are used in this incremental auction, as transactions are completed solely through bilateral trades.

The RPM auction mechanism determines the cost of capacity on an annual basis. The algorithms used by the RPM auction are meant to lower the total cost to all LSEs, while clearing the most capacity. The VRR curve can, in some situations, act only as a price ceiling on the price of capacity at the applicable reserve margin. For example, if the last offer in an auction is below and inside the VRR curve, the point on the VRR curve vertically above the final offer is the final clearing price of capacity.

Capacity Price

Capacity prices in the BRA auction are first calculated by determining the marginal price of capacity for the entire PJM. An analysis is then performed for all LDAs to determine if the capacity that cleared initially plus the Capacity Emergency Transfer Limit ("CETL") into the LDA fail to meet the reliability requirement of the LDA. The necessary locational price adder is then determined by performing an additional supply/demand balance using the supply curve (generator offers) and demand curve (VRR curve) of the region.

FERC's March 26, 2009 ruling on PJM's Reliability Pricing Model modified some rules regarding the inclusion of LDAs in the calculation of the capacity price. The ruling specifies that if any LDA had a locational price adder in any of the three preceding BRAs they would automatically receive a separate VRR curve. For the 2012-2013 auction, for example, PSEG North, EMAAC, SWMACC and MAAC all automatically received separate demand curves. It also increased the stringency of the CETL requirements for LDA's making it more likely like that zonal divergences appear in BRAs.

LSEs and capacity resources do not pay and receive the same capacity prices in constrained LDAs. Capacity resources receive the clearing price of the LDA, while LSEs in the same LDA are charged the weighted average of the capacity in that LDA plus whatever imports into the LDA that were calculated in the auction process.

PJM also has Minimum Offer Price Rules ("MOPR") for new generation resources. The previous MOPR were adopted in 2011 in order to mitigate "buyer-side" market power by requiring all new, non-exempted resources to bid at a floor price (i.e. ninety percent (90%) of the Net Cost of New Entry) or higher, unless the resource can demonstrate, through a unit-specific review process, that a lower bid is justified based on the economics of that unit. Last December, PJM submitted revisions to its MOPR proposing to replace the unit-specific review process with two broad exemptions: one for "competitive entry" and one for self-supply LSEs. Under the PJM proposal, a resource would be subject to the MOPR unless it fit within one of the exemptions.

In May 2013, FERC partially approved PJM's filing on the MOPR. As per the FERC Order 143 FERC ¶ 61,090[1], new resources would be subject to MOPR unless they fit into either the Competitive Entry exemption or the Self Supply exemption. However, FERC ordered that PJM should retain the unit-specific review so that resources ineligible for MOPR exemptions that have lower competitive costs than the default offer floor have a chance to demonstrate their competitive entry costs.

Capacity Import Limit

In its filing with FERC[2], PJM contended that since its conception in 2007, the capacity market's forward auctions have recognized locational constraints that limit the delivery of capacity within PJM. However, PJM's capacity market currently did not include capacity import limits on the delivery of capacity to the ISO from areas outside of PJM. Instead, PJM addressed this issue only by reviewing requests for firm transmission service into the ISO which are often not resolved until long after the external resource offers and clears in the capacity auction. Consequently, an external resource that clears the capacity auction but fails to secure firm transmission on satisfactory terms will not be available to PJM in the Delivery Year[3] as a capacity resource. PJM further explained that failure to recognize the limits on capacity imports may have adverse consequences on reliability.

Therefore, PJM revised the Reliability Assurance Agreement and Open Access Admission Tariff so that the RPM Auctions will recognize a limit on the amount of capacity from external generation resources that can be reliably committed to the PJM forward capacity auctions as a constraint on auction clearing. The new rules[4] include both an RTO wide capacity limit as well as five separate regional zonal limits.

Limited Demand Response Procurement Cap

In another filing with FERC,[5] PJM asserted that the current demand response ("DR") rules are inadvertently creating a vertical demand curve for Annual DR Resources[6], resulting in over-

[1] PJM Interconnection, L.L.C., 143 FERC ¶ 61,090 at P37, P38 (2013)

[2] PJM Interconnection, L.L.C., 147 FERC ¶ 61,060 at P3 (2014)

[3] In PJM, the term ranges from June 1st to May 31st (i.e. For the 2019/2020 Delivery Year, units that cleared in RPM is or will be fully in-service by June 1st, 2019 until May 31st, 2020)

[4] PJM Interconnection, L.L.C., Draft PJM/MISO Joint and Common Market Capacity Deliverability PJM Fact Finding #2 PJM Capacity Import Limit Methodology by PJM Planning Division (2014) https://www.pjm.com/~/media/committees-groups/stakeholder-meetings/pjm-miso-joint-common/20140528/20140528-item-07b-pjm-capacity-import-limit-methodology-white-paper.ashx

[5] PJM Interconnection, L.L.C., 146 FERC ¶ 61,052, at P6 (2014).

[6] PJM Interconnection, L.L.C., 146 FERC ¶ 61,052, at P6 (2014).

procurement of limited demand response resources. PJM stated that it realized that there is a long-term reliability detriment when the committed amounts of Extended Summer DR[7] and Limited DR[8] exceed their reliability targets over-procurement of the more-limited resources suppresses prices for the higher valued Annual Resources[7] – including both Annual DR and generation capacity resources – by preventing Annual Resources from interacting with the sloped demand curve and sending the appropriate price signals to the market. PJM proposed RPM market reforms to ensure that the capacity procured above the reserve margin is of a type that provides the greatest incremental reliability benefit and restores the sloped portion of the demand curve.

Thus, PJM established a Sub-Annual Resource Constraint[7] to limit the total amount of capacity that can be committed as either Extended Summer DR or Limited DR for each Delivery Year. Similarly, PJM established a Limited Resource Constraint[7] to limit the quantity of Limited DR that can clear the auctions. This limit will be equal to the Limited DR Reliability Target less the short Term Resource Procurement Target[7]. The change modifies the auction procurement procedure from using floors on the higher-availability products to ceilings on the lower-availability products.

DR Offer Requirements

In a filing with FERC, PJM explained that it has seen tremendous growth in the megawatt quantity of demand resources offered and cleared in the BRA and other RPM auctions, and that the quantity of demand resources offered into the 2012 BRA, in some areas, far exceeded the level of demand resources actually identified as needed even under reasonable growth expectations. PJM argued that such demand resource offer levels were "very aggressive" for a number of possible reasons, including:

- Overly optimistic assumptions about the ability of the demand resource provider to develop entirely new demand response;
- Double-counting of the same demand resources; or
- An assumption that resources need not offer in the BRA the demand response levels that they actually expect to provide.

In order to ensure that demand resources would be able to provide the offered demand reduction capability, PJM proposed that every DR provider must submit a DR Sell Offer Plan[8] at least 15 business days before the RPM auction. This Plan must consist of both a completed template document requiring certain information set forth in the Tariff and PJM Manuals, and a DR Officer Certification Form[9]. PJM also proposed to require that end-use customer site information be provided under circumstances that PJM considers to present the greatest risk of multiple Demand Resource offers relying on load reduction from the same end-users.

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7 PJM Interconnection, L.L.C., 155 FERC ¶ 61,062 at P1 (2016)

8 *See* Reliability Assurance Agreement at 1.43A (defining Limited Demand Response as a capacity product that may be called on by PJM from June through September, up to ten times, and for six hours at a time).

9 PJM Interconnection, L.L.C., 146 FERC ¶ 61,150, at P3 (2014)

The DR Officer Certification Form required a designated officer of the DR Provider to certify that the information supplied is true and correct, and that the DR Provider is submitting the plan "with the reasonable expectation, based upon its analyses as of the date of the certification, to physically deliver all megawatts that clear the RPM Auction through Demand Resource registrations by the specified Delivery Year." Schedule 6 at 6.A.2.b.

Requirements for Utilization of DR

PJM proposed a number of changes to its emergency demand response program in a FERC filing[10] to give it more flexibility in calling on such resources. PJM noted that emergency-only resources can choose to have either one-hour or two-hour advance notice of a dispatch. Approximately 94% of megawatts nominated for the 2013/2014 Delivery Year have selected a two-hour lead time according to PJM. Therefore, these DR resources are not required to achieve full load reduction until two hours from the time PJM issues a notice that Emergency Load Response is needed under emergency conditions.

To address this issue, PJM modified the notification time procedures to give itself more flexibility to call on DR such that, after a transition period, all DR that clear an RPM auction will be required to meet a default 30 minute notification time, unless they can demonstrate through an exception process that they have a physical limitation that would prevent them from reducing load in less than 60 or 120 minutes' notification time. The 30 minute default notification time would take effect starting with registrations for the 2015/2016 Delivery Year, and all subsequent years.

Generating Capability and the RPM

Resources in the RPM receive a capacity payment up to their net capability. This is defined as the net seasonal capacity of the unit, de-rated for its previous delivery year's 12-month average EFORd rating. For intermittent units, a three-year historical average capacity factor of the unit is used to derate the plant's capacity. Hydro units are not considered intermittent resources in the PJM.

Further revisions to the RPM have allowed for greater participation of demand side resources in the base auction and subsequent incremental auctions. Up until the 2016/2017 auction, PJM saw a consistent increase in the MW offerings of interruptible resources into the capacity market. The 2012-2013 auction ended the interruptible load for reliability product but allowed the same resources to bid as demand response. As a result, offered MW for demand response increased from 1,652.4 MW (unforced capacity or UCAP) in the 2011-2012 auction, to 9,847.6 MW (UCAP) in the 2012-2013 auction. Efficiency resources were allowed for the first time in the 2012-2013 auction. In that auction, 652.7 MW of efficiency resources were offered, of which 568.9 MW (UCAP) cleared. The 2014-2015 BRA had an increase in cleared energy efficiency resources to 822 MW (UCAP). The 2014-2015 auction was the first in which two additional demand resource products were permitted (Annual DR and Extended Summer DR). The total amount of demand resources that cleared the 2015/2016 auction stands at 14,832 MW (UCAP), which represents a 55% increase over the 2013-3014 auction. Demand response and energy efficiency represented nearly 10% of the total capacity relied upon to meet load for the 2015/2016 delivery period.

For the 2016/2017 auction, only 12,408 MW (UCAP) of demand resources cleared, with another 1,117 MW from energy efficiency resources. The drop in cleared demand response was roughly 17% relative to the 2015/2016 auction, with the drop in offered demand response even more pronounced at 27%. This trend continued in the 2017/2018 Delivery Year results. The quantity of DR offered in the 2017/18 auction was 22% lower than the prior year at 11,294 MW. The

[10] PJM Interconnection, L.L.C., 147 FERC ¶ 61,103, at P1 (2014)

quantity of cleared DR was 10,975 MW, 11.5% lower than the prior year. In the 2018/2019 auction, the amount of new capacity bids into the auction decreased by roughly 3 GW compared to 2017/2018, leading to an increase in value with insufficient supply to make up for this shortfall. Following years of low supply, we observed a reversal in 2019/2020 as there was a significant increase in procured capacity (5,373.6 MW) compared to 2018/2019 (2,954.3 MW).

Fixed Resource Requirement

The RPM allows LSEs to "opt-out" of the capacity market and address their capacity obligations through the Fixed Resource Requirement ("FRR") method. The FRR capacity obligation method allows LSEs to self-supply capacity to meet any part of their load obligations. LSEs that choose the FRR method must demonstrate an ability to meet current and forecasted peak load obligations with owned or contracted capacity. The FRR period is, at a minimum, five years, with a FRR plan due every year.

If the LSE has resources above and beyond its required amount, such resources can be sold at RPM auctions. However, the LSE cannot meet its capacity obligations through RPM auctions.

2014-2015 Auction Results

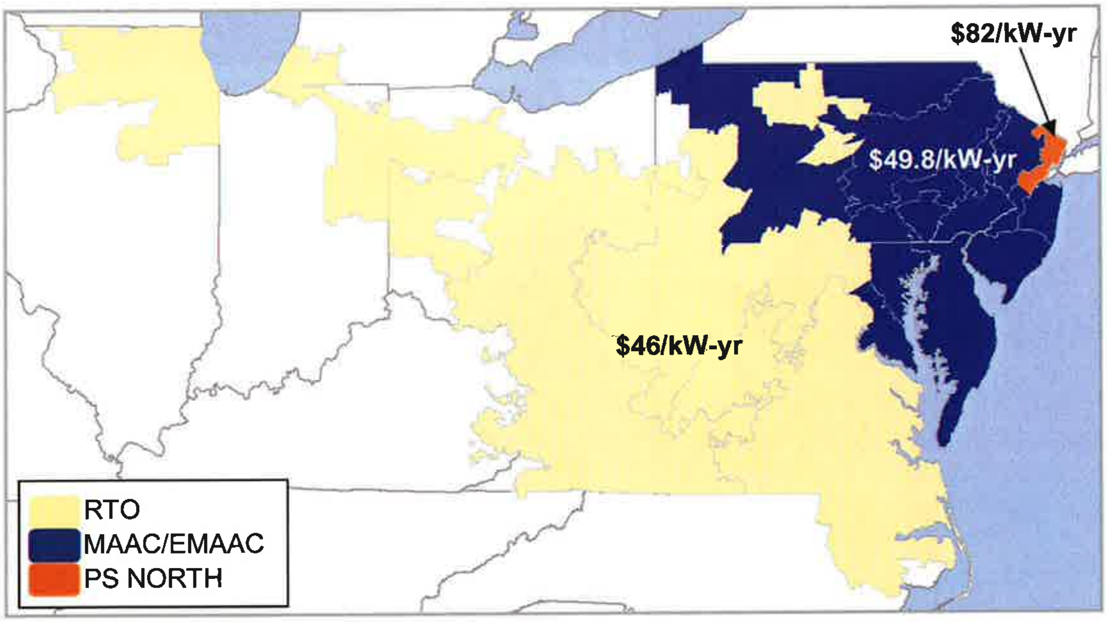
The results of the 2014-2015 auction which were posted on May 13, 2011, are displayed in Figure 3 below. A total of 149,974 MW of unforced capacity cleared the auction, representing a reserve margin over 19% at a RTO-wide clearing price of $45.9/kW-year ($125.99/MW-day). This price is over a 400 percent increase from the previous auction.

On April 12, 2011, FERC approved PJM's proposed revisions to its MOPR[11], which was designed to prevent low and uneconomic power sale bids from entering the capacity market. FERC's ruling made the MOPR more likely to be used to prevent uneconomic entry, and changed the following key items: raised the conduct screen threshold benchmark price for combined cycle (CC) and combustion turbine (CT) generation plants from 80% to 90% of Net Asset Class Cost of New Entry (CONE); indexed CONE to the Handy-Whitman index; and no longer exempts resources from MOPR that are developed because of state regulatory or legislative mandate.

The proposal by PJM was partly a response to plans by Maryland and New Jersey to procure generation outside of the PJM wholesale market through state requests for proposals. PJM believed the actions of these states would have depressed regional capacity prices if its rules were not changed. The revised MOPR is a positive outcome for natural gas-fired generators in the PJM capacity market, and it is expected to keep prices higher than originally anticipated in future auctions.

[11] PJM Interconnection, L.L.C., 135 FERC ¶ 61,022 (2011)

Figure 3: 2014-2015 Base Residual Auction Results (Nominal $/kW-yr)



Source: Pace Global and PJM.

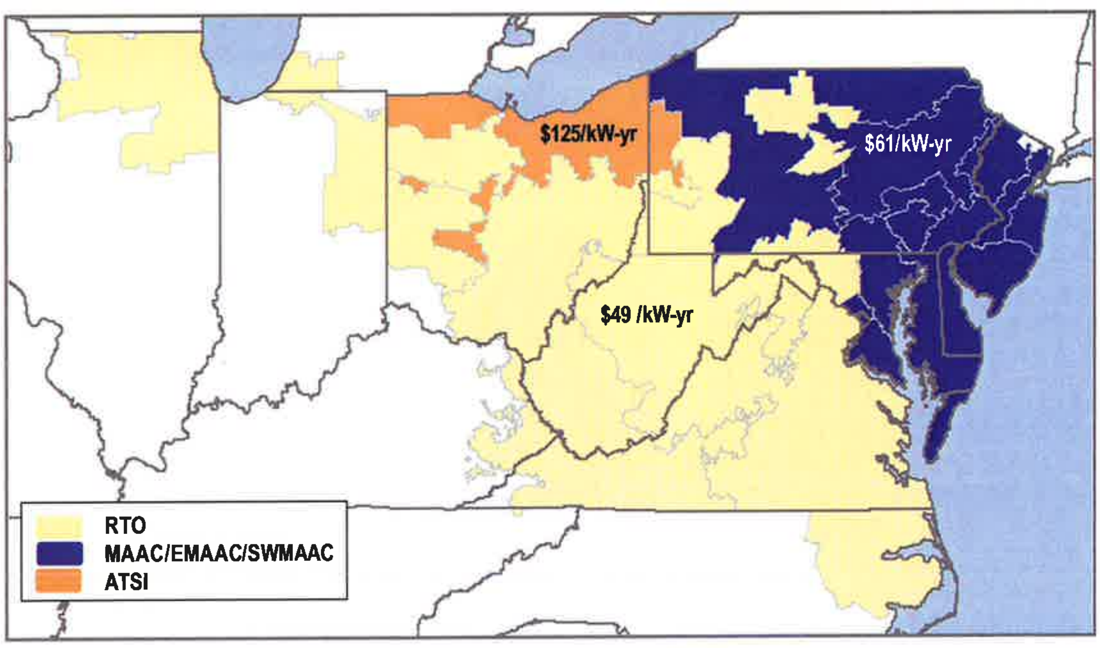
2015-2016 Auction Results

The results for the delivery year June 1, 2015 to May 31, 2016, saw the newly integrated ATSI region break out from the rest of the ISO. In response to significant planned coal capacity retirements in Ohio, the ATSI zone cleared at $125/kW-yr ($357/MW-day). The RTO cleared at $49.6/kW-yr ($136/MW-day), and the MAAC, EMAAC, and SWMAAC regions all cleared together at $61/kW-yr ($167/MW-day). Figure 4 below provides a map of the RPM clearing prices.

