delmarva power

A PHI Company

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December 6, 2012

Via Overnight Delivery

Alisa Bentley, Secretary
Delaware Public Service Commission
861 Silver Lake Boulevard
Cannon Building, Suite 100
Dover, DE 19904

Re: Delmarva Power & Light Company
December 3, 2012 Integrated Resource Plan
Filed Pursuant to 26 *Del. C.* §1007(c)(1)

Dear Secretary Bently:

Enclosed for filing with the Commission please find nine (9) copies of the PUBLIC version of the 2012 Integrated Resource Plan (IRP), with Appendix, of Delmarva Power & Light Company (Delmarva). A Confidential/Sealed version is being filed simultaneously herewith under separate cover.

As always, should you have any questions, please feel free to contact me by email or by my cell number (302) 353-7979.

Sincerely,

Todd L. Goodman

cc:

(each with 1 copy of Public IRP):

Michael L. Morton, Controller General
Ann S. Visalli, Office of Management and Budget
Collin O'Mara, Secretary, DNREC/Delaware Energy Office
Janis Dillard, Commission Staff
Michael D. Sheehy, Division of the Public Advocate

(without copies of Public IRP):

Service List *(the entire Public Version of the IRP and Appendix will be available on Delmarva Power's website for printing and viewing on December 7, 2012. The documents are too large to send to the members of the Service List via email without the risk of "crashing," filling or otherwise causing problems with the email systems of the recipients. Photocopying and delivering the documents to every member of the Service List would be unnecessarily expensive, wasteful and time consuming.)*

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Delmarva Power & Light Company
2012 Integrated Resource Plan

Filed: December 6, 2012

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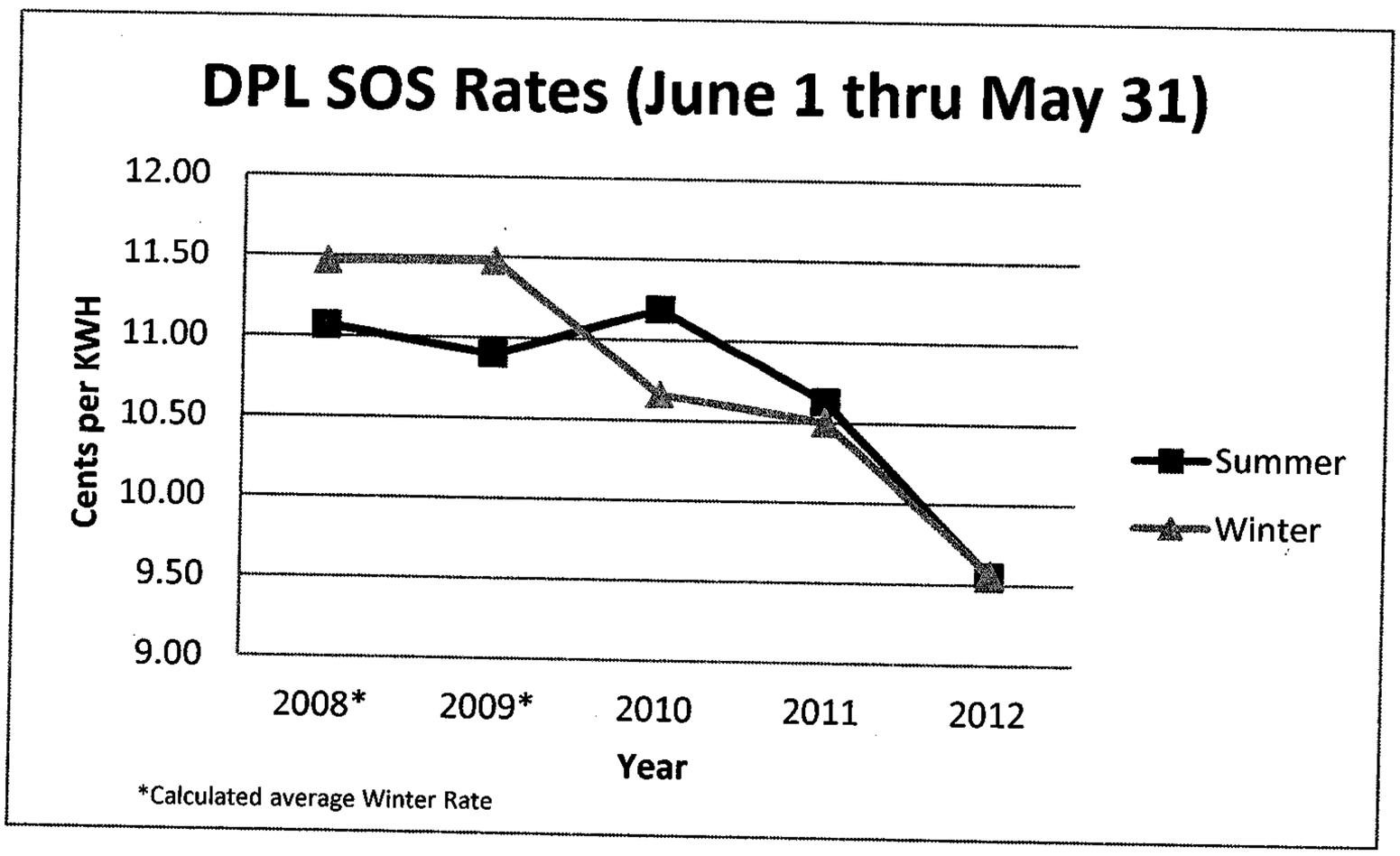
I. IRP EXECUTIVE SUMMARY

A. Summary of Integrated Resource Plan Findings

The development and preparation of the Delmarva Power & Light Company (Delmarva, Delmarva Power) 2012 Integrated Resource Plan (IRP) greatly benefitted from the collaborative IRP Working Group process. The IRP Working Group is an effective way for stakeholders to share information in a transparent manner and for Delmarva Power to obtain stakeholder input into the development of the IRP. While Delmarva is responsible for the content of the IRP, the IRP is a more valuable due to the efforts of the participants in the Working Group.

The retail energy supply rates experienced by Delmarva Power's Standard Offer Service (SOS) customers have been stable and decreasing since the last IRP was prepared in 2010. Since 2006, residential SOS customer energy supply rates for the summer period have fallen from 11.07 cents/kwh to 9.55 cents/kwh in 2012. This is shown in the chart below:



It is expected that the combination of available generation resources and transmission import capability into the PJM DPL Zone under PJM base case assumptions will be sufficient to meet PJM reliability requirements through 2022. This result is made more secure by the implementation of demand response programs designed to reduce customer demand during peak

load periods. The Delaware Public Service Commission has recently approved a Dynamic Pricing Program and a Residential Direct Load Control Program that supports this planning objective.

Air quality in Delaware and the Mid-Atlantic Region is expected to improve over the period 2012-2022. Based on US EPA evaluation models, the impact of this improvement in air quality is estimated to range from $980 million to $2.2 billion for Delaware and $13 to $29 billion for the Mid-Atlantic Region. These results are attributable to a number of factors including new regulations controlling air emissions from coal fired power plants, the increased use of natural gas fired power generation, the increased penetration of renewable generation resources and reductions in air emissions from other sectors, such as transportation.

Delmarva Power has assembled a diverse portfolio of renewable resources in order to comply with the State's Renewable Energy Portfolio Standard Act (REPSA). The expected "un-netted" impact on average SOS customer bills of meeting the REPSA standards ranges from $6.60 /month in 2013 to $15.15/month in 2022. Renewable generation, however, avoids the creation emissions of carbon dioxide, sulfur dioxide, and nitrous oxide, and the estimated health benefits of these avoided emissions can be significant.[1]

Sensitivity analyses indicates that adding an off shore wind resource to Delmarva Power's renewable portfolio will be very expensive and does not appear needed at this time. Sensitivity analyses for adding a gas-fired combined cycle generation unit indicate that such facilities may warrant additional consideration and discussion through the IRP Working Group process.

B. Background

This Integrated Resource Plan describes Delmarva's plan to procure the electrical energy requirements for its SOS customers for the 10 year planning period 2011 – 2020. This IRP is filed pursuant to Title 26, Section 1007 (c) (1) of the Delaware Code, which provides, in part:

[1] DNREC is currently in the process of promulgating rules for calculating the cost of renewable energy and may include the benefits of avoided air emissions in the calculation.

> [Delmarva] is required to conduct integrated resource planning.... In its IRP, [Delmarva] 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's] supply and demand forecast for the next 10-year period, and shall set forth the resource mix with which [Delmarva] proposes to meet its supply obligations for that 10-year period....

The legislation makes clear that while the IRP must investigate all potential opportunities for a diverse and reliable supply, including those that would create environmental benefits for Delaware, it must do so with a careful eye on costs. The legislation specifically provides that in developing the IRP, Delmarva must seek to meet its customer's energy supply needs "at the lowest reasonable cost"[2] and "at a minimal cost".[3] As such, the principal objectives of Delmarva Power's plan are to secure for SOS customers a reliable energy supply at a 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 public utility company serving electric and gas customers in Delaware and the portions of Maryland. In Delaware, the company serves over 301,000 electric energy customers, of which about 267,600 are residential customers. Delmarva also serves over 123,750 natural gas customers, all of whom reside in New Castle County. The IRP focuses only on electric customers.

With respect to delivery, Delmarva is an electric delivery company, focusing on the transmission and distribution of electricity to its customers. Delmarva does not generate any electricity or own any generation plants. Delmarva's Delaware operations are managed out of four in-state offices, one each in Wilmington, New Castle, Millsboro and Harrington. Among Delmarva's assets in Delaware are almost 860 miles of high voltage (69kV and higher) transmission lines and 71 distribution and transmission substations.

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[2] 25 *Del.C.*§1007(c)(1)(b).
[3] 25 *Del.C.*§1007(c)(1).

Under Delaware's electricity deregulation laws, Delaware customers can choose their own electric energy supplier. Those customers who do not choose a supplier are supplied by Delmarva through its SOS offering. As of September 28, 2012 about 96 % of Delmarva's residential customers are supplied under the SOS offering, and about 72% of non-residential usage is provided by competitive suppliers. This IRP is focused on the procurement of the energy supply requirements of the SOS customers only.

The breakdown of energy usage by residential and non-residential customers, for SOS and non-SOS service, for 2012 through September is shown in the following chart:

Figure 1 – Energy Usage (2012 through September)

D. **Load Forecast**

The following tables summarize the baseline load forecast for the IRP planning period 2013 – 2022:

Table 1 – Delmarva Total Baseline Forecast

Peak Demand (MW) and Energy Throughput (MWh)

	2013 Delmarva Delaware		2018 Delmarva Delaware		2022 Delmarva Delaware	
	MW	MWh	MW	MWh	MW	MWh
Residential	1,033	2,916,121	1,133	2,853,290	1,204	2,910,224
Small Commercial	28	188,233	31	195,355	33	197,783
Large Commercial & Light Industrial	844	5,622,711	935	5,835,427	994	5,907,981
Street Lights	0	37,768	0	38,464	0	39,031
Total	1,905	8,764,833	2,099	8,922,536	2,231	9,055,019

Table 2 – Delmarva SOS Baseline Forecast

Peak Demand (MW) and Energy Throughput (MWh)

	2013 Delmarva Delaware SOS		2018 Delmarva Delaware SOS		2022 Delmarva Delaware SOS	
	MW	MWh	MW	MWh	MW	MWh
Residential	996	2,810,730	1,092	2,750,170	1,161	2,805,046
Small Commercial	23	150,448	25	156,140	27	158,081
Large Commercial & Light Industrial	190	1,262,540	210	1,310,303	223	1,326,595
Street Lights	0	27,643	0	28,153	0	28,568
Total	1,209	4,251,361	1,327	4,244,766	1,411	4,318,290

The Load Forecast is described in more detail in Section IV of the IRP. Appendix 4 provides more detailed documentation of the forecast preparation.

E. Price and Price Stability

Table 3 below shows the expected mean energy prices for the Reference Case for Residential and Small Commercial (RSCI) and Large Commercial (LC) customers compared with the sensitivity cases for selected planning years. The sensitivity cases include a low and high gas case reflecting a range of possible natural gas prices. The CC case represents the addition of a hypothetical 300 Mw gas fired combined cycle generating facility in Delaware.

Table 3 Expected SOS Supply Costs RSCI and LC SOS Customers (Confidential Material Omitted)

Average Costs and Risks of Electricity Procurement for DPL as Expected in August 2012		
	RSCI Total Average Costs ($/MWh)	**LC Total Average Costs ($/MWh)**
Planning Year 2013		
Reference Case	[redacted]	[redacted]
Reference Case - High Gas	$102.05	$82.66
Reference Case - Low Gas	$91.81	$52.03
Planning Year 2015		
Reference Case	[redacted]	[redacted]
Reference Case - High Gas	$109.84	$85.04
Reference Case - Low Gas	$78.15	$54.39
Planning Year 2017		
Reference Case	$122.06	$84.67
Reference Case - High Gas	$139.83	$102.34
Reference Case - Low Gas	$104.29	$67.01
Reference Case and CC	$111.16	$76.83
Planning Year 2019		
Reference Case	$141.22	$96.20
Reference Case - High Gas	$160.92	$115.78
Reference Case - Low Gas	$121.53	$76.63
Reference Case and CC	$124.35	$84.01
Planning Year 2022		
Reference Case	$161.96	$106.74
Reference Case - High Gas	$183.18	$127.70
Reference Case - Low Gas	$140.75	$85.78
Reference Case and CC	$140.94	$91.57

Table 3 indicates that for RSCI SOS customers under the Reference Case, energy supply prices are expected to rise after 2015 after falling from 2013 to 2015. For RSCI SOS customers under the Reference Case, the 2013 expected supply cost is [redacted] per MWH which is projected to rise to $161.96 in 2022. For LC SOS customers, the corresponding supply prices are [redacted] and $106.74 respectively. A primary reason for this increase in energy prices is the expected increase of natural gas prices in the later years of the IRP planning period. Within this Table, the combined cycle sensitivity case improves the performance of the Reference Case portfolio.

Table 4 presents a projection of retail customer energy supply rates for Residential and MGT customers for the period 2013 through 2018. The projections are based on the Reference Case in nominal dollars.

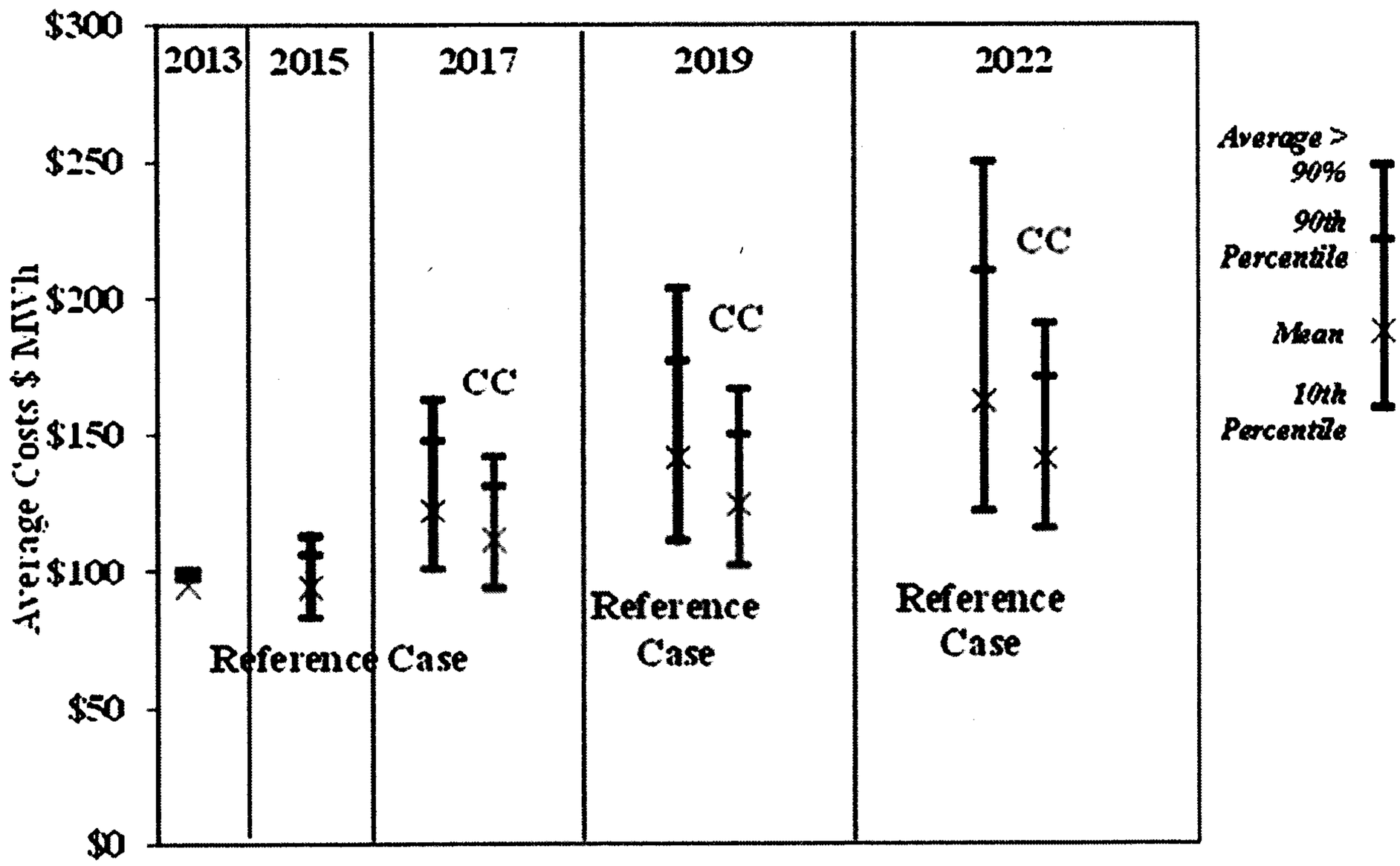
Table 4: Customer Energy Supply Rate Projections

(Confidential Material Omitted)

Planning Year	Residential Rates (Tariff "R")				MGT-S Rates			
	Demand ($/KW)		Energy(Cents/kWh)		Demand ($/KW)		Energy(Cents/kWh)	
	Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter
Currently Effective			9.55	9.56	11.7	7.4	4.01	4.96
2013/14	-	-	[redacted]		[redacted]			
2014/15	-	-						
2015/16	-	-						
2016/17	-	-	11.53	11.47	12.7	7.8	4.31	5.19
2017/18	-	-	12.45	12.34	13.8	8.5	4.68	5.64

In order to evaluate price stability, Delmarva prepared an analysis showing the expected range of prices for the Reference Case and the sensitivity cases over the planning period. Figure 2 below shows a graphical comparison of the results of this analysis.

Figure 2
Risk Ranges for RSCI FSA, With and Without CCs



In Figure 2, 10% of the possible price outcomes for that case occur above the "top" of each line and 10% occur below the "bottom" of the line. The cross mark in between the top and bottom shows the average across all potential outcomes. Figure 2 shows that the expected range of prices is increasing over time for the Reference Case.

Additional analysis of new offshore wind or new utility scale PV generation in Delaware was performed. Neither an offshore wind plant nor an additional solar project would be economically useful to the Reference Supply Portfolio costs and would add significantly to the cost of supply.

F. Environmental

i. Emissions

As part of the IRP, Delmarva prepared an analysis of the expected power plant emissions occurring over time for the Reference Case. The following charts (Figures 3 through 5) depict the emission levels of carbon dioxide (CO_2), sulfur dioxide (SO_2) and nitrous oxide (NO_X)

expected from power plants in the PJM Delmarva zone for every other year from 2012 through 2022.

Figure 3

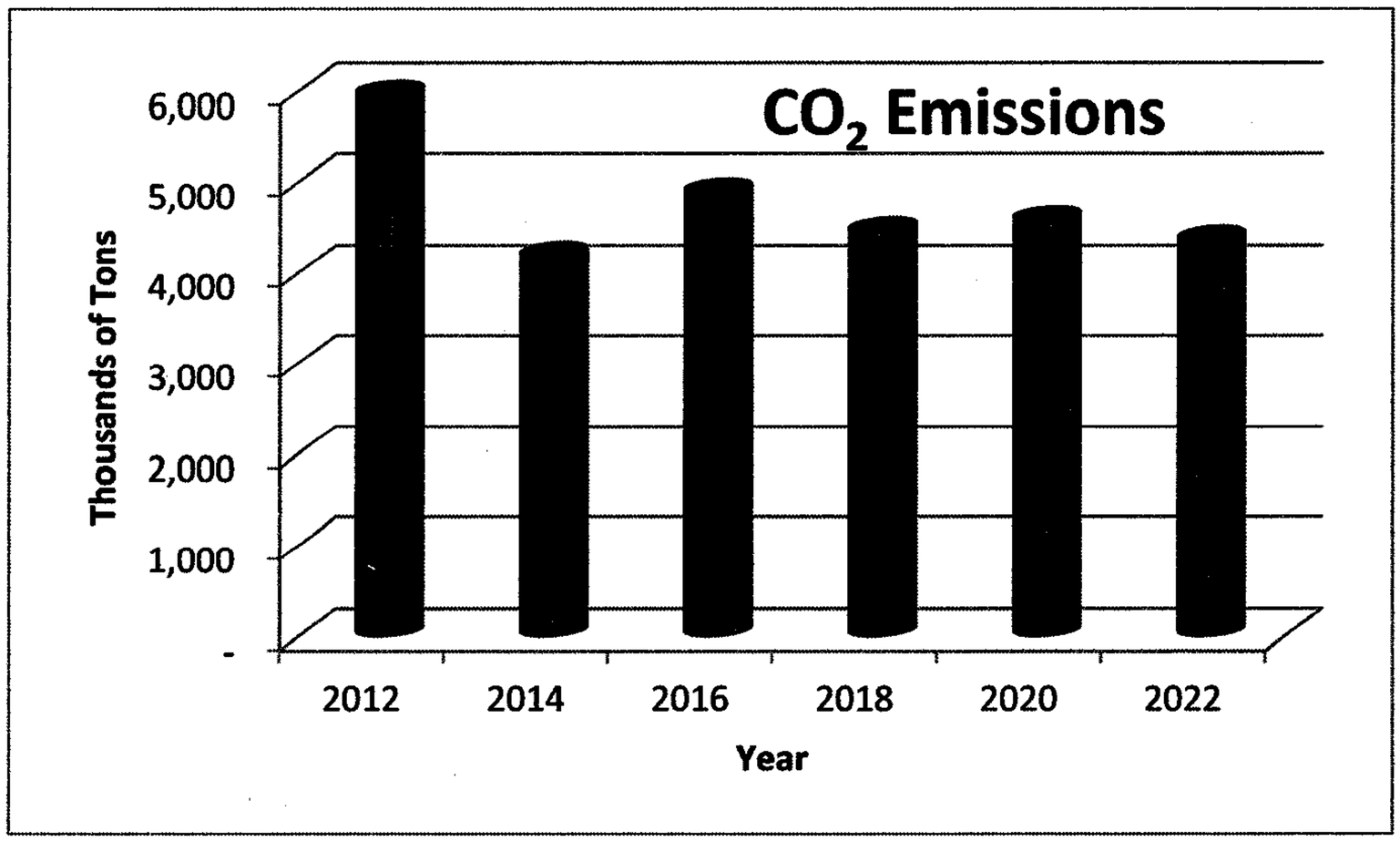


Figure 4

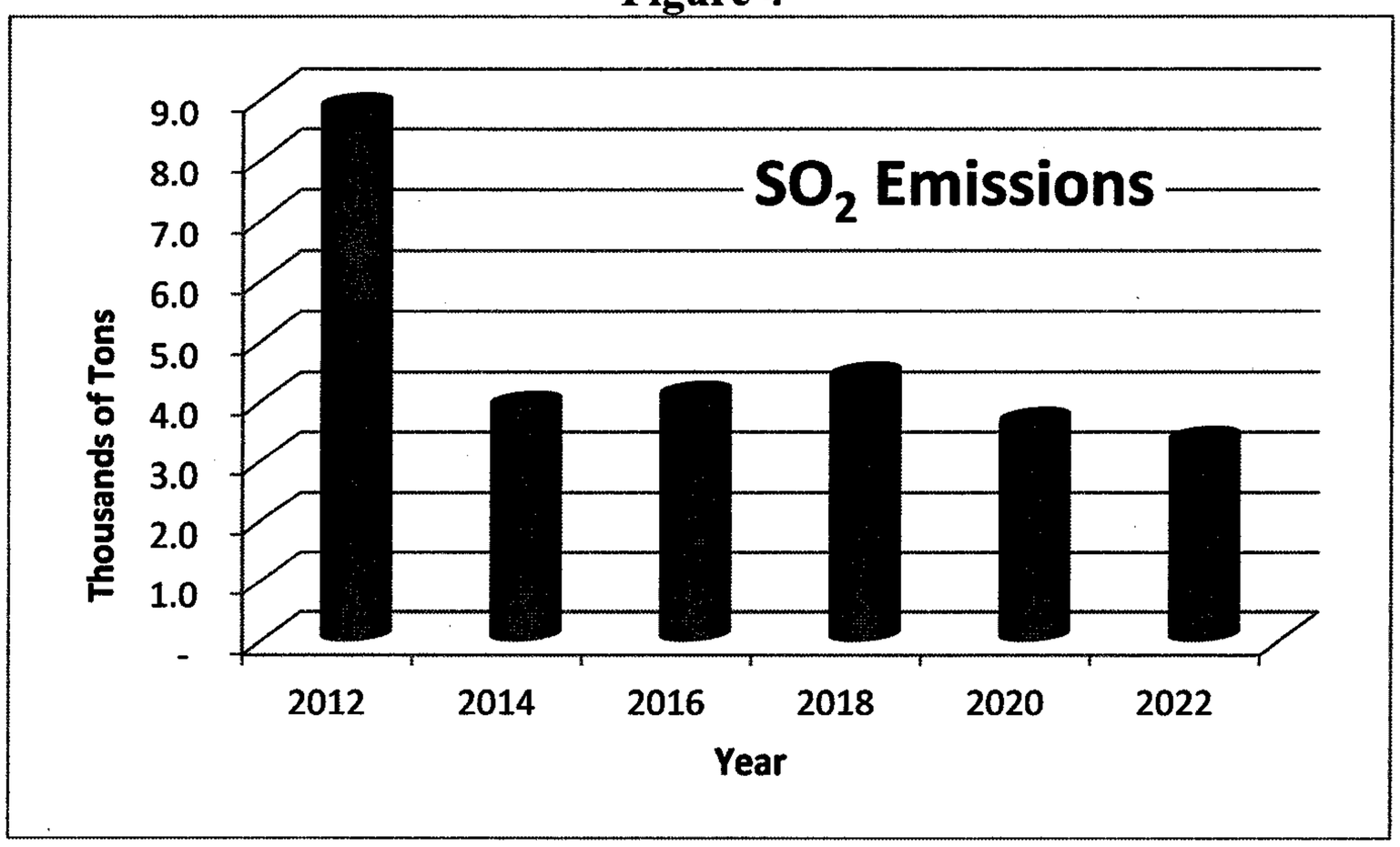
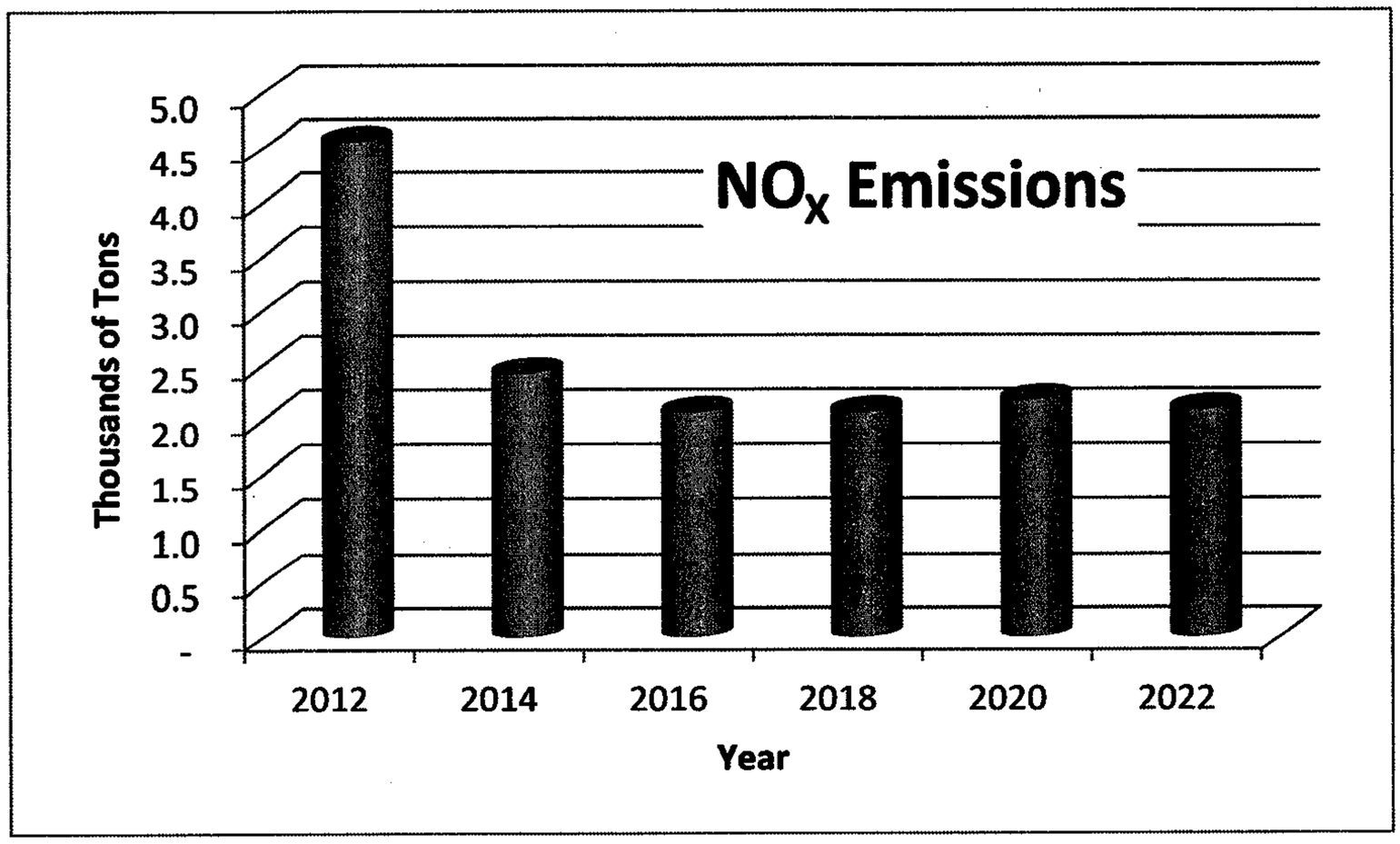


Figure 5



These charts indicate that the Reference Case emissions of CO_2, SO_2 and NO_X are expected to decline significantly in the Delmarva zone during the ten-year planning period as compared to 2012 levels. These projections reflect tightening federal and regional clean air standards, generation retirements and additions, as well as actions that Delaware has taken to increase renewable generation, reduce electric energy consumption and demand, and provide better emission controls for electric generation from coal resources. Collectively, these federal, regional and local actions are expected to improve air quality in the State.

ii. Impact on Human Health

The change in power plant emissions over time can be used to evaluate the change in ozone and particulate matter that affects air quality and impacts human health in Delaware. Using environmental modeling tools developed by the US Environmental Protection Agency (EPA) and available in the public domain, the IRP provides an estimate of the human health impacts for the Reference Case comparing changes in air quality between 2013 and 2022. The methods and procedures of the analysis are described in Section IX and Appendix 8 of the IRP.

Due to the uncertainty surrounding the preparation of the estimated impact of changes in air quality on human health, the estimates are presented as a range of values as opposed to a single value. Table 5 below shows the estimated range of monetized human health benefits as derived from the EPA models that are expected to occur for Delaware resulting from improvement in air quality in the Reference Case from 2013 to 2022.

Table 5

Total BenMAP-Derived Monetized Health-Related Benefits for $PM_{2.5}$ and Ozone (Millions $2010 U.S. Dollars/Year) Associated with the Changes in Air Quality from 2013 to 2022.

	Delaware	
	High End	Low End
2013–2022		
PM-Mortality (Laden, 3% discount rate)	1,800	
PM-Mortality (Pope, 7% discount rate)		630
PM-Morbidity	45	45
Ozone-Mortality (Levy)	300	300
Ozone-Morbidity	6	6
Total	*2,151*	*981*
Total (2 significant figures)	2,200	980

More detailed PM-Mortality estimates are presented in Appendix 8 based upon a number of expert studies. In Table 5 only the highest value (Laden) and lowest value (Pope) are presented.

The estimated human health benefits arising from the Reference Case by 2022 shown in Table 5 are very significant. These results are affected by the expected changes in power plant emissions that can be attributed to a number of factors including:

- The expected operation of over 12 GW of new gas fired generation and retirement of about 2 GW of coal fired resources in PJM by 2022,
- Expected reductions in emissions from remaining coal generation,
- Increases in the expected implementation of renewable resources within Delaware and other Mid-Atlantic regions (including Delmarva's renewable resource portfolio),
- Ongoing demand side management activity including the implementation of smart grid technology and associated dynamic pricing and load control programs.

These factors, as well as other factors not related to power generation resources, contribute to improving air quality and human health over the 10 year planning horizon. More details on this analysis are in a detailed technical summary report provided as Appendix 8.

G. Renewable Energy

i. RPS Compliance

In 2011, Delmarva Power became responsible for obtaining Renewable Energy Credits (RECs) to comply with the State RPS standards for all distribution customers.[4] Delmarva Power has created a portfolio of renewable resources that when supplemented with REC and SREC offsets from the Bloom energy project and spot market purchases, will assure compliance with RPS. Renewable resources in Delmarva Power's portfolio include contracts with:

- AES Armenia Mountain for up to 50Mw of wind resources
- Gestamp Roth Rock for up to 40 Mw of wind resources
- enXco Chestnut Flats for up to 38 Mw of wind resources
- Dover Sun Park for 70% of the 10 Mw of solar resources
- Delaware SREC Procurement Pilot Program for up to 7.68 Mw of solar resources secured through the SEU.

ii. Impact on Customer Bills

Securing RECs and SRECs needed to comply with REPSA is forecast to affect a typical 1,000 kWh residential monthly bill on a "non-netted" basis by $6.60 in compliance year 2013.[5] This impact is expected to increase to $15.15 a month in compliance year 2022. However, as described in this IRP, the monetized human health impacts of cleaner air are significant. DNREC is currently in the process of developing rules for calculating the cost of compliance with REPSA and these rules may include provisions for "netting" the costs that are avoided by renewable energy resources (such as external health costs). Netting the external health cost and other cost avoidance benefits of renewable energy may significantly reduce the impact on customer bills.

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[4] Certain larger industrial customers may "opt out" of this requirement.
[5] "Compliance" year 2013 is the period June 1, 2013 – May 31, 2014.

H. IRP Planning Objectives and Action Plans

Delmarva Power has six planning objectives for its procurement of SOS supply obligations in Delaware. For each of these six objectives, the following discussion includes objective measures, progress since the December, 2010 IRP towards meeting the objective and action plans for the future.

1. Reasonable Cost and Price Stability

Objectives:

a) Delmarva Power will evaluate generation, transmission and demand side resource options during the planning period to ensure that sufficient and reliable resources to meet customer needs are acquired at a reasonable cost.

b) Delmarva Power will seek to provide year over year price stability in the prices paid by SOS customers for their total electricity supply.

Measures:

a) Obtain Commission acknowledgement that the IRP does not appear unreasonable in meeting these objectives.

b) Annually provide the Commission information showing changes in rates and procurement cost adjustments

Progress since 2010

On January 10, 2012, the IRP filed December 1, 2010 by Delmarva Power was ratified by the Commission issuance of Order No 8083 and, as the following table illustrates, since 2010 Delmarva's Residential and Small commercial (RSCI) SOS supply process has been able to meet customer needs while lowering supply prices.

DE SOS Procurement - Rate Comparison for 12-Month Procurement Period					
2011 over 2010			2012 over 2011		
	%	¢		%	¢
Summer	-5.0%	-0.56	Summer	-10.2%	-1.08
Winter	-1.5%	-0.16	Winter	-9.0%	-0.94

Delmarva's strategy of procuring laddered, three year Full Requirements Service (FRS) contracts through a reverse auction bidding format, along with falling prices for natural gas, appear to be the primary factors for providing reasonable cost and stable-priced electricity.

Action Plan:

The following actions are expected to occur in the next five years:

a) In accordance with EURCSA, the Company will prepare and file an Integrated Resource Plan at least once 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, 2014.

b) The IRP will provide an evaluation of various resource mixes showing both the expected outcome in terms of average price and the potential range of outcomes around the expected price.

2. Reliability

Objective:

- Ensure that the electric system serving Delmarva Power's customers meets all NERC, RFC, PJM, PHI and Delaware transmission electrical reliability requirements.

Measures:

a) Schedule for completing PJM approved zonal RTEP projects as listed on the "RTEP Construction Status" page on the PJM Website (www.pjm.com).

b) 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

ii. Constrained hours of operation

Progress since 2010

The following table summarizes the transmission system upgrades made in the State of Delaware since November, 2010.

Table 6

Description	In-Service Date	Cost ($M)
Easton - Bozman to 69kV – Build new line	12/31/2010	$5.16
Lank - Five Points 69kV - Upgrade Conductor	6/1/2011	$1.70
Indian River Substation - Add 3rd 230/138kV Transformer	6/1/2011	$7.42
Loretto - Princess Anne 69kV - Rebuild Line	5/31/2011	$2.55
Oak Hall - Wattsville 138kV - Build new line and add a 138/69kV transformer at Wattsville	5/31/2011	$13.97
Darley - Silverside 69kV Reconductor	12/31/2011	$1.31
Indian River - Bishop 138kV - New Line	6/2/2012	$19.30
Add two additional breakers at Keeney 500 kV	6/1/2012	$5.06
Easton 69kV Substation Reconfiguration	6/1/2012	$1.13
Kenney 69kV - Establish Ring Bus	6/20/2012	$2.73
Indian River 230kV SVC - Install Reactors	6/15/2012	$2.35
Bishop - Ocean Bay 138kV Relay Upgrade	6/15/2012	$0.28
Nelson 138kV SVC - Install Reactors	6/29/2012	$2.26
Edgemoor AT-20 230/138kV - Replace Transformer	7/5/2012	$3.30
Keeney - Steele 230kv Relay Upgrade	4/31/2012	$0.20
Wattsville and Piney Grove 69kV - Install Relays for Kenney Sub	5/31/2012	$0.32

In addition, in April 2012, Delmarva Power provided updates to the Commission as part of the annual Docket 50 transmission standards targets.

Action Plan:

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).

3. Renewable Energy

Objectives:

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 renewable energy resources over the planning period sufficient to meet the requirements as specified by the Delaware Renewable Energy Portfolio Standards Act (REPSA) for its SOS customers.

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 regulations currently being promulgated by DNREC, provide cost of RPS compliance information if needed.

Measures:

a) Meet the annual RPS requirements for SOS 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 compliance payment requirements.

c) As may be required by forthcoming regulation, provide information needed to determine the cost of RPS compliance.

Progress since 2010

The Dover Sun Park, one of the largest solar installations in the Mid-Atlantic region, became commercially operational during the Summer of 2011. Delmarva has a 20 year contract to purchase 70% of the SRECs created by this facility. Accompanying this contract, Delmarva signed an agreement with the Delaware Sustainable Energy Utility (SEU) which allows the SEU to purchase a portion of the SRECs generated by the Sun Park during its first two years of operation for the purpose of preserving the life of excess SRECs.

Gestamp Roth Rock, a wind farm located in Western Maryland which provides up to 40 MW of wind energy under contract to Delmarva Power, became operational in August 2011. The enXco Chestnut Flats wind farm located in Central Pennsylvania provides up to 38 Mw of wind energy began service in December 2011.

The Delaware PSC approved an SREC Procurement Pilot Program in 2011 that authorized the SEU to conduct a competitive solicitation for Solar RECs that would then be sold through long term contracts to Delmarva Power. In 2012, the SEU awarded 166 twenty year contracts for Delaware-sited solar systems totaling 7.68 MW of Capacity.

Action Plan:

The following are expected to take place over the next five years:

1. Continue receiving energy and REC's from the following executed and approved contracts from land-based wind generators:

    a. AES Armenia Mountain Wind Energy

    b. Gestamp Roth Rock Wind Energy

    c. enXco Chestnut Flats Wind Energy

2. Continue receiving SREC's from the following approved contracts from solar providers:
   a. The Dover Sun Park
   b. The Solar REC Procurement Pilot Program
3. Incorporate REC and SREC offsets derived from the Bloom Energy Project to help meet the State RPS.

4. Demand Response

Objective: Implement utility provided, technically feasible, and cost effective demand response programs with a focus on contributing towards meeting the peak demand reduction goals of 15% by 2015 of the Energy Conservation and Efficiency Act of 2009. Utility provided new demand response programs are expected to be enabled by Delmarva Power's deployment of an Advanced Meter Infrastructure (AMI) in Delaware.

Measure: Peak demand reduction capability and achievements will be measured each year beginning in 2013.

Progress since 2010:

1. Advanced Metering Infrastructure for over 99% of Delmarva Power electricity customers in Delaware have been installed.
2. An education campaign to inform customers about the additional information available as a result of the AMI installation is well in progress.
   - Presented detailed energy use information through monthly electricity bills.
   - Presented detailed energy use information through Delmarva Power's internet based My Account.
3. Initiated the operation of dynamic pricing during the summer of 2012.
4. Received Commission approval on November 5, 2012 for a new residential direct load control program. Delmarva Power continued operation of legacy direct load control programs throughout 2010, 2011 and 2012.

5. Held quarterly meetings with SEU representatives to discuss DSM initiatives.

Action Plan

Over the next two years:

Residential Demand Response Programs

1. Conduct residential dynamic pricing and direct load control program education efforts beginning the first quarter of 2013.
2. Enroll customers in the new direct load control program and install equipment beginning in 2013.
3. Conduct program load reduction events beginning during the summer of 2013.

Non-Residential Demand Response Programs

1. Implement non-residential phase-in of dynamic pricing for AMI Field Acceptance Test SOS customers.
2. 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.

5. <u>Energy Efficiency</u>

Objective: Collaborate with the SEU on the implementation of SEU selected programs. SEU selected programs will contribute towards meeting the Energy Conservation and Efficiency Act of 2009 savings targets of 2% of the 2007 electricity consumption by 2011, increasing to 15% by 2015.

Measures: Achieved energy reductions will be measured beginning in 2011 by the SEU.

The Delaware Legislature created the Delaware Sustainable Energy Utility ("SEU") in 2007 to coordinate and promote the sustainable use of energy in Delaware. The SEU was given responsibility for implementing energy efficiency and conservation programs in Delaware.

Progress since 2010:

1. The SEU planned and designed energy efficiency and conservation programs.
2. The SEU implemented selected programs. A large number of these programs have been concluded.
3. The SEU has met with Delmarva Power on a quarterly basis to discuss planned activities.

Action Plan:

1. Delmarva Power will continue to discuss program savings opportunities with the SEU on a quarterly basis.
2. The SEU selects its specific mix of programs, savings measures and targeted market sectors.
3. The SEU will implement its selected programs and savings measures.

6. Utility Provided Energy Efficiency Programs

Objective: Implement utility energy efficiency initiatives (transmission improvements, street lighting, and possibly a Combined Heat and Power (CHP) program)

Measure: Provide annual achieved energy savings beginning 2013.

Progress since 2010:

1. Installed high efficiency transformers and replaced transmission conductors.
2. Installed distribution line capacitors, which resulted in lower losses on the system.
3. Replaced Mercury Vapor (MV) streetlights with High Pressure Sodium (HPS) streetlights.
4. Evaluated LED street lighting technology potential future LED street lighting conversions)

Action Plans:

1. Implement transmission and distribution improvement measures as described in the RTEP.

2. Continue installation of high efficiency transformers.
3. Continue streetlight improvement plan.
4. Work with SEU to determine CHP or other program utility implementation opportunities.

I. Recommended Path Forward

The IRP Working Group provides an effective way to share information in a collaborative and transparent manner among stakeholders. Delmarva Power recommends that the IRP Working Group process continue.

Delmarva's current procurement strategy, which has been developed and refined on an on-going basis over the years, has been to:

1. Through a reverse auction process, procure a series of laddered three year contracts for Full Service Requirements Agreements (FSA) for Residential and Small Commercial SOS customers and one year FSAs for Large Commercial SOS customers,
2. Construct a portfolio of renewable energy resources to provide for the needs of Delmarva Power's customers which increases in size over time consistent with the requirements of the Delaware Renewable Portfolio Standards (RPS), and,
3. Bundle the renewable portfolio together, including any applicable offsets from the Bloom Energy fuel cells, with the FSA's to complete the procurement of electrical requirements for SOS customers.

This strategy has provided SOS customers with reasonable and stable energy prices and should be continued. In addition, as markets change, Delmarva Power can discuss these changes and appropriate responsive actions with the IRP Working Group. Moreover, each year Delmarva, the Public Advocate, Commission Staff, and numerous other stakeholders engage in a process overseen by the Commission designed to review and, where necessary, improve the SOS bidding process. That annual process has resulted in improvements, such as the reverse auction bidding process and changes to the FSA's. These annual SOS process improvement workshops will continue.

Further, the reduction in power plant emissions expected under the Reference Case between 2013 and 2022 provides significant improvements in air quality and health benefits for the State

of Delaware. Based upon EPA models of air quality, the range of expected health benefits under the Reference Case occurring in 2022 relative to 2013 in Delaware is $980 million to $2.2 billion Delmarva's current procurement strategy provides an appropriate balance to secure reliable and reasonable cost energy supply, provide price stability and environmental benefits and should be continued.

In the Fall of 2012, the Delaware Public Service Commission approved Delmarva Power's application for a Dynamic Pricing Program and for a Residential Load Control Program. The reduction in energy usage and peak demand expected from the implementation of these programs will supplement Delmarva's procurement practices.

II. Summary Historical IRP Background

Pursuant to the Electric Utility Retail Customer Supply Act ("EURCSA"), which was enacted in 2006, Delmarva Power is required to prepare and file an Integrated Resource Plan every two years.[6] The IRP is designed to provide a comprehensive review of Delmarva Power's plans to procure energy for SOS customers for the next ten years after the filing.[7]

Prior to the 2012 IRP, the most recent IRP prepared by Delmarva Power was submitted to the Commission and State Agencies on December 1, 2010. The 2010 IRP was the first to be submitted under the regulations adopted by the Commission on December 8, 2009, by Order No. 7693 in PSC Regulation Docket No. 60. On January 10, 2012 the Commission issued Order No. 8083 in which the 2010 IRP was ratified. The Commission further approved most of the "Proposed Path Forward on Delmarva Power & Light Company's Integrated Resource Plan ("IRP"): Joint Proposal to Ratify PSC Docket No 10-2."[8] Copies of the Path Forward and Order No 8083 are provided in Appendix 3.

Events since the last IRP

Upon approval of the Path Forward, Delmarva Power and other parties began a series of workshops and collaborative discussions regarding the planning and development of the 2012 IRP. Topics discussed at these workshops included Load Forecasting, Demand Side Management, Transmission Planning, Generation Interconnection, IRP model assumptions, and Scenario/Sensitivity Analysis. Numerous parties participated in some or all of these discussions including, but not necessarily limited to, Delmarva Power, Commission Staff, DNREC, DPA, Caesar Rodney Institute, the Mid Atlantic Renewable Energy Coalition (MAREC), the Delaware SEU, Calpine and NRG.

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[6] 26 *Del C.* §1007(c)(1).
[7] *Id.*
[8] The Commission did not approve Section 4 of the Path Forward that suggested that Delmarva may not be required to submit an IRP every two years (See Order 8083, item 2, pp 3)

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 December 2010 when the last IRP was filed, a number of events have occurred that impact the preparation and development of Delmarva Power's IRP. The 2012 IRP incorporates these events into the resource planning analysis to the extent such information was available before the analysis for the IRP needed to begin in order to meet the December 2012 filing requirement. Brief descriptions of the more important events that have occurred from a resource planning perspective since the 2010 IRP was submitted are described below.

Bluewater Wind Power Purchase Agreement

In 2008, Delmarva Power entered into a power purchase agreement with Bluewater Wind for up to 200 MW of offshore wind energy from an offshore wind farm to be constructed 10 to 11 miles off the Delaware coast. The Bluewater Wind project was scheduled to begin operation in 2015 and was included as a renewable generation resource in the 2010 IRP. However, in January 2012, NRG, the parent company of Bluewater Wind, terminated the power purchase agreement with Delmarva Power and announced that active development of its offshore wind projects would be placed on hold. Consequently, the Bluewater offshore wind project is no longer included as a resource in Delmarva's 2012 IRP. Although the Bluewater Wind project is no longer modeled as part of the IRP Reference Case, the 2012 IRP includes a sensitivity analysis of a generic offshore wind facility.

May 2012 PJM Capacity Auction

As part of the PJM Capacity market that takes place in May of each year, a Base Residual Auction (BRA) is held for electrical capacity to be provided three years in the future. Resources which clear the BRA are considered firmly committed to provide this future capacity. In May of 2012, the yet to be constructed Calpine Garrison Energy Project, a 309 MW gas fueled combined cycle facility, cleared the BRA for the capacity year 2015.[9] This plant, which cleared the BRA

[9] PJM Capacity year 2015 is June 1, 2015 – May 31, 2016.

without any guarantee of ratepayer subsidy, is located near Dover and is included as a resource in Delmarva Power's 2012 IRP beginning in 2015.

Mid Atlantic Power Pathway (MAPP)

Delmarva Power has long supported the construction of the **Mid-Atlantic Power Pathway** (MAPP), a high voltage transmission line that would run from Possum Point in Virginia through Chalk Point and Calvert Cliffs in Maryland and across the Chesapeake Bay to Vienna, MD and then to Indian River Delaware. During the summer of 2012 the PJM Board decided to remove the MAPP from PJM's regional transmission plans. According to PJM, this decision was based on a reduced load forecast, increased demand response and new generation resources. The 2012 IRP does not include the MAPP project as a transmission resource in the analysis.

Delmarva Power Becomes Responsible for RPS Compliance for all Distribution Customers

In July, 2011, changes to the Renewable Portfolio Standard (RPS) enabling legislation were enacted that greatly expanded Delmarva Power's role in complying with RPS. Prior to these changes, Delmarva Power was responsible for procuring Renewable Energy Credits (RECS) in the amounts specified in the RPS legislation for its Standard Offer Service (SOS) customers only. The July 2011 changes expanded the scope of Delmarva Power's RPS compliance efforts to include *all* distribution customers,[10] not just SOS customers. Because RPS compliance is based on annual MWH sales, Delmarva Power must procure much larger amounts of RECs each year to remain in compliance. As discussed further in this IRP, this has a significant impact on Delmarva Power's longer term plans to procure RECs to maintain compliance with the RPS.

SREC Procurement Pilot Program

Amendments to the state-wide RPS legislation enacted in 2010 established a Renewable Energy Task Force. In 2011, the Renewable Energy Task Force recommended that the Delaware Public

[10] As discussed elsewhere in this IRP, there is a provision in the legislation for certain larger industrial customers to become exempt from RPS compliance.

Service Commission approve a Solar Renewable Energy Credit (SREC) Procurement Pilot Program. Under the Procurement Pilot Program, the Delaware Sustainable Energy Utility (SEU) would conduct competitive solicitations to obtain SRECs that would then be sold to Delmarva Power. The SREC Pilot Program was approved by the Commission in DPSC Order No 8093. In April 2012, the Delaware Sustainable Electric Utility (SEU) conducted the first round of the SREC Procurement Pilot Program and, as a result, awarded twenty-year SREC contracts to 166 Delaware sited qualifying solar systems totaling 7.68 MW of electrical capacity. The SRECs now being produced by these facilities are purchased by Delmarva Power and are used by the Company to help meet its solar RPS obligations.

Qualified Fuel Cell Provider Program

In July 2011, the Governor of the State of Delaware signed legislation that establishes that the energy output from fuel cells manufactured in Delaware capable of running on renewable fuels ("Qualified Fuel Cell Provider") is an eligible resource for RECs under the Renewable Portfolio Standards Act. The legislation further requires that the Delaware Public Service Commission adopt a tariff under which Delmarva Power would be an agent that collects payments from its customers and disburses the amounts collected to a qualified fuel cell provider that deploys Delaware-manufactured fuel cells as part of a 30-megawatt generation facility. The legislation further stipulates that the payments from customers be offset by the market revenues received by the qualified fuel cell provider from its selling of capacity and energy into the wholesale market netted against its cost of fuel. The legislation also provides for a reduction in Delmarva Power's REC and solar REC requirements based upon the actual energy output of the 30-megawatt generation facility. In October 2011, through Order No. 8062, the Commission approved the tariff submitted by Delmarva Power in response to the legislation.

The State identified Diamond State Generation Partners ("Diamond State" or "Bloom Energy") as the fuel cell provider. Bloom plans to construct a fuel cell facility at two locations in Delaware. The first site, a 3 MW fuel cell facility at Brookside, went into commercial operation on June 18, 2012. The second site, a 27 MW facility located near Red Lion, is to be phased into operations on or before September 30, 2014.

US EPA Air Pollution Rules

On July 6, 2011, the US Environmental Protection Agency (EPA) finalized the Cross-State Air Pollution Rule (CSAPR). CSAPR requires upwind states to reduce power plant emissions that contribute to ozone and/or fine particle pollution in other downwind states. Later in 2011 however, the CSAPR Rule was challenged in the U.S. Court of Appeals.

On August 21, 2012, a three judge panel the U.S. Court of Appeals for the District of Columbia court struck down the Environmental Protection Agency's CSAPR. On October 5, 2012 EPA filed an appeal of the August 12 decision seeking a re-hearing of the case before the entire US Appeals Court for the District of Columbia. Delaware was included in the group of 10 states and various cities petitioning in favor of the re-hearing.

At the time of the CSAPR decision, the IRP analysis was already well underway and the resource planning and air quality modeling could not be started anew if Delmarva were to meet the December 2012 IRP filing requirement. Due to the potential impact of CSAPR on the future resource mix, prices and air emissions, Delmarva Power has prepared and included within this IRP a sensitivity case on the expected resource mix and air emissions with and without CSAPR.

Advanced Metering Infrastructure

Delmarva Power began deploying Advanced Metering Infrastructure (AMI) following the Commission's approval in Order No. 7420. Significantly for the IRP, AMI enables the implementation of Dynamic Pricing. Since December, 2010, Delmarva Power has essentially completed the installation of AMI smart meters for its approximately 300,000 residential and small business electric customers in its Delaware service territory.

Dynamic Pricing

On March 23, 2011, Delmarva Power filed an Application to Implement and Advanced Metering Enabled Dynamic Pricing Plan and Dynamic Pricing Rider DP. On January 31, 2012 the

Delaware Public Service Commission approved the Settlement Agreement entered into by Delmarva Power, Commission Staff and the Division of Public Advocate, approving the proposed phase-in implementation of its AMI enabled Dynamic Pricing Program for its Standard Offer Service 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, branded as the "Peak Energy Savings Credit," applies to Delmarva Power's residential and small and medium non-residential customers.

The program began implementation in June 2012 with approximately 7,000 residential customers who participated in the AMI Field Acceptance Test, which took place in 2009. This part of the Phase-in concluded on September 29, 2012 and is in the process of a Phase I Assessment, whereby the program will incorporate results and improvements obtained from the experience gained from the application of the program to this first group of customers.

Residential Direct Load Control

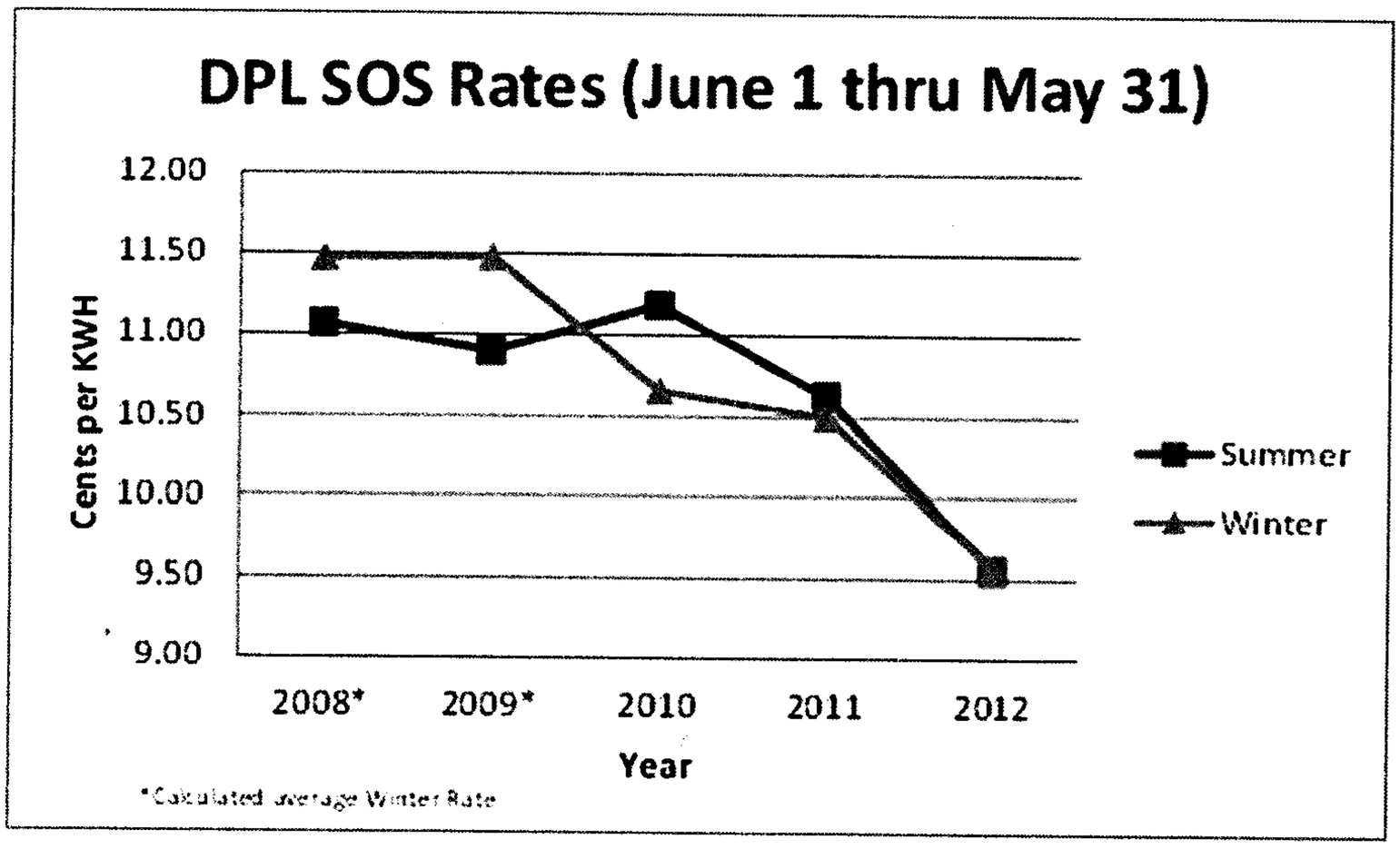
On July 28, 2011, Delmarva Power filed an Application to establish a new Residential Air Conditioning Cycling Program through the Residential Direct Load Control Rider "R-DLC" with the Delaware Public Service Commission. The Department of Natural Resources intervened in the proceeding. Several workshops were held with Commission Staff and the Public Advocate in attendance, and informal exchanges of questions and answers occurred during the Spring, Summer and Fall of 2012.

On October 17, 2012, Commission Staff issued their Report overall in support of the program. On November 5, 2011 the Commission approved the program which will be marketed to Delmarva Power's customers as the Energy Wise Rewards program.

Low Natural Gas Prices

Finally, the development of shale gas resources including the Marcellus Shale region in the Mid Atlantic/New York area and the expansion of gas transportation resources has greatly increased the availability of natural gas and driven down prices to ten-year lows. This has impacted the

expected generation resource mix in the region and placed downward pressure on energy prices generally including electricity. In fact, since the last IRP was submitted in December 2010, the energy component of Delmarva Power's retail customer electric rates has continued to decrease. This is shown in the chart below.



III. Overview of IRP Analysis and Modeling Structure

This Section of the IRP describes the overall analytical approach and major modeling tools used in the analysis. This is followed by six subsections describing in more detail the key components of the IRP and Delmarva Power's energy procurement strategy. These subsections include discussions of the following:

1. The Load Forecast
2. Demand Side Management (DSM)
3. Transmission
4. Supply Resources
5. Environmental Externalities
6. Renewable Resources

The intent of Delmarva Power's Integrated Resource Plan is to provide Delmarva's customers and regulators with a road map of how, at the time this plan was filed, the Company intends to procure electric energy for our Standard Offer Service customers for the next ten years in a way that balances cost, price stability and environmental benefits. Delmarva's overall approach to developing the IRP is based upon the following general analytical approach:

1. Begin by preparing a detailed view of the future from 2013 – 2022 for an expected or "Reference" Case. The preparation of the Reference Case requires an intensive modeling effort employing generation system planning models, portfolio analysis models, and environmental analysis models. The results of the Reference Case provide the expected view of future prices, price stability, and environmental benefits for Delmarva's customers.
2. After completion of the Reference Case, sensitivity analysis is performed around several key planning assumptions to gain a better understanding of the risk associated with some of the critical assumptions underlying the Reference Case.
3. Provide the Public Service Commission with the results of the IRP analysis in a clear and concise manner for their consideration under the current IRP Docket.

In order to prepare a plan that meets the broad objectives of the IRP, it is necessary to use several separate but related planning models. The following narrative describes how the various planning tools included in the technical analysis are aligned to provide the information needed to determine a preferred energy procurement strategy, while meeting the Commission's approved IRP regulations.

The following key planning tools were used in developing the IRP Reference Case:

- The Integrated Planning Model (IPM®) developed by ICF. IPM® is a resource planning model that considers supply, demand and transmission resources. IPM® also provides information on power plant emissions.
- The Portfolio Model (PM) developed by the Brattle Group. This model is used to evaluate price stability of the Reference and Scenario cases.
- The Community Multi-scale Air Quality (CMAQ) and Benefits Mapping and Analysis Program (BenMAP) models developed by the US Environmental Protection Agency. These models are used to translate the change in air emissions between the initial planning year and 2022 into quantified estimates of the effect of these changes on air quality and human health.

Each of these models performs specific tasks related to Delmarva's IRP requirements. The remainder of this section describes each of these models, their functions, capabilities and interrelationship with one another.[11]

a. The IPM® model

The IPM® is the first analytical processor in the Delmarva IRP development chain. IPM® is a multi-regional generation planning and production cost model. For Delmarva's IRP, the model is focused on the Delmarva Zone and PJM. The Delmarva Zone includes all of Delaware and the Maryland and Virginia portions of the Delmarva Peninsula. The model provides a detailed look at the expected future state of generation resources over the planning period 2013 - 2022. The key inputs into IPM® include the load forecast, fuel costs, PJM RTEP approved transmission

[11] More technical descriptions of each of these models are provided in the Appendices of this IRP.

investments, energy efficiency programs and goals, demand reduction programs and targets, renewable energy requirements, and prevailing and expected environmental regulations at the State, Regional, and Federal levels.

In order to provide the picture of future generation markets for Delmarva's planning period of 2013 – 2022, the model comprehensively evaluates a large number of supply side and demand side resources to produce the least cost solution of existing and future generation resources. The evaluation produces a forecast of new generation facilities that will be economic, resources that will be retired, how much energy is produced by each available generation resource, what emissions are created by each generation resource, and expected capacity and energy prices for the DPL zone and PJM.

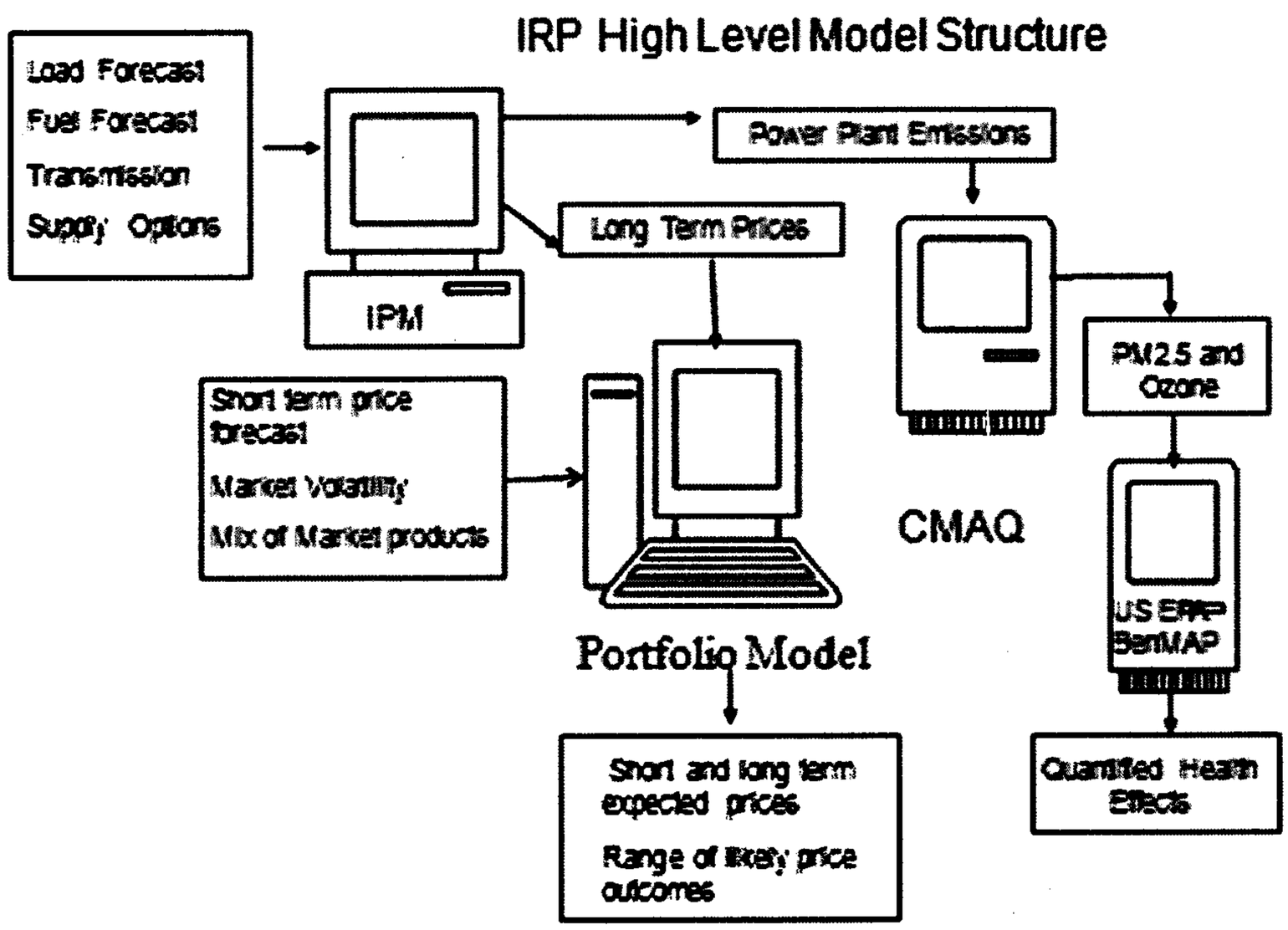
The generation resources evaluated by IPM® include the following:

- Traditional fossil fueled generation
    - Gas fired combustion turbines
    - Gas fired combined cycle facilities
    - Traditional and super-critical coal fired facilities
    - Integrated Gasification Combined Cycle
    - Oil fired facilities
- Nuclear generation
- Renewable resources
    - Off-shore wind
    - Land based wind
    - Solar
    - Biomass
    - Land-fill gas.
    - Fuel Cell Technology

A more detailed listing and specific information on the assumed cost and performance characteristics of these resources may be found in Technical Appendix 4.

The outputs of the IPM® provide key information for the other planning tools used in the IRP. The energy and capacity price forecasts are passed onto the Portfolio Model for an evaluation of future prices and price stability. Power plant emission data for criteria pollutants nitrous oxides (NO_x), sulphur dioxide (SO_2), mercury (Hg) and carbon dioxide (CO_2) are passed on to the CMAQ and BenMAP models which are used in the evaluation of human health effects. A high level overview of this process is shown in Figure 1.

Figure 1



b. <u>The Portfolio Model</u>

The Portfolio Model (PM) is a stochastic model used primarily to evaluate the price stability of various planning options. The model is also used to perform risk analysis and review the sensitivity of the results to various planning assumptions. The PM relies on the output from the IPM® to obtain estimates of longer term energy and capacity prices. In the shorter term, the PM

relies on market data from electric and gas markets to generate forward electricity price curves. In order to simulate electricity prices in future years, PM requires the additional input of current market price volatility information and the terms of the pricing related to Delmarva's renewable energy contracts and Full Service Agreements.

Using the forward price information, hourly SOS customer load data, the contract price information and expected output of wind, solar resources and the Bloom energy project, and forward price volatility, the PM uses Monte Carlo Techniques to simulate a range of future energy prices for SOS customers.[12] The price ranges produced by the PM analysis can be depicted by various percentage ranges.

In this IRP, the PM is used to evaluate the price and price stability characteristics of the Reference Case. The PM is also used to evaluate various sensitivity cases around the Reference Case including changes in expected natural gas prices. More detailed descriptions of the sensitivities analyzed by the Portfolio Model are provided in Appendix 6.

c. Environmental Models

The CMAQ and BenMAP models are analytical tools used in the evaluation of the effect of power plant emissions on human health. Both CMAQ and BenMAP were developed by the US Environmental Protection Agency and are available in the public domain. The CMAQ model takes the inventory of air emissions from all sources, including power plant air emissions data from the IPM®, and along with detailed meteorological information, calculates expected changes to ambient air quality for the pollutants of interest. For this IRP, the CMAQ model performs these detailed calculations over a four kilometer grid covering most of the PJM footprint in the Mid-Atlantic States. This process is quite computationally intensive and time consuming. BenMAP uses the output from CMAQ to estimate the impacts on human health in dollar terms associated with the changes in air quality simulated by CMAQ.

Delmarva is also required by regulation to provide appropriate life-cycle analysis of resource alternatives in the IRP. However, the Commission indicated in Order 8083 when discussing the

[12] A more detailed description of the Portfolio Model is provided in Technical Appendix 6.

frequency of filing an IRP, that Delmarva may use existing models and studies if they are still relevant and accurate. Delmarva prepared and submitted a life-cycle analysis in the IRP filed December 1, 2010. The 2010 life-cycle analysis is both relevant and accurate and is incorporated by reference into this IRP.

IV. Load Forecast

Delmarva's ten year energy procurement plan to provide the electrical requirements for SOS customers is based on an internally prepared load forecast covering the planning period through 2022. Section 4 of the IRP regulations provides detailed requirements for preparing a range of load forecasts as well a review of historical load data. Detailed documentation of Delmarva's load forecasts and its forecasting methods, intended to meet these requirements, is attached as Appendix 4. For the IRP, Delmarva 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 DSM programs. When both the expected impacts of future DSM programs, which are estimated separately from the econometric baseline forecast, and expected hourly SOS customer loads are subtracted from the baseline forecast, the result is termed the Reference Case Forecast. A summary of the major forecast results is provided below.

Baseline Forecast

The following table summarizes the baseline forecast for summer peak demand (MW) and energy throughput (MWh) for 2013, the initial year of the IRP planning period, and 2022, the last year of the IRP planning period, for Delmarva Delaware's three major categories of customers (with street lights added as a fourth category for energy throughput). The table also provides the summer peak demand and energy throughput for the SOS component of each category for the same two years.

Baseline Forecast – Peak Demand (MW) & Energy Throughput (MWh)

a. Delmarva Delaware Total - 2013 & 2022

Peak Demand (MW) and Energy Throughput (MWh)

	2013 Delmarva Delaware		2018 Delmarva Delaware		2022 Delmarva Delaware	
	MW	MWh	MW	MWh	MW	MWh
Residential	1,033	2,916,121	1,133	2,853,290	1,204	2,910,224
Small Commercial	28	188,233	31	195,355	33	197,783
Large Commercial & Light Industrial	844	5,622,711	935	5,835,427	994	5,907,981
Street Lights	0	37,768	0	38,464	0	39,031
Total	1,905	8,764,833	2,099	8,922,536	2,231	9,055,019

b. Delmarva Delaware SOS - 2013 & 2022

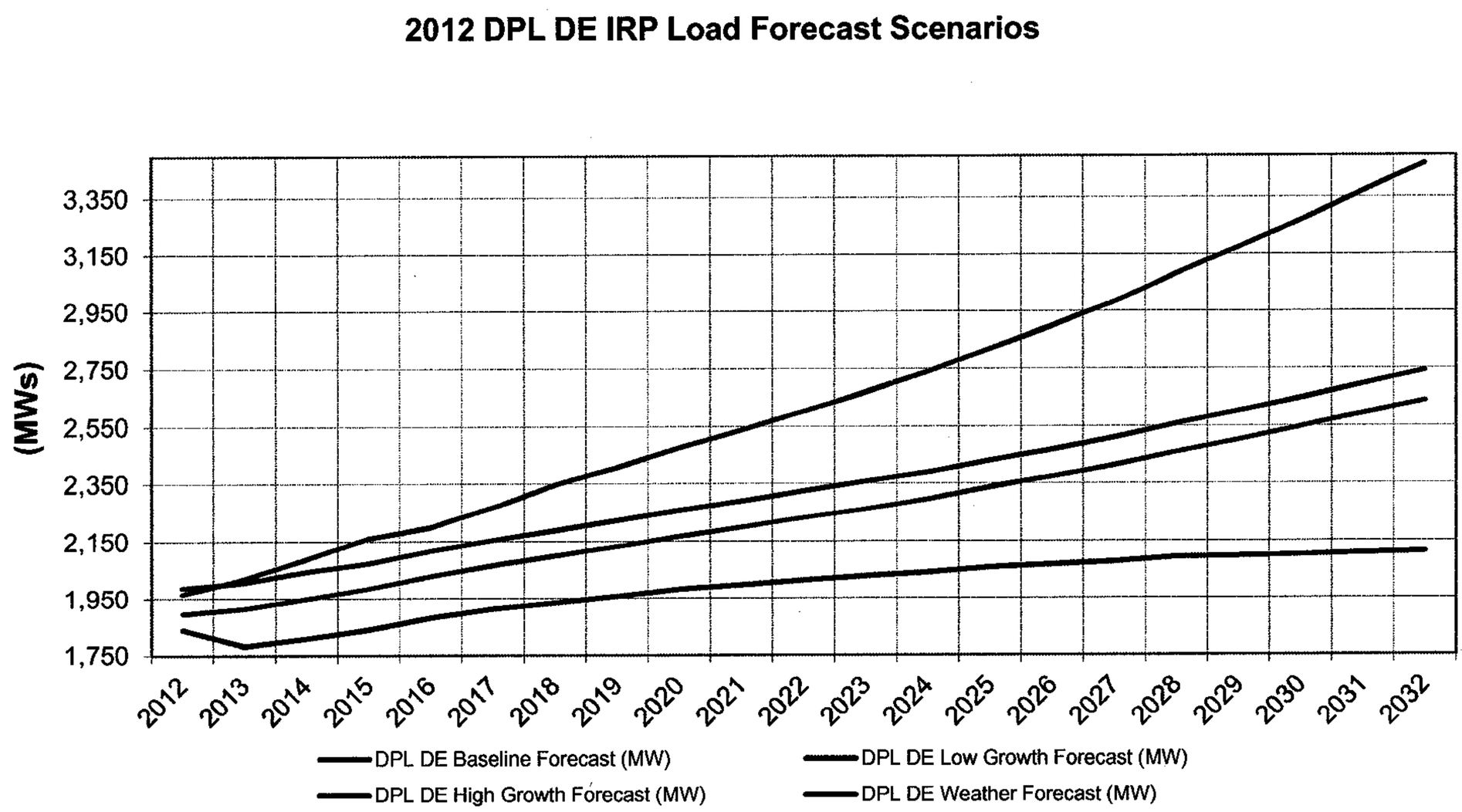
Peak Demand (MW) and Energy Throughput (MWh)

	2013 Delmarva Delaware SOS		2018 Delmarva Delaware SOS		2022 Delmarva Delaware SOS	
	MW	MWh	MW	MWh	MW	MWh
Residential	996	2,810,730	1,092	2,750,170	1,161	2,805,046
Small Commercial	23	150,448	25	156,140	27	158,081
Large Commercial & Light Industrial	190	1,262,540	210	1,310,303	223	1,326,595
Street Lights	0	27,643	0	28,153	0	28,568
Total	1,209	4,251,361	1,327	4,244,766	1,411	4,318,290

Load Growth Scenarios

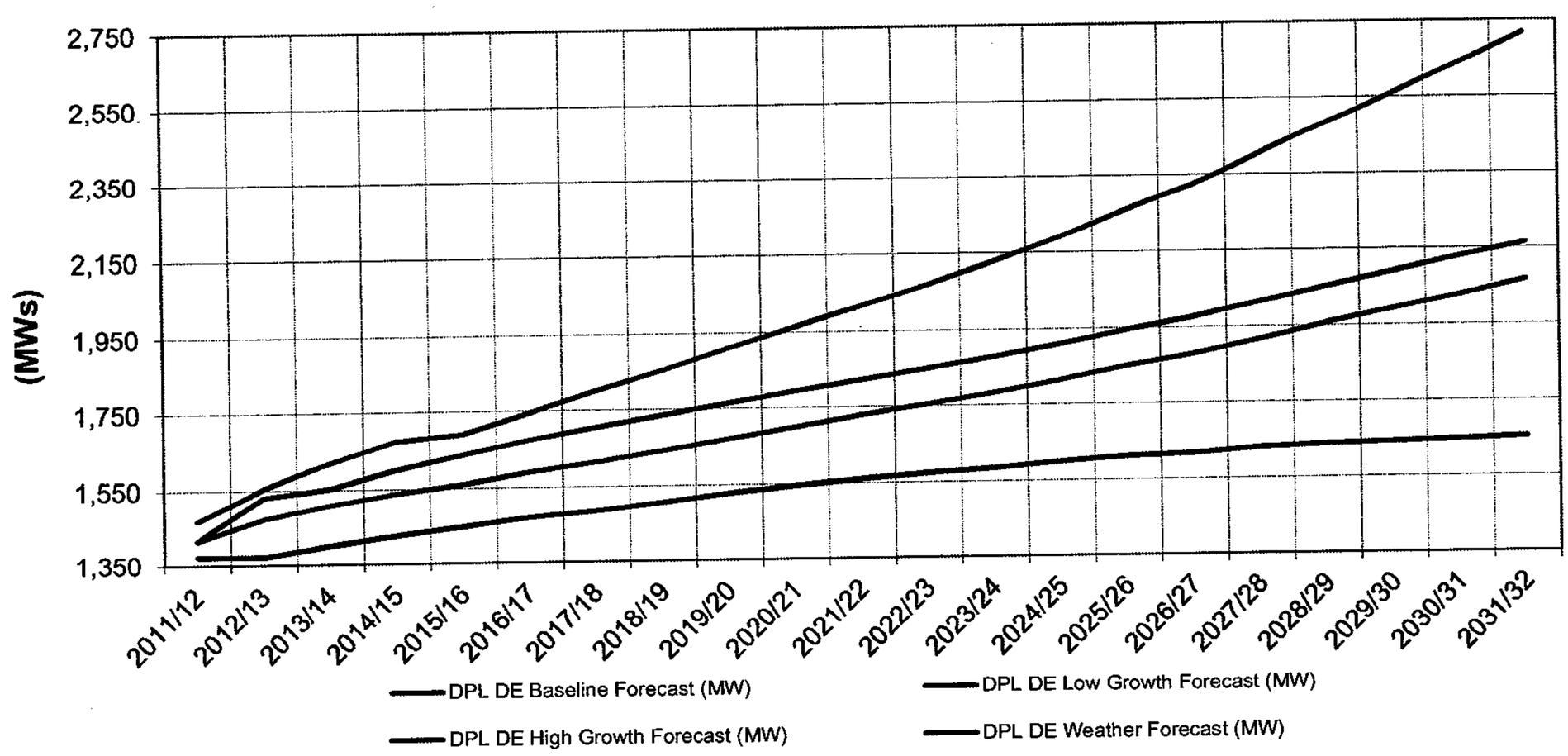
In addition to providing a "baseline" forecast, the IRP regulations require Delmarva to prepare a range of load growth forecasts for a number of different assumptions. The range of forecasts can be used in the IRP sensitivity analyses. The following tables present, for differing assumptions, the Company's forecast for the unrestricted summer and winter peak demand, as well as the forecast for MWh , for all Delmarva Delaware customers over the ten year IRP planning period.

DPL Delaware Jurisdictional Summer Peak Demand
(MWs)



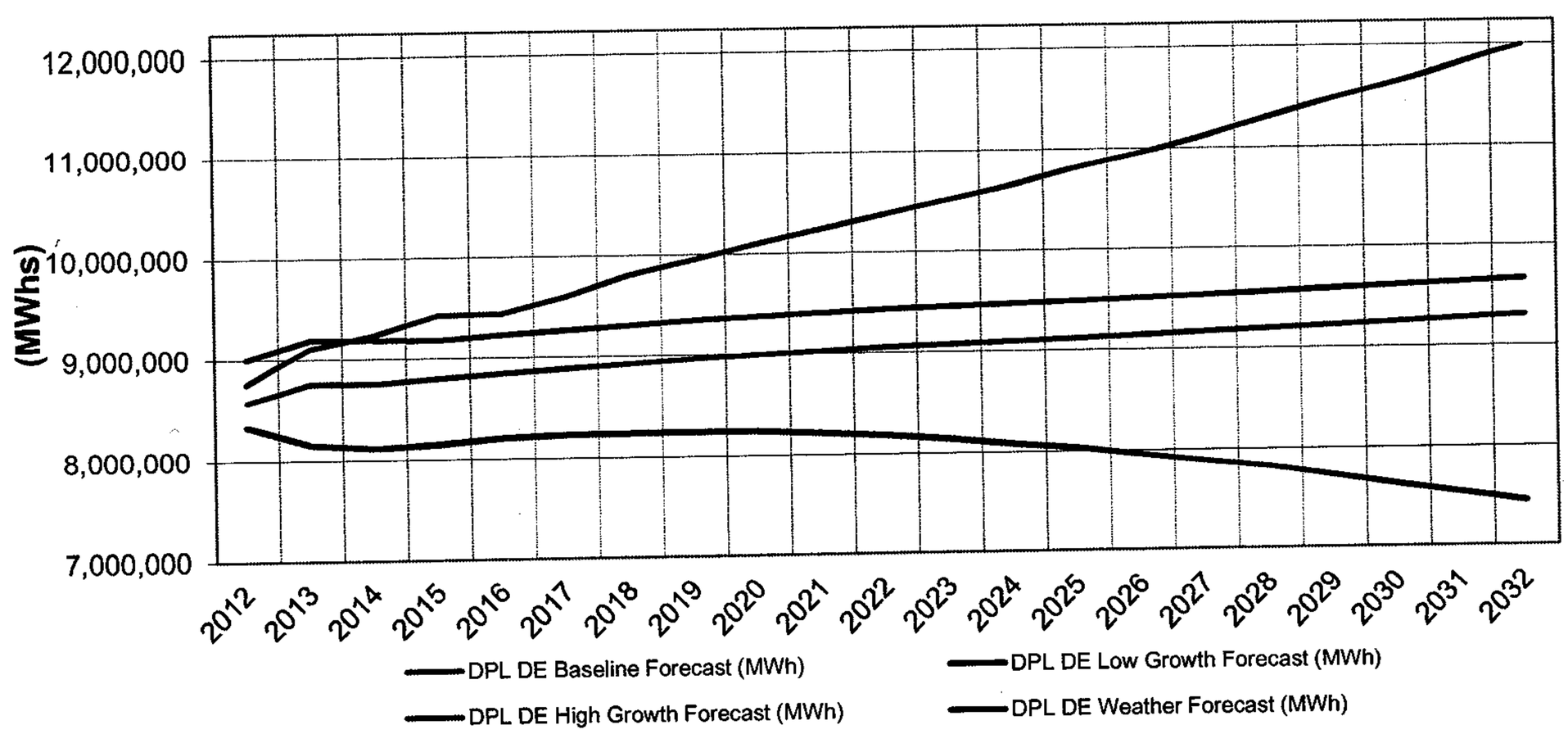
DPL Delaware Jurisdictional Winter Peak Demand (MWs)

2012 Winter DPL DE IRP Load Forecast Scenarios



DPL DE Jurisdictional Energy Throughput MWH

2012 DPL DE IRP Energy Forecast Scenarios



In the tables above, the heavy green line represents the Baseline Scenario; 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 Scenarios. 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 Scenario. 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 Scenario, monthly heating and cooling degree days are set equal to their historical average plus two standard deviations.