Record amounts of new generation and demand and energy efficiency resources cleared the market during the auction. In total, 164,561.2 MW of capacity resources were procured, implying a reserve margin of 20.2% (0.6% higher than the previous year). A key driver of this auction's results was a record amount of planned capacity retirements (nearly 15 GW) that are expected to occur in the next three years. These retirements are driven by the expectation for environmental compliance regulations and costs. Despite a slightly higher RTO-wide reserve margin, transmission constraints and geographically concentrated retirements (especially in the ATSI region) led to clearing prices higher than those seen in the previous auction.

Nearly five GW (71 percent of offers) of new generation, 15 GW (74 percent) of demand response resources, and 900 MW (98 percent) of energy efficiency resources were procured. These were all record highs for the BRA. This auction also followed the recent trend of having an increase in the amount of gas-fired generation that cleared. All resource bids were subject to the MOPR.

Figure 4: 2015-2016 Base Residual Auction Results (Nominal $/kW-yr)

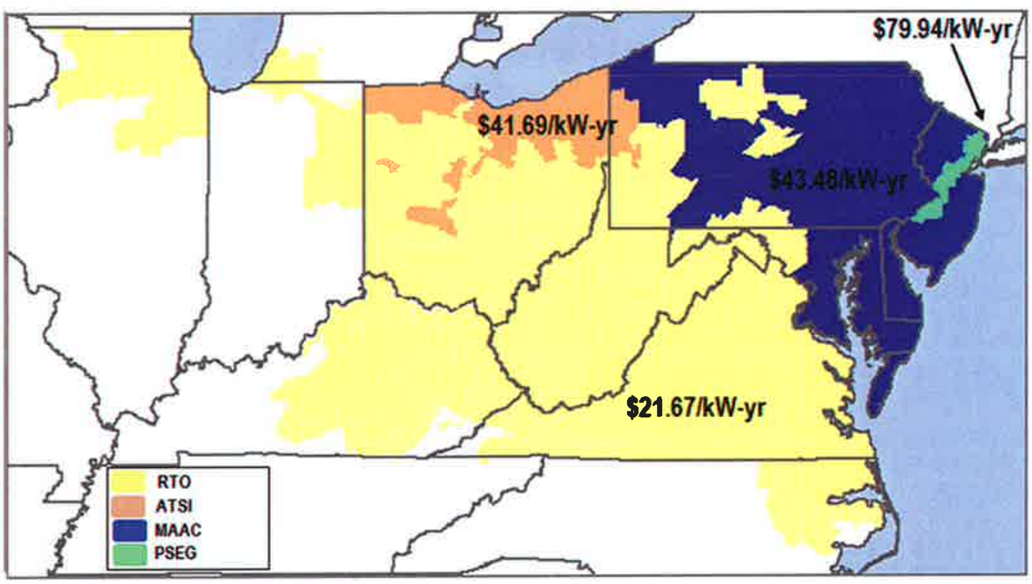


Source: Pace Global and PJM

2016-2017 Auction Results

The 2016/2017 auction for the delivery period June 1, 2016 to May 31, 2017 included the demand and capacity of the East Kentucky Power Cooperative, the newest member of PJM. This auction also utilized a 5% higher Net CONE relative to the 2015/2016 auction, as well as a change in the MOPR. New competitive generation capacity totaling 11 GW was granted MOPR exclusions by FERC for this auction. Roughly 5 MW of competitive and self-supply exempted capacity cleared the auction. As mentioned earlier, the results of this auction included prices that were lower than expected. Prices in the MAAC region cleared at $43.48/kW-yr ($119.13/MW-day), 29% lower than in the previous year. Prices in the ATSI region, which broke out for the first time in last year's auction, cleared at $41.69/kW-yr ($114.23/MW-day). This represents a 68% decrease from the previous year. Prices in the PS region cleared at $79.94/kW-yr ($219/MW-day), roughly 31% higher than in the previous auction. RTO prices cleared at $21.67/kW-yr ($59.37/MW-day), 56% lower than in the previous auction. The lower clearing prices are primarily a result of increased imports from MISO which increased by nearly 90% year-over-year. Other potential drivers include new generation capacity clearing with potential MOPR exclusions and anemic demand growth. The auction also appears to have been significantly influenced by bidding behavior of existing resources, resulting in cleared resources being price takers. Figure 5 below provides a map with RPM clearing prices.

Figure 5: 2016-2017 Base Residual Auction Results (Nominal $/kW-yr)



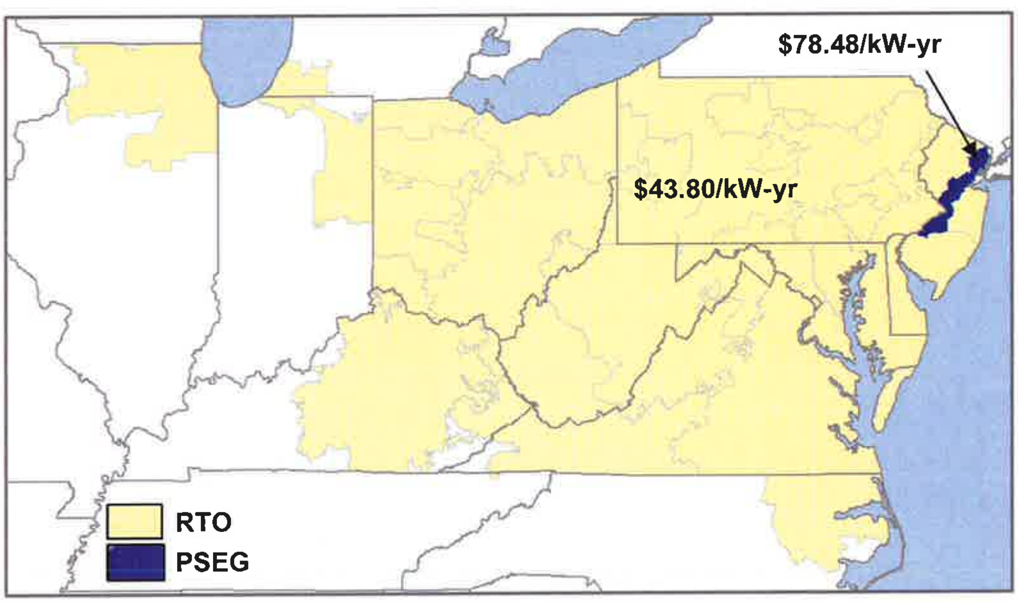
Source: Pace Global.

2017-2018 Auction Results

The 2017/2018 BRA for the delivery period June 1, 2017 through May 31, 2017 saw prices equilibrate across much of the ISO with the Public Service Electric and Gas Company (PSEG) region the only LDA breaking out with higher price separation from the rest of the RTO, as shown in Figure 6 below. Prices across the entire ISO, excluding PSEG, cleared at $43.80/kW-yr ($120/MW-day). This is slightly higher than the previous auction for the MAAC ($119.3/MW-day) and ATSI ($114.23/MW-day) regions, but more than double prices from the previous auction for the rest of the Unconstrained RTO ($59.37/MW-day). Meanwhile, prices in the PSEG LDA cleared about 2% lower than the previous auction, with values at $78.48/kW-yr ($215/MW-day).

The primary change in value from the previous auction resulted in the Unconstrained RTO Locational Delivery Area (LDA) where prices more than doubled year-to-year. Numerous factors contributed to this increase in capacity value. Starting with this auction, PJM introduced the concept of Capacity Import Limits (CIL) which placed a ceiling on the quantity of external resources that could be reliably committed to the PJM grid. This helped contribute to a decrease in external capacity imports of roughly 3 GW from the previous auction levels. In addition, roughly 1.5 GW less of Demand Response resources cleared this auction relative to the prior year. The net decrease in resources procured from external imports and DR led to the need for more than 6 GW of new capacity resources to clear the auction, a record amount in the annual BRA. Finally, lower net revenue expectations from generators from persistently low natural gas prices contributed to higher net CONE values across the system which pushed prices upwards.

Figure 6: 2017-2018 Base Residual Auction Results (Nominal $/kW-yr)



Source: Pace Global.

2018-2019 Auction Results

EMAAC LDA and ComEd LDA were constrained LDAs in the 2018/2019 BRA as shown in Figure 7 below. The RCP for CP Resources located in the rest of RTO outside of these LDAs is \$60.14/kW-year (\$164.77/MW-day). The RCP for CP Resources in the EMAAC LDA is \$82.28/kW-year (\$225.42/MW-day) and RCP for CP Resources in the COMED LDA is \$215.00/MW-day. For comparison purposes, the Annual RCP in the 2017/2018 BRA across the entire RTO was \$43.80 (\$120/MW-day), with the exception of the PSEG LDA where the Annual RCP was \$78.46/kW-year (\$215/MW-day). The primary driver of this increased value was the determination of constrained zones in COMED and EMAAC, as well as a decline in the amount of new capacity bid into the auction (roughly 3 GW less than the 2017/2018) with little additional supply to make up for this shortfall.

Figure 7: 2018-2019 Base Residual Auction Results (Nominal \$/kW-yr)

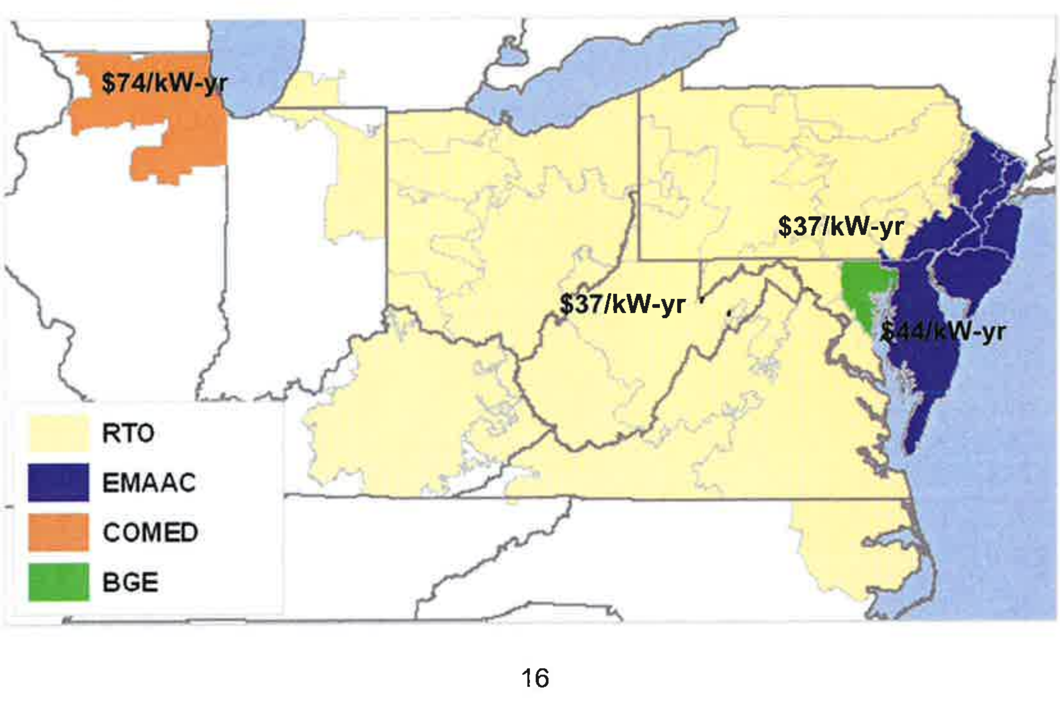
Source: Pace Global.

2019-2020 Auction Results

The RCP for CP Resources located in the rest of RTO is $100.00/MW-day. As shown in Figure 8 below, the EMAAC LDA, ComEd LDA and BGE LDA were constrained LDAs in the 2019/2020 BRA with locational price adders of $7.21/kW-year ($19.77/MW-day), $37.51/kW-year ($102.77/MW-day) and $0.11/kW-year ($0.30/MW-day), respectively, for all resources located in those LDAs. The RCP for CP Resources in the EMAAC LDA is $43.72/kW-year ($119.77/MW-day), the RCP for CP Resources in the COMED LDA is $74.01/kW-year ($202.77 /MW-day), and the RCP for CP Resources located in the BGE LDA is $36.61/kW-year ($100.30/MW-day). For comparison purposes, the RCP for CP Resources located in the rest of RTO in the 2018/2019 BRA was $60.14/kW-year ($164.77/MW-day). The RCP for CP Resources in the EMAAC LDA was $82.28/kW-year ($225.42/MW-day) and the RCP for CP Resources in the COMED LDA was $78.48/kW-year ($215.00 /MW-day) in the 2018/2019 BRA. The BGE LDA cleared with the rest of RTO with a RCP for CP Resources of $60.14/kW-year ($164.77/MW-day) in the 2018/2019 BRA. This decline in prices was driven by an increase in new capacity offered, which resulted in an ISO system-wide reserve margin well above targets.

The 2019/2020 BRA saw a significant increase in procured capacity (5,373.6 MW) compared to 2018/2019 (2,954.3 MW). This increase, coupled with an increase in energy efficiency capacity offered, more than overcame the decline in generation uprates, imports and demand response resources that were offered, increasing the RTO reserve margin to 22.4%, or 5.9% higher than the target margin of 16.5%. The 2019/2020 BRA saw an increase in renewable resources bid into the auction compared to the 2018/2019 BRA, the equivalent of 7,453.8 MW of wind capacity bid into the auction compared to an equivalent of 6,594 MW in the previous auction (wind is credited at 13% of nameplate capacity). For solar, these values were 881.6 MW and 483 MW, respectively (at a 38% nameplate credit). These bids point towards a continued and escalating share for renewables of PJM system-wide capacity for at least the near term.

Figure 8: 2019-2020 Base Residual Auction Results (Nominal $/kW-yr)



Source: Pace Global.

ANCILLARY SERVICES MARKET

Ancillary services support the reliable operation of the transmission system. Currently, PJM operates two ancillary service markets: Regulation service and Synchronized Reserve service.

- Regulation services supply the grid with electricity on short notice. Providers of synchronized reserves must have the capacity with the ability to ramp up quickly in response to an immediate need for additional power. Demand resources are also eligible to review synchronized reserve payments.

- Synchronized Reserve services account for minor short-term changes in power demand by helping match generation to load in real-time. LSEs can provide regulation by using their own generation to meet load, or by purchasing it from the market. PJM operates two Synchronized Reserve markets: The RFC Synchronized Reserve Zone is governed by the ReliabilityFirst Corporation, and the Southern Synchronized Reserve Zone is governed by SERC.

In addition to Regulation services and Synchronized Reserve, Black Start Service supplies electricity for system restoration in the unlikely event that the entire grid would lose power. In addition, to ensure adequate operating reserve and for spot market support, pool-scheduled generation and demand resources that operate as requested by PJM are guaranteed to fully recover their daily offer amounts. As part of reactive services, in case the output of generating resources is altered by PJM for the purpose of maintaining reactive reliability, these generating resources are guaranteed to fully recover their daily offer amounts or compensated for their lost opportunity costs. Furthermore, daily credits are provided to eligible generators and demand response resources that clear day-ahead based on their cleared MWh of day-ahead scheduling reserve times the day-ahead scheduling reserve clearing price.

As per the October 2012 PJM rule changes, if the plant has a historical precedence of performing well in terms of responding to ancillary service requests, they are more likely to be called upon to provide ancillary services in the future. The new PJM rules introduced Performance-based Regulation to comply with FERC Order 755. The regulation provides for better aligning of compensation with actual performance for resources that provide regulation service. The new compensation structure creates greater incentive compensation for high performing existing units and incentive for development of new, fast responding technologies such as batteries or flywheels to participate in the market.

ENERGY MARKET

The PJM ISO operates a multi-settlement system for energy transactions under a locational marginal pricing system. The following section summarizes the mechanics of this system.

Day-Ahead Market

One day prior to actual dispatch, market participants submit supply offers and demand bids for the upcoming day. Using these offers and bids, the ISO constructs aggregated supply and demand curves for each node. By means of a least cost security constrained dispatch algorithm, the ISO determines the market clearing price – the intersection of the supply and demand curves. Offers that clear are the supply quantities below the clearing price, and bids that clear are the demand quantities above the clearing price.

The pre-cleared quantities imply flows across the transmission system to satisfy load at each node. The ISO performs a simultaneous feasibility test to identify transmission constraints that would inhibit these flows and re-dispatches the system to compute adjusted prices at source and sink nodes, known as Locational Marginal Prices ("LMP"). LMP is intended to incent the siting of capacity near load centers and are calculated as follows:

$$LMP = System\ Marginal\ Price + Marginal\ Losses + Congestion$$

Cleared supply quantities are paid the LMP at the relevant source node. Cleared demand quantities pay the LMP at the relevant sink node (or an average price for all nodes in a demand zone).

The day-ahead market cleared quantities serve as schedules of supply and demand for the upcoming day. The schedules are financial and not physically binding. They function as forward contracts between suppliers and load serving entities. Scheduled supplies must produce the committed day-ahead quantities the following day, in real-time, or buy power in the real-time market to replace quantities not generated. Similarly, demand quantities have the right to consume the day-ahead quantity at the day-ahead clearing price. Demand that exceeds the day-ahead amount is purchased in the real-time market at real-time LMPs.

Real-Time Market

The real-time market is a spot market for electricity. The spot prices for energy are calculated at 5-minute intervals and reflect current system conditions notably, actual demand, generator availability, and transmission congestion. If these system conditions differ from the conditions assumed at the time of the day-ahead market, then generation schedules and demand consumption will differ from the schedules determined in the day-ahead market settlement. These deviations are established and priced in the real-time market settlement.

Generators with supply offers that did not clear in the day-ahead market may resubmit adjusted offers into the real-time energy market. During the real-time dispatch, the ISO is continuously monitoring system conditions and actual demand to anticipate projected needs, and, if necessary, to commit any additional resources not already scheduled in the day-ahead settlement.

Based on anticipated conditions, the ISO produces expected real-time price signals and associated generation dispatch amounts. Generators are expected to meet these dispatch requirements – if they do not, actual realized prices will differ from the ex-ante price signals. Therefore, the generators will set real-time prices only if they adhere to the dispatch requirements.

Real-time market settlement produces LMPs for each pricing node based on actual system conditions and transmission congestion. All deviations from the day-ahead supply and demand schedules are settled at the real-time prices. Suppliers who do not produce their day-ahead commitments pay real-time prices for quantities not produced. Suppliers who produce more than their day-ahead schedules are compensated at real-time prices for quantities exceeding day-ahead commitments. Similarly, demand bidders are paid (or pay) the real-time prices for day-ahead quantities not consumed (or additional consumption) in real-time. In this fashion, the real-time settlement is a balancing market for energy.

FINANCIAL TRANSMISSION RIGHTS

The PJM-ISO uses a combination of Financial Transmission Rights ("FTR") and Auction Revenue Rights ("ARR") to distribute revenue related to transmission congestion and allow market participants to hedge risks associated with such congestion.

Financial Transmission Rights ("FTR") are defined as "financial instruments…that entitle the holder to a stream of revenue (or charges) based on the hourly Day Ahead congestion price difference across the path." The purpose of FTRs is to allow market participants to hedge against the risk of congestion charges. The need for FTRs arose due to the ISO collecting greater revenues from load-serving entities than it paid to generators during periods of congestion. FTRs are available as an obligation or as an option. Options can have only positive values, while obligations can have negative values if congestion occurs in the opposite direction of the FTR.

Auction Revenue Rights ("ARR") award the holder the right to receive an allotment of the revenues collected during PJM's annual and monthly FTR auctions. No auctions are used to allocate ARRs to market participants. ARRs are distributed to firm PJM transmission service and firm point-to-point transmission customers, at no cost. ARRs designate a specific pathway and megawatt value that corresponds to certain FTRs that are to be sold during auctions.

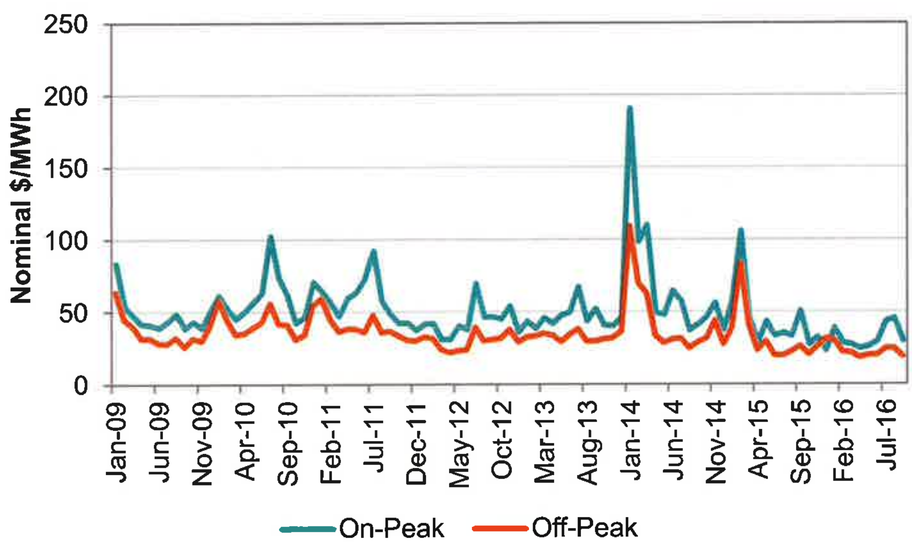
The ARR allocation is a multistage process. LSEs first apply for ARRs from specific resources along paths that serve their load. Later stages in the process allow the LSEs to then request any remaining ARRs throughout the system along paths that serve their load. At the end of each stage, a security constrained analysis of the requests for ARRs is performed in order to allow the PJM to remain revenue neutral. The analysis is designed to prevent the allocation of insufficient or excess ARRs during the allocation process.

Holders of ARRs can either convert them into FTRs for their own use or make them available in FTR auctions. ARRs are allocated to LSEs only on an annual basis, subject to reassignment due to load switching between LSEs and are only available and convertible to market participants as an obligation. Therefore, holders of FTR obligations hold a liability when they are acquired from the PJM. If congestion is negative, or traveling in the reverse designation of the ARR, the holder of the FTR would be forced to compensate the PJM for the congestion.

HISTORICAL ENERGY PRICES

Figure 9 and Table 1 below provide a summary of historical monthly electricity prices for the PJM-DPL zone. Prices in this region closely follow the price of natural gas, which is marginal for many hours of the year. This can be seen in a sharp decline after commodity prices fell in 2008, with the price of natural gas bottoming out in the spring of 2012. Power prices in the first half of 2014 spiked due to the extremely cold winter, which caused plant outages, reduced working gas storage levels, and drove up natural gas prices in PJM. Other spikes tend to happen during the summer months when power demand is high and scarcity pricing is evident.

Figure 9: Monthly PJM DPL Energy Prices 2009-2016 (Nominal $)



Source: Pace Global and PJM ISO.

Table 1: Peak and Off Peak Monthly Energy Prices (Nominal $/MWh)

PJM DPL	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2009	83.49	53.68	47.37	41.52	40.84	39.20	43.25	48.75	38.50	43.04	39.02	50.88
2010	61.30	52.04	45.00	50.10	56.42	63.01	102.51	73.08	61.16	42.41	46.35	70.68
2011	64.55	56.30	47.07	59.66	63.35	72.55	92.37	57.62	48.66	42.12	42.35	37.30
2012	41.58	42.08	31.08	30.90	40.23	37.98	69.77	46.41	46.61	45.18	54.22	36.12
2013	43.52	38.47	46.03	42.09	47.66	49.81	67.30	43.62	52.12	40.71	40.25	45.95
2014	190.83	98.44	110.20	49.60	47.89	64.58	56.95	37.47	41.32	46.65	56.43	37.69
2015	57.30	105.99	46.49	28.86	43.42	33.50	35.45	33.16	50.75	27.50	32.50	23.20
2016	38.83	28.62	27.34	24.60	26.23	29.64	43.48	45.64	29.94			

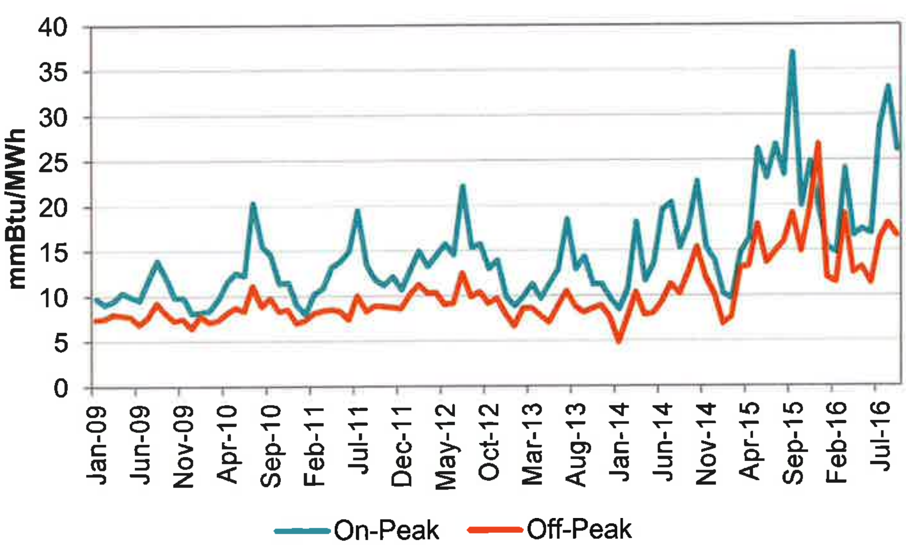
PJM DPL	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2009	63.80	44.57	40.10	31.51	31.80	28.35	28.08	32.39	26.02	31.81	29.83	40.62
2010	58.10	44.11	34.21	35.28	39.23	42.86	56.17	41.79	41.04	30.95	34.28	54.84
2011	59.33	44.67	36.44	38.56	38.29	36.00	47.66	35.76	36.80	33.43	30.51	30.02
2012	32.74	31.66	24.19	22.04	23.21	23.93	39.46	29.94	30.99	31.81	37.76	29.20
2013	32.63	33.42	35.28	33.95	29.50	34.20	38.34	29.70	29.71	31.12	31.84	36.30
2014	109.36	69.74	62.97	33.62	28.57	30.93	31.72	25.03	29.08	31.69	44.00	27.73
2015	38.64	83.76	41.08	23.49	29.65	19.93	19.71	22.64	26.30	20.55	25.85	31.70
2016	30.53	22.19	21.66	18.51	19.89	19.97	24.58	24.87	19.06			

Source: Pace Global and PJM ISO.

HISTORICAL MARKET HEAT RATES

Figure 10 below shows the historic market heat rates for the PJM DPL zone. The very low off-peak heat rates seen in 2008, and prior, came as a result of high gas prices and coal influence on power prices from neighboring PJM regions, particularly during the off-peak period. Since the collapse in gas prices in 2009, the implied heat rates have steadily increased due to consistently low natural gas prices. However, in Eastern PJM and the DPL zone, summer scarcity has been high, with summer heat rates around 20 MMBtu/MWh. High electricity demand during the winter cold snap in early 2014 resulted in high market heat rates normally seen during the summer months.

Figure 10: Historical PJM DPL Market Heat Rates (2009-2016)



Source: Pace Global, PJM ISO, and SNL.

MARKET DEMAND PROFILE

Electricity prices are driven in part by the growth in electricity demand. Pace Global has developed an independent demand forecast for PJM and surrounding regions.

Pace Global's independent demand forecast is based on current and projected economic conditions along with normal weather. The projected peak demand forecast is shown in Table 2 below, and the average demand projections are shown in Table 3 below. The peak and average demand growth rates over the forecast time horizon tend to be around one percent, with variations across the PJM footprint.

Table 2: Peak Demand Projections for PJM (MW)

Year	AEP	APS	Central	ComEd	DPL	East	ATSI	Penelec	South	Dom.
	MW	*MW*	*MW*	*MW*	*MW*	*MW*	*MW*	*MW*	*MW*	*MW*
2017	33,553	7,869	9,153	20,326	3,639	25,715	12,131	2,770	11,994	18,497
2018	33,959	7,963	9,242	20,526	3,661	25,906	12,281	2,827	12,063	18,893
2019	34,138	8,005	9,300	20,767	3,672	25,916	12,346	2,823	12,101	19,176
2020	35,368	8,460	9,820	21,428	3,815	26,526	12,792	2,901	12,848	19,680
2021	35,478	8,463	9,817	21,429	3,823	26,350	12,844	2,909	12,813	19,909
2022	35,781	8,481	9,810	21,579	3,816	26,433	12,953	2,912	12,787	20,094
2023	36,040	8,494	9,823	21,776	3,809	26,497	13,055	2,918	12,851	20,279
2024	36,275	8,555	9,921	21,972	3,825	26,541	13,127	2,926	12,872	20,532
2025	36,444	8,611	9,981	22,108	3,852	26,553	13,180	2,959	12,910	20,691
2026	36,557	8,654	10,009	22,306	3,862	26,752	13,211	2,984	12,990	20,788
2027	36,761	8,675	10,133	22,448	3,873	26,768	13,291	3,001	13,012	21,078
CAGR 2017-27	0.8%	0.9%	0.9%	0.9%	0.6%	0.4%	0.8%	0.7%	0.7%	1.2%

Source: Pace Global.

Table 3: Average Demand Projections for PJM (MW)

Year	AEP	APS	Central	ComEd	DPL	East	ATSI	Penelec	South	Dom.
	MW	*MW*	*MW*	*MW*	*MW*	*MW*	*MW*	*MW*	*MW*	*MW*
2017	24,105	5,777	6,717	11,864	2,197	14,000	7,957	2,151	7,593	11,506
2018	24,438	5,849	6,795	12,050	2,215	14,151	8,070	2,178	7,647	11,822
2019	24,614	5,890	6,831	12,158	2,223	14,190	8,128	2,193	7,682	12,019
2020	24,664	5,899	6,800	12,169	2,220	14,126	8,143	2,196	7,682	12,041
2021	24,799	5,926	6,811	12,247	2,226	14,098	8,189	2,207	7,706	12,174
2022	24,991	5,959	6,833	12,358	2,230	14,126	8,253	2,219	7,733	12,295
2023	25,185	5,988	6,857	12,465	2,236	14,157	8,318	2,230	7,757	12,434
2024	25,366	6,026	6,900	12,594	2,246	14,211	8,379	2,244	7,798	12,584
2025	25,559	6,064	6,942	12,727	2,254	14,250	8,441	2,258	7,834	12,728
2026	25,729	6,101	6,987	12,852	2,263	14,296	8,494	2,272	7,865	12,841
2027	25,929	6,140	7,045	12,994	2,271	14,337	8,559	2,286	7,903	12,996
CAGR 2017-27	0.7%	0.6%	0.4%	0.8%	0.3%	0.2%	0.7%	0.6%	0.4%	1.1%

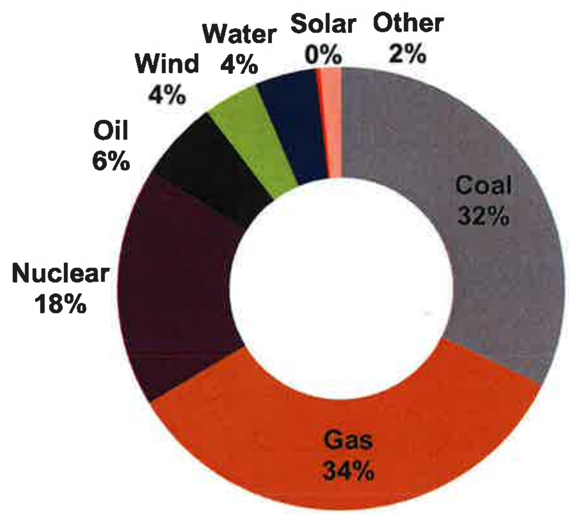
Source: Pace Global.

MARKET SUPPLY PROFILE

EXISTING GENERATING CAPACITY PROFILE

Figure 11 below displays the current installed generating capacity mix for PJM. The total installed capacity is close to 200 GW. As shown, around a third of the total is currently coal-fired, with another 34 percent from natural gas. Nuclear capacity is also significant, with renewables and oil-fired steam capacity making up the remainder. While eastern PJM has a gas-dominant capacity mix, generating resources in the west are currently dominated by coal, with significant electricity flows eastwards towards higher demand locations.

Figure 11: Installed Capacity Profile for PJM (MW)



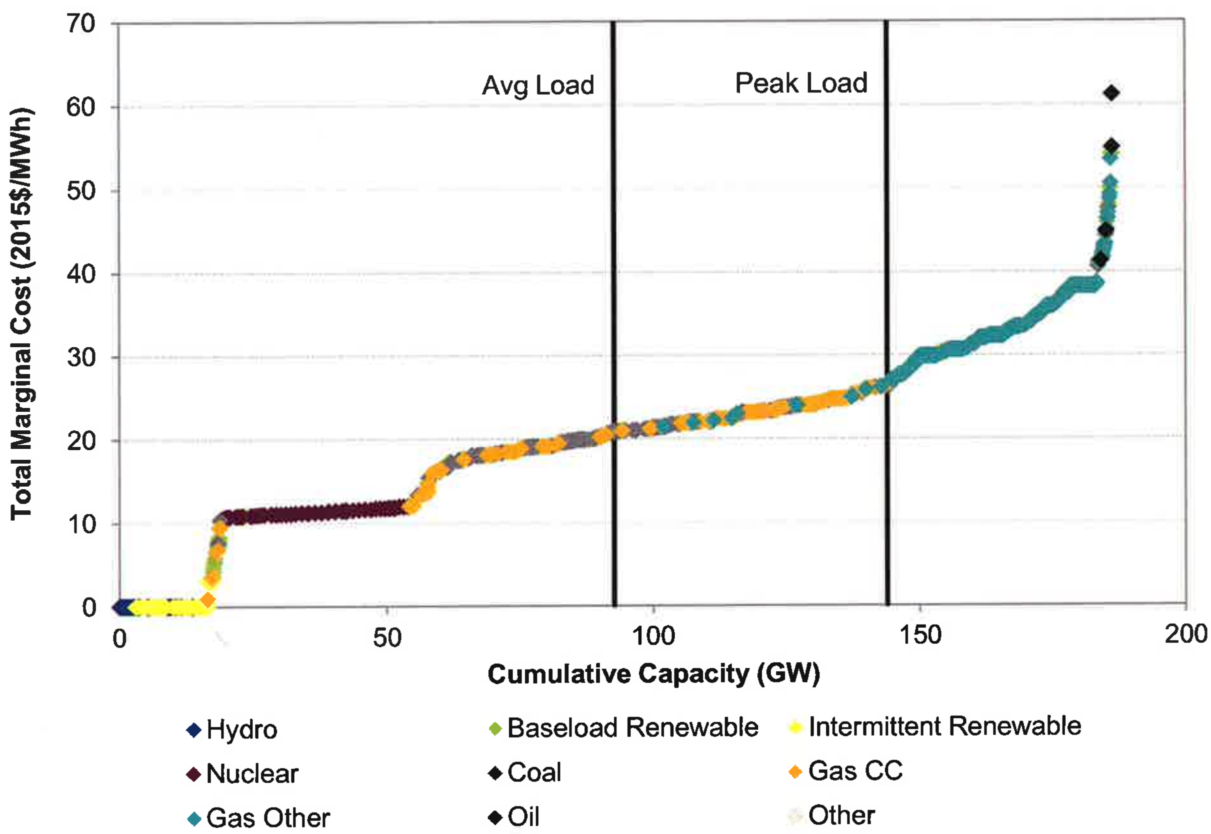
Source: Pace Global and PJM.

SUPPLY CURVE

Figure 12 below displays the existing supply curve for the PJM region for year 2016 based on the capacity of the installed resources. The vertical axis represents the variable cost of generation expectations at specified levels of supply.

For the PJM region, the supply curve indicates that the baseload capacity is derived from primarily nuclear, coal-fired and natural gas-fired resources. Given the current closeness of marginal costs between coal plants and efficient combined cycle gas plants, this capacity competes directly for many hours of the year. During peak demand hours, coal and gas-fired peaking units are expected to set the price of power.