IRP Load Forecast Requirements

Technical Appendix 4 includes a discussion of the methodology used in developing these forecasts and provides further information on these forecasts including:

- Historical data and future estimates of:
  - Five year historical loads, current year-end estimate and 10 year weather adjusted forecast
  - 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
- 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.

SOS Reference Forecast

As mentioned earlier, the Baseline Forecast described above does not include the effects of future DSM programs. For purposes of procuring a portfolio to provide SOS customer energy requirements, the expected energy savings from DSM programs needs to be subtracted from the Baseline Forecast of SOS customer energy to arrive at the amount of annual energy expected to be procured for SOS customers in the Reference Case. In addition, the loads of expected Hourly Supply customers also need to be subtracted.

The Reference Portfolio Forecast represents the expected Delaware jurisdictional SOS load for which Delmarva is obligated to make contractual arrangements for energy supply.

The following table summarizes the calculation for the reference portfolio load.

SOS Reference Portfolio Forecast

Delaware SOS Customer MWH

	2013	2014	2016	2018	2020	2022
Baseline SOS	4,251,361	4,155,052	4,200,299	4,244,766	4,284,939	4,318,290
less Hourly SOS	351,678	359,183	362,475	364,982	367,543	369,520
Less SOS DSM	411,724	554,751	727,997	795,087	975,199	1,066,782
SOS Reference Case	3,487,960	3,241,118	3,109,827	3,084,697	2,942,198	2,881,989

V. DEMAND SIDE MANAGEMENT ANALYSIS

The Delmarva Power IRP evaluates demand side management (DSM) programs as potential resource options for meeting Delmarva Power Delaware customer energy and capacity requirements. In contrast to supply side options such as new generating units, DSM options reflect potential savings in either the total consumption of electrical energy, reduction of system demand during peak periods or both. Demand Side Resources were examined to support energy efficiency, conservation, and demand response in compliance with the Delaware Energy Conservation & Efficiency Act of 2009.

The Delaware Energy Conservation & Efficiency Act of 2009[13] (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[14] to achieve, at a minimum, energy savings 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.[15] Pursuant to *29 Del. C. §8059,* the Delaware Sustainable Energy Utility is tasked with coordinating and promoting the sustainable use of energy in Delaware. The SEU is responsible for implementing energy efficiency and conservation programs in Delaware while Delmarva Power is responsible for implementing Demand Response (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).[16] Additionally, the current regulations[17] governing the preparation of this and future IRP states that it shall include:

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

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[13] 26 *Del. C.* §§1500-1507.

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

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

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

[17] 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.

26 *Del. C.* § 1020 states:

> "IRPs filed with the Commission pursuant to §1007 of this Chapter shall include a detailed description of energy efficiency activities. Electricity demand response programs shall be directly implemented by the utility. Demand-side management and other energy efficiency activities shall be implemented by the SEU (as defined in §8059 of Title 29), in collaboration with the utility. The contributions of the utility-implemented and SEU-implemented programs shall be considered in meeting the Energy Efficiency Resource Standards required under Chapter 15 of this Title."

Delmarva Power has also examined and included an analysis of the likely energy and demand reductions that will result from code and standard improvements in projecting the total attainable demand and energy consumption savings.

In accordance with The Act, the EERS Workgroup was created to consider the various energy efficiency issues identified in the statute, including providing guidance on the interpretation of the statute's targets. Delmarva Power was an active participant in this workgroup. In June of 2011, the EERS Workgroup submitted to the Secretary of DNREC the "State of Delaware Energy Efficiency Resources Standards Workgroup Report" (EERS Report). The EERS Report, among other things, further defined the consumption and demand targets for the Affected Electric Energy Providers. The 2015 reduction goals for Delmarva Power were determined to be 284 MW for peak electricity demand and 1,329,054 MWh for annual electric energy consumption. (EERS Report, pp. 35 and 36) Although the EERS Workgroup did not establish interim year goals, for planning purposes, Delmarva Power has assumed that the interim year goals prior to 2015 can be derived based upon a straight line ramp up between 2011 and 2015. The resulting reduction targets for Delmarva Power for years 2013, 2014, and 2015 are presented in Table 1.

Table 1

DELMARVA POWER REDUCTION GOALS		
Year	Cumulative MW Reduction for that Year	Cumulative MWh Reduction for that Year
2013	137	762,606
2014	205	1,052,701
2015	284	1,329,054

At this time, the Act and the EERS Report do not addresses what the consumption and peak demand reduction requirements will be after 2015. In the absence of a clear directive, Delmarva Power has assumed that the goal for each successive year after 2015 would be to continue calculating the goal as 15% of the EERS Report mandated 2007 consumption and peak demand minus each following year's otherwise forecasted consumption and peak demand.

Overall DSM Cumulative Impacts

Delmarva Power, in consultation with the IRP stakeholders, has assumed for the 2012 IRP Reference Case that the state prescribed 2015 electric energy and demand goals will be achieved. At stakeholders' request, the Company has conducted a sensitivity analysis to explore the impact of not achieving these goals. This analysis is discussed later in section..

The assumed DSM Reference Case cumulative impacts for the Delmarva Power, the SEU, and WAP DSM initiatives for the IRP planning horizon 2013 – 2022 are shown numerically in Tables 2 and 3.

Table 2

Reference Case Energy Savings Estimates

(All Delmarva Power Delaware Distribution Customers)

Reference Case Projected Delmarva Power Cumulative DSM Energy Impacts (MWh)										
DSM Initiative	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**
AMI Enabled Reductions	33,000	34,000	33,000	33,000	32,000	32,000	32,000	31,000	31,000	32,000
Distribution Efficiency Improvements	12,392	16,523	20,654	24,785	28,916	33,047	37,177	41,308	45,439	49,570
Transmission Efficiency Improvements	5,614	5,855	6,096	6,342	6,594	6,850	7,110	7,374	7,642	7,914
Combined Heat & Power	61,503	95,335	129,167	162,999	196,831	251,191	305,552	359,912	414,272	468,633
Street Lighting Improvements	2,557	2,670	2,783	2,896	2,896	2,896	2,896	2,896	2,896	2,896
Delaware Weatherization Assistance Program	2,654	3,539	4,424	5,308	6,193	7,078	7,962	8,847	9,732	10,617
Residential Direct Load Control	2,156	5,823	9,418	11,865	11,865	11,865	11,865	11,865	11,865	11,865
Non-Residential Direct Load Control	-	102	732	1,260	1,289	1,316	1,345	1,367	1,391	1,412
Improved Codes and Standards	110,386	147,181	183,977	220,772	257,567	294,363	331,158	367,953	395,125	422,297
SEU Residential EE Programs	124,073	169,144	210,734	218,559	226,708	222,062	240,431	253,843	253,843	253,843
SEU C/I EE Programs	408,270	572,529	728,070	641,268	558,196	484,881	559,199	634,340	634,340	634,340
Total Cumulative Energy Impact (MWh)	762,606	1,052,701	1,329,054	1,329,054	1,329,054	1,347,549	1,536,695	1,720,705	1,807,546	1,895,387
Cumulative Energy Goal Achievement	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%

Table 3

Reference Case Demand Savings Estimates

(All Distribution Customers)

Reference Case Projected Delmarva Power Cumulative DSM Demand Impacts (MW)										
DSM Initiative	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**
AMI Enabled Dynamic Pricing	84	120	116	113	110	108	106	104	105	107
Distribution Efficiency Improvements	1	2	2	3	3	4	4	5	5	6
Transmission Efficiency Improvements	2	2	2	2	2	2	2	2	2	2
Combined Heat & Power	9	14	18	23	28	36	44	52	60	68
Street Lighting Improvements	-	-	-	-	-	-	-	-	-	-
Delaware Weatherization Assistance Program	1	1	1	1	2	2	2	2	3	3
Residential Direct Load Control	21	35	41	61	61	61	61	61	61	61
Non-Residential Direct Load Control	-	2	15	26	27	27	28	28	29	29
Improved Codes and Standards	29	39	48	58	67	77	87	96	103	110
SEU Residential EE Programs	33	45	57	59	61	60	65	68	68	68
SEU C/I EE Programs	105	147	186	161	136	114	131	149	149	149
Total Cumulative Demand Impact (MW)	284	406	487	507	497	491	530	568	585	603
Cumulative Demand Goal Achievement	207%	198%	172%	178%	175%	173%	187%	200%	206%	212%

Energy Efficiency and Conservation

In earlier IRPs prior to 2010, Delmarva Power employed an energy efficiency impacts evaluation process which involved the analysis of potential individual efficiency measures where each measure was evaluated for cost-effectiveness using the Total Resource Cost Test (TRC). This process required energy and demand impacts for cost-effective measures to be calculated. This was conducted as part of a more traditional IRP process where the screening assesses the economic performance of measures through standard cost-benefit tests with the intent to select the most economically efficient and cost-effective portfolio, since utility ratepayer funds would be used to implement the programs. At this time, the SEU is responsible for determining:

1. The energy savings measures to be targeted by the SEU.
2. The screening criteria to be used by the SEU to select measures and programs.

The SEU is charged with implementing programs that address efficiency in electricity, natural gas, and other fuels throughout the State, however, the impacts of the SEU activities in the Company's IRP include only electricity savings estimates within the Delmarva Power service territory.[18] The SEU program selection process is not constrained by the traditional utility cost-effectiveness screening process for several reasons:

1. The SEU's programs do not currently use ratepayer funds, and therefore have no direct impact on rates.
2. Over time, the SEU expects to move away from direct rebates that were funded by the American Recovery and Reinvestment Act (ARRA) towards self-sustaining financing and performance contracting. The TRC and other conventional cost-benefit tests typically assume that rebates are the primary method to encourage participation.
3. Since the SEU's programs include electricity, natural gas and other fuels, screening is based more on insuring the availability of programs for all market segments and that all fuels are addressed.

The Delaware Sustainable Energy Utility

As of October 2012, the SEU has developed and implemented a variety of energy efficiency and conservation (EE&C) programs, a portion of which are no longer in operation due to completion of funding available from the ARRA. At this time the SEU is continuing to identify and evaluate the appropriate mix of programs going forward. This work is ongoing and, therefore, specific program initiatives are not available from the SEU at this time. SEU sponsored programs have included programs targeting savings opportunities in all market sectors across a wide range of end use measures.[19] All programs relied primarily upon federal stimulus funding except for the

[18] The SEU's activities are not subject to Delaware Commission oversight. Delmarva Power representatives meet with SEU representatives periodically to exchange information. Delmarva Power invited the SEU to identify any program plans for inclusion with the IRP.

[19] According to the draft report provided by the SEU, titled "Delaware Energy Efficiency Program Evaluation, Measurement, and Verification Report," the SEU sponsored programs have achieved an annual electric energy savings of 47,559 MWh in the Delmarva Power Delaware area. The Delmarva Power Delaware specific savings were estimated based upon the ratio of annual electricity sales in Delmarva Power compared with other Delaware distribution utilities. An additional 11,493 MWh of annual electric energy savings have been achieved through the SEU's energy performance contracts in the Delmarva Power Delaware area.

Performance Contracting Program which uses tax-exempt bonds and other private sources.[20] The types of programs implemented by the SEU are described below to provide an indication of the types of programs that might be offered in the future.

Programs offered prior to December 2010:

1. ENERGY STAR® Residential Appliance Rebate Program – This program offered Delaware residents up to $200 on certain ENERGY STAR qualified clothes washers, dishwashers, room air conditioners, or gas water heaters. Rebates were supported in part by funds from the American Reinvestment and Recovery Act. *This program was terminated as planned on August 31, 2010.*

Programs offered since December, 2010:

1. Efficiency Plus Homes –
   a. Efficient Home Lighting Program – *Program concluded in August 2011*
   b. ENERGY STAR qualified Heating and Cooling Rebate Program– *Program concluded in December 2010.*
   c. Home Performance with ENERGY STAR (existing homes) – *Program concluded in March 2012.*
   d. Green for Green Program (new construction) – *Program concluded in March 2012.*
2. Efficiency Plus Program for Business – Offered prescriptive and custom equipment incentives and financing. - *Program concluded in September 2011.*
3. Efficiency Plus Program for Institutions and Non-Profits – Offered prescriptive and custom equipment incentives and financing. – *Program concluded in September 2011.*
4. Low Income Multi-Family Housing Loan Program – *Single project and completed.*

[20] Additional program funding was provided from auction proceeds from Delaware's participation in the Regional Greenhouse Gas Initiative ("RGGI").

5. Performance Contracting for Institutions and Non-Profits – *Currently the only program offered. Funded through tax-exempt bonds and other private financing sources.*

At this time the SEU is continuing the Performance Contracting for Institutions and Non-Profits and the SEU plans to re-implement their Green for Green Program. The SEU has budgeted $2.5 million dollars for its Energize Delaware programs in 2013 and is actively planning to bring new programs on in addition to the Green for Green Program. Additional SEU programs are needed at this time to achieve the electric energy and demand reduction goals. If funding is available, any of the above listed programs could be offered in the future.

Potential SEU Energy Efficiency Programs that have not been offered in the past

In addition to the programs previously offered by the SEU, Delmarva Power has prepared a list of potential EE&C programs that are representative of the typical types of EE&C programs implemented in other jurisdictions or have been previously identified by the SEU. These programs typically are cost-effective using a traditional TRC test and could be implemented by the SEU in the future if sufficient funding becomes available.

Potential Residential Programs:

1. Expanded Residential Home Retrofits – Expansion of the previously offered Home Performance with ENERGY STAR. Customers could be eligible for low-interest financing from the SEU. Many of the recommendations are expected to provide sufficient bill savings (from energy bills) to cover the costs of the improvements over the life of the loan.
2. Appliance Recycling – This program encourages customers to recycle old inefficient appliances to ensure that are they removed from the electric grid and disposed of in an environmentally safe way. The appliances must be in working condition at the time of pickup in order to ensure that energy is being saved from their disposal. In exchange for each old electrical appliance, a customer receives a complimentary haul-away and a monetary reward.

3. Quick Home Energy Check-up - This program provides residential customers with a quick energy audit and the installation of free energy savings measures such as CFL and/or LED light bulbs, smart strips and faucet aerators.
4. Behavior Based Program – Under this program comparative billing reports would be created and mailed to residential customers. The reports provide comparative energy use information and tips regarding energy savings techniques. Typically the reports also refer customers to energy efficiency or demand response program participation opportunities. Programs such as this one have achieved proven behavioral based reductions in energy use.

Potential Non-Residential Programs:

1. Expanded Commercial/Industrial Energy Efficiency Programs – Expansion of the SEU's Efficiency Plus for Business Program. Customers would be eligible for low interest financing from the SEU for pre-approved measures and custom measures meeting program criteria for payback. Many of the recommendations will provide enough bill savings (from energy bills) to cover the costs of the improvement over the life of the loan.
2. Retro Commissioning – This program is a systematic process that improves the overall energy efficiency in an existing building by ensuring the equipment and control systems are operating properly. In addition to reducing operational inefficiencies that would result in energy savings, the Retro Commissioning process provides additional benefits in the form of improved comfort, enhanced air quality and reduced occupant complaints.
3. New Construction programs for Commercial buildings - This program would be similar to the residential "Green for Green" program offered by the SEU for commercial buildings.
4. Combined Heat and Power Program – This program provides financial incentives to encourage the installation of distributed generation to meet the electricity requirements of commercial and industrial customers. Please see the additional discussion of this program in the following section for further program information
5. Small commercial program to provide targeted assistance for the installation of high efficiency measures.

Potential Combined Residential and Non-Residential Programs:

1. Sustainable Communities Program – This SEU program would be a community-level development effort (as compared to individual participants) – a neighborhood, group of businesses, participants in a geographic area, etc. who would recommend to the SEU the installation of specific energy efficiency measures and distributed renewables. The program could be divided into two markets segments:

    a. Large Commercial & Industrial ("C&I") Energy Efficiency Program – This program would promote energy efficiency and distributed renewables in the private large commercial and industrial sectors using a performance contracting approach.
    b. Residential, Commercial, and Industrial Efficiency Program – This program would help to promote energy efficiency and distributed renewables in the residential sector (at a minimum) and possibly extending to other sectors.

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 prepared several years ago on electrically-heated homes by the University of Delaware's Center for Energy and Environmental Policy, WAP estimates KWh savings of 22% on average per household. In program year 2009 (4/1/09 – 3/31/10) the program served a total of 1,221 homes statewide. WAP plans to serve approximately 1,100 homes during each program year going forward.[21]

[21] Information provided by Ken Davis, Manager, Weatherization Assistance Program. Phil Cherry, Administrator of the Program, has confirmed that these are the best available assumptions at this time.

Combined Heat and Power Potential

The Act states that there shall be established requirements to include procedures for counting combined heat and power savings towards the energy and demand savings goals.[22] Delmarva Power conducted a separate study during 2010 of Combined Heat and Power ("CHP") potential in the Delmarva Power service territory of Delaware. The results of this study remain applicable for the current IRP analysis, although savings achievements will be shifted further out in time because the program has not been implemented. (Please refer to the Delmarva Power & Light Company 2010 Integrated Resource Plan, Attachment 1 to Exhibit B titled "Combined Heat and Power Market Assessment for Delmarva Power", May 2010, prepared by ICF International.)

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 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 gases emissions.

To estimate the potential for CHP in Delmarva's Delaware service territory, Delmarva Power used the *ICF CHP Market Model.* This model estimates cumulative CHP market penetration as a function of competing CHP system specifications, current and future energy prices, and electric

[22] It is not clear at this time whether the SEU will be pursuing implementation of a CHP program. In the event that the SEU chooses not to do so, Delmarva Power may propose a plan for approval by the Public Service Commission to design and implement a CHP program.

and thermal load characteristics for target markets. The CHP analysis included the following four steps:

- Estimate CHP Technical Market Potential – An estimate of the technically suitable CHP applications by size and by industry. This estimate was derived from the screening of customer data based on application and size characteristics that were used to estimate groups of facilities with appropriate electric and thermal load characteristics conducive to CHP.
- CHP Technology Characterization – For each market size range, a set of applicable CHP technologies were selected for evaluation. These technologies were characterized in terms of their capital cost, heat rate, non-fuel operating and maintenance costs, and available thermal energy for process use on-site.
- Estimate of Energy Price Projections – Present and future fuel and electricity prices were estimated to provide inputs into the CHP net cost calculation.
- Estimate of CHP Market Penetration – Within each customer size, the competition among applicable CHP technologies was evaluated. Based on this competition, the economic market potential was estimated and shared among competing CHP technologies. The rate of market penetration by technology was then estimated using a market diffusion model.

<u>CHP Market Penetration Results</u>

CHP market penetration was analyzed for two alternative sets of input assumptions:

- Base Case – existing federal incentives for CHP with no assumed supplemental SEU or utility provided incentives.
- Incentive Case – a 20% reduction in the capital cost was assumed in addition to existing federal tax credits.

The resulting difference between these two cases provides the estimated energy and peak demand grid savings.

CHP Incentive Case – 20% Capital Cost Reduction

An incentive scenario representing a 20% capital cost reduction for CHP was evaluated to measure the increase in market penetration. This is a potential incentive program that Delmarva Power or the SEU could establish to increase the adoption of CHP in its service territory.[23] The gas and electric pricing and all other assumptions are the same as the *Base Case* assumptions.

In the Base Case (what would be expected without incentives), the projected CHP market penetration in the next five years is 16.6 MW out of an economic potential of 39.5 MW. Addition of the 20% capital cost reduction incentive increases the five year market penetration to 26.5 MW out of an economic potential of 62.9 MW. By 2025, the cumulative market penetration in the Base Case is 59.1 MW. The 20% capital cost reduction is estimated to increase this market penetration by 28.4 MW to a total of 87.4 MW – a 48% increase in the market size.

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. Consequently, Delmarva Power has two programs currently approved which are being phased-in in 2012 and 2013 and has developed demand response potential projections for one other program. These three combined programs address all customer market segments for Delmarva Power Delaware. The approved and projected programs have been designed specifically to participate in available demand response market opportunities within the PJM capacity and energy markets.[24] Participation in these markets provides a potential revenue stream to offset a portion of program costs, provides PJM dispatchers demand response programs that can be used to help maintain system reliability during high load periods, and helps to

[23] The Delaware Energy Efficiency Investment Fund that is managed by the Delaware Division of Energy and Climate has expressed an interest in pursuing CHP opportunities as well.
[24] PJM market demand response rules are evolving and therefore existing rules will change over time. Delmarva Power participates in the PJM stakeholder process related to these market rule changes.

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 various incentives for participating in each program and the reduction of energy consumption during specific periods of time.

Dynamic Pricing – "Peak Energy Savings Credit"

On March 23, 2011, Delmarva filed an Application to Implement and 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, Commission Staff and the Division of Public Advocate, and on January 31, 2012, issued its Final Findings, Opinion and Order (Order No. 8105) approving the proposed phase-in implementation of its Advanced Metering Infrastructure enabled Dynamic Pricing Program for its Standard Offer Service customers. The approved rate is structured as a default Critical Peak Rebate rate with the ability for the customer to opt-out of the program. The program will be offered to all Delmarva Power residential SOS customers and all Delmarva Power small and medium non-residential SOS customers. The program is currently titled the "Peak Energy Savings Credit Program."

The program provided dynamic pricing signals beginning in June 2012 to approximately 7,000 residential customers who participated in the AMI Field Acceptance Test (FAT) which took place in 2009. This part of the residential dynamic pricing phase-in concluded on September 29, 2012. Delmarva Power is incorporating the lessons learned from the phase-in to further improve and refine the program during 2013.

In June 2013, the second phase of the program will begin with the remaining Delmarva Power residential SOS customers being defaulted to the dynamic pricing rate. In addition,

approximately 240 small and medium non-residential FAT will be moved to the moved to the rate. The final phase of program implementation will begin in June 2014 where all Delmarva Power residential and small and medium non-residential SOS customers will be placed on the dynamic pricing rate.

Delmarva Power and the Brattle Group have 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 ongoing Baltimore Gas & Electric Company's (BGE) dynamic pricing pilot, and the California statewide pricing pilot. The residential impacts of dynamic pricing programs in Delaware were estimated by adapting the Pricing Impact Simulation Model (PRISM) developed through the California smart meter pilot studies to the price elasticities that were estimated through the BGE study. Non-residential customer price elasticities were based upon results from the comprehensive California dynamic pricing pilots. All pricing estimates 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 116 MW of peak demand reduction by 2015. 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.

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.

Delmarva Power has estimated that residential customers will reduce their energy consumption by 1.5% annually due to the availability of detailed energy use information to Delmarva Power customers.[25]

Delmarva Power's specific projected programs include:

- A residential air conditioner direct load control program consisting of a choice of smart thermostats or outdoor switches.
- A small commercial customer packaged air conditioner direct load control program consisting of a choice of smart thermostats or outdoor switches.

Table 4 contains the results of Delmarva Power's recent cost-effectiveness screening for the Company's approved residential direct load control program. The presented cost-effectiveness calculation is conservative and it does not include capacity and energy price mitigation benefits. Both programs are expected to be very cost-effective under the Total Resource Cost Test.

Table 4

Residential Direct Load Control Cost Effectiveness Results

Total Resource Cost Test (All $ Values in $1,000,000)		
Costs	Benefits	Ratio
$ 26.38	$ 65.31	2.48

Residential Direct Load Control

On November 5, 2012, Delmarva Power received Public Service Commission approval of its proposed Residential Direct Load Control Program ("DLC"). The new DLC program is titled the Energy Wise Rewards™ Program. The DLC program is a voluntary customer program designed to update, expand, and over time, replace the legacy Energy For Tomorrow central air conditioning/heat pump load control program with newer technology. The new program will

[25] See also a paper by Ahmad Faruqui, Sanem Sergici, and Ahmed Sharif, "Impact of Informational Feedback on Energy Consumption – A Survey of the Experimental Evidence", *Energy: The International Journal,* April 2010.

provide a voluntary and simple method for residential consumers with central air conditioning or heat pump systems to automatically reduce peak electricity demand during peak usage periods and to reduce overall air conditioning and heating system energy consumption. The program will accomplish this through the installation of either a remotely controllable smart thermostat or direct load control switch. (Participating customers will have the option of choosing either of the devices.) These devices will reduce the air conditioner load on the electric system after receipt of a Delmarva Power command signal. The smart thermostats will be capable of being programmed to automatically vary temperature settings, thereby providing added energy savings opportunities for Delmarva's customers. The planned program will be integrated with Delmarva Power's AMI system. This will permit the Company to rely upon the two-way communication capability of the AMI system and participant credits will be based upon the dynamic pricing rebate rate.

As shown in Table 3, available peak demand reduction capability for the Residential DLC Program is projected to be 41 MW by the 2015 summer. Associated energy savings are estimated to exceed 9,000 MWh by year-end 2015.

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 peak electricity demand during peak usage periods and to also reduce their overall electricity consumption. Similar to Delmarva Power's residential direct load control program, this program will provide 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.) Available peak demand reduction impacts for the Non-Residential Direct Load control are projected to be 15.2 MW by 2015. Projected energy savings are estimated to exceed 700 MWh annually by year-end 2015. These savings estimates are included within Table 9 in the non-residential program figures. Delmarva Power will seek Commission approval of this program later in 2013 after the residential direct load control program implementation has begun.

Transmission and Distribution Efficiency Improvements

The Act defines Energy Efficiency to include "the reduction in transmission and distribution losses associated with the design and operation of the electrical system."

Transmission Loss Reductions

Delmarva Power's transmission system is continually being upgraded. These upgrades are a result of the PJM Regional Transmission Expansion Process which has the responsibility of ordering new transmission facilities to be built in order to meet all applicable reliability criteria. PJM has the responsibility for planning and operating the transmission system. Each year, PJM takes a detailed forward look to make sure that the transmission system that is required to supply future load growth meets the appropriate reliability criteria. PJM then determines what additions to new transmission facilities or upgrades to existing transmission facilities are required. Besides increasing the reliability of the transmission system, these system upgrades have the added benefit of reducing system losses. Adding new facilities or upgrading existing facilities in many cases reduces the impedance of the system and allows the transmission system to function more efficiently, meaning that more of the power generated or imported is used to serve the distribution system rather than being consumed on the system as transmission line and transformer losses.

A study was performed to compare the 2012 transmission topology with the topology that is expected to exist in 2017 with all of the transmission upgrades required between 2013 and 2017 included in the analysis. The results of these added upgrades are expected to reduce the transmission system losses by 0.3% annually. Using the Delmarva Power FERC Form No. 1 from 2011/Q4, this translates to an approximate savings of 2,280 MWh on an annual basis. The transmission system additions and upgrades that are presently part of the PJM Regional Transmission Expansion Plan for the period 2013 to 2017 are shown in Table 6.

The reduction in transmission losses from Year 2013 through 2022 for Delaware electric customers are expected to be 1.8 MW's and 4,631 MWh over that time period. Table 5 contains the projected incremental savings for each year. The savings through Year 2022 may be higher if the PJM RTEP process determines that there is a need to reinforce the system through additional transmission upgrades. The PJM RTEP results have only been fully evaluated through the 2016/2017 PJM planning year. These studies are re-evaluated every year and the results may alter future transmission improvements.

Table 5

Incremental Reductions in Transmission Losses Due to System Upgrades

Years 2013 – 2022

Incremental Reductions in Transmission Losses Due to System Upgrades from Year 2013 - 2022										
	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
MW	0.5	0	0.4	0	0.1	0.1	0.1	0.2	0.2	0.2
MWh	1528	0	1223	0	306	309	312	317	318	318

Notes:

1. The MW value represents the savings in transmission losses for Delmarva (Delaware customers only)
2. The MWHr numbers were calculated based on loading factors from the FERC Form 1 "Energy Sales" 2011 Q4
3. The data past Year 2017 was based on Demand growth for MW and Energy growth for MWHr

Capacitor Control Program

Delmarva Power plans to implement a new Distribution VAR Dispatch (DVD) System. This System will have two-way communication with capacitors controlled by a centralized computer system integrated with an Energy Management System. The System will also include local voltage override on each bank and a stand-alone operation mode that will serve as a voltage controlled capacitor bank in the event that communication is lost.

The concept and equipment for this program were selected as part of the PHI Blueprint for the Future initiative. This system will also have the capability to remotely operate capacitor banks by the system operators should a situation arise. Current plans are to install controllers on capacitor banks tied together with two-way communication via the installed Silver Spring AMI Network and having a centralized control algorithm integrated with the EMS. The DVD System

will have the capability to maintain unity power factor at the substation and on the individual distribution feeders. Implementation of this system is expected to begin in year 2013 with savings ramping up as the project progresses.

Energy Savings from Higher Efficiency Transformers
Compared to Industry Minimum Efficiency Levels

Electric distribution transformers are evaluated consistently throughout the PHI utility companies using the minimum efficiency tables contained in NEMA 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 pending TSL-2 level efficiency criteria. Consistent with moving forward with this effort, Delmarva Power is now evaluating transformers using the Total Owning Cost (TOC) Methodology as specified in NEMA TP1-2002, Section 2.

Near the end of 2009, Delmarva Power, through its parent Company, PHI, awarded a multi-year contract for the purchase of liquid immersed distribution transformers to several manufacturers based on the TOC Methodology for evaluating transformers. In order to meet the DOE recently-implemented (January 2010) high efficiency transformer specifications, some transformer manufacturers chose to quote their bids using amorphous metal steel for core construction in their units.

Amorphous Metal (AM) is a unique alloy structured of atoms that occur in random patterns. Conventional grain oriented steel (silicon steel) has an organized crystalline structure with much higher resistance to magnetization, which leads to higher core losses. AM is a metallic alloy with no crystalline structure due to the use of Boron in the alloy. Lower losses in AM transformers are a direct result of the lower loss in the base material. The absence of the crystalline structure leads to lower hysteresis losses in the core, and the higher resistivity and lower thickness of the metal leads to lower eddy current losses in the core. This results in total losses for AM at about one third of those found in silicon steel transformers.

Delmarva Power awarded one transformer manufacturer a contract to supply both single and three-phase pad mount transformers and that the manufacturer will also supply AM units. Other manufacturers chose to supply silicon steel transformers built to the new DOE efficiency levels. The successful manufacturer for single phase pole type transformers will be supplying silicon steel for core construction for all but eight stock transformer types. The remaining eight will be constructed with AM. These three types of transformers, the pole-type and both pad mount-types, account for the vast majority of the transformers to be used in Delaware.

As both AM units and higher efficiency silicon steel units are delivered, they will be used in new construction after existing inventories are depleted. Manufacturers and utilities alike recognize the high potential to save energy by installing low loss transformers for new construction. In addition, as older transformers are replaced, these higher efficiency units will be used. Even higher energy savings can be realized by replacing old high loss transformers with new low loss designs, including both amorphous and DOE efficiency units.

Table 6 contains the expected annual average demand reduction, in kilowatts, resulting from the reduction in losses of new higher efficiency transformers when compared to the DOE minimum efficiency levels implemented January 1, 2010. The table also indicates the expected annual energy savings due to the use of AM and silicon steel transformers when purchased using the TOC methodology as compared to the DOE minimum efficiency levels. Since the DOE minimum efficiency levels are the current standard in the industry effective 2010, Delmarva Power will achieve this energy savings as these units are installed.

Table 6

Average Demand & Energy Savings over Industry Minimum Efficiency

Average Demand & Energy Savings Over Industry Minimum Efficiency

Transformer Type & Core Construction	Estimated Annual Quantities (Units)	Total Aggregate Nameplate KVA	Expected Annual Avg. Demand over DOE (kW)	Expected Annual Energy Savings (MWh)
1-Phase Pad Amorphous	813	53,307	181	1,587
3-Phase Pad Amorphous	129	53,875	164	1,433
1-Phase Pole Amorphous	875	29,025	97	851
1-Phase Pole Silicon Steel	576	33,168	30	260
Total	2,393	169,375	472	4,131

Table 7 below contains both the cumulative annual average demand (in kW) and the cumulative annual energy savings (in MWh) that will be realized through the purchase of higher efficiency transformers as a result of evaluating using the Total Owning Cost Methodology of NEMA TP1-2002, Section 2.

Table 7

Cumulative Expected Annual Energy Savings from Transformer Purchases by TOC Methodology

Cumulative Expected Annual Energy Savings from Transformer Purchases by TOC Methodology

Higher Efficiency Transformers Purchased for Delaware	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Estimated Annual Quantities (Units Installed)	2,393	2,393	2,393	2,393	2,393	2,393	2,393	2,393	2,393	2,393
Cumulative Annual Average Demand Savings (kW)	1,415	1,886	2,358	2,829	3,301	3,772	4,244	4,716	5,187	5,659
Cumulative Annual Energy Savings (MWh)	12,392	16,523	20,654	24,785	28,916	33,047	37,177	41,308	45,439	49,570

Assumptions:
1. Transformer usage will be flat for next several years based on forecasted URD and housing construction.
2. All transformers purchased within each year will be installed within that year.

Savings from Mercury Vapor to High Pressure Sodium Streetlight Replacements

As a result of EPACT 2005, the Federal Government banned the manufacture and importation of Mercury Vapor (MV) 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 (HPS" streetlights throughout its three regional utility companies, including Delmarva Power.

There are several advantages for converting to HPS from MV technology. Both sources are in the High Intensity Discharge (HID) family of lighting products, where gas vapors are held captive in an arc tube and, when a current is applied, the gas particles are excited and result in the production of an intense light. MV is the oldest form and least efficient (lowest efficacy) of the HID lighting choices. HPS offers a level of performance that is acceptable to many users, and improvements have been made over the years to develop the product to where it provides advantages over the MV source. Both HPS and MV lighting technologies have the same average life of 24,000 hours of operation for a standard lamp. HPS lamps also provide a softer, warmer color of light when transitioning from areas of complete darkness. While all HID lamps contain a specific level of Mercury, HPS lamps contain less mercury than MV and other HID sources. HPS also has better "lumen maintenance" than MV technology. Basically, an HPS lamp maintains its lumen output longer than an MV lamp while approaching its end of life. An HPS lamp will remain brighter for the same life span when compared to an MV lamp. On average, when both lamps are replaced after 5-1/2 years, the MV lamp will look visually dimmer than the HPS lamp.

Delmarva Power will reduce the energy consumption of current MV lamp users by offering increased lumen output of light for the customer at a lower power consumption value (wattage) by replacement of existing lamps with HPS lamps. For example, customers presently using a 175W MV lamp receive approximately 7,900 lumens of light. Delmarva Power will provide a 100W HPS lamp and increase the customer's lumen output by approximately 25% to 10,000 lumens. These types of improvements can be made because HPS offers an efficacy of 120

lumens per watt when compared to the 50 lumens per watt output of MV. Given the same power output, HPS provides more than twice as many lumens as MV.

Table 8 contains the annual energy savings (in MWh) that will be realized through the MV to HPS Group Replacement Program for the Delmarva region which began in 2008.

Table 8

High Efficiency Street Lighting Savings

Delaware MV to HPS Conversion Project	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Fixtures/Lamps to be Replaced (number)	450	450	450	450	0	0	0	0	0	0
Cumulative Annual Energy Savings (MWh)	2,557	2,670	2,783	2,896	2,896	2,896	2,896	2,896	2,896	2,896

Demand and Energy Savings from Delmarva Power Initiatives Only

The projected cumulative impacts of the combined Delmarva Power's DSM initiatives for the IRP Reference Case are shown in Table 9 below.[26]

Table 9

Reference Case Projected Delmarva Power Cumulative DSM Impacts

Reference Case Projected Delmarva Cumulative DSM Impacts (2012 IRP)										
	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Energy Impacts (MWh)										
Residential Load Control	2,156	5,823	9,418	11,865	11,865	11,865	11,865	11,865	11,865	11,865
Non-Residential Load Control	0	102	732	1,260	1,289	1,316	1,345	1,367	1,391	1,412
T&D Efficiency Improvements	20,563	25,048	29,533	34,023	38,406	42,793	47,183	51,578	55,977	60,380
CHP Potential Savings	61,503	95,335	129,167	162,999	196,831	251,191	305,552	359,912	414,272	468,633
AMI Enabled Reductions	33,000	34,000	33,000	33,000	32,000	32,000	32,000	31,000	32,000	32,000
Total Energy Impact	117,222	160,307	201,850	243,147	280,390	339,165	397,945	455,722	515,506	574,290
Demand Impacts (MW)										
Residential Load Control	20.9	35.3	41.2	61.2	61.2	61.2	61.2	61.2	61.2	61.2
Non-Residential Load Control	0.0	2.1	15.2	26.2	26.8	27.4	28.0	28.5	29.0	29.4
T&D Efficiency Improvements	3.0	3.6	4.1	4.7	5.2	5.8	6.3	6.9	7.4	8.0
CHP Potential Savings	8.8	13.6	18.5	23.3	28.2	36.1	44.0	51.9	59.8	67.6
AMI Enabled Dynamic Pricing	84.0	120.0	116.0	113.0	110.0	108.0	106.0	104.0	105.0	107.0
Total Demand Impact	116.7	174.6	195.0	228.4	231.4	238.4	245.5	252.4	262.3	273.2

[26] The exact implementation schedule of these and other programs will depend on the final Delaware Sustainable Energy Utility implementation timing and the timing of any required regulatory approvals for utility provided programs. Third party vendor capability, equipment availability, and program market receptivity will also affect the timing of initiatives. Savings estimates were developed based upon information available to Delmarva Power as of May 2010. The CHP incentive program identified in the table could be offered by either Delmarva Power or the Delaware Sustainable Energy Utility.

Impacts on Savings from Changes in Codes and Standards

The Act further states that there shall be requirements to establish methods for calculating codes and standards savings, including the use of verified compliance rates. Delmarva Power has also 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 and are not already captured in the load forecasting 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 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 impact of the air conditioning minimum efficiency requirements that are not captured by either load forecasting or the identified SEU programs was 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. Likewise, the load forecasts only account for the savings that have been recognized from new equipment which has been installed, not what will be installed in the future. An analysis was performed to estimate the impacts resulting from the higher minimum efficiencies required for residential and non-residential air conditioning replacement. The results of the analysis are shown in Table 10.

Table 10

Codes and Standards Impacts

Estimated Cumulative Codes and Standards Energy Impacts (MWh)										
	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Residential	61,210	81,613	102,017	122,420	142,823	163,227	183,630	204,033	214,813	225,593
Non-Residential	49,176	65,568	81,960	98,352	114,744	131,136	147,528	163,920	180,312	196,704
Total	110,386	147,181	183,977	220,772	257,567	294,363	331,158	367,953	395,125	422,297

Modeling Assumptions

Demand Side Management Impacts Aggregation and Goal Contributions

In order to prepare the energy and demand impacts of the various demand side efforts described above for use in the IPM modeling process, the impacts were aggregated to achieve the goals identified in Table 1. To reach the identified goals, impacts from the approved SEU Programs, Residential and Non-Residential Load Control, T&D Efficiency Improvements, CHP, AMI Enabled Dynamic Pricing and codes and standards were totaled. In years 2013 – 2022, where the impacts from these DSM initiatives did not reach the goals identified in Table 1, impacts sufficient to reach the goals were included from the prospective SEU programs. When impacts from the prospective SEU programs were included, the residential and C/I program contributions are in the same proportion as residential and C&I shares of the total projected SEU Prospective Program impacts.

Initiative Savings for Legislatively Established Target Year 2015

Charts 11 and 12 graphically represent the mix of initiatives selected to achieve the energy and demand savings for year 2015.

Chart 11

2015 Energy Saving Sources

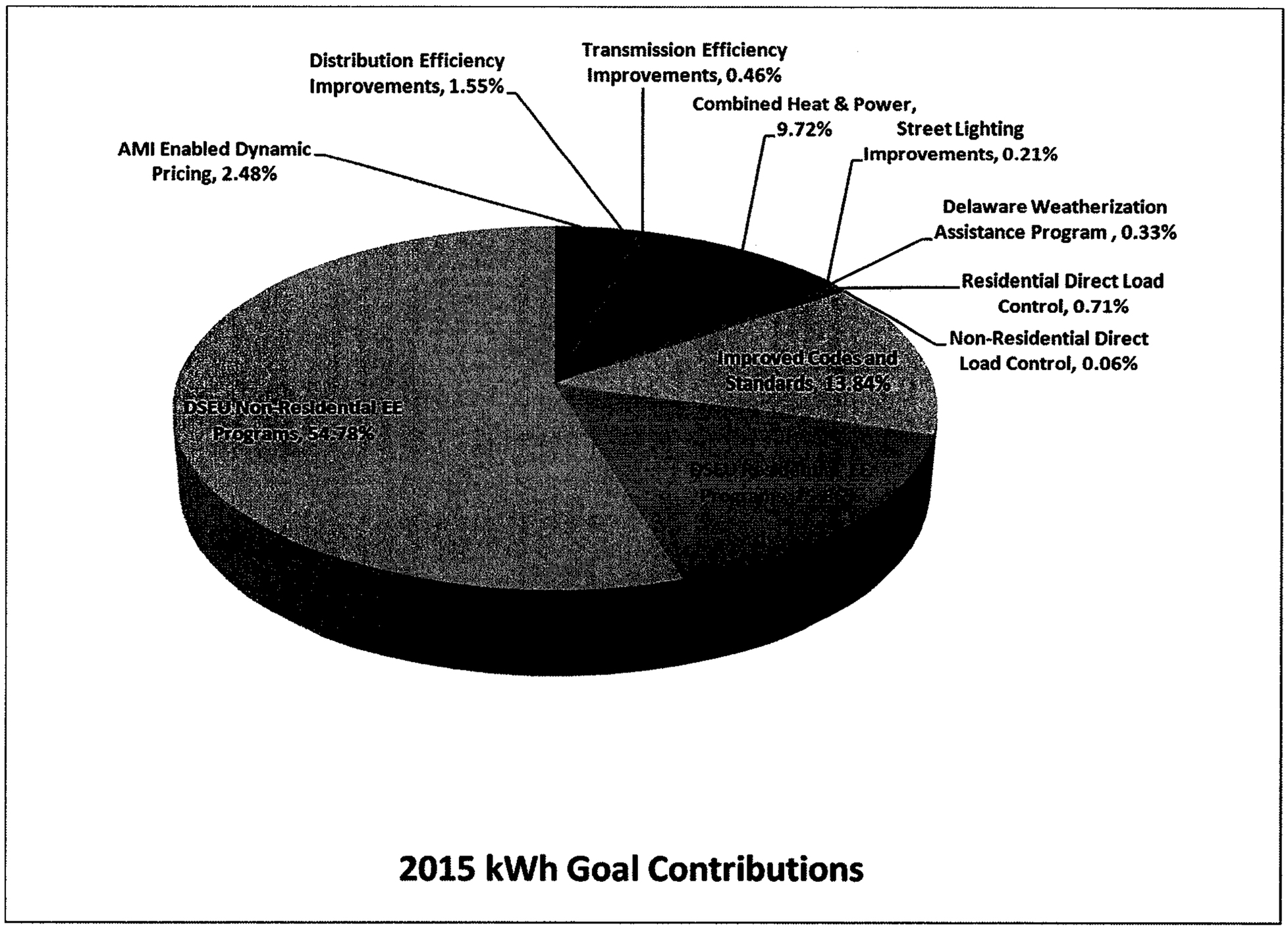
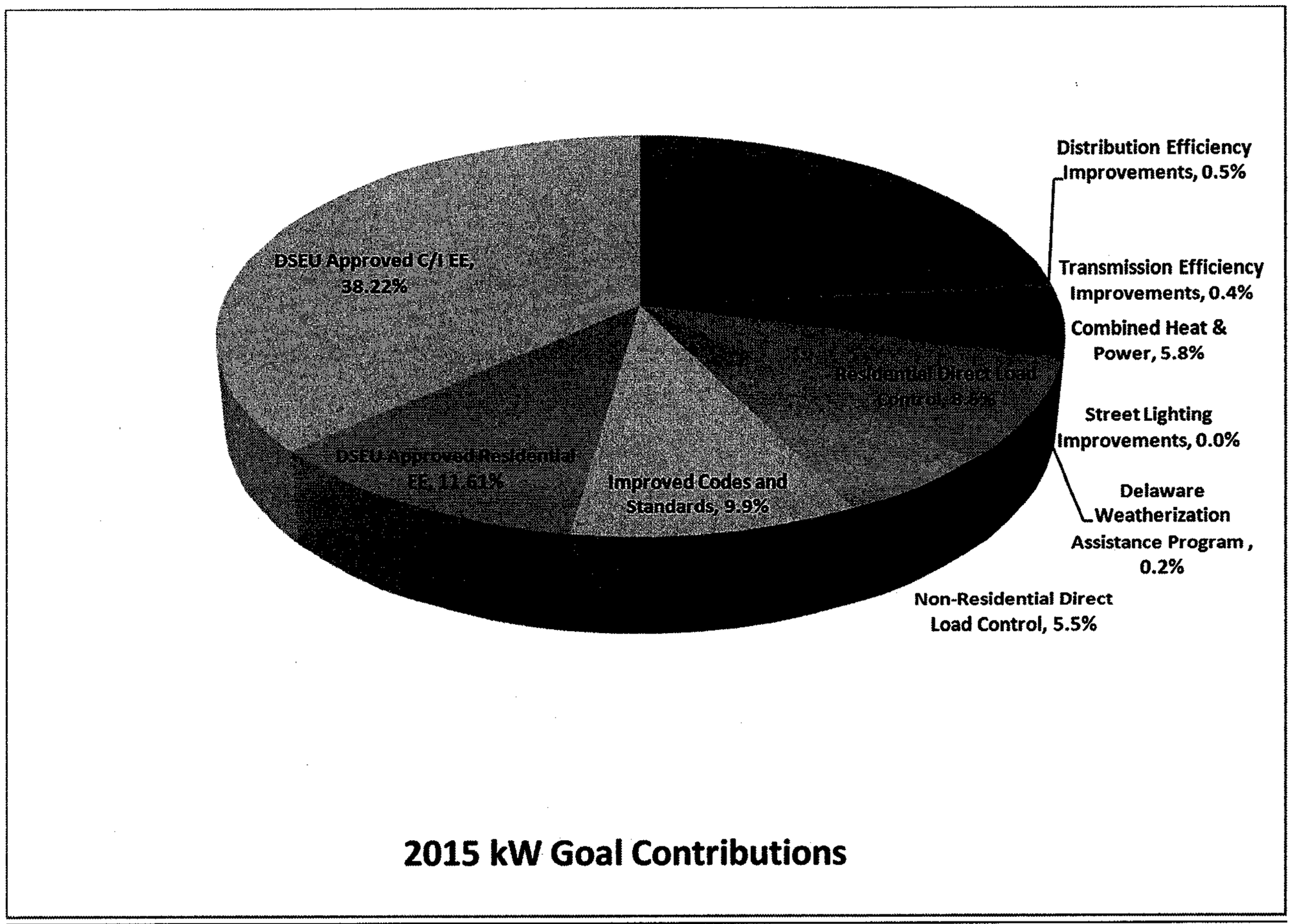


Chart 12

2015 Peak Demand Savings Sources



Allocation of Impacts Across Hours

To prepare the demand side energy impacts for use in the IPM model, it is necessary to create an hourly impact load shape. Since the energy impacts provided by the SEU and other entities were not created using hourly modeling, the necessary load shapes could not be developed directly from the available data. An alternative methodology was employed which used hourly information from the ICF Energy Efficiency Planning Model library to create a representative hourly load shape from the annual energy impacts described above.

The library planning model selected for use was the South Atlantic North (SAN) census region model. The SAN model is an energy efficiency potential model for the states of Delaware, Maryland, Virginia and West Virginia. The SAN model was selected because of its relevance to Delaware and the similarity of the efficiency measure groups which were analyzed and the measures likely to be included in the SEU programs, which comprise a large share of the energy efficiency impacts. The efficiency measure groups that are considered in the SAN model are shown in Table 12.

Table 12

SAN Model Efficiency Measure Groups

SAN Model Efficiency Measure Groups	
RES Efficient Windows	COM Efficient HVAC
RES Efficient Insulation	COM Efficient Boilers
RES Reduced Infiltration	COM Efficient Ducts
RES Efficient Ducts	COM Fluorescent Lighting
RES Efficient Space Cooling Equipment	COM Metal Halide Lighting
RES Efficient Space Heating Equipment	COM Solid State Lighting
RES Efficient Electric Water Heating	COM ENERGY STAR Appliances
RES Incandescent to Fluorescent Lighting	COM CPU Power Management
RES Halogen to Fluorescent Lighting	COM Efficient Refrigeration
RES Solid State Lighting	COM LEED Certification
RES Efficient Refrigerators	COM Building Retro-Commissioning
RES Efficient Clotheswashers	COM Building Commissioning

The hourly load shapes were developed in a three-step process. The first step was to develop hourly factors for total residential and non-residential measures in the model which represent an individual hour's contribution to each annual kWh of residential and non-residential savings. The second step was to aggregate the annual incremental energy-efficiency impacts for residential and non-residential initiatives. The final step was to multiply the appropriate residential or non-residential hourly factor by the total annual impact to calculate each hour's annual contribution. This calculation was performed for each year from 2013 – 2037.

Hourly load shapes are not required for the analysis of load control impacts in the IPM Model. For load control impacts the annual residential and non-residential impacts are utilized.

Contingency Planning

In section 3.2.7 of the new rules governing the preparation of future IRPs, there is a requirement that there be a contingency plan "should one of the supply, demand, or transmission options be either delayed or not realized."

The Act contains a requirement in 26 *Del. C.* § 1502(b) stating that "Affected Electric Energy Providers shall submit to the State Energy Coordinator a report on April 1, for the prior year, demonstrating that it, in cooperation with the SEU and the Weatherization Assistance Program, has achieved cumulative Energy Savings in the previous year that are at least equal to the Energy Savings required by regulations adopted by the Secretary pursuant to 1502(a) of this Chapter."

Several factors could impact when and if Delmarva Power's planned demand response programs or the SEU's energy efficiency programs realize the projected savings. For the Delmarva Power demand reduction programs, timing of receipt of Commission approval of the non-residential direct load control program is a key variable. For the SEU, insufficient funding or other factors could delay or prevent the implementation of energy efficiency and conservation programs and/or limit their operation. Additionally, both Delmarva Power demand response programs and SEU energy efficiency programs are subject to impacts caused by the Delaware economy. Program market receptivity will impact the timing and quantity of achieved electric energy and electric demand reductions.

In the event that any of the DSM programs do not attain the expected savings impacts and it is reflected in the required annual report that Delmarva Power has not achieved the energy savings required for the given year, the Act permits an additional Energy Efficiency Charge to be created on Delmarva Power's utility bills and it states that "...[s]hould an Affected Energy Provider determine that an energy efficiency charge is necessary to achieve the goals, they may make such

a recommendation in the Workgroup study...." This Energy Efficiency Charge could then be used to directly fund additional DSM activities within Delmarva Power's service territory. Additionally, if savings are not achieved by 2015, the Company will initiate working groups with all stakeholders, including the SEU, to discuss possible revisions to program plans and other alternatives. During these meetings, the Company will offer alternative programs and approaches to achieving energy and demand savings.[27]

Sensitivity Analysis

In the Reference Case, Delmarva Power assumes that the energy reduction targets defined by the Energy Efficiency Act of 2009 are achieved. These goals include a 15% reduction from 2007 energy consumption levels by 2015 and the IRP Reference Case assumes that this target will be met on schedule. The following sensitivity analysis examines the impact assuming that the energy efficiency savings goal was met in 2022 rather than in 2015. In this scenario it was assumed that in 2015 25% of the energy efficiency and conservation program reduction set forth in the Reference Case[28] goal would be met and that a ramp up of programs would occur until the original 2015 electric energy savings goal is achieved in 2022. A comparison of the reference case to the sensitivity analysis is shown in Graph 1. The economic value of the area between the two lines represents the "lost opportunities" of the later achievement of this goal for Delmarva Power customers.

[27] The SEU is free to develop whatever supplemental initiatives or energy efficiency programs it determines appropriate.
[28] Delmarva Power IRP, Demand Side Management Analysis Table 2.

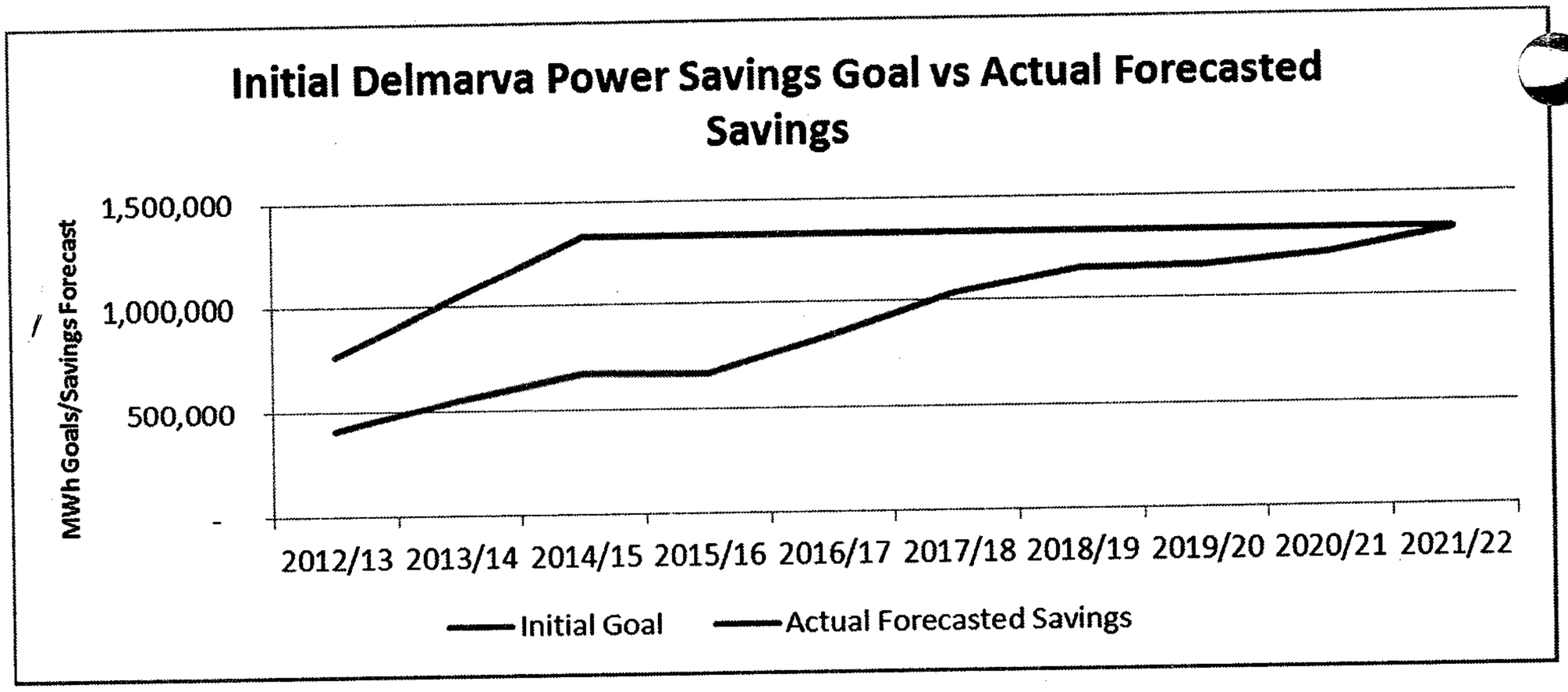


Table 2 below shows the lost opportunity in electric energy and peak demand reduction that are not achieved under this sensitivity. In this sensitivity analysis, the initial shortfall in 2015 represents 75% of the expected energy and demand savings that was forecast in the Reference Case for energy efficiency and conservation programs. This shortfall gradually diminishes and is eliminated at the end of 2022.[29]

Table 2

Lost Opportunities Measured in MWh and MW per PJM Planning Period

	2012/13	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22
MWh Lost Opportunity	354,171	492,464	654,840	667,008	478,544	291,175	177,298	167,111	115,258	8,649
MW Lost Opportunity	110	153	193	140	89	37	33	28	0	-27

Table 3 shows the calculated lost wholesale opportunity costs associated with this scenario. There are several types of costs that were quantified in this analysis. These include the cost of energy that would have been avoided in the Reference Case, the cost of additional capacity required as a result of the energy efficiency shortfall and the cost of additional Renewable Energy Credits that Delmarva Power would have to purchase as a result of the increased energy consumption increasing the amount of RECs needed to comply with the state Renewable Portfolio Standards requirement. These costs are valued based on the output of the IPM® model.

[29] The majority of the additional energy efficiency savings would be provided by the Delaware Sustainable Energy Utility (SEU).

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As shown below the annual lost opportunity cost could be significant in a number of years. The overall lost opportunity cost is over $230 Million on a cumulative basis.

Table 3

Value of Lost Opportunity Cost in Millions of Dollars per PJM Planning Period

	2012/13	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22
MWh Lost Opportunity $	$13,551	$ 21,429	$ 29,990	$ 32,241	$ 23,605	$ 15,847	$ 10,346	$ 10,110	$ 7,200	$ 555
MW Lost Opportunity $	$ 7,442	$ 13,650	$ 9,612	$ 8,586	$ 7,558	$ 3,786	$ 3,773	$ 3,245	$ 28	$ (3,410)
RPS Additional Cost	$ 129	$ 583	$ 813	$ 1,854	$ 2,196	$ 1,721	$ 1,278	$ 1,425	$ 1,168	$ 100
Total Lost Opportunity Cost	$21,122	$ 35,662	$ 40,415	$ 42,680	$ 33,359	$ 21,354	$ 15,398	$ 14,780	$ 8,396	$ (2,755)

If these numbers were adjusted to the retail or customer level the lost opportunity costs would increase due to line losses and required RECs as well as supplier hedge premiums. In addition, energy and capacity price mitigation impacts will be lost. This will result in higher PJM market prices for both capacity and energy for all Delaware customers for a period of time. Other lost benefits that are associated with this scenario include a loss of environmental benefits and positive reliability impacts.

VI. Transmission

Delmarva Power's transmission facilities are located within the PJM Regional Transmission Organization (RTO). Delmarva Power 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.
- Adequate transmission capacity to reliably and efficiently deliver the generation capacity where it is needed.

PJM meets these objectives by administering competitive markets that encourage merchant 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 and determine the most appropriate system upgrades to mitigate those violations. The selected upgrades are ultimately included in the PJM Regional Transmission Expansion Plan (RTEP).

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 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, develops a detailed near-term and long-range plan to ensure that the transmission system has sufficient capability to serve the load and that generation resources within PJM are deliverable. 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. For example, the load flow cases that were used for 2017 planning year assumed that Indian River units #1, #2, and #3 were all retired.

The table below lists pending individual transmission system upgrades that comprise the near-term plan for projects in Delaware. 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. The information listed is also available on the PJM web site. PJM will finalize a complete list of projects by the end of the year that will be used as part of the 2012 RTEP report which will be issued by February 2013.

Table 1– Transmission System Planned Upgrades

Upgrade ID#	Project Description	In-Service Date	Estimated Cost ($M)
B0792	Reconfigure Cecil Sub into 230 and 138 kV ring buses, add a 230/138 kV transformer, remove relay limits on Cecil-Colora 230 kV line & Cecil-Glasgow 138 kV line, and operate the 34 kV bus normally open	6/1/2013	$10.80
B0725	Steele Sub - Add 3rd 230/138kV Transformer	6/1/2013	$9.75
B0733	Harmony Sub - Add 2nd 230/138kV Transformer	6/1/2013	$14.82
B0754	Rebuild 10 miles of Glasgow to Mt. Pleasant 138 kV line and upgrades necessary substation equipment to bring the normal rating to 298 MVA and the emergency rating to 333 MVA	6/1/2013	$16.34
B0873	Build 2nd Glasgow-Mt Pleasant 138 kV line	6/1/2013	$12.76
B0732	Rebuild Vaughn-Wells 69 kV line	6/1/2013	$1.20
B0752	Reybold - Lums Pond 138 kV: Replace two circuit breakers to bring the emergency rating up to 348 MVA	6/1/2013	$1.00
B0874	Reconfigure Brandywine substation	6/1/2013	$16.98
B1899.2	Install new variable reactors at Cedar Creek 230 kV	12/31/2013	$2.86
B1246	Re-build the Townsend - Church 138 kV circuit	6/1/2014	$14.42
B1899.3	Install new variable reactors at New Castle 138 kV and Easton 69 kV	12/31/2014	$5.35
B1247	Re-build the Glasgow - Cecil 138 kV circuit	6/1/2015	$6.80
B1249	Reconfigure the existing Sussex 69 kV capacitor	6/1/2015	$1.27
[redacted]			

Table 2 below shows the Delaware RTEP projects that were constructed by year since the last Delaware Integrated Resource Plan was submitted. The 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 – Transmission Projects completed in Delaware 2011-2012

Upgrade ID#	Project Description	In-Service Year
B0568	Add third Indian River 230/138 kV transformer	2011
B0480	Rebuild Lank - Five Points 69 kV	2011
B0481	Replace wave trap at Indian River 138kV on the Omar - Indian River 138kV circuit	2011
B1899.1	Install new variable reactors at Indian River and Nelson 138 kV	2012
B0751	Add two additional breakers at Keeney 500 kV	2012
B0737	Build a new Indian River-Bishop 138 kV line	2012

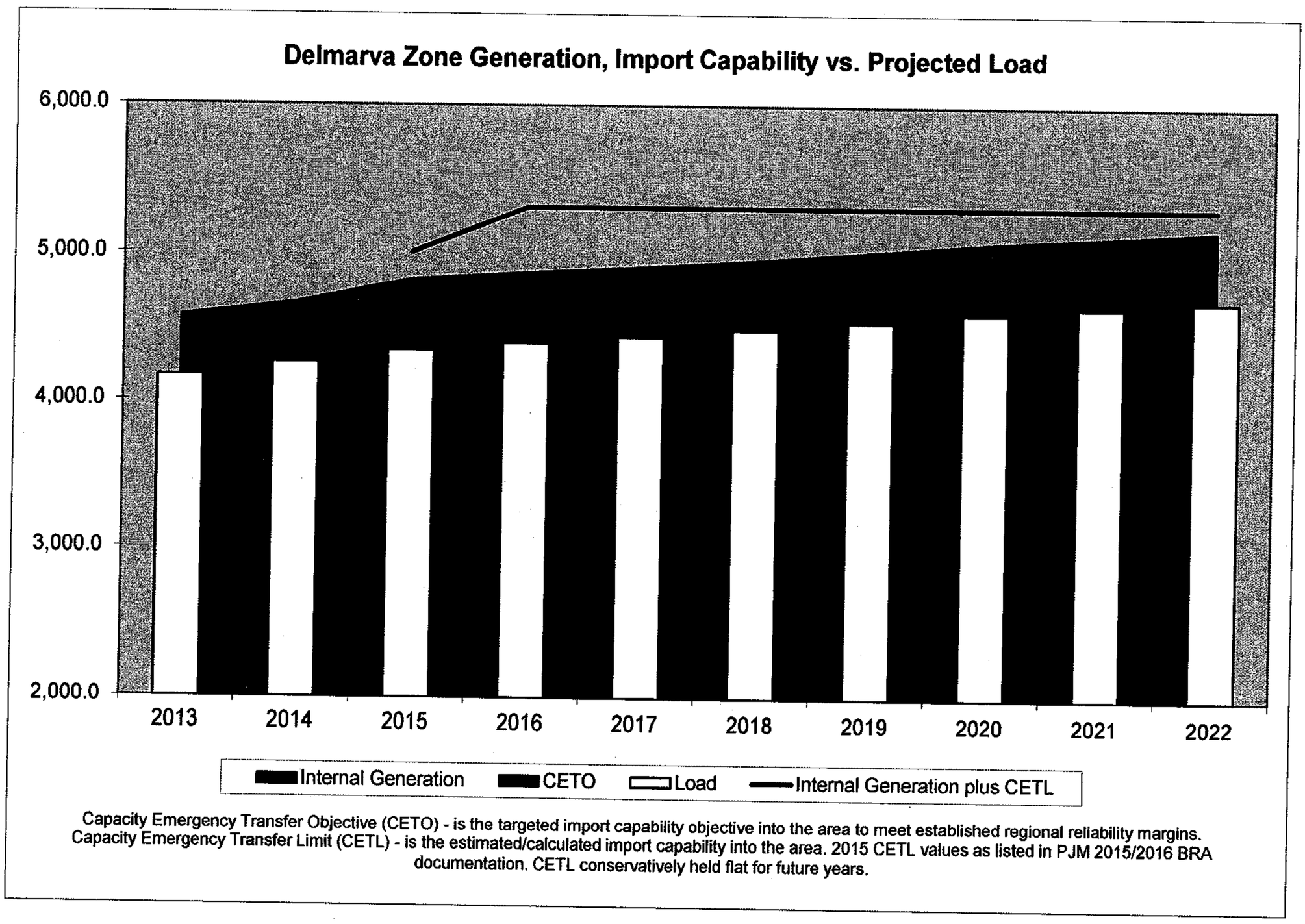
As previously noted, in addition to the detailed plans developed for the next five years, PJM also works with stakeholders, including Delmarva Power, to develop a 15-year plan which addresses the need for new major backbone transmission projects at higher voltages. PHI/Delmarva Power previously identified the Mid-Atlantic Power Pathway as a major 500kV backbone transmission project which would provide additional capacity and reliability to the Delmarva Peninsula. On August 27, 2012, PHI/Delmarva Power received notice of the PJM Board's decision to remove the MAPP project from PJM's regional transmission expansion plans.

Grid conditions have changed since the MAPP project was originally planned, and the updated analysis performed by the transmission planning staff at PJM no longer showed a need for the MAPP project to maintain grid reliability during the planning period. In particular, lower load projections resulting from a slower economy, coupled with recent generation additions and increased demand response, are the factors that reduced the need for this project. As a result of PJM's decision to cancel the MAPP project, PHI/Delmarva Power does not have any backbone transmission projects in PJM's 15-year plan. Currently, there are no planned major backbone transmission projects in Delaware.

The graphical data in Figure 4 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 2015. CETO values for years prior to and after were extrapolated based on the 2015 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 2015. PJM plans for a minimum CETL to CETO ratio of 115%. The chart above conservatively holds CETL values for years 2016 – 2023 constant. The rise in the "Increased Generation plus CETL" value in 2016 is attributed to increased generation on the Delmarva system. Based on PJM's published CETL to CETO value of greater than 115% for Delmarva in 2015, 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 4 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 4 – Delmarva Zone Generation, Import Capability vs. Projected Load



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Contingency Plan

The PJM RTEP considers the near-term (five years out) and long-term (15 years out) needs of the regional transmission system and is updated on an annual basis. As new decisions are made during the RTEP process, Delmarva Power updates its plans accordingly.

Changes to the RTEP process

As per the requirements of The Federal Energy Regulatory Commission (FERC) Order 1000 issued on July 21, 2011 requiring changes to the Transmission Planning and Cost Allocation processes, PJM and stakeholders have been working through the PJM Regional Planning Process Task Force (RPPTF) to revise the affected PJM planning protocols to align them with the requirements outlined in the Order. 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 content of PJM stakeholder meetings can be viewed via the RPPTF link on the PJM website.

VII. Supply Side Resources

This Section of the IRP discusses the generation supply options analyzed in this study.

SUPPLY-SIDE RESOURCE OPTIONS CONSIDERED

In order to optimize the resource mix overtime, the analysis considered alternative power supply options. The optimization was based on a discounted cash flow and cost minimization decision process endogenous to the IPM®. The generation addition options which were characterized within IPM® and considered as possible options include:

Natural Gas-Fired Combined Cycle – These plants use a combination of steam turbine and combustion turbine technologies and capture the waste heat from the gas turbine exhaust produced during electricity generation and reuse it to generate steam for the steam turbine to generate additional electricity. Combining these two cycles results in higher overall efficiency.

Natural Gas-Fired Peaking Combustion Turbine – This plant has lower thermal efficiency and capital costs and shorter construction lead times than Combined Cycle and Cogeneration Units. These peaking units also offer quick start capability.

Areoderivatives (LMS100s) - Similar to peaking combustion turbines, aeroderivative capacity offers short construction times, quick start capability, and have lower capital costs than combined cycles. LMS100s typically are sized at much smaller increments than combustion turbines, have a smaller footprint, can be constructed in a much shorter time, and are more thermally efficient. However, these units also have a higher capital cost than combustion turbines.

Integrated Gasification Combined Cycle (IGCC) - Instead of burning coal directly, IGCC plants convert coal into gas prior to combustion. Gasification helps in achieving lower levels of pollutant emissions. Using a combined-cycle technology, higher thermal efficiencies are achieved. IGCC plants have higher capital costs than traditional pulverized coal plants.

Supercritical Pulverized Coal (SCPC) - Nearly all U.S. coal plants are designed to use pulverized coal, and supercritical plants are designed to increase the plant's thermal efficiency. The plant is highly controlled for sulfur dioxide (SO_2), nitrogen oxides (NO_x), and mercury (Hg). Because

this type of coal plant is actively being considered by other utilities, it is modeled as an option for other northeastern U.S. utilities.

Nuclear – Nuclear generation is currently the second largest generation source in the U.S. New nuclear facilities face a number of hurdles prior to any future development largely due to siting concerns. The potential for newly constructed units and uprates at existing facilities are directly accounted for in this analysis.

Solar – Central and rooftop/distributed generation options are considered.

Wind – On- and off-shore wind facilities are considered. Wind resources are generally the dominant source of generation expected to meet requirements under Renewable Portfolio Standard programs. The analysis considers the potential for new wind resources to be added throughout PJM and the US. On-shore resources are characterized at three distinct tiers of units based on the combination of the expected facility performance and the construction costs of units. The Step 1 resources have the lowest capital costs while the Step 3 resources have the highest. Each Step may achieve varying output levels (capacity factor) depending on the ambient conditions which are defined by wind classes; each step has 4 associated wind classes which are modeled, Class 3, 4, 5, and 6. Capacity factor is 32% for Class 3, 34% for Class 4, 38% for Class 5, and 40% or higher for Class 6 resources. In addition, off-shore units are also considered in the analysis within coastal market areas and have a distinct cost and performance characteristics.

Biomass - Biomass plants use organic materials such as wood, agricultural and animal waste. Biomass resources are considered a renewable resource. Within this analysis, Biomass resources are also typically considered as carbon neutral.

Landfill Gas - Landfill gas plants use the gas (methane) naturally produced by the decomposing garbage in the landfill to generate electricity. Landfill Gas resources are considered to be renewable resources.

Power Purchases and Sales Reflecting Short-Term Market Conditions – Wholesale power import and export options are modeled in each hour. For the peak, capacity or reliability transactions are modeled.

Demand Side Resources – Demand response and energy efficiency programs have been used by the utilities to lower levels of peak and energy demand. In recent years, the most notable development has been the increase in DSM qualifying for the PJM capacity auction. Given the treatment in PJM of demand side options as a capacity resource, they are treated on a like basis in the overall analysis for generic options. For Delmarva, the specific program planned and projections have been input to this analysis as given.

Exhibits 2.1 and 2.2 present a summary of the assumptions related to new conventional resource options for Delaware. Exhibit 2.3 presents costs and characteristics for renewable resources. The capital cost assumptions reflect ambient conditions in Delaware and demonstrate regional variances depending on the cost of labor and construction material in those regions. All costs are in 2010 dollars.

Exhibit 2.1: Delaware Conventional Resource Options Capital Cost Assumptions

Resource Type	Earliest Online Year	Capital Cost (2010$/kW)	Forced Outage Rate
Peaking Units (LMS100 and Combustion Turbine)	2013	~950	2.4%
Combined Cycle	2015	~1,400	1.3%
Aeroderivatives (LMS100)	2013	~1,300	1.3%
Supercritical Pulverized Coal	2018	~3,000	6.3%
Integrated Gasification Combined Cycle	2019	~3,800	6.3%
Nuclear	2021	~6,500	3.5%

A typical combined cycle unit requires a lead time of 36 months or more prior to coming on-line. A typical coal plant requires an even longer lead time of 4 to 5 years. Given the longer lead-time required for a combined cycle unit versus a combustion turbine unit, we assume that no new

combined cycle units are possible before the summer of 2015 unless they are already under construction. New coal plants including IGCC plants are assumed to be available after 2019, unless in an advanced stage of development. New nuclear options become available in 2021. However, upratings to existing facilities are available during the IRP study period.

The capital costs are expected to decline in real terms at about 1 percent annually on average as a result of expected technological advancements. Technological improvements also enhance plant efficiencies reflected by improvements in heat rates over time. Combined cycle technology is assumed to improve to greater levels of efficiency from roughly a 7,100 BTU/kWh lifetime heat rate for through version 3 of the "F" technology, to levels closer to 6,800 BTU/kWh by the end of the forecast period. The lower heat rate is associated with advances in technology including movements to technologies such as version 5 of the "F" technology and the "G" technology.

Capital costs are expected to decline in real terms by about 1% annually on average as a result of expected technological advancements. Technological advancements also enhance plant efficiencies reflected by improvements in heat rates over time.

Exhibit 2.2: Higher Heating Value Heat Rate (Btu/kWh)

Year	Combined Cycle	Combustion Turbine	Jet Engine (LMS 100)	Coal IGCC CCS
2014	-	10,905	9,468	-
2016	6,800	10,905	9,468	-
2018	6,800	10,905	9,468	-
2020	6,800	10,905	9,468	10,156
2022	6,800	10,905	9,468	10,156

Exhibit 2.3 presents the capital expenses for renewable technologies considered in modeling.

Exhibit 2.3: Delaware Renewable Resource Options Assumptions Summary

Resource Type	Earliest Online Year	Capital Cost (2010$/kW)
Onshore Wind Step 1	2013	~2,000
Onshore Wind Step 2	2013	~2,500
Onshore Wind Step 3	2013	~3,100
Offshore Wind	2016	~4,000
Solar Photovoltaic-Distributed	2013	~4,000
Biomass	2016	~6,000
Landfill Gas	2013	~2,800

1. Regional adjustment factors are applied to the costs above to reflect regional variations in labor and materials markets and altitude/temperature differentials on gas-fired technologies. Capital costs include interconnection costs.
2. Capital cost includes EPC, Soft Costs, AFUDC and generic transmission upgrades.
3. Wind development options are modeled based on geographically determined potential for higher end wind classes. Large scale development is typically class 3 or above. Class 3 capacity factors roughly 32% while class 6 is roughly 40%. Wind development costs are differentiated by site conditions primarily tied to the proximity to the transmission network. Delaware onshore potential is primarily class 3 or below and is concentrated on the coast line. Delaware also has offshore potential which is included as a development option.

The federal government offers production tax credits (PTC) and Investment Tax Credits (ITC) to encourage wind and other renewable generation development. The modeling assumption utilized for PTC reflects 2.2 cents/kWh for wind 1.1 cents/kWh for non-wind renewables through the end of 2012 for wind units and 2013 for other eligible technologies. The ITC (30%) is available through 2016 at full value and it is phased out gradually over the next four years. Any applicable credits will be accounted for in modeling.

Onshore wind options are considered in various configurations to reflect the characteristics to construct and the operational output capabilities at alternate locations. In this analysis we consider three steps of on-shore wind and a single off-shore wind option. In addition to the varying cost steps which reflect the difficulty in constructing facilities (for example, Step 3

reflects a facility in a remote location which would require extensive upgrades such as roadway clearing and lengthy transmission interconnection to come on-line while Step 1 reflects a relatively accessible location requiring typical site and interconnection investment), each step reflects the potential to build wind class 4, 5, and 6 facilities. Wind classes reflect the wind speed and height of the turbines which translate into varying and improving capacity factors at the higher classes. Based on the geographic characteristics of the area, the onshore wind potential in Delaware is extremely limited to only the lowest wind classes which tend to have high costs and lower capacity factors. As such, wind options modeled within Delaware are consistent with this limited amount of onshore resource.

Offshore wind facilities are thought to offer several advantages over on-shore facilities. The major advantages are:

1. Wind speeds are generally stronger; a 25-40 percent gain in wind speed is typical at a few miles off-shore.
2. The potential for large contiguous development areas exists.
3. Offshore wind tends to be less turbulent, translating into less wear and tear on the turbines.
4. Offshore wind shear is lower than on-shore. This means that the boundary layer of slower moving air near the sea surface is thinner than the comparable area on land. This phenomenon allows for use of shorter towers to reach the desired hub-height average wind speed for turbine operation.

However, offshore facilities also have several disadvantages compared to onshore wind units. Among the disadvantages are the higher costs, the extremely limited experience in constructing, permitting, operating, and maintaining the facilities and their platforms. Further, due to the limited experience, the impact on the marine environment, the impact on other environmental issues, and the construction and maintenance requirements and costs also have a high degree of uncertainty surrounding them.

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FINANCING ASSUMPTIONS FOR NEW RESOURCE OPTIONS

The following table illustrates the financial assumptions used for new resources in Delaware.

Exhibit 2.4: New Resource Options Financing Assumptions for Delaware

Financial Assumptions	Combustion Turbine	Combined Cycle/Cogeneration	Coal/Nuclear Average	Intermittent Renewables
Debt/Equity Ratio (%)	55/45			
Nominal Debt Rate (%)	5.8			
Nominal After Tax Return on Equity (%)	10.8			
Income Taxes[1]	40.6			
Other Taxes[2] (%)	0.8			
General Inflation Rate (%)	2.5			
Debt Life (years)	15	20	20	15
Levelized Real Capital Charge Rate (%)	9.4	9.3	9.1	8.9

Note: Financing assumptions are identical for all areas of the country, but taxes vary regionally.

1. Includes federal and state taxes.
2. Includes property taxes and insurance.

For additional capacity needed over and above the firm commitments identified as having broken ground, the model adds capacity based on the resource options described in Exhibits 2.1 and 2.2 above.

VIII. Renewable Energy Resources

As part of the Renewable Energy Portfolio Standards Act (REPSA), the State of Delaware requires that Delmarva Power purchase an increasing amount of Renewable Energy Credits (RECs) from qualified renewable energy sources through 2025. Compliance with this requirement over the IRP planning horizon of 2013 – 2022 is an important focus of the 2012 IRP. To demonstrate compliance with the RPS legislation, Delmarva Power must provide to the State documentation that RECs meeting the requirement have been retired. In general, one REC is created for every MWh generated by an eligible renewable energy resource.[30] There is also a requirement for a minimum percentage of RECs to be generated from solar photovoltaic resources. For simplicity, 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 as amended by the Delaware General Assembly in June, 2010.[31] The percentages shown in the Table can be applied to Delmarva Power's forecast annual MWH sales to determine Delmarva Power's expected annual quantity of RECs to ensure RPS compliance.

Table 1

Delaware Eligible Renewable Energy Requirements

Complinace Year	Minimum Cumulative % from Eligible Energy Resources	Minimum Cumulative % from Eligible Solar Resources
2013/14	10.0%	0.60%
2014/15	11.5%	0.80%
2015/16	13.0%	1.00%
2016/17	14.5%	1.25%
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%

[30] An exception is related to the impacts of each MWH generated by a Qualified Fuel Cell Project (QFCP). While a QFCP does not produce RECs directly, each MWH produced from a Qualified Fuel Cell can be used to offset Delmarva's RPS obligations.
[31] 26 *Del.C.* § 354.

As indicated in Table 1, in 2013, the first plan year in this IRP, Delmarva Power is required to procure 10% of its supply requirements from renewable resources, including at least 0.6% from solar resources. By planning year 2022/23, the percentage increases to 22% for all qualifying resources, with at least 2.75% from solar resources. The percentages in Table 1 can be applied to the Reference Case MWH forecast for all Delmarva Power distribution customers adjusted for: 1.) larger industrial customers that have chosen, as allowed by legislation, to not participate in the Delaware RPS; and, 2.) REC requirements for customers whose RPS requirements are meet by their third-party supplier through existing contracts phased out as Delmarva Power transitions to meeting the REC requirements of all distribution customers. The forecast REC requirements for all distribution customers indicating the expected RECs needed for RPS compliance by year for both solar and non-solar eligible resources are shown in Table 2.

Table 2

REC and SREC Expected Annual Requirements

Complinace Year	RPS Load Obligaton (MWH)	Tier 1 Requirement (RECs)	Solar Carve-Out (SRECs)
2013/14	6,348,943	634,894	38,093
2014/15	6,290,994	723,464	50,327
2015/16	6,053,684	786,979	60,536
2016/17	5,952,527	863,116	74,406
2017/18	5,982,907	957,265	89,743
2018/19	5,927,171	1,037,255	103,725
2019/20	5,766,151	1,095,569	115,323
2020/21	5,646,117	1,129,223	127,037
2021/22	5,583,251	1,172,483	139,581
2022/23	5,525,832	1,215,683	151,960

The forecast 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. The results shown in Table 2 will change depending on the load forecast used and assumptions 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. Delmarva Power plans to do this through a combination of:

- Contracted Resources;
- Bloom Energy Offsets; and,
- Spot Purchases.

A. Contracted Resources

As a result of REPSA, and as approved by the Delaware PSC, Delmarva Power has already contracted for a portfolio of wind and solar resources to help meet the renewable energy requirements for its eligible distribution customers. The specific contracts are listed below in the order that they have or are expected to begin producing RECs to support Delmarva Power's compliance with REPSA.

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 (PPA) with AES to purchase up to 50 MW of the wind energy and RECs from this project. This project is expected to generate approximately 129,000 MWH of renewable energy and RECs annually. This facility became operational in December 2009.
2. Dover Sun Park: Delmarva Power agreed to 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 is one of the largest solar installations in the Mid-Atlantic region and became commercially operational during the Summer of 2011. Accompanying this contract, Delmarva Power signed an agreement with the Delaware Sustainable Energy Utility (SEU) which allows the SEU to purchase a portion of the SRECs generated by the Sun Park during its first two years of operation for the purpose of preserving the life of excess SRECs. Under

the terms of the SEU/Delmarva Power agreement, the SEU will return the preserved[32] SRECs to Delmarva Power in later years when the RPS solar requirements are greater.