Figure 12: PJM Supply Curve (2016)



Note: Some oil-fired units with significantly high marginal costs are not shown in this graphic.

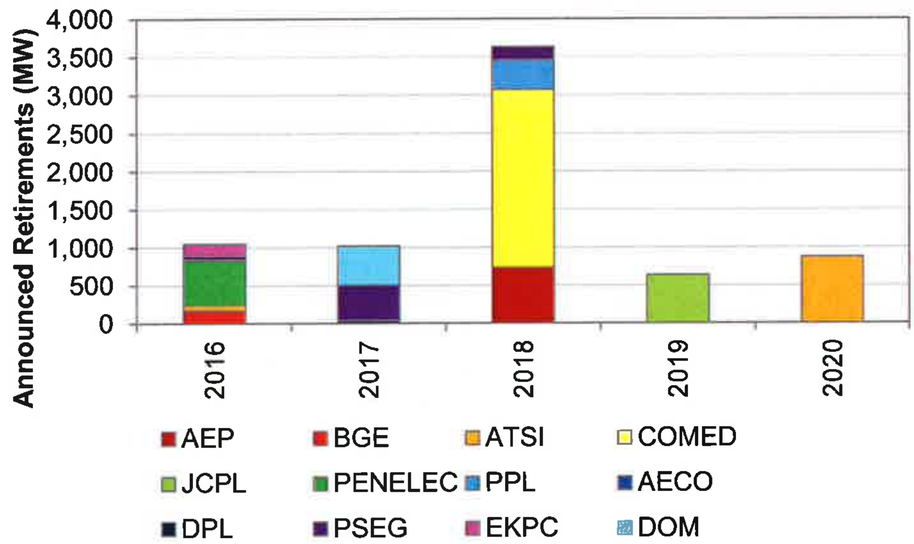
Source: Pace Global, Energy Velocity.

CAPACITY RETIREMENTS

Figure 13 below displays the current announced retirements in PJM. Due to the Mercury and Air Toxics Standard (MATS) rules[12] becoming effective recently, the ISO has seen its highest record of retirements in year 2015. Roughly 60% of announced coal retirements until year 2021 are in the AEP, ComEd, and adjoining ATSI and DEOK zone. In addition to the listed announced retirements, Pace Global expects a significant amount of additional coal capacity to be at risk of retirement as a result of pending EPA regulations, continued low gas prices, and potential future carbon compliance costs impeding the ability of the coal industry to cover fixed costs. For comparison, Figure 14 below shows the total capacity retired in PJM since 2000 for comparison.

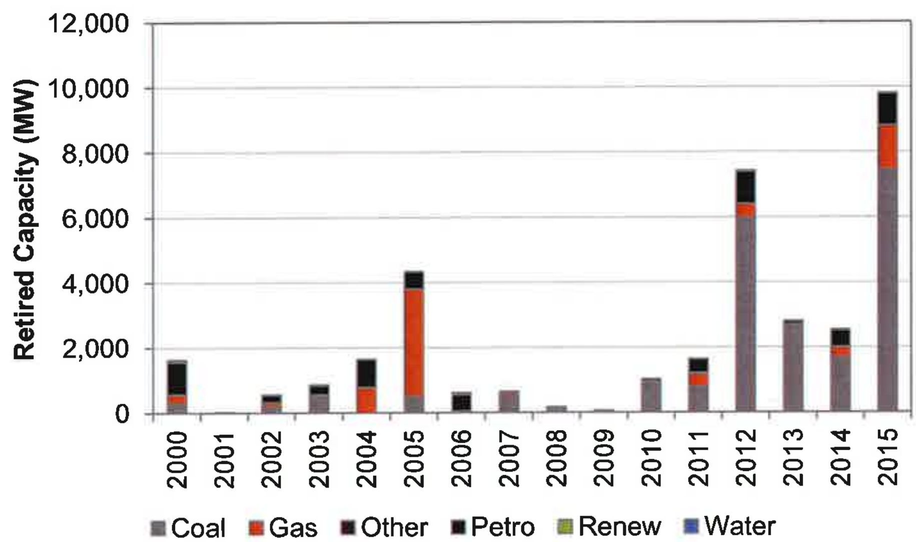
[12] https://www.epa.gov/mats/regulatory-actions-final-mercury-and-air-toxics-standards-mats-power-plants

Figure 13: **PJM Planned Retirements by Zone**



Source: Pace Global, Energy Velocity, Nuclear Regulatory Commission, and EIA

Figure 14: **Historical PJM Capacity Retirements**



Source: Pace Global analysis of Energy Velocity data.

CAPACITY EXPANSION

In assessing future capacity expansion, Pace Global reviews announced projects and included those that are in advanced stages of development, including projects under construction in its analysis.

Reserve margins are expected to fall in the near term due primarily to generation retirements, and new capacity additions are already under construction throughout the ISO, having cleared in the last few capacity auctions. In the near term, the 780 MW CPV St. Charles plant and the 1,000 MW Wildcat plant in Maryland are the most relevant new gas-fired additions near the DPL Zone. Beyond announced capacity, Pace Global's analysis builds generic capacity additions in response to economic signals from the energy, capacity, and REC markets.

APPENDIX 8

Appendix 8
Fuel Market Assessment

PRICE RELATIONSHIPS AMONG FUEL MARKETS

The petroleum, natural gas and coal markets each have their own distinct pricing dynamics. However, fuel interchangeability in some end-use applications, and oil-based natural gas pricing conventions in Europe and Asia, create value linkages that can often overshadow other value considerations, creating a degree of price correlation. An example is the New England heating market, where fuel oil and natural gas compete for market share. Although short-term fuel switching capability is limited to the largest residential and commercial heating systems, the price of heating oil provides a soft cap on natural gas prices in the region. While gas prices usually move independently of heating oil prices, when demand is high and supplies are tight the two commodities trade in close correlation to spot markets. Similarly, while coal-gas-oil interchangeability is limited to a relatively small number of large boilers, an increase in oil and gas prices allow coal producers to raise prices without fear of market share loss, creating another weak but evident link. Conversely, a fast drop in natural gas prices to low levels, such as those that prevailed in early 2012, much of 2015, and again in early 2016, can induce some fuel switching and put downward pressure on coal prices. In general, the price correlation of oil and gas markets has been closer than that of gas and coal markets in the U.S., but deviations from any established pricing relationship between the fuels can be prolonged and significant if the supply/demand balances in any two commodities are out of step.

Generally speaking, the crude oil market is truly a global market, with prices adjusted consistently for locational value and product quality. Price deviations only arise due to a mismatch between the availability of a particular grade of crude and market demand or compatible refinery capacity. The second half of 2014, when oil prices dropped precipitously, demonstrated that such price deviations will readily occur when markets are out of balance. The strength of global oil supplies from U.S. shale, uninterrupted Iraqi capacity, and continuing OPEC production, combined with slowing demand growth in Europe and China, resulted in a more than 50 percent decline in prices from $107 to below $50 by the end of 2014, below $30 by early 2016, and $45 by mid- to late-2016. But oil is easily and cheaply transported by pipe, rail, truck or ship, and is easy to store in above-ground tanks. Natural gas, by contrast, is relatively difficult and expensive to transport and store, requiring high-pressure pipelines and underground reservoirs to contain and control the gaseous fuel. Therefore, natural gas markets have historically been geographically demarcated by integrated production, transmission, storage and distribution systems that are self-contained and largely isolated from other such systems.

In Europe and Asia, the natural gas industry was created and managed primarily by central governments, large state-sanctioned monopolies, and a handful of dominant suppliers of both pipeline gas and ocean-borne liquefied natural gas (LNG), a super-cooled fluid with 600 times the energy density of vapor-phase natural gas. In such concentrated and controlled markets, crude oil and oil product prices have been used as a fair-value metric for pricing both domestic gas supplies and imported volumes. By contrast, the North American gas industry emerged from the independent efforts of thousands of privately-owned producers, pipelines, local distributors and major consumers, and has been predominantly self-sufficient through its evolution over the past 200 years. Therefore, in the 25+ years since wellhead price decontrol came to the U.S. and Canada, the North American gas market has been a generally self-contained and independent commodity market, with prices governed by local supply and demand balances on a daily basis. Regional markets are well integrated by an extensive system of pipeline infrastructure, and the high level of transparent transactional activity that provides a reliable price discovery mechanism. As a result, the statistical correlation of price changes in gas and oil markets has been loose over the last decade, and correlation between the two commodities is currently very low.

If and when the U.S. starts competing for LNG cargoes during periods of high demand (major LNG markets are all located in the Northern Hemisphere and experience synchronous peaks in demand), there would be a growing gravitational pull on the U.S. gas market to align itself with world LNG market pricing. In light of the many independent market developments needed to produce this effect, the timing and sequencing of its occurrence is impossible to predict with any accuracy, but increasing North American statistical price correlation between oil and gas could become evident towards the end of this decade or might be deferred for many years to come, if ever, if domestic gas resources are aggressively developed.

As the global oil market is least affected by the price of other fuels, Pace Global's market driver summary for the petroleum market is presented first.

PETROLEUM

WTI Crude Oil Prices

After hovering between $20 and $40/bbl for two decades, crude oil prices have shown significant increases in volatility during the past seven years. Between summer 2008 and summer 2009, the market value of a barrel of West Texas Intermediate ("WTI") crude oil varied by roughly $110, with the crude price touching $147/bbl in July 2008 before dropping to below $40/bbl in January and February of 2009 and then rebounding back to the $70-80/bbl level where they remained through the end of 2010. In 2014, increased production of crude oil in the Permian Basin began to outpace pipeline infrastructure to move the crude to refineries, causing prices for crude in the Permian at Midland, Texas, to fall below similar crudes priced at Cushing, Oklahoma. In addition, West Texas Sour began to trade at times at a $10 premium to WTI. This was a temporary differential but it highlighted the impact of infrastructure constraints as the continent adjusts to changing supply dynamics (e.g., rising crude production from the Bakken, Permian, and Eagle Ford).

Market fundamentals were a significant part of the large price swings, but clearly the financial and economic downturn – first in the U.S. but quickly spreading around the world – played a substantial role. In 2011, despite a 4 percent increase in domestic production, prices rose to an annual average of $95/bbl as unstable political conditions in oil-producing regions of the Middle East and North Africa (MENA) threatened the global supply. In the second half of 2014, the combination of rapidly increasing North American crude production, rolling crises in the Middle East and North Africa region, and a slowing rate of growth in consumption in many regions have swung the pendulum hard toward an oversupply situation, causing prices to plummet. Whereas the average spot price in 2013 was just under $100/bbl, and in 2014 was just over $96/bbl, the price of crude oil crashed to below $50 in early January 2015 and averaged just under $49/bbl in 2015. WTI bottomed out at $26/bbl in February 2016 and is currently at $45/bbl in early October 2016. Figure 1 shows historical WTI prices combined with current forwards.

Pace Global anticipates the oversupply situation to persist for some time, keeping downward price pressure on crude oil for the next 1-2 years, with geopolitical factors playing a large role in particular the OPEC cartel which opted for the most part to sustain production. OPEC voted in late September 2016 to curtail production by just 2%, which caused an immediate jump in price of 5%. But OPEC market share has been stagnant since 2015, at 32% of global production, and is not likely to have an outsize impact on markets. Although many countries depend heavily on high oil prices to maintain their state-subsidized social spending plans, the OPEC heavyweight, Saudi Arabia, has sufficient sovereign wealth fund reserves to withstand up to three years of $50/bbl oil. Furthermore, they are likely to come out stronger in a low-price environment that will cull many overly-leveraged shale producers. They also benefit from seeing the rug pulled out from under their regional rivals, Iran and Syria. Meanwhile, in the U.S., oil production continued to grow for much of 2015 largely due to momentum and targeted drilling and despite the reduction in capital expenditures for new exploration and production. Companies focused heavily on the most productive areas of their portfolios, producing more barrels with fewer drilling rigs and well completions. At the same time, uncertain demand growth prospects in much of the EU region as well as relatively slower growth in China (forecasted by the IMF at 6.3 percent for 2016, a significant slowdown from recent years) will help to keep prices low on lower demand, though the low prices themselves will eventually spur an increase demand.

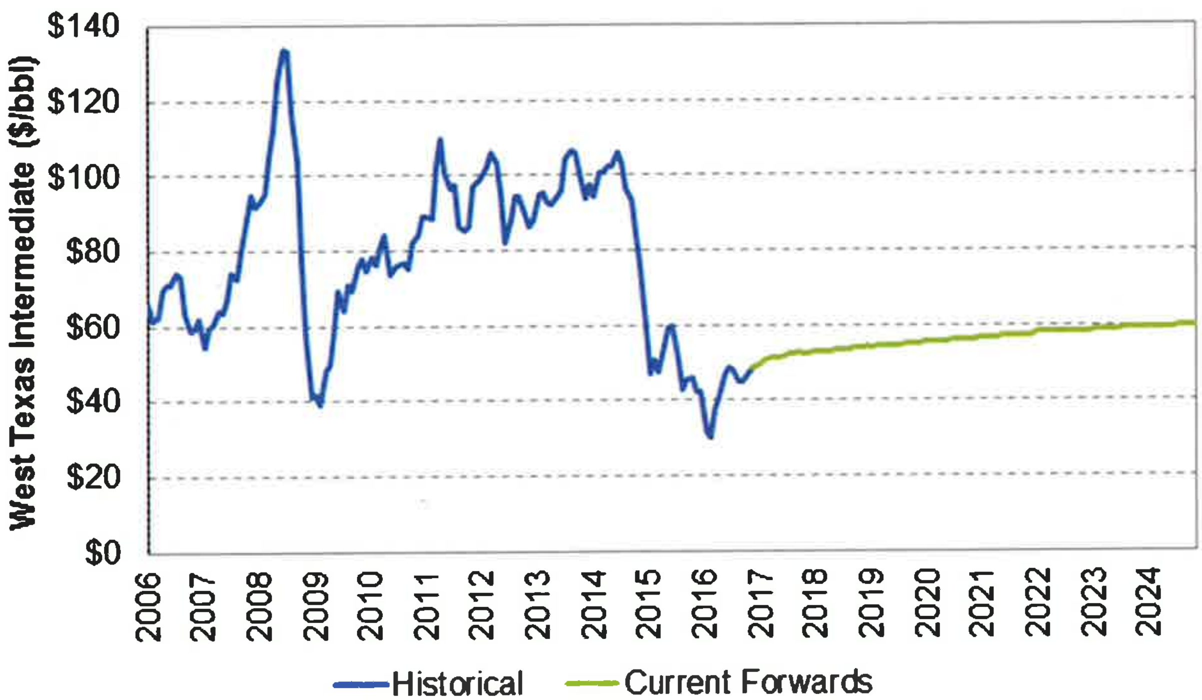
This decline in crude oil prices is not expected to significantly impact the regional natural gas prices. Crude oil and natural gas are linked insofar as crude oil production often results in gas production, known as associated gas. Currently, about 14 percent of gas produced in the U.S. is associated gas, mostly in the Bakken (ND), Eagle Ford (TX), Permian (TX) and Woodland (TX-OK) plays. An additional link between these two commodities is through natural gas liquids (NGLs). NGL pricing is highly correlated to the price of oil and NGLs like propane and butane have provided additional revenue uplift to producers who sought higher returns from the NGLs that, until recently, were more valuable than gas.

With oil at approximately $45/bbl in late-2016, oil-directed drilling has been curtailed and the NGL uplift revenue has vanished. Producers have pulled back on new drilling in plays such as those mentioned above. While oil-directed rig counts have declined, oil production increased for much of 2015 and leveled off in late 2015/early 2016. This is because many producers have a range of acreage in their portfolios that allow them to reduce drilling, concentrate on the most highly productive acreage, and increase production by focusing on the most productive wells. This strategy will work for some time, but we are seeing that in 2016 production is declining without additional drilling.

Gas-directed rigs have also declined with the drop in the price of gas. Most producers have announced their capital expenditure plans and production targets for 2016. Although CAPEX plans are down sharply, overall gas production has continued to grow, in large part because most dry gas plays continue to be economic at today's gas prices. Breakeven prices in the Marcellus range from $1.50-3.00/MMBtu, which with today's prices is sufficient to incentivize continued production. In addition, regional prices in the Marcellus are improving as new pipeline projects provide incremental takeaway capacity that relieves the downward price pressure from overproduction.

So, whereas oil prices have had an effect on gas production in places like the Bakken, Eagle Ford, Permian and Woodland plays, and to a small extent in the Utica play, Pace Global expects Marcellus and Utica gas production to grow from 21.1 Bcf/d in July 2016 to 26.8 Bcf/d by December 2020. Natural gas prices would need to remain below $2/MMBtu for an extended period of time for there to be a significant curtailment in Marcellus production and significantly impact regional gas prices, but we have already seen Henry Hub prices rise to $2.70/MMBtu in the summer of 2016.

Figure 1: **Historical and Forward WTI Prices (Nominal$/Bbl)**



Source: Pace Global. Forwards as of 10/03/16.