3. Gestamp Roth Rock: Delmarva Power has entered into a PPA with Gestamp to provide RECs and energy from a 40 MW wind farm located in Western Maryland [nameplate capacity]. The wind farm became operational in August 2011 and contract purchases began in August of 2011.
4. enXco Chestnut Flats: Delmarva Power entered into a PPA with enXco to provide RECs and energy from a 38 MW wind project located in Central Pennsylvania. This project began service in December 2011.
5. Delaware SREC Procurement Pilot Program: Under the SREC Procurement Pilot Program approved by the Delaware PSC in 2011, the Delaware SEU conducted a competitive solicitation for SRECs from customer sited facilities in April 2012. As a result, the SEU awarded 166 twenty year contracts for Delaware-sited solar systems totaling 7.68 MW of Capacity. As part of the SREC Procurement Pilot Program, Delmarva Power has a contract with the SEU to purchase the SRECs that the SEU secured through the Pilot Program. SRECs from the contract agreement with the SEU began to be available in Summer 2012.
6. Delaware 2013 SREC Procurement Program: Delmarva Power is preparing a filing with the Commission to seek approval of a next round of SREC solicitation. This filing is based on the recommendation of the Delaware Renewable Energy Task Force and, if successful, would result in the procurement of approximately 7,000 SRECS per year from customer-sited facilities beginning in compliance year 2013/14.

The five current RPS eligible projects and programs represent a total of 128 MW of wind generation and 17.68 MW of solar generation resources. This diverse portfolio of renewable energy resources establishes a strong foundation for Delmarva Power's compliance with the Delaware RPS requirements. Over the period 2013-2022, these projects will create a renewable resource "supply stack" of RECs and SRECs that, along with spot market purchases, will allow Delmarva Power to meet its customers' needs. Table 3 below shows the projected REC and

[32] RECs and SRECs normally expire if not used with 3 years after the month of generation, when SRECs are in the possession of the SEU this time frame is extended.

SREC[33] supply from Delmarva Power's contracted renewable resources over the planning period:

Table 3

Projection of RECs Created by Existing Contracts

Complinace Year	AES Armenia Wind (RECs)	Gestamp - Roth Rock (RECs)	Gamesa - Chestnut Flats (RECs)	Dover SunPark (SRECs)	SREC Financing Pilot Program (SRECs)
2013/14	129,210	105,120	99,864	14,126	11,472
2014/15	129,210	105,120	99,864	17,025	11,415
2015/16	129,210	105,120	99,864	17,835	11,358
2016/17	129,210	105,120	99,864	18,865	11,301
2017/18	129,210	105,120	99,864	13,845	11,245
2018/19	129,210	105,120	99,864	13,776	11,188
2019/20	129,210	105,120	99,864	13,707	11,132
2020/21	129,210	105,120	99,864	13,639	11,077
2021/22	129,210	105,120	99,864	13,571	11,021
2022/23	129,210	105,120	99,864	13,503	10,966

Table 4 below shows how Delmarva Power's "supply stack" of SRECs obtained from contracted resources is currently expected to match up with the projected RPS requirements over the 2013- 2022 planning period.

Table 4

Contracted Resources Position vs. Projected REPSA Requirement

Complinace Year	Solar Carve-Out Requirement (SRECs)	Contracted SREC Supply (SRECs)	Net Position (SRECs)	Tier 1 Requirement (RECs)	Contracted REC Supply (RECs)	Net Position (RECs)
2013/14	38,093	25,598	-12,495	634,894	359,792	-275,102
2014/15	50,327	28,440	-21,887	723,464	362,634	-360,830
2015/16	60,536	29,193	-31,343	786,979	363,387	-423,592
2016/17	74,406	30,166	-44,240	863,116	364,360	-498,756
2017/18	89,743	25,090	-64,653	957,265	359,284	-597,981
2018/19	103,725	24,964	-78,761	1,037,255	359,158	-678,097
2019/20	115,323	24,840	-90,483	1,095,569	359,034	-736,535
2020/21	127,037	24,715	-102,322	1,129,223	358,909	-770,314
2021/22	139,581	24,592	-114,989	1,172,483	358,786	-813,697
2022/23	151,960	24,469	-127,491	1,215,683	358,663	-857,020

[33] The SRECs from contracted resources are adjusted to reflect the impact of multipliers for in-state labor and parts within REPSA. SRECs from the Dover SunPark include those held by the SEU as they are expected to be resold to Delmarva Power.

As shown in Table 4, based on existing contracted wind resources alone, Delmarva Power is in a net "short" position. In the 2010 IRP, Delmarva Power did not expect to be short. However, a change in REPSA occurred in 2011 that required Delmarva Power to procure RECs for all distribution customers, rather than just Delmarva's SOS customers, beginning in compliance year 2012/13. This change significantly expanded Delmarva Power's need for additional RECs. However, as discussed in the next section, additional amendments to REPSA create a provision that the output from fuel cells manufactured and installed in Delaware to reduce or "Offset" part of Delmarva Power's RPS obligations (both solar and non-solar).

B. Qualified Fuel Cell Provider Program

In July 2011, the Governor of the State of Delaware signed legislation that establishes that the energy output from fuel cells manufactured in Delaware capable of running on renewable fuels ("Qualified Fuel Cell Provider") is an eligible resource for RECs under the Renewable Energy Portfolio Standards Act (REPSA). The legislation further requires that the Delaware Public Service Commission (the "Commission") adopt a tariff under which Delmarva Power would be an agent that collects payments from its customers and disburses the amounts collected to a qualified fuel cell provider that deploys Delaware-manufactured fuel cells as part of a 30-megawatt generation facility and that the payments from customers be offset by the market revenues received by the Qualified Fuel Cell Provider from its selling of capacity and energy into the wholesale market netted against its cost of fuel. The legislation also provides for a reduction in Delmarva Power's REC and SREC requirements based upon the actual energy output of the 30-megawatt generation facility. In October 2011, in Order No. 8062, the Commission approved the tariff submitted by Delmarva Power in response to the legislation.

The State identified Diamond State Generation Partners ("Diamond State" or "Bloom Energy") as the Qualified Fuel Cell Provider. Bloom plans to construct fuel cell generation facilities at two locations in Delaware. The first site, a 3 MW fuel cell facility at Delmarva Power's Brookside substation, went into operations on June 18, 2012. The 2nd site, a 27 MW facility located near Delmarva Power's Red Lion Substation, is to be phased into operations on or before September 30, 2014.

Bloom uses natural gas to generate electricity through a fuel cell. While this process creates some CO2, there are virtually no other air emissions from the fuel cell. A major difference between the Bloom Energy fuel cell and wind and solar resources is that Bloom is not an intermittent resource. In fact, the Bloom facilities are expected to operate at very high capacity factors (96%) on an annual basis. Consequently, virtually every MW of Capacity obtained from the Bloom project is capable of and expected to produce.

The amendments to REPSA provide that each MWH produced by a Qualified Fuel Cell Project (QFCP) allow Delmarva Power to offset its RPS obligations. Essentially, the output of the Bloom facilities, as a QFCP, will reduce the non-solar REC and SREC requirements that would otherwise be needed to satisfy REPSA.

Delmarva Power assumed that each MWH of Bloom would be used to offset either 1/6 of an SREC or 2 RECs, depending which was projected to be most cost-effective each year.[34] Although the Department of Natural Resources and Environmental Control (DNREC) will be responsible for determining the actual RPS offsets each year, Delmarva Power made the assumptions stated above based on testimony presented by DNREC in the Qualified Fuel Cell Provider Tariff approval process. Although the output of the QFCP will be used to offset Delmarva Power's RPS Obligation, for ease of presentation, these offsets are expressed as equivalent RECs (ERECS) and equivalent SRECS (ESRECS) in this report.

Table 5 below shows the projected amount of the non-solar REC and SREC offsets expected to be created from the Bloom fuel cells that will help offset Delmarva Power's REPSA requirements.

[34] In addition, the Bloom offsets are limited to 25% of the solar requirements through compliance year 2016/17 and 30% for the remainder of the IRP study period.

Table 5

Bloom Energy

Non Solar and Solar REC Offsets

Complinace Year	Projected Bloom Generation (MWH)	SREC Offsets (ESRECs)	REC Offsets (ERECs)
2013/14	166,230	9,523	218,181
2014/15	252,288	12,582	353,595
2015/16	252,288	0	504,576
2016/17	252,288	0	504,576
2017/18	252,288	0	504,576
2018/19	252,288	0	504,576
2019/20	252,288	0	504,576
2020/21	252,288	0	504,576
2021/22	252,288	0	504,576
2022/23	252,288	0	504,576

Tables 6 and 7 below show Delmarva Power's projected net position adjusted to reflect the expected impact of the Bloom fuel cells 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) if projections are accurate. A positive net position indicates that additional RECs are available to be "banked" and used in a future year.

Table 6

Bloom Impact on Delmarva Power's Projected Net Solar Position

Complinace Year	SREC Requirement	Bloom ESRECs	Contracted SREC Supply	Net Position
2013/14	38,093	9,523	25,598	-2,972
2014/15	50,327	12,582	28,440	-9,305
2015/16	60,536	0	29,193	-31,343
2016/17	74,406	0	30,166	-44,240
2017/18	89,743	0	25,090	-64,653
2018/19	103,725	0	24,964	-78,761
2019/20	115,323	0	24,840	-90,483
2020/21	127,037	0	24,715	-102,322
2021/22	139,581	0	24,592	-114,989
2022/23	151,960	0	24,469	-127,491

Table 7

Bloom Impact on Delmarva Power's Projected Net RPS Position

Complinace Year	REC Requirement	Bloom ERECs	Contracted REC Supply	Net Position
2013/14	634,894	218,181	359,792	-56,922
2014/15	723,464	353,595	362,634	-7,235
2015/16	786,979	504,576	363,387	80,984
2016/17	863,116	504,576	364,360	86,803
2017/18	957,265	504,576	359,284	-6,602
2018/19	1,037,255	504,576	359,158	-173,521
2019/20	1,095,569	504,576	359,034	-231,959
2020/21	1,129,223	504,576	358,909	-265,738
2021/22	1,172,483	504,576	358,786	-309,121
2022/23	1,215,683	504,576	358,663	-352,444

C. Spot Purchases

As mentioned earlier, both RECs and SRECs can be purchased from the spot market to satisfy any shortfall in the amount of RECs and SRECs Delmarva Power may need to ensure compliance with REPSA. Tables 6 and 7 above show that Delmarva Power expects to participate in the spot market for both RECs and SRECs over the period 2013-2022 unless additional contracts are sought and brought forward for approval by the Public Service Commission. Given relative low prices currently available in the respective spot markets, Delmarva Power anticipates purchasing RECs and SRECs from the spot markets until the Renewable Energy Taskforce makes alternative recommendations and the rule-making process with respect to the 1% solar and 3% total cost limit provisions of REPSA are finalized.

D. RPS Compliance Costs

The following tables present the projected "non-netted" costs of RPS compliance given Delmarva Power's contracted resources and the forecast of spot market prices produced by

ICF[35]. The term "non-netted" refers to the monetary costs that will be incorporated into a Delmarva Power customer bill. However, as subsequent material appearing in the section under the heading of "Non-price Impacts of RPS Compliance on Customer Bills" makes clear, there are significant human health benefits associated with the improvement in air quality that may be attributable to the implementation of the Delaware RPS.[36] While the IRP shows these quantified externality impacts for all sources from improving air quality, they are not reflected on the Delmarva Power bill. As described below, the quantified externality benefits are significant.

Table 8 represents the projected non-netted cost for Delmarva Power to meet the Solar Carve-out. The cost of solar compliance is projected to increase from approximately $6 million to $29 M over the planning period with a slight dip in compliance year 2015/16 when offsets from the Bloom fuel cell are projected to switch from offsetting solar to tier 1 obligations.

Table 8

Projection of the Cost to Comply with the RPS' Solar Carve-Out

Compliance Year	2013/14	2015/16	2017/18	2019/20	2022/23
Projected SREC by Source (SRECs)					
Dover SunPark	14,126	17,835	13,845	13,707	13,503
SREC Financing Pilot Program	11,472	11,358	11,245	11,132	10,966
Bloom Offsets	9,523	0	0	0	0
Spot-Solar	2,972	31,343	64,653	90,483	127,491
Total SRECs	38,093	60,536	89,743	115,323	151,960
SREC Cost (k$)					
Dover SunPark	$2,530	$3,242	$2,480	$2,455	$2,418
SREC Financing Pilot Program	$2,393	$2,376	$2,359	$2,344	$776
Bloom Offsets	$925	$0	$0	$0	$0
Spot-Solar	$357	$3,230	$8,883	$15,060	$25,817
Total Solar Complinace Costs (k$)	$6,205	$8,848	$13,722	$19,859	$29,011

[35] The compliance costs for the Bloom fuel cell and the wind contracts include the net revenue from market sales of energy and capacity (Bloom Only).

[36] The total health benefits occurring from improved air quality over the period 2013 to 2022 and shown in Section IX and Appendix 8 of the IRP are derived from the Reference Case and other publically available sources using US EPA models.

Table 9 presents the projected non-netted total cost to comply with the total RPS requirements[37]. Projected cost increase steadily across the planning period from $45.7 million for compliance year 2013/14 to $83.4 M for compliance year 2022/23.

Table 9

Projection of the Total Cost to Comply with the RPS Requirements

Compliance Year	2013/14	2015/16	2017/18	2019/20	2022/23
Projected REC by Source (RECs)					
Solar Supply	38,093	60,536	89,743	115,323	151,960
Wind Contracts	315,132	161,331	303,118	418,009	334,194
Bloom Offsets	218,181	504,576	504,576	504,576	504,576
Existing-REC	63,489	60,536	59,829	57,661	0
Spot-REC	0	0	0	0	224,953
Total RECs	634,895	786,979	957,266	1,095,569	1,215,683
REC Costs (k$)					
Solar Supply	$6,205	$8,848	$13,722	$19,859	$29,011
Wind Contracts	$17,658	$13,125	$14,807	$16,463	$14,418
Bloom Offsets	$21,196	$32,394	$28,979	$30,339	$29,821
Existing-REC	$63	$61	$60	$58	$0
Spot-REC	$0	$0	$0	$0	$10,180
Total RPS Complinace Costs (k$)	$45,122	$54,427	$57,567	$66,718	$83,430

E. Impact of RPS Compliance on Customer Bills

As part of the Settlement in Docket No 10-2 and as later approved by the Commission in Order 8083 on January 10, 2012, Delmarva Power agreed to estimate the impact of compliance with the Delaware RPS on customer bills as part of the 2012 IRP. As described earlier, Delmarva Power is now responsible for securing the RECs and SRECs required for annual compliance with REPSA for all distribution customers[38]. In order to help fulfill this obligation, 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 Bloom Energy project to help meet its RPS obligations. The third

[37] Through planning year 2019/2020, REPSA allows 1% of the total RPS obligation to be met with REC from "Existing" sources which were placed in-service on or before 12/31/1997.
[38] Certain large customers 1.5 Mw or over are eligible to "opt-out" of the RPS and consequently are not part of Delmarva's RPS compliance plan.

and final piece of the renewables compliance plan is to purchase RECs and SRECs from the spot market as needed to ensure the annual compliance requirements are met. In this section of the IRP, Delmarva Power provides estimates of the annual impact over the IRP planning horizon for each of these three components of RPS compliance on customer bills for both non-solar and solar resources.

Table 10 below provides a summary of the estimated "non-netted" impact of RPS compliance on a typical Residential customer bill for the period June 2013 – May 2023 based upon the IRP Reference Case assumptions[39]. For each planning year, the "non-netted" cost of compliance for both non-solar and solar renewable resources is shown as well as the cost of Delmarva Power's existing contract obligations, the Bloom energy offsets, and spot purchases.

Table 10

Impact of RPS Compliance on Typical Residential Customer Bills[40]

CONFIDENTIAL MATERIAL OMITTED

Compliance Year	2013/14	2015/16	2017/18	2019/20	2022/23
Avg. Residential Customer Bill (1000 kW/Month)					
Supply Component			$120.30	$136.68	$151.65
Transmission Component	$6.72	$6.85	$6.99	$7.13	$7.34
Distribution Component	$30.30	$30.91	$31.53	$32.16	$33.14
Total			$158.82	$175.98	$192.13
Solar Compliance Impact on Typical Customer Bill					
Total SREC Compliance Cost per Avg Bill (1000 KW)	$0.91	$1.32	$2.19	$3.35	$5.27
SREC % Impact on Avg. Customer Bill			1.38%	1.90%	2.74%
RPS Compliance Impact on Typical Customer Bill					
Total RPS Compliance Cost per Avg Bill (1000 KW)	$6.60	$8.10	$9.18	$11.24	$15.15
RPS % Impact on Avg. Customer Bill			5.78%	6.39%	7.88%

In evaluating the results of Table 10 it is important to keep several things in mind. First, DNREC is currently in the process of obtaining stakeholder input into the promulgation of regulations for determining the methods for calculating costs related to RPS compliance under

[39] In table 10, the distribution component does not include RPS & Bloom charges. Both the transmission and distribution charges are assumed to escalated at 1% per year from their current levels for this calculation.
[40] The average residential customer bill includes projected generation, transmission, and distribution charges. Current transmission and distribution charges were assumed to increase at 1% per year.

26 *Del. C.* §354 (i) and (j). Because these regulations are still in the development process, they were not available for Delmarva Power to use in preparing Table 10 as part of this IRP.

Second, the expected bill impact is heightened, at least in the shorter term, in large part by forecast low natural gas prices. Low natural gas prices keep market electricity prices low but increase the relative cost of Delmarva Power's renewable contracts to customers. This occurs because Delmarva Power pays a fixed contract price for the energy output from certain of its contracted renewable resources and simultaneously liquidates the output at the current prevailing market price at the PJM interconnection point of each such renewable project. As market prices for energy fall or remain low, there is less revenue from the market received by Delmarva Power to offset the fixed contract price[41].

These results also represent a prospective, not actual, view of the impact of RPS compliance on a typical customer bill. Due to the way the RPS requirements are structured, actual RPS compliance costs and impact on customer bills can only be calculated after year end. The results in Table 10 are also based upon assumptions embedded in the IRP Reference Case. Consequently, changes in expected future electricity market prices, customer loads or the achievement of energy conservation goals will impact these results. Another variable would be whether the Production Tax Credit (PTC), which is currently scheduled to expire at the end of 2012 (as assumed in the IRP Reference Case), is further extended by Congress.

Non-price Impacts of RPS Compliance on Customer Bills.

Section 6.1.4 of the regulations governing Delmarva Power in preparing the IRP requires the evaluation of the impact of environmental externalities associated with the Delmarva Power's energy procurement plans. Further the Renewable Energy Portfolios Standards Act ("REPSA") states:

> "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

[41] Delmarva Power's renewable contracts function as "hedges" to help provide price stability. If market prices rise the contracted resources will provide more economic benefits.

performance, and new economic development opportunities."

As part of this IRP and evaluation of the Reference Case, Delmarva Power has 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 are presented in Section IX and Appendix 8 of this IRP. In brief, these results show human health benefits due to improvements in air quality over the period 2013 – 2022 in the range of $980 million to $2.2 billion and $13 to $29 billion for Delaware and the Mid-Atlantic Region respectively. 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 IRP does not directly identify the separate contribution of renewable resources that are part of Delmarva Power's renewable resource compliance portfolio to the overall improvement in human health.

The separate contribution of renewable resources to improving air quality could be evaluated by rerunning the IPM® and air quality models under a scenario where renewables are not included in the generation mix and comparing this to the Reference Case and then performing the resource intensive air quality analysis. Because such an analysis would be expensive, time and resource consuming, Delmarva Power has employed a simpler approach described below to help provide a range of estimates of the impact on air quality benefits provided by renewable generation.

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, 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 facilities, produce air emissions such as carbon dioxide (CO2), Sulfur dioxide (SO2), and Nitrous Oxide (NOX) at

varying rates. Accordingly, when wind and solar resources generate power, other sources reduce their output and related air emissions.

Determining *exactly* how much CO2, SO2, and NOX are displaced by wind and solar resources is made difficult because marginal changes in PJM generation emissions are different for each and every hour during the year and the hourly production of intermittent wind and solar generation over a year's time is uncertain. Consequently, exactly matching the emissions avoided by intermittent resources can be a complex undertaking. Nevertheless, making some simplifying assumptions, information provided from the IPM® Reference Case on average PJM emission rates can be combined with the expected annual renewable resource generation MWH associated with Delmarva's renewable resource portfolio to obtain *a range* of benefits from generation air emission reductions that may be attributable to Delmarva Power's RPS compliance. Based on the implied values of a ton of SO2, NOx and CO2 from the IRP evaluation of changes in air quality over 2013 to 2022, the range of emission reductions can then be valued in dollar terms for the potential avoided health costs.

The Air Quality analyses presented in section IX and Appendix 8 of the IRP estimates 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 from electric power plant emissions in these states is estimated to range from $36 to $98 billion (U.S. $2010) for 2022. The 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 cost is attributable to SO2 emissions, 6% of the overall cost is attributable to NOx emissions, and 29% of the overall cost is attributable to primary PM2.5 emissions. Considering the 2022 EGU emissions totals (as estimated using IPM ®), the cost per ton for SO2 and NOx is estimated to be within the range of:

$43,000 – 110,000 for SO2, and $9,500 – 25,000 for NOx.

Also, as discussed in Appendix 8 of the IRP, the health cost per ton of CO2 is estimated to be within the range of $1 to $100 per ton.

From the IPM® Reference Case, average annual emission rates (tons/Mwh) for SO2, Nox and CO2 can be calculated for PJM resources that create these emissions[42]. This is shown in the table below:

Table 11

Average Emission Rates (ton/MWH)

	2013	2014	2016	2018	2020	2022
PJM co2 rate	0.81870	0.80096	0.79693	0.79702	0.78294	0.77365
PJM So2 rate	0.00175	0.00110	0.00097	0.00096	0.00091	0.00088
PJM Nox rate	0.00057	0.00053	0.00043	0.00044	0.00042	0.00041

The total amount of renewable resource generation MWH enabled by Delmarva Power's renewable portfolio over 2013 - 2023 is shown in Table 12 below[43].

Table 12

Delmarva Power Renewable Resource Portfolio

Total Renewable Generation MWh

	2013	2014	2016	2018	2020	2022
Contracted Resources	359,792	362,634	364,360	359,158	358,909	358,663
Bloom	166,230	252,288	252,288	252,288	252,288	252,288
Spot Purchases	0	0	0	114,250	265,738	352,444
Total Resources	526,022	614,922	616,648	725,696	876,935	963,395

[42] MWH outputs from Nuclear, Wind, and Solar resources are not used in the calculation of the average emission rates for CO2. The calculation of average emission rates for SO2 and Nox also exclude the additional output from fuel cells.

[43] This table shows total MWH (not RECs) produced by the renewable portfolio.

As discussed earlier, when these resources produce power, they displace other resources that would have otherwise created air emissions. As noted earlier, although the exact amount of displaced air emissions is difficult to estimate, such estimates can be made using the average emission rates shown above in Table 11 above using some simplifying assumptions. Assuming that the resources in Delmarva Power's renewable portfolio incrementally reduce air emissions at, say, either 50% or 25% of the average PJM emission rate on an annual basis, the following tables shows the reduction in air emissions that would otherwise have occurred[44]:

Table 13

Tons of Emissions Avoided by DPL Renewable Portfolio Resource

(assumes 50% of PJM average emission rates)

	2013	2014	2016	2018	2020	2022
co2	147,281	145,228	145,185	188,658	244,530	275,072
so2	460	337	299	350	401	424
nox	150	162	133	158	186	199

Table 14

Tons of Emissions Avoided by DPL Renewable Portfolio Resource

(assumes 25% of PJM average emission rates)

	2013	2014	2016	2018	2020	2022
co2	73,641	72,614	72,592	94,329	122,265	137,536
so2	230	168	149	175	200	212
nox	75	81	66	79	93	100

These tons of emission reductions can be applied to the $ value per ton discussed above to provide a range of estimates for the avoided emission costs attributable to Delmarva Power's

[44] Because the Bloom Energy fuel cells produce CO2, no CO2 reductions are attributed to the mwh produced by this resource.

RPS compliance plan. This is shown in the tables below which assume that the avoided emissions are valued at the low end of the range for avoided emission costs:

Table 15

Estimated Benefits of Reduced Air Emissions from Delmarva Power's Renewable Compliance (assuming 50% of average PJM emission rate avoided)

	2013	2014	2016	2018	2020	2022
CO2	$147,281.12	$145,228	$145,185	$188,658	$244,530	$275,072
SO2	$19,777,125	$14,478,834	$12,852,657	$15,040,069	$17,224,933	$18,226,921
Nox	$1,420,478	$1,540,204	$1,260,079	$1,502,449	$1,764,497	$1,894,444
Total	$21,344,884	$16,164,265	$14,257,920	$16,731,175	$19,233,959	$20,396,437

Table 16

Estimated Benefits of Reduced Air Emissions from Delmarva Power's Renewable Compliance (assuming 25% of average PJM emission rate avoided)

	2013	2014	2016	2018	2020	2022
CO2	$73,641	$72,614	$72,592	$94,329	$122,265	$137,536
SO2	$9,888,563	$7,239,417	$6,426,329	$7,520,034	$8,612,466	$9,113,461
Nox	$710,239	$770,102	$630,039	$751,224	$882,248	$947,222
Total	$10,672,442	$8,082,132	$7,128,960	$8,365,588	$9,616,979	$10,198,219

Alternative estimates of the dollar value of the external benefits of the emissions avoided by Delmarva Power's renewable resource compliance can be obtained by further varying the assumptions around the percentage of the average PJM emission rate avoided and the costs per ton of each type of emission.

IX. Environmental Externalities

The purpose of this section of the IRP is to provide a discussion of Delmarva Power's approaches and assumptions in determining the external costs of energy production on human health. More detailed information is available in Appendix 8.

The regulations governing the preparation of Delmarva's 2010 IRP were promulgated by the Delaware Public Service Commission on August 18, 2009. The regulations constitute a complete set of standards for the IRP. Among other requirements, these governing regulations require Delmarva Power to conduct an evaluation of environmental benefits and externalities associated with the utilization of specific methods of energy production.[45]

Most of the available literature on environmental externality points to global warming and the human health effects of air emissions as dominating energy externalities. This was a primary consideration in shaping the process used by Delmarva to quantify environmental benefits and impacts.

In order to assess the externalities associated with the Reference Case, Delmarva and its contractor, ICF, estimated the overall public health benefits resulting changes in air emissions from all sources, including power generation, over the planning period 2013 to 2022. For the Reference Case, the emissions from power plants in Delaware and other nearby regions are tracked so that changes in emissions between 2013 and 2022 can be determined. The primary pollutants of interest for this assessment are particulate matter (PM), ozone, sulfur dioxide (SO_2), nitrogen dioxide (NO_2), carbon dioxide (CO_2) and mercury (Hg).

[45] For purposes of this evaluation, *Environmental Benefit* means the positive environmental impact minus the negative environmental impact attained by specific actions including, but not limited to, energy generation and distribution, transmission service, conservation, customer-sited generation, DR, or DSM.

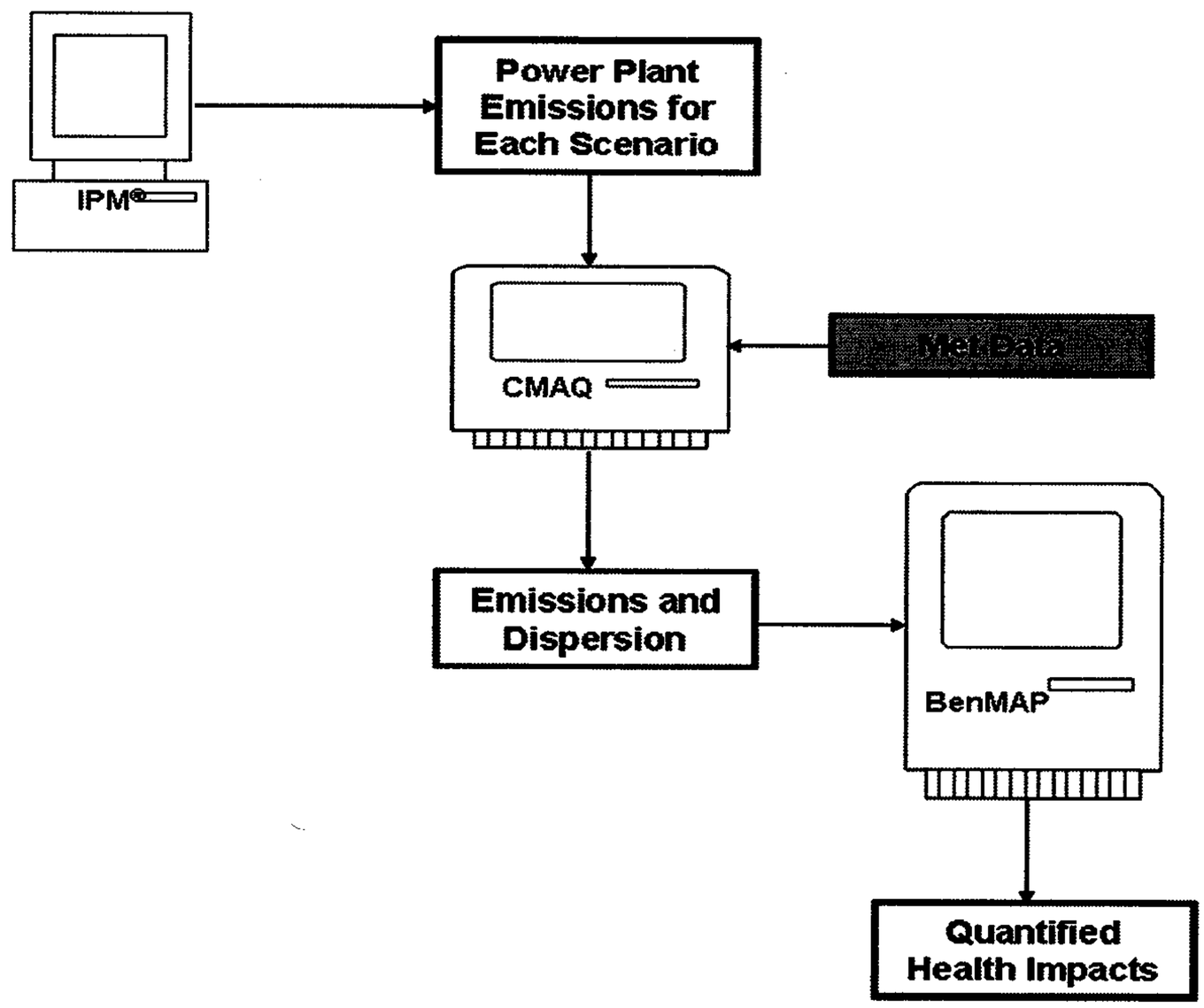
Environmental Impact means the result of an action, outcome or activity related to the IRP, on natural and physical resources including, but not limited to, wetlands, sea levels, fisheries, air quality, water quality and quantity, public health, climate impacts, land masses, and ground water.

Externalities means the social, health, environmental and/or welfare costs or benefits of energy which result from the production, delivery or reduction in use through efficiency improvements, and which are external to the transaction between the supplier (including the supplier of efficiency improvements) and the wholesale or retail customer. Externalities should be quantified and expressed in monetary terms where possible. Those externalities that cannot be quantified or expressed in monetary terms shall nonetheless be qualitatively considered.

i. Evaluation of Health Impacts of PM, Ozone, SO_2, and NO_2

The health impacts associated with PM, ozone, SO_2, and NO_2 are driven by the human inhalation of these pollutants in ambient air. Based on available health effects data, it was clear from the beginning that the health effects for human exposure to PM and ozone would be much higher than the health effects from exposure to SO_2 and NO_2 which are directly emitted from power plants and ozone which is a secondary pollutant formed in part by power plant emissions of nitrogen oxides (NO_x). As a result, the analysis of these pollutants focused on the health effects of PM and ozone exposure. To estimate impacts of PM and ozone on health and mortality (and the associated benefits of reductions in PM and ozone), changes in emissions had to be translated into changes in ambient air quality – primarily in terms of concentrations of $PM_{2.5}$ and ozone. $PM_{2.5}$ is directly emitted from coal, oil and gas-fired power plants and is also formed as a secondary product from the plant's emissions. Ozone is a secondary pollutant that is formed in the atmosphere by a series of reactions involving ultra violet (UV) radiation and precursor emissions of NO_x and volatile organic compounds (VOC). Therefore, it was necessary to account for the transport and dispersion of direct emissions of $PM_{2.5}$ as well as the chemical interactions that form secondary $PM_{2.5}$ and ozone.

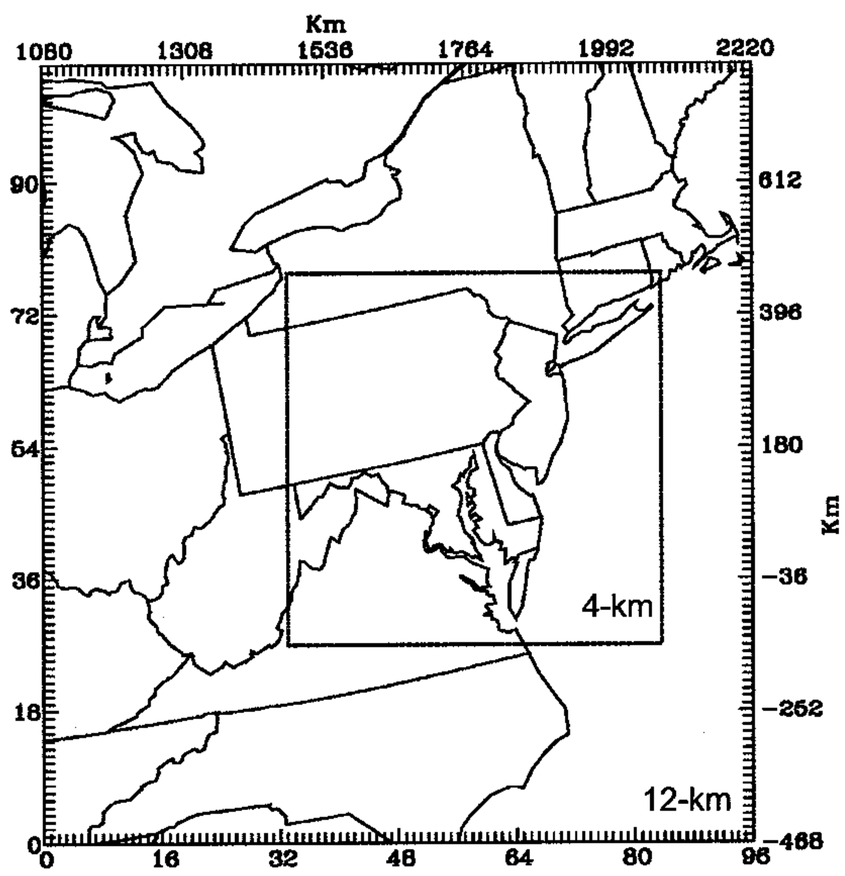
The IPM® modeling provided emission estimates for Delaware of changes in emissions of SO_2, NO_x, and CO_2 from power plants that resulted from the different years of the Reference Case. The IPM® emission estimates were used as input to an air quality model, EPA's Community Multi-scale Air Quality (CMAQ) model, to calculate expected changes to ambient air quality for the pollutants of interest. Based on the CMAQ results, Delmarva/ICF then used EPA's Environmental Benefits Mapping and Analysis Program (BenMAP) program to estimate health and economic benefits for ozone and $PM_{2.5}$ and qualitative methods to estimate health and economic benefits for mercury. This approach is illustrated in the figure below:



BenMAP is a modeling system developed by EPA's Office of Air Quality Planning and Standards to estimate national and regional benefits of air quality health impacts. BenMAP is driven by estimates of $PM_{2.5}$ or ozone levels (based on air quality modeling) and provides estimates of changes in health impacts and associated costs. BenMAP includes population data at census tract level and algorithms for characterizing demographic changes (age distribution) over time through the year 2025.

BenMAP can estimate changes in a wide range of health impact "endpoints" (including mortality and morbidity) that might occur with changes in $PM_{2.5}$ exposure. Mortality endpoints include changes in "all-cause" mortality, as well as mortality due to specific causes, such as cardiovascular disease, cancer, and chronic pulmonary disease. Morbidity endpoints include specific illnesses and symptoms (for example, asthma exacerbations), events requiring medical care (emergency room visits and hospital admissions), and adverse effects that involve lost work or restricted activity days. For each scenario, health endpoints such as premature mortality, hospital admissions, chronic bronchitis, chronic asthma, acute bronchitis, induced asthma, and acute respiratory symptoms were summarized and reported (see Appendix 8).

This approach included several annual applications of the CMAQ model including a 2020 baseline simulation and several alternative emissions scenarios. Version 4.6 of the CMAQ model was used for this study. The model was applied using meteorological inputs for 2001 and for the 12-kilometer resolution and four-kilometer resolution nested-grid modeling domain shown in the figure below.



Graphical and tabular summaries of the modeling results were prepared and the results were post-processed for input to the BenMAP tool. BenMAP was used to estimate the health impacts and economic benefits associated with the changes in air pollution simulated by CMAQ for each of the alternative emissions scenarios.

A full copy of the air quality and health impacts technical report is presented as Appendix 8.

ii. Evaluation of Health Impacts of CO_2 and Hg

Carbon dioxide and mercury emission changes were not evaluated in the BenMAP model. Given the complexities and uncertainties associated with any characterization of climate change and its ultimate impacts, a different, less formal approach was used to capture the health effects

of CO_2. A recent National Academy of Sciences (NAS) report[46] indicated a potential range of health impacts due to CO_2 emissions ranging from $1 to $100 per tonne. As a point of reference, the NAS report used a value of $30 tonne .

For Hg, Delmarva/ICF estimated the overall changes in Hg emissions associated with different scenarios (based on outputs from IPM®) and qualitatively describe the potential impacts of these changes.

In the 2010 IRP, Delmarva Power conducted a life-cycle analysis of several resource options including land based wind, off shore wind, and gas fired generation resources. Because these life cycle evaluations remain relevant and accurate, Delmarva Power did not undertake new life cycle analyses for the 2012 IRP. The 2010 IRP life cycle evaluations are incorporated by reference into this IRP.

[46] The Hidden Costs of Energy: Unpriced Consequences of Energy Production and Use, National Research Council of the National Academies, October 2009

X. The Reference Case Results

In preparing the IRP, Delmarva uses the concept of a "Reference Case" to represent Delmarva's expected view of the future procurement planning environment from 2013 - 2022. The Reference Case provides a structure for the IRP analysis and evaluations and a point of comparison with varying some of the key assumptions supporting the Reference Case.

The IRP Reference Case provides a dynamic view of the expected 2013 – 2022 future state of the electric system within Delaware and PJM. The major assumptions underlying the Reference Case reflect the current state of the overall electric system at the time the IRP modeling analysis is undertaken. For this IRP, the Reference Case reflects pertinent energy related legislation enacted by the Delaware General Assembly since the last IRP was filed in December 2010, the expected energy efficiency and conservation activities conducted by the SEU, expected Federal environmental regulations, and Commission approved renewable power purchase agreements and demand response programs.

The Reference Case provided in the 2012 IRP provides a detailed look at the results of Delmarva's expected future energy procurement practices for the period 2013 – 2022. The key data planning assumptions underlying the view of Delmarva's energy future implied by the Reference Case include the following:

1. The Delmarva load forecast (described in Section IV and Appendix 4);
2. Energy and demand response reduction targets described by the Energy Efficiency Act of 2009 (described in Section V);
3. Various PJM approved transmission system upgrades (described in Section VI);
4. The cost and operating characteristics of supply side resource options (described in Section VII and Appendix 5);
5. Delmarva's plan to procure REC's generated by renewable energy resources in sufficient quantity to meet the annual requirements of the Delaware Renewable Energy Portfolio Standards Act (described in Section VIII); and,

6. The expected implementation and timing of various environmental regulations affecting power generation. These assumptions are described in Appendix 5.

After Delmarva began the modeling efforts to complete the 2012 IRP, the Federal Cross State Air Pollution Rule (CSAPR) which had been scheduled to take effect in 2013, was vacated by the U.S. District Court. At the time that CSAPR was vacated, Delmarva could not restart the IRP modeling and still have the time and resources to meet the December 1, 2012 filing requirements of the IRP[47]. However, because of the potential importance of environmental regulations on the IRP results, Delmarva was able to prepare a sensitivity analysis of the potential impact of the changing environmental legislation. The results of this sensitivity analysis are provided later in this section and in Appendix 5. Delmarva also prepared additional sensitivity analyses around the Reference Case that are described below.

The remainder of this section presents detailed information for the Reference Case and the sensitivity analyses. Information is presented based on the IPM® results and the Portfolio Model results.

IPM® Results

The IPM® model provides detailed information about the expected state of electric power generation over the planning period including, planned generation expansion, generation output, and power plant emissions. A more technical description of IPM® is provided in Appendix 5.

Based on the IPM® analysis, Table 1 below shows the expected generation capacity by generation type in PJM under the Reference Case assumptions for the years 2013- 2022.

[47] December 1, 2012 is a Saturday so Delmarva Power actually filed the IRP on December 3, 2012.

Table 1

Expected Capacity (MW) by Resource Type

PJM RTO

	2013	2014	2016	2018	2020	2022
Coal	65,786	64,127	64,096	63,744	63,744	63,744
Combined cycle	25,359	25,924	29,525	31,162	34,928	37,962
Oil/Gas other	8,139	7,036	6,528	6,528	6,528	5,710
Hydro	7,433	7,433	7,468	7,468	7,468	7,468
Nuclear	33,707	33,707	33,707	33,707	33,057	33,057
Renewable	9,943	10,836	12,084	12,920	13,712	14,296
Biomass Gas	1	1	1	1	1	1
Biomass Residues	86	86	86	86	86	86
Biomass Solids	356	356	356	356	356	356
Cogen - Biomass	171	171	171	171	171	171
Cogen - Biomass Gas	30	30	30	30	30	30
Cogen - Landfill	20	20	50	50	50	50
Cogen - Other	109	109	109	109	109	109
Fuel Cell	18	30	30	30	30	30
Landfill	651	651	781	799	841	841
Solar PV	1,528	1,991	3,065	3,883	4,633	4,735
Steam - Other	489	489	489	489	489	489
Wind	6,482	6,901	6,915	6,915	6,915	7,397
Turbine	31,033	31,012	30,160	32,016	32,828	36,833
Total	181,400	180,075	183,567	187,546	192,266	199,070

Table 1 indicates that while the overall installed generation capacity in PJM is expected to increase by almost 18 GW from 2013- 2022, the change in the installed generation capacity by type of generation varies greatly. The amount of installed coal fired generation capacity is expected to decline by about 2 GW while the installed capacity of gas fired combined cycle (CC) technology is expected to increase over 12 GW. Land based wind generation capacity also increases by almost a GW and solar photovoltaic resources increase over 3 GW.

Corresponding to the PJM installed capacity illustrated in Table 1, Table 2 provides the expected annual energy by generation (GWH) resource type for 2013 – 2022.

Table 2

Expected Generation (MWH) by Resource Type

PJM RTO

	2013	2014	2016	2018	2020	2022
Coal	409,626	397,344	406,954	424,026	431,009	435,238
Combined cycle	127,012	137,694	151,112	154,986	180,908	199,767
Oil/Gas other	153	378	158	156	154	154
Hydro	16,339	16,544	16,884	16,969	16,969	16,969
Nuclear	261,532	261,623	259,433	257,730	255,884	254,542
Renewable	31,127	34,771	37,636	38,869	40,181	41,715
Biomass Gas	7	7	7	7	7	7
Biomass Residues	684	684	684	684	684	684
Biomass Solids	1,372	2,704	2,756	2,760	2,760	2,760
Cogen - Biomass	1,352	1,354	1,354	1,354	1,354	1,354
Cogen - Biomass Gas	237	237	237	237	237	237
Cogen - Landfill	158	158	368	368	368	368
Cogen - Other	861	861	861	861	861	861
Fuel Cell	82	242	250	250	250	250
Landfill	4,589	4,589	5,645	5,793	6,137	6,137
Solar PV	1,970	2,573	4,073	5,154	6,121	6,267
Steam - Other	3,869	3,869	3,869	3,869	3,869	3,869
Wind	15,947	17,494	17,533	17,533	17,533	18,921
Turbine	5,686	7,211	6,564	7,472	8,213	8,243
	-	-	-	-	-	-
Total	**851,475**	**855,566**	**878,741**	**900,207**	**933,317**	**956,628**

Total generation in PJM is expected to increase about 105,000 GWh over the planning period. Most of this increase comes from gas fired combined cycle generation (over 73,000 GWh), coal (almost 16,000 GWh) and renewables (over 10 GWh). While coal *capacity* decreases in PJM over the planning period due to retirement of older less efficient units, the remaining environmentally compliant units produce more *energy*.

Tables 3 and 4 below show the expected capacity (MW) and generation (GWH) for the Delmarva Zone for 2013 – 2022.

Table 3

DPL Zone Expected MW Capacity by Resource Type 2013 – 2022

DPL Zone

	2013	2014	2016	2018	2020	2022
Coal	601	436	436	436	436	436
Combined cycle	1,090	1,090	1,399	1,399	1,399	1,399
Oil/Gas other	734	734	734	734	734	734
Renewable	66	119	195	245	292	298
Fuel Cell	18	30	30	30	30	30
Landfill	16	16	29	29	29	29
Solar PV	32	57	107	157	202	208
Land Based Wind	-	16	30	30	30	30
Turbine	1,037	1,037	1,037	1,037	1,037	1,037
Other (Including Steam Turbines)	-	-	-	-	-	-
Total	3,528	3,415	3,801	3,851	3,897	3,903

Table 4

DPL Zone Expected GWH Generation by Resource Type 2013 – 2022

DPL Zone

DPL Zone Generation (GWh)	2013	2014	2016	2018	2020	2022
Coal	2,682	2,014	2,090	2,266	2,325	2,372
Combined cycle	2,898	2,901	3,946	3,937	3,933	3,403
Oil/Gas other	-	217	-	-	-	-
Renewable	234	472	688	753	818	826
Fuel Cell	82	242	250	250	250	250
Landfill	111	111	215	215	222	222
Solar PV	41	72	137	201	260	268
Land Based Wind	-	47	86	86	86	86
Turbine	1,082	1,126	735	695	818	771
Other (Including Steam Turbines)	-	-	-	-	-	-
Total	6,896	6,731	7,460	7,652	7,895	7,371

An attractive feature of the IPM® is that in preparing these generation forecasts, the model is able to keep track of power plant emissions. IPM® is able to track carbon dioxide (CO_2), sulfur dioxide (SO_2) and nitrous oxide (NO_x) emissions associated with each year of the Reference Case. As discussed in Section IX and Technical Appendix 8, the changes in power plant emissions between 2012 and 2023 for the Reference Case form the basis for the evaluation of environmental benefits.

Table 5 and Table 6 below show the expected total emissions for the Reference Case for both PJM and the DPL Zone based on the Reference Case.

Table 5

PJM

Emissions from Power Plants (Mtons)

	2013	2014	2016	2018	2020	2022
CO_2	468,318	459,652	476,327	493,985	511,868	523,679
SO_2	1,000	628	579	597	597	595
NO_X	325	302	257	270	277	280

Table 6

DPL

Emissions from Power Plants (Mtons)

	2013	2014	2016	2018	2020	2022
CO_2	4,691.27	4,193.34	4,882.17	4,450.71	4,571.98	4,358.14
SO_2	9.70	3.90	4.07	4.39	3.64	3.33
NO_X	3.25	2.42	2..06	2.06	2.17	2.08

As indicated in Table 5, the total amount of SO_2 and NO_x emissions created by power plants in PJM are expected to decrease significantly by 2022 in the Reference Case. The total amount of CO_2 in PJM, however, increases by about 11% over the IRP planning period in the Reference Case. Table 6 indicates that, in the DPL Zone, the total amount of SO_2 and NO_x emissions from power plants is expected to drop significantly from 2013 to 2022. Overall CO_2 emissions in the DPL Zone fall about 7% over the IRP planning period in the Reference Case.

Table 7 below shows the expected energy prices for the DPL Zone for the Reference Case.

Table 7 Expected DPL Zone Energy Prices 2013 – 2022

(Confidential)

DPL Zone

[redacted]	2013	2014	2016	2018	2020	2022
PJM-DPLN	42.81	43.51	46.00	53.49	54.70	55.08
PJM-DPLS	46.78	47.63	50.18	58.21	59.53	59.99

[redacted]	2013	2014	2016	2018	2020	2022
PJM-DPLN	32.60	33.64	35.97	41.46	42.43	42.46
PJM-DPLS	36.28	37.46	39.85	45.48	46.62	46.77

Note: Peak hours start at 7:00 am and end at 10:59 pm Monday through Friday.

Portfolio Model Results

In order to evaluate expected energy prices and price stability, Delmarva Power uses a Portfolio Model with inputs from the IPM® and other sources. Based upon market volatility, the Portfolio model simulates 1,000 possible price outcomes per year for Delmarva Power's expected portfolio of full service and renewable energy projects for SOS customers over the planning period. A detailed description of the Portfolio Model is provided in Appendix 6.

Based on the results of the Portfolio Model, Table 8 below shows the expected mean energy prices in nominal dollars for Residential and Small Commercial (RSCI) and Commercial (LC) customers for the Reference Case compared with the sensitivity cases for selected planning years. The sensitivity cases include a low and high gas case reflecting a range of possible natural gas prices. The CC case represents the addition of a hypothetical 300 MW gas fired combined cycle generating facility in Delaware.

Table 8 Expected SOS Supply Costs RSCI and LC SOS Customers (Confidential Material Omitted)

Average Costs and Risks of Electricity Procurement for DPL as Expected in August 2012		
	RSCI Total Average Costs ($/MWh)	**LC Total Average Costs ($/MWh)**
Planning Year 2013		
Reference Case	$[redacted]	$[redacted]
Reference Case - High Gas	$102.05	$82.66
Reference Case - Low Gas	$91.81	$52.03
Planning Year 2015		
Reference Case	$[redacted]	$[redacted]
Reference Case - High Gas	$109.84	$85.04
Reference Case - Low Gas	$78.15	$54.39
Planning Year 2017		
Reference Case	$122.06	$84.67
Reference Case - High Gas	$139.83	$102.34
Reference Case - Low Gas	$104.29	$67.01
Reference Case and CC	$111.16	$76.83
Planning Year 2019		
Reference Case	$141.22	$96.20
Reference Case - High Gas	$160.92	$115.78
Reference Case - Low Gas	$121.53	$76.63
Reference Case and CC	$124.35	$84.01
Planning Year 2022		
Reference Case	$161.96	$106.74
Reference Case - High Gas	$183.18	$127.70
Reference Case - Low Gas	$140.75	$85.78
Reference Case and CC	$140.94	$91.57

Table 8 indicates that for RSCI SOS customers under the Reference Case, energy supply prices are expected to rise after 2015 after falling from 2013 to 2015. For RSCI SOS customers under the Reference Case, the 2013 expected supply cost is $[redacted] per MWH, which is projected to rise to $161.96 in 2022. For LC SOS customers, the corresponding supply prices are $[redacted] and $106.74, respectively. A primary reason for this increase in energy prices is the expected increase of natural gas prices in the later years of the IRP planning period. Within this Table, the combined cycle sensitivity case improves the performance of the Reference Case portfolio.

Table 9 presents a projection of retail customer energy supply rates for Residential and MGT customers for the period 2013 through 2018. The projections are based on the Reference Case.

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Table 9: Customer Energy Supply Rate Projections

(Confidential Material Omitted)

Planning Year	Residential Rates (Tariff "R")				MGT-S Rates			
	Demand ($/KW)		Energy(Cents/kWh)		Demand ($/KW)		Energy(Cents/kWh)	
	Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter
Currently Effective			9.55	9.56	11.7	7.4	4.01	4.96
2013/14	-	-						
2014/15	-	-						
2015/16	-	-						
2016/17	-	-	11.53	11.47	12.7	7.8	4.31	5.19
2017/18	-	-	12.45	12.34	13.8	8.5	4.68	5.64

In order to evaluate price stability, Delmarva prepared an analysis using the Portfolio Model showing the expected range of prices for the Reference Case and the sensitivity cases over the planning period. Figure 1 below shows a graphical comparison of the results of this analysis.

Figure 1

Risk Ranges for RSCI FSA, With and Without CCs

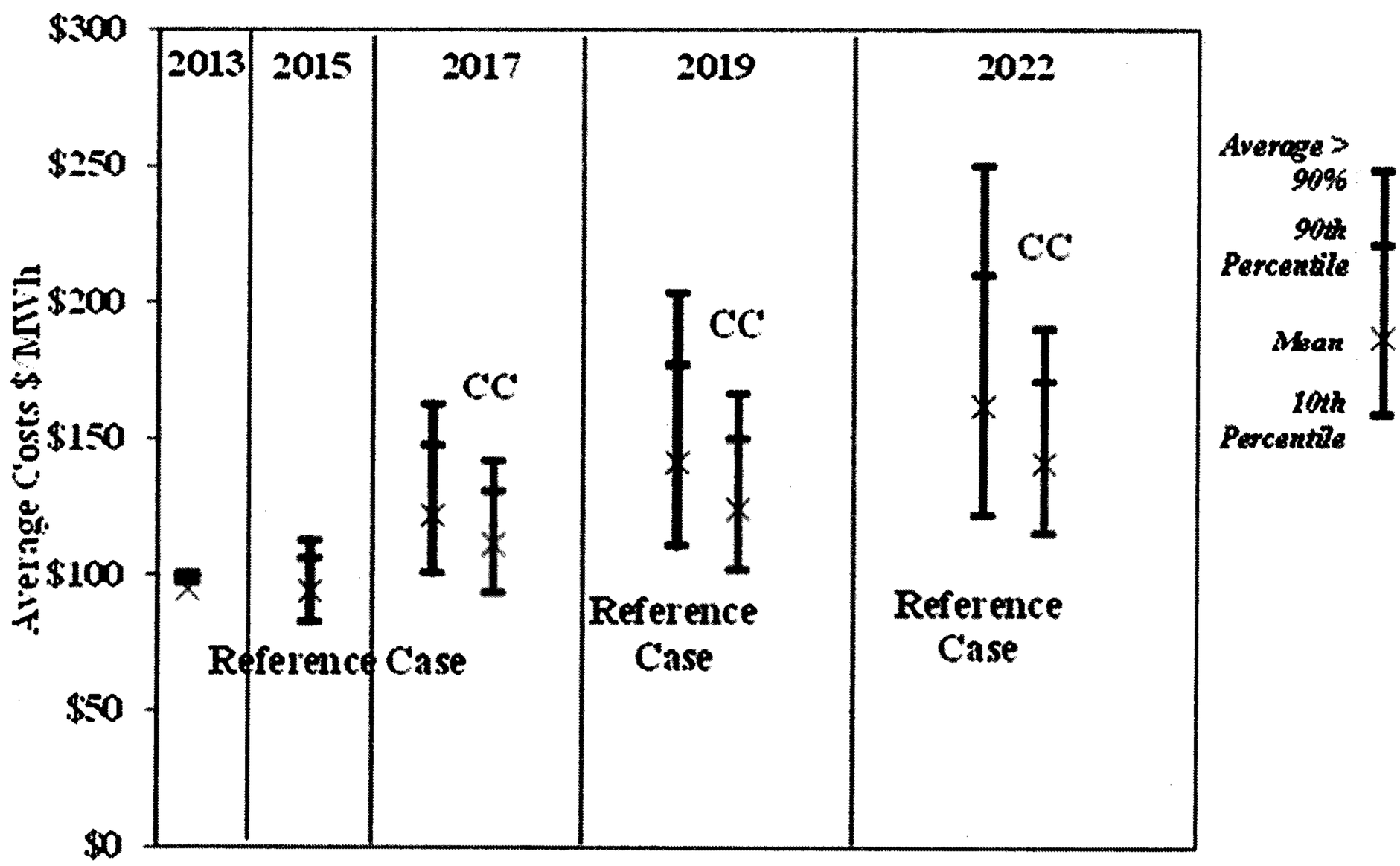

Figure 1 includes bars in red for the net costs of the FSA portfolio if a gas CC were added to the Reference Case supply portfolio, beginning in 2017. This is assumed to be a 300 MW CC with cost and performance characteristics equal to those used for a new CC in the recent PJM Net CONE study. In Figure 1, 10% of the possible price outcomes for that case occur above the "top" of each line and 10% occur below the "bottom" of the line. The cross mark in between the top and bottom shows the average across all potential outcomes. Figure 1 shows that the expected range of prices is increasing over time for the Reference Case. The lower positions and shorter lengths of the red bars (FSA with a CC) in Figure 1 indicate that the inclusion of a new CC with the FSA portfolio (under the assumed terms) drives down both the average cost and the risk range in each future year. This finding is consistent with the recent expansion of CC market development in Delaware and elsewhere in PJM.

The impact of off-shore wind on the Reference Case supply portfolio was derived from estimates of the terms of the Cape Wind project in Massachusetts.[48] This is an approximately 468 MW facility located in Nantucket Sound 4-11 miles off Cape Cod, intended to come online in 2016. It will include about 130 3.5 MW turbines, expected to cost around $5,600/kW and projected to operate at around a 37% capacity factor, with $30-$50/MWh for O&M expenses. A portion of its output is under a 15- year contract to National Grid for its Massachusetts customers, which begins at around $187/MWh in 2013 $, then grows annually at 3.5%. The levelized nominal price over the period 2013-2027 is equal to $230.40/MWh with tax credits and $261.60/MWh without[49]. The net costs are determined by starting with these gross cost and performance parameters from Massachusetts, then taking out the average energy prices and capacity value that such a plant would earn in Delaware under the projected PJM environment in the Reference Case. These net costs are $161 to $192 per MWh of expected output. Since these are well above zero, including any amount of such power in the FSA portfolio would raise its average price. For instance, if 150MW of such output was added to the FSA RSCI portfolio, these net costs of $161/MWh would add $78.6 million of annual costs, for a net increase of $33.80/MWh to the RSCI customers' average price.

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[48] Response to the Petition of Massachusetts Electric Company and Nantucket Electric Company d/b/a National Grid for approval by the Department of Public Utilities of amended power purchase agreements between National Grid and Cape Wind Associates, LLC., DPU 10-54, p. 11, 13.
[49] Idem, p. 10, 13.

A hypothetical utility-scale solar PV resource was also evaluated. It was assumed that this technology would cost around $3,500 per kW to construct and install, based on a 20 MW facility of single-axis PV panels in Delaware, capable of a 15% capacity factor. This results in revenue requirement (gross) costs that are quite high, approaching $400 to $450/MWh. About $120/MWh of these gross costs can be offset with market energy and capacity sales, but the resulting net costs, measured in REC prices needed to breakeven are still quite large – over $280/MWh. This is larger than the net costs of offshore wind. Because of this, a 20 MW facility would cause about a $3.2/MWh increase in FSA RSCI costs.

Environmental Health Impacts and Benefits

Based upon the environmental health impact and benefit assessment, air quality within the Mid-Atlantic States and the State of Delaware is expected to improve from 2013 to 2022. Tables 10 and 11 present emission inventory totals for the Mid-Atlantic states and the State of Delaware, respectively, for 2013 and 2022. The expected reductions in emissions between 2013 and 2022 are due to implementation of emission control technologies required by state and federal rules, the closure of older facilities, fleet turnover of on-road motor vehicles and off-road equipment, the introduction of cleaner engine technologies, and the use of cleaner fuels, such as natural gas.

Table 10

Emission Inventory Totals (tons/yr) by Sector for the 2013 Base Case and 2022 Reference Case for the IRP Modeling for the Mid-Atlantic States (New Jersey, Pennsylvania, Maryland, D.C., Delaware, and Virginia).

Pollutant	Sector	2013 Base Case	2022 Reference Case
NOx	EGU*	135,606	129,190
	Non-EGU/Point	161,304	159,026
	Non-point	162,173	161,700
	Non-road	302,452	253,926
	On-road Vehicle	448,253	167,917
SO_2	EGU	286,423	285,404
	Non-EGU/Point	201,114	195,277
	Non-point	160,541	160,472
	Non-road	35,113	37,725
	On-road Vehicle	3,998	4,004
Hg	EGU	1.8259	0.6434
	Non-EGU/Point	4.7052	5.2918
	Non-point	0.9741	1.0194

* EGU = Electric Generating Units

Table 11

Emission Inventory Totals (tons/yr) by Sector for the 2013 Base Case and 2022 Reference Case for the IRP Modeling for the State of Delaware.

Pollutant	Sector	2013 Base Case	2022 Reference Case
NOx	EGU*	2,492	1,524
	Non-EGU/Point	4,678	4,678
	Non-point	3,265	3,253
	Non-road	15,144	15,173
	On-road Vehicle	11,893	4,334
SO_2	EGU	9,702	3,332
	Non-EGU/Point	11,530	11,530
	Non-point	5,797	5,796
	Non-road	3,315	3,672
	On-road Vehicle	112	110
Hg	EGU	0.0265	0.0229
	Non-EGU/Point	0.5395	0.5423
	Non-point	0.0166	0.0182

* EGU = Electric Generating Units

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Figures 2a through 2c present emissions estimates by source sector for the State of Delaware for the Reference Case for NO_x, SO_2, and Hg. The figures present the expected reduction in these emissions between 2013 and 2022. They also illustrate the portion of overall emissions from the Electric Generating Units (EGU) sector.

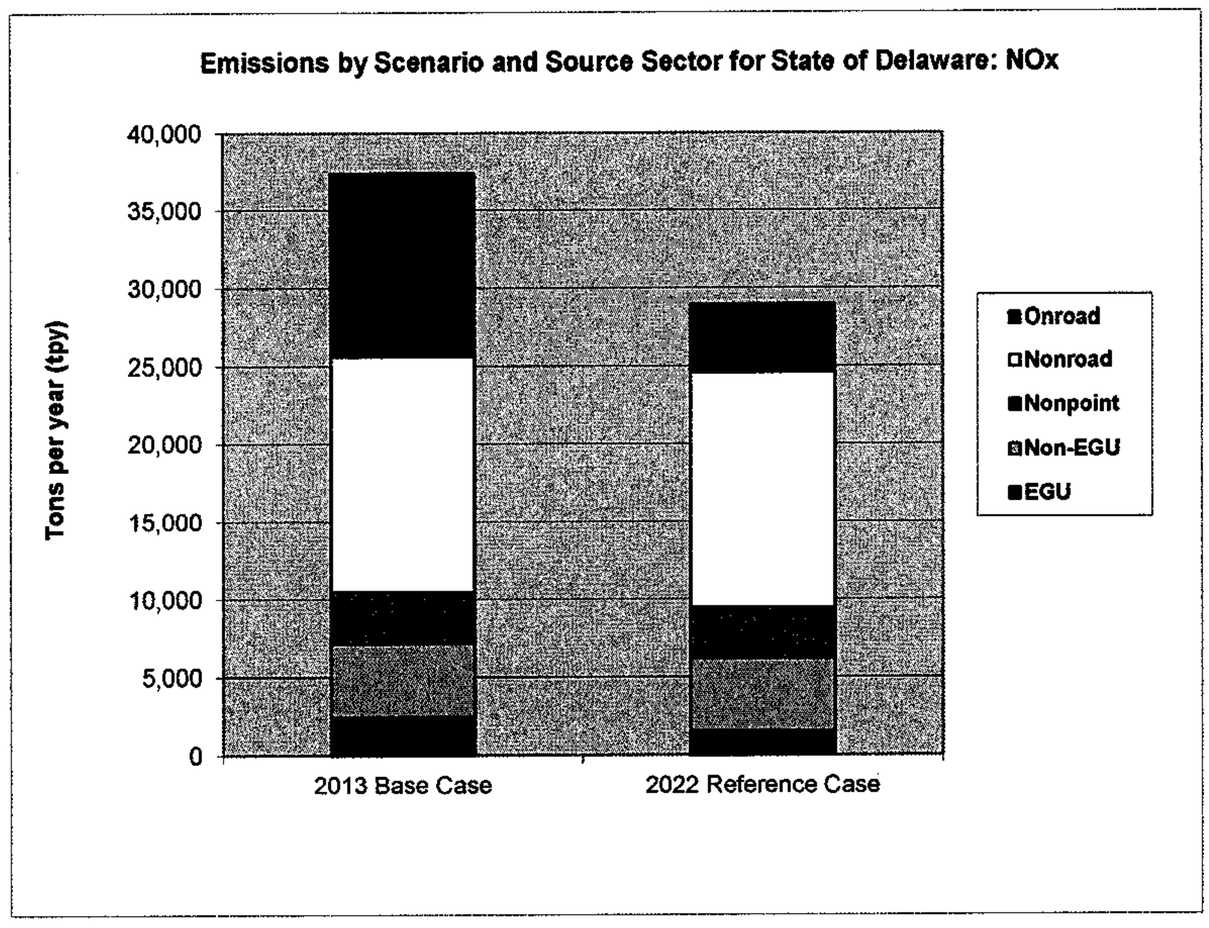
Figures 2a, 2b, 2c

Emission Totals by Source Category for the State of Delaware for the IRP Modeling Analysis

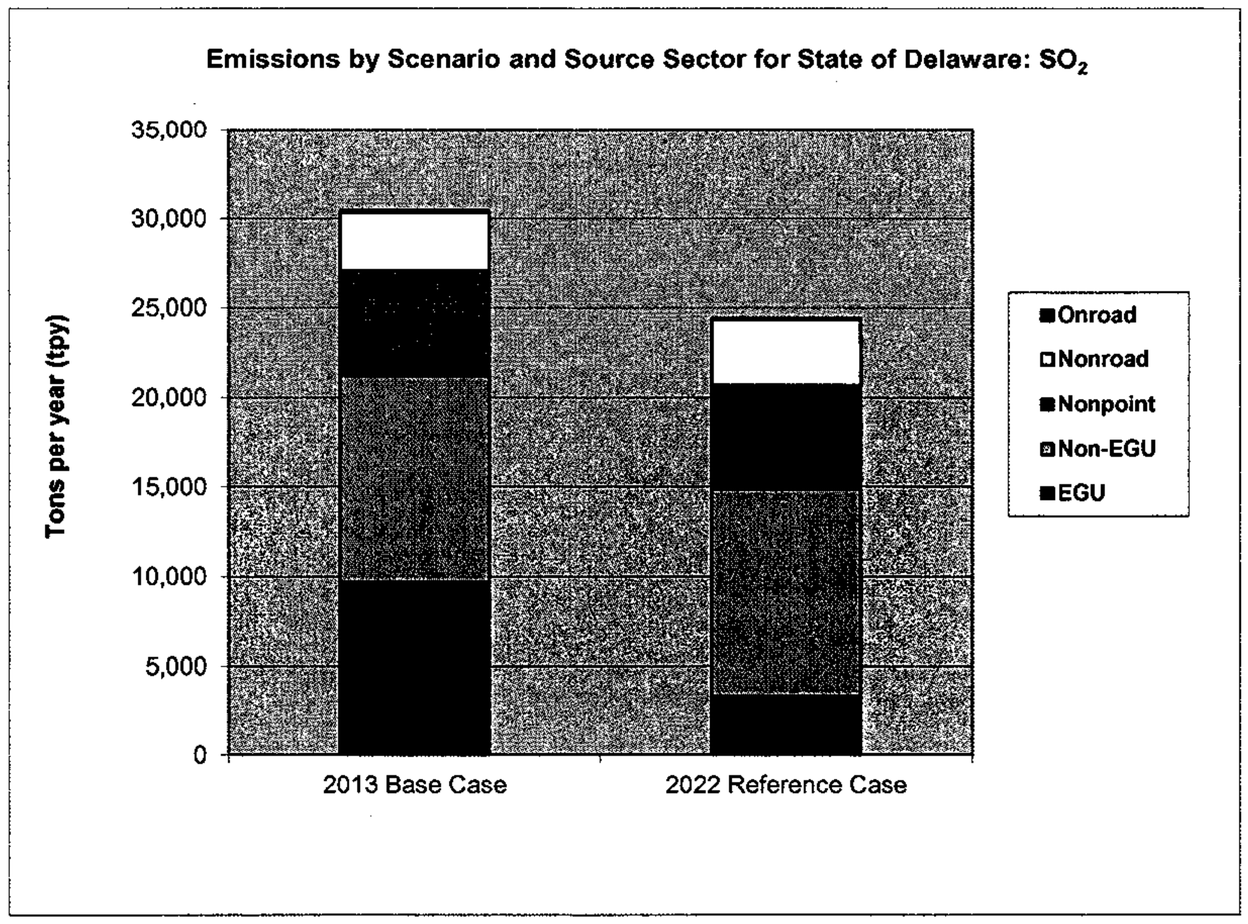
2013 Base, 2022 Reference Case,: NO_x, SO_2 and Hg

(a) NO_x (b) SO_2 (c) Hg

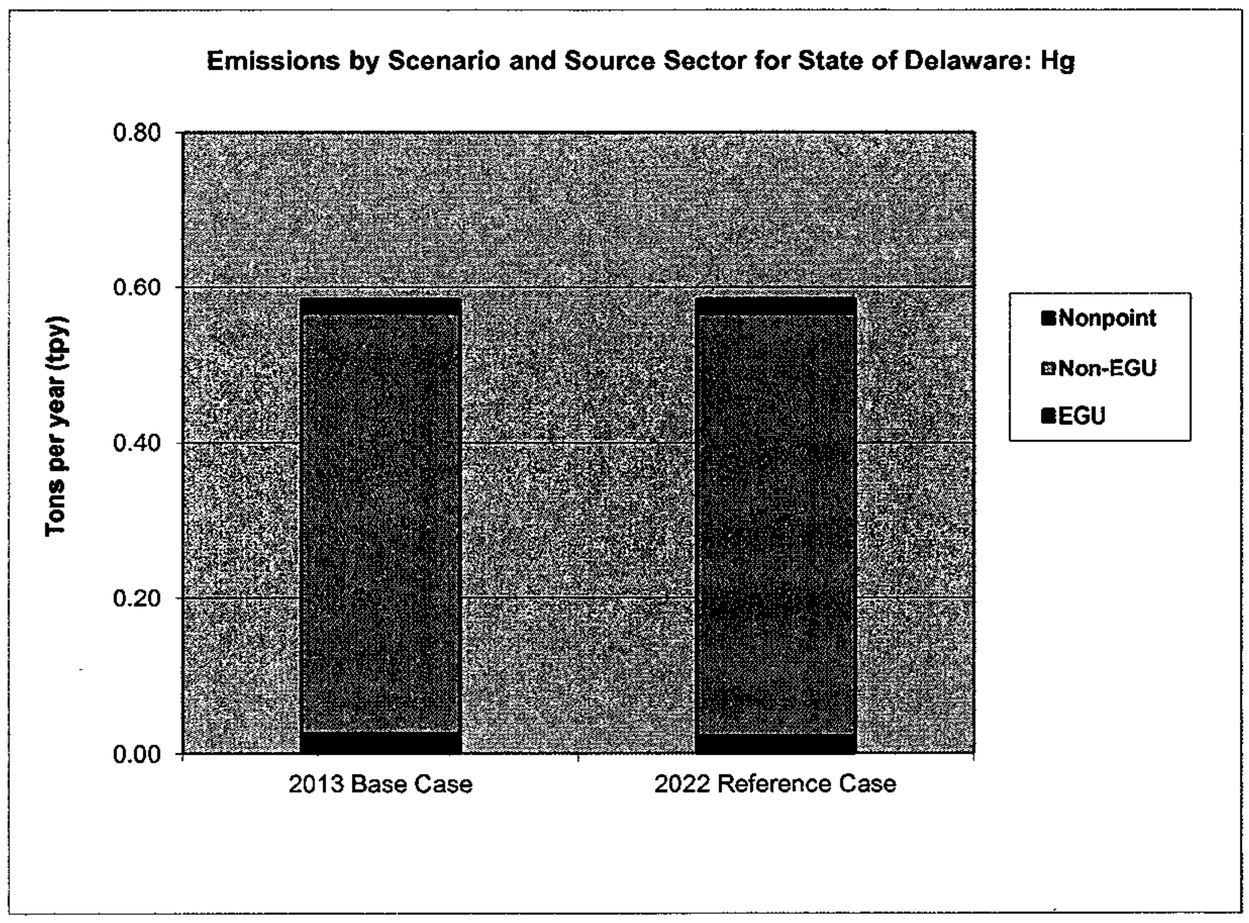
(2a)



(2b)



(2c)



The change in power plant emissions over time can be used to evaluate the change in ozone and particulate matter ($PM_{2.5}$) that affects air quality and impacts human health in Delaware. Using environmental modeling tools developed by the US Environmental Protection Agency (EPA) and available in the public domain, Delmarva Power estimated the human health impacts for the

Reference Case comparing 2013 with 2022. The methods and procedures of the analysis are described in Section IX and Appendix 8 of the IRP.

Due to the uncertainty surrounding the preparation of the estimated impact of changes in air quality on human health, the estimates are presented as a range of values as opposed to a single value. Table 12 below shows the estimated range of monetized human health benefits, derived from the EPA models, that is expected to occur for Delaware as a result of the improved air quality in the Reference Case from 2013 to 2022.

Table 12

. Total BenMAP-Derived Monetized Health-Related Benefits for $PM_{2.5}$ and Ozone (Millions $2010 U.S. Dollars/Year) Associated with the Changes in Air Quality from 2013 to 2022.

	Delaware	
	High End	Low End
2013–2022		
PM-Mortality (Laden, 3% discount rate)	1,800	
PM-Mortality (Pope, 7% discount rate)		630
PM-Morbidity	45	45
Ozone-Mortality (Levy)	300	300
Ozone-Morbidity	6	6
Total	*2,151*	*981*
Total (2 significant figures)	2,200	980

More detailed $PM_{2.5}$ Mortality estimates are presented in Appendix 8 based upon a number of expert studies. In Table 12 only the highest value (Laden) and lowest value (Pope) are presented.

The estimated human health benefits arising from the Reference Case by 2022 shown in Table 5 are very significant. These results are affected by the expected changes in power plant emissions that can be attributed to a number of factors including:

- The expected operation of over 12 GW of new gas fired generation and retirement of about 2 GW of coal fired resources in PJM by 2022,
- Expected reductions in emissions from remaining coal generation,
- Increases in the expected implementation of renewable resources within Delaware and other Mid-Atlantic regions (including Delmarva Power's renewable resource portfolio),
- Ongoing demand side management activity including the implementation of smart grid technology and associated dynamic pricing and load control programs.

These factors, as well as other factors not related to power generation resources, contribute to improving air quality and human health over the 10 year planning horizon. More details on this analysis are provided in Appendix 8.

Effect of change in US EPA Regulations

On July 6, 2011, the US Environmental Protection Agency (EPA) finalized the Cross-State Air Pollution Rule (CSAPR). CSAPR requires upwind states to reduce power plant emissions that contribute to ozone and/or fine particle pollution in other downwind states. The IRP Reference Case assumed that CSAPR would be in effect during 2013 – 2022.

However, on August 21, 2012, a three judge panel of the U.S. Court of Appeals for the District of Columbia struck down CSAPR. On October 5, 2012, EPA sought a re-hearing of the case before the entire US Appeals Court for the District of Columbia. Delaware was included in the group of 10 states and various cities petitioning in favor of the re-hearing.

At the time of the CSAPR decision, the IRP analysis was already well underway and the resource planning and air quality modeling could not be started anew if Delmarva were to meet the December 2012 IRP filing requirement. However, due to the potential impact of CSAPR on the future resource mix, prices and air emissions, Delmarva Power has prepared a sensitivity case on the expected resource mix and air emissions with and without CSAPR. Detailed results of this sensitivity are provided in Appendix 5 and the new assumed environmental regulations underlying this sensitivity are provided in Appendix 10. In the Sensitivity Case it is assumed that CAIR continues as currently designed followed by more stringent SO_2 and NO_x requirements starting in 2018.

Table 13 presents a comparison of the expected PJM capacity (MW) while Table 14 presents the associated generation (GWH) by resource type for this Sensitivity Case.

Table 13: Expected Total Capacity (MW) by Type – PJM Wide

Capacity Types	2013	2014	2016	2018	2020	2022
Coal	66,627	65,186	64,136	63,736	63,736	63,736
Combined cycle	25,359	25,924	29,525	31,355	35,241	38,383
Oil/Gas other	8,139	7,036	6,528	6,528	6,528	5,710
Hydro	7,433	7,433	7,468	7,468	7,468	7,468
Nuclear	33,707	33,707	33,707	33,707	33,057	33,057
Turbine	31,033	31,012	30,160	31,992	32,729	36,959
Renewable	9,941	10,835	12,083	12,919	13,711	14,275
Wind	6,482	6,901	6,915	6,915	6,915	7,377
Solar PV	1,528	1,991	3,065	3,883	4,633	4,735
Landfill	671	671	831	849	891	891
Biomass	644	644	644	644	644	644
Other	598	598	598	598	598	598
Fuel Cell	18	30	30	30	30	30
Total	**182,239**	**181,133**	**183,607**	**187,705**	**192,470**	**199,588**

Table 14: Expected Generation (GWh) by Type – PJM Wide

Capacity Types	2013	2014	2016	2018	2020	2022
Coal	414,484	407,087	410,812	421,652	428,312	432,254
Combined cycle	125,461	135,004	149,815	156,879	183,554	202,894
Oil/Gas other	153	375	156	156	154	154
Hydro	16,405	16,566	16,969	16,969	16,969	16,969
Nuclear	261,532	261,623	259,433	257,730	255,884	254,542
Turbine	5,437	7,013	6,547	7,518	7,966	8,128
Renewable	31,128	34,770	37,603	38,870	40,181	41,640
Wind	15,947	17,494	17,533	17,533	17,533	18,846
Solar PV	1,970	2,573	4,073	5,154	6,121	6,267
Landfill	4,747	4747	6013	6161	6505	6505
Biomass	3652	4984	5004	5042	5042	5042
Other	4,730	4,730	4,730	4,730	4,730	4,730
Fuel Cell	82	242	250	250	250	250
Total	**854,600**	**862,438**	**881,335**	**899,774**	**933,020**	**956,581**

Overall, the impact on coal generation and capacity on a PJM-wide basis is minor in comparison to the Reference Case (see Tables 1 and 2 above). In 2013, the projections indicate a very small increase in coal generation. Although the CSAPR would have potentially had stronger near-term impact on prices, the impact on generation is somewhat mitigated by 1) the expectation of continued relatively low gas prices (i.e. strong gas on coal competition); 2) relatively low expected demand growth; and 3) the significance of the MATs ruling on the operation of continued facilities leading into the 2015/2016 period.

Table 15 presents the emissions by type in the Sensitivity Case.

Table 15: Emissions by Type (Mtons) – PJM Wide

Emissions by Type	2013	2022
CO_2 (Mtons)	472,042	521,560
NO_x (Mtons)	331	269
SO_2 (Mtons)	1,272	586

Consistent with the differences in the capacity and generation outlook, there is little change anticipated due to the vacature of CSAPR under this sensitivity. However, it is anticipated that the installation or operation of control equipment in the very near term may differ. For example, facilities may operate their SCRs at lower levels or not operate seasonally at all if under caps. In the very near-term, this has some impact on NO_x and SO_2 emissions from the facilities within PJM, however, there is negligible difference in the long-term.

Appendix 1
2012 Delmarva Power Intergrated Resource Plan
Regulation Compliance Matrix

	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 IRP was filed on the first business day of the month, Monday, December 3, 2012.
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 this IRP and who will be available for responding to inquiries during the Commission's review of this IRP are provided in Appendix 2 of this IRP.
4	General 1.6	Confidential utility documents shall be presented under separate seal.		Confidential documents related to this IRP were presented to the Commission, Staff, DPA and DNREC under separate seal. Due to the timing of the filing of this 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	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 Section 1 of 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, 2012.
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 Monday, December 3, 2012.
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 web site and shall update these materials on the Company's web site 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 3, 2012.
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 III, V, VI, VII, VIII, and Appendices 5,6, and 7	model (IPM®) to evaluate the optimal combination of demand and supply side resources within PJM, including the Delmarva Zone. The IPM® uses the most recent PJM Regional Transmission Expansion Plan (RTEP) to characterize the expected future transmission grid. Supply side resources are described in Section VII and the IPM® is described more fully in Appendix 5. The RTEP is described in Section VI and demand side resources are described in Section V.
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.	IRP Section VIII, X and appendix 6	The Reference Case of the IRP 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 several alternate scenarios including additional off shore wind, solar and gas fired resources.
13	General 3.1.3	The IRP shall provide for a regulatory, stakeholder, and public input into the development of the IRP in accordance with normal Commission policies and practices.		An IRP Working Group, composed of representatives of Delmarva, Commission Staff, DPA, DNREC, the Caesar Rodney Institute, and other interested parties has met on numerous occasions to review and discuss key topics related to developing the 2012 IRP. The topics have included the load forecast, transmission planning, generation interconnection, Reference Case assumptions, and planned sensitivity analysis among other issues. Public workshops on the IRP are expected to be scheduled after the 2012 IRP is filed.
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 8083 in January, 2012. which ratified the IRP filed by Delmarva on December 1, 2010 and approved the Path Forward settlement agreement. Since that time, the IRP Working Group has met a number of times to discuss updated information and assumptions.
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 Section 1 of 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	Plan objectives and measures are described in the Executive Summary of the IRP. Each objective has measures ascribed to them. The major models used in developing the 2012 IRP include IPM® , Portfolio Model, CMAQ, and BenMAP. These models are used singly or in combination to simulate expected generation expansion, long term wholesale prices, price and price stability, and the health effects of incremental changes in 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.	IRP Section IV and Appendix 4	The load forecast is described in Section IV of the IRP. The forecast provides "high" and "low" forecast ranges as compared to the "baseline" forecast. The load forecast documentation is described in Appendix D.??

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 VII, Appendix 5	in Section VII and Appendix 5 of the IRP. Key assumptions for the Reference Case are provided in Sections VII and X of the IRP. The IRP presents information for the ten year planning period 2013-2022.
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.	Section X, Appendix 6	The IRP evaluates, as appropriate, the potential impact on price, price stability, and environmental benefits through sensitivity analyses relating to alternative load forecasts, DSM savings, natural gas prices and additional renewable and fossil fueled generation resources. This analysis is described more fully in Section ?? of the IRP.
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.	Executive Summary, IRP Section II and III	The process for the development of the IRP is described in detail in Section III. Discussions around the IRP process have taken place at the workshops with the other stakeholders.
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.	IRP Section X, Appendix 6	The results of various risk and sensitivity analyses around key parameters is described in Section X and Appendix 6 of the 2012 IRP.
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.	IRP Section IV and Appendix 4	DPL's IRP Reference Case load growth forecast is based on historical data and estimates of future DSM activity. More Detailed documentation of the load forecast is provided in 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.	IRP Section IV and Appendix 4	DPL's IRP Reference Case load growth forecast includes both winter and summer peak demand for Delmarva Delaware Load as shown in Appendix 4.
26	Load Forecast 4.1.2	The Company's load growth forecasts shall include Delmarva Delaware SOS load by customer class.	IRP Section IV and Appendix 4	DPL's IRP Reference Case load growth forecast includes a breakdown by customer class.
27	Load Forecast 4.1.3	The Company's load growth forecasts shall include weather adjustments, including consideration of climate change potential.	IRP Section IV and Appendix 4	DPL's IRP Reference Case load growth forecast 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).	IRP Section IV and Appendix 4	DPL's IRP Reference Case load growth forecast includes 5 year historical loads as shown in Appendix 4
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.	IRP Section IV 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 load 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.	IRP Section IV and Appendix 4	DPL's IRP Reference Case load growth forecast includes a description of the process the Company used to develop these forecasts as shown in the DE IRP Demand Forecast Documentation provided as Appendix 4.
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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.	IRP Section III and X and Appendix 6	The IRP process to develop the 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:	IRP Sections III,IV,V,VI,VII, VIII, IX	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;	IRP Section III	The IPM® 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;	IRP Section IX and Appendix 8	A detailed environmental analysis is provided in the IRP.
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 2012 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 2012 IRP.
38	Resource Portfolio Options 5.2.5	Resources that promote Fuel Diversity;	IRP Sections IX, X, and Appendix 6	The IRP contains an analysis of additional solar and wind resources.
39	Resource Portfolio Options 5.2.6	Resources or facilities that support or improve reliability; or	IRP Section III, VI, and Appendix 7	The IRP shows that there are sufficient generation resources to meet the expected load forecast over the IRP planning horizon.
40	Resource Portfolio Options 5.2.7	Resources that support or improve price stability.	IRP Section X, Appendix 6	The IRP contains a detailed evaluation of a number of alternative effects on price and price stability.
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, IRP Section VI and Appendix 7	The IRP includes a description of the transmission investments made since the last IRP and planned transmission investments needed to maintain reliability.
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. The contract for 200 Mw of Blue Water Wind, included in previous IRPs was not included in the 2012 plan.
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.	IRP Section V	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 V 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.	IRP Section V	Delmarva Power contracts to curtail. A description of on-going and past SEU activities is provided in Section V 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.	IRP Section V	Under the Solar REC Procurement Pilot Program approved by the Commission, Delmarva has 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.	IRP Section III, X	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.	IRP Section III, IV, V and X	The IPM® model provides an integrated planning platform. The savings targets from the Energy Efficiency Act of 2009 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.	IRP Sections III, V, IX and Appendix 8	These factors are considered in the IPM® , the DSM evaluations and the environmental analyses.
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.	Appendix 5, 10	The IRP provides a sensitivity analysis to show the impact of changes in Federal environmental legislation, high and low natural gas prices and different resource mixes.
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).	Appendix 9	This information is provided in Appendix 9.
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.	IRP Sections III, IX, Appendix 8	The IRP includes a current evaluation of the environmental benefits associated with the Reference Case.
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 2012 IRP incorporates the life-cycle impact analysis completed and filed as part of the 2010 IRP by reference.
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.	IRP Sections V, IX, X and Appendix 8	The IRP includes a current evaluation of the environmental benefits associated with the Reference Case. The environmental externality analysis does not assume that satisfying the EERS adequately addresses externalities.
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, IRP Section X, Appendix 6, Appendix 9	The IRP provides information on expected energy prices, customer rates, and RPS compliance costs over the planning period. The portfolio model analysis provides a range of possible future outcomes of SOS costs and sensitivity analysis is used to examine options to mitigate the risks associated with the recommended procurement strategy.

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.	Appendix 6	natural gas prices.
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.	IRP Section X and Appendix 6	The IRP contains sensitivity analyses on the Reference Case including changing environmental assumptions
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.		DPL submitted a copy of the 2012 IRP to DNREC on Monday, December 3, 2012.
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, IRP Section X, and Appendix 6	The IRP provides an evaluation of the potential change in energy costs and customer rates in accordance with the factors set forth in Section 5.2.
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, IRP Sections III, VII, VIII, X and Appendices 5 and 6	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 9	The forecast of supply rates is provided in Appendix 9. Forecast supply rates for 2013 - 2015 are considered confidential until the completion of the 2013 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 2010 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 their progress in implementing their IRPs.		The Company provided a report on the status of the IRP to the Commission, Governor and General Assembly in December 2011 and will provide a new report on or before December 31, 2012.
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 3, 2012.
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, 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 RFP will be stored and [illegible] for inspection and audit as needed.

Delmarva Power & Light Company
Appendix 2
Responsible Parties – 2012 Integrated Resource Plan (IRP)

Name	IRP Area of Expertise
Jack Barrar	IRP Process
Jaclyn Cantler	Transmission
Kemm Farney	Load Forecast
Todd Goodman	Regulatory and Legal Counsel
Frank Graves[1]	Portfolio Model; Risk Analysis
Jay Haney[2]	Air Quality Modeling
James Jacoby	Customer Rates
Lisa Pfeifer	Environmental
Maria Scheller[2]	IPM® Model
Stephen Sunderhauf	Demand Side Management
William R. Swink	Portfolio Design & Renewables Supply

[1]The Brattle Group
[2]ICF International

Appendix 3

This Appendix contains a copy of the first four pages of Delaware Public Service Commission Order No 8083 and a copy of the proposed Settlement Agreement in Docket 10-2 (the "Path Forward"). Order No 8083 approved most, but not all, of the provisions of the Path Forward.

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)	)	PSC DOCKET NO. 10-2

ORDER NO. 8083

AND NOW, this 10th day of January, 2012:

WHEREAS, on December 1, 2010, Delmarva Power & Light Company ("Delmarva") filed with the Delaware Public Service Commission ("the Commission") its Integrated Resource Plan ("IRP") as required under the Electric Utility Retail Customer Supply Act of 2006 ("EURCSA"), 26 *Del. C.* §1006 *et seq.*; and

WHEREAS, on or before May 31, 2011, the Public Service Commission Staff ("Staff'), the Division of the Public Advocate ("DPA"), the Department of Natural Resources and Environmental Control ("DNREC"), the Caesar Rodney Institute ("CRI"), NRG Energy ("NRG"), Calpine Corporation ("Calpine"), Mid-Atlantic Renewable Energy Coalition ("MAREC"), the Delaware Energy Users Group ("DEUG"), the Sierra Club ("Sierra Club") and the Retail Energy Supply Association ("RESA") filed comments on the IRP; and

WHEREAS, two interested non-intervenor participants - the Delaware Nurses Association and John Greer, Jr., P.E. - also filed comments on May 31, 2011; and

WHEREAS, on or before July 29, 2011, Delmarva filed a reply to the comments submitted by the aforementioned participants; and

WHEREAS, the designated Hearing Examiner deemed evidentiary hearings and briefing unnecessary; and

WHEREAS, on November 17, 2011, while the matter was pending before the Hearing Examiner, Delmarva, Staff, the DPA and the CRI reached an agreement entitled "Path Forward on Delmarva Power & Light Company's Integrated Resource Plan ("IRP"): Joint Proposal to Ratify PSC Docket No. 10-2 ("Path Forward");" and

WHEREAS, after consideration of the letters from the public, the discussions of the workshops held to consider the IRP, the comments filed by the parties and Delmarva's Reply Comments, the Hearing Examiner held that there was ample evidence to find that the requirements for public investigation and comment had been satisfied under 26 *Del.C.* §3010.9.2; and

WHEREAS, the Hearing Examiner submitted her Findings and Recommendations on November 22, 2011 recommending that the Commission ratify the IRP pursuant to 26 *Del. C.* §3010.2.0 as reasonable and in the best interests of Delaware ratepayers; and

WHEREAS, the Hearing Examiner further recommended that the Commission approve the proposed Path Forward as just and reasonable and in the public interest; and

WHEREAS, DNREC, MAREC, NRG and RESA filed exceptions to the Hearing Examiner's Findings and Recommendations; and

WHEREAS, the Commission met in open session on December 20, 2011 to consider the participants' arguments and exceptions;

NOW, THEREFORE, BY THE UNANIMOUS VOTE OF THE COMMISSIONERS, IT IS HEREBY ORDERED:

1. That, except as expressly set forth in the following ordering paragraphs, the Commission adopts the Findings and Recommendations of the Hearing Examiner, appended to the original hereof as Attachment "1," specifically her finding that the "Proposed Path Forward on Delmarva Power & Light Company's Integrated Resource Plan ("IRP"): Joint Proposal to Ratify PSC Docket No. 10-2" provides a mechanism for the parties and interested persons to improve upon the 2010 IRP, address specific concerns raised by the commentators to the current IRP and provide mandatory meetings to discuss and evaluate studies, scenarios and inputs for the next IRP to be filed on or before December 1, 2012.

2. That the Commission explicitly rejects that portion of the Hearing Examiner's Findings and Recommendations and Paragraph 4 of the "Proposed Path Forward on Delmarva Power & Light Company's Integrated Resource Plan ("IRP"): Joint Proposal to Ratify PSC Docket No. 10-2" to the extent that they suggest that Delmarva Power & Light Company is not required to file a new IRP every two years. We read 26 *Del. C.* §1007(c)(1) to require Delmarva to file an IRP every two years after the date of the first IRP on December 1, 2006. The statute is silent as to whether that IRP can be an "update," as the Path Forward suggests. We are not suggesting that Delmarva may not use existing models and studies if they are still relevant and accurate, but merely stating that unless the General Assembly amends Section 1007(c)(1), a full IRP is required every two years.

3. That the Commission ratifies the Integrated Resource Plan, appended to the original hereof as Exhibit "A" to the Hearing

Examiner's Findings and Recommendations, as filed in compliance with the Electric Utility Retail Customer Supply Act of 2006 ("EURCSA"), 26 *Del. C.* §1006 *et seq.*

4. That the Commission approves all other portions of the "Proposed Path Forward on Delmarva Power & Light Company's Integrated Resource Plan ("IRP"): Joint Proposal to Ratify PSC Docket No. 10-2," appended to the original hereof as Exhibit "B" to the Hearing Examiner's Findings and Recommendations.

5. That 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

/s/ Joann T. Conaway
Commissioner

/s/ Jaymes B. Lester
Commissioner

/s/ Dallas Winslow
Commissioner

/s/ Jeffrey J. Clark
Commissioner

ATTEST:

/s/ Alisa Carrow Bentley
Secretary

Path Forward on Delmarva Power & Light Company's Integrated Resource Plan ("IRP")
Joint Proposal to Ratify PSC Docket No. 10-2

The undersigned parties believe that Delmarva Power has met the requirements for ratification of the IRP. The Commission Staff ("Staff"), the Division of the Public Advocate ("DPA"), Caesar Rodney Institute ("CRI") and Delmarva Power & Light Company ("Delmarva" or "DPL") hereby request that the Hearing Examiner recommend that the Commission ratify the current IRP. Staff, DPA, CRI and Delmarva further request that the Hearing Examiner's recommendation provide that future IRPs proceed as set forth in the following proposals:

1. The IRP recommends that DPL continue to manage its supply portfolio in the manner currently approved by the Commission. As needed in the future,D PL will seek Commission approval through separate applications for changes to resources or process(es) to secure resources.

2. A process for stakeholder participation, in the form of an IRP Working Group, will meet at least once a quarter going forward.

3. The written comments of parties to PSC Docket No. 10-2 discuss recommended modifications for the next IRP filing, due in December 2012. An evaluation process for addressing the following modifications will be developed in collaboration with the IRP Working Group:

    a. Changes to load forecasting methods
    b. Additional analyses of DSM
    c. Provide documentation of IRP Scenario selection
    d. Use of an alternative Air Quality model to evaluate human health benefits
    e. More robust discussion of transmission options and interconnection issues
    f. Address the effect on customer bills resulting from the increased use of renewable resources

4. Instead of creating and submitting an entirely new, highly detailed filing every two years, DPL should alternate "new" filings, such as the 2010 IRP, with "updated" filings, where existing models and studies may be updated or additional studies may be added (in a manner compliant with EURCSA) to be defined in the IRP Working Group between now and Delmarva's next IRP filing (December 1, 2012). This modification to the process will allow for improvement to the IRP and IRP process, while avoiding unnecessary additional costs to Delmarva's SOS customers.

The IRP Working Group (or Special Task Team if appropriate) will discuss and collaboratively evaluate the following issues (in priority order):

1. Define "new" vs. "updated" versions of the IRP.
2. Discuss steps to be taken to continue the evaluation and potential implementations of natural gas fired generation on the Delmarva Peninsula, including, but not limited to: evaluation criteria, RFQs, RFPs, accounting issues on future PPAs, and the benefits of regulated versus merchant generation.
3. Assessment of alternatives to DPL's current procurement process for SOS customer supply requirements.

The signatories to this document also agree that the proper forum to initiate a process to consider rule changes to make electric choice more competitive should be through a separate Working Group outside of the IRP Working Group and future IRP Dockets..

/s/ Todd Goodman	/s/ William O'Brien	/s/ Michael Sheehy
Delmarva Power	DPSC Staff	Public Advocate
Caesar Rodney Institute		

Pepco Holdings, Inc

Appendix 4

DPL DE IRP Forecast Documentation

Peak Demand Forecasting

Electric Sales Forecasting

Electric Customer Forecasting

Regional Economics

delmarva power

PHI Economics and Forecasting Group

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I. Introduction

Business Purpose of This Document

This document explains the process used by Delmarva Power and Light Company (DPL) in preparing the projections of electric energy and power demand submitted as part of the Company's Integrated Resource Plan in Delaware. The purpose is to make those projections transparent, so that any interested reviewer will be able to clearly understand the procedures that were used. Throughout these 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 PHI's coverage of regional economic conditions in the state of Delaware and the Metropolitan Statistical Areas representative of the DPL footprint.

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

PHI Economics and Forecasting Group

Chapter V discusses PHI'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 DPL Baseline forecasts for the Delmarva Zone in the PJM transmission area. This forecast has been prepared by PHI 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

Forecasting is an economic activity. A "better," more involved, more complicated, more expensive forecast is only worthwhile if it creates even more value for the organization. In many cases smaller and simpler forecasts work perfectly well for the need at hand.

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 mailed, payments are received—and that documentation is then more or less carefully collated and used by us 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 DPL 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 raises DPL'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 all over 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.

DPL'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 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 H, the standard error of the regression for the regression relationship used to forecast the peak hour demand in the Delmarva Zone is 185 MW, with a historic average peak demand of 2,805 MW (average of monthly peak demand,

1992:6-2012:3). 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 +/-185*2 or +/-370 MW wide. In other words, the width of the confidence interval is roughly 13% 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.1are drawn from PJM's Annual Load Reports. Table I.1 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

DPL Zone	1-Year	2-Year	3-Year	4-Year	5-Year	6-Year	7-Year	8-Year
2011 PJM Unrestricted Forecast	78							
2010 PJM Unrestricted Forecast	(27)	19						
2009 PJM Unrestricted Forecast	12	(48)	68					
2008 PJM Unrestricted Forecast	182	318	310	372				
2007 PJM Unrestricted Forecast	(54)	156	296	294	362			
2006 PJM Unrestricted Forecast	(106)	(90)	140	284	263	333		
2005 PJM Unrestricted Forecast	(42)	43	127	362	527	551	646	
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)
Mean Error ('92-'11)	8.80	-0.05	-6.94	-6.47	-32.38	-74.40	-101.43	-154.31
Standard Error ('92-'11)	81.28	124.44	185.83	243.99	304.99	408.42	488.73	511.14

Based upon our experience, DPL believes that these data are representative of the results that would be reported for other similar forecasts. It has been DPL's experience that utility forecasts are usually unbiased. It has also been DPL'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 DPL'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 the retailer 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 "PHI Forecast System"). The system incorporates the features of the PHI 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. PHI 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 in the model equations having lagged dependent variables among the explanatory 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. The 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 DPL Economics and Forecasting Group's modeling philosophy is the sparing use of lagged dependent variables.

As indicated above, the PHI 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,
- Including a correction for serial correlation.

The PHI 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.

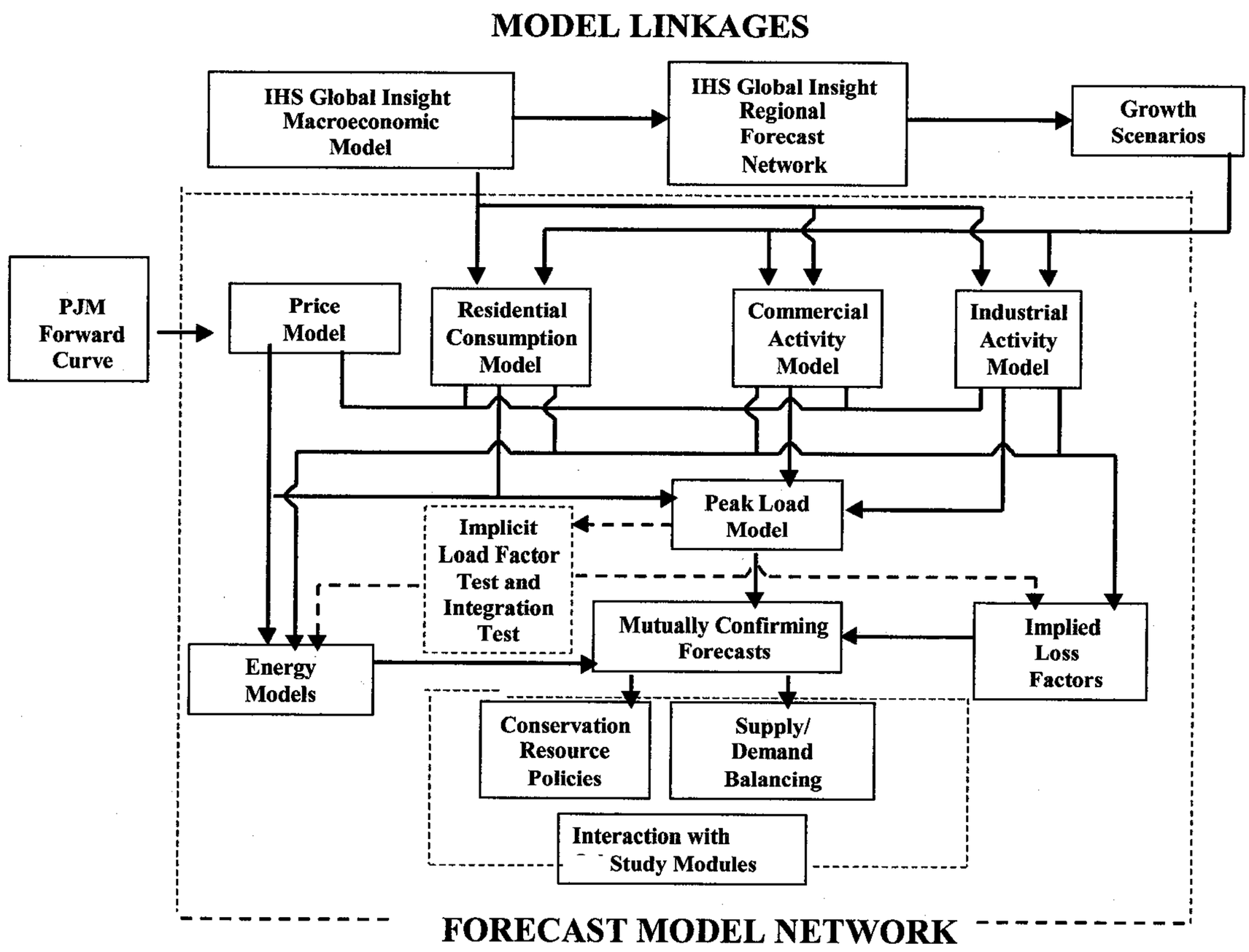
Forecasters too frequently either ignore or treat incorrectly the problem of serially correlated residuals. Correcting for serial correlation through the use of something as simple as appropriate differencing or through the use of a Cochrane-Orcutt or Hildreth-Lu procedure often serves to reduce the standard error of the regression — and hence the standard error of the forecast — dramatically, providing more efficient forecasts.

Of course, the PHI Economics and Forecasting Group employed other criteria as well in judging candidate equations in the construction of the PHI 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 PHI Economics and Forecasting Group's past experience with other models.

PHI's modeling approach for energy demand employs a regional economic activity sub-model to economic growth scenarios for the DPL 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 DPL service areas).

Figure I.1

The PHI 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 expect estimated price elasticities to fall within a

reasonable range consistent with our expectations given economic theory and industry consensus.

II. Assumptions and Data Considerations

PHI prepares its forecasts for DPL 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. 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 DPL DE is collected and reported by NOAA, reflecting conditions at the New Castle County Regional Airport. PHI 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 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 D; a discussion of the Mid Atlantic

economies prepared by the PHI Economics and Forecasting Group is included as Appendix C.

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 assume 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 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 PHI 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) representative of the DPL service territory. The mapping of economic statistics to the service territory is illustrated in Appendix B (maps were prepared by the U.S. Department of Commerce Census Bureau). The Company's analysis has shown that the DPL DE service territory is best represented by local economic activity in the Wilmington and Dover MSA. While DPL 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 spells over into the area 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 Global Insight, and explicitly incorporated into PHI's econometric forecasting models. While employment and income are the richest and most important regional economic concepts to model explicitly, the PHI forecasting team collects economic information on a wide range of concepts to form a comprehensive view of economic conditions in the service territory. Appendix C, the most recent newsletter produced by the PHI Economics and Forecasting Group, illustrates this point.

Last, the group 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 GI forecast. Provided in Appendix D are write-ups associated with the latest GI 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 GI 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 DPL 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

PHI 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, 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, 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 illustrates the real and nominal price history for DPL 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 2011 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

($/kWh, current and 2011$)

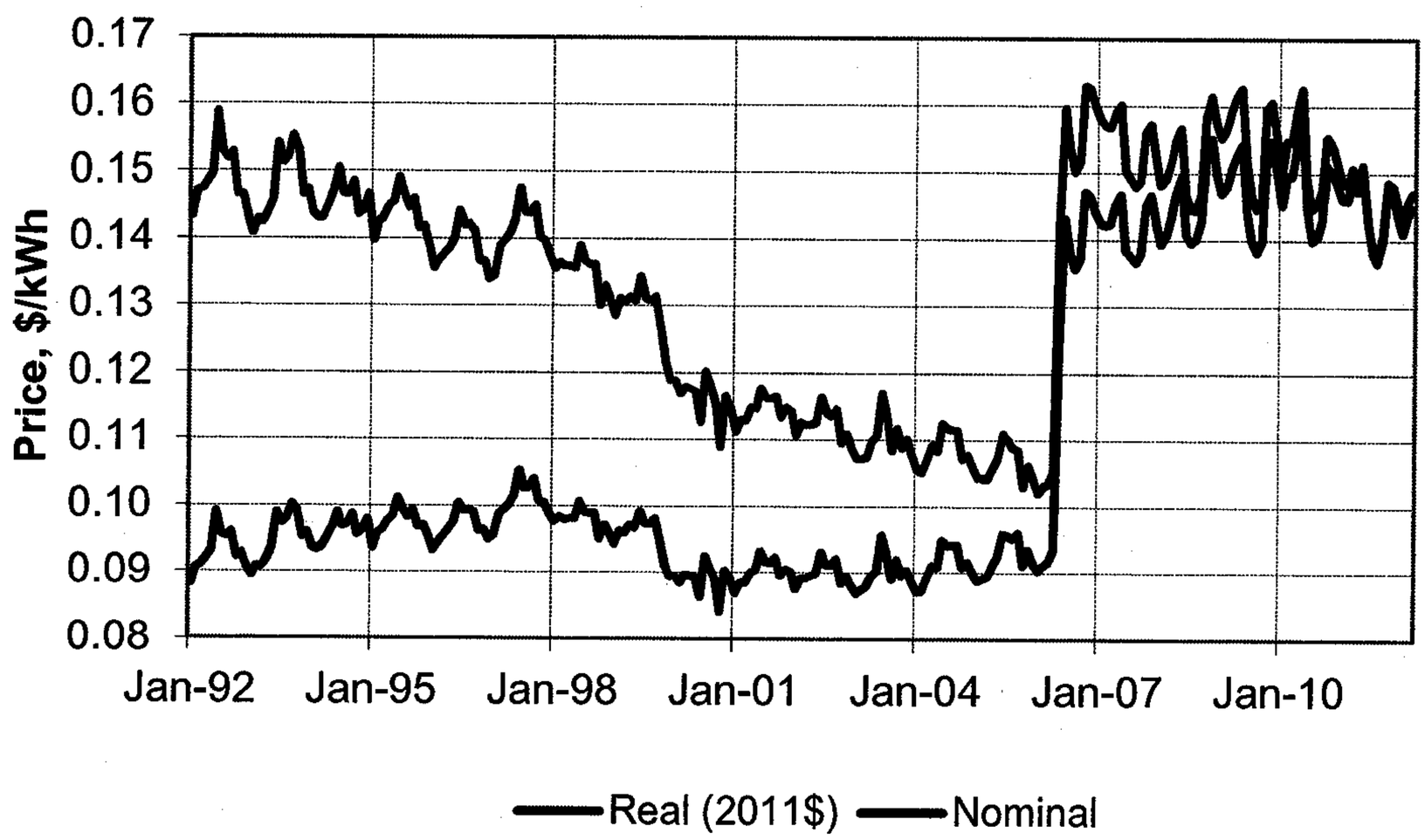


Figure IV.2 illustrates the forecast of real, all in electricity prices used in the DPL DE forecasts. To prepare price projections, the components of the all in price are divided into the commodity portion and the non-commodity portion, consisting of utility taxes,

surcharges and base transmission and distribution charges. Nominal prices are converted to real using the US Consumer Price Index, All-Urban, with prices expressed in 2011 dollars.

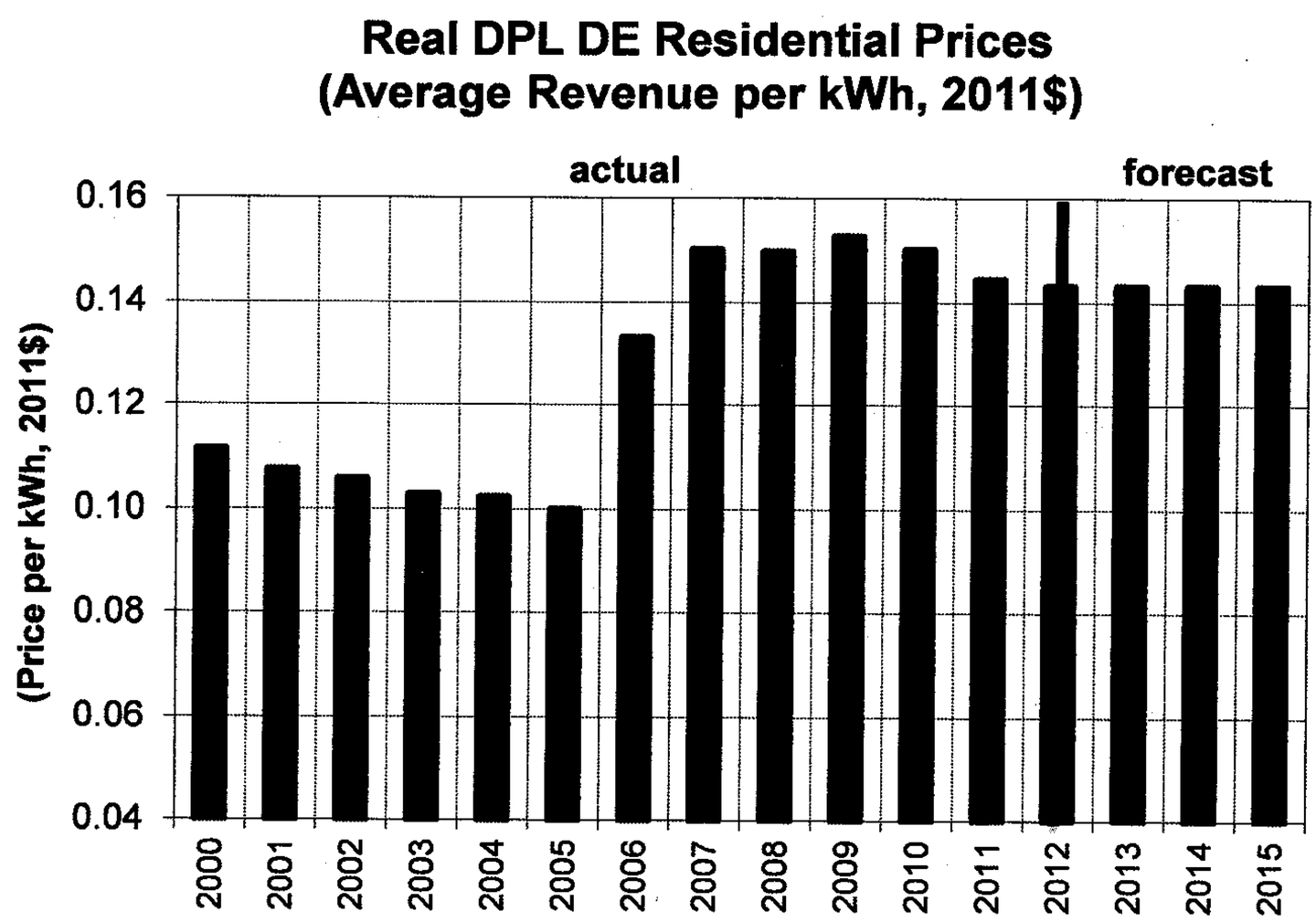
In Figure IV.2 the non-commodity portion of prices is assumed to grow with the rate of general inflation. The commodity component of prices is projected by modeling the supply portfolio.

In DPL DE the supply portfolio is divided into three tranches, and 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

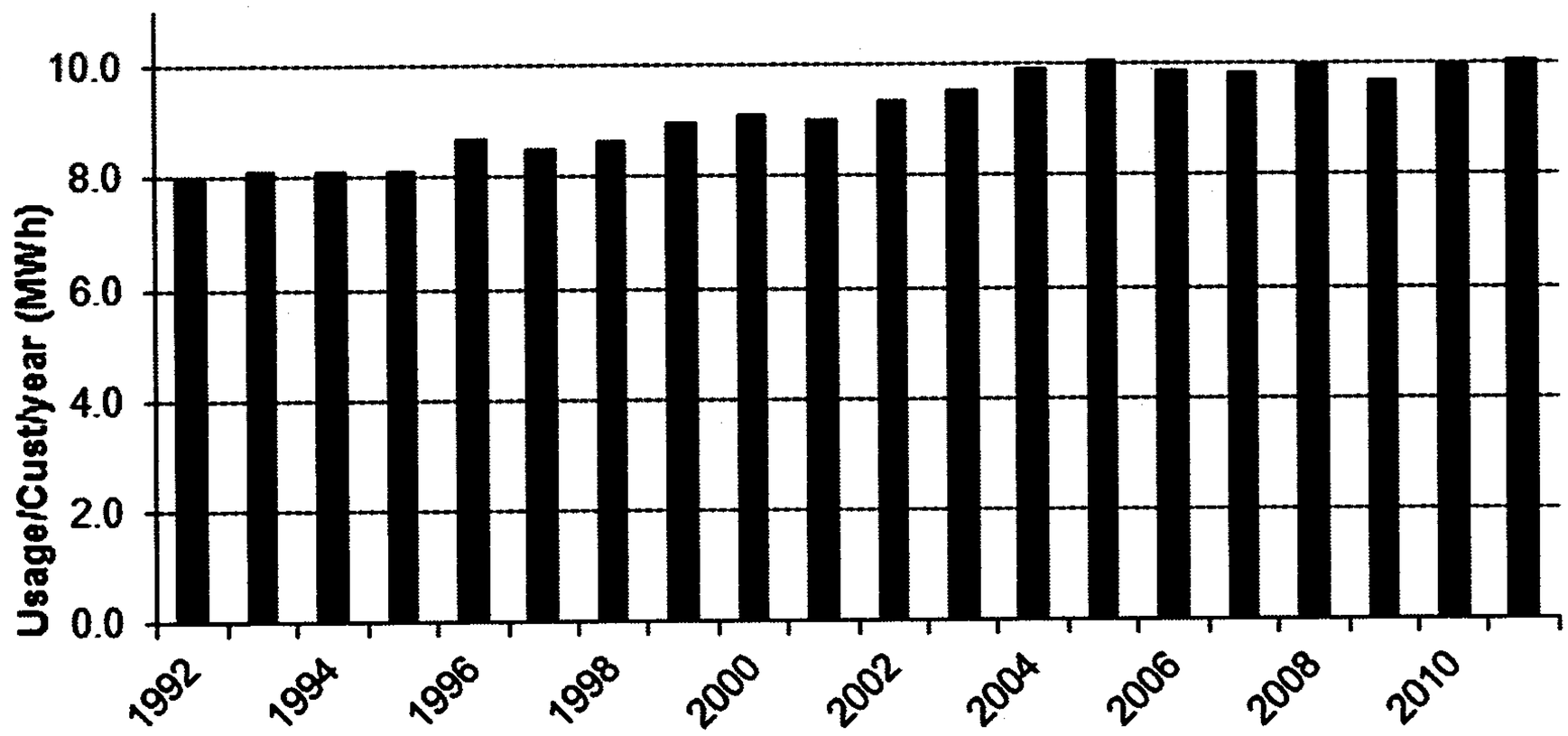
Real Price of Electricity, History and Forecast



By way of comparing historical prices with usage per customer, Figure IV.3 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.

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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; it is the actual historical sales. The forecast period assumes weather will have no effect on sales. 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 DPL 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 weather normals and to support special studies. Wilmington Airport meets this standard. Some alternative Delaware weather stations are shown in the 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

DPL 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 of the daily average dry

bulb temperature in degrees Fahrenheit over 65 for Cooling Degree Days and under 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, 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 this 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 that, 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 .25
- The remaining Degree days of the previous month is multiplied by .75
- The first 15 days of Degree Days of this calendar month is multiplied by .75
- The remaining Degree Days of this calendar month is multiplied by .25
- 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 that there is only a 10% possibility that that these conditions would not be exceeded.

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Weather Normalization Factor Estimation

The procedure for preparing the factors used in weather normalization at PHI 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 are received from the US National Oceanic and Atmospheric Administration (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 2012 study that was completed in December 2011, the summer period was defined as June 2, 2011 through September 30, 2011. The winter period was defined as December 2, 2010 through March 31, 2011. Each equation is examined

carefully for 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 E reports the weather normalized factors estimated for each year for the period 2008-2012.

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. DPL DE Energy Forecast

Introduction

The PHI 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 DPL DE Power Delivery Electric Forecast System explains electricity consumption in one of several revenue classes of sales:

- Residential Non-Space Heating Electric Sales (MWh),

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- Residential Space Heating Electric Sales (MWh),
- Commercial Electric Sales (MWh),
- 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 reports DPL DE electric sales (MWh) by year from 2001 through 2011. 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; growth was only 0.9% in 2011. 37% of residential sales are normally made to the residential space heat class. Finally, in the long run and on average, DPL DE residential electric sales amount to about 86% of DPL DE commercial sales, although the relationship is not constant.

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Table VI.1

DPL DE Historical Electric Sales (MWh)

	Residential Non Space Heat Sales (MWh)	Growth (%)	Residential Non Space Heat Usage (MWh/cust)	Residential Space Heat Sales (MWh)	Growth (%)	Residential Space Heat Usage (MWh/cust)	Total Residential Sales (MWh)	Growth (%)	Commercial Sales (MWh)	Growth (%)	Industrial Sales (MWh)	Growth (%)	Public Street Light Sales (MWh)	Growth (%)	Rsh/Res	Res/Com	Total Sales (MWh)	Growth (%)
2001	1,647,632		9.187	997,223		15.228	2,644,855		3,137,968		3,382,502		42,161		0.38	0.84	9,207,487	
2002	1,771,755	7.5%	9.752	1,004,207	0.7%	15.079	2,775,962	5.0%	3,156,168	0.6%	3,361,101	-0.6%	37,712	-10.6%	0.36	0.88	9,330,943	1.3%
2003	1,771,533	0.0%	9.627	1,094,897	9.0%	16.084	2,866,430	3.3%	3,201,446	1.4%	3,747,812	11.5%	36,072	-4.3%	0.38	0.90	9,851,760	5.6%
2004	1,845,713	4.2%	9.923	1,083,339	-1.1%	15.538	2,929,052	2.2%	3,310,333	3.4%	2,624,287	-30.0%	36,032	-0.1%	0.37	0.88	8,899,704	-9.7%
2005	1,906,492	3.3%	10.076	1,087,307	0.4%	15.388	2,993,799	2.2%	3,451,947	4.3%	2,520,242	-4.0%	36,754	2.0%	0.36	0.87	9,002,741	1.2%
2006	1,892,997	-0.7%	9.886	1,074,100	-1.2%	15.084	2,967,097	-0.9%	3,512,590	1.8%	2,378,548	-5.6%	37,186	1.2%	0.36	0.84	8,895,422	-1.2%
2007	1,898,039	0.3%	9.825	1,040,148	-3.2%	14.485	2,938,187	-1.0%	3,558,184	1.3%	2,357,339	-0.9%	37,549	1.0%	0.35	0.83	8,891,259	0.0%
2008	1,920,777	1.2%	9.968	1,036,251	-0.4%	14.285	2,957,028	0.6%	3,550,363	-0.2%	2,240,707	-4.9%	37,945	1.1%	0.35	0.83	8,786,043	-1.2%
2009	1,864,123	-2.9%	9.680	1,018,853	-1.7%	13.954	2,882,976	-2.5%	3,463,128	-2.5%	1,935,704	-13.6%	37,933	0.0%	0.35	0.83	8,319,741	-5.3%
2010	1,927,194	3.4%	9.986	1,049,097	3.0%	14.135	2,976,291	3.2%	3,513,428	1.5%	1,707,096	-11.8%	38,122	0.5%	0.35	0.85	8,234,937	-1.0%
2011	1,944,406	0.9%	10.080	1,058,871	0.9%	14.162	3,003,278	0.9%	3,496,919	-0.5%	1,812,838	6.2%	36,773	-3.5%	0.35	0.86	8,349,807	1.4%

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 F 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 times 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.

For example, in the equation for residential non space heating sales in Appendix H, the estimated coefficient for the interaction term between heating degree-days and customers is 0.000317. This estimated value indicates that for the typical residential non electric space heat household, an extra heating degree-day will cause the household to consume an additional 316 kWh. The same estimated coefficient for the residential electric space heat class is 0.001468, indicating that an additional heating degree-day causes a residential electric heat customer to increase its consumption by 1,468 kWh.

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 customers 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 customers 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. DPL 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 deal with the industrial customer class. DPL believes the number of industrial customers is not helpful to either electric because there is so much variation in size among the industrial customers.

The DPL 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 reports the number of DPL DE electric customers by year from 2001 through 2011. Prior to the beginning of the Great Recession, total residential customers grew at

approximately 1.5% annually. Since 2008 residential customer growth has slowed dramatically, and growth was only 0.2% in 2011. A fairly constant percentage of residential customers, 28%, are on a space heat tariff. Finally, in the long run and on average, about 8 residential electric customers are needed to support each commercial electric customer, although this ratio has been falling slowly over the past decade.

Table VII.1

DPL DE Historical Electric Customers

	Residential Non Space Heat Customers	Growth (%)	Residential Space Heat Customers	Growth (%)	Total Residential Customers	Growth (%)	Commercial Customers	Growth (%)	Rsh/Resid	Resid/Com
2001	179,349		65,486		244,835		28,909		0.27	8.47
2002	181,678	1.3%	66,598	1.7%	248,276	1.4%	29,567	2.3%	0.27	8.40
2003	184,021	1.3%	68,073	2.2%	252,094	1.5%	30,167	2.0%	0.27	8.36
2004	186,002	1.1%	69,720	2.4%	255,722	1.4%	30,755	1.9%	0.27	8.31
2005	189,217	1.7%	70,660	1.3%	259,877	1.6%	31,328	1.9%	0.27	8.30
2006	191,477	1.2%	71,207	0.8%	262,684	1.1%	31,933	1.9%	0.27	8.23
2007	193,191	0.9%	71,811	0.8%	265,002	0.9%	32,410	1.5%	0.27	8.18
2008	192,699	-0.3%	72,541	1.0%	265,240	0.1%	32,702	0.9%	0.27	8.11
2009	192,578	-0.1%	73,017	0.7%	265,595	0.1%	32,968	0.8%	0.27	8.06
2010	192,984	0.2%	74,219	1.6%	267,203	0.6%	33,111	0.4%	0.28	8.07
2011	192,891	0.0%	74,769	0.7%	267,660	0.2%	33,376	0.8%	0.28	8.02

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 economic activity in the electric service territories.

DPL finds that the most significant determinant of customers is nonfarm agricultural employment, published by the US Bureau of Labor Statistics. The relationship exists because both household formation and in 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, DPL does not forecast the number of industrial customers. The results for each of the regression equations appear as Appendix G to this chapter.

As an example, consider the first equation, RESCUSDE, residential non space heat customers within the DPL DE jurisdiction. The regression equation is estimated using monthly data from January 1991 through April 2012.

The regression contains one economic variable, the sum of total non-farm employment in the metropolitan statistical areas of Wilmington and Dover, lagged 6 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 six months indicates the approximate amount of time before new hiring translates into new residential non space heat customers. Finally, the estimated coefficient of 15.88801 indicates that for every 1,000 new employees hired in the Wilmington and Dover MSAs, DPL DE will add 15.9 residential non space heat customers. Note that the second equation, for residential space heat customers, reports that for every 1,000 new jobs DPL DE also gets 233.6 residential space heat customers. In other words, every 1,000 jobs eventually turns into 259 net new residential customers.

VIII. DPL DE Load Forecast

Introduction

Accompanying the retail energy and customer sub models are models which forecast electricity demand and energy usage at the zonal level (Peak Demand, Net System Output) and retail energy before losses are removed (Gross Retail Output.) Included in Appendix H is Eviews model output documenting the econometric estimates of the relationship between each electricity concept and independent variables deemed theoretically and empirically appropriate.

The three models share similar features modeled as functions of prices, weather, economics, and monthly and accounting dummy variables. Each equation contains an autoregressive term. The differences lie in the appropriate jurisdictional level of variable specification. For example, energy throughput in the Company's Delaware retail jurisdiction, Gross Retail Output, is modeled as a function of the DPL Delaware all in real electricity prices at the retail level. Net System Output and the Zonal Demand, however, use a DPL Zonal jurisdictional all in real price measuring prices more broadly defined and inclusive of the Maryland portion for example. The other example of this asymmetry in variable construction is the geography appropriate for measuring economic impacts. Again the Gross Retail Output forecast incorporates employment at the MSA level for Delaware (Wilmington), while the zonal concepts model the state of Delaware and the MSA representative of the DPL MD portion of the zone (Salisbury).

Table VIII.1 presents the outlook for energy throughput in the Company's Delaware retail jurisdiction. Weather conditions (heating and cooling degree days) are reported in the Wilmington HDD and CDD columns. The next column contains Gross Retail Output or the amount of energy the Company must provide the system before losses to serve the needs of its retail customers. Finally, the Calendar Month Retail Sales column contains annual energy on a Calendar Month basis.

Table VIII.1

DPL Delaware Energy Throughput

	Wilmington HDD	Wilmington CDD	Gross Retail Output (gWh)	Growth (%)	Calendar Retail Sales (gWh)	Growth (%)
2001						
2002	4,475	1,300	9,951		9,452	
2003	5,229	1,003	9,909	-0.4%	9,313	-1.5%
2004	4,911	1,034	9,502	-4.1%	9,014	-3.2%
2005	4,946	1,286	9,676	1.8%	9,233	2.4%
2006	4,372	1,135	9,266	-4.2%	8,709	-5.7%
2007	4,619	1,369	9,485	2.4%	8,856	1.7%
2008	4,590	1,170	9,123	-3.8%	8,767	-1.0%
2009	4,760	988	8,743	-4.2%	8,319	-5.1%
2010	4,642	1,503	8,675	-0.8%	8,471	1.8%
2011	4,654	1,403	8,853	2.1%	8,358	-1.3%
2012	4,176	1,154	8,809	-0.5%	8,581	2.7%
2013	4,176	1,154	9,274	5.3%	8,765	2.1%
2014	4,176	1,154	9,421	1.6%	8,758	-0.1%
2015	4,176	1,154	9,657	2.5%	8,802	0.5%
2016	4,176	1,154	9,794	1.4%	8,845	0.5%
2017	4,176	1,154	9,901	1.1%	8,884	0.4%
2018	4,176	1,154	9,972	0.7%	8,923	0.4%
2019	4,176	1,154	10,032	0.6%	8,962	0.4%
2020	4,176	1,154	10,094	0.6%	8,996	0.4%
2021	4,176	1,154	10,140	0.5%	9,026	0.3%
2022	4,176	1,154	10,178	0.4%	9,055	0.3%
2023	4,176	1,154	10,226	0.5%	9,078	0.3%
2024	4,176	1,154	10,282	0.6%	9,099	0.2%
2025	4,176	1,154	10,347	0.6%	9,121	0.2%
2026	4,176	1,154	10,423	0.7%	9,145	0.3%

Table VIII.2 presents how the energy forecast appears after it is rolled up to the Delmarva zone. Net Sendout is the amount of energy that must be available to the zone in order to serve the needs of all consumers within the zone. Net Sendout is roughly equivalent to the PJM concept Net Energy for Load, except that Net Energy for Load includes the

allocated losses from the shared 500 kV transmission system. It is expected that implied shares and losses will fall within a reasonable range.

Table VIII.2

Delmarva Zone Energy Throughput

	DPL System							
	Wilmington		Net		Gross		Calendar	
			Retail		Retail		Retail	
	HDD	CDD	Sendout (gWh)	Growth (%)	Output (gWh)	Growth (%)	Sales (gWh)	Growth (%)
2001			18,115					
2002	4,475	1,300	18,897	12.5%	14,338		13,620	
2003	5,229	1,003	19,110	1.9%	14,406	0.5%	13,607	-0.1%
2004	4,911	1,034	19,230	0.8%	14,270	-0.9%	13,478	-0.9%
2005	4,946	1,286	19,886	3.4%	14,582	2.2%	13,684	1.5%
2006	4,372	1,135	18,961	-4.7%	13,903	-4.7%	13,058	-4.6%
2007	4,619	1,369	19,576	3.2%	14,222	2.3%	13,262	1.6%
2008	4,590	1,170	18,985	-3.0%	13,720	-3.5%	13,015	-1.9%
2009	4,760	988	18,386	-3.2%	13,267	-3.3%	12,494	-4.0%
2010	4,642	1,503	19,193	4.4%	13,427	1.2%	12,853	2.9%
2011	4,654	1,403	18,820	-1.9%	13,390	-0.3%	12,688	-1.3%
2012	4,176	1,154	18,689	-0.7%	13,320	-0.5%	12,857	-1.4%
2013	4,176	1,154	19,236	2.9%	13,987	5.0%	13,159	3.8%
2014	4,176	1,154	19,433	1.0%	14,221	1.7%	13,155	2.0%
2015	4,176	1,154	19,720	1.5%	14,570	2.5%	13,222	2.3%
2016	4,176	1,154	19,910	1.0%	14,766	1.3%	13,287	2.2%
2017	4,176	1,154	20,057	0.7%	14,923	1.1%	13,345	1.8%
2018	4,176	1,154	20,163	0.5%	15,037	0.8%	13,402	1.6%
2019	4,176	1,154	20,255	0.5%	15,134	0.6%	13,461	1.5%
2020	4,176	1,154	20,345	0.4%	15,227	0.6%	13,512	1.5%
2021	4,176	1,154	20,413	0.3%	15,299	0.5%	13,558	1.3%
2022	4,176	1,154	20,478	0.3%	15,366	0.4%	13,603	1.4%
2023	4,176	1,154	20,559	0.4%	15,443	0.5%	13,641	1.4%
2024	4,176	1,154	20,652	0.5%	15,533	0.6%	13,679	1.3%
2025	4,176	1,154	20,757	0.5%	15,635	0.7%	13,718	1.5%
2026	4,176	1,154	21,182	0.0%	15,753	0.0%	13,760	0.0%

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As shown in Table VIII.3, the 2011 actual summer metered peak demand on the Delmarva Zone was 4,222 MW on July 22, 2011 at 5:00 PM. At the time of the peak demand there were 32 observed cooling degrees, as the ambient dry bulb temperature was 97 degrees Fahrenheit. The official weather normalized metered demand in the Delmarva Zone for the summer of 2011 was 3,974 MW. Adjusting for restrictions at the time of the peak, the unrestricted weather normalized load was 4,070 MW.

Table VIII.3

Delmarva Zone Summer Peak Demand

	Peak Date & Hour	WLM Cooling Degrees	Metered Non-Coincident (MW)	WN Metered Non-Coincident (MW)	Growth (%)	WN Unrestricted Non-Coincident (MW)	Growth (%)
2001	8/9/01 3:00 PM	24	3,611	3,537		3,709	
2002	7/29/02 4:00 PM	29	3,758	3,680	4.0%	3,827	3.2%
2003	8/22/03 5:00 PM	26	3,670	3,801	3.3%	3,811	-0.4%
2004	8/20/04 4:00 PM	21	3,636	3,805	0.1%	3,810	0.0%
2005	7/27/05 5:00 PM	29	4,174	4,010	5.4%	4,070	6.8%
2006	8/3/06 5:00 PM	29	4,288	4,060	1.3%	4,100	0.7%
2007	8/8/07 5:00 PM	30	4,178	3,973	-2.2%	4,130	0.7%
2008	6/10/08 5:00 PM	27	3,971	3,986	0.3%	4,010	-2.9%
2009	8/21/09 3:00 PM	13	3,843	3,960	-0.6%	3,960	-1.2%
2010	7/23/10 5:00 PM	28	4,056	4,018	1.5%	4,050	2.3%
2011	7/22/11 5:00 PM	32	4,222	3,974	-1.1%	4,070	0.5%
2012		26		4,031	1.4%	4,098	0.7%
2013		26		4,070	1.0%	4,138	1.0%
2014		26		4,147	1.9%	4,215	1.9%
2015		26		4,227	1.9%	4,295	1.9%
2016		26		4,319	2.2%	4,386	2.1%
2017		26		4,400	1.9%	4,468	1.9%
2018		26		4,470	1.6%	4,538	1.6%
2019		26		4,542	1.6%	4,609	1.6%
2020		26		4,620	1.7%	4,687	1.7%
2021		26		4,687	1.5%	4,754	1.4%
2022		26		4,756	1.5%	4,824	1.5%
2023		26		4,826	1.5%	4,894	1.5%
2024		26		4,899	1.5%	4,966	1.5%
2025		26		4,985	1.8%	5,053	1.7%
2026		26		5,065	1.6%	5,132	1.6%
2027		26		5,152	1.7%	5,220	1.7%

Table VIII.4 provides winter peak demand information for the Delmarva Zone. For the 2010/11 winter heating season, the actual zone peak of 3,385 MW occurred on January, 24 2011 at 8:00 AM. The weather normalized winter load was 3,350 MW.

Table VIII.4

Delmarva Zone Winter Peak Demand

	Peak Date & Hour	WLM MWHD	Metered Non-Coincident (MW)	WN Metered Non-Coincident (MW)	Growth (%)
2000/01	12/28/00 7:00 PM	41	2,917	3,088	
2001/02	2/5/02 8:00 AM	46	2,875	2,892	-6.3%
2002/03	1/24/03 8:00 AM	53	3,413	3,083	6.6%
2003/04	1/16/04 8:00 AM	55	3,398	3,122	1.3%
2004/05	1/28/05 8:00 AM	64	3,486	3,240	3.8%
2005/06	12/14/05 7:00 PM	43	3,180	3,180	-1.9%
2006/07	2/6/07 8:00 AM	55	3,603	3,360	5.7%
2007/08	2/11/08 8:00 AM	52	3,224	3,310	-1.5%
2008/09	1/16/09 7:00 PM	52	3,483	3,310	0.0%
2009/10	1/30/10 7:00 PM	47	3,313	3,350	1.2%
2010/11	1/24/11 8:00 AM	55	3,385	3,350	0.0%
2011/12		51		3,248	-3.1%
2012/13		49		3,381	4.1%
2013/14		49		3,466	2.5%
2014/15		49		3,532	1.9%
2015/16		49		3,581	1.4%
2016/17		49		3,646	1.8%
2017/18		49		3,702	1.5%
2018/19		49		3,767	1.8%
2019/20		49		3,837	1.9%
2020/21		49		3,904	1.7%
2021/22		49		3,967	1.6%
2022/23		49		4,029	1.6%
2023/24		49		4,094	1.6%
2024/25		49		4,167	1.8%
2025/26		49		4,249	2.0%
2026/27		49		4,315	1.6%

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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 DPL 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 2011 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 2011 DPL DE peak mentioned above, class forecasts are calculated as a constant share of the DPL 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%. That does not happen, however. 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

	DPL Zone Non-Coincident PHI forecast* (MW)	DE Share (MW)	DPL DE Share (MW)	DPL DE Res (MW)	DPL DE Small Com (MW)	DPL DE LC&I (MW)	DPL DE SL (MW)
2012	4,098	2,701	1,896	1,023	28	844	0
2013	4,138	2,727	1,914	1,033	29	853	0
2014	4,215	2,778	1,950	1,052	29	868	0
2015	4,295	2,831	1,987	1,072	30	885	0
2016	4,386	2,891	2,029	1,095	30	904	0
2017	4,468	2,945	2,067	1,116	31	921	0
2018	4,538	2,991	2,099	1,133	31	935	0
2019	4,609	3,038	2,132	1,151	32	950	0
2020	4,687	3,089	2,169	1,170	32	966	0
2021	4,754	3,134	2,199	1,187	33	980	0
2022	4,824	3,179	2,232	1,204	33	994	0
2023	4,894	3,226	2,264	1,222	34	1,008	0
2024	4,966	3,273	2,297	1,240	34	1,023	0
2025	5,053	3,330	2,337	1,262	35	1,041	0
2026	5,132	3,383	2,374	1,281	35	1,058	0
2027	5,220	3,440	2,415	1,303	36	1,076	0
2028	5,320	3,506	2,461	1,328	37	1,096	0
2029	5,411	3,566	2,503	1,351	37	1,115	0
2030	5,508	3,630	2,548	1,375	38	1,135	0
2031	5,606	3,695	2,593	1,400	39	1,155	0
2032	5,706	3,761	2,640	1,425	39	1,176	0
2033	5,807	3,828	2,687	1,450	40	1,197	0
2034	5,911	3,896	2,735	1,476	41	1,218	0
2035	6,016	3,965	2,783	1,502	42	1,240	0
2036	6,124	4,036	2,833	1,529	42	1,262	0
2037	6,233	4,108	2,884	1,556	43	1,284	0

*PHI MW forecast is unrestricted peak non-coincident with PJM Zonal Peak Demand
*PHI MW forecast does not include EE/DSM programs

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 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 SL (MW)
2012	986	23	190	0	37	6	655	0
2013	996	23	191	0	37	6	661	0
2014	1,014	23	195	0	38	6	673	0
2015	1,034	24	199	0	39	6	686	0
2016	1,056	24	203	0	40	6	701	0
2017	1,075	25	207	0	40	6	714	0
2018	1,092	25	210	0	41	6	725	0
2019	1,109	25	213	0	42	6	737	0
2020	1,128	26	217	0	42	6	749	0
2021	1,144	26	220	0	43	7	760	0
2022	1,161	27	223	0	44	7	771	0
2023	1,178	27	226	0	44	7	782	0
2024	1,195	27	230	0	45	7	793	0
2025	1,216	28	234	0	46	7	807	0
2026	1,235	28	237	0	46	7	820	0
2027	1,256	29	242	0	47	7	834	0
2028	1,280	29	246	0	48	7	850	0
2029	1,302	30	250	0	49	7	865	0
2030	1,325	30	255	0	50	8	880	0
2031	1,349	31	259	0	51	8	896	0
2032	1,373	31	264	0	51	8	912	0
2033	1,398	32	269	0	52	8	928	0
2034	1,423	33	273	0	53	8	944	0
2035	1,448	33	278	0	54	8	961	0
2036	1,474	34	283	0	55	8	978	0
2037	1,500	34	288	0	56	9	996	0

Over the period 2012-2014 in Table VIII.7 below, DPL DE residential sales will fall -3.0% per year on average. Contributing to the decline is a -1.7% per year contraction in residential space heat customers from their 2010 level. This serves to reduce consumption for the class total. Additionally, the near-term economic outlook for limited employment and flat real disposable income will hamper usage growth. Customers uncertain about future income and employment will conserve on current electricity

consumption. The resumption of sales growth in 2015 is consistent with an upturn in local economic conditions. Real disposable incomes will begin growing in late 2014 and accelerating employment growth will drive new customer formation. Both will contribute to expanding usage.

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 SL (MWh)
2012	3,071,067	3,626,400	1,845,663	177,256	5,294,807	37,609
2013	2,916,121	3,871,835	1,939,109	188,233	5,622,711	37,768
2014	2,784,809	3,892,002	2,042,955	192,251	5,742,707	37,907
2015	2,798,943	3,910,244	2,054,372	193,211	5,771,405	38,046
2016	2,817,821	3,928,665	2,060,682	194,012	5,795,335	38,184
2017	2,836,598	3,946,718	2,062,046	194,641	5,814,122	38,323
2018	2,853,290	3,964,693	2,066,088	195,355	5,835,427	38,464
2019	2,868,947	3,982,304	2,072,465	196,132	5,858,638	38,605
2020	2,884,082	3,999,869	2,073,220	196,725	5,876,364	38,746
2021	2,897,537	4,017,492	2,072,005	197,257	5,892,240	38,888
2022	2,910,224	4,034,700	2,071,065	197,783	5,907,981	39,031
2023	2,924,485	4,052,448	2,061,574	198,051	5,915,971	39,174
2024	2,940,160	4,070,484	2,048,730	198,219	5,920,995	39,317
2025	2,956,059	4,088,764	2,036,608	198,419	5,926,954	39,461
2026	2,973,098	4,107,160	2,025,496	198,655	5,934,001	39,605
2027	2,990,504	4,125,675	2,012,157	198,822	5,939,009	39,750
2028	3,008,489	4,144,428	2,000,143	199,041	5,945,531	39,895
2029	3,025,928	4,163,062	1,991,242	199,356	5,954,948	40,041
2030	3,043,469	4,181,780	1,982,379	199,675	5,964,484	40,188
2031	3,061,111	4,200,582	1,973,557	199,998	5,974,140	40,334
2032	3,078,856	4,219,468	1,964,773	200,326	5,983,916	40,482
2033	3,096,703	4,238,440	1,956,029	200,657	5,993,812	40,630
2034	3,114,654	4,257,497	1,947,323	200,992	6,003,828	40,778
2035	3,132,709	4,276,639	1,938,657	201,332	6,013,964	40,927
2036	3,150,868	4,295,868	1,930,028	201,675	6,024,221	41,077
2037	3,169,133	4,315,183	1,921,439	202,022	6,034,599	41,227

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 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 SL (MWh)
2012	2,960,076	141,674	1,188,911	27,528	110,991	35,582	4,105,896	10,082
2013	2,810,730	150,448	1,262,540	27,643	105,391	37,785	4,360,171	10,124
2014	2,684,163	153,659	1,289,484	27,746	100,646	38,591	4,453,223	10,162
2015	2,697,786	154,427	1,295,928	27,847	101,156	38,784	4,475,477	10,199
2016	2,715,982	155,067	1,301,301	27,949	101,839	38,945	4,494,033	10,236
2017	2,734,081	155,570	1,305,520	28,050	102,517	39,071	4,508,602	10,273
2018	2,750,170	156,140	1,310,303	28,153	103,121	39,215	4,525,123	10,311
2019	2,765,261	156,761	1,315,515	28,256	103,687	39,371	4,543,122	10,348
2020	2,779,849	157,235	1,319,496	28,360	104,233	39,490	4,556,868	10,386
2021	2,792,817	157,660	1,323,061	28,464	104,720	39,596	4,569,180	10,424
2022	2,805,046	158,081	1,326,595	28,568	105,178	39,702	4,581,386	10,463
2023	2,818,791	158,295	1,328,389	28,673	105,694	39,756	4,587,582	10,501
2024	2,833,900	158,430	1,329,517	28,778	106,260	39,790	4,591,478	10,539
2025	2,849,224	158,589	1,330,855	28,883	106,835	39,830	4,596,099	10,578
2026	2,865,647	158,778	1,332,438	28,989	107,451	39,877	4,601,563	10,617
2027	2,882,424	158,912	1,333,562	29,095	108,080	39,911	4,605,447	10,656
2028	2,899,759	159,086	1,335,027	29,201	108,730	39,954	4,610,504	10,694
2029	2,916,568	159,338	1,337,141	29,308	109,360	40,018	4,617,807	10,734
2030	2,933,475	159,593	1,339,282	29,415	109,994	40,082	4,625,202	10,773
2031	2,950,480	159,852	1,341,451	29,522	110,631	40,147	4,632,690	10,812
2032	2,967,583	160,113	1,343,646	29,630	111,273	40,212	4,640,270	10,852
2033	2,984,785	160,378	1,345,868	29,738	111,918	40,279	4,647,944	10,891
2034	3,002,087	160,646	1,348,117	29,847	112,567	40,346	4,655,711	10,931
2035	3,019,490	160,917	1,350,393	29,956	113,219	40,414	4,663,572	10,971
2036	3,036,993	161,192	1,352,696	30,066	113,875	40,483	4,671,525	11,011
2037	3,054,598	161,469	1,355,026	30,175	114,536	40,553	4,679,573	11,051

IX. DPL DE IRP Forecast Scenarios

Figure IX.1 (below) presents the Company's forecast for the unrestricted summer peak demand for DPL 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. 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

DPL Delaware Jurisdictional Summer Peak Demand

(MW)

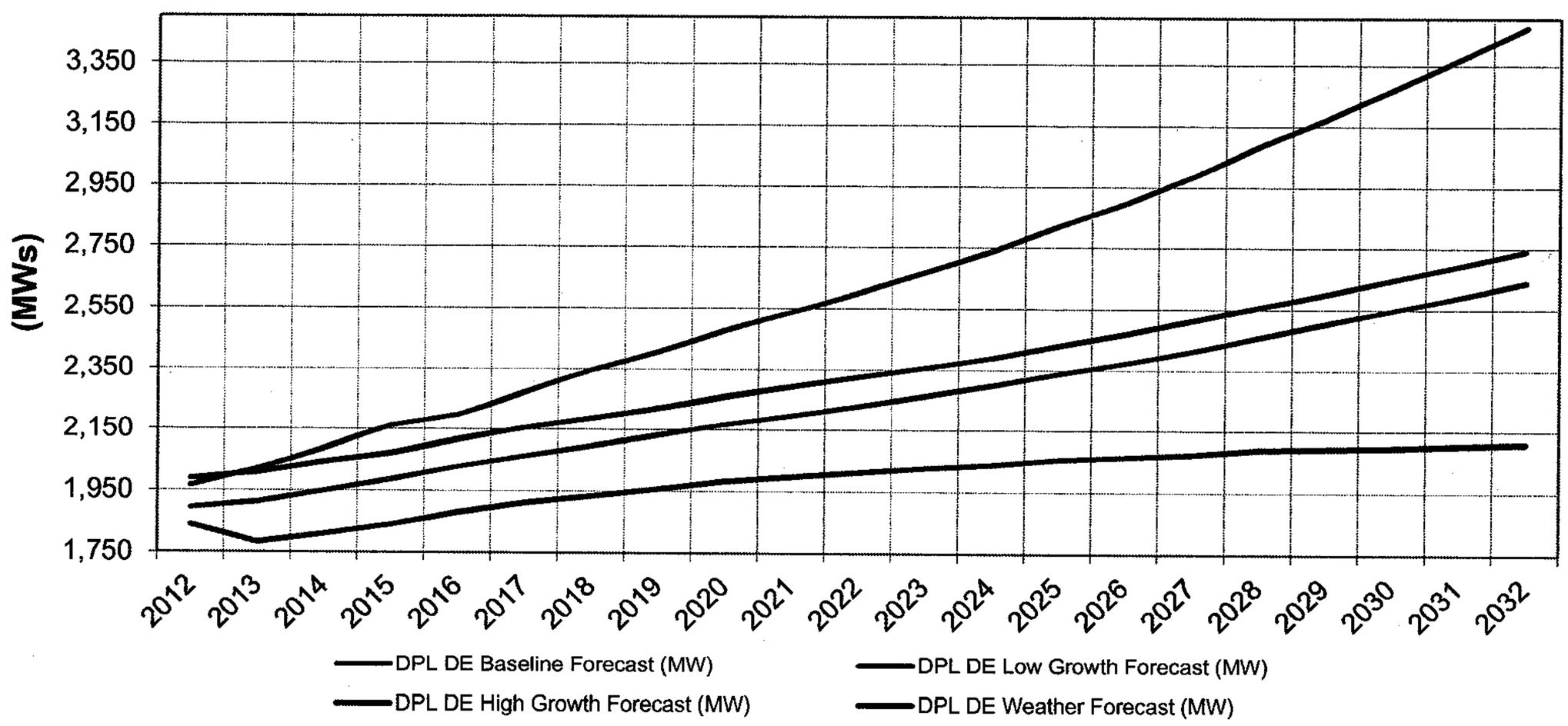
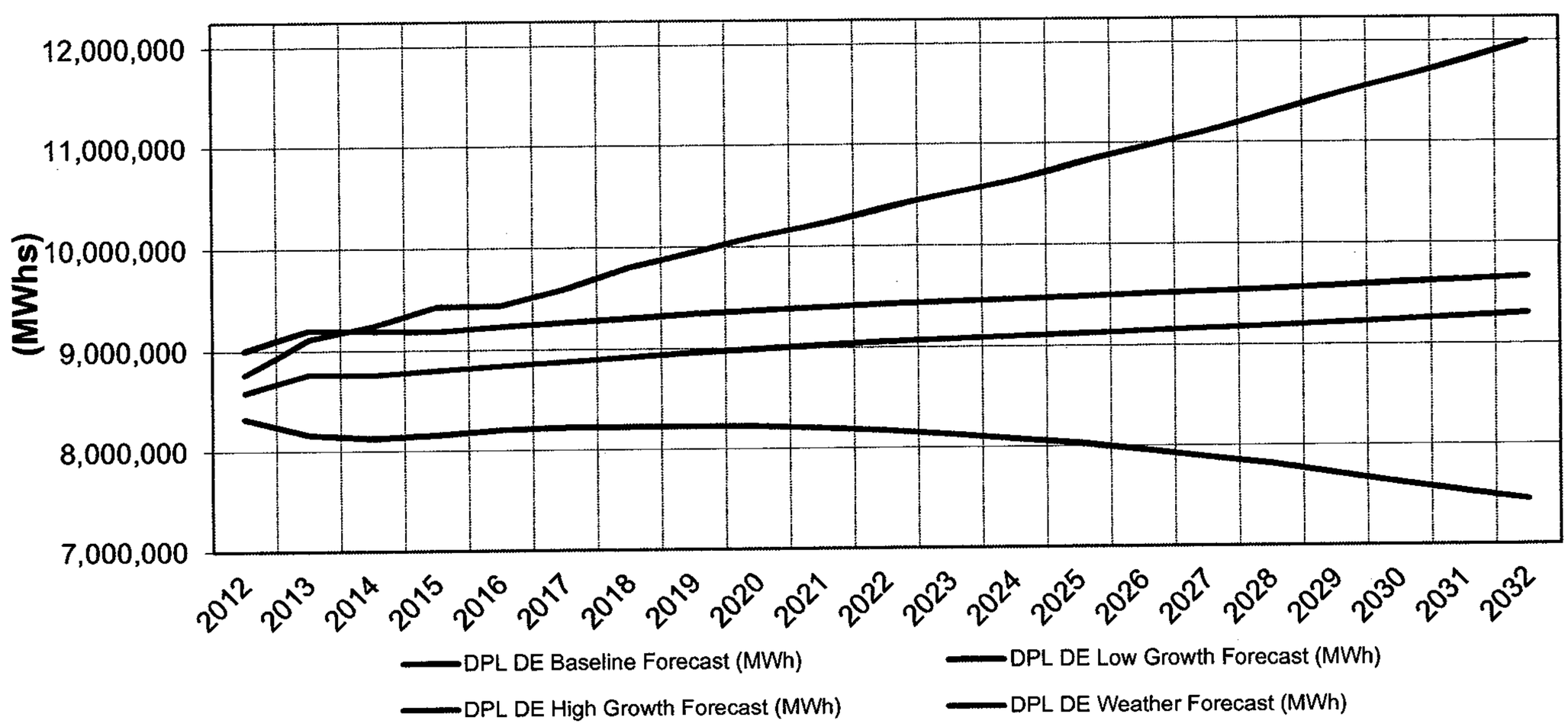


Figure IX.2 (below) illustrates energy throughput for the DPL DE jurisdiction within the Delmarva Zone, the amount of annual energy required to serve all DPL DE customers, inclusive of all losses and self-use, for these same four scenarios.

Figure IX.2

DPL DE Jurisdictional Energy Throughput

(MWh)

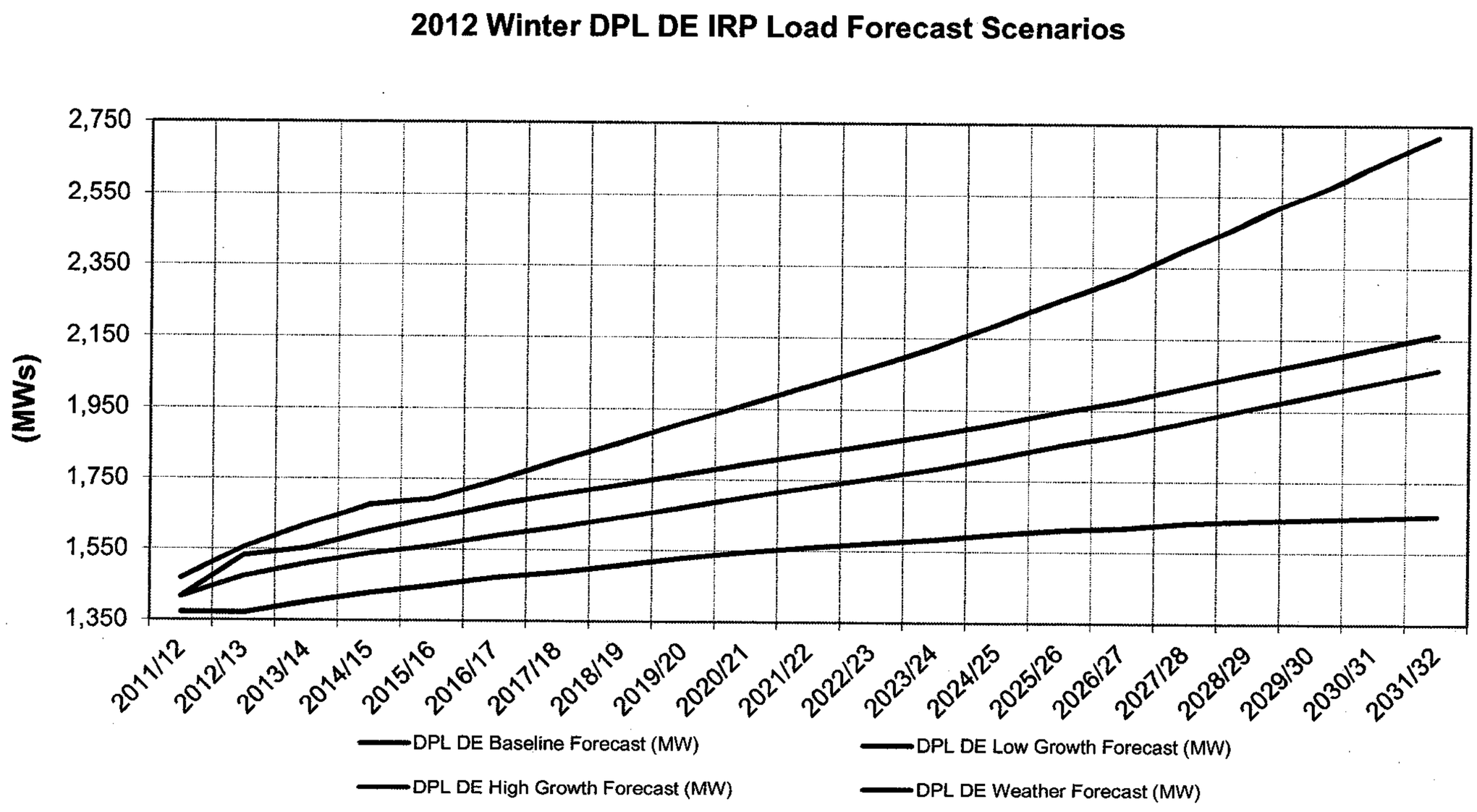


Finally, Figure IX.3 displays the DPL DE unrestricted winter peak forecast for each of the scenarios. These scenarios are constructed symmetrically to the ones provided in Figure IX.1.

Figure IX.6

DPL Delaware Jurisdictional Winter Peak Demand

(MW)



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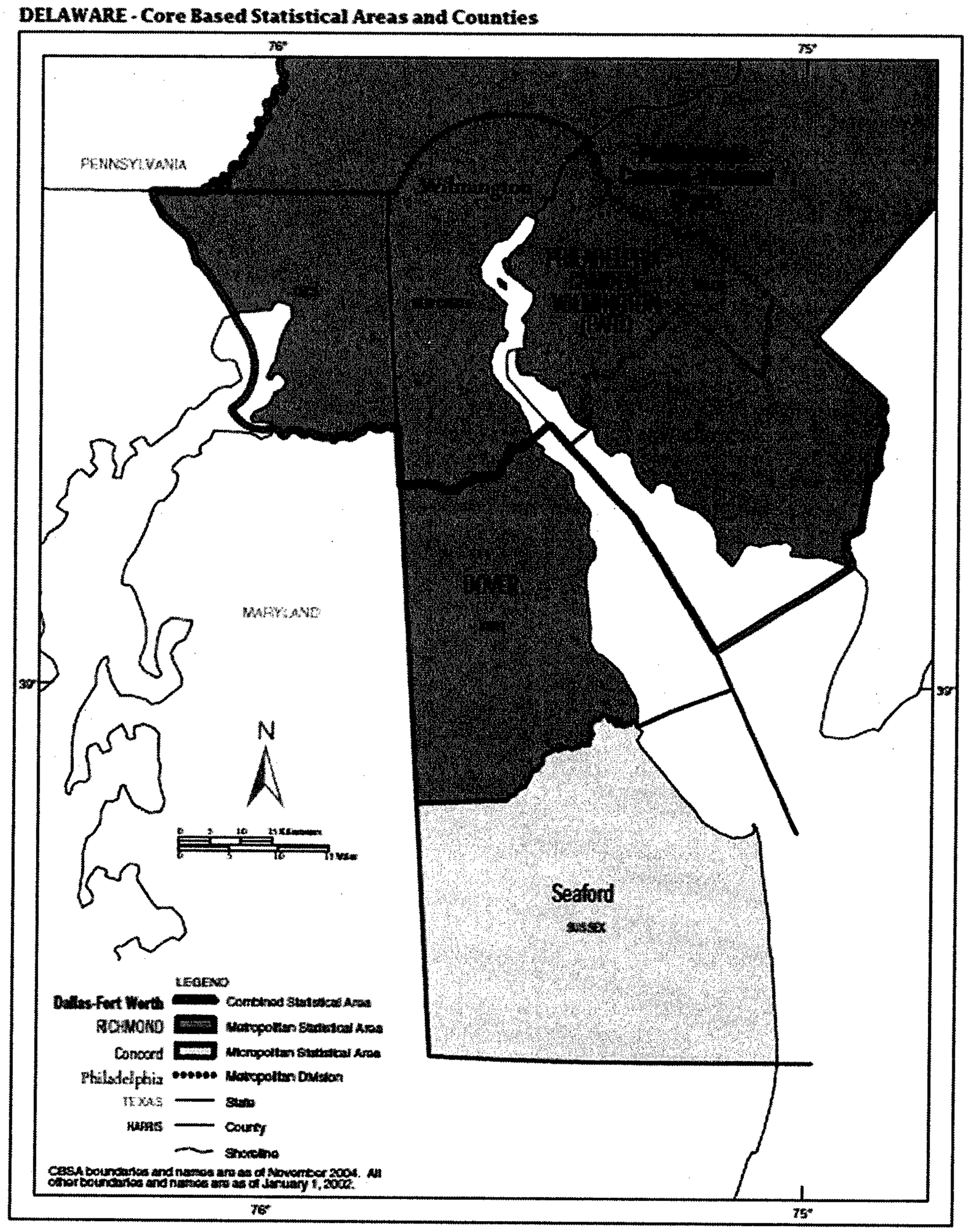
Appendix A: DPA Recommendations

	DPA Recommendation	PHI Response	Chapter Containing Response
1	DP&L should develop a more comprehensive reporting of the load forecast, expressly identifying all assumptions, key model inputs, forecasting model specification and outputs, and forecast outputs.	Forecast documentation now includes chapters for key assumptions, detailed input discussion, and separate chapters for each piece of the forecasting process. All model specifications and output are reported in Appendices.	Throughout
2	In modeling and projecting residential energy, DP&L should transition from an econometric model to an end-use model or a hybrid end-use/econometric model, which would provide for greater quantification and understanding of the many factors impacting residential consumption.	DPL does not think the extra expense of developing an end-use forecast will provide a noticeable increase in accuracy.	Chapter I: pg. 9
3	DP&L should test whether using different weather data for the southern portions of the state (perhaps using Dover or Georgetown data) would better predict load for that portion of its consumers. The southern portions of the state are more exposed to weather coming off of the Atlantic Ocean. These differing weather patterns impact electricity consumption.	Provided detailed discussion of weather normalization and weather modeling procedures. Highlighted characteristics a weather station must posses to meet the forecasting groups weather needs. Included alternate DE Weather stations that don't meet that criteria.	Chapter V: pg. 30 (alternate stations)
4	Total jurisdictional energy and zonal peak demand are broken down to the retail customer class level using sharing techniques, which should be described in greater detail in future reports.	Additional detail on sharing methodology is provided.	Chapter VIII, pg. 52
5	Future load forecast reports should provide more specifics regarding the relationship between the retail energy models and the jurisdiction and zone models, and how the results from each are represented in the final total energy forecast.	Discussion provided of mutually confirming forecasting system.	Throughout
6	There is no discussion of the customer class energy sales model inputs and no presentation of the associated model parameters and statistics. In future reports, DP&L should include this information.	Provided two new chapters describing the DPL DE Retail Energy and Customer Forecast. Energy and Customer model output provided in appendix to Chapters.	Chapters VI and VII: Appendix F and G
7	DP&L does not present the economic outlook as part of its load forecast documentation. Future reports should include a table presenting historical and projected economic variables used to develop the forecasting models.	Provided new Chapter on the economic forecast. PHI provided it's write-up of economic conditions in service territory as well as Global Insight forecast data and write-ups.	Chapters III: Appendix C and D
8	Describe forecast scenarios and present graphically, but not in tabular form.		Throughout, Chapter V: pg. 34 (Weather), Chapter IX: 59

Appendix B: Delaware Metropolitan Statistical Areas Map



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Appendix C: August 2012 Economic Newsletter

Housing, Construction & Employment Report

Economics and Forecasting | PHI Treasury | August 17, 2012

Thelma and Louise ... and the Fiscal Cliff

Executive Summary

- Three-and-a-half years ago, we wrote in this space that we would endure "unending discussions in the media about the jobless recovery." That was during the fall of 2008, when it seemed like we might be nearing the end of that long wait. We are still waiting. Dragging along the bottom of this bathtub in employment is taking longer than any other post WWII recession. **We still need a shock to the system that restores confidence** instead of damaging confidence.
- Many analysts are suggesting that meaningful improvement in the economy cannot occur until households repair their balance sheets through a slow process of deleveraging (working down household debt). That process has begun, but it will require years to complete. Our view is that **we must only wait until households become confident in the security of their jobs** and incomes.
- Employment growth within the PHI footprint will average 2% in 2012, expanding to 3% in 2013.

Housing

- **Housing in PHI North has taken another leg down**, with time to sale stretching out to 119 days and the average selling price now down to $187,000, down 18% from the peak.
- **Residential properties in Atlantic City now have an average time to sale of 128 days** and a median selling price of $194,827, down 28% from the peak.
- **The national inventory of unsold homes is now down to 9.3 months** of supply. Housing starts have been running about one-third their prerecession levels. Existing home sales have been improving, but new listings have kept the inventory of unsold homes surprisingly constant. The supply of unsold homes is now down to 6.6 months, slowly approaching the more normal level of 6 months supply.

Construction

- **No new office space is under construction in the Wilmington area**. In the Suburban MD area, the first quarter saw new space under construction go positive, with what is probably one property under construction. **In the District, new space under construction has climbed to 4.57 msf**, compared to a normal running rate of 10-12 msf.
- In Atlantic City construction at the Revel site is complete, and we are seeing the first signs of improvement with several large older casino/hotels announcing important remodeling projects. **Remodeling of casino/hotels is the first sign of improvement in Atlantic City** in every business cycle.

It's Still Not Over

According to the National Bureau of Economic Research, the official arbiter of the start and end dates for recessions, the Great Recession ended in June 2009. We are now in the 26th month of the recovery. We don't know how long this recovery will last, but since WWII the average trough-to-peak has been 58 months, although the trough-to-peak for the 2001 recession was 120 months and for the 1991 recession it was 92 months. Going with the average puts us a little less than half way through to the next peak. Did you miss it?

At the same time we live in fear of Euro-infection, election outcomes, the fiscal cliff, the debt ceiling debate and ancient aliens, any of which could lead us into the next recession. What should we really expect in 2013?

What the Experts Say

Each month the *Wall Street Journal* publishes a survey of 51 of the nation's prominent economic forecasters, mostly representing major banks, financial institutions and fee-for-service consultants. The most recent survey was conducted August 3-6, 2012.

In the WSJ survey, no respondent has even a single quarter of negative GDP growth in their baseline forecast. At the same time, the consensus is that there is a 22% "probability of a recession in the US within the next 12 months." 90% of the respondents agree that the fiscal cliff will drag down growth. Respondents are also in agreement that "we are already feeling the effects in hiring and investment" and that the economy is "flirting with a stall rate."

These seemingly conflicted views make it hard to visualize what 2013 might look like. For it to make sense, we need to think about the forecast a little differently than we normally do – at this point in time, it's not helpful to think of the future as a nice smooth trend line. Instead, the future is bimodal – either of two outcomes (at least) may occur.

On the one hand, many economists believe that after the November election there is an opportunity during the lame duck session to address the fiscal items that make up the fiscal cliff. If that does not occur, there is another opportunity during the first 13 weeks of the year to pass legislation that would retroactively undo some or all of the components of the fiscal cliff and to pass a debt ceiling bill. In this scenario, it is possible that 2013 could turn into an

increasingly normal recovery with economic growth in excess of 2%.

On the other hand, we may have to face the fiscal cliff coupled with another ugly debt ceiling debate. The majority of economists – it's not a consensus – calculate that the net effect will be to shave 1% to 2% off of real GDP growth for the first two quarters of 2013. That would be a relatively happy outcome, taking us down to the flat line, more or less. There is a minority of economists that believe the final impact could be a 5 percentage point hit to GDP growth, but that group is small and not vocal.

This leaves us with a bimodal forecast for the remainder of 2012 and the first half of 2013. We're used to thinking of future outcomes as a being smooth and normally distributed. That's not the case this time. Instead, there are two competing views; either (a) 2013 turns into a pretty normal year with approximately 2% growth, or (b) 2013 develops into a disappointing growth recession, with real GDP growth that ranges from very slightly negative to very slightly positive.

How do you plan for that? The economic outlook we are using expects very little growth in late 2012 and early 2013. The forecast is intended to strike the median between the two modes of our bimodal expectations.