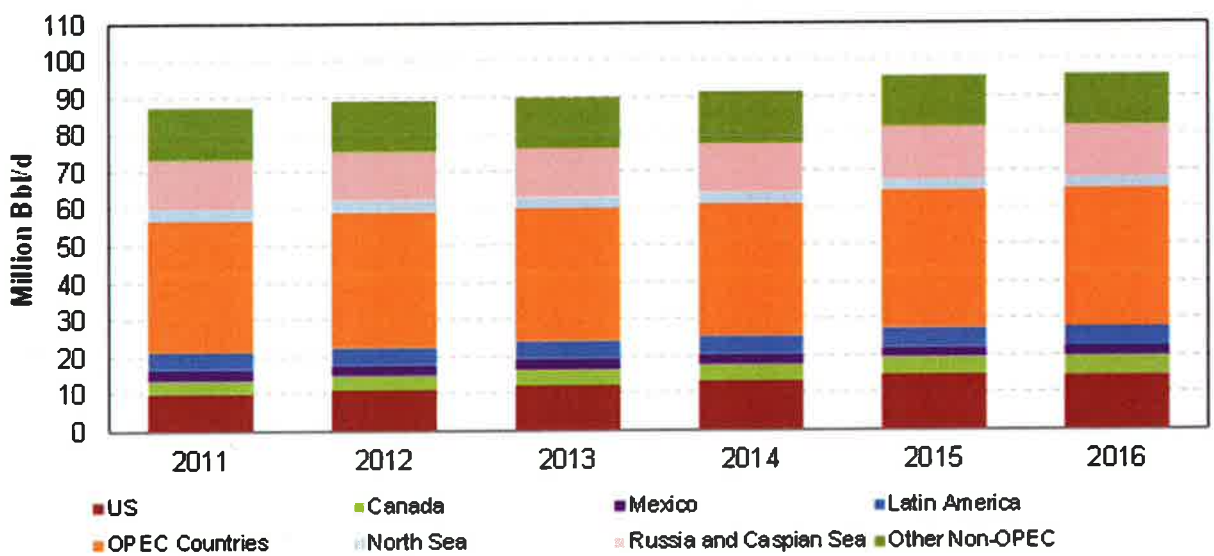
Oil Demand

As noted above, the U.S. economy preceded the rest of the world into economic recession during 2008, dragging oil consumption down 6 percent from 2007 levels. The OECD as a whole saw oil demand fall 3.6 percent, while global demand fell by less than one percent, given positive yet tempered growth in Chinese demand and continued demand growth in other non-OECD countries, particularly the Middle East. Domestic consumption increased 2.0 percent year-over-year in 2010, in line with modest economic recovery, but since then the trend has been generally downward. Consumption fell by 1.3 percent and another 1.8 percent in 2011 and 2012, respectively, before recovering 2.1% in 2013, as prices hovered between $90-110/bbl. Demand in 2014 was only 0.3% higher than the year before, but 2015 and 2016 saw an increase in consumption as automobile drivers, refiners, and other consumers took advantage of low prices.

Oil Supply

Global oil production by region, which has remained fairly consistent over the last several years, is provided in Figure 2 below. The recent EIA update on non-OPEC oil production shows that the steadily climbing oil price from 2003 into 2008 has borne fruit in terms of new production in 2009 and 2010, but these gains were largely offset by major declines in Mexico's giant Cantarell Field and aging North Sea properties. OPEC crude oil production was 33.1 million bbl/d in 2009, down 2.5 million bbl/d from year-earlier levels, in recognition of record-high inventory levels in the U.S. and elsewhere. It fell an additional 10 percent in 2010 to land at 29.8 million bbl/d; 2011 consumption increased by only 0.2 percent. OPEC production rebounded to 30.9 million bbl/d in 2012, representing a 3.6 percent year-over-year increase. OPEC production reached 32 million bbl/d in mid-2016. Meanwhile, global crude oil production grew by 2.6 percent year-over-year in 2012, to over 86 million bbl/d, and grew a modest 0.7 percent in 2013 to reach over 86.8 million bbl/d. As of mid-2016, global demand was 94.5 million bbl/d and falling. The U.S. continues to lead the world in crude production growth, which increased by nearly 50% (2.4 MMbbl/d) between 2008 and 2013. Pace Global expects the oversupply situation to persist for the next few years, which, coupled with declining demand, will weigh on global prices.

Figure 2: Oil Production by Region (Million Bbl/d)



Source: BP Statistical Review of World Energy 2016, Pace Global

NATURAL GAS

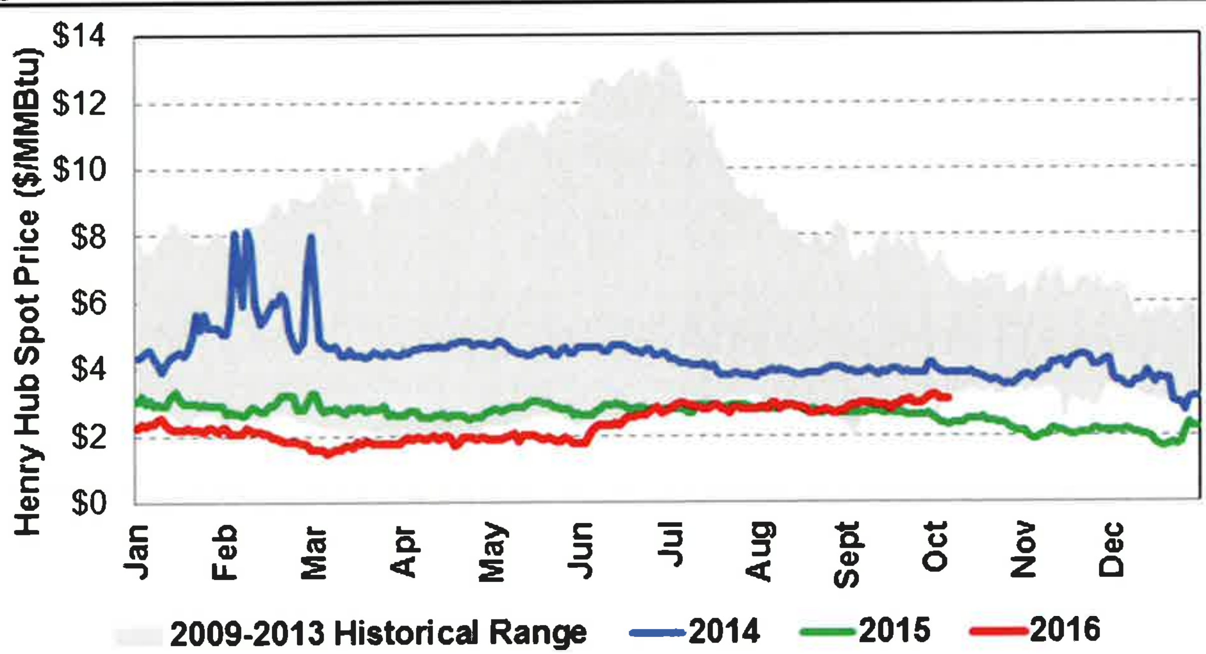
The principal location for natural gas trading in the U.S. is the Henry Hub in Louisiana. Due to the volume of physical trading at this location, Henry Hub has also become the location for financial market trading on the NYMEX. Regional gas prices are based on basis differentials from the Henry Hub to other delivery locations. Regional basis rises (widens) when local production declines, and the cost of transporting gas between regions increases and when rising demand causes high utilization of regional pipeline and storage infrastructure. Conversely, increases in local production, and the available pipeline and storage capacity relative to demand cause basis differentials to decline (narrow).

Henry Hub Price

U.S. natural gas production has been increasing steadily over the last six years, which can be attributed to unconventional shale plays that now account for more than 40 percent of the country's gas supply in 2016, up from 1 percent in 2000. During this time period, unconventional gas production has changed the perception of gas markets and has been the primary driver of Henry Hub pricing since prices dropped from winter 2008 highs. According to Baker Hughes, the U.S. gas rig count dropped from 2,031 rigs in September 2008 to a low of 404 rigs in May 2016 and, all the while, production continued at near record highs (see Figure 7). Rig counts have since rebounded to 522 as of late September 2016, but total gas production has been on the decline.

Since the end of 2010, prices at the Henry Hub have been at or below the previous five-year low. Figure 3 below shows the range of prices from 2009 to 2013, as well as where prices have been over the last three years, highlighting the major changes that have occurred in the natural gas markets largely as a result of shale development. An unseasonably cold and long winter in 2014 caused Henry Hub prices to return to the historical range, with periods reaching the upper end of that range. Prices in 2016 have remained below the historical range as the oversupply situation extends into 2016, though they did tick up by $0.70 in mid-2016 as concerns over future supply adequacy entered into the marketplace.

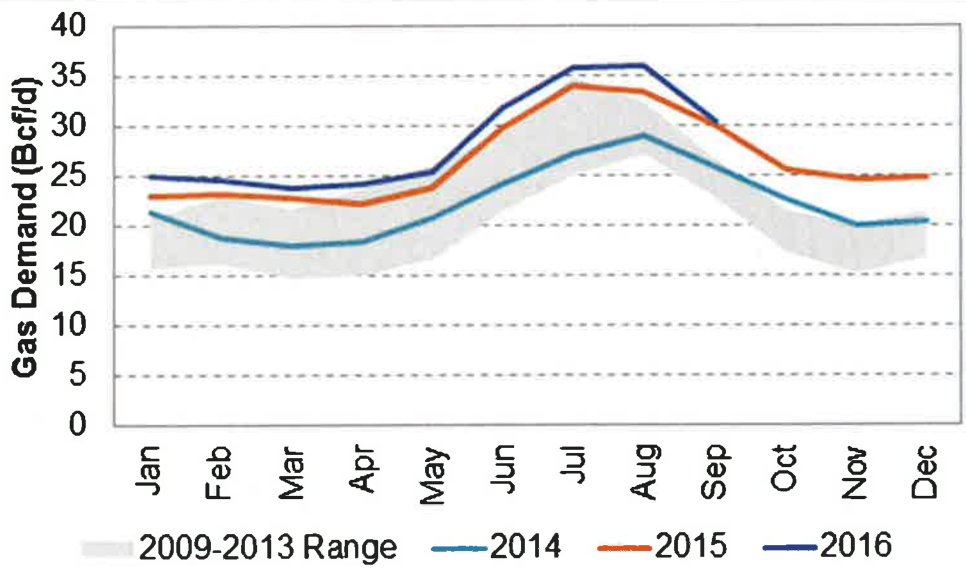
Figure 3: **Historical Henry Hub Price Range (Nominal$/MMBtu)**



Source: Pace Global, EIA

Figure 4 below, shows the monthly range of power sector gas demand in the U.S. Power sector gas demand in 2015 and 2016 has been at or above the historical range due to higher prices. This trend is expected to persist through the rest of the year.

Figure 4: Historical Power Sector Gas Demand (Bcf/d)

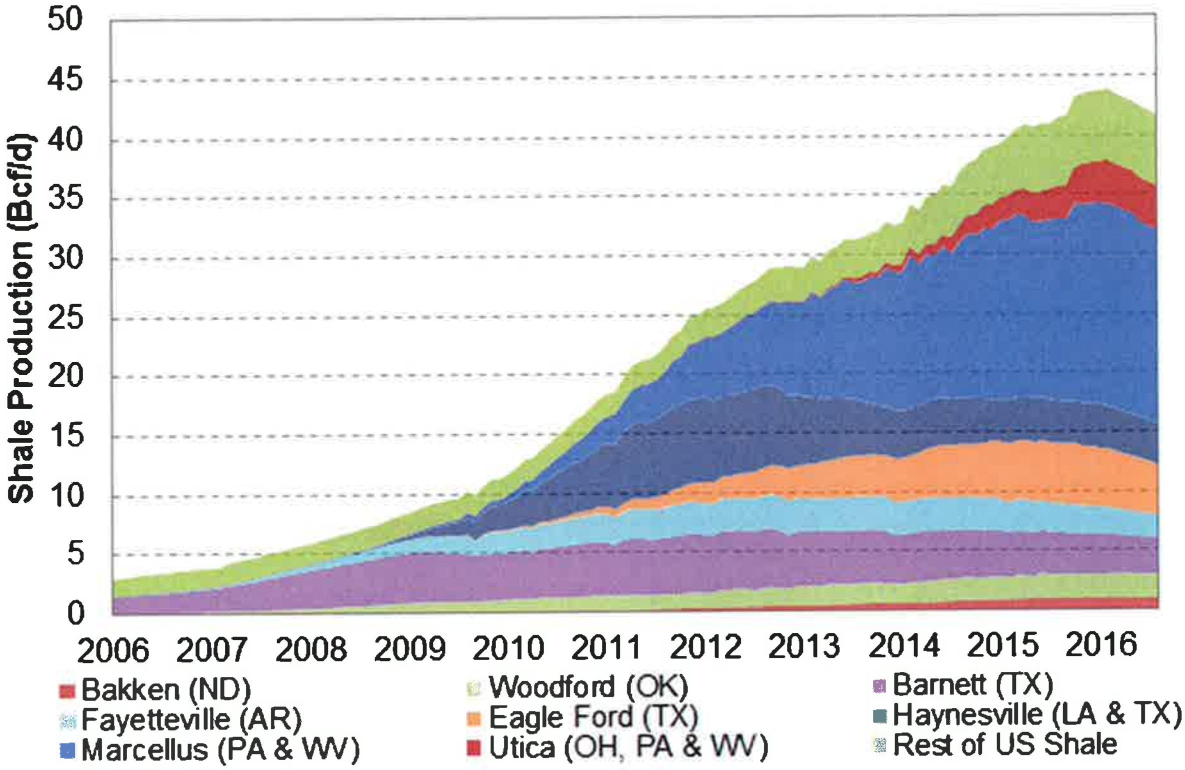


Source: Pace Global, EIA

Historically, the range of monthly power sector gas demand has been fairly narrow. With prices at record lows in 2012, and again in 2015 and 2016, however, gas-fired power generation has become more economical, resulting in coal-to-gas switching in many regions. Power sector gas demand in 2016 has been above the 2009-2015 range. Despite the increased demand, there was no significant price response, partly due to a market oversupply spurred by warm winters and continued strong shale production.

The six major shale plays in North America have seen a nearly 700 percent increase in production since 2008 (see Figure 5 below). The Marcellus shale play, located in Pennsylvania, West Virginia, and eastern Ohio, has changed the natural gas pricing dynamics in the Northeast, a region that has historically experienced very high gas prices in the winter due to high demand and transportation constraints. As drilling slows due to the general oversupply as well as waning investment in dry-gas shale play development, Pace Global expects the market to begin to stabilize, placing upward pressure on prices at the Henry Hub over the next three to four years.

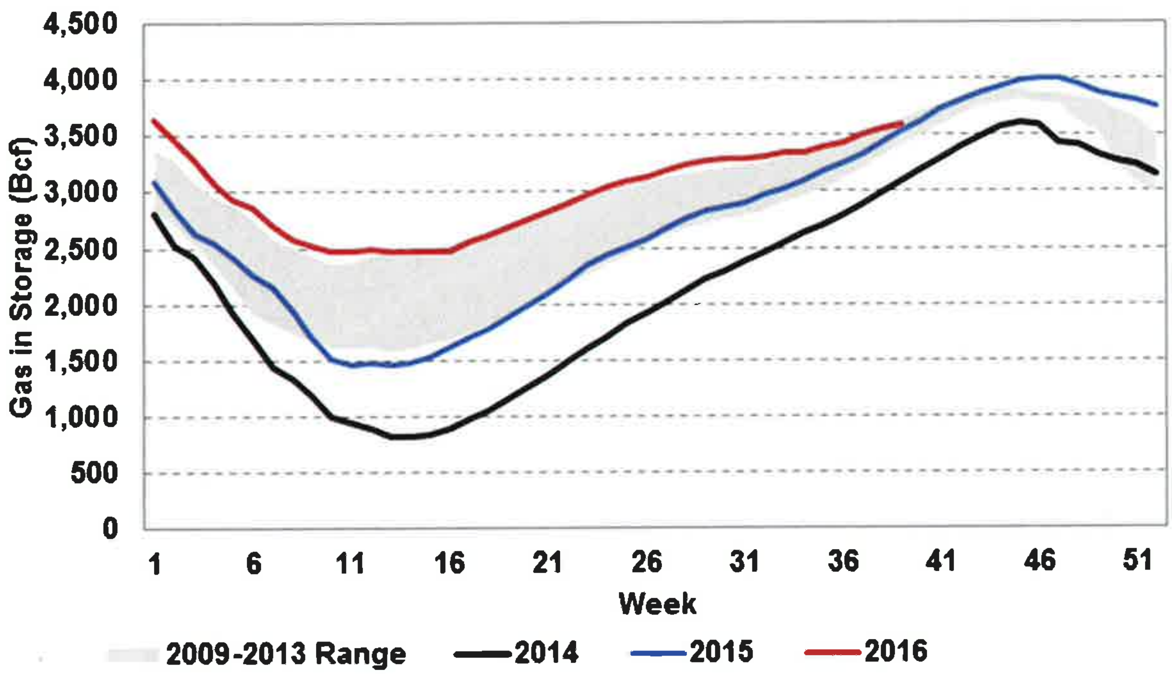
Figure 5: **Historical Gas Production by Shale Play (Bcf/d)**



Source: Pace Global, EIA

In 2014, an unusually cold winter (including the Polar Vortex) pushed working gas storage levels to levels as low as 822 Bcf (see Figure 6). Storage levels rebounded as shale production continued to rise rapidly and with an unusually warm 2014-15 winter and again in the 2015-2016 winter (erasing as much as 900 Bcf of demand). Current storage levels are above the range seen over the past seven years, which has been a contributing factor to the low gas prices seen in 2015 and 2016.