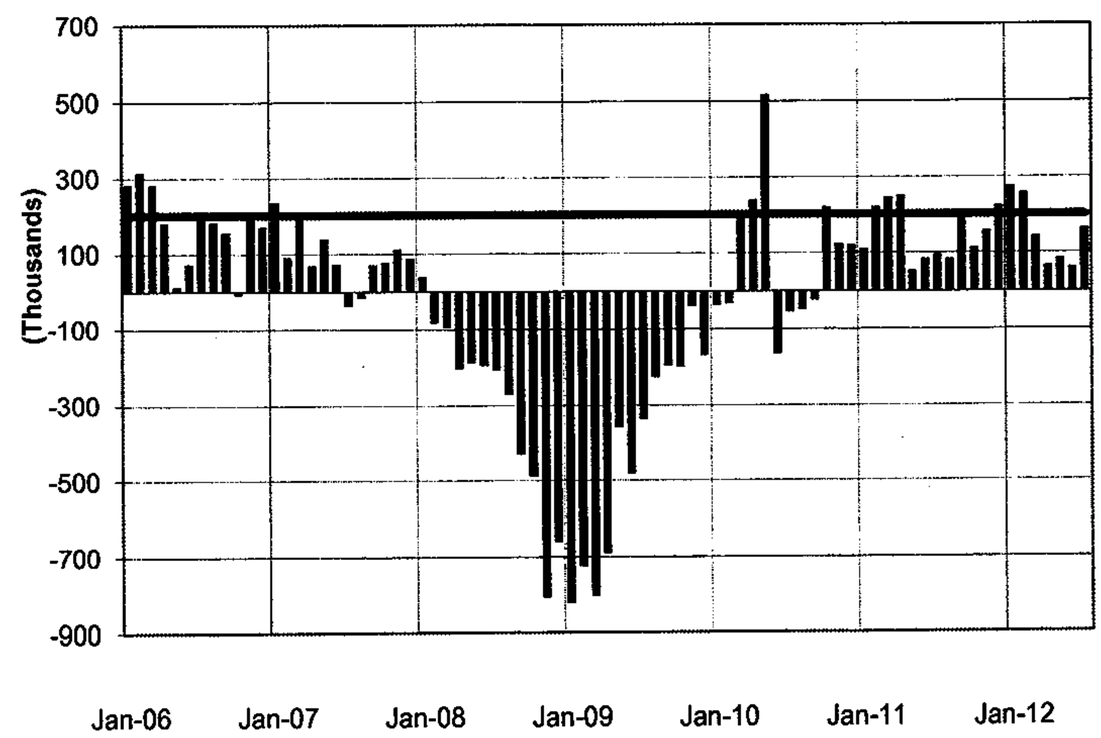
The Jobless Recovery Drags On ... and On

It has now been more than three and a half years since we first warned in our December 22, 2008 issue of this newsletter that we were looking forward to "unending discussions in the media about the jobless recovery." We're now producing jobs, but we're not producing many jobs – not nearly enough jobs to provide even for just the new entrants into the labor force. And it's still true that three things will be required before Americans become more optimistic about their consumption and spending plans:

- Jobs (a lot of jobs) so that people can be confident about their incomes;
- Stabilization in home prices so that people will not fear further loses in their largest store of wealth; and
- A continuing recovery in the stock market so that people will stop feeling like their 401(k) – and their hope for retirement – is evaporating.

Figure 1 shows the net number of jobs created or destroyed each month over the past five years. This data is from the Bureau of Labor Statistics monthly survey, the so-called "Jobs Report" that is released on the first Friday each month.

Figure 1
Monthly Growth in US Non-Farm Payrolls (1,000s)



We really are producing jobs, finally, but we're not yet up to a fast enough pace that it can actually start to make a small dent in the

unemployment rate. Unemployment is still firmly above 8%, and it will still be above 7% on Election Day.

This one issue – employment – has turned this election into the most acrimonious election we've seen in many years. It's a close call, with the two candidates polling equal shares in the voting. It will be a close election like the elections have been for the past decade, but the stakes are now much higher – we could easily see a result even more controversial than Bush/Gore.

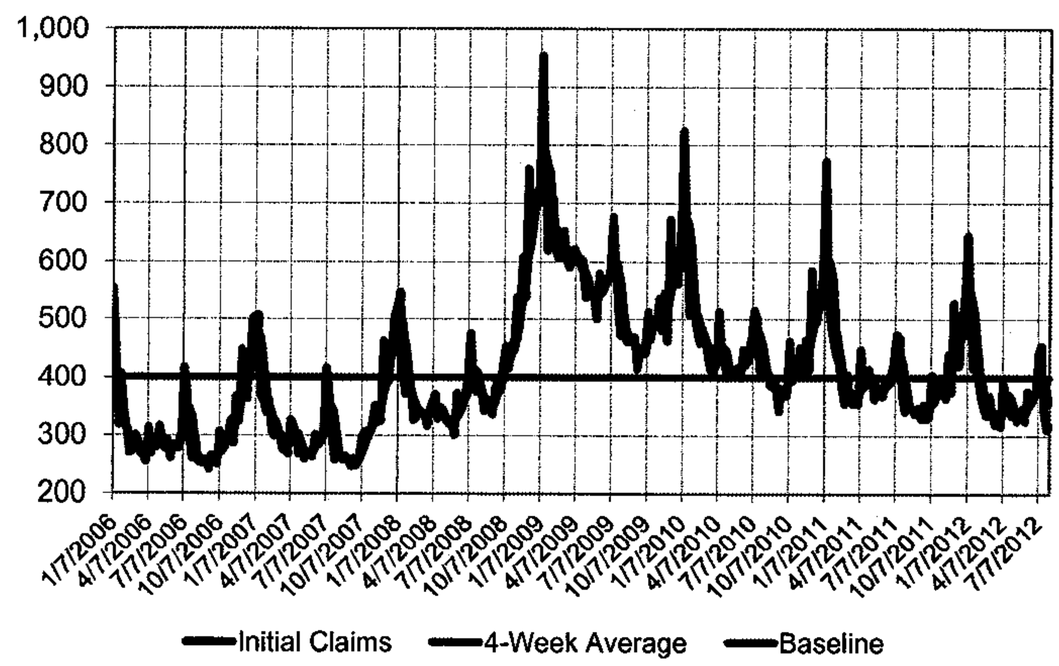
Economists calculate that about 200,000 new jobs are needed each month (the blue line in Figure 1) to offset new entrants into the labor force. As you can see, we're only just touching it at this point. Job creation has been enough to bring the unemployment rate down a little – to 8.3% in July – but that is still a long way from full employment, and many mainstream economists are suggesting that we may not reach the peak levels of employment that we enjoyed in 2007 for another three or four years. And the next recession could easily come first.

The uptick in hiring that we saw in July is significant. 163,000 new jobs were created in July, up substantially from the frustratingly slow pace observed over the prior three months. It now seems clear that the warm winter really did steal job formation from the spring. If we average job formation over the first seven months of the year, the monthly rate of job formation has been 151,000/month, virtually unchanged from the average rate of 153,000/month seen over the same period in 2011.

Usually we can get a look at how jobs are doing between monthly jobs reports by watching the weekly Initial Jobless Claims for Unemployment Insurance that are released each Thursday. In looking at Figure 2, it's interesting to compare with the 2.0% growth in real GDP posted in Q1 and the 1.5% growth posted in Q2.

Figure 2 makes it obvious that in order to get the unemployment rate down to lower levels, real GDP growth in the 3% to 3.5% rate will be required. That's really what we're missing – it is frequently observed that in "normal" recoveries, we would have had a number of quarters of 4% to 6% growth by this stage in the recovery.

Figure 2
Weekly Initial Unemployment Claims



In Figure 2, the black line is weekly initial jobless claims; we look at non-seasonally adjusted claims, the actual numbers, so we can see just how much volatility there really is unemployment claims.

The red line is the infamous 4-week moving average, a technique commonly used with this data to smooth out the jagged history and give us a feel for the "true" job market conditions. As you can see by comparing Figure 2 with Figure 1, monthly jobs growth tends to exceed it's key level of 200,000 new jobs per month (the blue line in Figure 1) – the amount needed to fully absorb the new entrants to the job market – when the number

of initial jobless claims dips below 400,000 per week (the blue line in Figure 2).

Those who were watching initial claims for an initial read on the July jobs number were terribly confused by the very weak claims. The claims data were signaling consistent with 1% real GDP growth, the growth actually observed during Q2, and the expectation was established that July job formation would be weak. Fortunately, the 163,000 new jobs actually created in July are consistent with much stronger growth – closer to 2% real GDP growth.

The strength of the July jobs number is causing macro forecasters to strengthen their outlook. We're now expecting 2% growth for the full year 2012, continuing into 2013. Is it safe to bet the farm on stringer jobs growth going forward just because July came in relatively strong? A close look at Figure 2 shows the pattern of initial claims continues to set sequentially lower highs and lower lows – a clear sign that claims are shrinking. As long as this pattern continues, we can remain optimistic that August jobs will echo the strength of the July jobs report.

How good can it get? Can we hope for a return to 4% Full Employment? Probably not. It seems more likely that we will end this recession by revising our definition of Full Employment to a number like 6%, 7% or even larger. Ten or twenty years ago economists initially quoted 3%, and later 4% and 5%, as the Full Employment rate of employment – the level where the only remaining unemployment is frictional (people changing jobs) and structural (people with the wrong skills). Before the recession it was frequently quoted at 6%. The next thing you hear on the subject may well be a public official arguing that it is now 7%, and we have "achieved full employment."

Employment Outcomes in PHI's Footprint

Closer to home, Figure 3 illustrates the outlook for employment growth within the footprint of PHI's three brand names, PEPCO, DPL and ACE. For each jurisdiction, the history and current outlook for employment is rebased to a level of 100% in July 2008 – the time of the most recent peak in employment. As can be seen, PEPCO (the blue line) surpassed its pre-recession peak in employment in September 2010. PEPCO is always a moderating force in downturns, insulated as it usually is by federal spending inside the beltway.

By comparison, DPL (the red line) is only slightly outpacing the performance of the overall US economy (the black line). Both are currently at a level of employment just slightly above 95% of the pre-recession peak. The US will surpass its pre-recession peak in August 2014, and DPL will reach the same target a year later, in late 2015.

ACE brings up the rear. Atlantic City and Vineland NJ are not going to return to their pre-recession levels of employment until well after January 2016. In fact, **the current expectation is that southern New Jersey will not reach its pre-recession level of employment until well after 2020.**

Figure 3
PHI Local Employment Growth
(Relative Scale, July 2008 = 100%)

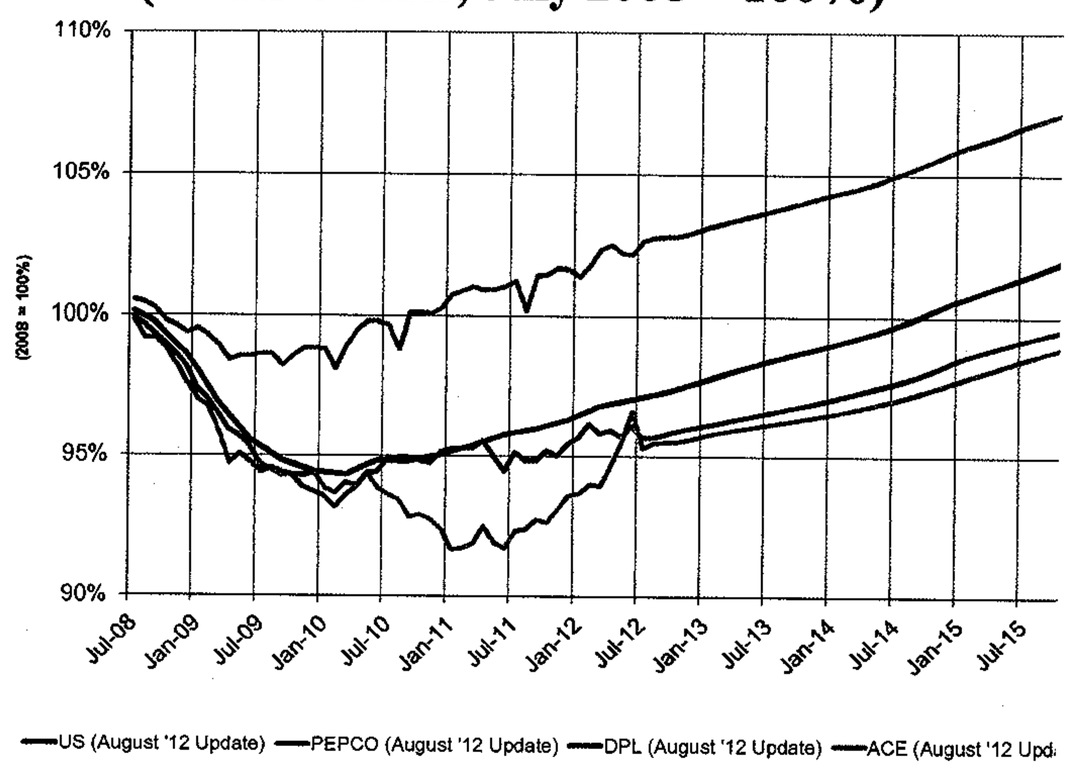


Table 1
PHI Local Unemployment

Comparative Unemployment Rates
(% of Labor Force)

	Dec '09	Dec '10	Dec '11	Apr '12
US	9.93	9.57	8.70	8.10
PHI	9.17	8.78	8.36	8.26
ACE	13.01	13.14	12.51	12.81
DPL	8.87	8.45	7.75	7.93
PEPCO	8.70	8.23	7.89	7.69
DPL Gas	8.95	8.33	7.58	9.23
DPL-DE	8.49	8.01	7.43	7.39
DPL-MD	9.78	9.50	8.51	9.23
PEPCO MD	6.39	5.83	5.05	5.32
PEPCO DC	10.47	10.08	10.07	9.51

More to the point, there is a real concern that we may see the next recession begin before south Jersey recovers to our previous employment peaks. It's almost a certainty that some parts of the country will not see the kind of robust economy that they enjoyed prior to 2008 for a very long time to come. South Jersey seems like it might be an example.

Table 1 illustrates the unemployment rates we've been experiencing in our brand name footprints. It's generally the case – the exceptions being PEPCO DC and ACE – that the unemployment rates observed in our brand name footprints have been much better than the national average.

South Jersey has been hit very hard, however. The Atlantic City and Vineland MSAs have seen their unemployment rates climb as high as 13% on two different occasions during this recovery. By December 2011 unemployment "recovered" to 12.5%. The unemployment rate has served as a signal of the pain experienced by households in ACE. It should be no surprise that during the winter of 2011/12 (the warmest winter on record) households took the opportunity to turn their furnaces off, leading to a very large an unexpected sales variance.

Surprise! The South Jersey Comeback

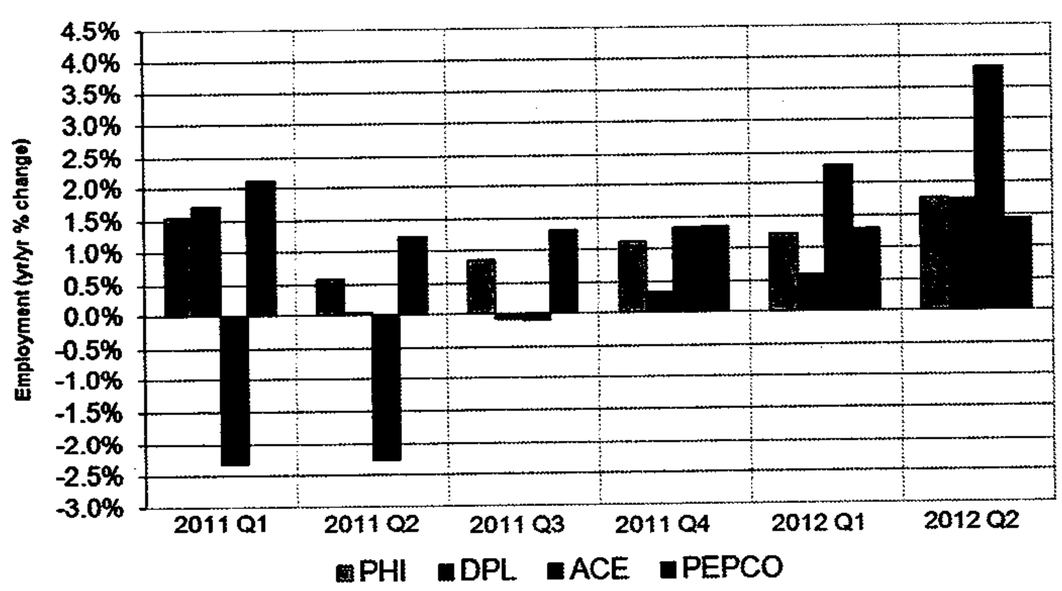
The Mid Atlantic is now seeing a recovery in employment that is a complete surprise to the forecasting houses, and it is not yet integrated into their local economic forecasts. South Jersey – Vineland and Atlantic City – are turning into huge beneficiaries.

Figure 4 shows the year over year growth rates for employment within the footprint of each of our

brand names. PEPCO (the red bar) has been plugging along, benefitting (at least until now) from the federal presence. The amazing story is in DPL (green bar) and ACE (blue bar).

In DPL, year-over-year employment growth finally turned positive in Q4 and gradually accelerated to 1.2% in June, with 5.8% year-over-year growth in manufacturing, 2.8% growth in financial services and 2.8% growth in healthcare.

Figure 4
PHI Local Employment Growth
(Year-over-year percent change)



That's quite a nice bounce, but it does not compare to the action we've seen in ACE. Year over year employment growth turned positive in November 2011 and reached 2.5% growth by February. In June it improved further to 5.3%!

To be clear, this rapid improvement in ACE employment is a blip. We expect the growth rate to begin to moderate later in 2012 and average about 1% growth throughout 2013.

The cause of the blip was the opening of the Revel casino/hotel in April 2012 and the direct creation of 5,500 hospitality related jobs – half of our ACE commercial sales are to the casino/hotels. The opening of the Revel has also prompted a spate of hotel remodeling (usually one floor at a time), but the stimulus related to this injection of spending will eventually fade.

Discussions with our Key Account Managers indicate the overall effect of the new casino is to cannibalize business from other casinos. They are competing for pieces out of the same pie. The feeling among local economists that specialize in NJ is that there is so much slack in the local economy that even an injection the size of the Revel will not lead to significant indirect job creation – the vendors that will serve the hotel will just serve its needs by taking up some the slack in their existing businesses. It did serve to break the ice, though, and it will foster some very modest but much needed growth.

Where Will the Jobs Come From?

Based on our experience in earlier recessions, we should expect the new jobs that we need to be created by small to mid-sized business. The big corporations employ many people, but they are not the most important contributors to job growth.

Looking first at the largest firms (in Figure 5), the best source of information on hiring plans is the Employment Index of the Institute For Supply Management's monthly survey (ISM, formerly NAPM or the "Napalm" report) monthly survey of corporate purchasing manager's expectations. The sample has approximately 400 respondents, primarily from Fortune 1,000 companies.

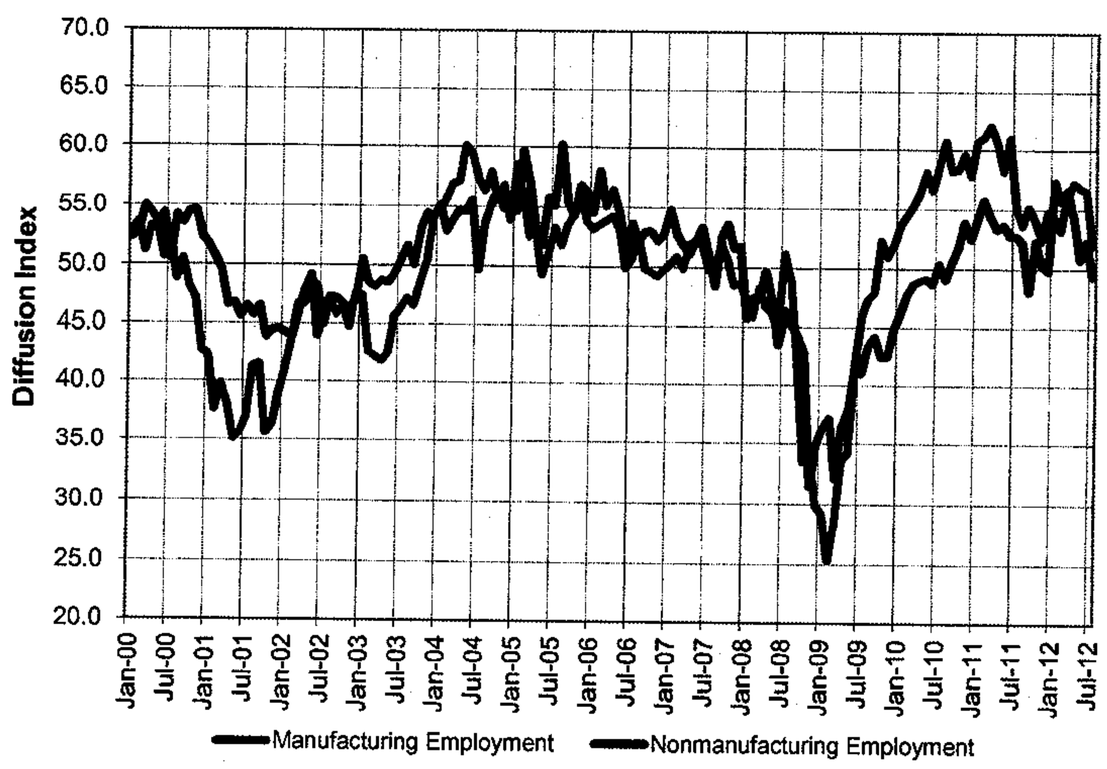
The ISM's question on employment plans was at 52.0 in June, the 34th consecutive month of the current expansion in this index (a reading above 50 indicates expansion in hiring). The reading of 52.0 tells us that a small majority of large firms plan to hire and expand their staff over the next six months.

The ISM is a diffusion index (positive responses minus negative responses) that has been indexed

to 50, so anything greater than 50 signifies an expansion in employment. An index number of 50 represents break-even, and index numbers close to 60 are moderately positive and almost always translate into improved net new hiring on the Bureau of Labor Statistics monthly jobs report.

The blue line in Figure 5 represents the hiring plans of the large corporations in the service sector. This index of hiring plans in non-manufacturing dipped to 49.3 in July, ending an expansion of just six consecutive months. If you are a non-manufacturing firm, the odds that you have plans to hire over the next 6 months is now the flip of a coin. The service sector should be playing a very important role in building a crescendo of job gains. It needs to start pretty soon – a feature of this recovery (and all recoveries) is that since the bottom in employment we have been expecting new hiring to be just over the horizon. Referring to the current outlook for local employment growth, it is still just over the horizon.

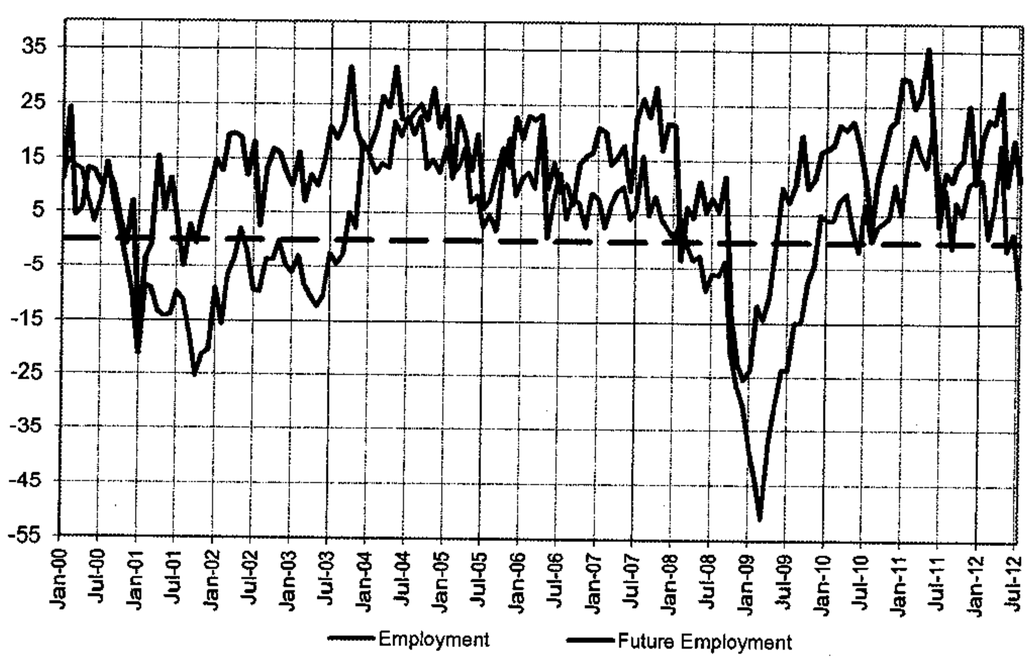
Figure 5
Institute for Supply Management
Manufacturing and Services Hiring Plans



Looking closer to home, the Philadelphia Federal Reserve Bank surveys manufacturers within their service area, including PA, NJ, DE and (all of) MD. Of all the data we have access to, this survey best replicates the PHI footprint. The results of the Philly Fed survey's questions related to hiring are shown in Figure 6. This is another diffusion index, so anything greater than zero signifies an expansion in employment.

Hiring by Mid Atlantic manufacturers has been expanding since December 2009, although it hit a decided soft spot in the summer of 2010. In July 2012 the index printed another soft reading of -8.4, indicating that during July the number of manufacturing respondents that reported current hiring activity dipped into the minority. While this dip seems to be reflective of the current softness in commercial sales, it is expected to be temporary and will reverse in the coming months.

Figure 6
The Philadelphia Fed Manufacturers Survey
Recent Hiring and Hiring Plans



More important, future hiring plans have been expanding from a very pessimistic base since June

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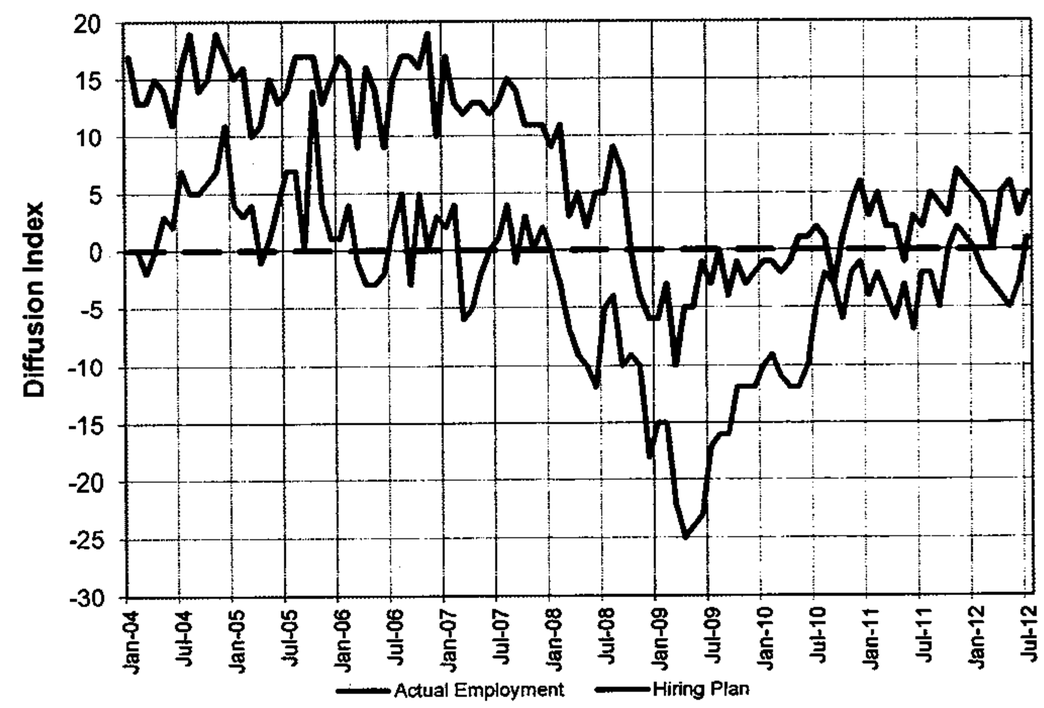
of 2009, and the number of firms with near term hiring plans remains a solid majority of respondents. Job creation by these manufacturers will begin to expand again over the next six months.

Many of these local manufacturers are smaller corporations, but they're still not the small, independent businesses where it is believed most of the hiring must take place. Many independent, smaller companies – those without actively traded common stock but with real employees rather than contractors – belong to the National Federation of Independent Business (NFIB). NFIB's chief economist, our friend Bill Dunkelberg, has been surveying the attitudes of independent business for more than 30 years. The results of their survey questions relating to employment and hiring plans are shown in Figure 7.

Independent business is reporting that most of their members employ fewer people than they did prior to 2008, and they're still thinking hard about how much staffing they require. Those adding to staff outnumber those still reducing staff by only a few percentage points. The trend is clearly up, but it is slow going.

Figure 7
National Federation of Independent Business Survey of Hiring Plans



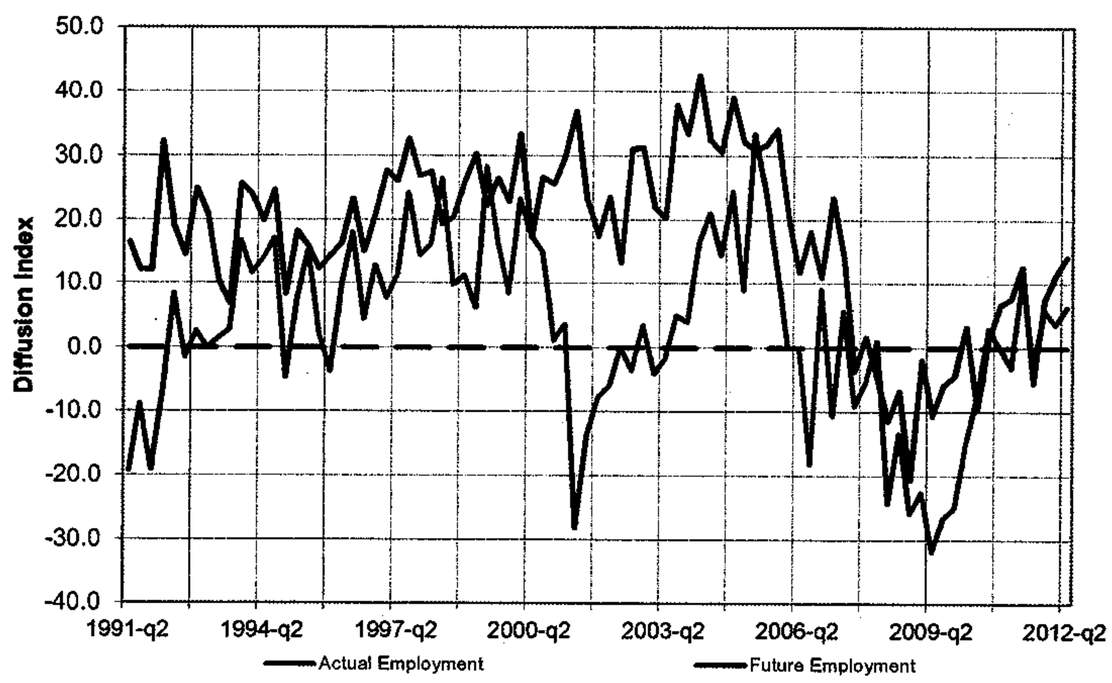
Many smaller businesses are strapped for cash, especially the ones that use contractors instead of employees. The smallest businesses are financed with personal credit cards and second mortgages, and they remain starved for capital. The slightly larger small businesses surveyed by NFIB say that the primary underlying problem is a lack of sales. They can't feel better about their businesses until the sales come back.

But what about our hardest hit area, served by the ACE brand name? Within the PHI footprint, the Philly Fed also conducts a survey of small business called the South Jersey Business Survey. The mailing list is essentially the South Jersey Chamber of Commerce. These smaller, local businesses are telling us (Figure 8) that they only returned to neutral on their expectations for the future in Q4 2011. A majority of them say that they employ fewer people than they did in the past (following the red line) but at least they have stopped reducing their workforce.

Their plans for future hiring (the blue line) are strengthening slowly. Figure 8 shows most clearly of all the data we've discussed just how

slowly things are improving for small local businesses, especially in South Jersey.

Figure 8
Philadelphia Fed South Jersey Business Survey
Survey of Hiring Plans



Why should we believe that the employment situation will improve toward the end of 2012 and on into 2013? It's not just blind faith and simple optimism – there are several important pieces of information that demonstrate that deep beneath the surface long-term improvements in employment are beginning to bubble up: hours worked, overtime and part-time employees, and changes in productivity. Businesses may not be hiring enthusiastically yet, but they are asking their current employees to work more hours, they are granting more overtime, and they are hiring part-time and temporary workers. On the other hand, part-time and temporary employees may have reached the limit of their ability to produce efficiently.

Figure 9 shows the average hours worked per week by private employees. Hours worked reached a low of 33.7 hours/week in October 2009, and has been recovering steadily ever since. We've almost recovered the losses in hours worked experienced during the recession. This is very important – the average worker is now working almost as many hours as they did at their peak.

As hours worked continues to expand, an increasing number of employees will become full time workers. As that happens, employers will need to hire new employees in order to continue expanding production. The trend in hours worked is now firmly in place; as more production is required, employers will have less choice about hiring new workers instead of assigning more work to existing staff.

Figure 9
Hours Worked By Private Employees

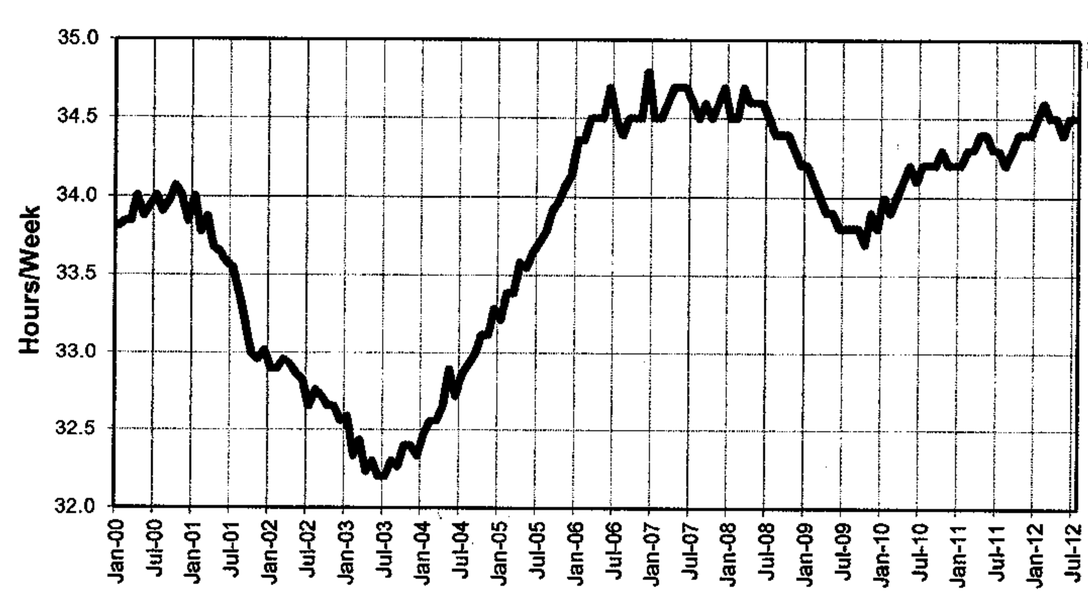


Figure 10 reports the number of overtime hours worked by manufacturing employees. Overtime hit bottom in March 2009 with an average of only 2.6 overtime hours/week worked by manufacturing employees. That average returned to 4.0 hours/week in January 2011 and has been between 4.0 and 4.2 hours ever since. We're now within about 3 hours/week of the very healthy levels reached in 2004-5. Once again, the signal is that the trend is firmly in place, and we are now

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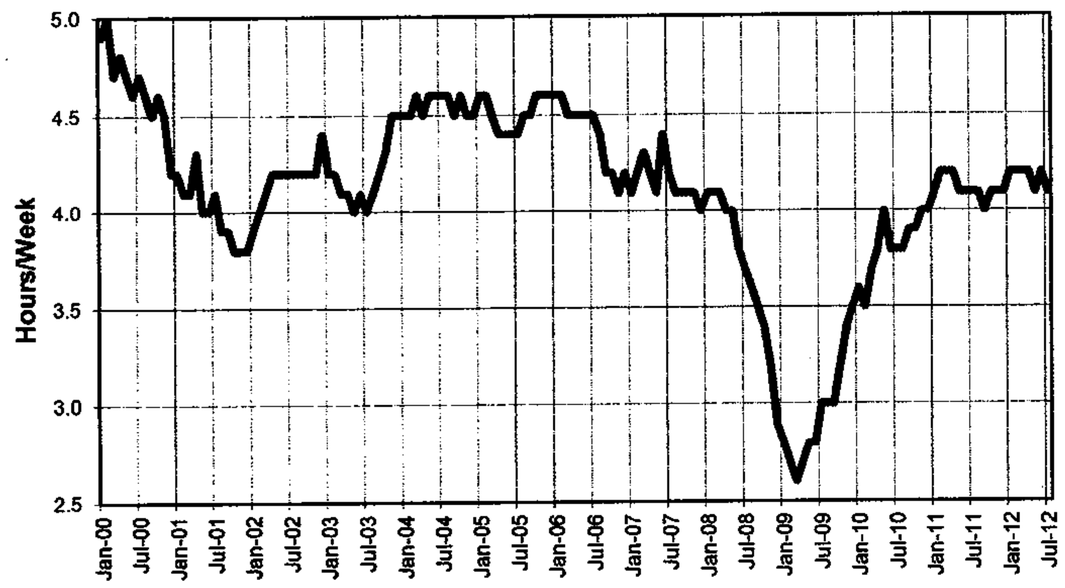
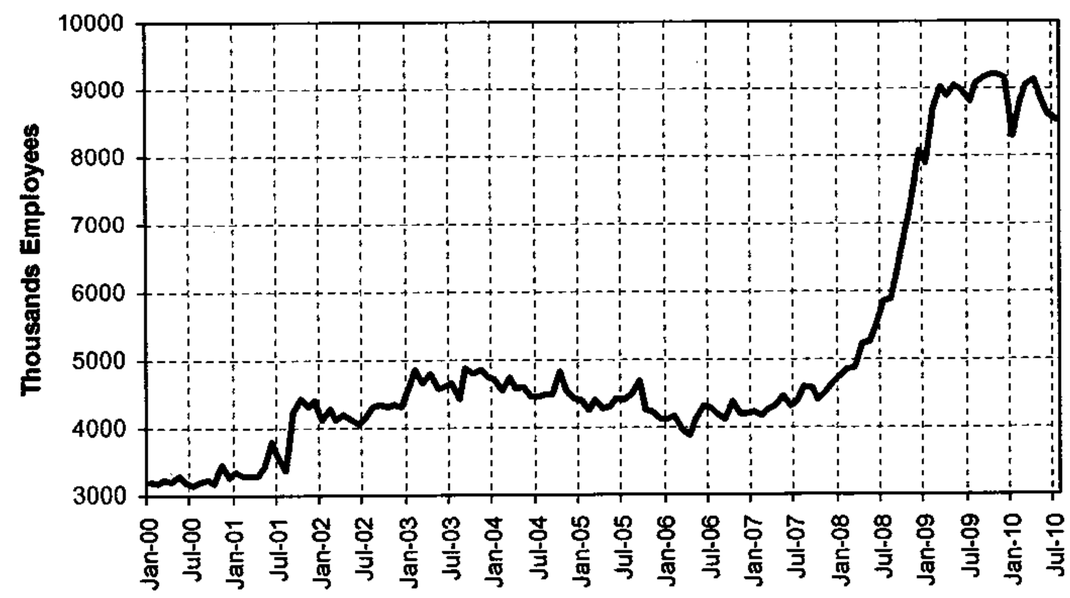
at the point where in order to increase manufacturing output, employers will need to expand their full time payroll.

Figure 10
Hours of Overtime Worked By Manufacturing Employees



Furthermore, we believe that the prospects for employment growth will continue to improve because part-time employment has jumped through the roof, despite some recent easing. Figure 11 shows the number of part-time employees aged 16 and older. It is amazing that the number of part time employees has almost doubled during the recession. Employers are not obligated to provide benefits for part-time employees, so in a cut-throat cost environment, part-time workers are very attractive.

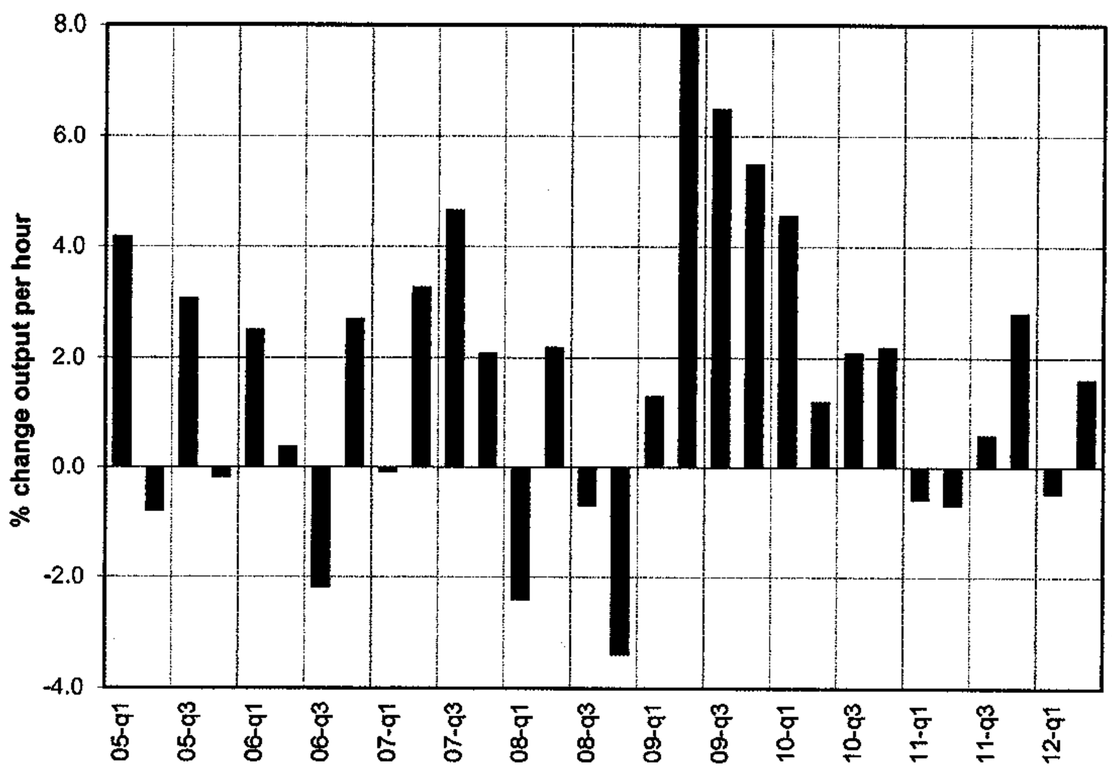
Figure 11
Part Time Employees Age 16 and Older



The attraction of part-time workers starts to fade, though, as economic conditions get better. Employers eventually find that as their book of business improves the advantages of having a mature, well-trained, dedicated and properly compensated employee are worthwhile because it allows the employer to deliver a higher quality, more competitive product. That's what we're waiting for.

Finally, after eight quarters of strong gains in productivity over the past nine quarters, workers may be reaching their limit as the Labor Department reported weak 1.6% productivity growth in Q2. Figure 12 shows the quarterly changes of nonfarm business productivity.

Figure 12
Output per Hour
(quarterly, year-over-year percent change)



Productivity has declined to much weaker current levels than was seen in 2009, when a smaller work force was working very efficiently to get the work done with fewer people. If productivity performance continues weak, increased hiring of full time employees will be necessary simply to get the work done. The alternative, using many more less productive part-time and temporary employees to get the still increasing work done will quickly become unprofitable.

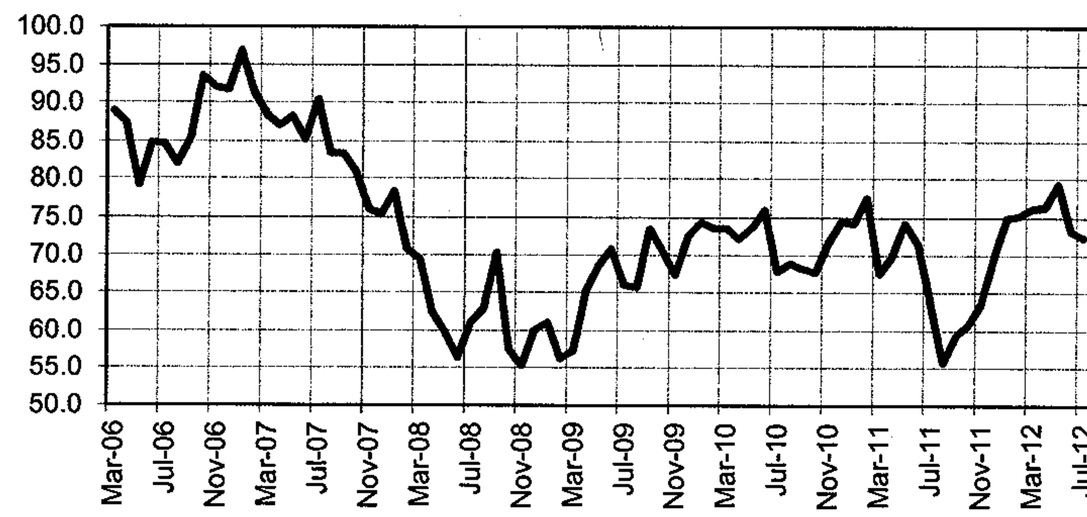
The pieces of this puzzle are indicating that employment will continue to improve slowly in the months to come, with occasional setbacks.

Consumer Sentiment

Unless consumers feel like current economic conditions are safe, the demand for housing will continue to be weak. We're very fortunate that consumers finally seem like they are beginning to be just a little more optimistic.

The July University of Michigan Final Index of Consumer Sentiment dropped to an index value of 72.3 in May. As can be seen in Figure 13, the index reached its lowest levels in June 2008 and then dragged along the bottom until February 2009. Those lowest levels were then revisited in August 2011. Since then it has retraced about half of the distance to its pre-recession level.

Figure 13
U of M Consumer Sentiment Survey



Nearly half of all consumers reported in July that their finances had recently worsened, with equal numbers attributing the decline to lower incomes and to higher prices. Complaints about rising prices have shifted from gas to food prices. Finally, only 10% of consumers expect any inflation-adjusted gains in their incomes in the next year, and just 22% think there is a better than even chance of real income gains over the next five years.

Looking at the components of the total index, consumers' opinion of current conditions strengthened slightly to a level of 82.7 in July, up from 82.5 in June and up from a level of 75.7 one year ago. While consumers may feel uncertain about their current finances (they should), they clearly believe that current economic conditions have improved dramatically. Consumers are

equally optimistic about the future – the July index of consumer expectations was 65.6, down very slightly from a level of 67.8 in June, but up dramatically from 55.9 one year ago. Consumers clearly believe that things are better than they were, and it gets better from here.

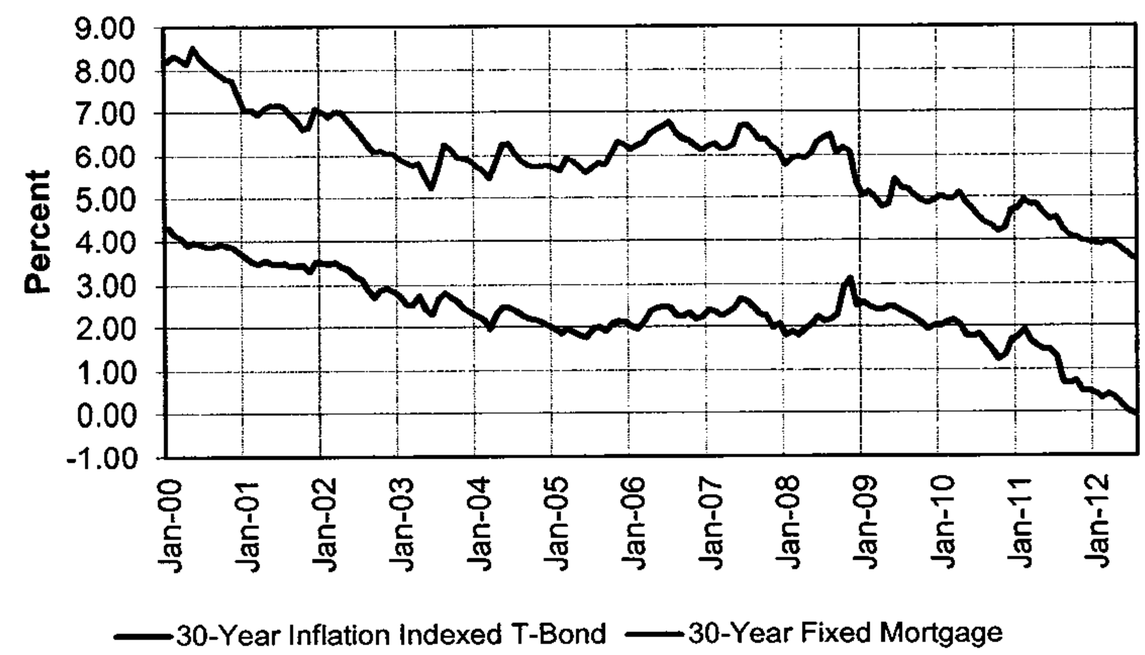
The Consumer Sentiment Survey is closely related to consumers' purchases of big-ticket items, and is an important first step towards a return of consumer spending. The index has made up about half of the loss it experienced between January 2007 and June of 2008, but it is not making further progress. It tells us consumers are healing and feeling more optimistic about the climate for spending, but they are not sanguine. It tells us further that six to twelve months from now consumers will be spending more on big-ticket items, especially cars, but also houses. That is, unless they really get scared.

Credit and Risk

The Federal Reserve's policy of fighting the Great Recession by expanding their balance sheet through the repurchase of treasury bonds (and other, less traditional securities) has served to lower T-Bond yields to levels last seen in the 1940s. T-Bond yields are now lower than expected inflation, implying that the least risky interest rate in the economy is now negative in real terms. In other words, if you own Treasury bills or notes, you're under water. For mortgage borrowers, the Fed has created a once-in-a-lifetime opportunity to finance housing on the cheap.

As can be seen in Figure 14, in normal times there is about a 400 basis point spread between the T-Bond yield and the average rate on 30-year fixed rate mortgages. So, mortgage rates will basically track Fed policy. So long as the Fed keeps to its intervention against the long rate, we can expect for mortgage rates to maintain at these historically very low levels.

Figure 14
Mortgage Rates and T-Bond Yields



The concern is that at some point in the next few months or years the Fed must begin deleveraging its balance sheet by selling some of the securities it has purchased in order to provide liquidity needed by the banking system. An alternative fear is that the yield on these securities has become so low that foreign investors may find them to be less attractive investments.

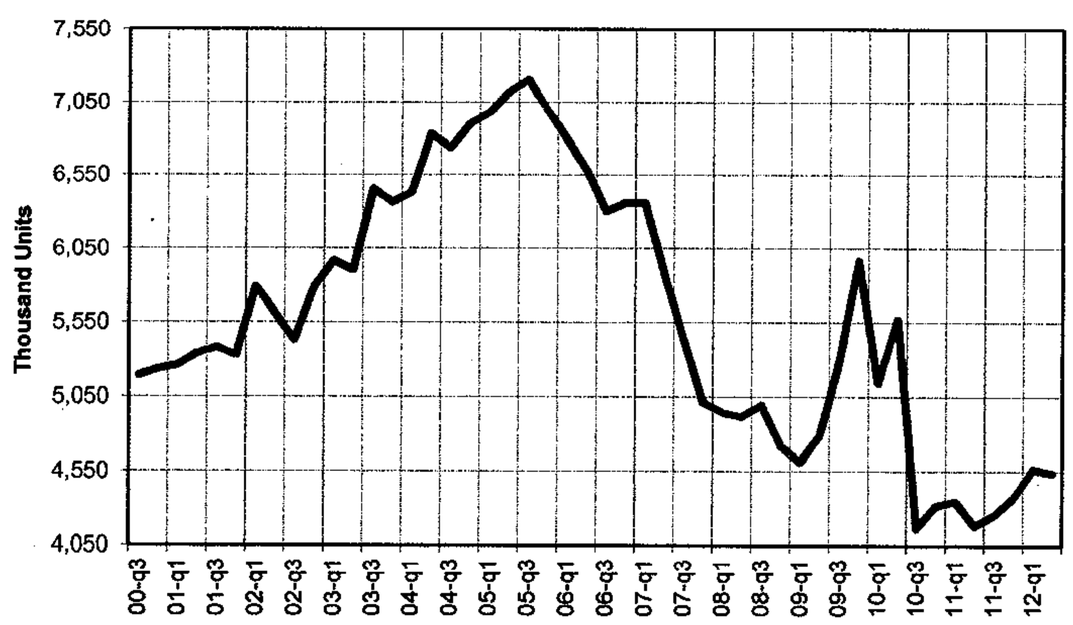
In either case, as the supply of US treasury securities increases relative to demand, bond prices will fall and their yields will rise. Over a period of several years, the yield on the T-Bond is almost certain to return to the 6% range, implying much higher mortgage rates (and much lower market prices for debt instruments). Looking back this will seem to have been a great time to take out a mortgage and buy a house.

Housing

PHI Economics and Forecasting Group

Perhaps the most painful part of the recent housing story is the dead cat bounce that Sales of Existing Homes (from the National Association of Realtors) made between the first quarter of 2009 and the end of 2010 (Figure 15). The number of sales and the prices realized revisited their recent lows and then went on to set new lows. Sales have now returned to 4.5 million sales annually, nowhere near the 7.0 million unit running rate seen in 2005.

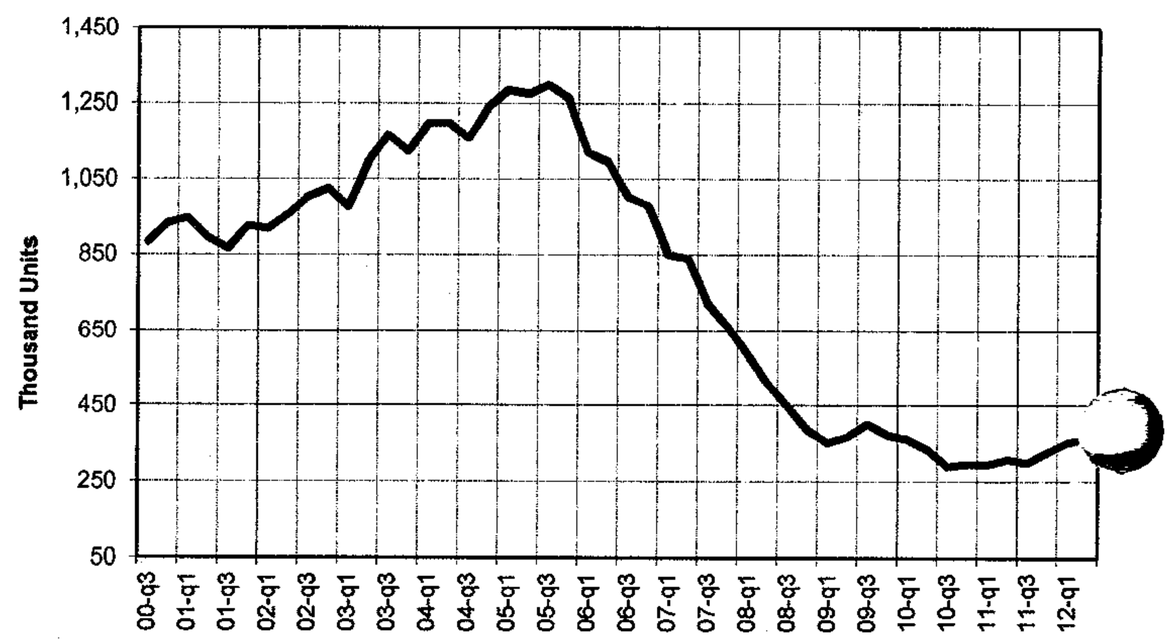
Figure 15
Sales of Existing Homes



Meanwhile, Sales of New Homes as reported by the National Association of Homebuilders (Figure 16) did not bounce, but have just been sitting dead in the water at about one-third of their 2005 peak. Homebuilders are starting to build new homes, slowly, but the new homes tend to be smaller and less expensive. It remains to be seen what the next generation of homes will look like, but this may be where household balance sheets come into play.

While we are comfortable arguing that consumers can begin buying again before they have completed the process of deleveraging, the debt they're carrying on their household balance sheet is almost certain to influence the type of house that they are eligible to buy under mortgage lending standards. Of course, mortgage-lending standards have gotten much tighter since the collapse (bankers say it's a return to normal), and these tighter rules may be one of the permanent changes in the landscape resulting from the Great Recession.

Figure 16
Sales of New Single Family Homes

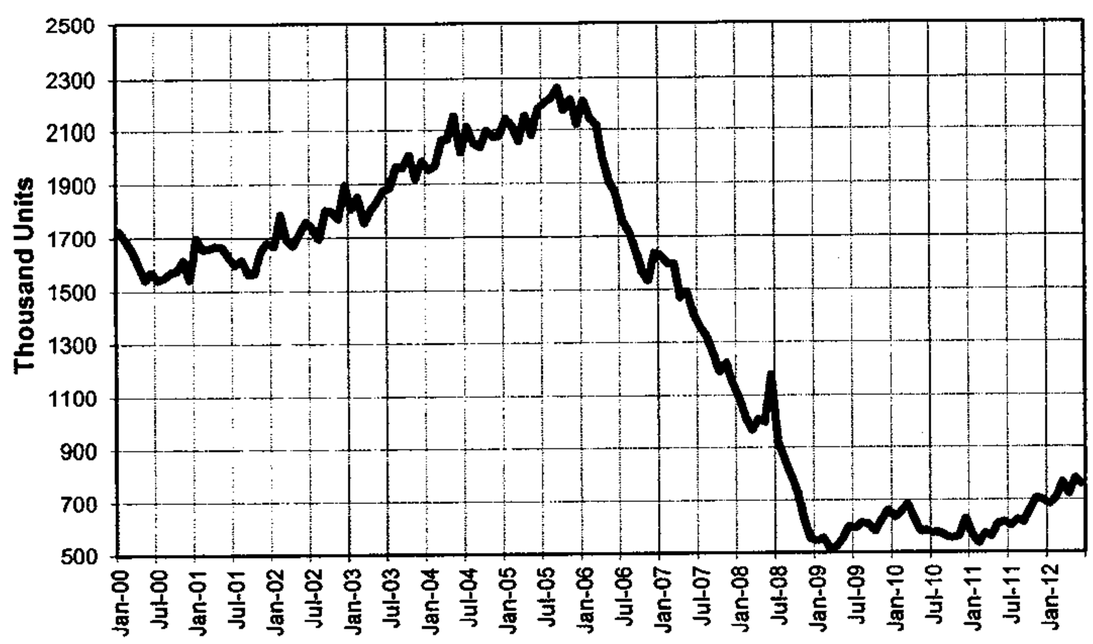


Since the trough of the recession, the inventory of new homes (nationwide) has shrunk from an average of 10.4 months supply in 2008 to 6.6 month's supply – nearly normal – in June 2012. The inventory of new homes for sale has changed very little. Instead, homes have been added to the For Sale listings almost as quickly as the number of sold homes has left the inventory.

Fortunately, the number of building permits and new housing starts has contracted to an exceptionally low level. As can be seen in Figure 17, monthly issuances of building permits has fallen to a level of less than one-third their prerecession level. This really is the hope for a recovery in housing. It is important that builders continue to place a small number of new homes

on the market. It is also important that the overhang of homes waiting to be listed for sale is worked off and the inventory of unsold homes remains in balance, roughly 6 month's supply of homes for sale. This process will undoubtedly require another one to two years to work out. Until then, we have to expect that our neighborhoods will be full of for sale signs and home prices will remain stagnant.

Figure 17
Single Family Building Permits



Housing In PHI North

We are very fortunate to have been given access by Prudential Fox-Roach to current data on actual housing transactions from the Philadelphia area Multiple Listing Services (Table 2). This data doesn't match our service areas exactly, but it comes very close. New Castle and Kent counties in DE contain a big portion of the activity in DPL DE, and are probably an accurate representation of the area we serve. On the ACE side of the river, we have data for almost all of the heavily populated areas within the jurisdiction. In Table 2 we're breaking the data out into two distinct markets – Atlantic County has so many special factors influencing price that it behaves differently than the rest of the region.

The PHI North real estate market, after seeming to hold up with only slight weakness earlier in the recession, has now started to weaken further. The average time to sell has stretched out to 120 days, longer than at any time during this cycle. Pricing had seemed to stabilize during 2010, but is now down to $185,153, another new low.

In Atlantic County, average home selling prices had rebounded from a low of $213,404 in 10:I to $226,735 in 11:II. They are now about 16% below their 2008 peak. The average number of days to sale is 139 days.

Table 2

PHI North and Atlantic Shore Housing Prices

PHI North Housing Market
New Castle, Kent, Burlington, Camden, Salem and Gloucester Counties (including only the townships served by PHI)

	08:QI	08:QII	08:QIII	08:QIV	09:QI	09:QII	09:QIII	09:QIV	10:QI
Number of Properties Sold	2,592	3,658	3,410	2,483	1,958	3,040	3,506	3,325	2,137
annual % chg	*-32.0%*	*-12.7%*	*-23.9%*	*-28.2%*	*-24.5%*	*-16.9%*	*2.8%*	*33.9%*	*9.1%*
Median Price of Properties Sold	$225,269	$230,038	$228,894	$212,989	$202,441	$214,323	$215,208	$200,121	$203,848
annual % chg	*-0.7%*	*-3.3%*	*-2.4%*	*-6.2%*	*-10.1%*	*-6.8%*	*-6.0%*	*-6.0%*	*0.7%*
Average Days On the Market	84	79	78	88	103	95	93	96	99
annual % chg	*26.8%*	*28.9%*	*24.3%*	*23.8%*	*21.5%*	*20.6%*	*18.9%*	*9.1%*	*-3.4%*

	10:QII	10:QIII	10:QIV	11:QI	11:QII	11:QIII	11:QIV	12:QI	12:QII
Number of Properties Sold	3,776	2,427	2,249	1,961	2,940	3,041	2,733	2,495	3,417
annual % chg	*24.2%*	*-30.8%*	*-32.4%*	*-8.2%*	*-22.1%*	*25.3%*	*21.5%*	*27.2%*	*16.2%*
Median Price of Properties Sold	$205,257	$214,527	$198,567	$185,153	$191,584	$191,219	$176,780	$172,779	$185,166
annual % chg	*-4.2%*	*-0.3%*	*-0.8%*	*-9.2%*	*-6.7%*	*-10.9%*	*-11.0%*	*-6.7%*	*-3.3%*
Average Days On the Market	92	90	100	120	112	106	111	115	106
annual % chg	*-3.2%*	*-2.6%*	*3.9%*	*21.4%*	*22.1%*	*17.3%*	*11.7%*	*-4.7%*	*-5.4%*

ACE NJ Shore Housing Market
Atlantic County, NJ

	08:QI	08:QII	08:QIII	08:QIV	09:QI	09:QII	09:QIII	09:QIV	10:QI
Number of Properties Sold	612	775	692	546	395	685	722	800	518
annual % chg					*-35.5%*	*-11.6%*	*4.3%*	*46.5%*	*31.1%*
Median Price of Properties Sold	$270,728	$271,845	$257,333	$227,265	$241,484	$250,708	$238,931	$221,309	$213,404
annual % chg					*-10.8%*	*-7.8%*	*-7.2%*	*-2.6%*	*-11.6%*
Average Days On the Market	110	103	116	135	125	120	115	120	118
annual % chg					*12.9%*	*16.4%*	*-0.6%*	*-11.4%*	*-5.2%*

	10:QII	10:QIII	10:QIV	11:QI	11:QII	11:QIII	11:QIV	12:QI	12:QII
Number of Properties Sold	824	626	616	495	687	613	601	559	771
annual % chg	*20.3%*	*-13.3%*	*-23.0%*	*-4.4%*	*-16.6%*	*-2.1%*	*-2.4%*	*12.9%*	*12.2%*
Median Price of Properties Sold	$232,891	$238,197	$225,118	$185,500	$208,727	$190,215	$184,040	$195,000	$194,827
annual % chg	*-7.1%*	*-0.3%*	*1.7%*	*-13.1%*	*-10.4%*	*-20.1%*	*-18.2%*	*5.1%*	*-6.7%*
Average Days On the Market	112	107	130	132	139	128	133	152	128
annual % chg	*-6.8%*	*-7.6%*	*9.0%*	*11.3%*	*23.8%*	*19.7%*	*2.0%*	*15.5%*	*-7.9%*

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PEPCO MD Housing Market
Montgomery and Prince George Counties

	07:QIII	08:QII	08:QI	08:QII	08:QIII	08:QIV	09:QI	09:QII	09:QIII	09:QIV
Number of Properties Sold	4,468	3,198	2,487	3,766	4,048	3,139	2,679	4,453	5,287	4,970
annual % chg	*-36.4%*	*-45.5%*	*-47.9%*	*-31.2%*	*-9.4%*	*-1.8%*	*7.7%*	*18.2%*	*30.6%*	*58.3%*
Median Price of Properties Sold	$400,965	$371,419	$361,274	$379,713	$346,191	$309,575	$284,784	$309,671	$296,036	$274,970
annual % chg	*2.6%*	*-3.3%*	*-6.0%*	*-5.4%*	*-13.7%*	*-16.7%*	*-21.2%*	*-18.4%*	*-14.5%*	*-11.2%*
Average Days On the Market	74	101	118	110	108	120	132	117	105	91
annual % chg	*48.2%*	*47.4%*	*38.9%*	*52.0%*	*45.4%*	*18.4%*	*11.3%*	*5.8%*	*-3.4%*	*-23.7%*

	10:QI	10:QII	10:QIII	10:QIV	11:QI	11:QII	11:QIII	11:QIV	12:QI	12:QII
Number of Properties Sold	3,947	6,246	4,595	4,098	3,660	4,986	4,519	3,982	3,484	5,087
annual % chg	*47.3%*	*40.3%*	*-13.1%*	*-17.5%*	*-7.3%*	*-20.2%*	*-1.7%*	*-2.8%*	*-4.8%*	*2.0%*
Median Price of Properties Sold	$257,020	$282,919	$287,023	$276,620	$241,598	$272,895	$271,525	$248,983	$243,763	$301,522
annual % chg	*-9.7%*	*-8.6%*	*-3.0%*	*0.6%*	*-6.0%*	*-3.5%*	*-5.4%*	*-10.0%*	*0.9%*	*10.5%*
Average Days On the Market	86	71	73	80	91	85	88	97	96	78
annual % chg	*-34.6%*	*-38.9%*	*-29.7%*	*-11.8%*	*5.4%*	*19.4%*	*20.0%*	*20.3%*	*6.2%*	*-8.7%*

PEPCO DC Housing Market

	07:QIII	08:QII	08:QI	08:QII	08:QIII	08:QIV	09:QI	09:QII	09:QIII	09:QIV
Number of Properties Sold	1,941	1,513	1,215	1,570	1,520	1,264	979	1,622	1,984	1,853
annual % chg	*-6.6%*	*-10.6%*	*-31.4%*	*-28.3%*	*-21.7%*	*-16.5%*	*-19.4%*	*3.3%*	*30.5%*	*46.6%*
Median Price of Properties Sold	$400,825	$398,300	$407,636	$424,300	$401,943	$373,333	$359,900	$396,833	$370,333	$366,666
annual % chg	*-4.5%*	*1.9%*	*0.2%*	*1.4%*	*0.3%*	*-6.3%*	*-11.7%*	*-6.5%*	*-7.9%*	*-1.8%*
Average Days On the Market	61	68	85	76	80	78	105	90	88	83
annual % chg	*6.4%*	*-1.0%*	*4.5%*	*19.3%*	*31.1%*	*14.8%*	*24.4%*	*17.5%*	*10.0%*	*7.3%*

	10:QI	10:QII	10:QIII	10:QIV	11:QI	11:QII	11:QIII	11:QIV	12:QI	12:QII
Number of Properties Sold	1,321	2,187	1,607	1,478	1,314	1,815	1,662	1,363	1,320	1,918
annual % chg	*34.9%*	*34.8%*	*-19.0%*	*-20.2%*	*-0.5%*	*-17.0%*	*3.4%*	*-7.8%*	*0.5%*	*5.7%*
Median Price of Properties Sold	$341,833	$388,167	$399,667	$409,500	$372,717	$421,000	$408,300	$402,967	$392,833	$451,333
annual % chg	*-5.0%*	*-2.2%*	*7.9%*	*11.7%*	*9.0%*	*8.5%*	*2.2%*	*-1.6%*	*5.4%*	*7.2%*
Average Days On the Market	84	64	62	70	86	73	72	74	77	56
annual % chg	*-20.3%*	*-29.0%*	*-29.2%*	*-16.4%*	*2.0%*	*14.1%*	*15.5%*	*6.2%*	*-9.7%*	*-23.4%*

PHI Office Space

US Non-Central Business District (Non-CBD) vacancy rates reached 16.3% in 2012 Q2 (Table 3), the lowest they have been since 2008.

Construction put in place decreased from the prior year in the non-CBD by a modest 6.6%. Non-CBD rents, at $31.01/sf are now at their highest level since 2008 Q4.

Table 3

US Market For Office Space

(CBD – Central Business District)

United States	08:QIV	09:QIV	10:QIV	11:QI	11:QII	11:QIII	11:QIV	12:QI	12:QII
Inventory (sf)									
CBD	1,425,826,040	1,462,778,645	1,449,333,202	1,508,121,305	1,502,209,577	NA	1,511,372,922	NA	NA
Non-CBD	2,794,744,264	2,910,179,898	2,855,030,793	2,907,088,559	4,405,484,605	4,425,723,543	2,937,674,406	4,585,978,417	4,582,895,043
Overall Vacancy Rate (%)									
CBD	11.9%	15.0%	15.4%	15.5%	14.9%	NA	14.7%	NA	NA
Non-CBD	15.8%	18.3%	18.7%	18.4%	17.2%	17.1%	18.1%	16.7%	16.3%
YTD Leasing Activity (sf)									
CBD	72,525,598	55,178,620	71,912,314	21,313,558	46,874,127	NA	87,322,784	NA	NA
Non-CBD	164,196,022	131,400,200	150,350,194	33,278,338	120,304,965	184,584,290	164,441,571	50,606,291	112,376,868
YTD Construction Completed (sf)									
CBD	8,787,392	15,494,045	9,082,819	3,353,171	3,841,913	NA	6,381,950	NA	NA
Non-CBD	57,237,472	36,986,090	13,619,191	2,324,686	7,475,502	13,663,868	8,867,559	3,661,226	6,984,892
Class A Direct Rental Rate ($/sf)									
CBD	$ 43.56	$ 39.44	$ 38.86	$ 32.97	$ 38.43		38.22		
Non-CBD	$ 28.23	$ 25.79	$ 26.13	$ 21.72	$ 30.39	$ 29.33	$ 25.00	$ 29.76	$ 31.01

In DC's CBD (see Table 4), vacancies have improved to 11.2%, relatively low by historic standards, but there is still only 1.8 million sf under construction, compared to 10-12 million sf prior to the recession.

Within the District's CBD, the office market normally grows at a surprisingly constant 10+ msf annually, and vacancy rates hold fairly constant in the 7%-7.5% range. The market has always grown with growth in office-based employment; much of it government driven, and the process seemed smooth and predictable. Even during the beginning of this recession, the conventional wisdom was that the stimulus would cause an expansion of government and related office based employment that would leave the DC market for commercial space relatively unscathed.

That comfortable story is no longer true. Vacancies are improving, but they are still too high to warrant new construction. The 9.7 msf that was under construction in 08:III is now substantially completed and serving as a burden on the market. The pace of construction has slowed dramatically.

Growth has been interrupted, vacancies are climbing and construction has slowed to a crawl. There are construction cranes on the horizon, making DC a very unusual skyline, but it is just an illusion. Leasing activity 2010 was a measly 4.5 msf, two-thirds more than 2009. Year to date in 2012 leasing activity has been 2.1 million sf.

Table 4

Washington DC and Suburban MD Market for Class A Office Space

(Source: Cushman and Wakefield, PHI Economics and Forecasting Group)

Washington D.C.	07:QIV	08:QIV	09:QIV	10:QIV	11:QI	11:QII	11:QIII	11:QIV	12:QI	12:QII
Inventory (sf)		40,054,530	45,694,571	48,962,697	104,097,924	104,097,924	104,658,885	104,950,191	105,509,154	105,792,113
No. Of Buildings (#)		132	148	161						
Overall Vacancy Rate (%)		10.8%	21.8%	18.1%	12.6%	11.5%	11.6%	11.9%	12.2%	12.5%
Direct Vacancy Rate (%)		9.7%	19.7%	16.6%	11.3%	10.1%	10.4%	10.8%	10.8%	11.2%
YTD Leasing Activity (sf)		2,572,104	2,718,060	4,570,597	2,207,886	3,100,714	3,979,705	4,847,048	1,246,052	2,099,566
Under Construction (sf)		8,610,363	3,828,057	1,502,806	1,823,263	1,397,613	1,948,589	2,011,560	2,068,475	1,817,930
YTD Construction Completed (sf)		1,567,734	5,606,698	3,008,458	751,866	430,900	1,312,827	1,604,133	0	370,545
YTD Construction Absorption (sf)		1,225,810	(115,592)	3,557,593	315,197	1,582,066	1,778,814	1,663,777	(186,035)	(350,161)
Direct Wtd Avg Class A Gross Rental Rate ($/sf)		$ 55.74	$ 57.73	$ 55.35	$ 56.22	$ 59.27	$ 59.33	$ 59.28	$ 59.58	$ 60.81
			$ 57.62							

Suburban Maryland	07:QIV	08:QIV	09:QIV	10:QIV	11:QI	11:QII	11:QIII	11:QIV	12:QI	12:QII
Inventory (sf)	57,376,154	55,720,760	56,642,739	55,106,306	54,881,396	54,881,396	54,881,396	54,881,396	54,923,488	54,923,488
No. Of Buildings (#)	670	636	631	611						
Overall Vacancy Rate (%)	11.9%	13.5%	17.7%	17.1%	17.3%	17.7%	17.6%	17.3%	16.9%	17.1%
Direct Vacancy Rate (%)	9.9%	11.3%	15.2%	15.6%	16.0%	16.4%	16.4%	16.2%	15.8%	16.1%
YTD Leasing Activity (sf)	3,611,027	3,112,357	2,565,304	2,699,850	492,050	1,097,842	1,949,557	2,617,619	343,887	670,743
Under Construction (sf)	2,273,789	1,536,443	313,130	-	358,440	627,202	804,439	1,295,347	1,489,347	1,489,437
YTD Construction Completed (sf)	1,021,743	1,052,460	1,186,653	313,130	-	-	-	-	-	-
YTD Construction Absorption (sf)	(326,173)	(288,235)	(1,184,004)	443,734	81,337	(358,291)	(340,618)	(235,543)	204,222	12,195
Direct Wtd Avg Class A Gross Rental	$ 31.26	$ 31.92	$ 31.46	$ 31.43	$ 30.88	$ 30.19	$ 30.47	$ 30.72	$ 31.17	$ 31.16

In contrast to DC, the Wilmington Office Space market (Table 5) is smaller and cheaper but vacant – the Wilmington CBD is now at 17.1%. The CBD has had nothing under construction for the past two years. The County had one property under construction in 2010 but now has nothing under construction. The only bright spot on the horizon is that rents in downtown Wilmington, currently averaging $25.35/sf on the leases being written and rents are holding firm through the recession. New Castle Non CBD rents, now $23.28/sf, are actually up from this time a year ago. Of course, that improvement is probably attributable to a difference in the quality of the space on a very small number of leases.

Table 5

Wilmington DE Market for Office Space

(Source: Cushman and Wakefield, PHI Economics and Forecasting Group)

New Castle - Non CBD	07:QIV	08:QIV	09:QIV	10:QIV	11:QI	11:QII	11:QIII	11:QIV	12:QI	12:QII
Inventory (sf)	7,896,313	8,063,435	8,376,475	8,284,220	8,284,220	8,422,220	8,422,220	8,422,220	8,359,208	8,451,657
No. Of Buildings (#)	150	152	154	154						
Overall Vacancy Rate (%)	15.3%	17.2%	15.6%	16.5%	16.0%	16.9%	15.7%	17.0%	17.5%	17.1%
Direct Vacancy Rate (%)	13.9%	16.7%	15.3%	15.8%	15.3%	16.3%	15.0%	16.4%	16.9%	16.6%
YTD Leasing Activity (sf)	324,065	320,193	115,994	490,083	34,287	76,949	102,472	131,966	67,707	163,235
Under Construction (sf)	60,000	-	-	-	-	-	-	-	-	-
YTD Construction Completed (sf)	37,000	110,000	-	-	-	-	-	-	-	-
YTD Construction Absorption (sf)	29,244	(154,086)	311,759	(29,356)	41,191	(961)	106,186	(12,564)	(27,342)	(24,776)
Direct Wtd Avg Class A Gross Rent	$ 24.53	$ 24.11	$ 22.83	$ 24.07	$ 23.92	$ 24.64	$ 24.58	$ 24.62	$ 24.01	$ 23.28

Wilmington - CBD	07:QIV	08:QIV	09:QIV	10:QIV	11:QI	11:QII	11:QIII	11:QIV	12:QI	12:QII
Inventory (sf)	6,718,032	6,818,032	6,785,377	7,088,041	7,088,041	7,088,041	7,088,041	7,088,041	7,088,041	7,088,041
No. Of Buildings (#)	38	40	38	40						
Overall Vacancy Rate (%)	18.0%	11.7%	18.9%	19.2%	19.4%	19.1%	19.5%	20.0%	19.4%	20.2%
Direct Vacancy Rate (%)	15.2%	18.2%	18.7%	19.0%	19.1%	18.9%	19.3%	19.9%	19.3%	19.7%
YTD Leasing Activity (sf)	292,712	373,203	59,632	120,383	41,456	76,949	112,056	172,983	24,148	42,534
Under Construction (sf)	111,000	158,770	158,770	-	-	-	-	-	-	-
YTD Construction Completed (sf)	402,290	26,000	-	158,770	-	-	-	-	-	-
YTD Construction Absorption (sf)	246,683	(209,509)	(39,742)	(84,204)	(3,347)	11,602	36,002	(63,549)	46,673	15,943
Direct Wtd Avg Class A Gross Rent	$ 27.10	$ 25.29	$ 25.83	$ 23.46	$ 23.78	$ 25.01	$ 25.40	$ 26.17	$ 25.41	$ 25.35

The ***Housing, Construction and Employment Report*** is prepared periodically by the PHI Economics and Forecasting Group. The Economics and Forecasting Group is charged with monitoring and tracking economic activity within the PHI jurisdictions.

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Appendix D: Global Insight Delaware Economic Reports

Delaware

This information was last updated on 20 AUG 2012, 3:38 PM EDT (19:38 GMT)

Analysis: At a Glance

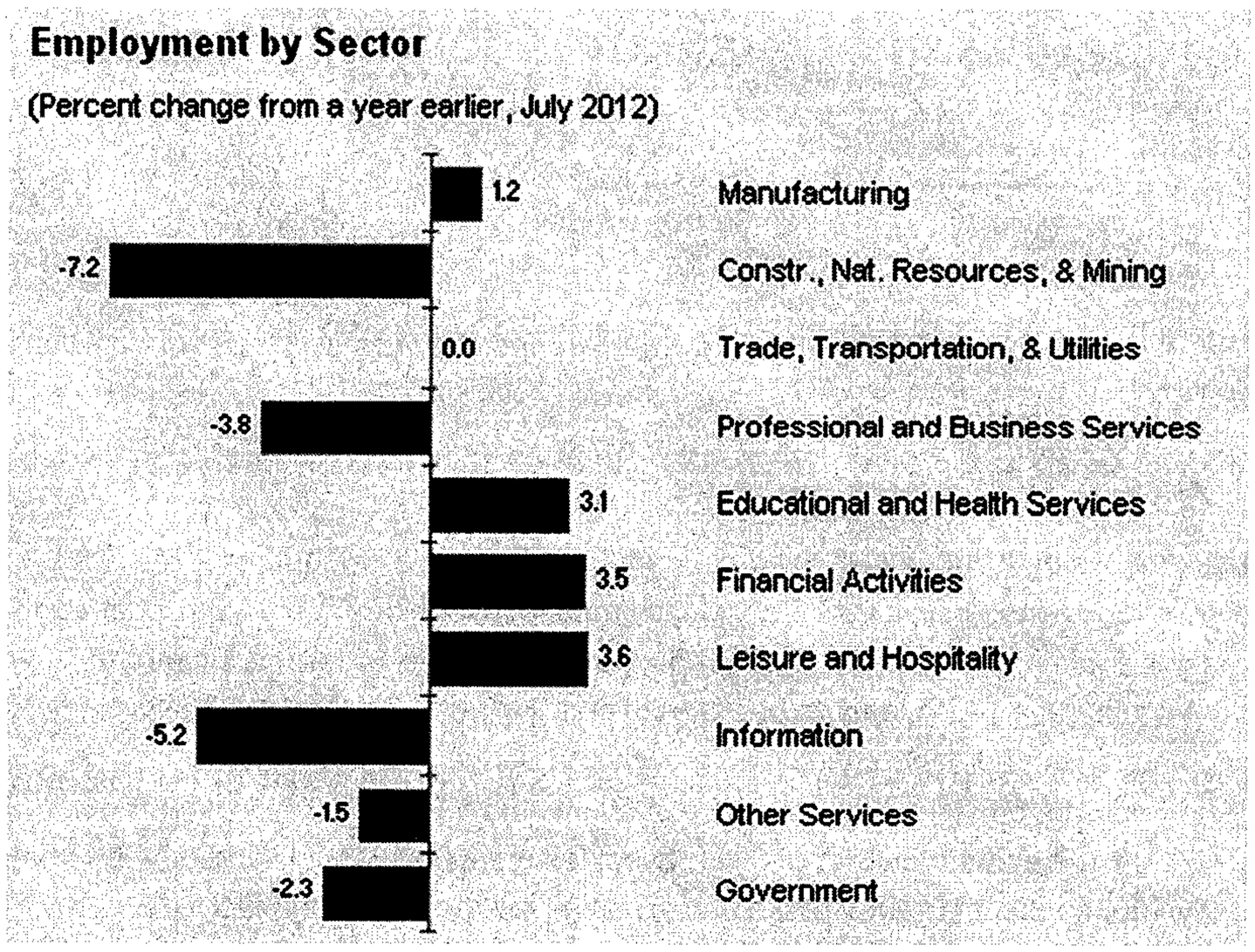
Payrolls Bounce Back to Start 2012.

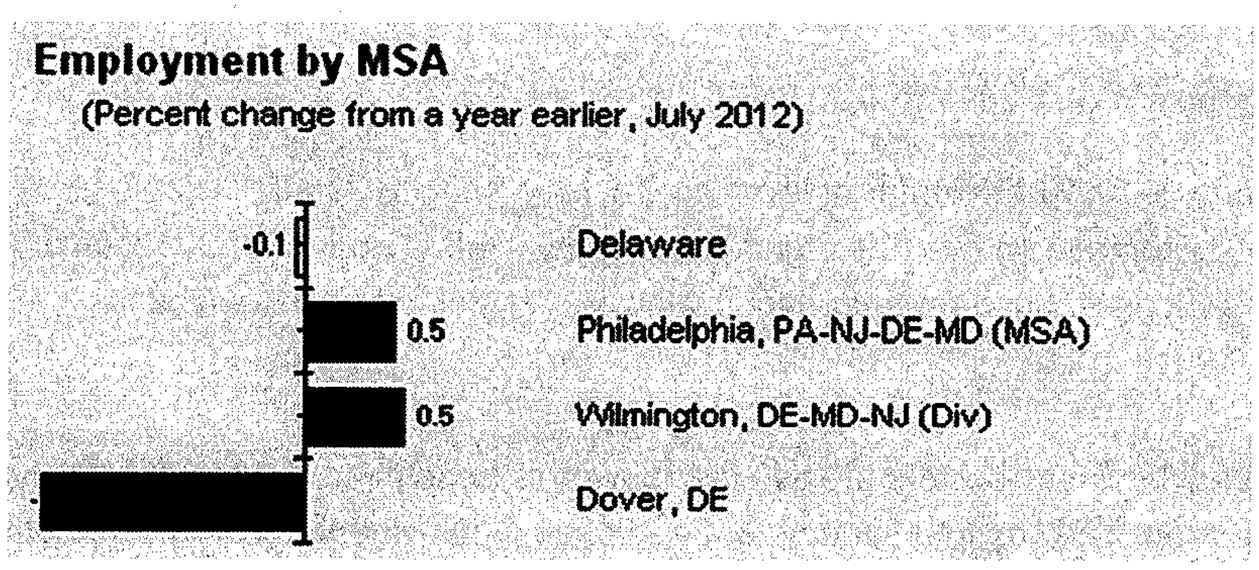
Delaware increased its total payrolls by 2,200 jobs in the first quarter of 2012. This amounts to 2.2% annualized growth as the state took a step in the right direction towards recovery from the Great Recession. The largest employment sector, trade and transportation, also happened to be the largest contributor to payroll growth, adding 800 net jobs (at an 4.3% annualized rate) to start the year. Professional business services also started strong and registered 4.9% annualized growth and added 670 jobs. Warm temperatures in January and February provided the retail trade sector with a bump of 3.5% annualized growth, following virtually no gain in the fourth quarter of 2011. Durables manufacturing also rebounded from 2011 losses and hired nearly 400, as Bloom Energy broke ground on a new manufacturing facility in Newark.

Financial Services as Important as Ever

Between the first quarters of 2008 and 2010, when nonfarm payrolls went from peak to trough, Delaware shed 34,400 jobs, an annualized 3.8% contraction over the eight quarters. By the first quarter of 2012, only about 35% of the jobs lost due to the recession had returned, and Delaware will not get back to peak employment until the third quarter of 2015.

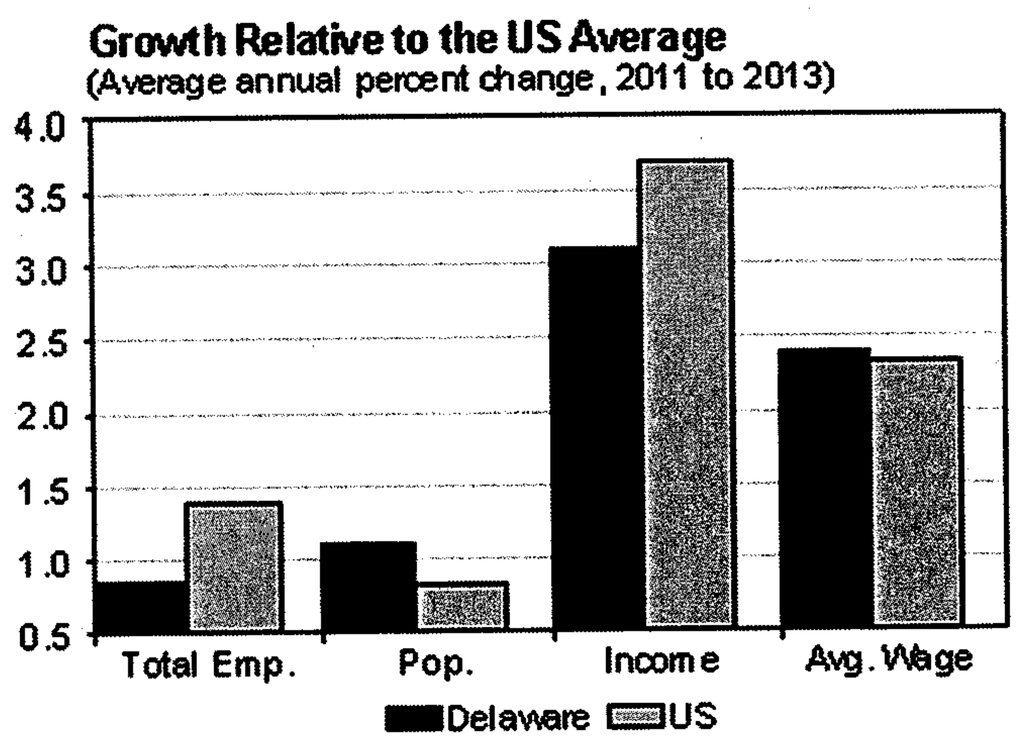
The financial services and professional/business sectors are two of Delaware's largest, accounting for nearly 30% of the total jobs lost in the recession. The key to a speedy return to peak employment will be recoveries within these important sectors.

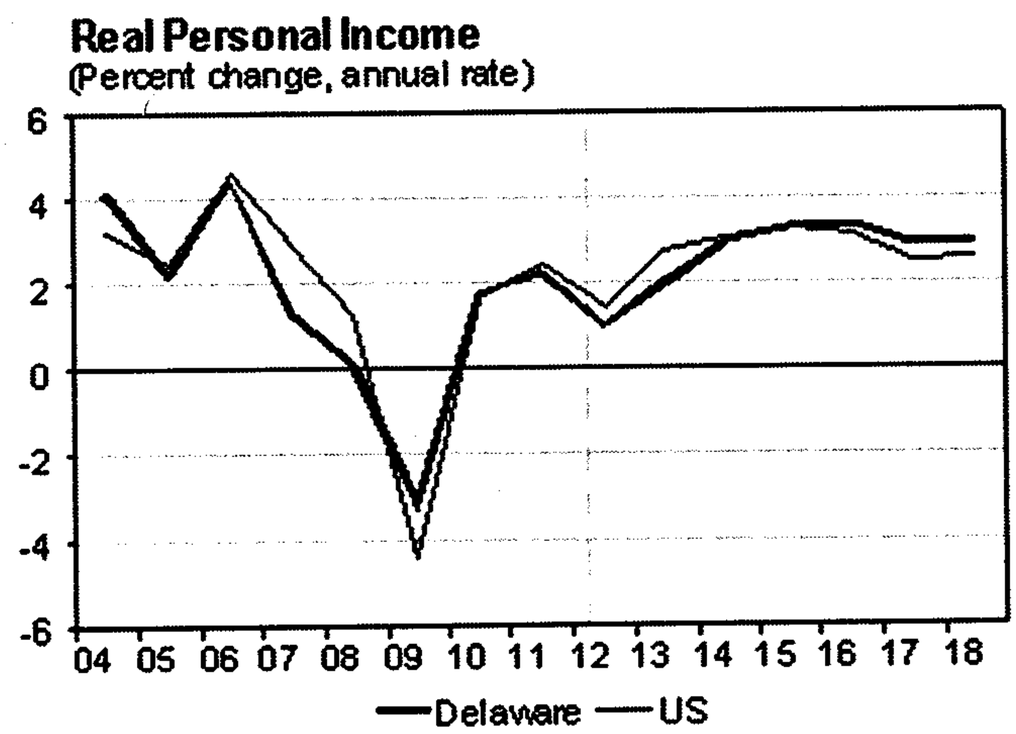




Issues to Watch

- The recent recession was driven by a liquidity crisis, which has caused a breakdown of several financial institutions. Financial services is one of the largest sectors in Delaware's economy; Bank of America is the largest employer in the state's financial sector, with a payroll of about 7,000. Bank of America, which is headquartered in North Carolina, announced in September plans to cut 30,000 total jobs by 2014. It is not yet clear how this will affect the financial institution's standing in Wilmington.
- Delaware has some significant competitive advantages compared with other states, including proximity to large metro areas such as New York (NY), Philadelphia (PA), Baltimore (MD), and Washington, D.C.; an above-average share of highly skilled scientific and technical workers; a critical mass of chemical, pharmaceutical, and biomedical companies; a tradition of technical innovation; high research and development spending by such companies as DuPont and AstraZeneca; modest but steady population growth; a low cost of living; and a favorable regulatory climate.





Near-Term Developments

For the second quarter of 2012, expect total nonfarm payrolls to slow and grow at a 1.0% annualized pace, and real gross state product (GSP) at 3.9%. While this economic growth will continue throughout 2012, we are forecasting these indicators to round out the year significantly higher than 2011. By the end of 2012 employment will grow at a 0.9% annualized rate, with real GSP growing a stronger 2.2%.

Delaware Outlook over the Next Four Quarters

		Baseline Scenario		
		Level	Percent	Rank
Year-over-year Change (2013Q3)	Employment	+5,264	+1.3	38
	Personal Income (Mil.$)	+1,433	+3.7	45
	Real Gross State Product (Mil. 2005$)	+1,374	+2.4	7
Level (2013Q3)	Unemployment Rate (%)	6.5		34
	Housing Starts	3,228		43

This information was last updated on 13 AUG 2012, 11:30 AM EDT (15:30 GMT)

Delaware Outlook over the Next Four Quarters

		Pessimistic			Optimistic		
		Level	Percent	Rank	Level	Percent	Rank
Year-over-year Change (2013Q3)	Employment	-333	-0.1	20	+8,507	+2.0	41
	Personal Income (Mil.$)	+543	+1.4	43	+1,930	+4.9	37
	Real Gross State Product (Mil. 2005$)	-249	-0.4	9	+2,597	+4.5	7
Level (2013Q3)	Unemployment Rate (%)	7.7		33	5.7		35
	Housing Starts	2,055		44	4,387		42

Analysis: Outlook

Changes to the Forecast (Short Term)

Real GSP	▲
Employment	▼
Personal Income	►
Unemployment Rate	►
Housing Starts	▼

▲ = Higher, ▼ = Lower , ► = No change

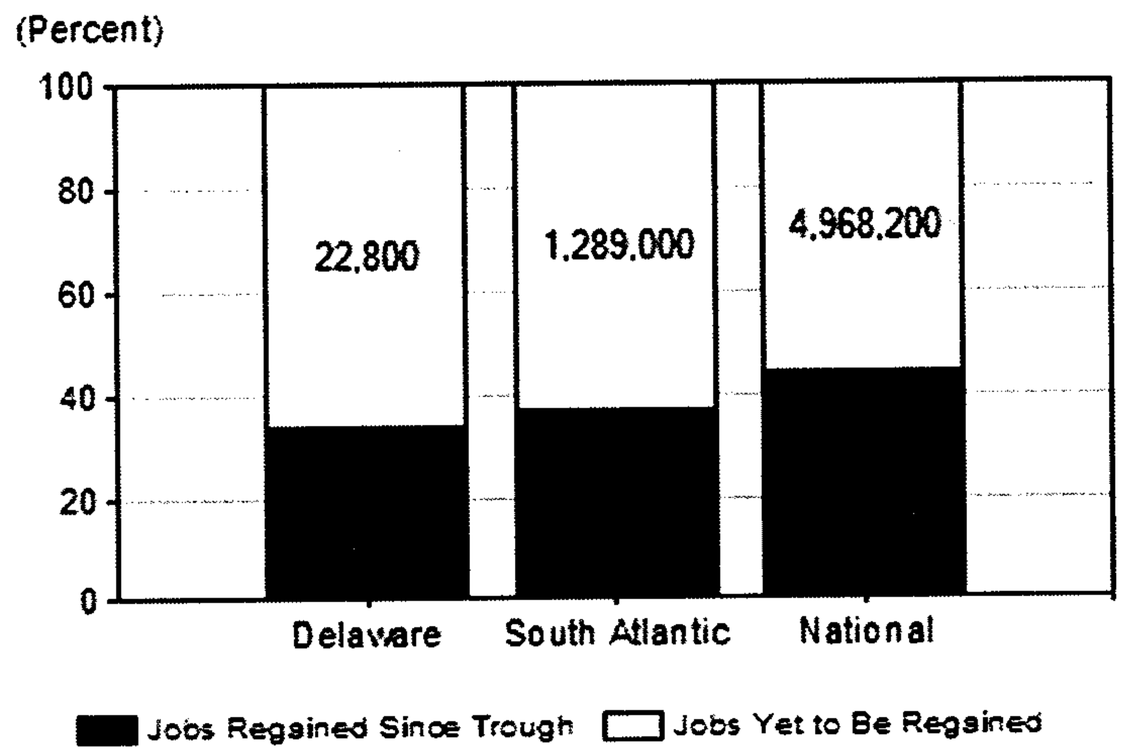
A Slow Recovery

After a 0.1% loss from payrolls in 2011, Delaware's economy is beginning to show signs of recovery, with payrolls forecasted to grow 0.9% in 2012.

During the recovery, professional business services, education/health services, and construction will expand at a moderate pace. Employment growth will average 1.4% annually from 2012 to 2016, while real GSP and real personal income climb more than 2.8% and 4.1% annually over this period.

Strong levels of in-migration will continue to push state population growth at a 1.2% rate over the forecast horizon.

Recession Recovery: Changes in Employment



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 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.

Economic Key Indicators

	2008	2009	2010	2011	2012	2013	2014	2015
Real Gross State Product (Mil. 2005 $)	53,692	54,737	56,398	57,293	58,126	59,215	61,211	63,227
Real Gross State Product (% change)	-5.1	1.9	3.0	1.6	1.5	1.9	3.4	3.3
Total Employment (Thous.)	436.8	416.4	413.8	417.3	419.7	424.4	431.0	439.0
Total Employment (% change)	-0.5	-4.7	-0.6	0.9	0.6	1.1	1.6	1.8
Manufacturing Employment (Thous.)	31.8	27.8	25.8	25.7	25.7	25.9	26.4	26.7
Nonmanufacturing Employment (Thous.)	405.0	388.6	387.9	391.6	394.1	398.5	404.7	412.2
Population (Thous.)	884.6	892.8	900.7	908.2	917.4	928.0	939.2	950.6
Population (% change)	1.3	0.9	0.9	0.8	1.0	1.2	1.2	1.2
Unemployment Rate (%)	4.9	7.9	8.0	7.3	6.8	6.5	6.4	6.0
Personal Income (% change)	3.3	-3.1	3.8	4.7	2.8	3.4	4.7	5.1
U.S. ECONOMY								
Real Gross Domestic Product (% change)	-0.3	-3.1	2.4	1.8	2.1	1.8	2.8	3.5
Employment (% change)	-0.6	-4.4	-0.7	1.2	1.4	1.4	1.6	2.0

This information was last updated on 25 JUL 2012, 12:39 PM EDT (16:39 GMT)

Analyst Contact Details: Charles Dougherty

DPL DE IRP Forecast Documentation

PHI Economics and Forecasting Group

August 31, 2012

Created on 29 Aug 2012

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Wilmington, DE-MD-NJ

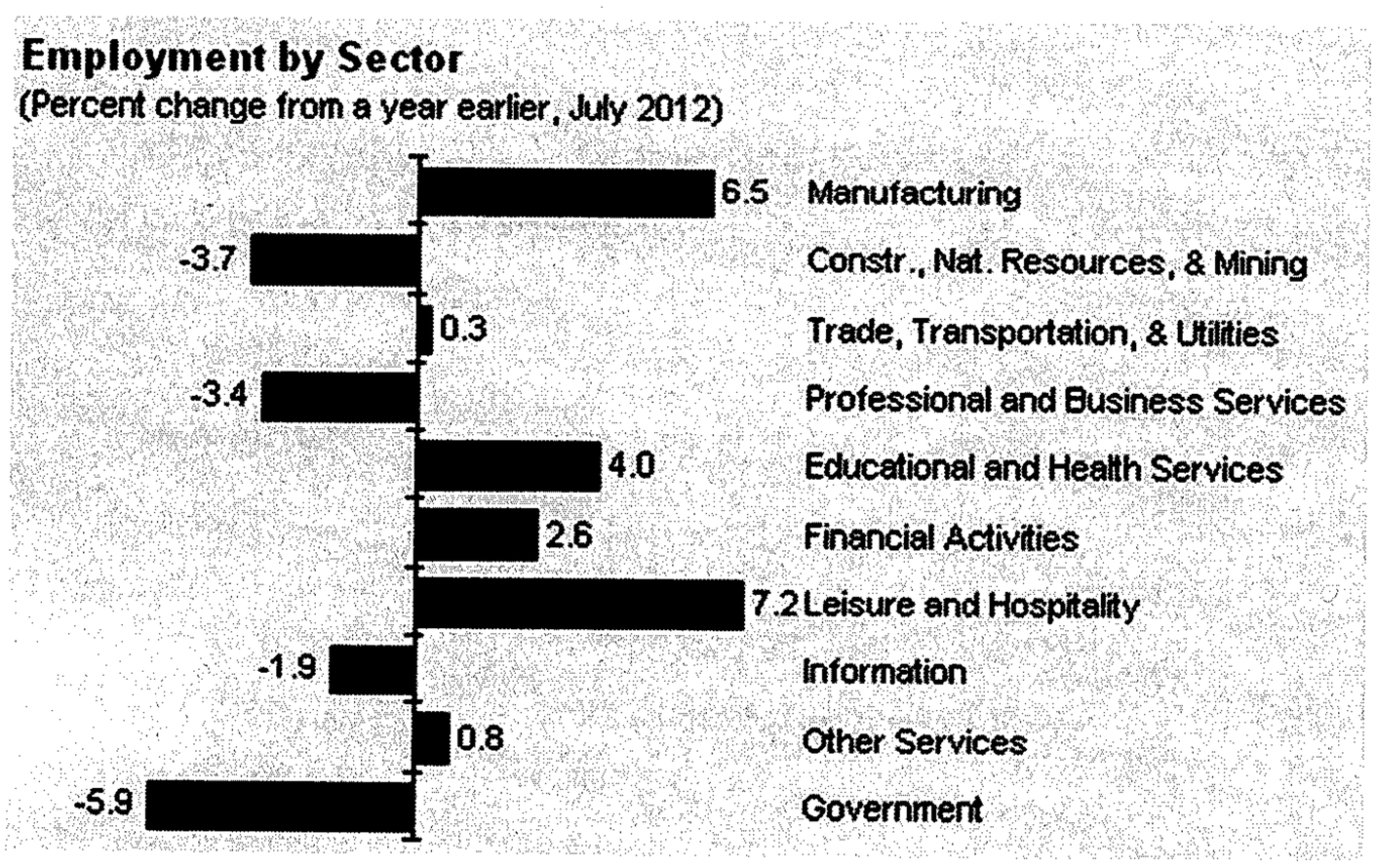
This information was last updated on 20 AUG 2012, 3:46 PM EDT (19:46 GMT)

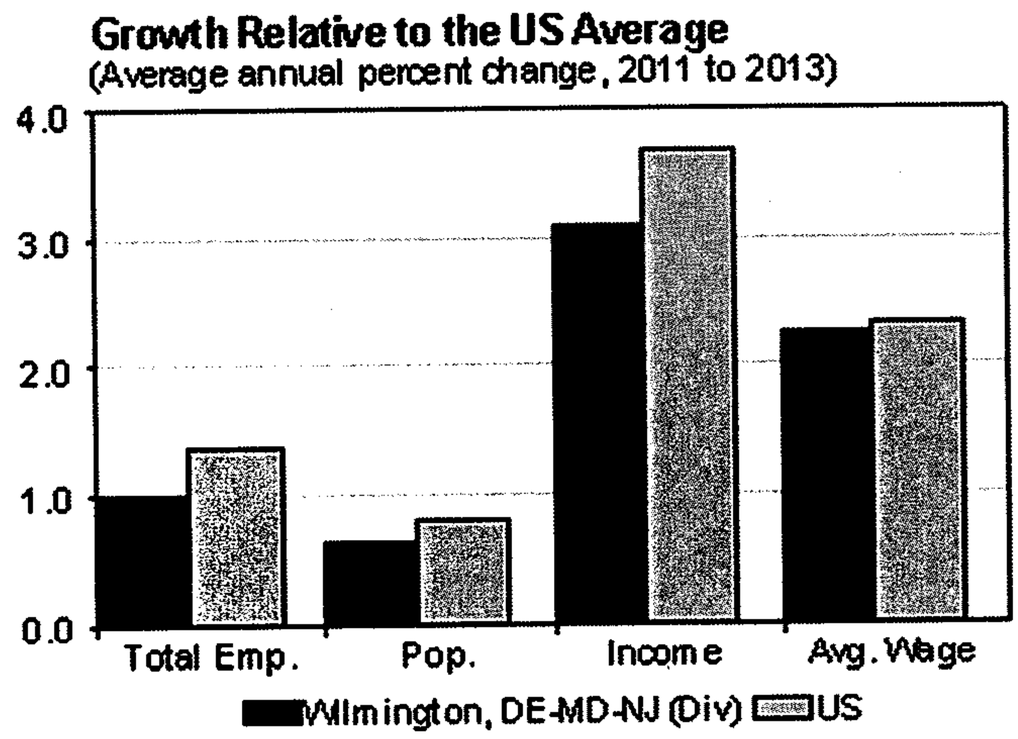
Analysis: At a Glance

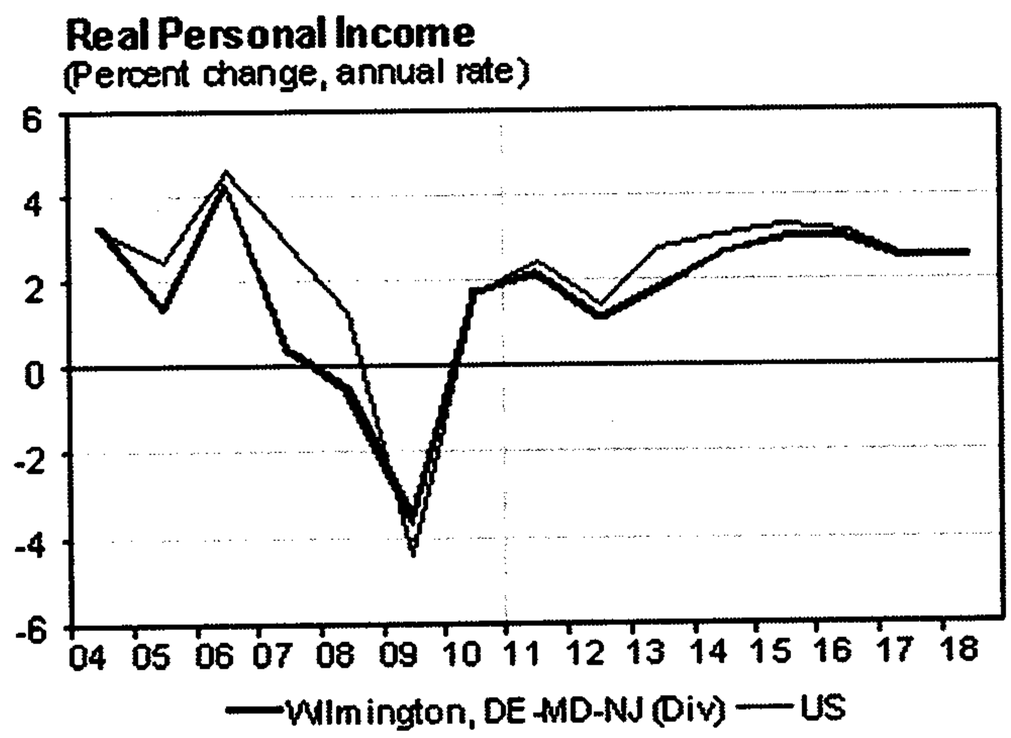
Strong Employment Growth Bucks the Trend

In the first quarter of 2012, Wilmington added nearly 4,000 jobs to its nonfarm payrolls, which increased 4.8% (annual rate). Its largest employment sector—trade, transportation and utilities—expanded 7.5%, adding over 1,000 net jobs. The professional and business services sector also contributed 1,400 jobs, growing at a 11.5% annualized rate—the strongest since 2004. January and February brought warmer-than-average temperatures to the region, which boosted retail trade payrolls by more than 800 jobs (a 10% annualized rate). Unfortunately, nice weather could not do the same the financial services sector—representing 12% of total employment in the metro, almost twice the national average—which has flat-lined to start the year.

Given the surge in employment and a contraction in the labor force, the unemployment rate decreased dramatically over the first few months of 2012, and is estimated at 7.3% in the first quarter.







Near-Term Developments

After a strong first quarter, the metro will return to more modest growth in the second quarter, as the warm temperatures probably only displaced the economic activity normally reserved for the spring. Overall, the Wilmington economy will expand total payrolls by 1.4% for the remainder of 2012.

This information was last updated on 12 JUN 2012, 11:36 AM EDT (15:36 GMT)

Analysis: Outlook

Significant Improvement over the Next Few Years

The Wilmington economy will gradually regain its momentum, registering employment growth of 1.4% in 2012, while real gross metro product expands 2.3%. In addition to education and healthcare, the renewed

growth in the financial and information industries will help create stronger job gains. During 2012–17, we forecast Wilmington will average solid 1.3% annual employment growth. The unemployment rate will finally fall back below 6% during 2016.

Economic Key Indicators

	2008	2009	2010	2011	2012	2013	2014	2015
Real Gross Metro Product (Mil. 2005 $)	46,344	47,295	51,674	52,622	52,973	53,930	55,757	57,614
Real Gross Metro Product (% change)	-4.9	2.1	9.3	1.8	0.7	1.8	3.4	3.3
Total Employment (Thous.)	349.4	332.6	328.4	330.8	334.5	337.5	342.3	348.6
Total Employment (% change)	-0.8	-4.8	-1.3	0.7	1.1	0.9	1.4	1.8
Manufacturing Employment (Thous.)	22.7	19.4	18.2	18.4	19.4	19.6	19.9	20.2
Nonmanufacturing Employment (Thous.)	326.7	313.2	310.3	312.4	315.1	317.9	322.4	328.4
Population (Thous.)	700.6	704.1	706.9	710.0	714.1	719.1	724.7	730.7
Population (% change)	0.6	0.5	0.4	0.4	0.6	0.7	0.8	0.8
Unemployment Rate (%)	5.0	8.4	8.7	7.9	7.3	7.0	6.9	6.5
Personal Income (% change)	2.7	-3.5	3.8	4.7	2.9	3.3	4.4	4.7
U.S. ECONOMY								
Real Gross Domestic Product (% change)	-0.3	-3.1	2.4	1.8	2.1	1.8	2.8	3.5
Employment (% change)	-0.6	-4.4	-0.7	1.2	1.4	1.4	1.6	2.0

This information was last updated on 12 JUN 2012, 11:36 AM EDT (15:36 GMT)

Analyst Contact Details: Charles Dougherty

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Dover, DE

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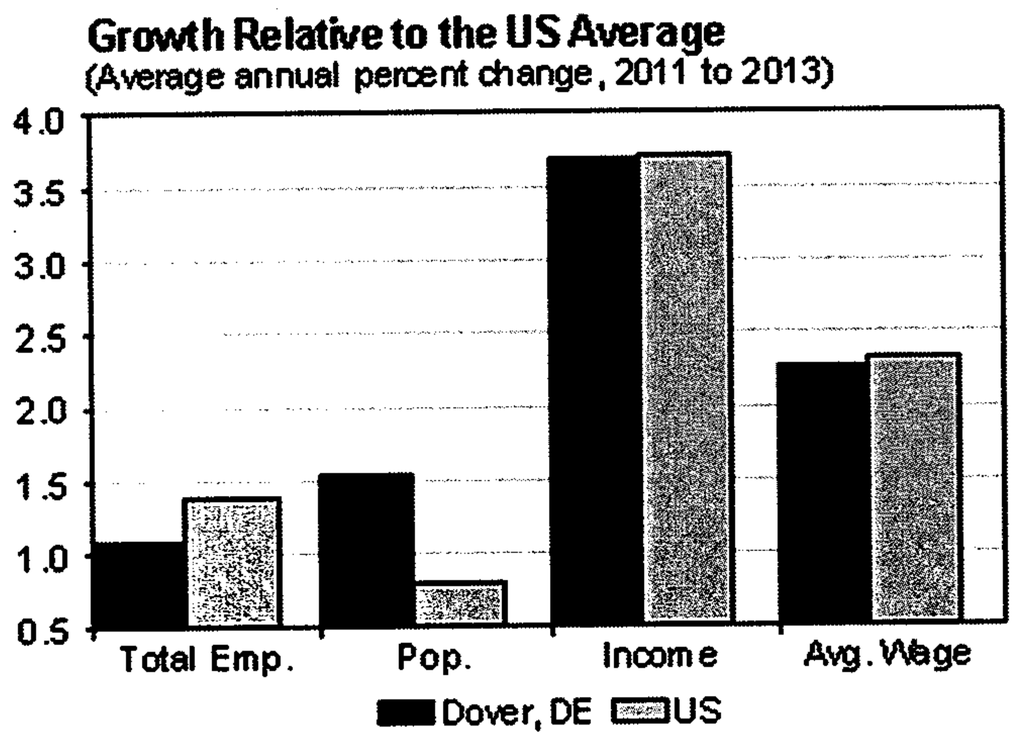
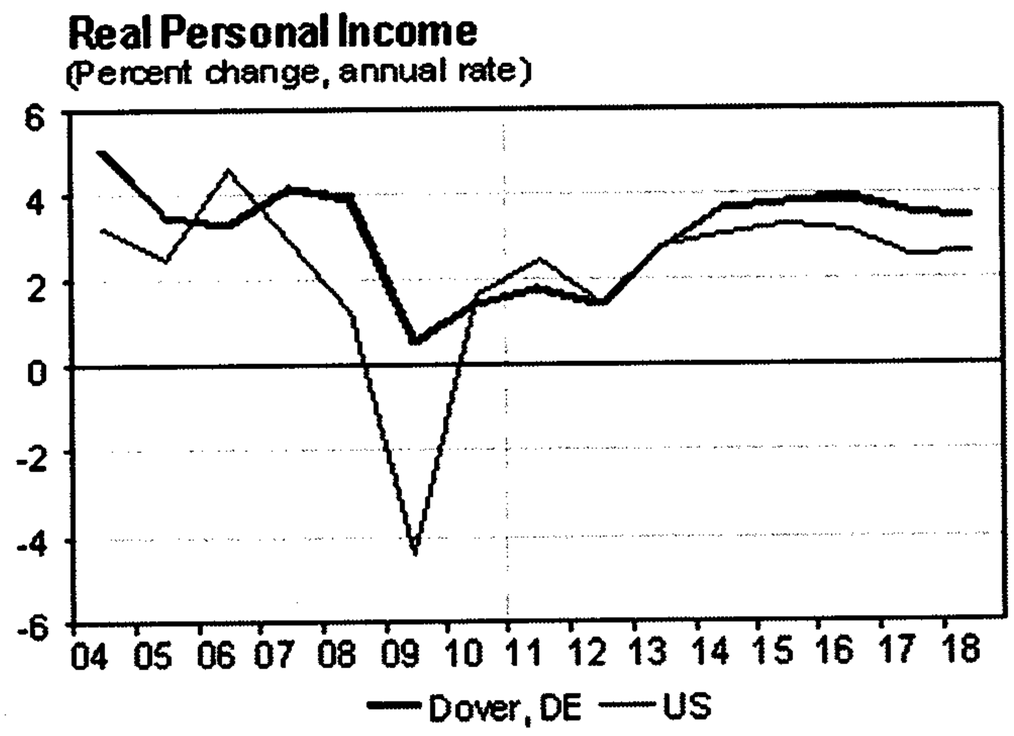
Analysis: At a Glance





Personal Income Indicators

	2008	2009	2010	2011	2012	2013	2014	2015
Per Capita Personal Income (Thous. $)	31.8	31.5	32.0	33.0	33.6	34.4	35.7	37.0
Per Capita Personal Income (% change)	4.9	-0.9	1.8	3.1	1.8	2.4	3.7	3.8
Average Annual Wage (Thous. $)	37.3	38.0	37.6	38.3	39.1	40.1	41.2	42.4
Average Annual Wage (% change)	1.5	2.0	-1.1	1.9	2.0	2.6	2.7	3.0

Total Personal Income (Mil. $)	5,019	5,051	5,224	5,452	5,629	5,863	6,184	6,532
Total Personal Income (% change)	7.3	0.6	3.4	4.4	3.2	4.2	5.5	5.6
Wage Disbursements (Mil. $)	2,598	2,549	2,553	2,628	2,699	2,810	2,936	3,081
Wage Disbursements (% change)	0.9	-1.9	0.2	2.9	2.7	4.1	4.5	5.0
Nonwage Income (Mil. $)	2,422	2,502	2,670	2,825	2,930	3,053	3,248	3,451
Nonwage Income (% change)	15.3	3.3	6.7	5.8	3.7	4.2	6.4	6.3

This information was last updated on 13 JUN 2011, 9:52 AM EDT (13:52 GMT)

Analysis: Outlook

Economic Key Indicators

	2008	2009	2010	2011	2012	2013	2014	2015
Real Gross Metro Product (Mil. 2005 $)	5,116	5,105	5,273	5,211	5,228	5,269	5,376	5,492
Real Gross Metro Product (% change)	-4.6	-0.2	3.3	-1.2	0.3	0.8	2.0	2.2
Total Employment (Thous.)	65.5	62.8	63.5	64.1	64.6	65.5	66.6	67.8
Total Employment (% change)	-0.8	-4.1	1.1	0.9	0.7	1.4	1.7	1.8
Manufacturing Employment (Thous.)	3.6	3.3	3.3	3.2	3.2	3.2	3.3	3.3
Nonmanufacturing Employment (Thous.)	61.9	59.5	60.2	60.9	61.4	62.3	63.3	64.5
Population (Thous.)	158.1	160.5	163.1	165.1	167.5	170.3	173.3	176.4
Population (% change)	2.4	1.5	1.6	1.3	1.4	1.7	1.8	1.8
Unemployment Rate (%)	4.8	7.7	8.0	7.4	7.1	6.7	6.5	6.0
Personal Income (% change)	7.3	0.6	3.4	4.4	3.2	4.2	5.5	5.6
U.S. ECONOMY								
Real Gross Domestic Product (% change)	-0.3	-3.1	2.4	1.8	2.1	1.8	2.8	3.5
Employment (% change)	-0.6	-4.4	-0.7	1.2	1.4	1.4	1.6	2.0

This information was last updated on 17 NOV 2009, 3:48 PM EST (20:48 GMT)

Analyst Contact Details: Charles Dougherty

Created on 29 Aug 2012

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DPL DE IRP Forecast Documentation

PHI Economics and Forecasting Group

August 31, 2012

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Appendix E: WN Factor Table

DPL DE Historical WN Factors

	CDD(65)				
	2012	2011	2010	2009	2008
RES	228,962.80	228,312.60	273,369.58	267,932.90	225,383.73
RSH	75,754.91	61,019.22	103,119.37	86,567.28	72,344.34
COM	145,881.80	112,514.50	125,886.45	131,596.40	113,819.23
Total	450,599.51	401,846.32	502,375.40	486,096.58	411,547.30

	HDD(65)				
	2012	2011	2010	2009	2008
RES	31,500.99	17,490.02	20,391.77	47,664.26	26,220.62
RSH	67,575.75	83,018.04	88,453.91	136,969.50	81,486.25
COM	46,865.77	33,301.76	44,626.96	46,560.58	18,131.63
Total	145,942.51	133,809.82	153,472.64	231,194.34	125,838.50

	HDD(35)				
	2012	2011	2010	2009	2008
RES	0.00	0.00	0.00	17,426.06	1.56
RSH	44,834.13	0.00	0.00	0.00	0.00
COM	0.00	0.00	0.00	0.00	23,455.72
Total	44,834.13	0.00	0.00	17,426.06	23,457.28

Appendix F: Estimated Sales Equations

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

DPL DE Residential Non Space Heat Electric Sales

==========

Dependent Variable: RESKWHDE

Method: Least Squares

Date: 06/25/12 Time: 15:45

Sample (adjusted): 1992M08 2012M03

Included observations: 236 after adjustments

Convergence achieved after 13 iterations

==========

Variable	Coefficien	Std. Error	t-Statistic	Prob.
C	-105637.4	12288.93	-8.596138	0.0000
@MOVAV(RESPRIDE(-3)/(CPIU(-3)/CPI11	-112568.3	32215.85	-3.494191	0.0006
BILLCDD65WLM*ACSATDE*RESCUSDE	0.001686	9.32E-05	18.09613	0.0000
BILLHDD65WLM*RESCUSDE	0.000317	1.61E-05	19.71326	0.0000
JAN	14232.24	1943.499	7.323000	0.0000
JUN	16154.37	2587.145	6.244093	0.0000
JUL	41166.65	4027.813	10.22060	0.0000
AUG	37439.59	4456.508	8.401105	0.0000

SEP	31797.40	3355.926	9.475000	0.0000
OCT	7625.561	2108.911	3.615876	0.0004
DEC	6435.626	1755.684	3.665595	0.0003
SEP04	20145.42	7226.466	2.787728	0.0058
@MOVAV(ETDOV+ETWLM,1)	258.6640	31.53538	8.202341	0.0000
@MOVAV(((PDINCDOV(-2)+PDINCWLM(-2))/1424.613)/C105.9243ETD13.44935TWL0.0000,4)				
AR(1)	0.075627	0.067071	1.127575	0.2607

R-squared	0.967805	Mean dependent var	140549.7
Adjusted R-squared	0.965765	S.D. dependent var	37880.71
S.E. of regression	7008.957	Akaike info criteri	20.60921
Sum squared resid	1.09E+10	Schwarz criterion	20.82937
Log likelihood	-2416.887	F-statistic	474.5227
Durbin-Watson stat	2.017600	Prob(F-statistic)	0.000000

Inverted AR Roots .08

DPL DE IRP Forecast Documentation

PHI Economics and Forecasting Group August 31, 2012

DPL DE Residential Space Heat Electric Sales

==========

Dependent Variable: RSHKWHDE

Method: Least Squares

Date: 06/25/12 Time: 15:45

Sample (adjusted): 1992M07 2012M03

Included observations: 237 after adjustments

Convergence achieved after 13 iterations

Variable	Coefficien	Std. Error	t-Statistic	Prob.
C	21690.31	8403.371	2.581144	0.0105
@MOVAV(RSHPRIDE(-3)/(CPIU(-3)/CPI1	-84919.63	21721.80	-3.909420	0.0001
BILLCDD65WLM*ACSATDE*RSHCUSDE	0.002551	0.000188	13.58633	0.0000
BILLHDD65WLM*RSHCUSDE	0.001468	4.54E-05	32.32630	0.0000
FEB04	23330.29	5794.080	4.026573	0.0001
SEP04	11976.10	5751.905	2.082110	0.0385
JAN	12134.21	1931.554	6.282095	0.0000
FEB	6824.060	2001.616	3.409275	0.0008
MAR	6761.722	1686.541	4.009225	0.0001
JUN	4522.660	1828.157	2.473891	0.0141
JUL	12364.37	2648.240	4.668901	0.0000
AUG	12504.96	2960.736	4.223599	0.0000

SEP	15756.56	2170.225	7.260332	0.0000
NOV	-3387.223	1464.087	-2.313540	0.0216
@MOVAV(ETDOV+ETWLM,1)	39.33067	23.30825	1.687414	0.0929
@MOVAV(((PDINCDOV(-1)+PDINCWLM(-1))-21.44403)/C83.41337ET-0.257081TWL0.7974,1)				
AR(1)	0.064387	0.070037	0.919324	0.3589

R-squared	0.960071	Mean dependent var	81922.65
Adjusted R-squared	0.957167	S.D. dependent var	26959.23
S.E. of regression	5579.513	Akaike info criteri	20.16062
Sum squared resid	6.85E+09	Schwarz criterion	20.40938
Log likelihood	-2372.033	F-statistic	330.6113
Durbin-Watson stat	1.997513	Prob(F-statistic)	0.000000

Inverted AR Roots .06

DPL DE IRP Forecast Documentation

PHI Economics and Forecasting Group August 31, 2012

DPL DE Commercial Electric Sales

Dependent Variable: COMKWHDE

Method: Least Squares

Date: 06/25/12 Time: 15:45

Sample (adjusted): 1992M04 2012M03

Included observations: 240 after adjustments

Convergence achieved after 14 iterations

Variable	Coefficien	Std. Error	t-Statistic	Prob.
C	-335288.0	19491.88	-17.20141	0.0000
@MOVAV(COMPRIDE(-2)/(CPIU(-2)/CPI1	-141118.6	65906.88	-2.141181	0.0333
BILLCDD65WLM*COMCUSDE	0.007975	0.000566	14.08401	0.0000
BILLHDD65WLM*COMCUSDE	0.001231	0.000184	6.701992	0.0000
JAN	11656.82	3678.708	3.168728	0.0017
AUG	-12404.68	4539.986	-2.732317	0.0068
SEP	9912.556	3837.517	2.583065	0.0104
NOV	-5971.609	3476.114	-1.717898	0.0872
@MOVAV(ETDOV+ETWLM,1)	1002.591	61.05497	16.42112	0.0000
@MOVAV(((PDINCDOV+PDINCWLM)/(CPIU/CP	2435.308	TDO239.0047,1)	10.18937	0.0000
AR(1)	0.149496	0.066198	2.258324	0.0249

R-squared	0.909335	Mean dependent var	253675.1
Adjusted R-squared	0.905376	S.D. dependent var	47028.91
S.E. of regression	14466.58	Akaike info criteri	22.04182
Sum squared resid	4.79E+10	Schwarz criterion	22.20135
Log likelihood	-2634.018	F-statistic	229.6782
Durbin-Watson stat	2.054877	Prob(F-statistic)	0.000000

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Inverted AR Roots .15

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DPL DE Industrial Electric Sales

Dependent Variable: INDKWHDE

Method: Least Squares

Date: 06/25/12 Time: 15:45

Sample (adjusted): 1992M12 2012M04

Included observations: 233 after adjustments

Convergence achieved after 8 iterations

Variable	Coefficien	Std. Error	t-Statistic	Prob.
C	186828.1	38217.51	4.888547	0.0000
@MOVAV(INDPRIDE(-2)/(CPIU(-2)/CPI11	-1299548.	343759.8	-3.780395	0.0002
@MOVAV(EMFWLM(-3)+EMFDOV(-3),1)	3786.514	665.4329	5.690301	0.0000
JIPU*CDD65WLM	0.245849	0.327191	0.751394	0.4532
AR(1)	0.151946	0.065508	2.319515	0.0213

R-squared	0.335499	Mean dependent var	226318.7
Adjusted R-squared	0.323841	S.D. dependent var	64964.16
S.E. of regression	53419.31	Akaike info criteri	24.63096
Sum squared resid	6.51E+11	Schwarz criterion	24.70501
Log likelihood	-2864.507	F-statistic	28.77864
Durbin-Watson stat	2.038470	Prob(F-statistic)	0.000000

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Inverted AR Roots                    .15

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DPL DE Public Street Light Electric Sales

Dependent Variable: PSLKWHDE

Method: Least Squares

Date: 06/25/12 Time: 15:45

Sample (adjusted): 1992M07 2012M04

Included observations: 193 after adjustments

Convergence achieved after 8 iterations

Variable	Coefficien	Std. Error	t-Statistic	Prob.
C	2702.415	512.5215	5.272783	0.0000
@MOVAV(PSLPRIDE(-2)/(CPIU(-2)/CPI11	-832.0084	1159.529	-0.717540	0.4739
@MOVAV(PSLCUSDE(-3),3)	1.670433	1.612160	1.036146	0.3015
MAR00	1492.363	220.8239	6.758158	0.0000
AR(1)	0.652283	0.051898	12.56852	0.0000

R-squared	0.530905	Mean dependent var	3111.510
Adjusted R-squared	0.520924	S.D. dependent var	326.5451
S.E. of regression	226.0193	Akaike info criteri	13.70468
Sum squared resid	9603924.	Schwarz criterion	13.78921
Log likelihood	-1317.502	F-statistic	53.19283
Durbin-Watson stat	1.642042	Prob(F-statistic)	0.000000

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Inverted AR Roots                          .65

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Appendix G: Customer Sub-Model Econometric Equations

Residential Non Space Heat Electric Customers

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Dependent Variable: RESCUSDE

Method: Least Squares

Date: 06/25/12 Time: 15:45

Sample (adjusted): 1991M08 2012M04

Included observations: 249 after adjustments

Convergence achieved after 18 iterations

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Variable	Coefficien	Std. Error	t-Statistic	Prob.
C	-190417.7	915080.7	-0.208088	0.8353
@MOVAV(ETDOV(-6)+ETWLM(-6),1)	15.88801	8.682698	1.829847	0.0685
FEB00	-15235.79	168.2692	-90.54413	0.0000
MAR00	7970.989	219.7577	36.27171	0.0000
APR00	-14787.58	242.8774	-60.88493	0.0000
MAY00	-4048.273	250.2624	-16.17612	0.0000
JUN00	1281.583	241.9496	5.296899	0.0000
JUL00	2275.700	216.4223	10.51509	0.0000

AUG00	2348.669	166.2345	14.12864	0.0000
JAN	289.7838	42.41596	6.831954	0.0000
FEB	233.0658	42.88867	5.434205	0.0000
MAR	165.6824	35.19993	4.706895	0.0000
DEC	171.3479	34.71458	4.935905	0.0000
AR(1)	1.000385	0.000970	1030.829	0.0000

R-squared	0.999804	Mean dependent var	178302.6
Adjusted R-squared	0.999793	S.D. dependent var	12254.29
S.E. of regression	176.3421	Akaike info criteri	13.23731
Sum squared resid	7307688.	Schwarz criterion	13.43508
Log likelihood	-1634.045	F-statistic	92105.93
Durbin-Watson stat	1.650444	Prob(F-statistic)	0.000000

Inverted AR Roots 1.00

Estimated AR process is nonstationary

DPL DE IRP Forecast Documentation

PHI Economics and Forecasting Group August 31, 2012

Residential Space Heat Electric Customers

Dependent Variable: RSHCUSDE

Method: Least Squares

Date: 06/25/12 Time: 15:45

Sample (adjusted): 1991M04 2012M04

Included observations: 253 after adjustments

Variable	Coefficien	Std. Error	t-Statistic	Prob.
C	-25522.15	3285.784	-7.767446	0.0000
@MOVAV(ETDOV(-2)+ETWLM(-2),2)	233.6085	8.485536	27.53020	0.0000
FEB00	10050.90	3552.018	2.829632	0.0050
APR00	-10271.33	3551.892	-2.891792	0.0042

R-squared	0.757330	Mean dependent var	64758.46
Adjusted R-squared	0.754406	S.D. dependent var	7146.681
S.E. of regression	3541.712	Akaike info criteri	19.19829
Sum squared resid	3.12E+09	Schwarz criterion	19.25416
Log likelihood	-2424.584	F-statistic	259.0281
Durbin-Watson stat	0.048580	Prob(F-statistic)	0.000000

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Commercial Electric Customers

Dependent Variable: COMCUSDE

Method: Least Squares

Date: 06/25/12 Time: 15:45

Sample (adjusted): 1991M05 2012M03

Included observations: 251 after adjustments

Convergence achieved after 45 iterations

Variable	Coefficien	Std. Error	t-Statistic	Prob.
C	64247.21	34218.92	1.877535	0.0617
@MOVAV(ETWLM+ETDOV-EMFWLM-ETDOV,4)	6.860017	5.159065	1.329702	0.1849
MAR00	3962.280	42.56187	93.09459	0.0000
APR00	479.6607	54.95863	8.727668	0.0000
MAY00	2405.455	60.17977	39.97116	0.0000
JUN00	2674.234	60.27502	44.36721	0.0000
JUL00	3076.514	54.92890	56.00903	0.0000
AUG00	3175.208	42.49277	74.72350	0.0000
OCT	-19.78767	7.103389	-2.785665	0.0058
DEC	51.04140	7.083178	7.206002	0.0000
AR(1)	0.998953	0.000972	1027.695	0.0000

R-squared	0.999824	Mean dependent var	28664.13
Adjusted R-squared	0.999817	S.D. dependent var	3389.390
S.E. of regression	45.87310	Akaike info criteri	10.53247
Sum squared resid	505042.0	Schwarz criterion	10.68697
Log likelihood	-1310.825	F-statistic	136455.3
Durbin-Watson stat	2.237690	Prob(F-statistic)	0.000000

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Inverted AR Roots 1.00

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DPL DE IRP Forecast Documentation

PHI Economics and Forecasting Group August 31, 2012

Street Light Electric Customers

Dependent Variable: PSLCUSDE

Method: Least Squares

Date: 06/25/12 Time: 15:45

Sample (adjusted): 1992M02 2012M03

Included observations: 199 after adjustments

Convergence achieved after 22 iterations

Variable	Coefficien	Std. Error	t-Statistic	Prob.
C	-1243.512	22570.64	-0.055094	0.9561
@MOVAV(ETDOV+ETWLM-EMFDOV-EMFWLM,5)	0.222401	0.178031	1.249222	0.2131
AR(1)	1.000288	0.004353	229.8074	0.0000

R-squared	0.997688	Mean dependent var	332.6332
Adjusted R-squared	0.997665	S.D. dependent var	32.64689
S.E. of regression	1.577678	Akaike info criteri	3.764745
Sum squared resid	487.8570	Schwarz criterion	3.814393
Log likelihood	-371.5922	F-statistic	42293.84
Durbin-Watson stat	1.629280	Prob(F-statistic)	0.000000

Inverted AR Roots 1.00

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Estimated AR process is nonstationary

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DPL DE IRP Forecast Documentation

PHI Economics and Forecasting Group August 31, 2012

Industrial Electric Customers

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Dependent Variable: INDCUSDE

Method: Least Squares

Date: 06/25/12 Time: 15:45

Sample (adjusted): 1998M05 2012M04

Included observations: 168 after adjustments

Convergence achieved after 5 iterations

Variable	Coefficien	Std. Error	t-Statistic	Prob.
C	156.0929	5.538955	28.18093	0.0000
@MOVAV(EMFDOV(-1)+EMFWLM(-1),3)	4.000001	0.184698	21.65698	0.0000
NOV99	10.40758	5.399806	1.927399	0.0558
DEC99	-36.92907	5.400470	-6.838122	0.0000
FEB00	-28.72223	4.844082	-5.929344	0.0000
APR00	-11.24319	5.673253	-1.981789	0.0493
MAY00	30.62364	6.636813	4.614208	0.0000
JUN00	15.88579	6.946296	2.286945	0.0236
JUL00	21.89395	7.018431	3.119494	0.0022
AUG00	44.66899	6.939454	6.436960	0.0000
SEP00	-17.29220	6.629009	-2.608565	0.0100
OCT00	-10.60827	5.667535	-1.871760	0.0631

JAN07	-10.22155	4.839926	-2.111922	0.0363
AR(1)	0.593212	0.065990	8.989456	0.0000

R-squared	0.955860	Mean dependent var	275.4286
Adjusted R-squared	0.952134	S.D. dependent var	25.70714
S.E. of regression	5.624263	Akaike info criteri	6.371712
Sum squared resid	4871.380	Schwarz criterion	6.632043
Log likelihood	-521.2238	F-statistic	256.5334
Durbin-Watson stat	2.711204	Prob(F-statistic)	0.000000

Inverted AR Roots	.59

Appendix H: DPL Zonal Load Model Equations

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

- Delmarva DE Gross Retail Output (MWh).

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Dependent Variable: LGRODPLDE

Method: Least Squares

Date: 06/29/12 Time: 14:39

Sample (adjusted): 2002M02 2012M03

Included observations: 122 after adjustments

Convergence achieved after 18 iterations

==========

Variable	Coefficien	Std. Error	t-Statistic	Prob.
C	-114094.5	326337.5	-0.349621	0.7273
ETDE*CDD65WLM	1.709046	0.077076	22.17355	0.0000
ETDE*HDD65WLM	0.372083	0.035044	10.61756	0.0000
@MOVAV(JPRIDE(-1)/(CPIU(-1)/CPI11),	-506460.2	322544.7	-1.570201	0.1193
@MOVAV(ETWLM(-2),1)	2349.670	943.3428	2.490791	0.0143
JAN	43575.23	10763.55	4.048405	0.0001
FEB	-18682.74	7734.366	-2.415549	0.0174

APR	-40189.51	5530.954	-7.266290	0.0000
JUL	18374.85	8384.542	2.191516	0.0306
AUG	36686.87	8185.916	4.481706	0.0000
NOV	-32633.23	7240.442	-4.507077	0.0000
DEC	21750.34	10329.18	2.105719	0.0375
OCT04	-38157.81	17407.83	-2.191991	0.0305
AR(1)	0.792718	0.062192	12.74630	0.0000

R-squared	0.956354	Mean dependent var	774065.1
Adjusted R-squared	0.951101	S.D. dependent var	97366.40
S.E. of regression	21530.78	Akaike info criteri	22.89997
Sum squared resid	5.01E+10	Schwarz criterion	23.22175
Log likelihood	-1382.898	F-statistic	182.0369
Durbin-Watson stat	2.105691	Prob(F-statistic)	0.000000

Inverted AR Roots	.79

- Delmarva DE Net System Output (MWh).

Dependent Variable: NSODPL

Method: Least Squares

DPL DE IRP Forecast Documentation

PHI Economics and Forecasting Group August 31, 2012

Date: 06/29/12 Time: 14:39

Sample (adjusted): 1999M12 2012M03

Included observations: 148 after adjustments

Convergence achieved after 9 iterations

Variable	Coefficien	Std. Error	t-Statistic	Prob.
C	580563.8	275556.5	2.106878	0.0370
(ETDE+ETSAL)*CDD65WLM	3.286477	0.144546	22.73658	0.0000
(ETDE+ETSAL)*HDD65WLM	1.101869	0.034928	31.54674	0.0000
@MOVAV(JPRIDPL(-3)/(CPIU(-3)/CPI11)	-922820.7	318273.5	-2.899458	0.0044
@MOVAV(ETDE(-7)+ETSAL(-7),8)	1528.058	610.6244	2.502452	0.0136
JAN	22559.44	10889.11	2.071744	0.0402
FEB	-112476.4	12240.06	-9.189206	0.0000
MAR	-59142.11	11750.11	-5.033326	0.0000
APR	-103254.2	9780.851	-10.55677	0.0000
JUN	52024.76	15475.41	3.361770	0.0010
JUL	129488.3	23516.44	5.506288	0.0000
AUG	135889.0	23042.24	5.897386	0.0000
SEP	61367.59	12450.35	4.928984	0.0000
NOV	-79371.00	8091.190	-9.809559	0.0000
FEB07	64409.61	29197.38	2.206006	0.0291

AR(1)	0.576345	0.072367	7.964228	0.0000

R-squared	0.978043	Mean dependent var	1576553.
Adjusted R-squared	0.975548	S.D. dependent var	204112.1
S.E. of regression	31917.23	Akaike info criteri	23.68149
Sum squared resid	1.34E+11	Schwarz criterion	24.00551
Log likelihood	-1736.430	F-statistic	391.9864
Durbin-Watson stat	2.140966	Prob(F-statistic)	0.000000

Inverted AR Roots .58

- Delmarva Zonal Peak Demand (MW).

Dependent Variable: MWDPL

Method: Least Squares

Date: 06/29/12 Time: 14:39

Sample (adjusted): 1992M06 2012M03

Included observations: 238 after adjustments

Convergence achieved after 8 iterations

Variable	Coefficien	Std. Error	t-Statistic	Prob.
C	-1705.335	208.2530	-8.188766	0.0000
(ETDE+ETSAL)*MWHDWIL	0.021317	0.002966	7.186474	0.0000
(ETDE+ETSAL)*MWCDWIL	0.082309	0.005240	15.70916	0.0000
@MOVAV(JPRIDPL(-1)/(CPIU(-1)/CPI11)	-2518.401	1097.180	-2.295341	0.0226
@MOVAV(ETDE(-2)+ETSAL(-2),1)	5.653262	0.626680	9.020972	0.0000
@MOVAV(((PDINCDE(-1)+PDINCSAL(-1))/(25.51389/CP	3.731031	TDE	6.838294	AL(0.0000)
JAN	115.9637	46.24974	2.507337	0.0129
APR	-449.3681	49.32108	-9.111075	0.0000
MAY	-450.7076	47.65810	-9.457103	0.0000
AUG	162.0502	45.15728	3.588573	0.0004
OCT	-336.6832	52.02465	-6.471610	0.0000
NOV	-250.0744	47.44584	-5.270734	0.0000
AR(1)	0.162789	0.069499	2.342331	0.0200

R-squared	0.902916	Mean dependent var	2805.266
Adjusted R-squared	0.897738	S.D. dependent var	578.7907
S.E. of regression	185.0879	Akaike info criteri	13.33261
Sum squared resid	7707940.	Schwarz criterion	13.52227
Log likelihood	-1573.581	F-statistic	174.3820
Durbin-Watson stat	1.960096	Prob(F-statistic)	0.000000

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Inverted AR Roots .16

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Appendix I: Delmarva Zone Peak Demand By Rate Class

DPL DE IRP Forecast Documentation

PHI Economics and Forecasting Group August 31, 2012

Delmarva Zone Summer Peak Demand By Rate Class

(Non-Coincident With PJM System Peak, July 22, 2011, 5:00 PM)

CUSTCLASSCODE	CUSTCLASSNAME (Description)	kWh at HE 07/22/11-17:00
DE_DEMECT	DE_DEMECTRANS	444201.098
DE_GSPTOU	Delaware General Service Primary Tou	379405.196
DE_GSPTOUH	Delaware General Service Primary Tou Hourly	5723.122
DE_GSPTOUMIN	Delaware General Service Primary Tou	4990.131
DE_GSSPHTG	Delaware General Service Space Heating	5803.004
DE_GSTTOU	Delaware General Service Transmission Tou	86615.482
DE_GSWTRHTG	Delaware General Service Water Heating	107.833
DE_LGSTOU	Delaware Large General Service	115395.13
DE_LGSTOUH	Delaware Large General Service Hourly	1300.51
DE_MGSOPS	Delaware Medium General Service Off Peak	4649.381
DE_MGSSBASIC	Delaware Medium General Service	254874.521
DE_ODECPRI	Delaware ODEC Primary	9171.301
DE_ODECT	DE_ODECTRANS	365517.648
DE_OLBASIC25	Delaware Outdoor Lighting Rate 25	0
DE_OLBASIC30	Delaware Outdoor Lighting Rate 30	0
DE_ORLBASIC	Delaware Outdoor Recreational Lighting	0
DE_RSBASIC	Delaware Residential Service	757861.423
DE_RSHEATING	Delaware Residential Heating	282287.212
DE_RSTOUND	Delaware Residential Tou Non Demand	569.12
DE_SGSBASIC	Delaware Small General Service	28752.49
MD_BERLINT	MD_Berlin Trans	4054.101
MD_GSP3TOU	Maryland General Service Primary Tou 3	84821.454
MD_GSPTOU	Maryland General Service Primary	18503.395
MD_LGS3TOU	Maryland Large General Service Tou 3	18170.922
MD_LGSTOU	Maryland Large General Service	54731.005
MD_ODECPRI	Maryland ODEC Primary	61622.442
MD_ODECT	MD_ODECTRANS	197752.252
MD_OLBASIC25	Maryland Outdoor Lighting Rate 25	0
MD_OLBASIC30	Maryland Outdoor Lighting Rate 30	0
MD_ORLBASIC	Maryland Outdoor Recreational Lighting	0
MD_RSBASIC	Maryland Residential Service	592509.249
MD_RSTOUND	Maryland Residential Tou Non Demand	341.926
MD_SG2BASIC	Maryland Small General Service 2	155918.204
MD_SG2OPS	Maryland Small General Service Off Peak 2	1999.824
MD_SGSBASIC	Maryland Small General Service	50036.782
MD_SGSCON	MD_SGSCONOWINGO	4510.589
MD_SGSOPS	Maryland Small General Service Off Peak	11.455
MD_SGSSPHTG	Maryland Small General Service Space Htg	22164.613
MD_SGSTN	Maryland TELECOM NETWORK	433.882
MD_SGSWH	MD_SGSWWTRHTG	33.907
VA_ODECT	VA_ODECTRANS	153359.403

Delmarva Zone Winter Peak Demand By Rate Class

(Non-Coincident With PJM System Peak, January 24, 2011, 8:00 AM)

CUSTCLASSCODE	CUSTCLASSNAME (Description)	kWh at HE 01/24/11-08:00
DE_DEMECT	DE_DEMECTRANS	286093.786
DE_GSPTOU	Delaware General Service Primary Tou	339998.727
DE_GSPTOUH	Delaware General Service Primary Tou Hourly	735.626
DE_GSPTOUMIN	Delaware General Service Primary Tou	5154.867
DE_GSSPHTG	Delaware General Service Space Heating	5724.858
DE_GSTTOU	Delaware General Service Transmission Tou	99066.708
DE_GSWTRHTG	Delaware General Service Water Heating	183.526
DE_LGSTOU	Delaware Large General Service	102635.397
DE_LGSTOUH	Delaware Large General Service Hourly	755.081
DE_MGSOPS	Delaware Medium General Service Off Peak	2524.621
DE_MGSSBASIC	Delaware Medium General Service	172856.667
DE_ODECPRI	Delaware ODEC Primary	7920.822
DE_ODECT	DE_ODECTRANS	273144.556
DE_OLBASIC25	Delaware Outdoor Lighting Rate 25	867.42
DE_OLBASIC30	Delaware Outdoor Lighting Rate 30	2379.891
DE_ORLBASIC	Delaware Outdoor Recreational Lighting	10.653
DE_RSBASIC	Delaware Residential Service	304626.279
DE_RSHEATING	Delaware Residential Heating	386939.795
DE_RSTOUND	Delaware Residential Tou Non Demand	296.199
DE_SGSBASIC	Delaware Small General Service	24521.858
MD_BERLINT	MD_Berlin Trans	12724.432
MD_GSP3TOU	Maryland General Service Primary Tou 3	67532.291
MD_GSPTOU	Maryland General Service Primary	24852.087
MD_LGS3TOU	Maryland Large General Service Tou 3	14403.045
MD_LGSTOU	Maryland Large General Service	48786.623
MD_ODECPRI	Maryland ODEC Primary	61644.456
MD_ODECT	MD_ODECTRANS	170736.901
MD_OLBASIC25	Maryland Outdoor Lighting Rate 25	396.775
MD_OLBASIC30	Maryland Outdoor Lighting Rate 30	810.878
MD_ORLBASIC	Maryland Outdoor Recreational Lighting	19.164
MD_RSBASIC	Maryland Residential Service	601442.922
MD_RSTOUND	Maryland Residential Tou Non Demand	357.662
MD_SG2BASIC	Maryland Small General Service 2	100420.765
MD_SG2OPS	Maryland Small General Service Off Peak 2	694.817
MD_SGSBASIC	Maryland Small General Service	41129.266
MD_SGSCON	MD_SGSCONOWINGO	4336.4
MD_SGSOPS	Maryland Small General Service Off Peak	14.753
MD_SGSSPHTG	Maryland Small General Service Space Htg	18974.802
MD_SGSTN	Maryland TELECOM NETWORK	447.545
MD_SGSWH	MD_SGSWWTRHTG	18.237
VA_ODECT	VA_ODECTRANS	140268.852

Glossary: Data Dictionary

Zonal or Jurisdictional Energy and Demand Variables

LGRODPLDE – DPL's Gross Retail Output for the DPL Delaware jurisdiction. This is the amount of energy put into the system, before losses, to serve the needs of DPL's jurisdictional retail sales. Measured in MWh.

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

NSODPL – The monthly metered Net Sendout for the Delmarva Zone. This data differs from the PJM Net Energy for Load in that the latter includes the losses on the 500 kV system that are allocated back to the zones by PJM. Measured in MWh.

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

CPI11 – A factor, equal to 215.2239183, that is 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.

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

ETSAL – 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 DPL 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 DPL 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 DPL 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 DPL in serving Standard Offer Service customers.

Dummy Variables

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

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

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

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

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

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

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

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

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

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

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

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

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

APPENDIX 5

Supporting Documentation for the Delmarva Delaware 2012 IRP Filing Resource Modeling

November 20, 2012

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INTRODUCTION

This document serves to provide supporting documentation related to the assumptions and results of the Delmarva Power ("Delmarva" or "DPL") Delaware Integrated Resource Plan (IRP). The majority of information contained here-in is focused on modeling assumptions or methodology. As appropriate, background material related to the approach and scope are also included here-in.

Delmarva has relied on a combination of 1) deterministic based modeling for market fundamentals, and 2) stochastic modeling for portfolio planning. The overall modeling approach used for Delmarva relies on determining a structure to minimize costs for serving RSCI and LC SOS customers in Delaware. This is an accepted analytic approach used in resource planning studies considering the range of both demand and supply side options as well as uncertaintly surrounding market pricing.

This document focuses on the fundamentals modeling and provides a detailed description of the modeling platform and driving assumptions. This type of forward fundamentals based analysis requires a very large number of calculations that can only be done using a computer model. Delmarva chose to use the Integrated Planning Model (IPM®) to minimize production costs including transmission and environmental allowance costs for Delmarva RSCI and LC SOS customers in Delaware. ICF's IPM® tool is widely accepted in both the private and public sectors in North America and internationally. It has undergone extensive public review as it is the main tool used by the U.S. EPA for the analysis of pollution control programs affecting the power sector. Further, the model is widely accepted by rating agencies and investment banking institutions, and it has been used in hundreds of industry and plant valuation assignments for power industry participants. The model has been used extensively ito support litigation and administrative regulatory proceedings including the largest stranded cost case in U.S. history, multiple IRP proceedings, and multiple bankruptcy proceedings.

The remainder of this report is structured to provide an analytical background on the model used, the key features of the PJM market simulation and the key assumptions driving the resource planning results. Detailed results of the modeling excercise are presented in the final chapter.

ANALYTIC APPROACH

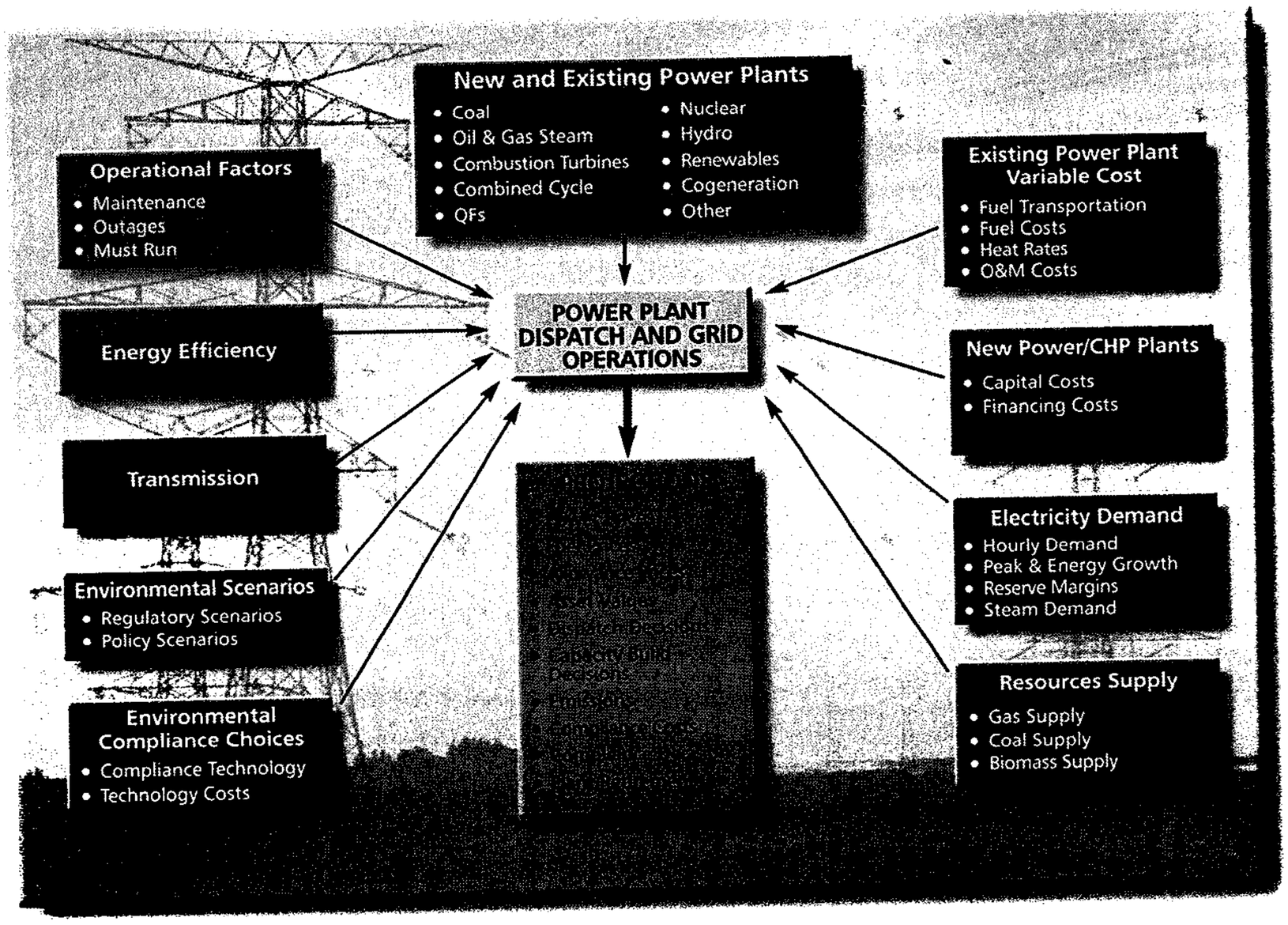
ICF's Integrated Planning Model™ (IPM®) was used to develop a fundamentals based, long-term forecast for Delmarva Power and Light. IPM® simulates power market operations at the wholesale level for energy generation and installed capacity requirements in order to determine the most cost effective service to all customer classes while minimizing risks inherent in the electric utility business including price volatility.

The IPM® Platform

IPM® is an optimization model that uses a linear programming formulation to optimize investment decisions for electric generation, centralized heat production, electric transmission and demand side management, as well as the use of those resources in long time horizons covering the full life cycles of the current investment projects. Investment options are selected by the model given the cost and performance characteristics of available options, forecasts of customer demand for electricity as well as reliability criteria. System dispatch, which determines the proper and most efficient use of the existing and new resources available to utilities and their customers, is optimized given the resource mix, unit operating characteristics, fuel and other costs. Unit and system operating constraints provide system-specific realism to the model's simulations. The model is dynamic; that is, it has the capability to use forecasts of future conditions, requirements, and option characteristics to make decisions for the present. This replicates, as much as possible, the perspective of power plant developers, regulatory personnel, and the public in reviewing important investment options for the electric power industry and electricity consumers. In a basic setup, decisions are made based on minimizing the net present value of capital plus operating costs over the full planning horizon.

IPM® also has the capability to simulate market equilibrium between supply and demand (see Exhibit 1.1). This advanced setup of the model simulates a global equilibrium for the electric power market and a number of other markets including emissions allowance markets. In this advanced approach, electric energy and capacity demands (resulting from the reliability requirements), as well as non-electric demand for fuels are represented by step-wise demand curves assigned to different geographical locations. At the same time, fuel supply is represented with step-wise supply curves also distributed over various geographical locations. The optimality criterion is to minimize the total system cost net of benefits to the consumer, which is mathematically equivalent to maximizing the generally known notion of net consumer benefits.

Exhibit 1.1: The IPM® Modeling Framework Analyzes Supply and Demand Resources on Equal Footing



Several factors are taken into account in simulating long-term optimal behavior of the energy markets in IPM®:

- Investment choices are made from a wide variety of resource options as determined by the user. A unique feature of IPM® is its ability to represent and account for the different characteristics of alternative types of resource options. Options can include demand-side resources (e.g., conservation and load management programs), non-utility sources of power (e.g., bulk power purchases from independent power producers and cogenerated power), increased utilization of existing resources (e.g., life extension and increased use of existing generating facilities and even greater bulk power purchases from utilities outside the region), as well as mature and advanced utility generating technologies (e.g., fluidized bed combustors and integrated gasification combined cycle units).

- Generating options are characterized in terms of their capital costs, operating and maintenance costs, fuel costs, fuel quality, heat rates, pollution control equipment, reliability, and lead times. In the case of demand-side options, characteristics include capital and program administration costs, market penetration rates, and load shape impacts. Load management options (e.g., water heater service interruption or air conditioner cycling) can be dispatched in an optimal manner similar to the dispatch of utility generating units. The amount and scheduling of available power and its costs characterize possible bulk power purchase options, either for the economy or for the firm.

- Decisions about fuel conversion, retrofits, repowering, life extension, and economic retirements are based upon trade-offs between capital costs and fuel savings over the planning horizon, as well as how these options compare with other available alternatives.

- Selection of fuels for each generating unit is based upon fuel prices and price escalation rates, availability constraints, usage constraints (e.g., an oil or gas plant that is not coal-capable cannot burn coal), emissions characteristics, and environmental regulations. Options can include alternative strategies for meeting environmental constraints.

- Transmission is simulated at a zonal level allowing commercially significant and physical transmission constraints to be captured directly, and to allow for optimal dispatch of units across neighboring areas to achieve cost minimization.

GEOGRAPHIC SCOPE AND TRANSMISSION CONSTRAINTS CONSIDERED FOR THE ANALYSIS

The IPM® modeling relied on herein covers not only the Delmarva Delaware service area, but also the rest of PJM and the North American power markets. A greater level of focus is given to the PJM market directly; however, all of North America is considered in order to allow for accurate reflection of transmission flows, fuel market flows (coal rail/barge movements and gas pipeline movements) and to capture the impact of regional and national air emission control policies.

PJM today operates the world's largest centrally dispatched grid and administers the world's largest wholesale electricity market in terms of demand. The PJM area covers all or parts of thirteen states, Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia and the District of Columbia. The PJM market has 179 GW of generating capacity and about 550 market buyers, sellers and traders of electricity in a region including more than 60 million people. PJM's peak demand is roughly 153 GW (coincident peak) or about 20% of total U.S peak demand.

In its original form, the PJM Independent System Operator (ISO) comprised 10 control zones: Atlantic Electric Company (ACE), Baltimore Gas & Electric (BGE), Delmarva Power and Light (Delmarva Power), Jersey Central Power & Light Company (JCPL), Metropolitan Edison Company (Met-Ed), PECO Energy Company (PECO), Pennsylvania Electric Company (PENELEC), Potomac Electric Power Company (Pepco), PPL Electric Utilities Corporation (PPL), and Public Service Electric and Gas Company (PSEG). In 2001, Rockland Electric Company (RECO) joined PJM. This broad area was also known as the Mid-Atlantic Area Coordinating Council (MAAC), and is now sometimes referred to as "PJM Mid-Atlantic" or colloquially as "PJM Classic."

Since the inception, the geographic scope of PJM has continued to expand both to the south and west and is now more than double in size. In 2001, Allegheny Power Company joined PJM and became the first control area within the region now referred to as the PJM Western Region. In spring 2004, Commonwealth Edison (COMED) became a part of PJM ISO. Later in 2004, two additional control areas were added to the Western region of PJM, namely American Electric Power (AEP) and Dayton Power & Light Company (DP&L). In January 2005, Duquesne Light (DQE or DLCO) also became a part of the PJM Western region; however, in early 2008,

the FERC conditionally approved Duquesne's transfer from PJM to MISO. Dominion Power is also a part of PJM. In 2011 the American Transmission Systems, Inc. integrated with PJM dollowed by Duke Energy Ohio, Inc. and Duke Energy Kentucky in 2012. In 2012, East Kentucky Power Cooperative field to join PJM; if approved, the integration could occr as early as mid-2013.

The PJM market is modeled as several zonal areas based on the current PJM defined transmission congestion areas. Exhibit 1.2 illustrates the transmission zones currently considered by PJM.

Exhibit 1.2: PJM Transmission Zones

Source: PJM Load Forecast Report 2012.

Transmission flows are determined by the model based on limits of the physical transmission grid.

PJM MARKET STRUCTURE

The PJM market is an acknowledged leader in terms of competitive market structure. Some of the key features of this market include:

- Liquidity – There is a functioning industry spot market operating primarily on a day-ahead mode. Thus, there is always a market for competitively bid supply.

- Transmission Access – The energy markets employ Locational Marginal Pricing (LMP) in which each location's price reflects not only marginal bid prices, but also transmission congestion and loss effects. The crucial feature is that the most competitive bid that takes into account other generation as well as transmission factors is chosen. Contracts or other mechanisms cannot be used to hinder access of independent merchant plants. ICF's modeling comports closely with these arrangements.

PJM currently operates four basic types of markets: (i) energy, (ii) capacity (i.e., the Reliability Pricing Model or RPM), (iii) ancillary services, and (iv) firm transmission rights (FTRs), summarized in Exhibit 1.3 below.

Exhibit Error! No text of specified style in document.**.3: PJM Market Overview**

Market	Real-Time Energy Market		Day-Ahead Energy Market		Capacity Market	Ancillary Services Market	Financial Transmission Rights (FTR) Market
	RTO/ISO	Bilateral	RTO/ISO	Bilateral	RTO/ISO	RTO/ISO	RTO/ISO
PJM	Yes	Yes	Yes	Yes	Yes – 3 years forward	Yes	Yes

Source: PJM ISO

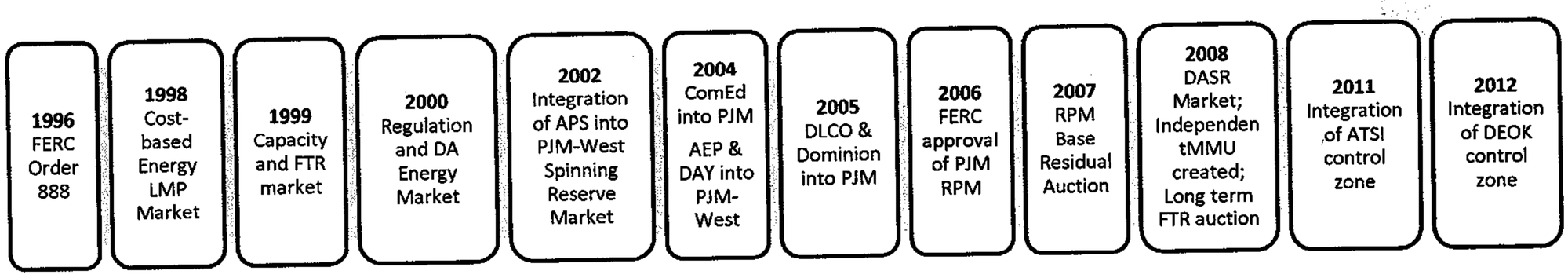
- Energy Markets – PJM utilizes a day-ahead and real-time dispatch market to satisfy customer load demands. Dispatch is conducted through a variable cost bidding system in which least cost generators are selected for dispatch in merit order. PJM manages all dispatch and transmission throughout the PJM market area.

- Ancillary Service Markets – There are other generation related PJM markets such as regulation and spinning reserves. These markets can provide incremental value to generators beyond energy and capacity payments.

- Installed Capacity Markets – In addition to the electrical energy markets, there is a PJM installed capacity market. It provides supplemental revenues to ensure sufficient availability of supply. This market is in the process of a reform that will enhance efficiency by disaggregating the capacity markets into sub-markets and providing formulas to determine the payment for each market under different levels of supply. It has been argued that this will rationalize the market and raise prices as suppliers market shares increase and greater predictability is provided. ICF models these revenues in anticipation of these locational capacity markets and certain features of the payment formulas. ICF has not explicitly modeled the Reliability Pricing Model (RPM) 3-year forward market, but rather models the key elements of the proposed structure such as sub-regional markets and lower capacity prices with greater supply to determine what spot market prices would be based on the market fundamentals at that time.

Exhibit 1.4 below illustrates key developments including inception of market products and changes in area covered.

Exhibit 1.4: PJM Key Market Milestones



LMP – Locational Marginal Pricing
DA – Day Ahead energy market
RPM – Reliability Pricing Model
DASR – Day-ahead scheduling reserve

CHAPTER TWO – RESOURCE OPTIONS

This chapter discusses the generation supply options analyzed in this study.

SUPPLY-SIDE RESOURCE OPTIONS CONSIDERED

In order to optimize the resource mix overtime, the analysis considered alternative power supply options. The optimization was based on a discounted cash flow and cost minimization decision process endogenous to the IPM®. The generation addition options which were characterized within IPM® and considered as possible options include:

Natural Gas-Fired Combined Cycle – These plants use a combination of steam turbine and combustion turbine technologies and capture the waste heat from the gas turbine exhaust produced during electricity generation and reuse it to generate steam for the steam turbine to generate additional electricity. Combining these two cycles result in higher overall efficiency.

Natural Gas-Fired Peaking Combustion Turbine – This plant has lower thermal efficiency and capital costs and shorter construction lead times than Combined Cycle and Cogeneration Units. These peaking units also offer quick start capability.

Areoderivatives (LMS100s) - Similar to peaking combustion turbines, aeroderivative capacity offers short construction times, quick start capability, and have lower capital costs than combined cycles. LMS100s typically are sized at much smaller increments than combustion turbines, have a smaller footprint, can be constructed in a much shorter time, and are more thermally efficient. However, these units also have a higher capital cost than combustion turbines.

Integrated Gasification Combined Cycle (IGCC) - Instead of burning coal directly, IGCC plants convert coal into gas prior to combustion. Gasification helps in achieving lower levels of pollutant emissions. Using a combined-cycle technology, higher thermal efficiencies are achieved. IGCC plants have higher capital costs than traditional pulverized coal plants.

Supercritical Pulverized Coal (SCPC) - Nearly all U.S. coal plants are designed to use pulverized coal, and supercritical plants are designed to increase the plant's thermal efficiency. The plant is highly controlled for sulfur dioxide (SO_2), nitrogen oxides (NO_x), and mercury (Hg). Because this type of coal plant is actively being considered by other utilities, it is modeled as an option for other northeastern U.S. utilities.

Nuclear – Nuclear generation is currently the second largest generation source in the U.S. New nuclear facilities face a number of hurdles prior to any future development largely due to siting concerns. The potential for newly constructed units and uprates at existing facilities are directly accounted for in this analysis.

Solar – Central and rooftop/distributed generation options are considered.

Wind – Both on-shore and off-shore wind facilities are considered. Wind resources are generally the dominant source of generation expected to meet requirements under Renewable Portfolio Standard programs. The analysis considers the potential for new wind resources to be added throughout PJM and the US. On-shore resources are characterized at three distinct tiers of

units based on the combination of the expected facility performance and the construction costs of units. The Step 1 resources have the lowest capital costs while the Step 3 resources have the highest. Each Step may achieve varying output levels (capacity factor) depending on the ambient conditions which are defined by wind classes; each step has 4 associated wind classes which are modeled, Class 3, 4, 5, and 6. Capacity factor is 32% for Class 3, 34% for Class 4, 38% for Class 5, and 40% or higher for Class 6 resources. In addition, off-shore units are also considered in the analysis within coastal market areas and have a distinct cost and performance characteristics.

Biomass - Biomass plants use organic materials such as wood, agricultural and animal waste. Biomass resources are considered a renewable resource. Within this analysis, Biomass resources are also typically considered as carbon neutral.

Landfill Gas - Landfill gas plants use the gas (methane) naturally produced by the decomposing garbage in the landfill to generate electricity. Landfill Gas resources are considered to be renewable resources.

Power Purchases and Sales Reflecting Short-Term Market Conditions – Wholesale power import and export options are modeled in each hour. For the peak, capacity or reliability transactions are modeled.

Demand Side Resources – Demand response and energy efficiency programs have been used by the utilities to lower levels of peak and energy demand. In recent years, the most notable development has been the increase in DSM qualifying for the PJM capacity auction. Given the treatment in PJM of demand side options as a capacity resource, they are treated on a like basis in the overall analysis for generic options. For Delmarva, the specific program planned and projections have been input to this analysis as given.

Exhibits 2.1 and 2.2 present a summary of the assumptions related to new conventional resource options for Delaware. Exhibit 2.3 presents costs and characteristics for renewable resources. The capital cost assumptions reflect ambient conditions in Delaware and demonstrate regional variances depending on the cost of labor and construction material in those regions. All costs are in 2010 dollars.