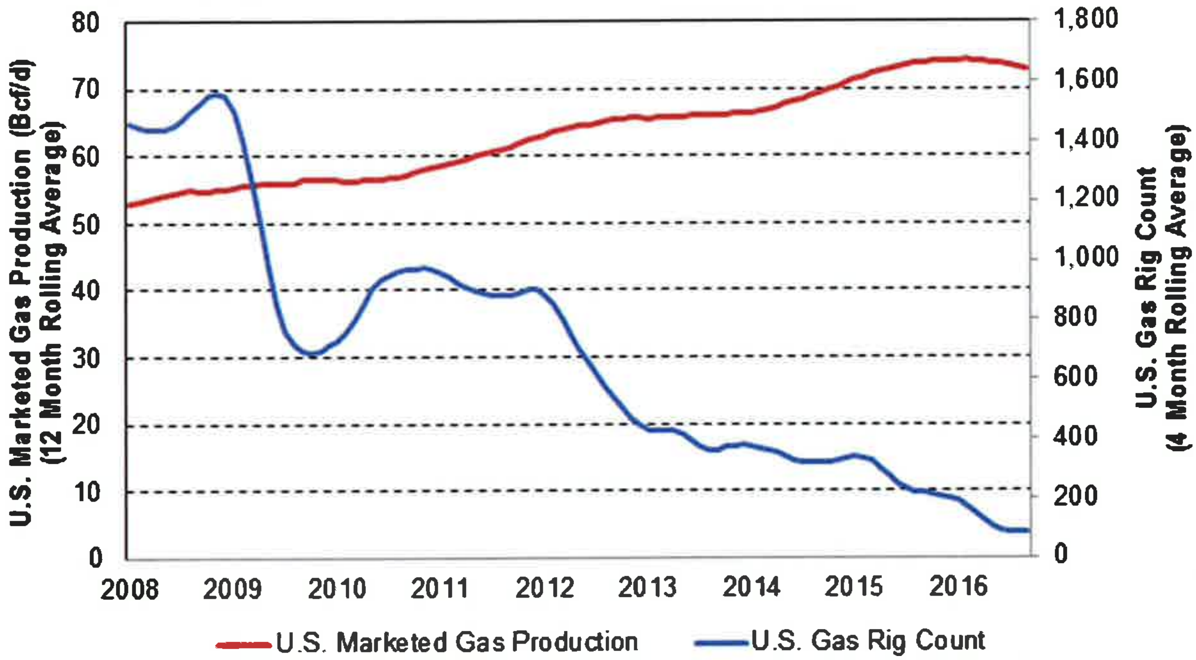
Exhibit 6: **U.S. Natural Gas Working Storage**



Source: Pace Global, EIA

Henry Hub cash price levels languished at the start of 2011, struggling to rise above \$5.00/MMBtu even in the premium winter months, and continued to lag throughout 2012. Spot prices during the first half of 2012 averaged only \$2.36/MMBtu, the lowest price for that time period since 1999, and only slowly began to recover during the second half of 2012 to \$3.14/MMBtu. In 2013, Henry Hub cash prices increased to \$3.73, but then moved steadily downward from 2014 to 2016 as production outweighed demand. As a result, U.S. natural gas producers slowly began adjusting their business models to find better investments than dry natural gas drilling and production. The number of gas rigs drilling in the U.S. rebounded from recessionary lows, as seen in Figure 7 below, but rigs drilling for gas have fallen substantially since 2012. This is partly due to increased efficiencies, partly due to rigs deployed to drill for crude oil, and partly due to low gas prices. The percentage of U.S. rigs drilling for oil has eclipsed those drilling for natural gas since early 2011, a strong trend that can be seen in Figure 8 below. However, reduced CAPEX in gas drilling as a result of very low prices is beginning to have the effect of rationalizing production and helping to balance the currently oversupplied gas market.

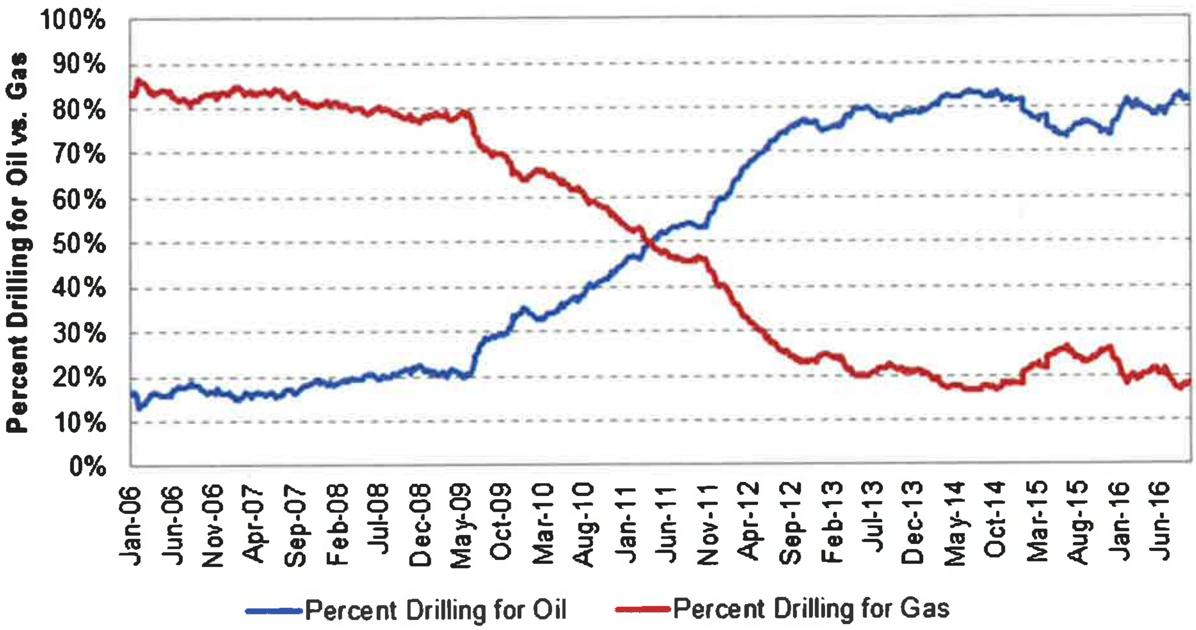
Figure 7: **U.S. Natural Gas Production and Drilling Rig Count**



Sources: Rig count – Baker Hughes; production – EIA. Updated through September 2016.

Around 2010, rigs could be seen being removed from dry gas plays where development of core areas is largely complete, such as the Barnett Shale, and being redeployed in oil plays such as the Bakken Shale in North Dakota, and in the liquids-rich natural gas plays such as the Eagle Ford Shale in south Texas. Part of this trend could be attributed to rigs that were freed up as they were no longer under hold-by-producing lease terms. Hold-by-producing lease terms required natural gas producers to drill wells in order to secure their long-term leases on land, and this was one reason that they continued to drill new wells even with Henry Hub prices languishing, supporting the oversupply situation in the markets. In the past few years, rigs that were drilling under now-freed-up lease terms were free to move to oil and natural-gas-liquids-rich plays like the Utica and Eagle Ford shale plays. The additional revenue uplift from oil and NGLs production helped spur additional associated gas production. However, with the decline of oil and gas prices since the end of 2014, rigs are stacked up and the overall rig count (oil and gas) stands at 522 as of early October 2016, with 81.4 percent focused on oil. This represents a decline of nearly 75 percent from the high in late 2011.

Figure 8: **Percentage of U.S. Rigs Drilling For Oil vs. Rigs Drilling for Gas**



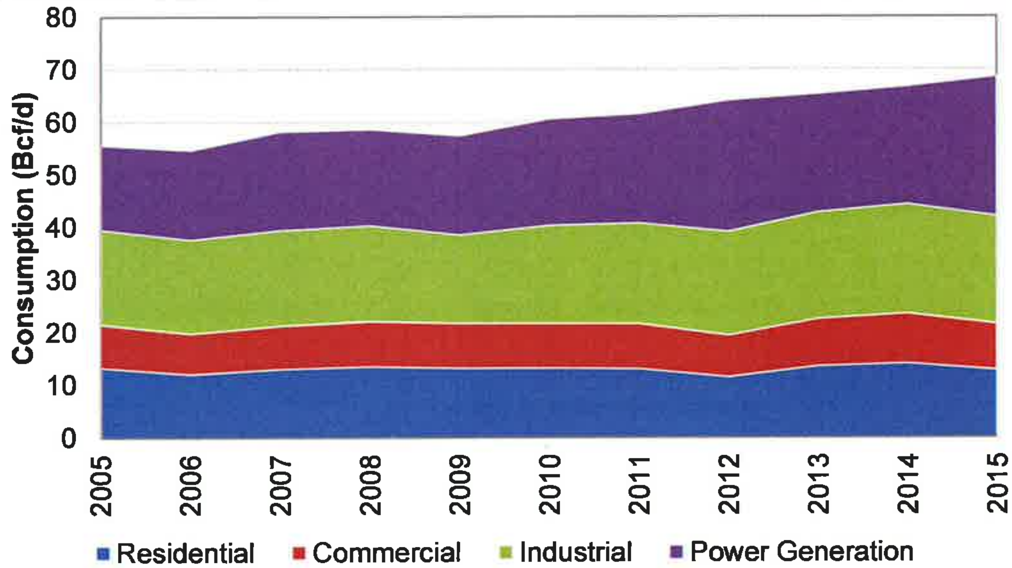
Source: Baker Hughes. Updated through September 2016.

According to the EIA, 2010 total U.S. gas consumption rose 5.1 percent over 2009, largely driven by gas use in the electricity generating sector, which was up 7.5 percent and industrial demand which had a year-over-year gain of 10.7 percent in 2010. Consumption in 2011 rose 1.2 percent over the previous year, in large part driven by more power sector demand. With low prices resulting in coal-to-gas switching, year-over-year consumption growth in 2012 was significantly higher, at 4.4 percent, over 2011. Power sector demand for gas in 2012 rose 20.6 percent over 2011. The rebound in gas prices seen in 2013 significantly degraded the gas generation advantage resulting in a decline of gas consumption for power generation of 10 percent. There was also a decline in 2014, but only by half a percent. In 2015, power sector gas burn rose by 19 percent and 2016 gas burn is on track to be the strongest ever.

Generally, a trend of increased gas usage in the power sector at the expense of coal burn has emerged since the summer of 2009. With natural gas prices still relatively cheap as compared to recent years, and coal facing regulatory pressures (see below for a discussion of the coal markets), there has been some switching to gas-fired units from coal-fired units in the dispatch order in certain NERC regions, particularly in shoulder-season months. Utilities in regions where gas transportation costs are relatively low and coal transportation costs are high, i.e. the SERC region, have announced the shutdown of certain coal units in favor of increasing utilization at intermediate gas units. Pace Global has captured this increased demand for natural gas in its hourly modeling of plant dispatch in the regions studied in this report.

Figure 9 below shows total historical gas demand by sector. Outside of power generation, natural gas demand growth has been generally weak for quite some time. On the industrial front, gas usage had been slipping since the early 2000s, when demand was running well above 20 Bcf/d. Industrial gas consumption in the recent recessionary period in the U.S. dropped precipitously, hitting a low of 16.9 Bcf/d in 2009. The situation has since improved – industrial gas usage in the U.S. in 2015 averaged 20.5 Bcf/d and is expected to grow further as industrial customers take advantage of systemically low gas prices and build new plants.

Figure 9: Historical Natural Gas Consumption by Sector (Bcf/d)



Source: Pace Global

Major uncertainties on the demand side include the power sector response to new environmental regulations, including the Clean Power Plan. Another key factor is the economic displacement of coal by natural gas in response to low gas prices. Natural gas consumption in the power sector has been increasing of late, but this trend is expected to attenuate somewhat as natural gas prices recover with the onset of LNG exports. Continued investment in wind and solar power has helped to make gas-fired generation the most practical source of standby and supplemental power as wind speeds, solar irradiance, and electricity load vary dramatically throughout the day.

Table 1 below displays Pace Global's expected price projections for natural gas at the Henry Hub as well as gas delivered to the PJM region. The forecast is based on 18 years of current market forwards blended over the next 18 months with Pace Global's fundamental longer term view of market prices, after which the forecast is purely based on the fundamentals-based view.

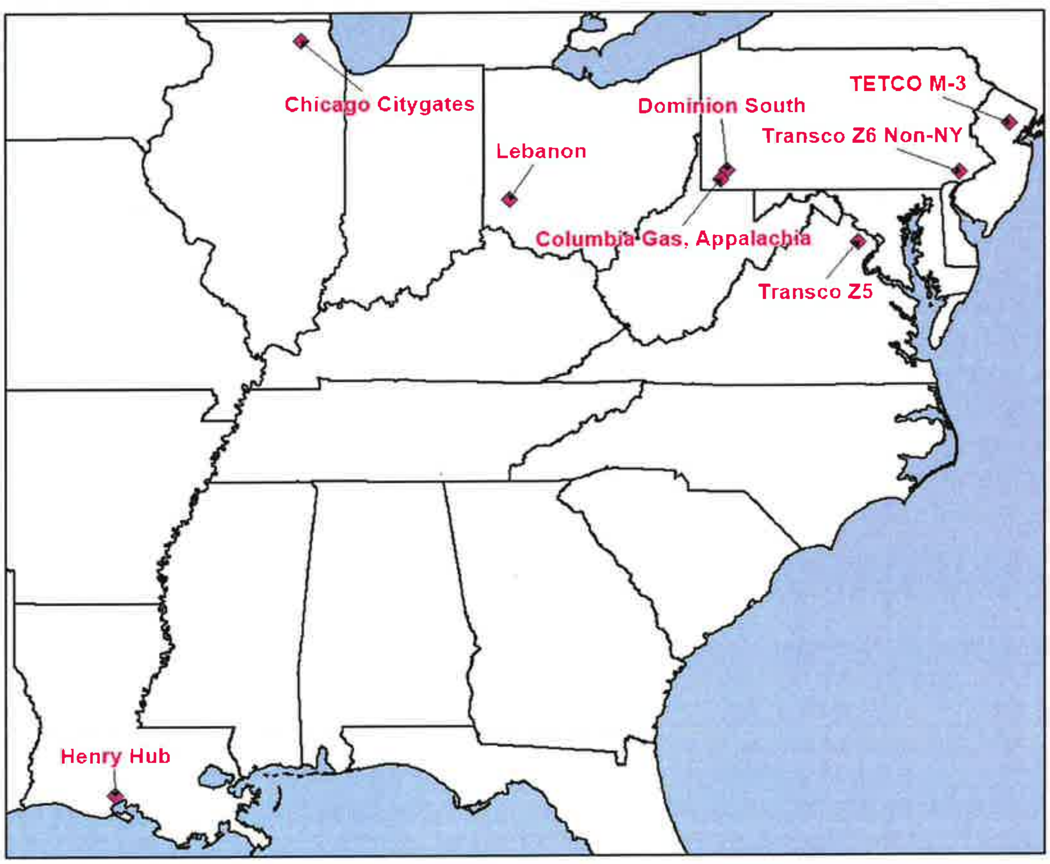
Table 1: Reference Case Natural Gas Price Forecast

		AEP	APS	Central	ComEd	Delmarva	East	ATSI	PENELEC	South	Dominion	AEP
	Henry Hub	*Lebanon*	*Columbia Gas, Appalachia*	*Tetco M-3*	*Chicago Citygates*	*Tetco M-3*	*Transco Z6 Non-NY*	*Columbia Gas, Appalachia*	*Dominion South. Tetco M-3*	*Tetco M-3*	*Transco Z5*	*Lebanon*
2016	2.64	2.58	2.52	2.00	2.64	2.00	2.29	2.52	1.93	2.00	2.73	2.58
2017	3.09	3.05	2.93	3.13	3.11	3.13	3.62	2.93	2.71	3.13	3.80	3.05
2018	2.96	2.87	2.77	3.15	2.95	3.15	3.45	2.77	2.81	3.15	3.61	2.87
2019	3.18	3.10	3.03	3.39	3.18	3.39	3.37	3.03	3.15	3.39	3.47	3.10

2020	3.78	3.67	3.62	3.91	3.73	3.91	3.78	3.62	3.70	3.91	3.85	3.67
2021	3.95	3.84	3.78	4.07	3.90	4.07	3.93	3.78	3.86	4.07	4.01	3.84
2022	4.08	3.95	3.89	4.17	4.03	4.17	4.02	3.89	3.95	4.17	4.13	3.95
2023	4.12	4.00	3.92	4.18	4.08	4.18	4.01	3.92	3.96	4.18	4.16	4.00
2024	4.19	4.06	3.96	4.19	4.15	4.19	4.03	3.96	3.98	4.19	4.21	4.06
2025	4.29	4.16	4.01	4.22	4.26	4.22	4.08	4.01	4.01	4.22	4.30	4.16
2026	4.38	4.22	4.04	4.24	4.34	4.24	4.10	4.04	4.00	4.24	4.37	4.22
2027	4.38	4.18	3.98	4.20	4.35	4.20	4.05	3.98	3.98	4.20	4.34	4.18
2028	4.36	4.14	3.92	4.13	4.34	4.13	3.98	3.92	3.92	4.13	4.30	4.14
2029	4.37	4.15	3.98	4.11	4.35	4.11	3.92	3.98	3.92	4.11	4.33	4.15
2030	4.40	4.18	3.99	4.10	4.38	4.10	3.96	3.99	3.93	4.10	4.36	4.18
2031	4.46	4.23	4.06	4.14	4.43	4.14	4.00	4.06	3.97	4.14	4.42	4.23
2032	4.52	4.28	4.10	4.16	4.51	4.16	4.06	4.10	4.03	4.16	4.46	4.28
2033	4.53	4.28	4.12	4.17	4.52	4.17	4.04	4.12	4.01	4.17	4.45	4.28
2034	4.52	4.27	4.09	4.14	4.50	4.14	4.00	4.09	4.00	4.14	4.45	4.27
2035	4.55	4.29	4.12	4.20	4.54	4.20	4.01	4.12	4.05	4.20	4.48	4.29

Source: Pace Global

Figure 10: Map of Relevant Gas Hubs

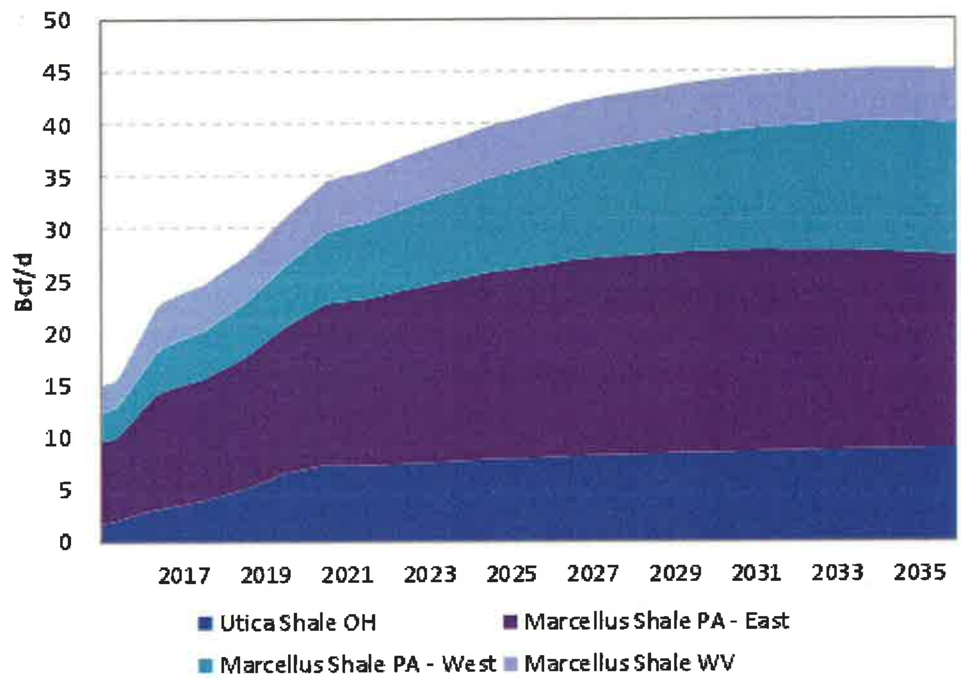


Source: Pace Global, Ventyx

Gas Markets in the PJM Region

Gas production from the Marcellus Shale and now the Utica Shale plays have grown at unprecedented rates in recent years, prompting a dramatic and ongoing reconfiguration of the North American natural gas transmission system. Some 30 Bcf/d of proposed pipeline projects are planned through 2020, which will add significant takeaway capacity (though not 30 Bcf/d worth of takeaway capacity, as some pipe will only increase intra-regional capacity) from this region to allow supplies to reach demand markets. The rapid expansion of production in this region has slowed somewhat in the face of sustained low prices but has begun to resume its upward trajectory as supplies slowly tighten and the Northeast remains an engine of production growth. Figure 11 below provides Pace Global's view on future production from this region. Our outlook is supported in the short- to mid-term by rig counts, well counts, and traded forward contracts that provide an economic view of expected production.

Figure 11: Appalachian Gas Production to 2035



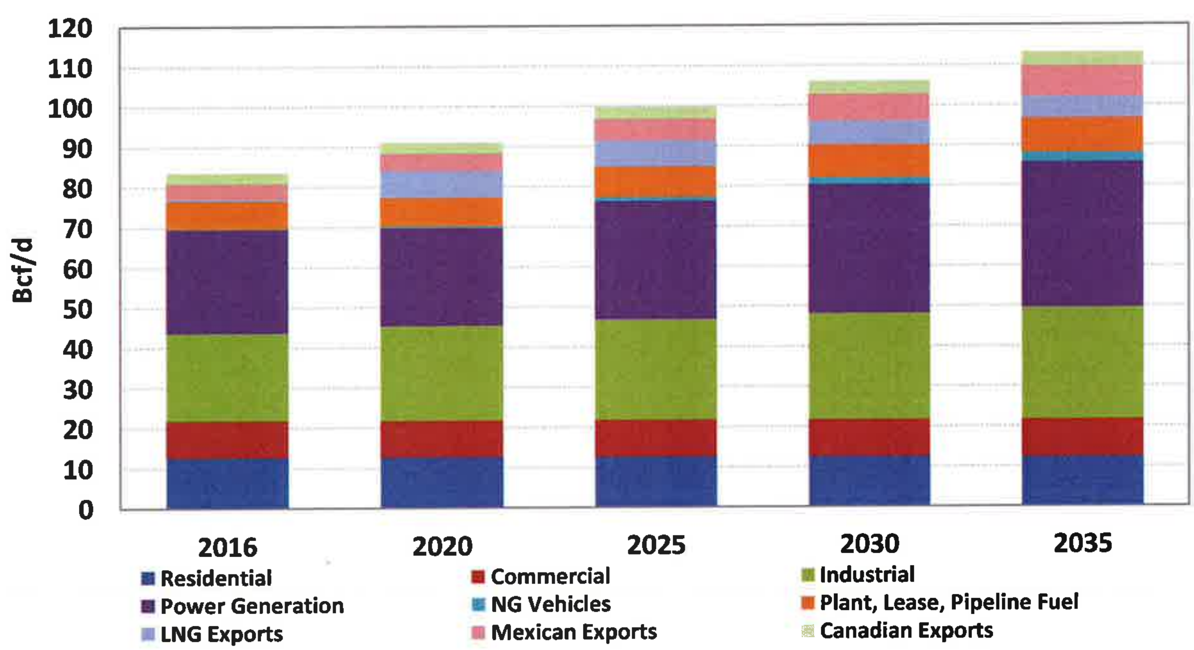
Source: Pace Global and Genscape.

The Utica Shale play is characterized as a liquids-rich play, meaning that the gallons per million cubic feet (GPM) of natural gas liquids (the NGLs known as ethane, propane, butane, iso-butane, and pentane) are higher than in other areas such as the northeastern Pennsylvania Marcellus region. Before the drop in the price of oil, NGLs were fetching roughly twice the value of gas on a per MMBtu basis. Accordingly, drilling activity, until recently had been heavily focused on the Utica and the southwestern Pennsylvania Marcellus region. Currently, with prices recovering in the Northeast as new pipeline takeaway capacity comes online, gas production is expected to rise especially in the Northeast Pennsylvania region. Overall, the Marcellus is not expected to experience a downturn in production because there is a large backlog of drilled but uncompleted wells ("DUCs") that can come online at roughly 70% of the cost of a new well, helping to keep operators nimble and production levels elevated.

As a result of the prodigious production that has come online and the takeaway capacity constraints that generally lag new supply, gas prices (and basis to Henry Hub) are expected to remain low in the Appalachian basin for the foreseeable future. Effectively, pipeline capacity will be in a persistent lagged state of production, given the expected growth in supply. This situation, coupled with a small but non-negligible revenue uplift provided by NGLs that adds to associated gas production, will help to keep production elevated and put consistent long-term downward pressure on prices in this region.

Although North American gas markets currently remain in a supply-driven environment, significant new demand is expected in the coming few years. On a national level, Pace Global expects the power generation sector to grow robustly as coal-fired plants are retired, gas supply costs remain low, and the need for rapid-ramp generation increases to complement intermittent renewable generation. U.S. LNG exports are expected to reach nearly 7 Bcf/d by 2020, exports to Mexico will exceed 4 Bcf/d by this same year, and industrial demand will add nearly 2 Bcf/d of incremental demand by 2020. Figure 12 below provides Pace Global's Reference Case view of U.S. gas demand. It is important to note that a large portion of Marcellus and Utica gas production is expected to move southward to the Gulf Coast to satisfy coming demand in the form of exports (LNG, Mexican), industrial demand, and power generation demand.

Figure 12: U.S Gas Demand to 2035 (Bcf/day)



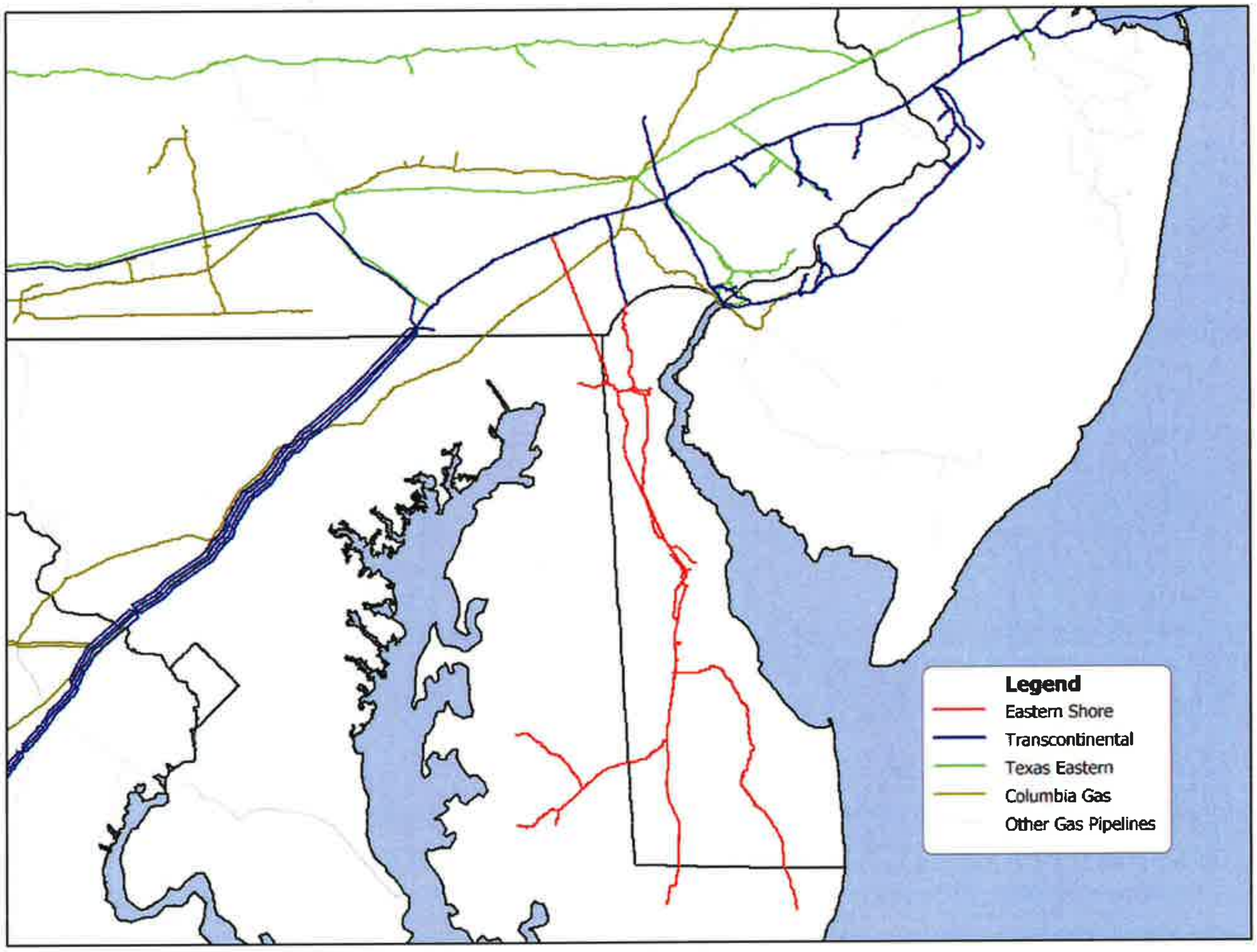
Year	Residential	Commercial	Industrial	Power Generation	NG Vehicles	PPL	LNG Exports	Mexican Exports	Canadian Exports	TOTAL
2016	12.7	9.3	21.7	25.9	0.2	7.0	0.5	3.6	2.7	83.6
2020	12.7	9.1	23.6	24.4	0.4	7.1	6.8	4.2	2.7	91.1
2025	12.7	9.2	25.0	29.6	1.0	7.6	6.5	5.4	3.0	99.8
2030	12.6	9.2	26.4	32.2	1.8	8.0	6.0	6.6	3.2	106.0
2035	12.5	9.3	27.8	36.2	2.5	8.5	5.3	7.5	3.5	113.2

Note: PPL stands for plant, pipeline and lease fuel (i.e., un-marketed gas)

Source: Pace Global.

The Eastern Shore pipeline that serves the Delmarva Peninsula is supplied by the Transcontinental (Transco) pipeline with two interconnects at Parkesburg, PA and Hockessin, DE; by the Texas Eastern (TETCO) pipeline with an interconnect at Honey Brook, PA; and by the Columbia Gas pipeline with an interconnect at Daleville, PA. There are a few key dynamics at work on the Transco pipeline. These include a partial reversing of south-to-north flows via the Atlantic Sunrise project, which will bring 1,700 MMcf/d of Marcellus gas down from the Northeast PA Transco Leidy line by April 2018. In addition, the Dominion Cove Point LNG export project will add up to 700 MMcf/d of baseload demand on Transco's Zone 5. These two projects will mitigate each other to an extent, but price volatility is likely to increase in any event. Both the Columbia pipeline and Dominion pipelines are also interconnected with the Cove Point LNG project, with access to Marcellus gas from Southwest PA and Utica gas from Ohio and West Virginia. In general, the expansion of these three pipelines and the low-cost Marcellus gas that will push outward on these pipelines is expected to benefit the customers of the Delmarva Peninsula over the long-term. Figure 13 below provides a view of the Peninsula with respect to these pipelines.

Figure 13: Pipelines near the Delmarva Peninsula



Source: Pace Global.

Gas Pipeline Build-Out and Capacity Constraints

The rapid expansion of shale gas production in the Marcellus and Utica plays has strained pipeline infrastructure in the region. The lack of takeaway capacity to move low-cost gas supply to premium markets in New England, New York, Chicago, and increasingly the Gulf Coast has led to artificially depressed prices in the region. However, many pipeline projects are on the books to alleviate these capacity constraints and monetize the large arbitrage opportunities that exist between the Marcellus/Utica and demand markets. Table 2 below provides a comprehensive list of pipeline projects in the region, including in-service dates, capacities, and flow states. Most of these projects are expected to move forward, which will help to narrow the large basis gap between Dominion South, for example, and Henry Hub.

Table 2: Pipeline Projects

No.	Project Name	Pipeline Operator Name	Parent Company	Project Type	In-Service Date	Inc. Ccty (MMcf/d)	Flow Path State(s)
1	EQT Ohio Valley Connector Project	Equitrans	EQT Midstream	Lateral	Oct-16	900	WV, OH
2	AGT Salem Lateral Project	Algonquin Gas Transmission	Spectra Energy	Lateral	Nov-16	115	MA
3	Algonquin Incremental Market (AIM)	Algonquin Gas Transmission	Spectra Energy	Expansion	Nov-16	342	PA, NY, CT, RI, MA
4	DTI Clarington Project	Dominion Transmission	Dominion	Expansion	Nov-16	250	WV, OH
5	DTI Lebanon West II	Dominion Transmission	Dominion	Expansion	Nov-16	130	OH
6	DTI Monroe to Cornwell	Dominion Transmission	Dominion	Expansion	Nov-16	205	OH, WV
7	NGPL Chicago Market Expansion	NGPL Co. of America	Kinder Morgan	Expansion	Nov-16	238	IL
8	REX Clarington West	Rockies Express Pipeline	Tallgrass Energy	Reversal	Nov-16	800	OH, IN, IL
9	TETCO Gulf Markets Expansion (Phase I)	Texas Eastern Transmission	Spectra Energy	Expansion	Nov-16	350	PA, OH, KY, TN, MS, AL, MS, LA
10	TGP Connecticut Expansion Project	Tennessee Gas Pipeline	Kinder Morgan	Expansion	Nov-16	72	NY, CT
11	Transco Garden State Expansion (Phase I)	Transco	Williams	Lateral	Nov-16	90	NJ
12	TCO Rayne XPress Project	Columbia Gulf Transmission	NiSource	Expansion	Nov-16	1,000	KY, TN, MS, LA
13	TGP Connecticut Expansion Project	Tennessee Gas Pipeline	Kinder Morgan	Expansion	Nov-16	72	NY, CT, MA
14	TCPL King's North Project	TransCanada	TransCanada	Expansion	Nov-16	440	ON
15	Roadrunner Gas Transmission (Phase II)	Oneok Partners	JV: Oneok, Fermaca	Expansion	Mar-17	400	TX, CHH
16	TGT Northern Supply Access (Z4 Leb Rct to Z1/SL)	Texas Gas Transmission	Boardwalk Pipeline Partners	Expansion	Apr-17	334	OH, IN, KY, TN, MS, AR, LA
17	TGT Northern Supply Access (Z3 SV Rct to Z1/SL)	Texas Gas Transmission	Boardwalk Pipeline Partners	Expansion	Apr-17	250	OH, IN, KY, TN, MS, AR, LA
18	Dakota Pipeline	WBI Energy	MDU Resources Group	New Pipeline	Apr-17	400	ND
19	Sabal Trail Tansmission (Phase I)	Sabal Trail Transmission	JV: Spectra, NextEra	New Pipeline	May-17	818	AL, GA, FL
20	Transco Hillabee Expansion (Phase I)	Transco	Williams	Expansion	May-17	818	AL
21	Florida Southeast Connection	Florida Southeast Connection	Florida Power and Light	New Pipeline	May-17	400	FL
22	Transco Dalton Expansion	Transco	Williams	Lateral	May-17	448	GA
23	ET Rover Pipeline (OH del)	ET Rover Pipeline	Energy Transfer	New Pipeline	Jun-17	750	PA, WV, OH
24	Transco Atlantic Sunrise Project	Transco	Williams	New Pipeline	Apr-18	1,700	PA, MD, VA
25	Transco Garden State Expansion (Phase II)	Transco	Williams	Lateral	Aug-17	90	NJ
26	TETCO Gulf Markets Expansion (Phase II)	Texas Eastern Transmission	Spectra Energy	Expansion	Aug-17	300	TX, LA
27	ET Rover Pipeline (TX/GC del)	ET Rover Pipeline	Energy Transfer	New Pipeline	Sep-17	1,200	PA, WV, OH, IN, IL, KY, TN, MS, LA
28	ET Rover Pipeline (Mich/Dawn del)	ET Rover Pipeline	Energy Transfer	New Pipeline	Sep-17	1,300	PA, WV, OH, MI, ON
29	IGT Wright Interconnect Project	Iroquois Gas Transmission	TCPL	Expansion	Oct-17	650	NY
30	DTI Leidy South	Dominion Transmission	Dominion	Expansion	Oct-17	155	PA, MD, VA
31	DTI New Market Project	Dominion Transmission	Dominion	Expansion	Nov-17	112	PA, NY
32	NFG Northern Access 2016 Project	National Fuel Gas	National Fuel Gas	Expansion	Nov-17	350	PA, NY, ON
33	Panhandle Backhaul Project	PEPL Co.	Panhandle Eastern Pipe Line Co.	Expansion	Nov-17	750	MI, OH, IN, IL
34	Trunkline Backhaul Project	Trunkline Gas Company	Trunkline Gas Company	Expansion	Nov-17	750	IL, TN, MS
35	IGT South-to-North (SONO) Project	Iroquois Gas Transmission	TCPL	Reversal	Nov-17	650	CT, NY, ON
36	PNGTS Continent to Coast (C2C) Expansion Project	Portland Natural Gas	TCPL	Expansion	Nov-17	300	NH, ME
37	CNYOG MARC II Hub Line Project	Central New York Oil & Gas	Crestwood Midstream	New Pipeline	Nov-17	1,000	PA
38	NEXUS Gas Transmission	NEXUS Gas Transmission	JV: DTE, Enbridge, Spectra	New Pipeline	Nov-17	1,200	OH, MI, ON
39	Prairie State Pipeline	Tallgrass Energy	JV: Tallgrass, AGL	New Pipeline	Nov-17	1,500	IL
40	Spectra Atlantic Bridge (New England Divy)	Spectra Energy	Spectra Energy	Expansion	Nov-17	600	NJ, NY, CT, MA, NH, ME
41	TCO Leach XPress Project	Columbia Gas Transmission	NiSource	Expansion	Nov-17	1,530	PA, OH, WV, KY
42	TETCO Access South Project	Texas Eastern Transmission	Spectra Energy	Reversal	Nov-17	320	PA, WV, OH, KY, TN, AL, MS
43	TETCO Adair Southwest Project	Texas Eastern Transmission	Spectra Energy	Reversal	Nov-17	200	PA, WV, OH, KY