Exhibit 2.1: Delaware Conventional Resource Options Capital Cost Assumptions

Resource Type	Earliest Online Year	Capital Cost (2010$/kW)	Forced Outage Rate
Peaking Units (LMS100 and Combustion Turbine)	2013	~950	2.4%
Combined Cycle	2015	~1,400	1.3%
Aeroderivatives (LMS100)	2013	~1,300	1.3%
Supercritical Pulverized Coal	2018	~3,000	6.3%
Integrated Gasification Combined Cycle	2019	~3,800	6.3%
Nuclear	2021	~6,500	3.5%

A typical combined cycle unit requires a lead time of 36 months or more prior to coming on-line. A typical coal plant requires an even longer lead time of 4 to 5 years. Given the longer lead-time required for a combined cycle unit versus a combustion turbine unit, we assume that no new combined cycle units are possible before the summer of 2015 unless they are already under construction. New coal plants including IGCC plants are assumed to be available after 2019, unless in an advanced stage of development. New nuclear options become available in 2021. However, upratings to existing facilities are available during the IRP study period.

The capital costs are expected to decline in real terms at about 1 percent annually on average as a result of expected technological advancements. Technological improvements also enhance plant efficiencies reflected by improvements in heat rates over time. Combined cycle technology is assumed to improve to greater levels of efficiency from roughly a 7,100 BTU/kWh lifetime heat rate for through version 3 of the "F" technology, to levels closer to 6,800 BTU/kWh by the end of the forecast period. The lower heat rate is associated with advances in technology including movements to technologies such as version 5 of the "F" technology and the "G" technology.

Capital costs are expected to decline in real terms by about 1% annually on average as a result of expected technological advancements. Technological advancements also enchance plant efficiencies reflected by improvements in heat rates over time.

Exhibit 2.2: Higher Heating Value Heat Rate (Btu/kWh)

Year	Combined Cycle	Combustion Turbine	Jet Engine (LMS 100)	Coal IGCC CCS
2014	-	10,905	9,468	-
2016	6,800	10,905	9,468	-
2018	6,800	10,905	9,468	-
2020	6,800	10,905	9,468	10,156
2022	6,800	10,905	9,468	10,156

Exhibit 2.3 presents the capital expenses for renewable techonologies considered in modeling.

Exhibit 2.3: Delaware Renewable Resource Options Assumptions Summary

Resource Type	Earliest Online Year	Capital Cost (2010$/kW)
Onshore Wind Step 1	2013	~2,000
Onshore Wind Step 2	2013	~2,500
Onshore Wind Step 3	2013	~3,100
Offshore Wind	2016	~4,000
Solar Photovoltaic-Distributed	2013	~4,000
Biomass	2016	~6,000
Landfill Gas	2013	~2,800

1. Regional adjustment factors are applied to the costs above to reflect regional variations in labor and materials markets and altitude/temperature differentials on gas-fired technologies. Capital costs include interconnection costs.
2. Capital cost includes EPC, Soft Costs, AFUDC and generic transmission upgrades.
3. Wind development options are modeled based on geographically determined potential for higher end wind classes. Large scale development is typically class 3 or above. Class 3 capacity factors roughly 32% while class 6 is roughly 40%. Wind development costs are differentiated by site conditions primarily tied to the proximity to the transmission network. Delaware onshore potential is primarily class 3 or below and is concentrated on the coast line. Delaware also has offshore potential which is included as a development option.

The federal government offers production tax credits (PTC) and Investment Tax Credits (ITC) to encourage wind and other renewable generation development. The modeling assumption utilized for PTC reflects 2.2 cents/kWh for wind 1.1 cents/kWh for non-wind renewables through the end of 2012 for wind units and 2013 for other eligible technologies. The ITC (30%) is available through 2016 at full value and it is phased out gradually over the next four years. Any applicable credits will be accounted for in modeling.

Onshore wind options are considered in various configurations to reflect the characteristics to construct and the operational output capabilities at alternate locations. In this analysis we consider three steps of on-shore wind and a single off-shore wind option. In addition to the varying cost steps which reflect the difficulty in constructing facilities (for example, Step 3 reflects a facility in a remote location which would require extensive upgrades such as roadway clearing and lengthy transmission interconnection to come on-line while Step 1 reflects a relatively accessible location requiring typical site and interconnection investment), each step reflects the potential to build wind class 4, 5, and 6 facilities. Wind classes reflect the wind speed and height of the turbines which translate into varying and improving capacity factors at the higher classes. Based on the geographic characteristics of the area, the onshore wind potential in Delaware is extremely limited to only the lowest wind classes which tend to have high costs and lower capacity factors. As such, wind options modeled within Delaware are consistent with this limited amount of onshore resource.

Offshore wind facilities are thought to offer several advantages over on-shore facilities. The major advantages are:

1. Wind speeds are generally stronger; a 25-40 percent gain in wind speed is typical at a few miles off-shore.
2. The potential for large contiguous development areas exists.
3. Offshore wind tends to be less turbulent, translating into less wear and tear on the turbines.
4. Offshore wind shear is lower than on-shore. This means that the boundary layer of slower moving air near the sea surface is thinner than the comparable area on land. This phenomenon allows for use of shorter towers to reach the desired hub-height average wind speed for turbine operation.

However, offshore facilities also have several disadvantages compared to onshore wind units. Among the disadvantages are the higher costs, the extremely limited experience in constructing, permitting, operating, and maintaining the facilities and their platforms. Further, due to the limited experience, the impact on the marine environment, the impact on other environmental issues, and the construction and maintenance requirements and costs also have a high degree of uncertainty surrounding them.

FINANCING ASSUMPTIONS FOR NEW RESOURCE OPTIONS

The following table illustrates the financial assumptions used for new resources in Delaware.

Exhibit 2.4: New Resource Options Financing Assumptions for Delaware

Financial Assumptions	Combustion Turbine	Combined Cycle/Cogeneration	Coal/Nuclear Average	Intermittent Renewables
Debt/Equity Ratio (%)	55/45			
Nominal Debt Rate (%)	5.8			
Nominal After Tax Return on Equity (%)	10.8			
Income Taxes[1]	40.6			
Other Taxes[2] (%)	0.8			
General Inflation Rate (%)	2.5			
Debt Life (years)	15	20	20	15
Levelized Real Capital Charge Rate (%)	9.4	9.3	9.1	8.9

Note: Financing assumptions are identical for all areas of the country, but taxes vary regionally.

1. Includes federal and state taxes.
2. Includes property taxes and insurance.

For additional capacity needed over and above the firm commitments identified as having broken ground, the model adds capacity based on the resource options described in Exhibits 2.1 and 2.2 above.

EMISSION REGULATIONS

The Reference Case for this analysis includes those regulations that are likely to occur over the time horizon of the analysis, including those already in place in Delaware and on a national basis.

Exhibit 3.1: Key Environmental Regulation Assumptions in Delaware

Regulation	Pollutant	Permitted Levels	Criteria	Enactment	Source
Title 7 DNREC section 1146	NO_x	2009: 0.15 lb/MMBtu 2012: 0.125 lb/mmbtu; annual unit level tonnage limits	Affects Indian River (NRG), Edge Moor (Conectiv), McKeen Run (one unit) (city of Dover)	11/16/2006	http://www.awm.delaware.gov/info/regs/Pages/aqmmultipreg.aspx
	SO_2	2009: 0.37 lb/MMBtu 2012: 0.26 lb/mmbtu; annual unit level tonnage limits			
	Hg	Unit-level regulation: Phase 1 (2009): 80% capture or rate limit of 1.0 lb/TBtu; Phase 2 (2013): 90% capture or rate limit of 0.6 lb/TBtu			
RGGI (Regulation # 1147) [1]	CO_2	approx.10% reduction from current levels by 2019	All generators > 25 MW	2008	http://www.awm.delaware.gov/Info/Regs/Pages/RGGI.aspx
SB 119	Renewables	25% by 2025, including 2.005% solar	eligible renewable technologies	7/10/2010	http://legis.delaware.gov/LIS/lis145.nsf/vwLegislation/SS+1+for+SB+119/$file/4161450004.doc?open

1. RGGI is a regional program with state level implementation and allowance allocations. The Delaware plan under RGGI is shown above.

Working with DNREC, Indian River LLC agreed to retire Units 1, 2 and 3. According to the Consent Agreement with DNREC, the 91 MW Indian River Unit 2 was retired, effective May 1, 2010 and unit 1, also 91 MW, was retired on May 1, 2011. The 165 MW Indian River Unit 3 retirement is scheduled for December 31, 2013. Beyond December 31, 2013, only Indian River Unit 4, which is the newest and largest unit rated at 420 MW, will continue its operation.

Programs affecting sulfur dioxides, nitrous oxides, and mercury are shown in Exhibit 3.2 with additional discussion of carbon programs following.

Exhibit 3.2: Key National Environmental Regulation Assumptions Affecting Multiple Market Areas

Regulation	Timing
SO_2 and NO_x (CSAPR) Reference Case	2012
SO_2 and NO_x (CAIR) Sensitivity Case	2012
Air Toxics (MATS)	2015
CCR (coal ash) Disposal	2018
CO_2 (National)	2023+
Water Intake (316b)	2025

Overview of Federal Green Air, Waste and Water Regulatory Requirements

A high level of uncertainty continues to characterize the current air regulatory context, with electric generators facing a wide range of upcoming requirements from EPA, Congress or both. The Reference Case considers a set of requirements representative of the alternatives in the long run for CO_2 (GHGs), SO_2, NO_X, and hazardous air pollutants (HAPs), including mercury.

The Reference Case assumes EPA regulation of SO_2, NO_X and HAPs under the Clean Air Act:

- State-specific requirements for SO_2 and NO_X emissions with limited regional allowance trading under EPA's Cross-States Pollutant Rule. On August 21, 2012, after the finalization of assumptions for the Reference Case considered here, the Court of Appeals for the D.C. Circuit vacated Cross-State Air Pollution Rule ("CSAPR"). In 2008, the D.C. Circuit struck down and remanded Clean Air Interstate Rule ("CAIR"), the predecessor to CSAPR, with instructions to USEPA to continue administration of the CAIR until the replacement rule was implemented. Here, in light of the vacatur of the CSAPR, the D.C. Circuit has instructed USEPA to "continue administering CAIR pending [USEPA's] promulgation of a valid replacement." A second scenario, which reverts to CAIR, was considered in part and will be presented in the results section.
- Hazardous air pollutants (HAPs) under a maximum achievable control technology (MACT) standard. For the purpose of this analysis, the HAPs MACT is assumed to require control with an SO_2 scrubber, fabric filter and activated carbon injection (ACI), either with existing or newly installed controls.

Cross-State Air Pollution Rule (CSAPR) and Clean Air Interstate Rule (CAIR)

As earlier mentioned, in 2012 Federal courts vacated CSAPR and left the Clean Air Interstate Rule (CAIR) in effect. This followed a court issued stay of CSAPR in December 2011. This, in turn, followed a court decision in 2008 to remand CAIR back to EPA.

Based on the timing of this decision making, the Reference Case for this IRP considers the CSAPR in place over the planning horizon. A sensitivity case has also been considered which reverts to CAIR for the near term, and assumes that in 2018, when Phase II of the CAIR program would have been in effect, it is assumed that more stringent SO_2 and NO_x standards go in place. Given the proposed 2012 annual standard for $PM_{2.5}$ is a 15% reduction from the 1997 annual standard (15μg/m^3 to 12μg/m^3), the 2018 budgets were derived by reducing the 2015

CAIR budgets by 15%. Further, only intrastate trading is allowed and interstate trading is not allowed. Since the assumption is that CAIR II will be a new program with a new currency that is specific to each state, there is no banking allowed into 2018.

It is also assumed that the EPA will proceed with implementation of the proposed 2012 NAAQS for $PM_{2.5}$.

Mercury and Air Toxics Standards

EPA finalized the Mercury and Air Toxics Standards Rule ("MATS") in December 2011. The Rule was developed under Section 112 of the Clean Air Act, which defines a number of hazardous air pollutants ("HAPs"). Under this section, EPA is charged with developing regulations to reduce listed pollutant emissions. Pollutants regulated under Section 112 cannot be reduced using a cap and trade system. Instead, the EPA must determine a maximum achievable control technology ("MACT") limitation based on the top 12 percent of existing units. The regulation takes the form of an emission standard at the facility-level. As such, units/facilities will either have to control emissions or face retirement. The final MATS Rule specifies emission rate limits for 3 pollutant classes, requiring control of mercury, acid gases ("HCl"), and particulates as surrogates for over 100 controlled pollutants.

For mercury, which is listed as a HAP, one of the most common control technologies is activated carbon injection ("ACI"). The regulation may also require other control investments to meet the standards for other HAPs, including regulations of hydrogen chloride ("HCL") as a surrogate for toxic acid gases and particulate matter as a surrogate for non-mercury toxic metals. ICF and others project that these investments – required on many small units over 40-50 years old presently operating at lower capacity factors – will result in the retirement of several gigawatts of coal-fired capacity. In addition to the HAPs regulations, several states already have standards in place for mercury.

This analysis assumes federal MACT standards consistent with those set by EPA in its final MATS, as released December 21, 2011. Units are required to meet the mercury and acid gas standards in the rule. For compliance with the particulates standards ("PM"), each unit must be equipped with a fabric filter or an adequately sized ESP, upgrade its ESP, or add a new fabric filter. States with existing Hg rules are assumed to proceed as planned, so long as they meet minimum requirement as defined by the federal MACT.

Water and Coal Combustion Residuals Regulations

The Clean Water Act (CWA, 1972) also includes several key provisions impacting power markets. It prohibits unauthorized discharge of pollutants from point sources to U.S. waters, it requires National Pollutant Discharge Elimination System ("NPDES") permits that regulate the discharge of pollutants (issued by EPA, state or tribe), requires EPA to develops effluent limitation guidelines and standards, and requires states to develop water quality standards that are the basis for the limitations required in NPDES permits.

Section 316(b) of the CWA addresses cooling water withdrawals, as opposed to discharges, by point sources subject to the NPDES program. It grants EPA the authority to regulate "location, design, construction and capacity of cooling water intake structures" to ensure that these

structures reflect "the best technology available ("BTA") for minimizing adverse environmental impact."

The water intake structure standards address impingement, where aquatic life is trapped against intake screens and injured or killed as a result, and entrainment, where organisms are drawn into the facility and killed by pressure and high temperatures. Compliance with the impingement requirements must be implemented no later than eight years after the final rule is issued. On July 24 2012, in a settlement agreement, EPA received an extension to finalize the rule by July 27, 2013. Assuming eight years in the proposed rule would require compliance with the impingement standard no later than July 2021. Compliance with the entrainment standards will be determined by the states, but may take until after 2020 to grant time for the necessary studies, public input and final determinations.

Following the ash pond failure at TVA's Kingston plant in 2008, EPA released a proposed rule in April 2010 for the handling of ash or coal combustion residuals ("CCRs") under the Resource Conservation and Recovery Act ("RCRA"). EPA's final rule for the management of coal combustion residuals is due in 2012. EPA offered two potential regulatory approaches in its proposal; one under RCRA Subtitle C (governing hazardous waste management and disposal) and another under Subtitle D (governing solid and municipal waste management and disposal). While the two are similar in many ways, the option to classify and regulate CCRs as hazardous waste would impose significantly higher disposal cost.

Reference Case CO_2 Regulatory Requirements

National CO_2 Program

In the current Congress, the prospects for a multi-sector cap and trade program to reduce greenhouse gas emissions are very slim. While momentum for such a program increased sharply in 2009 with the passage of the Waxman-Markey bill through the House of Representatives, Congress has taken no further action and congressional leaders have referred to cap and trade legislation as "dead." Meanwhile, EPA has continued to move forward with regulation of greenhouse gases under the Clean Air Act, though at a pace slower than anticipated.

As of January 2011, new and modified emitting facilities are required to adopt Best Available Control Technologies ("BACT") to reduce greenhouse gas emissions, which will be determined on a project-by-project basis, under the Clean Air Act's Prevention of Significant Deterioration ("PSD") Permitting Program. This requirement demands that all new facilities undertake a BACT determination process in order to receive a permit to operate. The permit will be subject to state and EPA review to determine whether the BACT process was thorough and if the chosen BACT option is sufficient. This process will add to the cost and time required to file a permit, as well as uncertainty to the permitting process.

On March 27, 2012, EPA issued its first-time proposed NSPS affecting new and modified sources of greenhouse gases. The proposed limit is 1,000 pounds per megawatt hour, a level that can be met by natural gas combined cycles or coal generation with carbon capture and sequestration ("CCS") technology capable of capturing about 50 percent of its CO_2. NSPS may eventually allow for the formation of a cap and trade program for GHGs under the Clean Air Act, similar to what was proposed under Section 111(d) of the Clean Air Act for the Clean Air Mercury Rule.

Some members of Congress are attempting to delay or halt the EPA's efforts to regulate greenhouse gas emissions. Legislative efforts have so far been unsuccessful but continue nonetheless. The White House would likely veto such a bill, but Congress may also act to limit funding for the EPA's efforts to enact regulation under the Clean Air Act through the appropriations process.

While not imminent, ICF believes it is still likely that a national CO_2 price signal will come into being at some point, at least for the power sector. To reflect this assumption, taking into account the current lack of momentum in Congress, ICF's Reference Case analysis includes the initiation of a national CO_2 policy starting in 2023. Although this does not directly affect the IRP planning period, for such a policy to go forward, several years of planning are implicit. As such, decisions in the late term of the IRP forecast due consider the longer term consequences of the CO_2 program assumptions.

The Regional Greenhouse Gas Initiative

On the regional level, participating Northeastern and Mid-Atlantic states have developed a CO_2 market under the Regional Greenhouse Gas Initiative ("RGGI") program. Pennsylvania and New Jersey do not participate in RGGI program. RGGI is a market-based program to reduce emissions of CO_2.

Currently, the RGGI members are in discussions focused on potentially revamping the RGGI program realization of CO_2 reductions. Although several potential options for change are being explored, no single proposal has moved forward at the time of this analysis. The assumed price trajectory assumes a continuation of the current RGGI program goals.

Air Emission Rates and Control Costs

Plant level emissions are determined by the pollutant content of fuels, installed emission control technologies and plant dispatch. Coal power plants have the option to burn multiple types of coal with a range of sulfur and mercury contents. Units may switch fuels to comply with environmental constraints. NO_x emission rates for existing units in IPM® were populated based on EPA's 2008 and 2009 Clean Air Markets Emission Database, which is primarily comprised of data from Continuous Emissions Monitoring Systems (CEMS). Mercury emission modification factors are based upon the EPA 1999 ICR data.

Power plants also have the option to install control technologies such as Wet Limestone Forced-Oxidized Scrubber (wet scrubber), Spray Dry Absorbers (dry scrubbers), Activated Carbon Injection (ACI), Selective Catalytic Reduction (SCR) and Selective Non-Catalytic Reduction (SNCR). Plant retirement and mothballing are also explicitly modeled.

The electricity system also has the capability to reduce emissions by adjusting system dispatch. Under a cap-and-trade system, the model considers the variable cost of emitting (buying allowances) and rearranges system dispatch to minimize generation costs.

RENEWABLE PORTFOLIO STANDARDS (RPS)

In addition to the state level controls for fossil units described above, Delaware has actively pursued standards which would encourage "green" generation sources. Exhibit 3.3 presents the current Delaware renewable targets as set forth in the Senate Substitute No. 1 for Senate Bill No. 119. Under the RPS program, a market for tradable renewable energy credits will exist. Delmarva is required to have sufficient credits to meet the stated requirements and will be able to purchase credits directly from qualified facilities or from market clearinghouses. Renewable Energy Credit (REC) values are determined by the demand for green power and the characteristics of sources available to supply that demand. The total demand will be met by existing and new renewable generators specified by cost, performance and resource availability. IPM® brings together these essential components of renewable power development in a single integrated structure to determine market equilibrium conditions within the broader context of the electric, fuel and environmental markets. RPS standards are modeled for all other areas with existing policies.

Specific carve outs were assumed for Delaware Solar RPS. The 30 MW Bloom Fuel Cell is assumed to be able to offset 1/6 amount of standards up to Year 2026, and then 1/3 amount of standards up to 2033. Also, distributed solar in Delaware can contribute 100% to the solar requirement, other existing Delaware solar units and utility scale photovoltaic solar units can offset 33.33% only after 2017.

Exhibit 3.3: Delaware Renewable Portfolio Standard Annual Targets (%)

Year	Eligible Renewables	Solar
2010	5.0	0.018
2011	7.0	0.2
2012	8.5	0.4
2013	10.0	0.6
2014	11.5	0.8
2015	13.0	1
2016	14.5	1.25
2017	16.0	1.5
2018	17.5	1.75
2019	19.0	2
2020	20.0	2.25
2021	21.0	2.5
2022	22.0	2.75
2023	23.0	3
2024	24.0	3.25
2025	25.0	3.5

Historically, the fuel mix in PJM has been dominated by low cost nuclear and coal generation. However, increasing natural gas use for electricity generation has occurred in PJM and throughout the U.S. in general. In PJM, natural gas fuels account for more than 90% percent of capacity additions that have come online since 1999. Over this time period, new highly efficient combined cycle generation has become the technology of choice for several reasons including environmental friendliness, cost and shorter lead times. This trend is also evident in Delmarva where of the 1.4 GW of new capacity that has come online since 1999, 1.0 GW is gas-fired. Exhibits 4.1.and 4.2 illustrate the capacity and generation mix for PJM as reported in the PJM State of the Market Report for 2011. PJM capacity and generation is dominated by coal, nuclear and natural gas-fired technologies.

Exhibit 4.1: PJM Capacity Mix - 2011

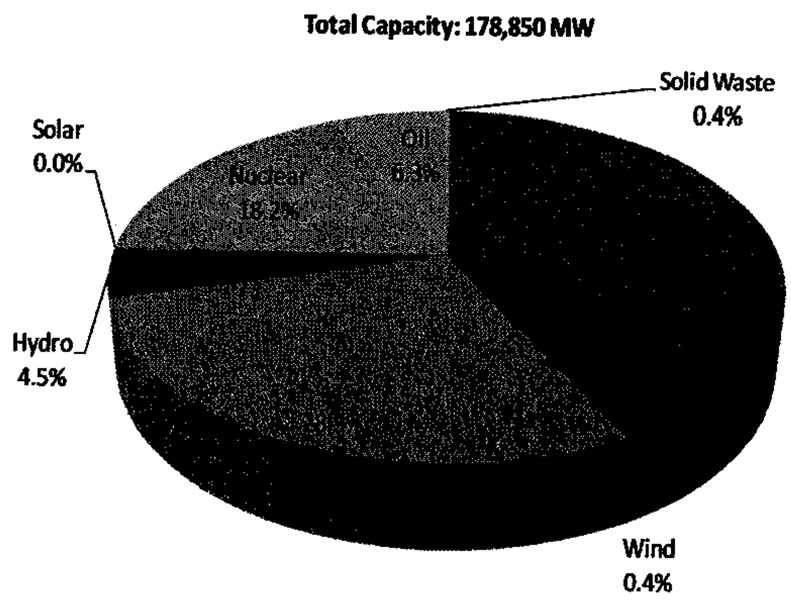
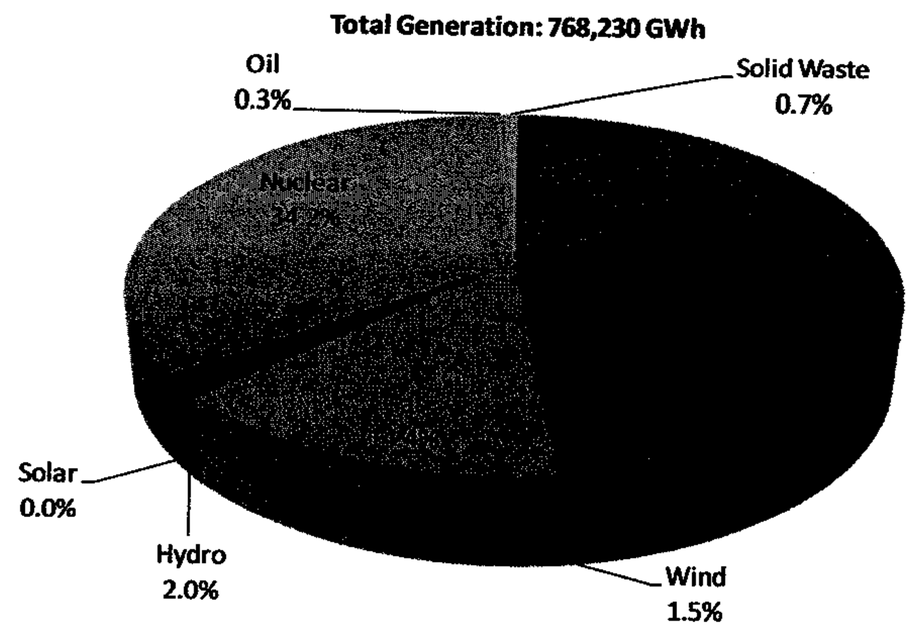


Exhibit 4.2: PJM Generation Mix 2011



FUEL TYPES ANALZED

The Reference Case Analysis considered the following fuel options: Coal, Petroleum Coke, Natural Gas, Oil, and Biomass. Each of these is discussed in more detail below.

- **Coal** –Existing coal plants in Delaware have historically met the bulk of their coal needs from the Central Appalachian coal fields in West Virginia, Virginia and Kentucky. Since all the new power plant options have controls to decrease SO_2 emissions, and are flexible with respect to the coal quality, a wider range of coal types in addition to those listed above were considered.

- **Petroleum Coke** – Petroleum coke is a by-product of petroleum refining and has high energy density and sulfur content. The price of petroleum coke is typically very low, on a per BTU basis for plants near refining centers in the U.S. Gulf, because few plants can readily use this type of fuel. The use of significant quantities of petroleum coke requires not only sulfur dioxide emissions control, but also flexible coal generation technology such as IGCC and CFB. Thus, the demand for petroleum coke has been limited and commodity prices have been very low.

- **Natural Gas** – Natural gas is used grid wide in PJM and much of the eastern US. In the late 1990s and early 2000s, the dominant type of resources added to the North American power grid were gas-fired resources.

- **Oil** – Oil-fired generation comprises a very small share of the generation resource mix in PJM and throughout the US. PJM does have several older steam generators which can rely on either residual fuel oil or natural gas. In addition, peaking capacity can often fire on distillate fuel or natural gas.

- **Biomass** – ICF has developed assessments of biomass supply based on EIA's Annual Energy Outlook which are used in this analysis.

Natural Gas Prices

ICF's natural gas price forecast is presented in Exhibit 4.3. The natural gas price forecast reflect a combination of the Henry Hub NYMEX futures price in the near term and ICF International's fundamentals-based forecast in the mid to long term. The 2012 Henry Hub reflects an average of historical gas prices for January 1, 2012 - July 31, 2012 and 2012 futures strip traded over July 1, 2012 - July 31, 2012 for the rest of the year. The 2013 price reflects future strip traded over July 1, 2012 – July 31, 2012. The 2014 price reflects an average of traded futures for 2014 and natural gas prices that is solved for endogenously within ICF's Integrated Planning Model framework for the period starting in 2015 using a fundamentals-based approach.

As stated, starting in 2015, ICF utilizes its own fundamentals based forecast using ICF's Gas Market Model (GMM). GMM is a full supply/demand equilibrium model of the North American gas market. The model solves for monthly market clearing prices by considering the interaction between supply and demand curves at each of the model's over 100 nodes, or market hubs, which cover the U.S. Lower-48, Canada, Alaska, and Mexican border points (see Exhibit 4.4). On the supply-side of the equation, prices are determined by production and storage price curves that reflect prices as a function of production and storage utilization. LNG import volumes are solved at each of the existing import terminals as well as terminals that are projected to come on-line in the forecast period. On the demand-side, prices are represented by a curve that captures the fuel-switching behavior of end-users at different price levels. The model balances supply and demand at all nodes in the model at the market clearing prices determined by the shape of the supply and demand curves. Prices are also influenced by "pipeline discount" curves, which reflect the change in basis or the marginal value of gas transmission as a function of pipeline load factor.

Delivered prices vary across regions due to varying basis differentials, fuel taxes, and local distribution charges. Additionally, commodity and transportation prices vary with demand on a seasonal basis in accordance with our forecasts and historical trends, e.g., higher prices in the winter than in other seasons. ICF employs GMM outputs and market/historical data to derive basis differentials and seasonality trends. For Delaware, ICF assumed 7% fuel tax. Additionally, delivered gas price in the southern part of the peninsula has about a $0.1/MMBtu premium over the delivered price in North.

Exhibit 4.3
Natural Gas Price Assumptions (2010$/MMBtu)

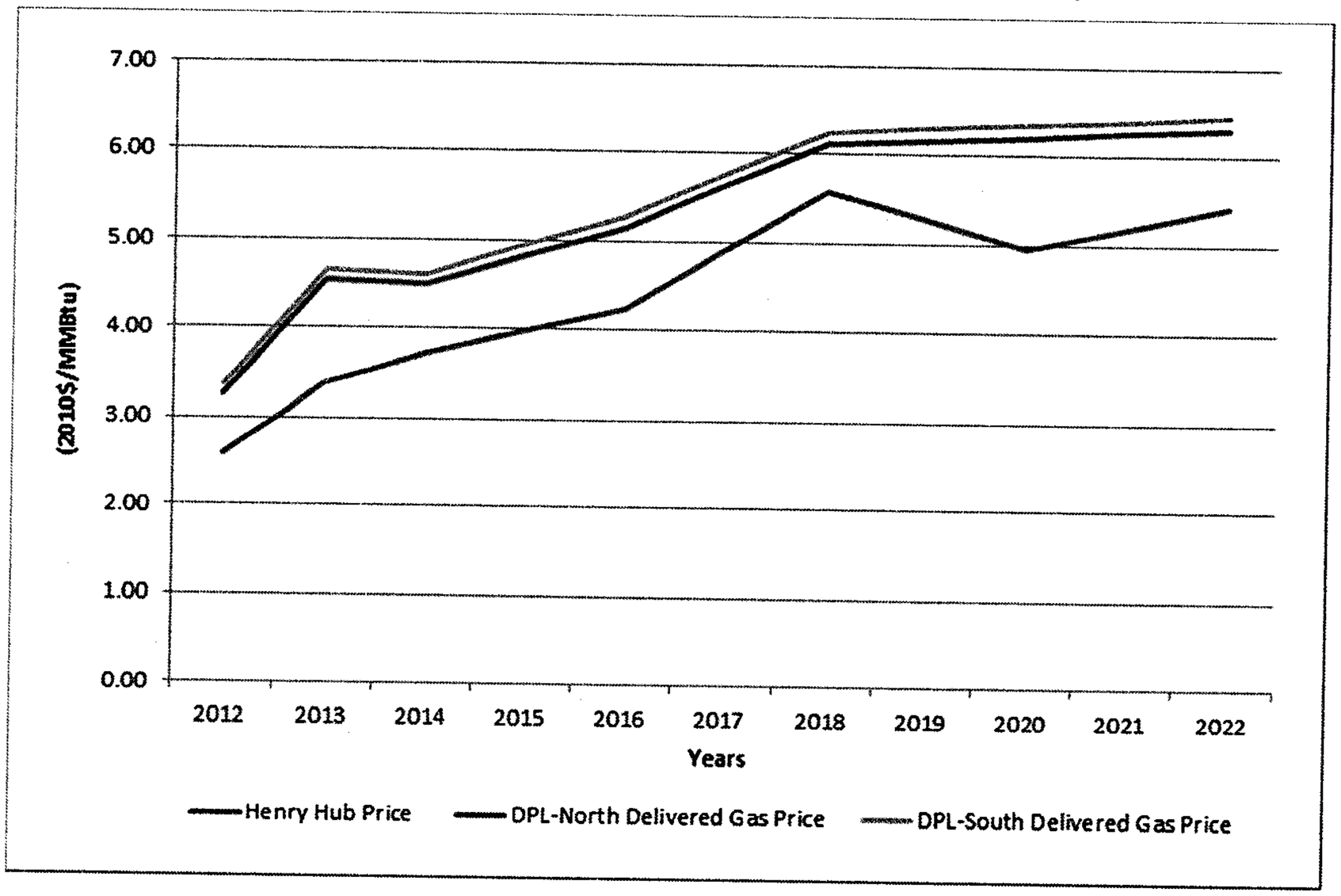
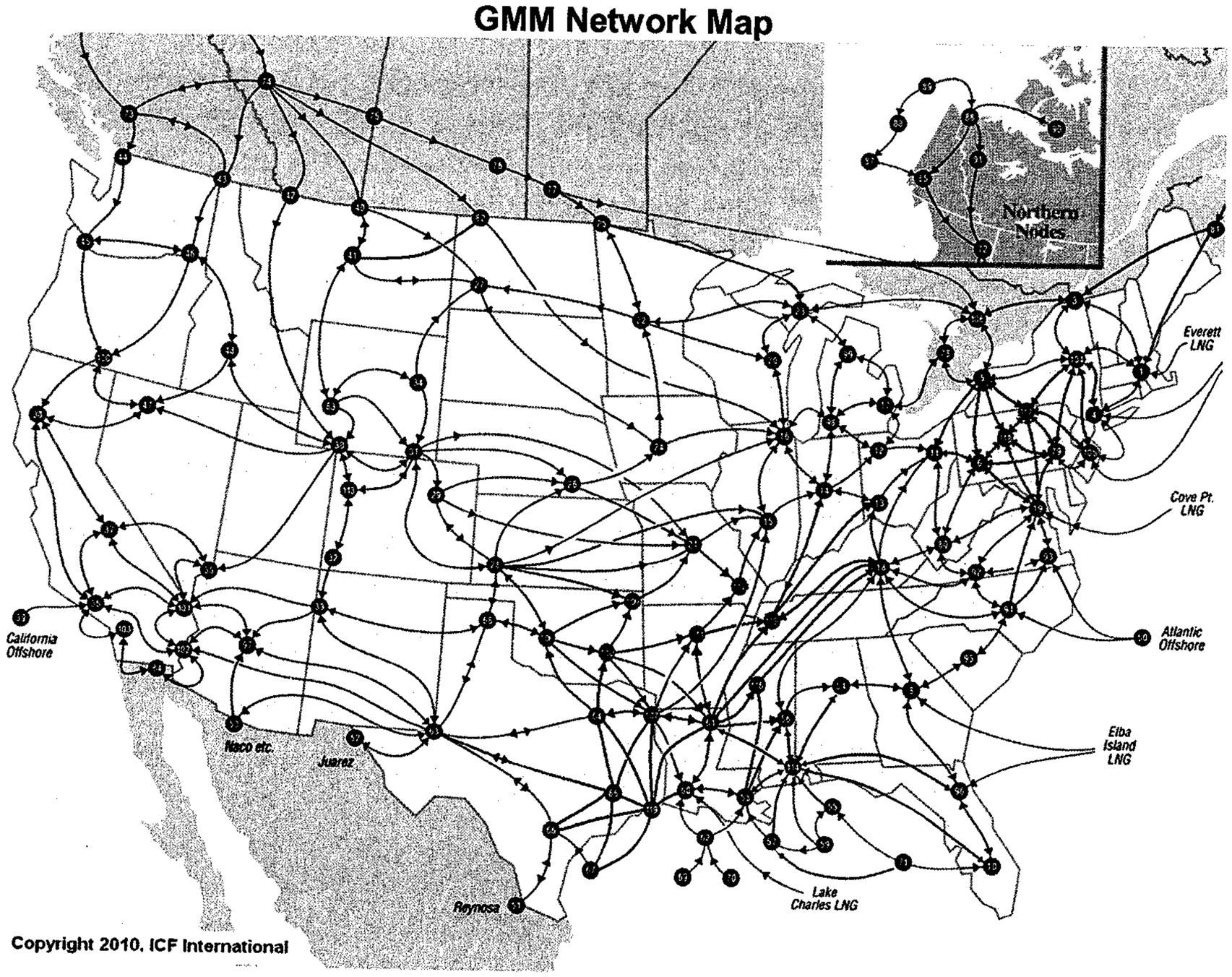


Exhibit 4.4
GMM Network Map



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The current low gas price environment reflects a loose supply/demand balance which is a result of increase in gas supply combined with a significant decrease in gas demand caused by one of the warmest winters on record. In 2011, U.S. gas production rose by nearly 5 Bcfd due to increases in shale gas production. About half of the production increase came from the Haynesville shale. The much warmer-than-normal winter temperatures across most of the U.S. reduced gas demand for space heating by as much as 10 Bcfd in January alone. While low prices have prompted increased gas use in the power sector, demand increased due to coal-to-gas switching was not nearly enough to make up for the reduced demand for space heating in the residential and commercial sectors. As a result of the supply increases and low demand, storage inventories are 900 Bcf above typical end-of-winter levels, and spot prices dropped to $2 per MMBtu earlier in 2012. With the two thirds of 2012 complete, the Henry Hub price is projected to average $2.6 per MMBtu.

While gas prices are projected to be moderate compared to the high levels observed in 2008, ICF does not project a return to the low price environment of the 1990s. Increased use of natural gas for power generation has absorbed all the surplus productive capacity that led to the low price in the 1990s. Also, domestic production has become more costly with the decline of mature production areas and the development of new unconventional gas supplies, such as shale and tight gas. Growth in power generation gas demand may be greater than projected, depending on the outcome of the debate over carbon emission policy and the cost of other generating technologies.

The current low price environment is not sustainable in the long run. Gas-directed drilling, which had already started to slow at the end of 2011, will continue to decline with the near-term low prices. Producer are reducing their activities in dry gas plays and shifting to areas with higher concentrations of oil and natural gas liquids, as prices for these commodities have remained high. Drilling activity in the Haynesville Shale, a key area for recent production growth, has dropped dramatically within the past year. The reduction in gas-directed drilling activity will eventually lead to a tightening of gas supplies. On the demand side, both industrial and power generation gas consumptions have been steadily increasing, and (assuming future weather is closer to the average of the past 30 years) residential and commercial demand will also be significantly higher in the coming year.

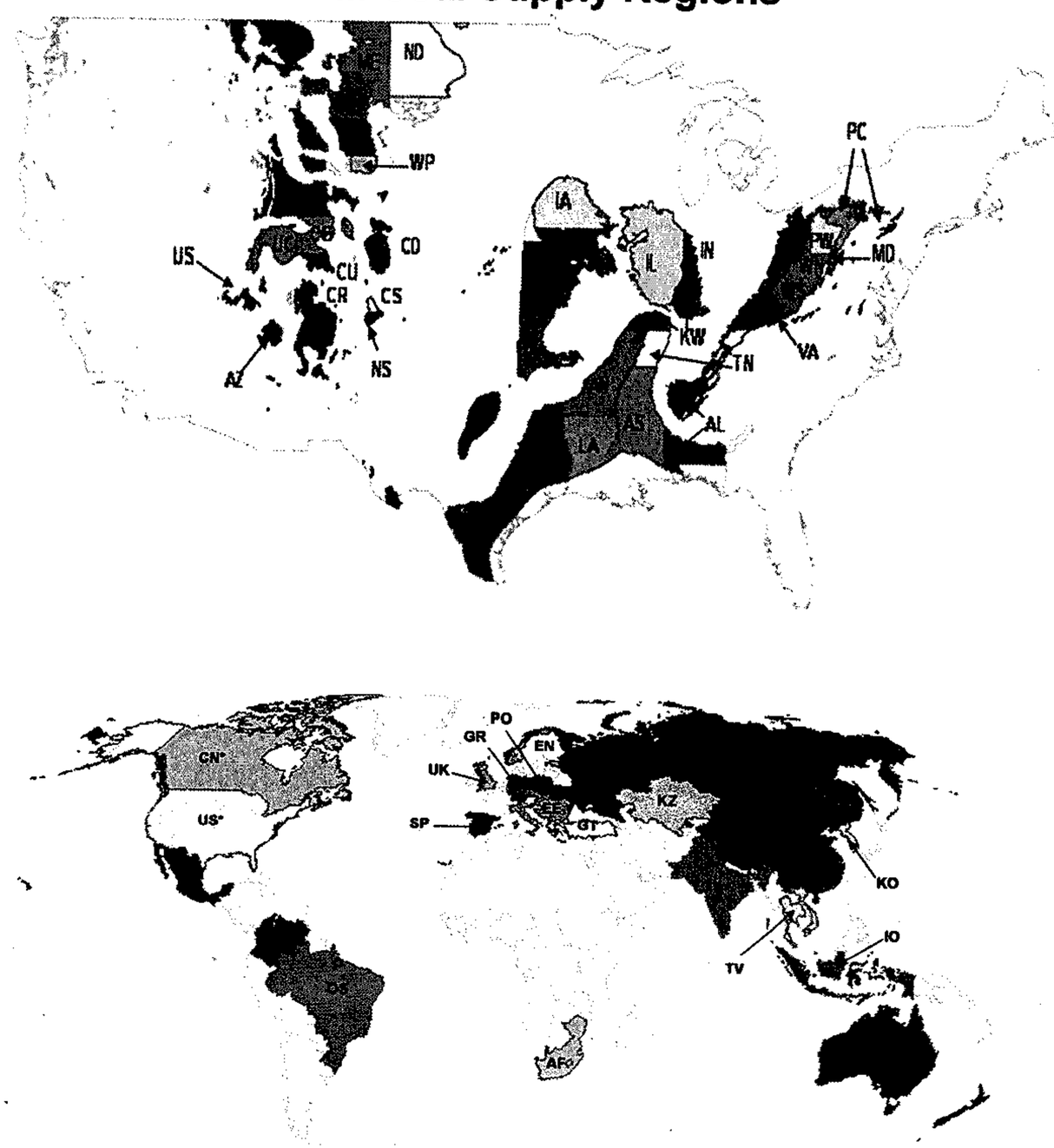
Going into the winter of 2012/13, gas prices are projected to gradually increase. A return to normal weather in the coming winter in conjunction with slowing production activity throughout 2011 and 2012 is projected to raise gas prices back to close to $4.00 per MMBtu level by 2013/2014. The natural gas prices in Exhibit 4.3 represent the futures market for 2013 which is somewhat lower than the fundamentals based outlook.

From 2014 to 2015, prices are projected to increase gradually, as the combined growth in domestic production outpaces the growth in gas demand. Imported LNG and Canadian gas production and exports to the U.S. will continue to decline. Prices are expected to remain around $4 per MMBtu until 2015/2016, when the combined impact of new air emissions regulations and new LNG export facilities in Western Canada and the U.S. Gulf Coast drive up gas demand, and gas prices increase to the $5.5/MMBtu level by 2022.

COAL FORECASTS

In IPM®, coal pricing is endogenously solved for in the model. Coal resources are tracked and classified as in one of 39 U.S. coal supply regions or 25 international coal supply regions, shown below in Exhibit 4.5.

Exhibit 4.5
IPM Coal Supply Regions



Coal supply curves for each of the 64 supply regions are created in CoalDOM®, an ICF modeling tool, by assigning every existing coal mine to one of 16 prototype coal costing models. A coal supply curve is generated for each coal type produced from each coal supply region for each year. The coal types are differentiated by rank and sulfur content. The coal types also differ in mercury and chlorine content depending on the source region. The coal supply curves are then used as inputs to ICF's Integrated Planning Model (IPM®). Coal plants in IPM® are assigned to one of 200 different coal demand regions that are defined by location and mode of delivery. A coal transportation matrix links supply and demand regions in IPM®, which determines the least cost means to meet power demand for coal as part of an integrated optimal solution for power, fuel, and emission markets.

ICF coal price projections in the near-term reflect some recovery from their currently depressed levels. However, the new regulations along with low natural gas prices continue to put downward pressure on U.S. coal prices, at the same time that eastern coal production costs continue to increase due to increased regulatory scrutiny, safety inspections, and permitting delays. These developments are being offset by growing overseas demand for U.S. coking coal and continued interest in steam coal. The coking coal demand from Asia and the increasing thermal coal sales to Europe in 2011 provided leverage for coal sold into the domestic

market. However, with the softening of both domestic and international coal demand, coal prices have plummeted in the last year. Coal demand has been hit hard by the low gas prices as well as an extremely mild winter. A return to more normal weather patterns will help boost coal demand in mid to late 2013 as stockpiles are drawn down.

ICF projects that Central Appalachian (CAPP) prices recover from the current unsustainably low levels and remain at about $70/ton. Demand for high-sulfur Illinois basin and higher heat content Northern Appalachian (NAPP) coal will grow as more coal plants install scrubbers; thus, we expect prices for these coals to remain strong through 2020.

CHAPTER FIVE – REFERENCE AND SENSITIVITY CASE RESULTS

Chapter Five presents results of the Reference Case and the Sensitivity Case including the resource mix that would optimally serve the PJM market.

REFERENCE CASE

Exhibit 5.1 presents a comparison of the expected capacity while Exhibit 5.2 presents the associated generation by resource type.

Exhibit 5.1: Expected Total Capacity (MW) by Type – PJM Wide

Capacity Types	2013	2014	2016	2018	2020	2022
Coal	65,786	64,127	64,096	63,744	63,744	63,744
Combined cycle	25,359	25,924	29,525	31,162	34,928	37,962
Oil/Gas other	8,139	7,036	6,528	6,528	6,528	5,710
Hydro	7,433	7,433	7,468	7,468	7,468	7,468
Nuclear	33,707	33,707	33,707	33,707	33,057	33,057
Turbine	31,033	31,012	30,160	32,016	32,828	36,833
Renewable	9,943	10,836	12,084	12,920	13,712	14,296
Wind	6,482	6,901	6,915	6,915	6,915	7,397
Solar PV	1,528	1,991	3,065	3,883	4,633	4,735
Landfill	671	671	831	849	891	891
Biomass	644	644	644	644	644	644
Other	598	598	598	598	598	598
Fuel Cell	18	30	30	30	30	30
Total	**181,400**	**180,075**	**183,568**	**187,545**	**192,265**	**199,070**

Exhibit 5.2: Expected Generation (GWh) by Type – PJM Wide

Capacity Types	2013	2014	2016	2018	2020	2022
Coal	409,626	397,344	406,954	424,026	431,009	435,238
Combined cycle	127,012	137,694	151,112	154,986	180,908	199,767
Oil/Gas other	153	378	158	156	154	154
Hydro	16,339	16,544	16,884	16,969	16,969	16,969
Nuclear	261,532	261,623	259,433	257,730	255,884	254,542
Turbine	5,686	7,211	6,564	7,472	8,213	8,243
Renewable	31,127	34,771	37,636	38,869	40,181	41,715
Wind	15,947	17,494	17,533	17,533	17,533	18,921
Solar PV	1,970	2,573	4,073	5,154	6,121	6,267
Landfill	4,747	4747	6013	6161	6505	6505
Biomass	3652	4986	5038	5042	5042	5042
Other	4,730	4,730	4,730	4,730	4,730	4,730
Fuel Cell	82	242	250	250	250	250
Total	**851,475**	**855,565**	**878,741**	**900,208**	**933,318**	**956,628**

The modeling analysis performed fundamental analysis of the region which includes optimizing the capacity and energy costs within PJM on a forward basis. The energy and capacity costs which would be available to the load serving entities are projected over the time horizon. Exhibit 5.3 presents the wholesale energy prices projected by the fundamental model for the Delmarva Delaware area. The energy cost shown is the simple average of the energy costs in all the hours of the year.

Exhibit 5.3 presents the emissions by type in the Reference Case.

Exhibit 5.3: Emissions by Type (Mtons) – PJM Wide

Emissions by Type	2013	2022
CO_2 (Mtons)	468,318	523,679
NO_x (Mtons)	325	280
SO_2 (Mtons)	1,000	595

Exhibit 5.4 and 5.5 present the all-hours energy prices and annual capacity prices for DPL North and DPL South zones, respectively.

Exhibit 5.4: All-hours Wholesale Energy Price (2010$/MWh)

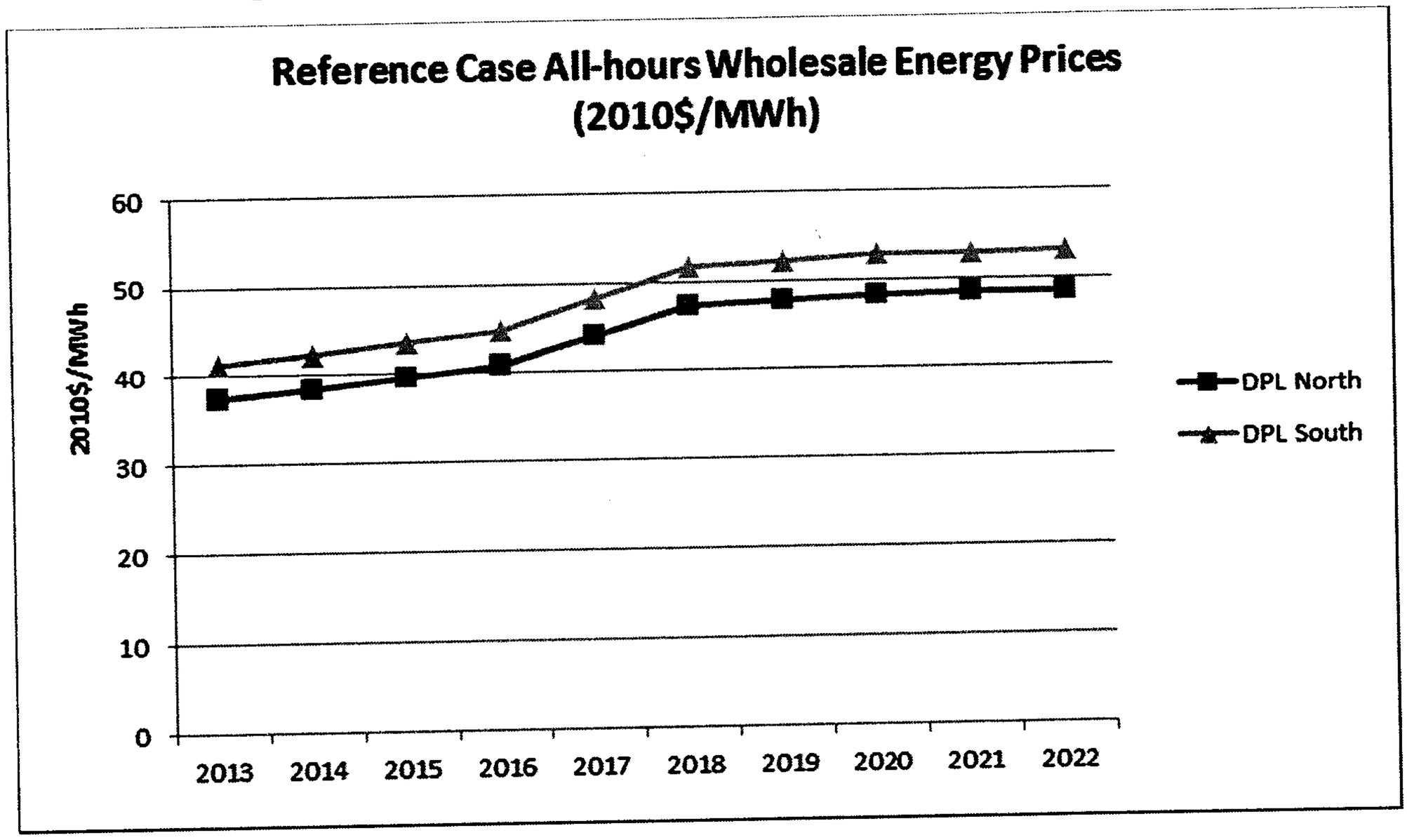
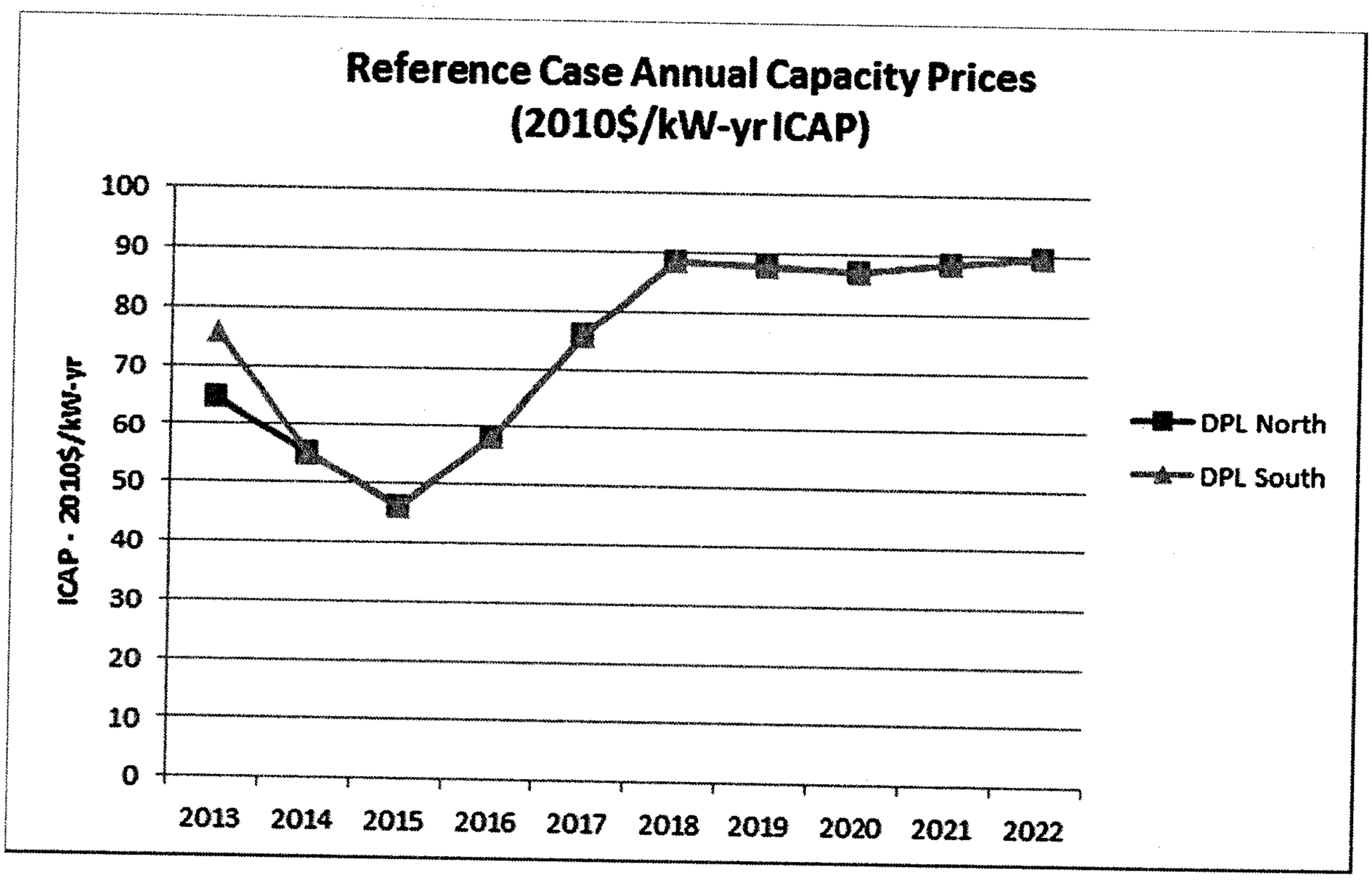


Exhibit 5.5: Capacity Price (ICAP-2010$/kW-yr)



SENSITIVITY CASE

The Reference Case assumes that EPA's Cross State Air Pollution Rule (CSAPR) would be in effect beginning January 1, 2013, when the modeling efforts began for the Reference Case in July. On August 21, 2012, the U.S. Court of Appeals for the DC Circuit vacated CSAPR, temporarily reinstating the Clean Air Interstate Rule (CAIR). In order to study the impact of the recent vacatur of CSAPR, ICF has designed a sensitivity case removing CSAPR from the model.

In the Sensitivity Case it is assumed that CAIR continues as currently designed followed by more stringent SO_2 and NO_x requirements starting in 2018.

Exhibit 5.6 presents a comparison of the expected capacity while Exhibit 5.7 presents the associated generation by resource type for the Sensitivity Case.

Exhibit 5.6: Expected Total Capacity (MW) by Type – PJM Wide

Capacity Types	2013	2014	2016	2018	2020	2022
Coal	66,627	65,186	64,136	63,736	63,736	63,736
Combined cycle	25,359	25,924	29,525	31,355	35,241	38,383
Oil/Gas other	8,139	7,036	6,528	6,528	6,528	5,710
Hydro	7,433	7,433	7,468	7,468	7,468	7,468
Nuclear	33,707	33,707	33,707	33,707	33,057	33,057
Turbine	31,033	31,012	30,160	31,992	32,729	36,959
Renewable	9,941	10,835	12,083	12,919	13,711	14,275
Wind	6,482	6,901	6,915	6,915	6,915	7,377
Solar PV	1,528	1,991	3,065	3,883	4,633	4,735
Landfill	671	671	831	849	891	891
Biomass	644	644	644	644	644	644
Other	598	598	598	598	598	598
Fuel Cell	18	30	30	30	30	30
Total	**182,239**	**181,133**	**183,607**	**187,705**	**192,470**	**199,588**

Exhibit 5.7: Expected Generation (GWh) by Type – PJM Wide

Capacity Types	2013	2014	2016	2018	2020	2022
Coal	414,484	407,087	410,812	421,652	428,312	432,254
Combined cycle	125,461	135,004	149,815	156,879	183,554	202,894
Oil/Gas other	153	375	156	156	154	154
Hydro	16,405	16,566	16,969	16,969	16,969	16,969
Nuclear	261,532	261,623	259,433	257,730	255,884	254,542
Turbine	5,437	7,013	6,547	7,518	7,966	8,128
Renewable	31,128	34,770	37,603	38,870	40,181	41,640
Wind	15,947	17,494	17,533	17,533	17,533	18,846
Solar PV	1,970	2,573	4,073	5,154	6,121	6,267
Landfill	4,747	4747	6013	6161	6505	6505
Biomass	3652	4984	5004	5042	5042	5042
Other	4,730	4,730	4,730	4,730	4,730	4,730
Fuel Cell	82	242	250	250	250	250
Total	**854,600**	**862,438**	**881,335**	**899,774**	**933,020**	**956,581**

Overall, the impact on coal generation and capacity on a PJM-wide basis is minor. In 2013, the projections indicate a very small increase in coal generation. Although the CSAPR would have potentially had stronger near-term prices, the impact on generation is somewhat mitigated by 1) the expectation of continued relatively low gas prices (i.e. strong gas on coal competition); 2) relatively low expected demand growth; and 3) the significance of the MATs ruling on the operation of continued faciltities leading into the 2015/2016 period.

Exhibit 5.8 presents the emissions by type in the Sensitivity Case.

Exhibit 5.8: Emissions by Type (Mtons) – PJM Wide

Emissions by Type	2013	2022
CO_2 (Mtons)	472,042	521,560
NO_x (Mtons)	331	269
SO_2 (Mtons)	1,272	586

Consistent with the differences in the capacity and generation outlook, there is little change anticipated due to the vacature of CSAPR under this sensitivity. However, it is anticipated that the installation or operation of control equipment in the very near term may differ. For example, facilities may operate their SCRs at lower levels of not operate seasonally at all if under caps. In the very near-term, this has some impact on NO_x and SO_2 emissions from the facilities within PJM, however, there is negligible difference in the long-term.

Exhibit 5.9 presents the all-hours energy prices and Exhibit 5.10 presents annual capacity prices for DPL North and DPL South zones, respectively. The market prices reflect very little difference between the CSAPR and CAIR sensitivities.

Exhibit 5.9: All-hours Wholesale Energy Price (2010$/MWh)

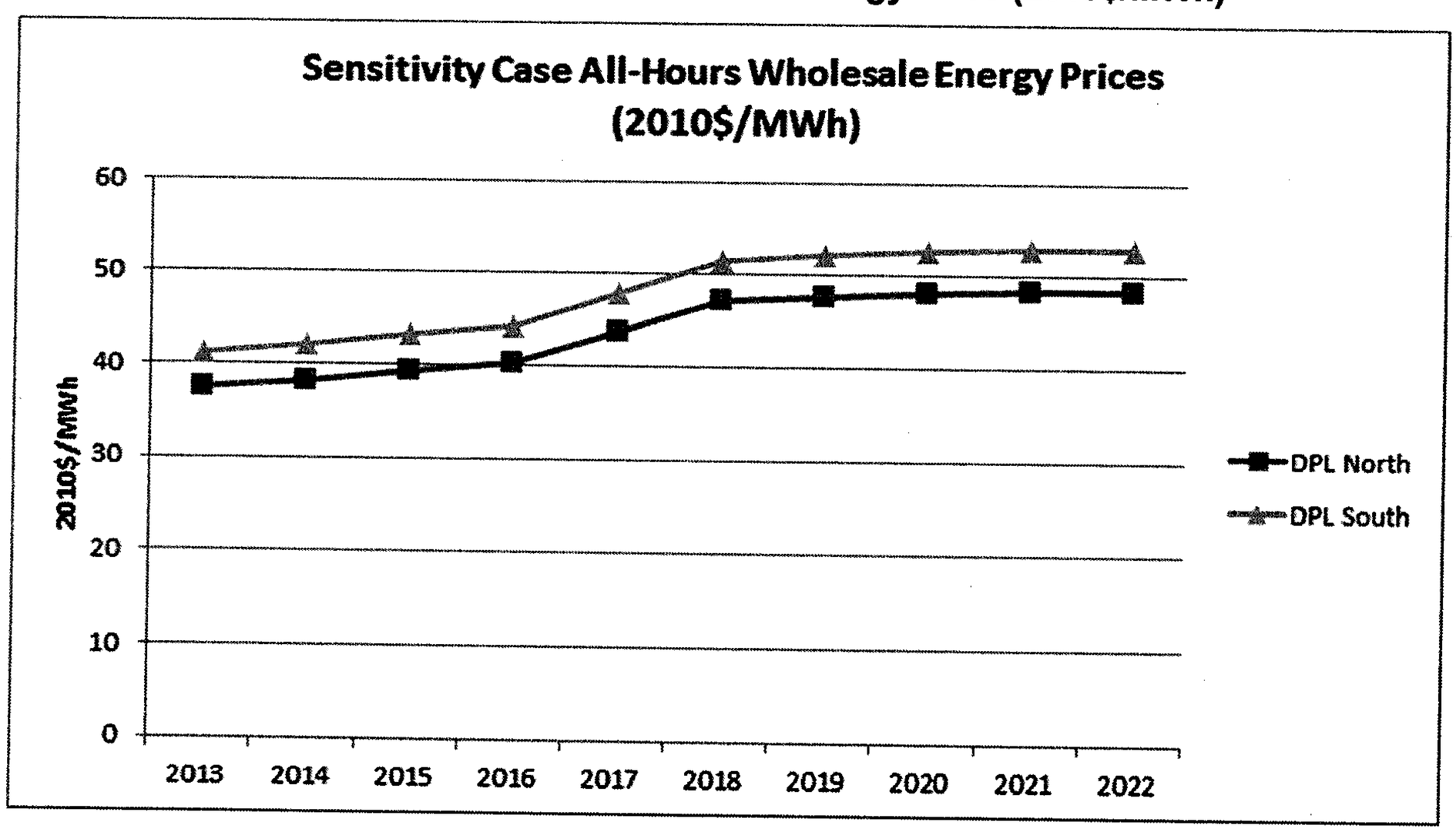
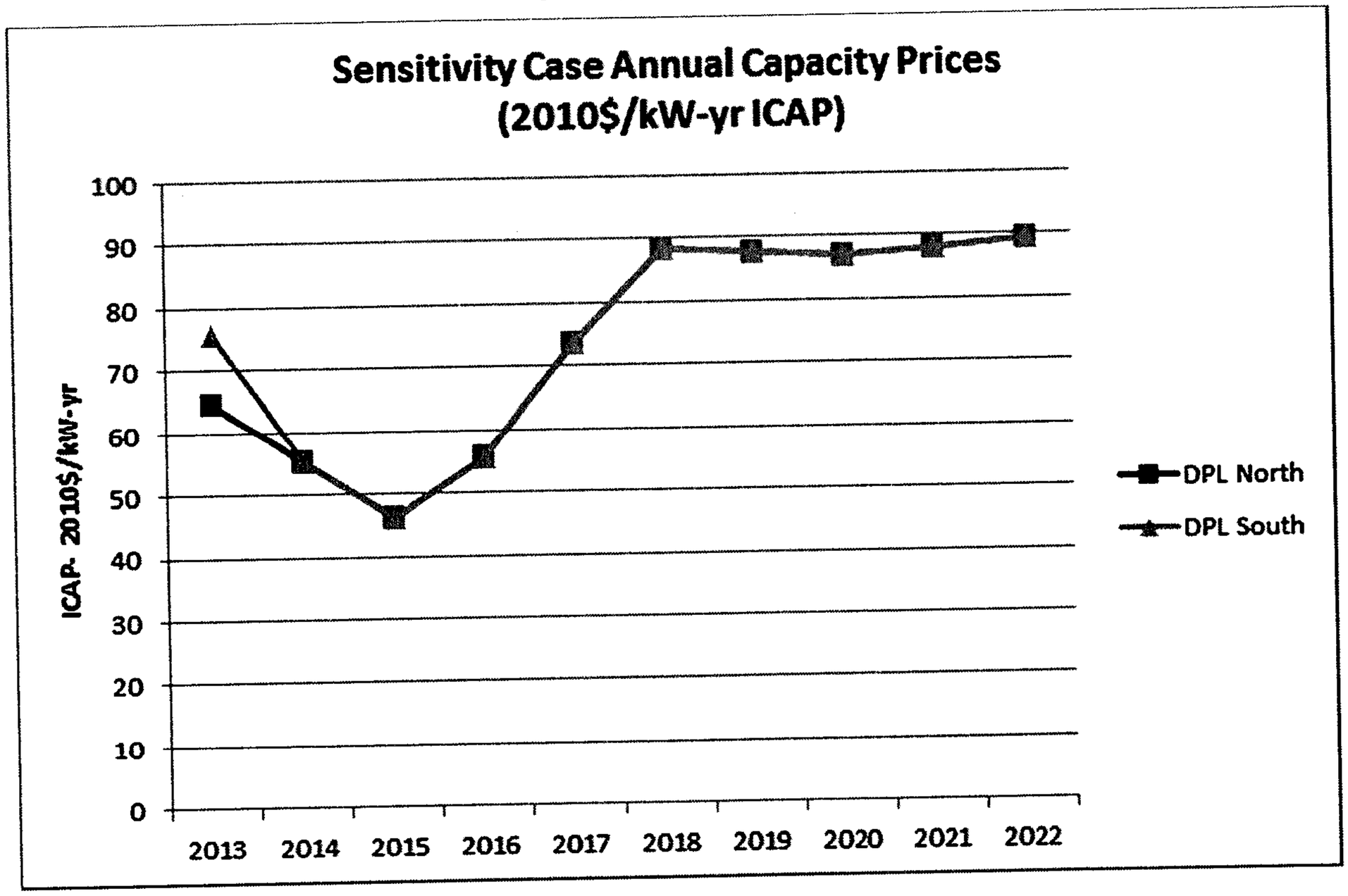


Exhibit 5.10: Capacity Price (ICAP-2010$/kW-yr)



APPENDIX 6

DELMARVA POWER AND LIGHT COMPANY

BEFORE THE DELAWARE PUBLIC SERVICE COMMISSION

CONCERNING PORTFOLIO PERFORMANCE

FOR INTEGRATED RESOURCE PLANNING

INTRODUCTION AND SCOPE OF ANALYSIS

Delmarva Power & Light (Delmarva) is providing its 2012 Integrated Resource Plan (IRP) that describes its current view of the likely costs and risk characteristics of future power supplies needed for its Standard Offer Service (SOS) to its Residential and Small Commercial and Industrial (RSCI) customers and its Large Commercial (LC) customers. The reference supply portfolios for these customers are comprised of a blend of existing and projected future Full Requirements Service Agreements (FSA) contracts obtained through a series of semi-annual Requests for Proposals (RFPs). The FSAs provide a bundled set of fixed-price, competitive market products to meet the full energy supply needs of our SOS customers -- with the exception of the requirements of the State's Renewable Portfolio Standards (RPS). Beginning June 2011, none of the existing or future FSAs will provide the renewable energy necessary to meet this obligation, so those needs will be satisfied by Renewable Energy Credits (RECS) held by Delmarva. The renewable portfolio is bundled with the FSAs to provide for the electrical needs of Delmarva's SOS customers.

The information in this report is provided to assist the Commission in evaluating the expected performance of the Resource Portfolio over the planning period (planning years 2013 through 2023). The Portfolio Model used to simulate risk and uncertainty surrounding future FSA procurements serves to demonstrate prevailing and forecasted market characteristics, and the cost uncertainty associated with SOS supply.

The Reference Case (RC) consists of the existing and new FSA contracts, plus the projected costs of RPS compliance. The FSAs are modeled as 3-year rolling contracts for RSCI customers and 1-year rolling contracts for LC customers, both of which are procured semi-annually in two tranches, in November and in February. Figure 1 below provides a summary for FSA contract portfolio turnover.

Figure 1—Layering of Procurements for SOS Customer Classes

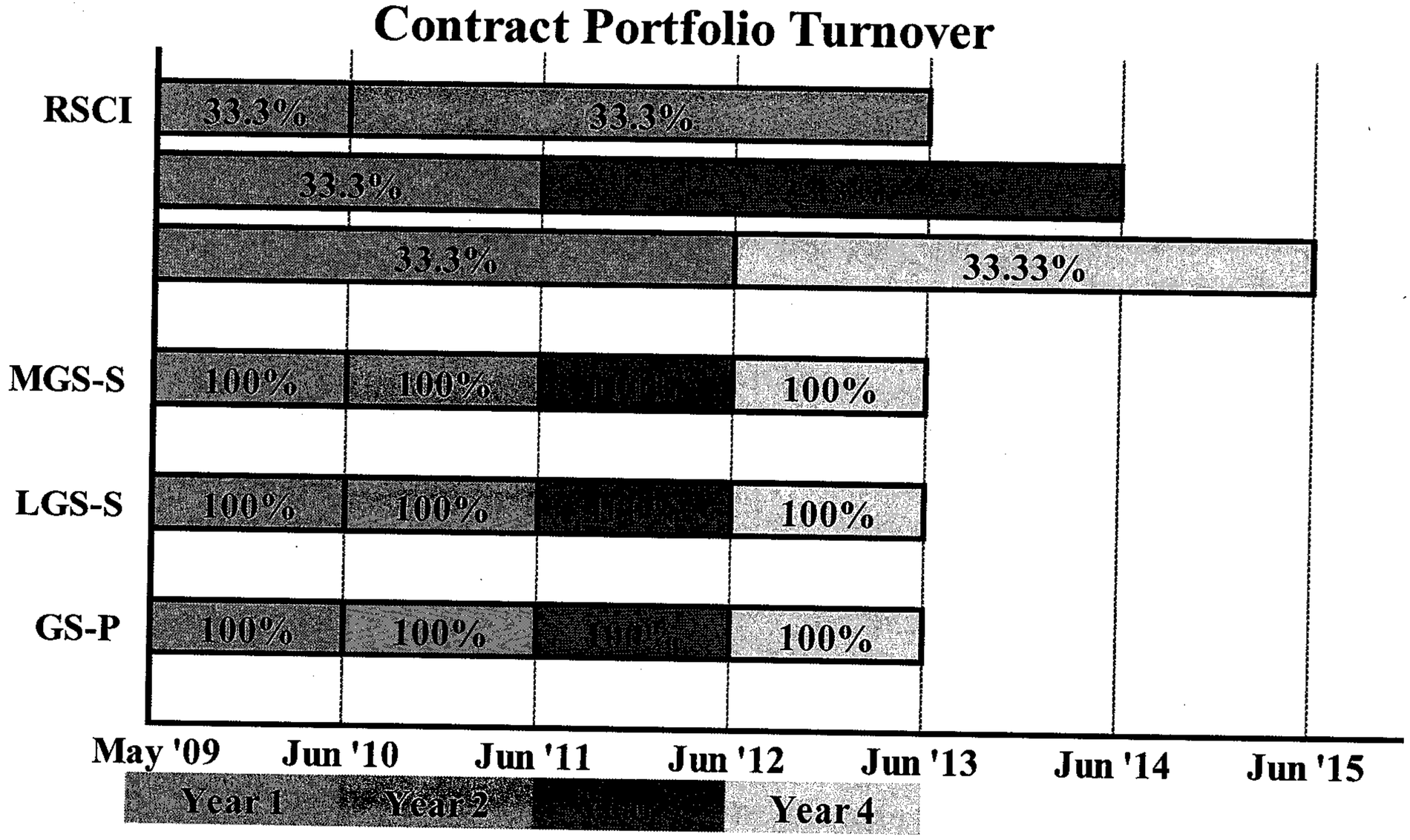


Figure 2 provides the blended cost of existing FSA contracts and the percentage of SOS customer requirements already covered for the planning years 2012, 2013 and 2014 by virtue of past RFPs. These costs are included in calculating the expected FSA supply costs and the projection of customer rates provided in IRP Appendix 9.

Figure 2: Blended Existing FSA Costs (Nominal $)

	RSCI Customer			LC Customers		
Planning Year	Blended Cost $/MWH		% of Requirements	Blended Cost $/MWH		% of Requirements
	Summer	Winter		Summer	Winter	
2012	89.10	84.70	100.00%	n/a	n/a	100.00%
2013	86.78	82.85	66.67%	-	-	-
2014	85.34	81.61	33.33%	-	-	-

For the 2013 planning year, 1/3 of RSCI SOS load and the entire LC load will not be covered by existing FSA contracts. Delmarva will continue to satisfy the remaining requirements with annual RFPs for procurement in two installments (one in November and one in February) for 3-year contracts, each for a portion of its expected RSCI SOS load. It will concurrently solicit 1-year contracts for a portion of expected LC load in each procurement installment. In this analysis, future FSA procurements are simulated as though 1/3 of total RSCI customer needs are procured every year on a 3-year rolling basis and total LC needs are procured annually on a 1-year rolling basis. The analysis performed herein reflects the cost and risk implications of these future competitive procurements.

This 2012 IRP assessment also presents impacts on SOS customers of an additional supply mix scenario which could add new, physical generation resources to the Resource Portfolio (RP). Specifically, we consider the impact of 300 MW from a gas-fired combined cycle (CC) facility, assumed to come online in 2017 and having cost and performance characteristics based on PJM's recent Net CONE study.

Separately, we assess the likely costs per MWh of off-shore wind resources assumed to come online in 2017, with cost and performance characteristics similar to what is expected for Massachusetts' Cape Wind Project, as well as the likely net unit costs utility-owned solar PV resources, also assumed to come online in 2017 in Delaware. The uncertain energy performance

(or value) of these resources is not simulated in our Monte Carlo portfolio model. Instead, their net costs are compared to expected market prices. As will be shown later, these renewable resources appear to be so costly that even unlikely high capacity and energy revenues cannot make them valuable to the portfolio.

This report does not assess the attractiveness of a gas CC on a present value, full-life basis. Rather, it looks at the CC's impact on the range of likely average annual FSA portfolio costs per nominal MWh for select years over the IRP planning horizon: 2013, 2015, 2017, 2019, and 2022. Moreover , a new CC would not have energy output that is closely related to the shape of the RSCI or LC customer loads. This is because the gas generation would be dispatched in the wholesale PJM wholesale market, only if/when it is economic to do so. Accordingly, it is evaluated as being added financially to the portfolio, rather than displacing other purchases in it or serving SOS loads directly. This method more accurately reflects what is being done with the physical scheduling and accounting of existing wind resources.

The analysis contained herein is based on market conditions that prevailed in the beginning of August, 2012. At that time, Delmarva and its advisors (ICF International and *The Brattle Group*) obtained or developed comprehensive market and forecast information for the planning period 2013-2022. The primary purpose of this report is to compare the relative attractiveness of different scenarios over that horizon, not to make a precise forecast of what expected future prices will actually be. The biggest single risk factor affecting the likely future cost of power or the attractiveness of new resources is the price of natural gas, which is often on the margin (price setting) in PJM. Accordingly, the supply scenarios are re-evaluated under discrete assumptions of significantly higher or lower natural gas prices and corresponding changes in PJM electricity prices.

The evaluation conducted herein uses the portfolio simulation approach similar to that described in previous Delmarva IRP submittals, including Delmarva's 2010 Revised Update to the 2008 IRP, and the 2008 IRP filing itself. The risk simulation approach was first deployed by Delmarva's Power Procurement Group in that 2008 IRP, in conjunction with the same economic advisors (ICF and Brattle). For this filing, ICF developed the long term fundamental market

outlook, while *The Brattle Group* applied market risk parameters to the ICF projections to obtain FSA costs per MWh and their associated uncertainty.

This report summarizes the key results, then briefly describes the risk simulation model and interprets the results. This report presents detailed tabular and graphical results for SOS customers segmented by RSCI and LC customer groups. Results presented in this report are in nominal dollars and are for the most part presented for RSCI customer supply. All of the major risk considerations, and comparisons of market prices to the costs of alternative physical supply resources, can be visualized using just the RSCI results. An average annual 2.5% inflation rate has been assumed, based on prevailing macroeconomic forecasts summarized in the latest Blue Chip Economic Indicators.[1] In addition, a set of results for RSCI and Large Commercial customers in nominal dollars and real 2012 dollars is provided in Attachment A and B, respectively.

KEY FINDINGS

Figure 3 presents the expected and likely ranges of costs per MWh from FSAs in the Reference Case ("RC") portfolio for 2013, 2015, 2017, 2019 and 2022. The table presents the expected cost per MWh of the RC portfolio in each of these years, along with the range of annual average costs foreseen for the 10th and 90th percentiles of simulated possible outcomes. Those ranges are the result of Monte Carlo simulations of 1,000 electric energy (but not capacity) price scenarios per year, in which the possible outcomes are drawn from distributions that describe forward financial market expectations and volatility as of August 1, 2012, centered on ICF's long term projections. Panel A of the Figure shows the RSCI portfolio results, with and without a gas CC added in year 2017 and beyond. Off–shore wind and solar resources are not added to these results, because their costs (discussed later) are far higher than market or CC costs. The LC costs, again with and without a CC from 2017, are shown after the RSCI results in Panel B.

[1] Blue Chip Economic Indicators, pp.14-15, March, 2012.

Figure 3: Reference Case FSA Supply Cost Projections

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Panel A: RSCI Customers

RSCI Customers Planning Year 2013

	Total Expected Electricity Volume (MWh)	Total Average Costs ($/MWh)	High Average Costs 90.0% ($/MWh)	Low Average Costs 10.0% ($/MWh)	Average Costs Above 90% ($/MWh)
Reference Case Total	2,544,877				

RSCI Customers Planning Year 2015

	Total Expected Electricity Volume (MWh)	Total Average Costs ($/MWh)	High Average Costs 90.0% ($/MWh)	Low Average Costs 10.0% ($/MWh)	Average Costs Above 90% ($/MWh)
Reference Case Total	2,378,072				

RSCI Customers Planning Year 2017

	Total Expected Electricity Volume (MWh)	Total Average Costs ($/MWh)	High Average Costs 90.0% ($/MWh)	Low Average Costs 10.0% ($/MWh)	Average Costs Above 90% ($/MWh)
Reference Case Total	2,324,185	$122.06	$147.68	$100.82	$162.62
Reference Case and CC	2,324,185	$111.16	$130.98	$93.57	$141.79

RSCI Customers Planning Year 2019

	Total Expected Electricity Volume (MWh)	Total Average Costs ($/MWh)	High Average Costs 90.0% ($/MWh)	Low Average Costs 10.0% ($/MWh)	Average Costs Above 90% ($/MWh)
Reference Case Total	2,248,287	$141.22	$177.03	$110.84	$203.43
Reference Case and CC	2,248,287	$124.35	$150.02	$102.10	$166.52

RSCI Customers Planning Year 2022

	Total Expected Electricity Volume (MWh)	Total Average Costs ($/MWh)	High Average Costs 90.0% ($/MWh)	Low Average Costs 10.0% ($/MWh)	Average Costs Above 90% ($/MWh)
Reference Case Total	2,190,268	$161.96	$210.26	$122.12	$250.02
Reference Case and CC	2,190,268	$140.94	$171.29	$115.18	$190.63

Panel B: LC Customers

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RSCI Customers Planning Year 2013

	Total Expected Electricity Volume (MWh)	Total Average Costs ($/MWh)	High Average Costs 90.0% ($/MWh)	Low Average Costs 10.0% ($/MWh)	Average Costs Above 90% ($/MWh)
Reference Case Total	2,544,877				

RSCI Customers Planning Year 2015

	Total Expected Electricity Volume (MWh)	Total Average Costs ($/MWh)	High Average Costs 90.0% ($/MWh)	Low Average Costs 10.0% ($/MWh)	Average Costs Above 90% ($/MWh)
Reference Case Total	2,378,072				

RSCI Customers Planning Year 2017

	Total Expected Electricity Volume (MWh)	Total Average Costs ($/MWh)	High Average Costs 90.0% ($/MWh)	Low Average Costs 10.0% ($/MWh)	Average Costs Above 90% ($/MWh)
Reference Case Total	2,324,185	$122.06	$147.68	$100.82	$162.62
Reference Case and CC	2,324,185	$111.16	$130.98	$93.57	$141.79

RSCI Customers Planning Year 2019

	Total Expected Electricity Volume (MWh)	Total Average Costs ($/MWh)	High Average Costs 90.0% ($/MWh)	Low Average Costs 10.0% ($/MWh)	Average Costs Above 90% ($/MWh)
Reference Case Total	2,248,287	$141.22	$177.03	$110.84	$203.43
Reference Case and CC	2,248,287	$124.35	$150.02	$102.10	$166.52

RSCI Customers Planning Year 2022

	Total Expected Electricity Volume (MWh)	Total Average Costs ($/MWh)	High Average Costs 90.0% ($/MWh)	Low Average Costs 10.0% ($/MWh)	Average Costs Above 90% ($/MWh)
Reference Case Total	2,190,268	$161.96	$210.26	$122.12	$250.02
Reference Case and CC	2,190,268	$140.94	$171.29	$115.18	$190.63

These tables show that the expected price levels of the RC portfolio change somewhat over time. Energy prices grow fairly gradually while other costs drop in 2015 followed by fairly rapid increases. This causes a small dip in 2015 projected FSA costs, followed by a steady increase to 2022 (for RSCI customers). Figure 4 is a graph of this pattern, along with the components causing the change.