No.	Project Name	Pipeline Operator Name	Parent Company	Project Type	In-Service Date	Inc. Ccty (MMcf/d)	Flow Path State(s)
44	TGP Broad Run Expansion Project	Tennessee Gas Pipeline	Kinder Morgan	Expansion	Nov-17	200	WV, KY, TN, MS, AL, LA
45	TETCO Eastern Lebanon Extension	Texas Eastern Transmission	Spectra Energy	Expansion	Nov-17	180	PA, OH
46	Transco New York Bay Expansion Project	Transco	Williams	Expansion	Nov-17	115	NJ, NY
47	2017 Vector Pipeline Expansion Project	Vector Pipeline	Vector Pipeline LP	Expansion	Nov-17	1,400	IL, IN, OH, MI
48	TGP Triad Expansion Project	Tennessee Gas Pipeline	Kinder Morgan	Lateral	Nov-17	180	PA
49	TGP Susquehanna West Project	Tennessee Gas Pipeline	Kinder Morgan	Lateral	Nov-17	145	PA
50	Constitution Pipeline	Constitution Pipeline	JV: Williams, Cabot, others	New Pipeline	Nov-18	650	PA, NY
51	Transco Gulf Trace Project	Transco	Williams	Expansion	Dec-17	1,200	LA
52	Transco Virginia Southside Expansion Project II	Transco	Williams	Expansion	Dec-17	250	VA
53	CGT Cameron Access Project	Columbia Gulf Transmission	NiSource	Expansion	Dec-17	800	LA
54	Creole Trail Pipeline Expansion (Phase III)	Creole Trail	Cheniere	Expansion	Dec-17	1,500	LA
55	Millennium CPV Valley Lateral Project	Millennium Pipeline	Millennium Pipeline Co.	Lateral	Feb-18	130	NY
56	TGP SW LA Supply Project	Tennessee Gas Pipeline	Kinder Morgan	Lateral	Feb-18	295	LA
57	Coastal Bend Header Project	Gulf South Pipeline Co.	Boardwalk Pipeline Partners	Lateral	Apr-18	1,540	TX
58	Transco Diamond East Project	Transco	Williams	Expansion	Jul-18	1,000	PA, NJ
59	TCO WB Xpress Project (East to Loudoun)	Columbia Gas Transmission	NiSource	Expansion	Oct-18	500	WV, VA
60	TCO WB Xpress Project (West to Broad Run)	Columbia Gas Transmission	NiSource	Expansion	Oct-18	800	WV, KY
61	Millennium Eastern System Upgrade	Millennium Pipeline	Millennium Pipeline Co.	Expansion	Oct-18	200	NY
62	PennEast Pipeline Project	UGI Enery Services	JV: AGL, NJR, South Jersey, UGI	New Pipeline	Nov-18	1,107	PA, NJ
63	Empire Central Tioga County Extension	Empire Pipeline	National Fuel Gas	Expansion	Nov-18	300	PA, NY
64	ANR Midwest Market Access Pipeline	ANR Pipeline Company	TCPL	New Pipeline	Nov-18	2,400	OH
65	Atlantic Coast Pipeline	Dominion Transmission	JV: AGL, DTI, Duke, Piedmont	Expansion	Nov-18	1,500	WV, VA, NC
66	Mountain Valley Supply	Equitrans	JV: EQT Midstream, NextEra	New Pipeline	Nov-18	2,000	WV, VA
67	Spectra Access Northeast	Spectra Energy	JV: Spectra Energy, NE Utilities	Expansion	Nov-18	925	NY, CT, RI, MA
68	TETCO Appalachia to Market (A2M)	Texas Eastern Transmission	Spectra Energy	Expansion	Nov-18	1,000	OH, WV, PA, NJ
69	TGP Northeast Energy Direct Supply Path	Tennessee Gas Pipeline	Kinder Morgan	New Pipeline	Cancelled	1,300	NY, MA
70	TGP Northeast Energy Direct Market Path	Tennessee Gas Pipeline	Kinder Morgan	New Pipeline	Cancelled	1,200	PA, NY
71	TCO Mountaineer Express	Columbia Gas Transmission	NiSource	Expansion	Nov-18	2,200	OH, PA, WV
72	Dominion Supply Header Project	Dominion Transmission	Dominion	New Pipeline	Nov-18	1,500	WV, PA
73	Washington Expansion	Northwest Pipeline	Williams	Expansion	Nov-18	750	WA, OR
74	Roadrunner Gas Transmission (Phase III)	Oneok Partners	JV: Oneok, Fermaca	Expansion	Jan-19	70	TX, CHH
75	Trunkline Lake Charles LNG Export Expansion	Trunkline Gas Partners	Energy Transfer	Expansion	Jan-19	1,000	TN, MS, LA
76	Transco Appalachian Connector	Transco	Williams	New Pipeline	Apr-19	2,000	OH, WV, VA
77	TCPL Eastern Mainline Project	TransCanada	TransCanada	Expansion	Jun-19	1,203	ON
78	Pacific Connector for Jordan Cove Energy Project	Jordan Cove LNG	JV: Williams, Jordan Cove LNG	New Pipeline	Jun-19	1,000	OR
79	TETCO Stratton Ridge Expansion Project	Texas Eastern Transmission	Spectra Energy	Expansion	Jun-19	500	TX, LA
80	Sabal Trail Tansmission (Phase II)	Sabal Trail Transmission	JV: Spectra, NextEra	New Pipeline	May-20	206	AL, GA, FL
81	Transco Hillabee Expansion (Phase II)	Transco	Williams	Expansion	May-20	206	AL
82	Delfin LNG Project Pipeline	Delfin LNG	Fairwood Peninsula Energy Corp.	New Pipeline	Jun-20	1,500	TX
83	Oregon Pipeline	Oregon Pipeline Co.	Oregon LNG	New Pipeline	Sep-20	1,250	OR
84	Sabal Trail Tansmission (Phase III)	Sabal Trail Transmission	JV: Spectra, NextEra	New Pipeline	May-21	106	AL, GA, FL
85	Transco Hillabee Expansion (Phase III)	Transco	Williams	Expansion	May-21	106	AL
86	SoCalGas North-South Project	SoCalGas	JV: SoCalGas, SDG&E	Expansion	N/A	800	CA

Source: Pace Global.

COAL

Recent Trends in Coal Markets

U.S. coal demand in 2015 fell nearly 13 percent compared with the previous year. This drop in consumption was largely driven by low natural gas prices which have led to coal-to-gas switching in the power sector, and a significant amount of coal plant retirements. Power sector coal consumption in 2015 decreased 13.5% compared to 2014. Environmental regulations such as MATS have led to a significant level of coal retirements.

Other drivers that will dictate future coal demand include renewable portfolio standards at the state and federal level and the possibility of environmental regulations around hydraulic fracturing. Consumption could decrease even more sharply if states choose to pursue aggressive renewable generation targets. However, legislation limiting hydraulic fracturing could reverse the current gas market oversupply with implications for higher coal demand.

National Coal Supply and Demand Assumptions

Demand-Side Drivers

Overcapacity in the coal industry throughout most of the 1990s resulted in low prices, which forced smaller producers to either exit the industry or be acquired by larger, financially stronger players. These low prices also resulted in the closure of many mines and limited investment in new productive capacity.

High natural gas prices between 2003 and 2008 caused the increased dispatch of coal-fired power plants. Between 2003 and 2005, coal consumption exceeded coal supply, resulting in a drawdown of inventories. However, U.S. coal production increased by approximately 27 million tons in 2006, allowing stocks to rebuild, and then declined slightly in 2007; production slightly exceeded demand in 2008. The 2009 global recession greatly depressed power demand and resulted in an 8.3 percent decline in coal production. Since then, production has grown by just shy of 1 percent annually in the wake of modest economic recovery. Emerging markets like China have led to increasing coal exports, which may continue to grow if domestic gas prices remain low. The recent low gas prices have slightly depressed coal production, which fell by 6.9 percent in 2012 compared to 2011.

The global economic downturn greatly depressed coal demand and prices, forcing many Appalachian producers to restrict production. Additionally, gas prices have fallen to levels not seen since the 1990s. Gas prices continue to trade below their 10-year average. As long as gas prices remain low, coal demand will be negatively impacted. Some of the older, less efficient coal units are being supplanted by gas to meet base and intermediate load demand at current gas prices. Over the longer term, however, Pace Global expects that gas prices will rebound to prices in the $5-6 per MMBtu range on an annual basis. When this occurs, coal demand is projected to rise. However, Pace Global expects coal-fired generation's share of the U.S. electric generating market to decline significantly during 2022-2035 as federal CO_2 emissions regulations take effect. Coal's market share of total U.S. generation is expected to be close to the 2015 level (35%) during 2019-2021, but to decline steadily during 2022-2035, reaching about 18% by 2035.

Over the past several years, demand for coal at industrial facilities has slowly declined as manufacturing's share of the U.S. economy has declined. This trend applies to both metallurgical coal (used in coke ovens for steelmaking), and steam coal (used to generate steam and electric power at industrial facilities.) However, demand for metallurgical coal has declined at a slower rate than demand for steam coal. Environmental considerations have incentivized some industrial generating facilities to convert from steam coal to cleaner-burning fuels (primarily natural gas.) For these reasons, steam coal demand at U.S. industrial facilities is expected to decline at rates roughly similar to the expected overall decline in demand for coal-fired generation, remaining close to its current level of about 41 million tons through 2020, and then falling to about 21 million tons by 2035. Metallurgical coal demand at U.S. industrial facilities is expected to remain at approximately its current level of 20 million tons through 2020, and then gradually decline to about 15 million tons by 2035.

Supply-Side Drivers

During the first half of 2015, mining costs in the four largest US coal supply regions declined by amounts ranging from about 1%-4%, as coal producers focused intensely on cost management in an environment of declining demand. The largest cost reductions, of approximately 4%, occurred in Central Appalachia and the Illinois Basin. The cost of compliance with environmental and mine safety regulations related to coal production is still relatively high. This has the greatest impact on per-ton production costs in Central Appalachia, partly due to the relatively small average size of Central Appalachian coal mines, and partly due to strict environmental regulation of valley fills, which are not needed in the other coal supply regions. The combination of high mining costs and high environmental compliance costs is expected to keep production costs higher for Central Appalachian coal than for other U.S. steam coals over the long term. Although production levels, production costs, and forward prices for Central Appalachian steam coal dropped significantly during 2015 for the third year in a row, this coal will still struggle to be cost-competitive with coals from other regions of the United States over the long term. The low pricing for Central Appalachian steam coal that is assumed in this forecast can only be achieved by assuming that higher-cost mines continue to shut down and production continues to decline.

Recently, the net increase in mining costs in Central Appalachia, Northern Appalachia, the Illinois Basin, and the Powder River Basin has been less than the rate of overall inflation. There is not any published mining cost information for Colorado coal mines that is directly comparable to the cost data shown on slides 12-13 for the other four major U.S. coal supply regions. Average labor productivity at the marginal mine types in Central Appalachia, the Illinois Basin, and the Powder River Basin mines increased slightly during early 2015 as a result of coal producers' focus on cost management and the concentration of declining coal production at the most efficient mines. Average labor productivity at Northern Appalachian longwall mines remained constant at the 2014 level during early 2015.

Labor productivity at Central Appalachian, Northern Appalachian, Powder River Basin, and Colorado coal mines is expected to decline gradually over the long term due to the effects of reserve depletion. Average labor productivity at Illinois Basin continuous mines remained relatively constant during 2006 – 2014, and has increased slightly during early 2015. Average productivity at longwall mines has increased significantly, resulting in an increase in the overall productivity of Illinois Basin underground mines. In part, this is due to the fact that Illinois Basin coal reserves are very abundant relative to current production levels, so reserve depletion has less effect on mining costs in the Illinois Basin than in other regions. Additionally, as Illinois Basin coal production has expanded over the past several years, more productive newer mines (both continuous mines and longwalls) have offset the decline in productivity at existing mines. Average productivity at Illinois Basin mines is expected to remain at a relatively high level throughout the forecast period as a higher proportion of the overall Illinois Basin coal production is sourced from newer mines. Older mines with higher production costs will tend to be idled first during periods of low coal demand.

Central Appalachian steam coal production is expected to continue declining steeply throughout the forecast period, from about 48 million tons in 2015 to 10 million tons by 2035, as demand for this high-cost coal at U.S. generating plants continues to decline. Central Appalachia is expected to continue producing significant in volumes of metallurgical coal for both domestic and international use, resulting in expected total Central Appalachian coal production volumes of about 97 million tons in 2015 to 60 million tons in 2035.

Northern Appalachian coal production is expected to increase from about 121 million tons during 2015 to about 132 million tons by 2020, and then decline to about 82 million tons by 2035 as federal CO_2 emission caps take effect. The expected increase in Northern Appalachian coal production by 2020 reflects some replacement of Central Appalachian steam coal in the domestic market, as well as a slight increase in exports of Northern Appalachian metallurgical coal.

Illinois Basin coal production is expected to increase slightly in the near term, reaching 134 million tons by 2020 as Illinois Basin coal continues to replace Central Appalachian coal in the domestic market. By 2035, Illinois Basin coal production is expected to decline to about 76 million tons as federal CO_2 emission caps take effect.

Production of Powder River Basin coal is expected to increase from about 400 million tons in 2015 to about 424 million tons by 2020, and then decline to about 260 million tons by 2035, as declining domestic demand for this coal after 2020 is partially offset by increased export opportunities, primarily in the Asian market, via west coast ports.

Liquidity

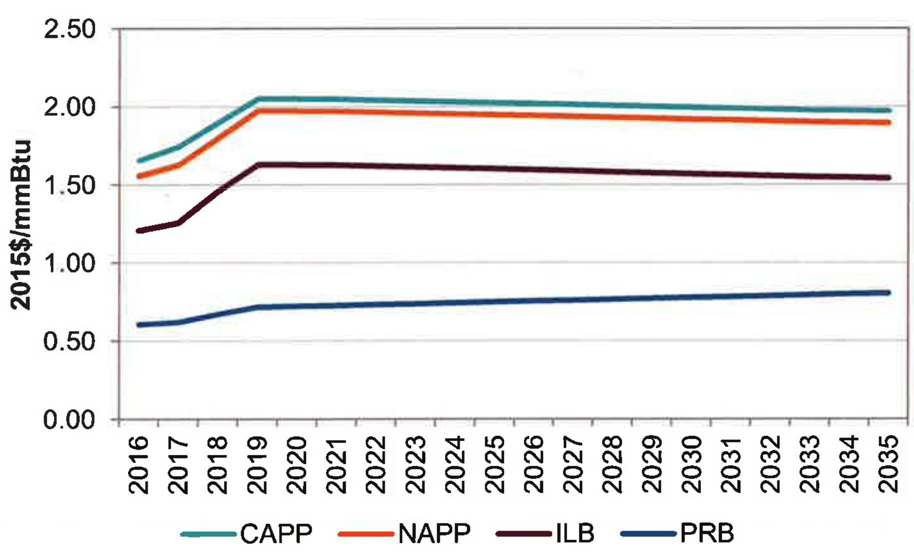
The domestic coal market is considerably less liquid than the natural gas, oil, or oil products markets. Historically, electricity generators have purchased approximately 80-90% of their coal under contracts lasting one year or more in order to ensure security of supply. However, with the weak coal market, utilities are resorting more and more to the spot markets and short-term coal contracts. In December 2015, 14.4% of coal deliveries were delivered via spot purchase agreements, about twice as high as the 2010 levels. Some of the contributing factors to this trend are uncertainty regarding environmental regulations, and coal producers' reluctance to secure long-term contracts at the current low prices. Pace Global expects such trends to be mitigated with the rising coal prices in the near term.

Coal Market Prices

Pace Global assesses basin-level market fundamentals and develops projections based on current market forward signals and expected market trends. In the near term, as shown in Figure 14 below, all four major coal basins are expected to see modest increases in prices, following the trajectory in the forward price curve. This reflects coal producers' reluctance to sign multi-year coal supply agreements at the current low spot prices, even in market conditions of very low demand. In addition, coal demand is expected to recover somewhat by 2019 as natural gas prices increase. In all of the major U.S. coal supply regions, coal pricing is expected to reach the levels necessary to fund incremental ongoing investments in existing mines by 2019. These price levels are necessary to sustain the expected 2019-2021 coal production levels in each coal supply region.

Coal demand in all of the major U.S. coal supply regions is expected to fall steadily during 2022-2035 as a result of federal regulation of CO_2 emissions. In all of the major U.S. coal supply regions except the Powder River Basin, the closure of the less efficient mines in each region, and the concentration of the remaining coal production at the most efficient mines, is expected to cause coal prices to decline slightly in real terms, as the operating efficiencies gained at lower production levels more than offset the expected effects of reserve depletion. In the Powder River Basin, the coal seams slope downward. Thus, stripping ratios at these surface mines are expected to increase gradually over time even at reduced coal production rates, leading to gradual real increases in mining costs and coal prices.

Figure 14: Reference Case Coal Prices for Four Basins



Source: Pace Global.