Figure 4: RSCI FSA Costs Over Time, With Energy And Other Cost Components
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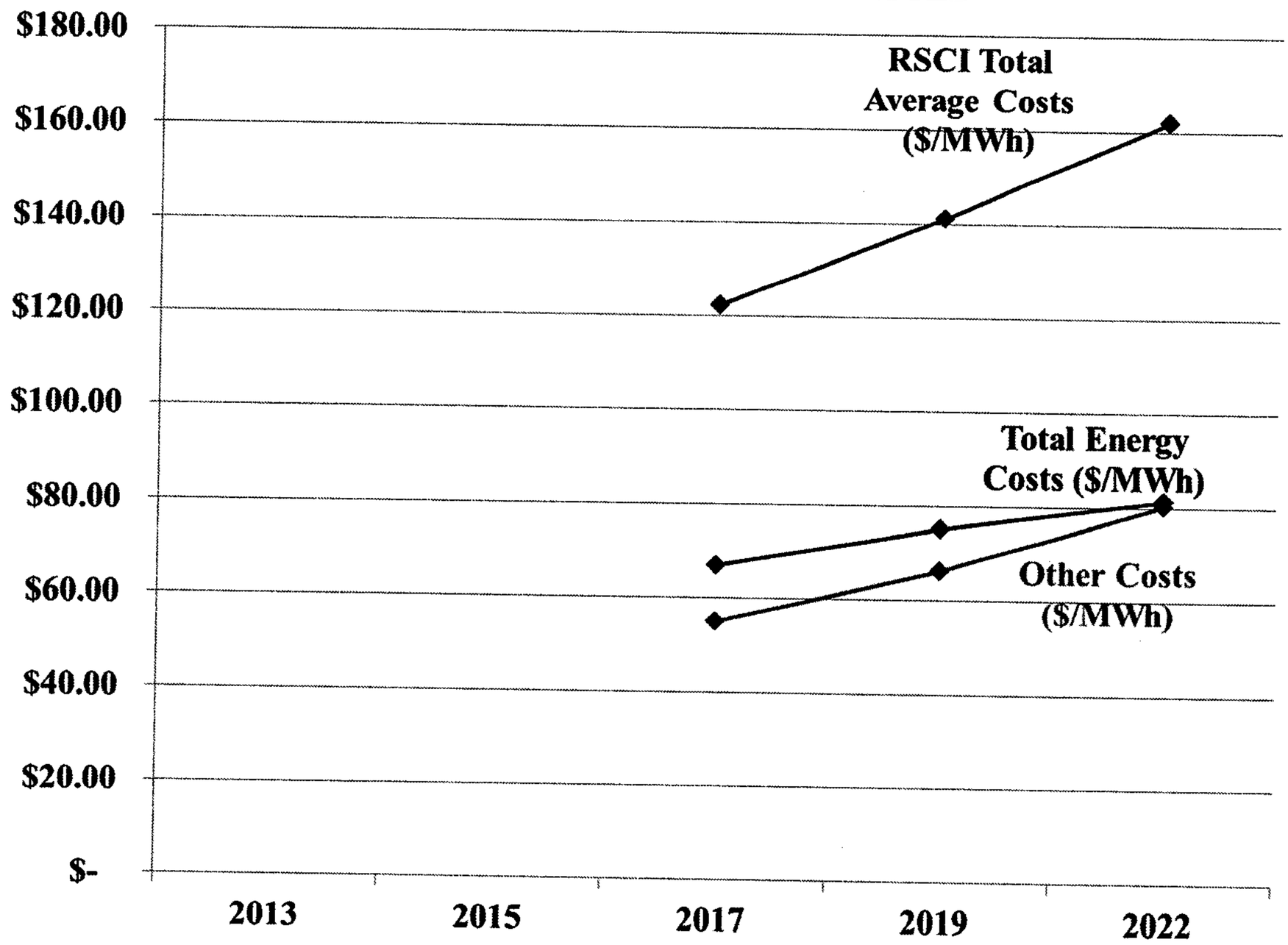

This figure shows that RSCI FSA costs are likely to rise considerably through 2022, largely due to rising fixed costs of PJM products and services other than energy being added to the relatively flat energy component of FSA costs.[2] These other non-energy costs include capacity payments, ancillary services, and RECs.[3]

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[2] The energy component of the FSA price is largely determined by forward energy prices trading in wholesale markets in PJM, but it also includes adders for congestion to DPL from market trading hubs like PJM-West, load shaping premiums, line losses, and a premium for various kinds of risks and other costs

Figure 5 shows how the price risk for FSA RSCI service increases over time, again in the reference case centered on current market forwards for gas and electricity and ICF's long run projections. The length of the vertical bars indicates the range of uncertainty surrounding future prices. For the Reference Case bars (blue, left-most in each time frame), the bottom of the bar is at the 10th percentile of likely costs, while the top is at the average of the unit costs for the top decile (90th to 100%-ile) of simulated FSA prices. These blue bars shift up and become longer (riskier) by 2022.

In 2013, the bar is short, with relatively little risk, because costs and risks are significantly constrained by the fixed price of the existing FSA contracts. Thereafter, those contracts will be replaced, but at prices that are uncertain today (hence risky). The farther in the future such procurements will occur, the riskier they become from today's vantage point – simply because there is more time for conditions to change, hence more forecasting error. That is, these risk ranges are shown from the perspective of likely prices today for those future years. The increasing lengths do not mean that 2022, for instance, will be any riskier in 2021 than 2013 is today. It just means it is more remote in time from 2012. These ranges also do not reflect the possibility of large, sustained discrete changes in natural gas costs. Those possibilities are evaluated separately later in this report.

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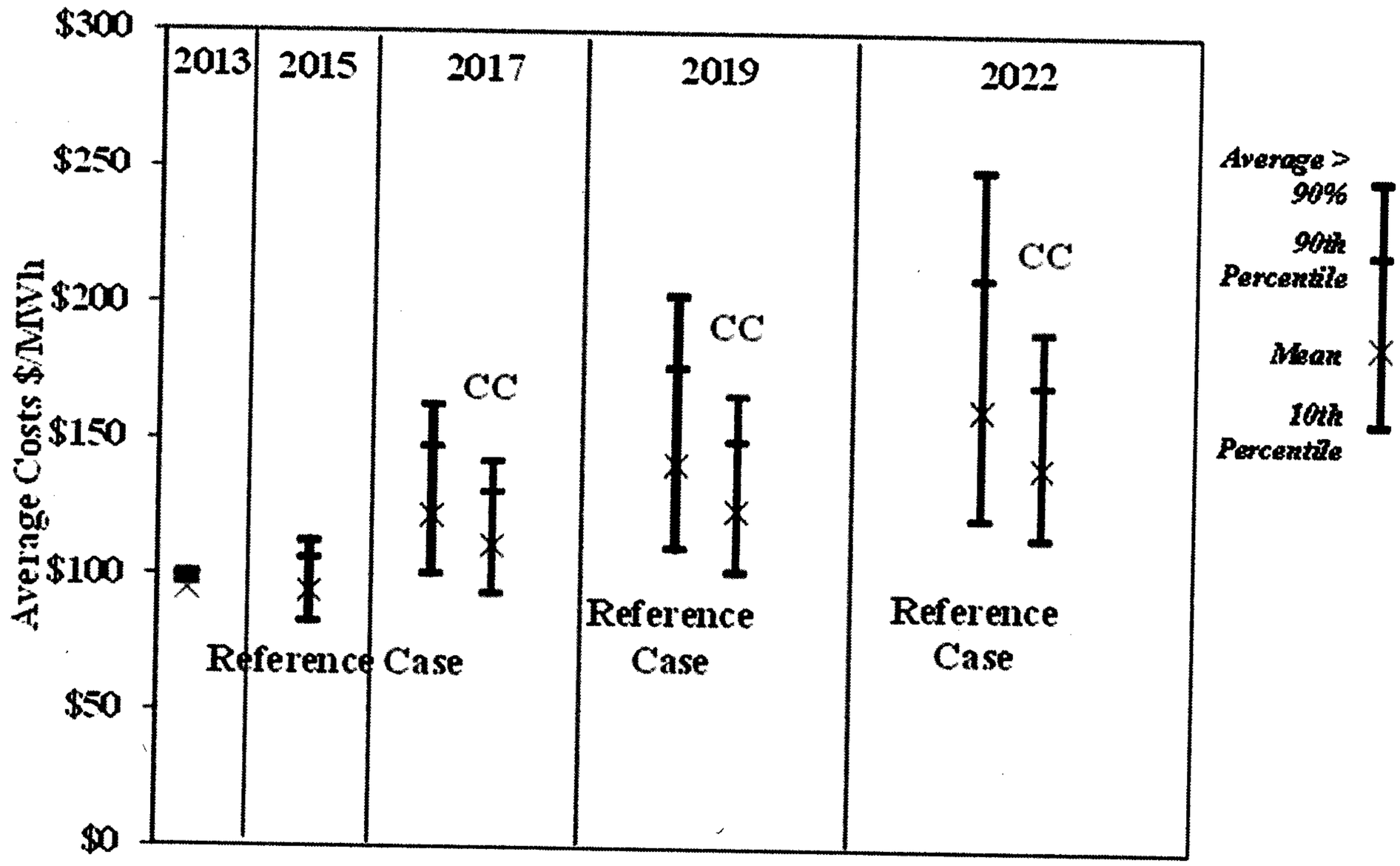
arising from having to offer a fixed price in FSA RFPs for a service that has inherently uncertain supply costs and requirements.

3 In Figure 4, the non-energy costs in 2013 are approximate. As shown, they are the incremental costs per MWh for these services in 2013. The actual cost of these components in the 2013 FSA is unobservable because the FSA RFPs obtain a single price for the entire 3-year service. However, the total FSA price in this figure ($[redacted] per MWh) is not approximate, because it is based on blending the existing FSA contracts with the 1/3 share of the 2013 incremental cost.

Figure 5: Risk Ranges for RSCI FSA, With and Without CCs



The above figure includes bars in red for the net costs of the FSA portfolio if a gas CC were added to the supply portfolio, beginning in 2017. This is assumed to be a 300 MW CC with cost and performance characteristics equal to those used for a new CC in the recent PJM Net CONE study. Specifically, the unit is assumed to have the following parameters:

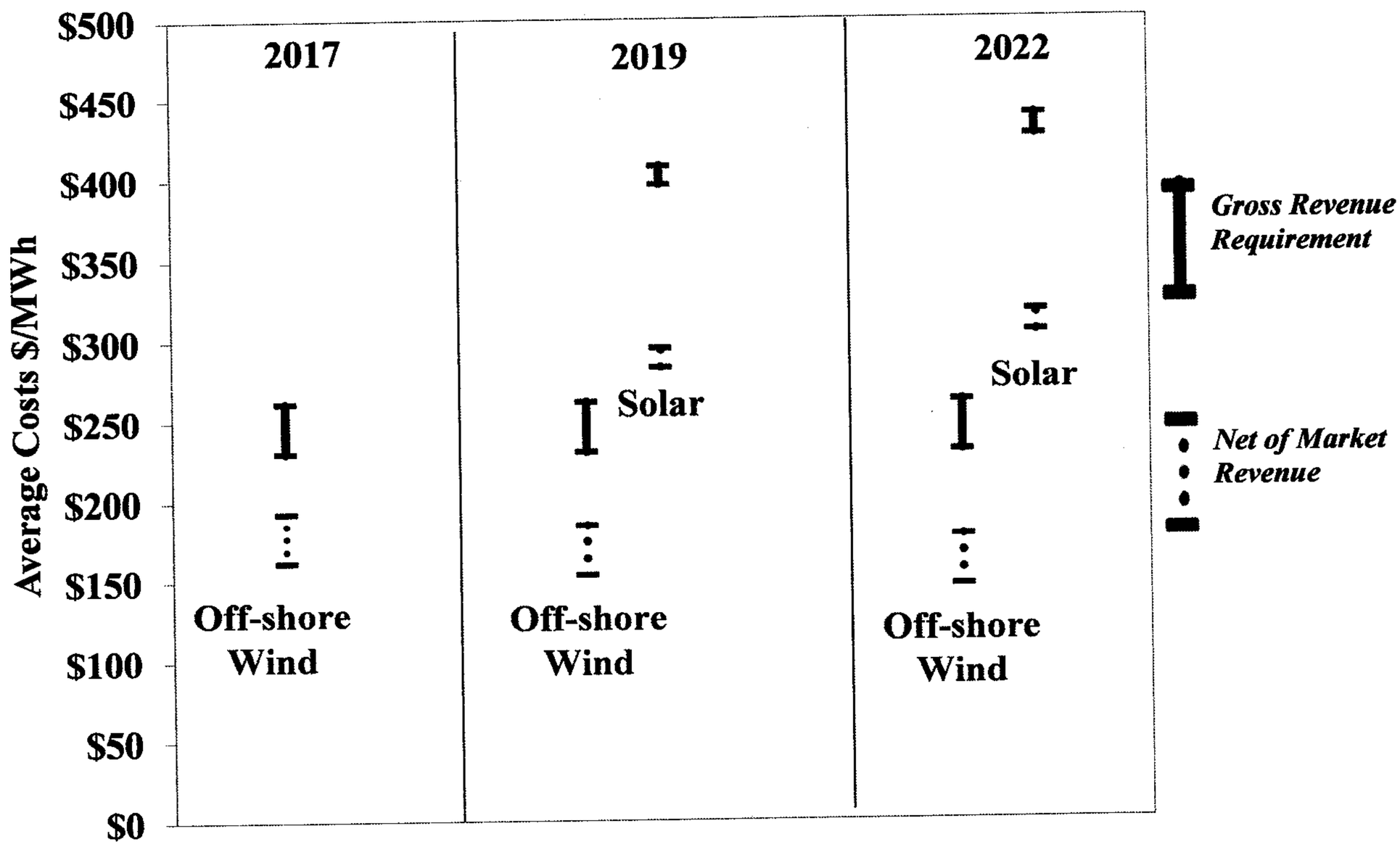
Overnight construction cost per kW (2017$):	$1,135
Full load average heat rate (Btu/kWh):	7,000
Fixed O&M (2017$/kW-year):	$18.89
Useful life (basis for capital recovery):	20 years
After tax weighted average cost of capital:	8.1%

The lower positions and shorter lengths of the red bars (FSA with a CC) in Figure 5 above indicate that the inclusion of a new CC with the FSA portfolio under the assumed terms drives

down both the average cost and the risk range in each future year. This finding is consistent with the recent expansion of CC market development in Delaware and elsewhere in PJM.

We also consider the economics of renewable resources as possible supplements to the FSA portfolios. However, it is not necessary to simulate their full market risk characteristics to perceive their economics. **Figure 6** shows the likely costs of new offshore wind or new utility scale PV generation in Delaware.

Figure 6: Gross and Net Costs of Renewables



*The high/low off-shore wind estimates are the Cape Wind estimates, before and after tax credits. The high/low solar costs are with and without normalization of the investment tax credit.

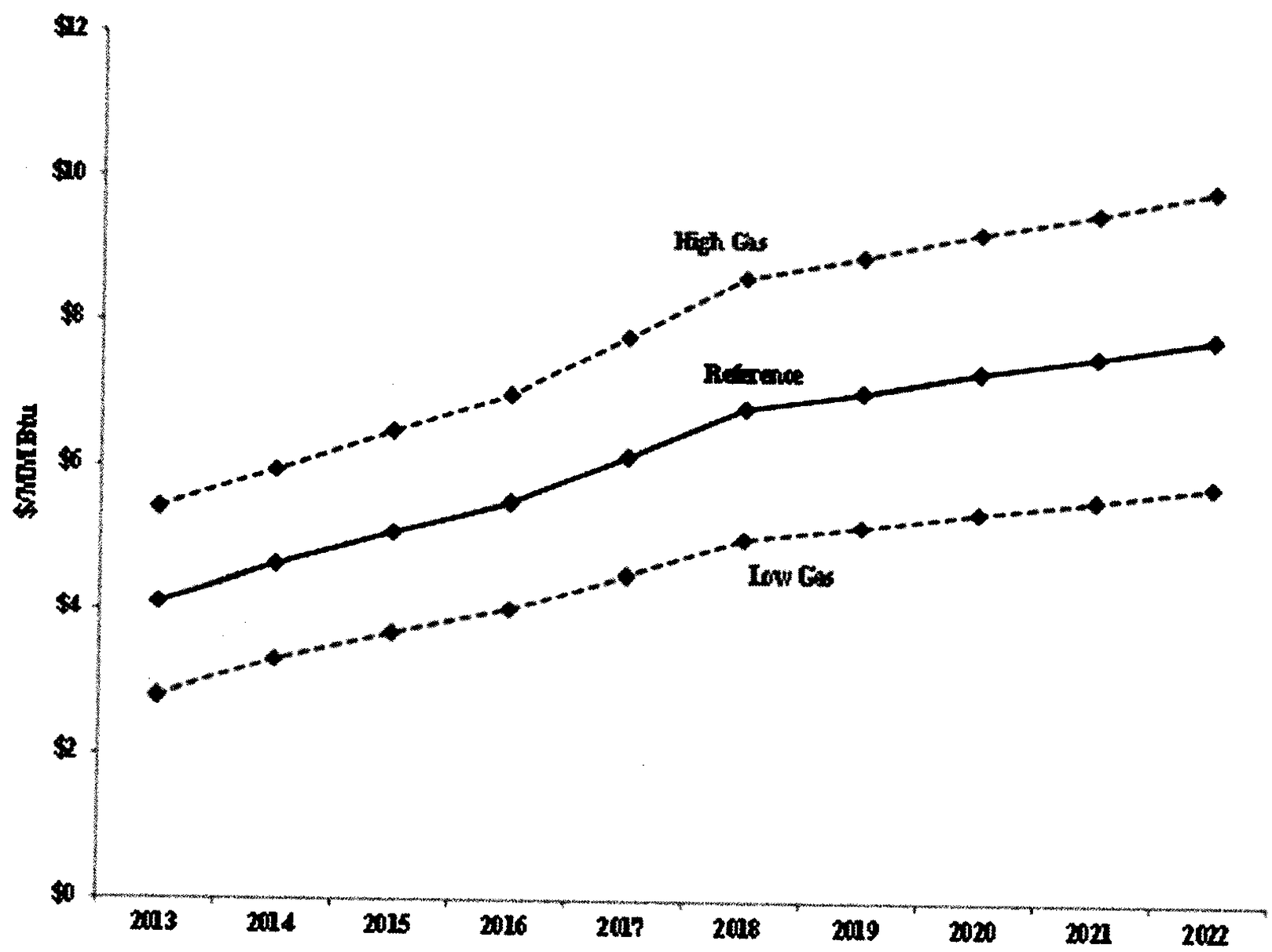
This same figure shows that neither an offshore wind plant nor an additional solar project would be economically useful to FSA costs. The paired bars shown for wind and solar are for the gross and net costs of such resources, not for their costs folded into the FSA portfolios. The top of these bars indicates the costs to simply pay for the ownership and operation of the assets, with and without tax credits. The bottom of these bars indicates their costs after netting out expected capacity and energy revenues, i.e. their implied REC costs needed to break even. For these

assets to cause a net decrease in FSA costs, their net costs would have to be below zero, i.e. their revenues would have to more than cover their costs. Here, the lower end of the net cost range is well above $100/MWh.

These cost estimates are not based on specific offers to Delmarva, nor on specific projects being considered for the Delaware area. Rather, the offshore wind analysis is based on the Cape Wind project. The solar costs are based on a 20MW single-axis PV facility for which the costs were estimated in PHI's IRP Reference Case.

To test the sensitivity of the FSA portfolio to gas prices, with and without a new CC, we analyzed two discrete sensitivities in which the prices of gas are either materially higher or lower than in the Reference Case.

Figure 7: Alternative Average Gas Price Scenarios



In the High (Low) Gas case, it is assumed that average future gas prices will be one standard deviation above (below) the current ICF projections. This causes the high prices to reach $7.80/MMBtu in nominal terms by 2017, about $1.80 per MMBtu above the reference case. In the low price scenario, gas prices are only $4.50/MMBtu in 2017. These alternative gas prices affect power prices in the same direction, since gas has been on the margin about 31% of the time in 2012 (through September)[4]. To make these power price adjustments, the implied heat rates from the reference case for PJM electric prices in the Delmarva zone are held constant for the gas price sensitivities. (This may slightly overstate gas's influence in the high scenario, and understate it in the low case, as some substitution away/ towards gas would occur in those conditions.)

Under these assumptions, a gas CC becomes somewhat more attractive with high gas prices and somewhat less so with low gas, but a CC is still attractive compared to market prices of energy and capacity. Renewable resources (off-shore wind and solar PV), however, remain higher in cost than market-based supply even with high gas prices.

Of course, Delmarva recognizes that access to future off-shore wind and solar resources may occur on considerably different terms than have been available or feasible until now. It is possible that technological improvements and scale effects will drive down construction or O&M costs, and it is also possible that climate policy will become a material factor in resource preferences in the coming years. If so, it will then be appropriate (and timely) to reevaluate how Delmarva can best achieve the state RPS goals. However, for the moment, it is clear that off-shore wind and renewable resources have become relatively more expensive since the prior Delmarva IRP, largely because market prices for conventional power have fallen and increased (cleaner) gas-fired generation is likely.

Figure 8 presents a projection of customer rates for Residential and MGT customers for the period 2013 through 2017. The projections are based on the Reference Case portfolio results presented above. Projections for all customer classes are provided in IRP Appendix 9.

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[4] 2012 Quarterly State of the Market Report for PJM, January through September, p.29.

Figure 8: Tariff Rate Projections (Nominal $)
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Planning Year	Residential Rates (Tariff "R")				MGT-S Rates			
	Demand ($/KW)		Energy(Cents/kWh)		Demand ($/KW)		Energy(Cents/kWh)	
	Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter
2013/14	-	-						
2014/15	-	-						
2015/16	-	-						
2016/17	-	-	11.53	11.47	12.66	7.81	4.31	5.19
2017/18	-	-	12.45	12.34	13.82	8.53	4.68	5.64

BACKGROUND ON PORTFOLIO PROCUREMENT AND RISK MANAGEMENT

The RSCI SOS and LC supply portfolio procurement problem facing Delmarva (or any supplier of full-requirements retail service) is a complex one. There are several kinds of uncertainty that must be anticipated, several ways of achieving price stability, and several kinds of constraints on the possible solutions that must be recognized. Key uncertainties include:

- Future load levels and shapes (which in turn depend on how many customers may switch to or from 3rd party retail suppliers as well as other factors, such as weather),
- Power prices in the wholesale spot and forward markets for energy and capacity,
- Prices of PJM services and obligations, such as ancillary services, congestion, losses and RPM capacity,
- Construction costs, plant performance, and fuel prices, if physical assets are to be part of the portfolio composition.

A first step in portfolio planning is to have market outlooks or forecasts of these factors, as well as measures of their uncertainty, expressed as possible future price ranges along with associated probabilities and the correlations among them.[5] To the extent possible, this information should be taken from the wholesale power and financial markets, rather than from fundamental forecasts, because market prices reflect conditions under which parties will actually trade – and the FSA portfolios will rely on parties utilizing wholesale market transactions. However,

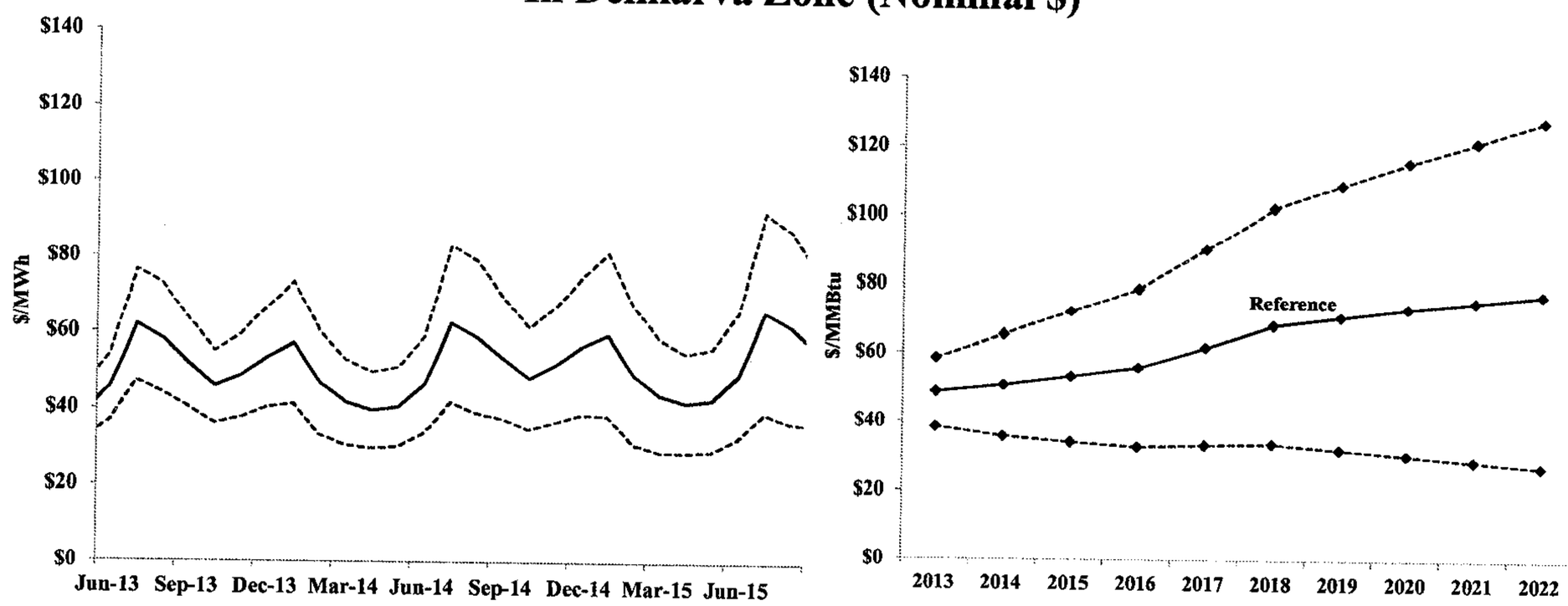
[5] Correlation is a statistical measure of the extent to which uncertain factors tend to change in the same direction.

electricity market price data is only available for a few years forward (gas is available for up to twelve years forward), so long term studies are also required for structural forecasts of future prices based on projected scenarios for market conditions. Long term fundamental evaluations also allow consideration of factors and policies that are possible but not yet formalized or traded. Once these expected wholesale price parameters are quantified, they can be used to project possible future costs of alternative retail supply portfolios across a broad range of market circumstances that could unfold.

The Brattle Group has developed a model to predict the likely ranges of future electricity costs to RSCI SOS and LC customers under different combinations of financial and physical generation resources over time. This evaluation was conducted using an enhanced version of the portfolio simulation model described in previous Delmarva IRP submittals, with the most detailed description in Delmarva's November 3, 2008 Revised Update to its IRP, at pages 18-42. The model applies industry-standard risk-simulation techniques grounded in financial economic theory and market-based data for estimating future costs and risks.

A key input to portfolio planning and risk analysis is the expected prices and uncertainty associated with future power purchases. For this purpose, we have used the ICF monthly forecasts for wholesale electricity (energy and capacity) and natural gas prices in the Delmarva zone, coupled with uncertainty information from broker quotes on options traded against forward on-peak monthly contracts at PJM West. The ICF electricity and gas prices also are based on forward market prices for the first few years of their projections, consistent with the Brattle volatility data. As of August 1, 2012, the estimated on-peak forward curve at the Delmarva zone, according to the ICF forecast, is shown in in Figure 9.

Figure 9: ICF Projected On-Peak All-Hours Monthly Average Spot Electricity Prices In Delmarva Zone (Nominal $)



In this graph, the dark blue line is the ICF forecasted on-peak monthly price of power at the Delmarva zone, estimated as of August 1, 2012. See Section VII and Appendix 5 for a description of ICF's modeling tools and assumptions.

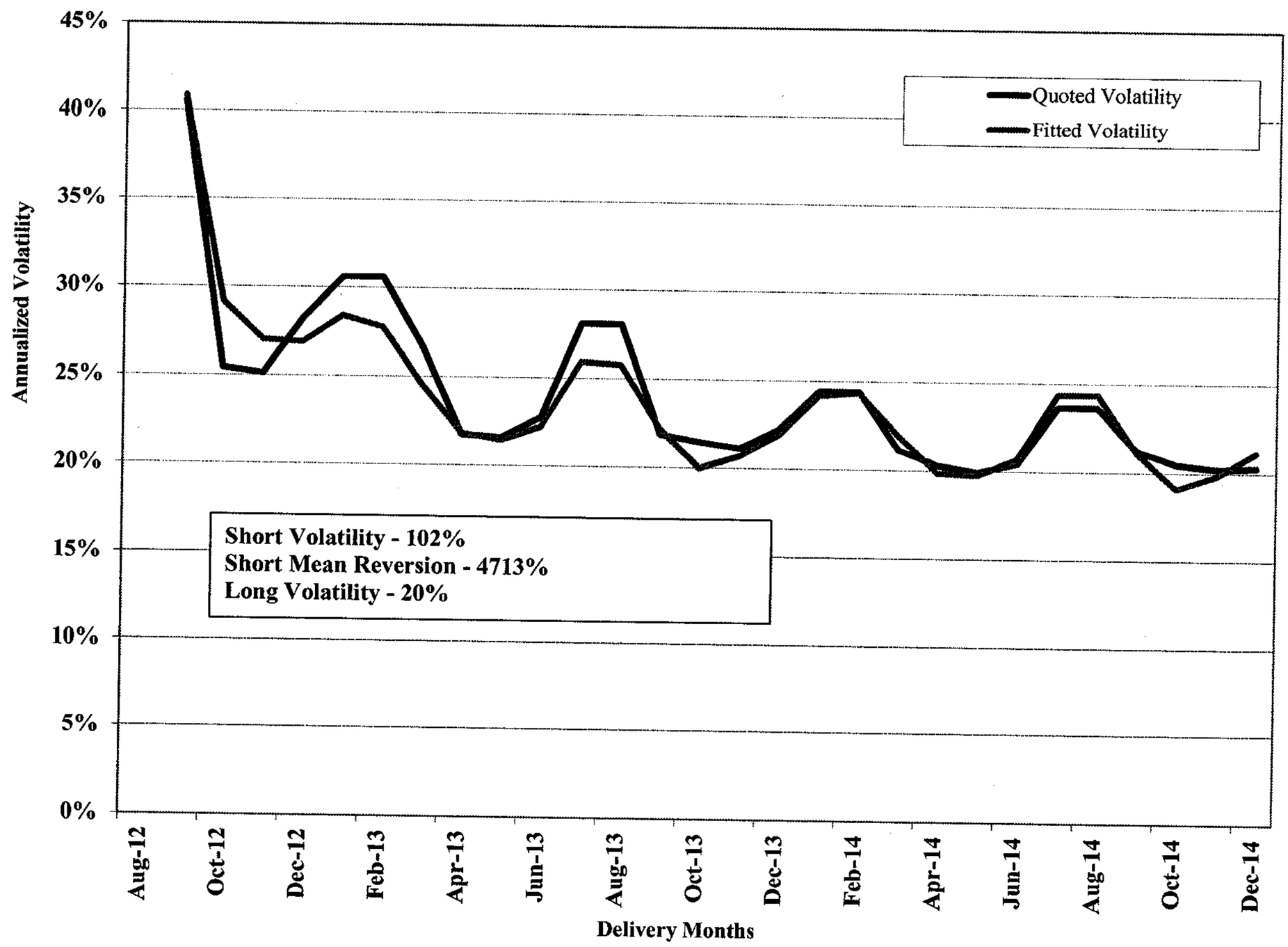
The dashed pink and red lines above and below the solid blue line in Figure 9 depict the ranges around those forward prices that describe the market uncertainty regarding what the actual average monthly spot prices could turn out to be. Like the monthly forward price, the monthly uncertainty has a pattern of seasonality, being greater for certain months, as well as having a tendency to dampen over time. Those probability ranges were obtained from brokers, who infer them from the price of option contracts trading for those future delivery months. The price of an option depends on the volatility of the underlying commodity or security upon which the option is based. That is a key element of the well-known result obtained by Black and Scholes regarding option pricing. Accordingly, the price of traded options can be "reverse engineered" to calculate the "implied" volatility in a future delivery period that is implicit in the corresponding option price.

The expected volatility of energy prices differs depending on what delivery month is being considered, as well as on when it is being considered, *i.e.,* on how far one is looking into the future. This must be taken into account when simulating how the price for FSA purchases in future months may change relative to today's prevailing forward prices. To do this, a two-factor statistical model is fitted to the volatility quotes to obtain a price volatility function that can be

used for any given purchase date and delivery period in the future. The first factor captures the forward curve's sensitivity to new information. It is called a "short factor," meaning it captures the transitory impact of news (like weather uncertainty or unplanned outages) that has mostly a near-term impact on prices in the forward curve. This factor tends to have little influence on distant future expectations, so its influence on expected volatility dissipates over time. This dissipation tendency is captured with a "mean reversion" rate (estimated from the volatility quotes data) that gives the short term factor a declining influence each period into the future. The second factor, called the "long factor," can be thought of as reflecting uncertainty in persistent influences on power prices, such as uncertainty in long-run marginal costs of new generation.

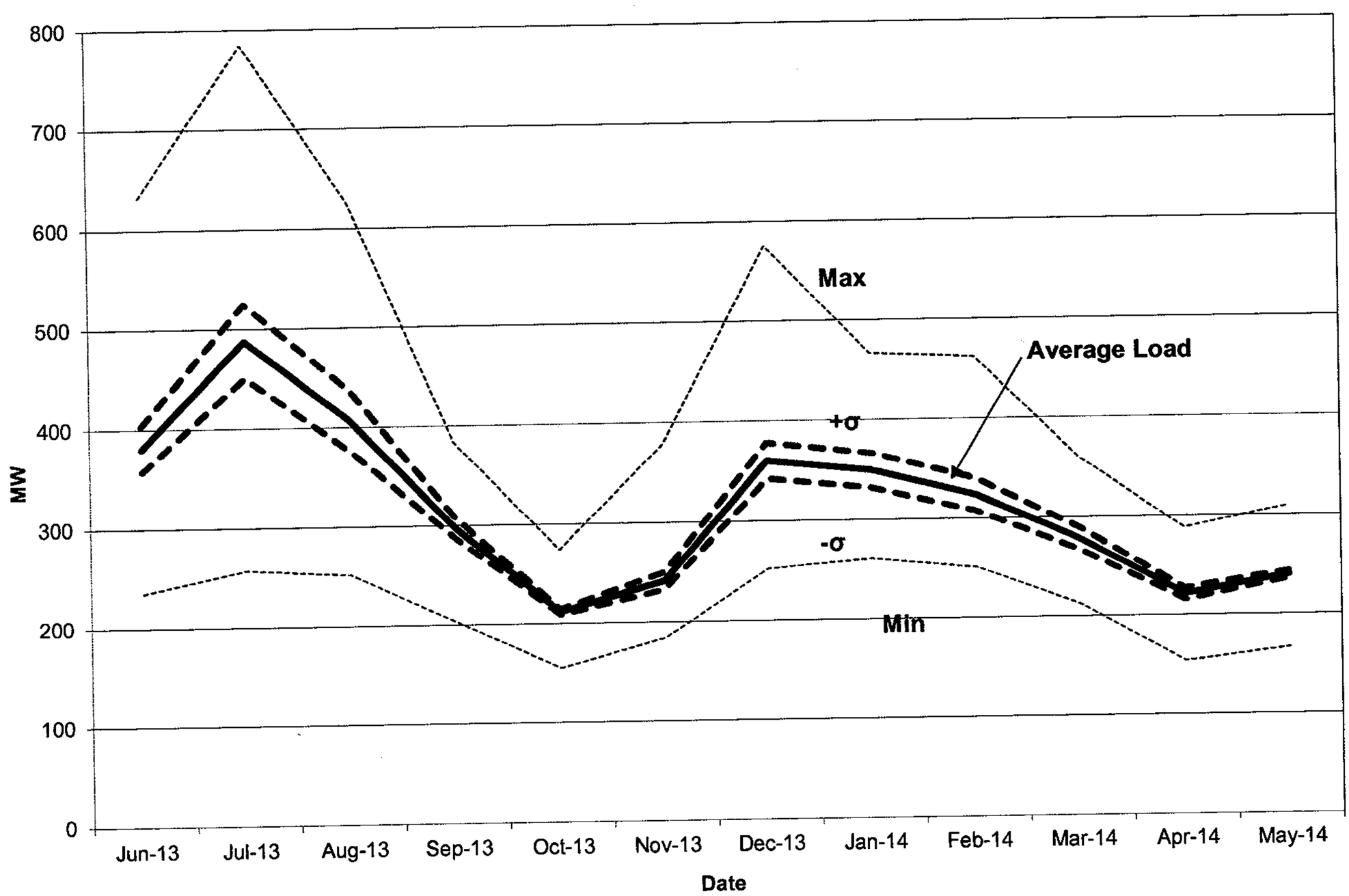
The pink line in **Figure 10** below shows the fitted two-factor model results compared to the quoted volatilities prevailing at the beginning of August 2012 (depicted by the solid blue line). The fit is in very close agreement to the quotes, but it is more useful, as it has restated those volatilities in terms of time to delivery and seasonality factors. This allows it to be used for assessing how forward prices for power could change between now and future procurements, and what degree of uncertainty to expect in average monthly spot prices for power in the delivery month (for any portion of load covered by spot, such as balancing quantities).

Figure 10: PJM West Peak Volatility Term Structure Fit
As Of August 1, 2012



The other key input to portfolio planning and risk analysis is future load. The average projected hourly load levels (by month, in MWs) for Delmarva's RSCI customers for the twelve months beginning June 2013, along with the associated typical weather uncertainty considered, are shown in **Figure 11** below.

Figure 11: Delmarva RSCI SOS Monthly Average Peak Period Load Shape



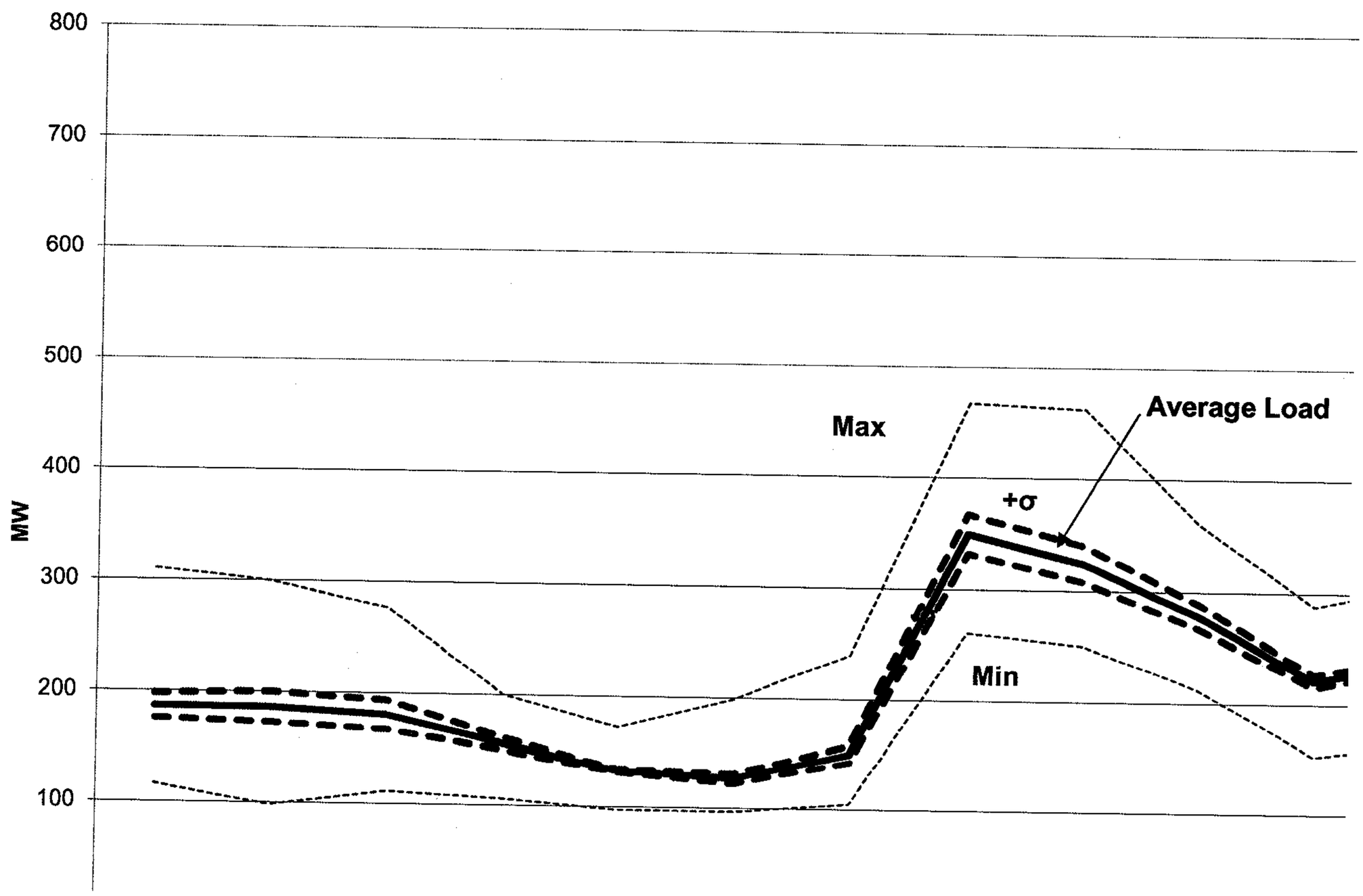
This figure reflects only the load during on-peak hours for RSCI customers projected from historical load experienced over January 2009 through December 2011, as adjusted for potential conservation impacts based on Delmarva's cost/benefit analyses of conservation and demand management activities similar to what the Sustainable Energy Utility (SEU) would conclude and pursue. These load levels determine how much energy an FSA supplier can expect to have to provide during on-peak hours in a typical year (and assuming no change in customer migration to third-party suppliers).

Note that the average load is around 317 MW, while the minimum hourly load is around 154 MW (again, for peak hours). The minimum hourly load for off-peak hours is about 155 MW.

The weather uncertainty surrounding average monthly loads is not very large, a few percent.[6] Maximum hourly loads can be almost 1.7 times the average for any given month, with an annual peak of almost 785 MW. However, high load levels occur in relatively few of the hours in a month. It will not generally be possible to cover the exact expected demand with standard forward contracts for power, so FSA bidders must expect to incur some risks from transactions in the spot market at uncertain prices and volumes.

The average projected hourly load levels (by month, in MWs) for Delmarva's LC customers for the twelve months beginning June 2013 along with the associated typical weather uncertainty considered, are shown in **Figure 12** below.

Figure 12: Delmarva LC SOS Average On-Peak Monthly Loads



6 The weather uncertainty simulated here is not specific to PHI, but is realistic for utilities in PJM. Daily and hourly weather uncertainty, not reflected in this analysis, would be much larger.

Again, this figure reflects only the load during on-peak hours for LC customers projected from historical load experienced over January 2009 through December 2011, and adjusted for potential conservation impacts. The average load for LC customers varies much less over the seasons than the average load for RCSI customers. The level of it is about a third less than the average load for RCSI customers, around 211 MW, while the minimum hourly load is around 97 MW (again, for peak hours). The minimum hourly load for off-peak periods is about 72 MW. Maximum hourly loads can be 1.7 times the average for any given month, with an annual peak of over 465 MW. However, high load levels occur in relatively few of the hours in a month. In percentage terms, or per MW, the monthly load uncertainty for LC customers is comparable to the RSCI customers.

With the above expected prices and loads and their corresponding uncertainty, plus a simple analysis of how spot electric prices and short term (hourly) load uncertainty have been correlated in the past, the analytic components necessary to simulate various portfolios are available. Using these prices and the associated price-volatility function, the simulation model randomly "draws" a set of future forward and spot prices that could arise for purchase dates in the future. Based on weather-related load uncertainty, the loads for each month are also "drawn" by the simulation model.

Future FSA price ranges are simulated based on their exposure to market factors, like monthly forward price and load uncertainty and intraday price and load shapes. That is, the model simulates where the 1-year (for LC) and 3-year (for RSCI) strips of on- and off-peak forward prices could be positioned at the time of future RFPs, based on current forwards and statistical sampling around the fitted volatilities. These forward prices are purchased in the model in the proportions needed to cover the on- and off- peak monthly loads, over the time frames appropriate to the type of FSA customer, then scaled up for load shaping and losses.

Only the level of average monthly load is uncertain in the Brattle model even though there is additional uncertainty at a finer time scale. To capture the latter, monthly average price levels are converted to hourly shapes using historical Delmarva LMP price patterns for a typical week in each month. Intraday price patterns are recognized deterministically, with hourly price and

load shapes specific to each month; hourly uncertainty in these two factors is not modeled. However, scaling factors are applied to reflect the historical positive correlations between intraday spot prices and load requirements. Other uncertainties, like customer switching and credit risks, are captured by a risk premium of 8% added to the FSA price. The 8% value applied here is an average of apparent bid premiums over direct wholesale costs and retail surcharges in SOS procurements that occurred throughout the last 5-10 years in eastern states with retail choice.

For each load draw and calculated FSA price, a calculation is made of the resulting portfolio costs. The simulation model repeats the draws over and over (1,000 times in this case) to obtain a set of projected outcomes that span the likely range of possible costs in each future delivery period. The average of all the draws is the current forward price of power adjusted for the risk premium. The riskiness of the alternative portfolios can then be visualized and compared using graphs that depict the range of potential delivered costs along with their associated probabilities.

The simulation model calculates the risks surrounding only the energy costs of an FSA portfolio. The non-energy costs for capacity, ancillary services, and RECs are added to the ranges of observed energy prices to get a total FSA price. The forecasts for those factors come from ICF, and are based on both the current PJM prices (where available, such as the RPM prices for capacity through 2015) and fundamental analysis of future needs and costs. Uncertainty in these factors is not modeled – which may cause these results to slightly overstate future FSA risks, since capacity prices tend to move opposite to energy prices. (PJM's Net CONE that positions the VRR demand curve is obtained by subtracting likely energy revenues from the fixed and financial costs of a new CT or CC.)

The size of Delmarva's SOS supply obligations is based on load and DSM forecast. The tables in Attachment C of this document show how Delmarva's projection of obligations relating to RSCI and LC customer supply were derived from the forecasted loads and DSM impacts.

The status of Delmarva's current renewable portfolio relative to its projected obligations under Delaware's Renewable Portfolio Standards is presented in Attachment D of this document. The

projected average cost of complying with Delaware's RPS is calculated in Attachment D and were included in the portfolio supply costs projections included in this study.

RESULTS – INITIAL PERIOD, 2013, 2015 AND 2017

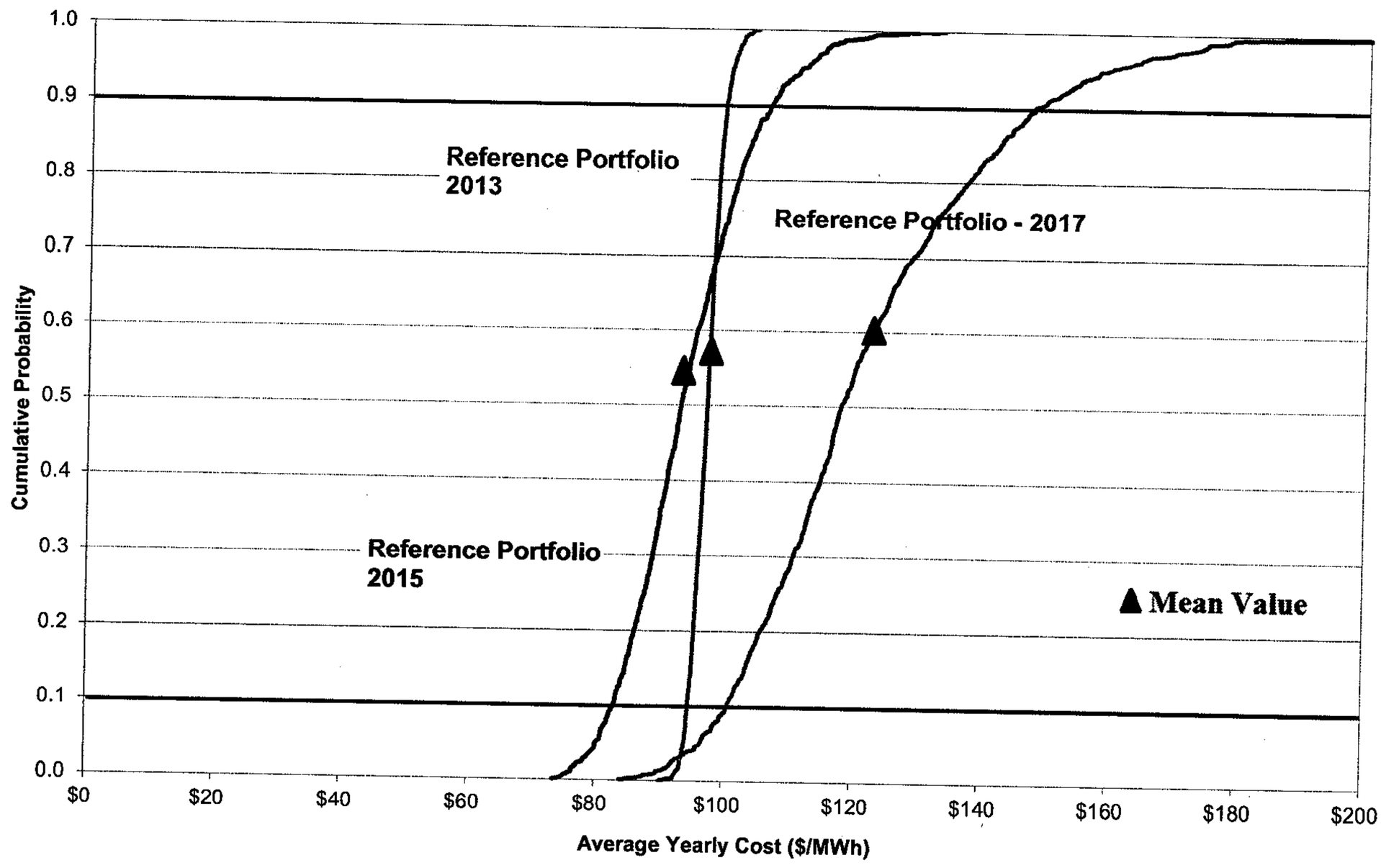
In 2013, the FSA cost for RSCI customers already includes 2/3 of the costs of past RFPs. That is, as of August 2012, only 1/3 of its energy requirements had not been placed under contract. For the remaining third to be procured in November 2012 and February 2013 (for deliveries in PJM's 2013 delivery year in June 2013, the capacity, ancillary services and REC costs will add about $[redacted]/MWh[7] to the 3 year forward retail energy cost of about $[redacted]/MWh. However, this will be averaged in with prior FSA costs for a total of about $[redacted]/MWh for RSCI customers and about $[redacted]/MWh for LC customers. The LC customers enjoy a lower cost partly because of their flatter loads and partly because they are served with one-year contracts, allowing the energy component of their FSA portfolio to reflect current low market prices.

The risk ranges associated with these FSA portfolios can be visualized by S-shaped curves showing the probability (on the y-axis) of prices exceeding the levels shown on the x-axis. A steeper curve is less risky while a flatter curve is more risky. Figure **13** below shows the range of RSCI FSA prices for 2013, 15, and 17 as projected with respect to August 2012. The 2013 curve is quite steep, due to the fact that most of it is already purchased or involves fixed costs, and there is not much time until it will be fully covered. The 2015 curve is centered at a lower price but is somewhat riskier (flatter) while the 2017 curve is flatter still and moves outwards to the right (more expensive on average) because by then, both capacity and energy prices have risen considerably. This was seen previously in

Figure 4.

[7] The capacity cost and ancillary services components will be scaled down by 1/3 before being rolled into the 2013 FSA RSCI price.

Figure 13: RSCI FSA Price Distributions For 2013-2017 Under Reference Case Conditions (Nominal $)



Gas-fired Generation Asset

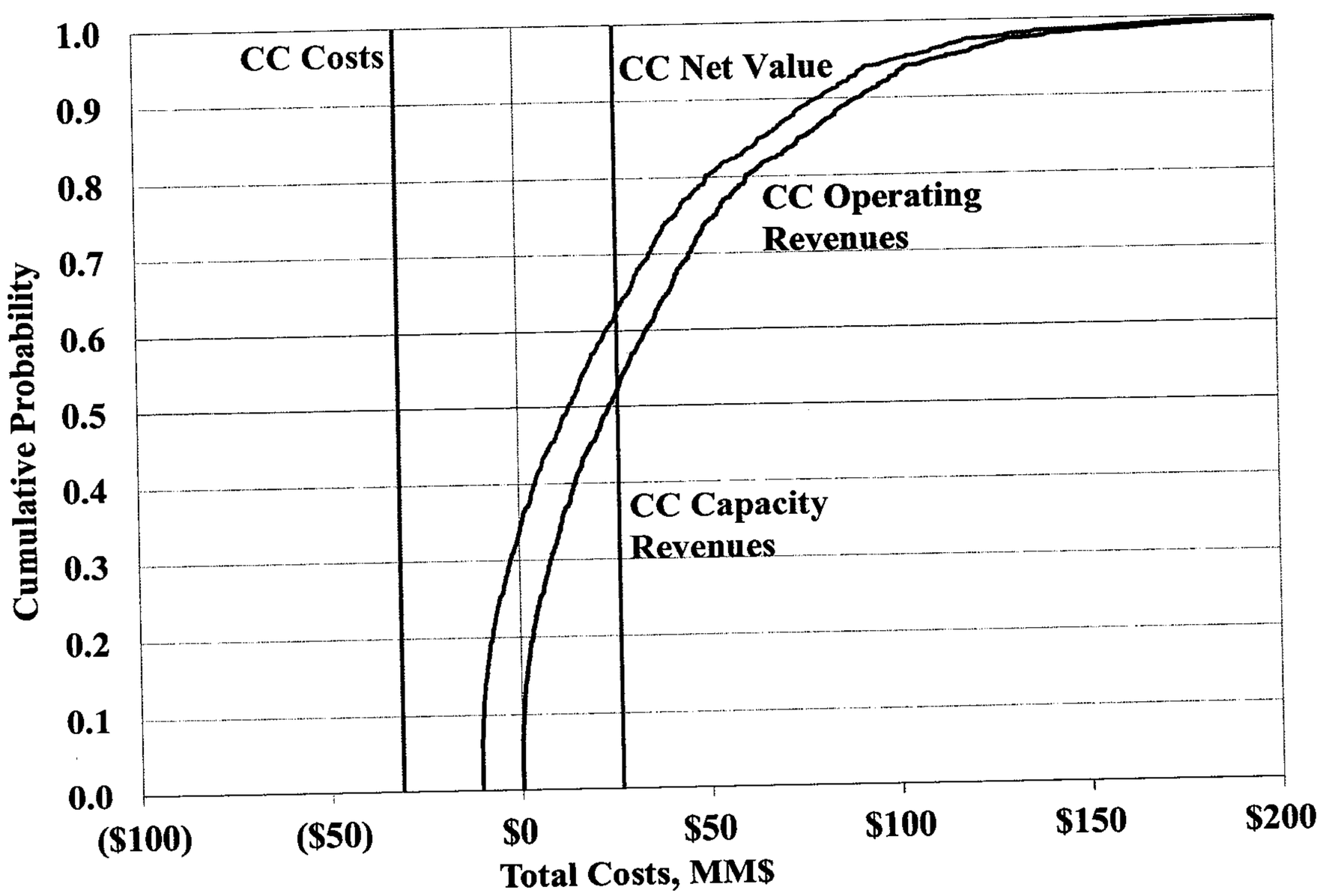
Based upon stakeholder input received during the IRP Working Group process, Delmarva agreed to evaluate whether a gas-fired generation plant could reduce the costs or risks of RSCI and LC service. This prospect has been evaluated by considering the addition of a 300 MW Combined Cycle (CC) facility in Delmarva in 2017. The cost associated with this CC facility are simulated as the levelized nominal carrying charges for a merchant owner of a new CC plus fuel costs incurred at the monthly spot prices of natural gas delivered to the eastern part of PJM near Delmarva's service territory.

As noted in the introductory summary of results, a new CC by 2017 appears to be economical relative to the August 2012 market outlook, assuming that such a unit could be built in Delmarva's territory for unit costs equivalent to the PJM Net CONE cost assessments. (These

may be too favorable to the simulated unit, because the PJM CONE study is based on a larger, 600MW unit. However, unless the penalty for a smaller unit is quite large, these results should still be reasonable for a 300MW unit.)

The initial year (2017) stand-alone economics of the CC facility are shown in **Figure 14,** which compares the annual fixed costs of the CC (shown in the vertical green line on the left side of the graph) to the uncertain market revenues foreseeable in the Delmarva zone from its spot energy sales and capacity (under the same simulated market conditions in the RC) – shown as the curving dark blue line on the right. The net revenue curve, obtained by subtracting the fixed costs from the uncertain revenues is the red curve in the middle, and it is positive about two thirds of the time. The curve has the potential to be significantly positive, while its potential losses are moderate in comparison.

Figure 14: 2017 Gas CC Costs and Revenues Under Reference Conditions (Nominal $)



Simulating its production in the Monte Carlo model, with randomized gas and spot power prices based on gas forward curves and volatilities, the CC achieves about a 65% capacity factor in 2017.

On average, this CC in the Delmarva zone would more than recover its expected annual costs in 2017. Its expected net revenue in excess of breakeven costs and profits in this year is $34.1 million. If this profit were credited to Delmarva's SOS customers, it would reduce the expected FSA price that year by $10.90/MWh for RSCI customers, and $7.84/MWh for LC customers (assuming its net benefit is split 67/33 between the two groups, based on load shares). A CC would also reduce the risk ranges for RSCI and LC customers' future FSA, bringing the RSCI 90-10 range down from $46.86/MWh to $37.41/MWh. This risk reduction occurs largely because the gas unit would be dispatched only when it would reduce electric prices, thereby clipping off those market extremes for customers.

As will be seen below, a CC becomes more attractive in subsequent years, due to rising energy and capacity prices in PJM which help to offset the carrying costs on the CC.

Off-Shore-Based Wind Generation Assets

The off-shore wind estimates in **Figure 5** were derived from estimates of the terms of the Cape Wind project in Massachusetts.[8] This is an approximately 468 MW facility located in Nantucket Sound 4-11 miles off Cape Cod, intended to come online in 2016. It will include about 130 3.5 MW turbines, expected to cost around $5,600/kW and projected to operate at around a 37% capacity factor, with $30-$50/MWh for O&M expenses. A portion of its output is under a 15-year contract to National Grid for its Massachusetts customers, which begins at around $187/MWh in 2013 $, then grows annually at 3.5%. We have shown its levelized nominal price over the period 2013-2027; this is equal to $230.40/MWh with tax credits and $261.60/MWh without[9]. The net costs are determined by starting with these gross cost and performance

[8] Response to the Petition of Massachusetts Electric Company and Nantucket Electric Company d/b/a National Grid for approval by the Department of Public Utilities of amended power purchase agreements between National Grid and Cape Wind Associates, LLC., DPU 10-54, p. 11, 13.

[9] Idem, p. 10, 13.

parameters from Massachusetts, then taking out the average energy prices and capacity value that such a plant would earn in Delaware under the projected PJM environment in the Reference Case. These net costs are $161 to $192 per MWh of expected output. Since these are well above zero, including any amount of such power in the FSA portfolio would raise its average price. For instance, if 150MW of such output was added to the FSA RSCI portfolio, these net costs of $161/MWh would add $78.6 million of annual costs, for a net increase of $33.80/MWh to the RSCI customers' average price.

RESULTS – 2019 - 2022

In the balance of the ten-year IRP assessment period through 2022, we extrapolate the market conditions and also evaluate whether a solar resource added in 2019 might be attractive due to its on-peak energy production. **Figure 15** shows the Reference Case FSA curves for RSCI customers in all simulated years, and **Figure 16** shows the same for the LC customers (on the same scale for ease of comparison).

Figure 15: RSCI FSA Costs in 2013 - 2022

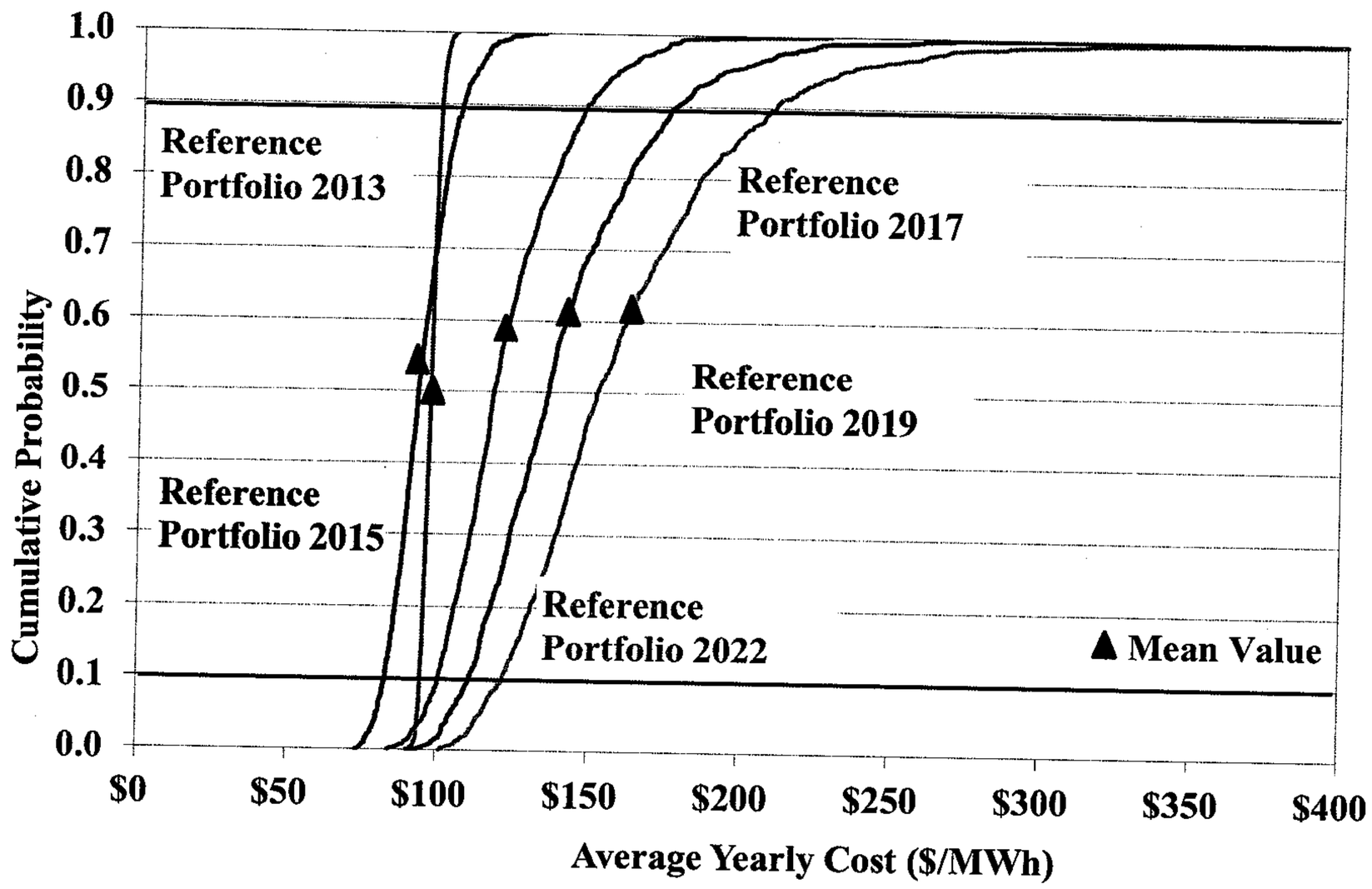
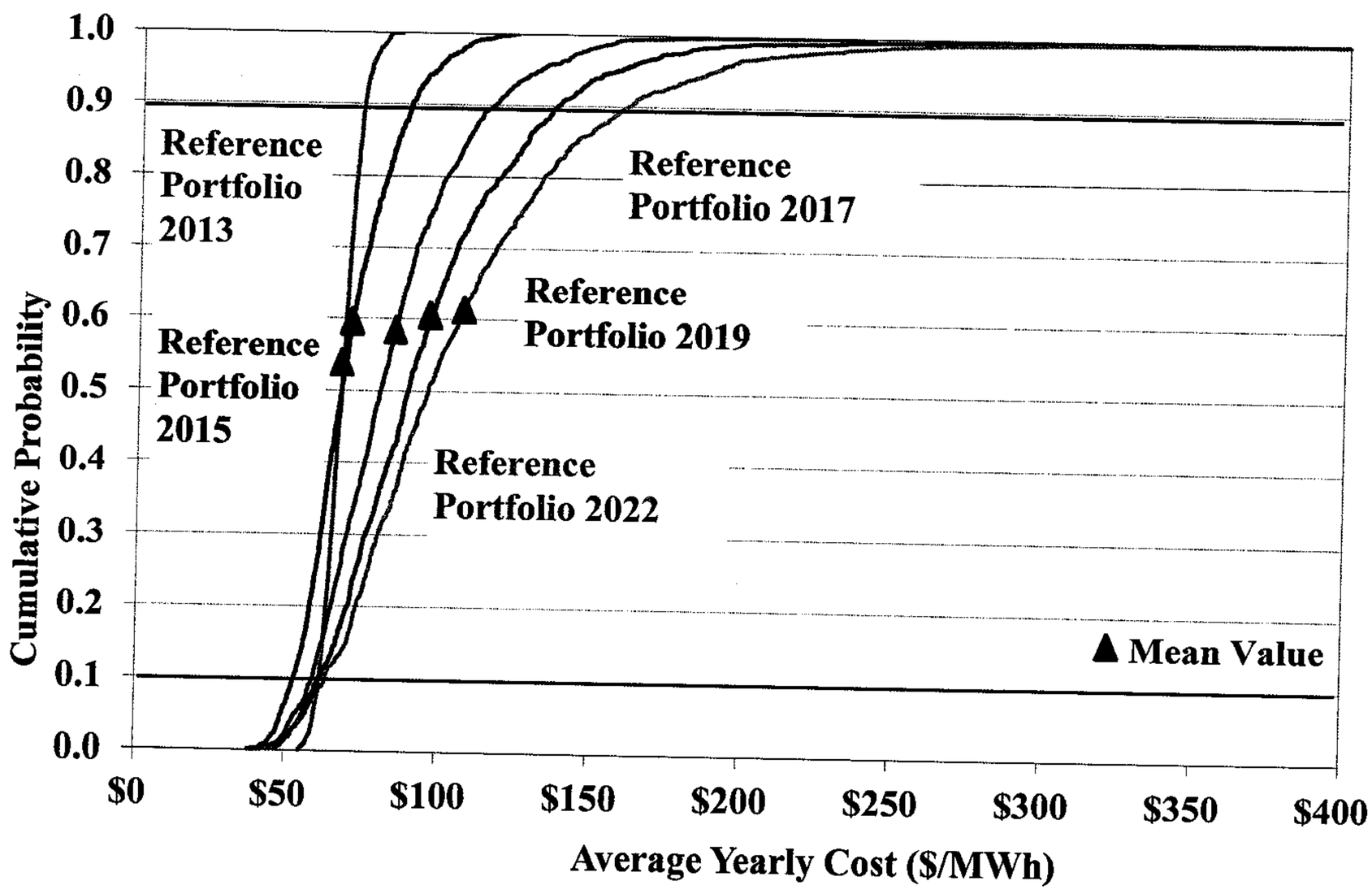


Figure 16: LC FSA Costs in 2013 - 2022



In both of the above, the curves shift significantly to the right and become noticeably flatter (riskier) in 2019 and 2022. The rightward shift, i.e. the increase in average costs, is largely due to the non-energy costs, which are projected to rise steadily and rapidly from 2015 on.

Partly as a consequence of these increases in market prices, a CC becomes more attractive and helpful to reducing FSA costs in future years. Its profitability increases to $61.99 million per year in 2022, and, given the underlying assumptions, it would allow a reduction of 12.98% in the RSCI FSA that year, and 14.21% for the LC FSA. This does not suggest that a CC need be built or acquired on behalf of Delmarva's SOS customers. Rather, it suggests that future entry of CCs into the PJM market is likely, and this will reduce prices to levels more commensurate with the breakeven costs of that technology. If so, SOS customers will benefit without having to secure or sponsor the investment.

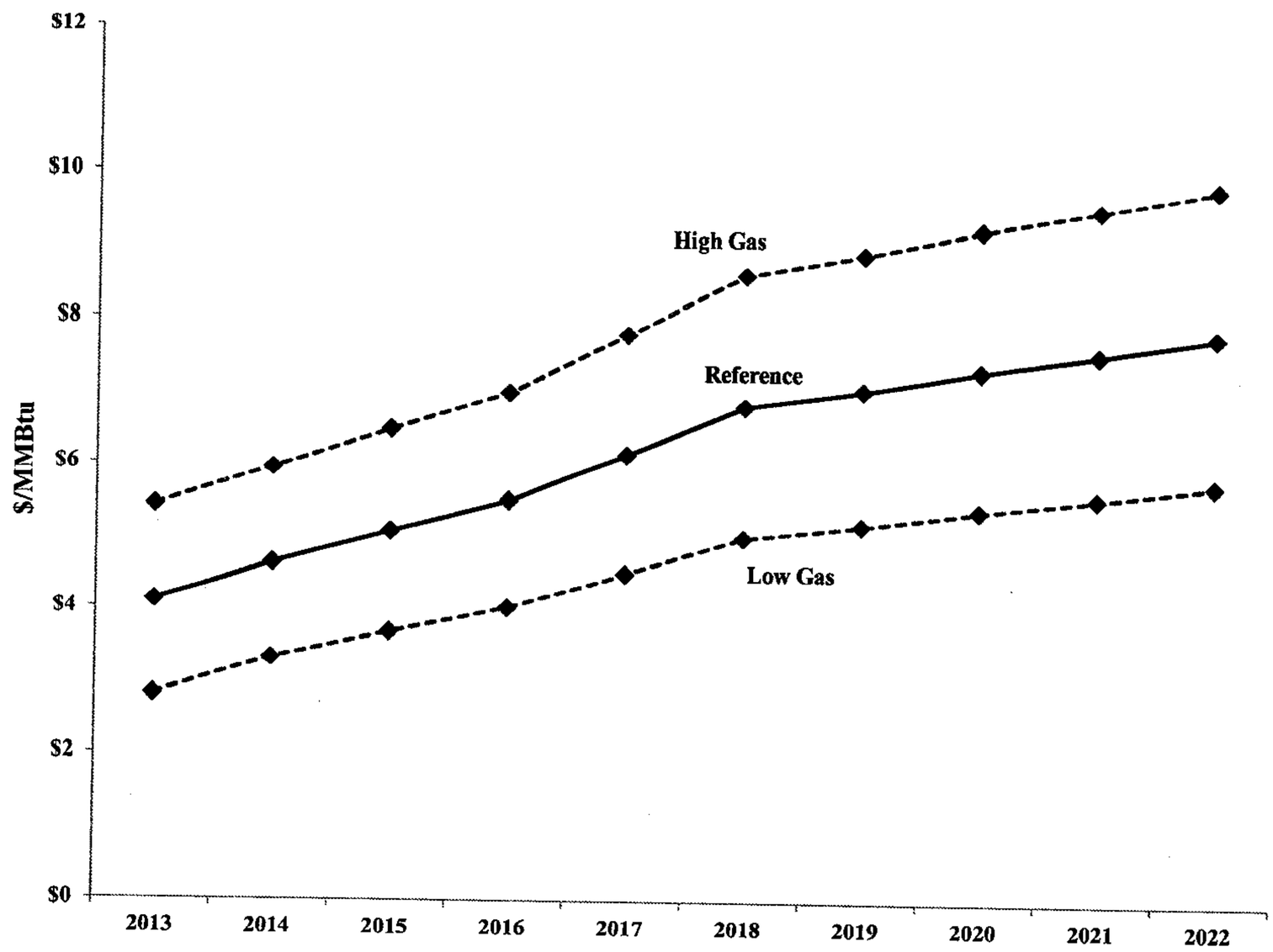
For 2019, we also evaluated the costs of a hypothetical utility-scale solar PV resource. We assume this technology would cost around $3,500 per kW to construct and install, based on a 20 MW facility of single-axis PV panels in Delaware, capable of a 15% capacity factor. As was shown in **Figure 6**, this results in revenue requirement (gross) costs that are quite high, approaching $400 to $450/MWh. (Two levels of gross costs were shown in **Figure 6**, differing by whether the 30% ITC is normalized or flowed through.) About $120/MWh of these gross costs can be offset with market energy and capacity sales, but the resulting net costs, measured in REC prices needed to breakeven are still quite large – over $280/MWh. This is larger than the net costs of offshore wind. Because of this, a 20 MW facility would cause about a $3.2/MWh increase in FSA RSCI costs.

GAS PRICE SENSITIVITIES

Because natural gas has had such a dramatic and sudden influence on power markets, and an uncertain future, we consider the effect of significantly lower or higher natural gas prices. Conceivably lower gas prices could emerge due to a continued boom in shale gas production and more regional pipelines to take it to market, while prices could rise if there were environmental restrictions on fracking and/or dramatic increases in gas demand (e.g., due to coal plant

retirements and/or export of gas as LNG to Europe and Asia). **Figure 17** below depicts the sensitivity ranges we consider around the Transco Zone 6 forward prices (same as depicted in **Figure 7**). These are one standard deviation bands, defined by the implied volatilities as of August for natural gas call options.

Figure 17: Natural Gas Price Sensitivities For Delivered Prices to PJM Transco Zone 6, Non-NY



Note that a one standard deviation price movement around the current forwards is not particularly unusual as a single possible variation in future forward price realizations. However, these sensitivity cases assume all future draws or realizations of natural gas prices are centered on a new forward price mean, which is either one standard deviation higher or lower than the current forward prices in every future period. Thus, these are fairly extreme changes from current expectations. Results of the above described sensitivities are summarized in

Figure 18.

Figure 18: Matrices of Gas-Price Sensitivity Results For RSCI Customers With and Without a CC

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Panel A – FSA Portfolio

RSCI FSA Results ($/MWh)

	Low Gas	Reference	High Gas
2013			
2015			
2017	$104.29	$122.06	$139.83
2019	$121.53	$141.22	$160.92
2022	$140.75	$161.96	$183.18

Panel B – FSA With Gas CC

RSCI FSA and CC Results ($/MWh)

	Low Gas	Reference	High Gas
2013	n/a	n/a	n/a
2015	n/a	n/a	n/a
2017	$97.84	$111.16	$124.48
2019	$110.39	$124.35	$138.28
2022	$124.99	$140.94	$153.42

The first of the above panels shows that higher or lower gas prices change RSCI FSA prices relatively symmetrically by about plus or minus $5/MWh in 2013 vs. about $21/MWh in 2022. The second panel shows that a gas CC is valuable by and after 2017 in every gas price situation compared to an FSA portfolio without it, and the advantage of a CC increases in the high gas cases and falls slightly in the low gas cases. This is an expected result from the new CC's heat rate advantages over the marginal units setting the price in PJM costs.

Even with high gas prices, off-shore wind and solar remain uneconomic, at currently projected costs and relative to projected market prices. Recall from **Figure 6** that the net costs of off-shore wind and solar were found to be well over $100/MWh. Adding a $1 per MMBtu to gas prices adds about $4-$6/MWh to the electricity prices (varying by month), so even a $5/MMBtu increase by 2022 (quite a dramatic shift, that seems very unlikely at present and is much larger than the change in the high gas scenario) would cause about a $20-$30/MWh increase in power costs, not enough to make either renewable have attractive net costs.

CONCLUSIONS

At present, it appears very economical to continue relying on RFPs for RSCI and LC SOS procurement in Delaware. Market prices for energy are relatively low and stable, and supply adequacy is not in question. A new CC may be attractive by around 2017, and indeed there are developers pursuing such capacity expansion throughout much of eastern PJM including Delaware. If developed, this may reduce the projected increase in non-energy costs, especially for capacity. Delmarva does not need additional RECs at this time, so there is no reason to pursue additional solar or off shore wind projects.

ATTACHMENT A

RESULTS FOR RSCI CUSTOMERS
(NOMINAL $ AND REAL 2012 $)

Table 1: Supply Cost Projections (RSCI Customers)
Panel A: Nominal $
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RSCI
Nominal Dollars

Electricity Hedging Option	Total Expected Electricity Volume (MWh)	Total Average Costs ($/MWh)	Delta (%)	High Average Costs 90.0% ($/MWh)	Low Average Costs 10.0% ($/MWh)	Difference between High and Low Average Costs ($/MWh)	Delta ($/MWh)	Difference as Percent of Average
Settlement Period: Planning Year 2013								
Reference Case	2,544,877							
Settlement Period: Planning Year 2015								
Reference Case	2,378,072							
Settlement Period: Planning Year 2017								
Reference Case	2,324,185	$122.06		$147.68	$100.82	$46.86		**38.39%**
Reference Case and CC	2,324,185	$111.16	**-8.9%**	$130.98	$93.57	$37.41	**-$9.45**	**33.65%**
Settlement Period: Planning Year 2019								
Reference Case	2,248,287	$141.22		$177.03	$110.84	$66.19		**46.87%**
Reference Case and CC	2,248,287	$124.35	**-11.9%**	$150.02	$102.10	$47.92	**-$18.27**	**38.54%**
Settlement Period: Planning Year 2022								
Reference Case	2,190,268	$161.96		$210.26	$122.12	$88.14		**54.42%**
Reference Case and CC	2,190,268	$140.94	**-13.0%**	$171.29	$115.18	$56.11	**-$32.03**	**39.81%**

Panel B: Real 2012 $
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RSCI
Real Dollars (2012$)

Electricity Hedging Option	Total Expected Electricity Volume (MWh)	Total Average Costs ($/MWh)	Delta (%)	High Average Costs 90.0% ($/MWh)	Low Average Costs 10.0% ($/MWh)	Difference between High and Low Average Costs ($/MWh)	Delta ($/MWh)	Difference as Percent of Average
Settlement Period: Planning Year 2013								
Reference Case	2,544,877							
Settlement Period: Planning Year 2015								
Reference Case	2,378,072							
Settlement Period: Planning Year 2017								
Reference Case	2,324,185	$107.88		$130.53	$89.11	$41.42		**38.39%**
Reference Case and CC	2,324,185	$98.25	**-8.9%**	$115.76	$82.70	$33.06	**-$8.36**	**33.65%**
Settlement Period: Planning Year 2019								
Reference Case	2,248,287	$118.81		$148.93	$93.25	$55.68		**46.87%**
Reference Case and CC	2,248,287	$104.61	**-11.9%**	$126.21	$85.90	$40.31	**-$15.37**	**38.54%**
Settlement Period: Planning Year 2022								
Reference Case	2,190,268	$126.53		$164.26	$95.40	$68.86		**54.42%**
Reference Case and CC	2,190,268	$110.10	**-13.0%**	$133.81	$89.98	$43.83	**-$25.02**	**39.81%**

Figure 1: Comparative Risk of the RC and Scenario Portfolios (Nominal $)

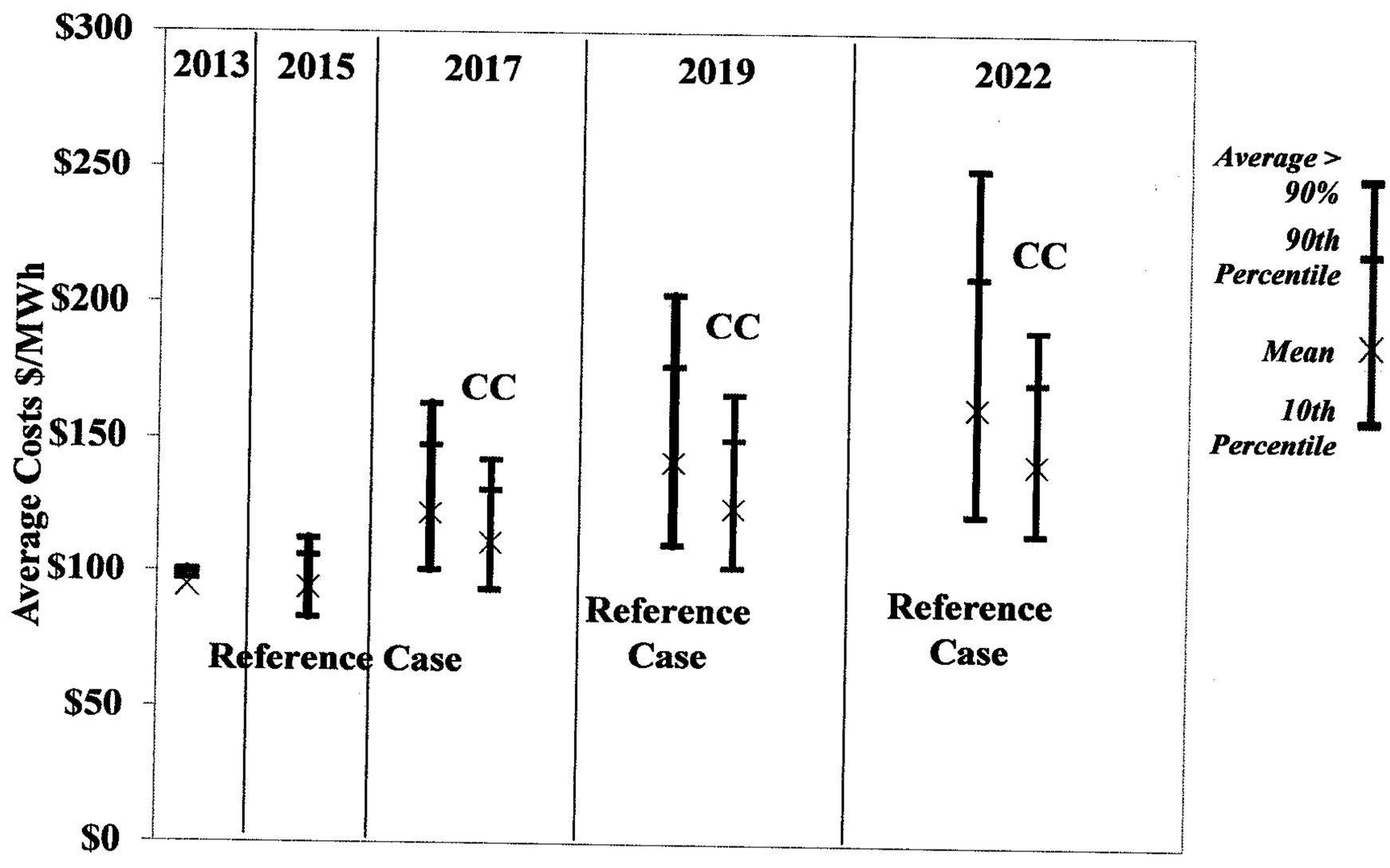

Table 2: Tariff Rate Projections

Panel A: Nominal $

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Planning Year	Residential Rates (Tariff "R")				MGT-S Rates			
	Demand ($/KW)		Energy(Cents/kWh)		Demand ($/KW)		Energy(Cents/kWh)	
	Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter
Currently Effective			9.55	9.56	11.7	7.4	4.01	4.96
2013/14	-	-	[redacted]		[redacted]			
2014/15	-	-						
2015/16	-	-						
2016/17	-	-	11.53	11.47	12.7	7.8	4.31	5.19
2017/18	-	-	12.45	12.34	13.8	8.5	4.68	5.64

Panel B: Real 2012 $

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Planning Year	Residential Rates (Tariff "R")				MGT-S Rates			
	Demand ($/KW)		Energy(Cents/kWh)		Demand ($/KW)		Energy(Cents/kWh)	
	Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter
Currently Effective			9.55	9.56	11.7	7.4	4.01	4.96
2013/14	-	-	[redacted]		[redacted]			
2014/15	-	-						
2015/16	-	-						
2016/17	-	-	10.45	10.39	11.5	7.1	3.91	4.71
2017/18	-	-	11.00	10.90	12.2	7.5	4.14	4.99

Table 3: Sensitivity Results (RSCI Customers)

Panel A: Nominal $

Sensitivity Analysis Nominal Dollars - 2022 Planning Year

Electricity Hedging Option	Total Expected Electricity Volume (MWh)	Total Average Costs ($/MWh)	**Difference ($) within Sensitivity**	**Delta (%) to Base Case**	High Average Costs 90.0% ($/MWh)	Low Average Costs 10.0% ($/MWh)	Difference between High and Low Average Costs ($/MWh)
Reference Case							
Reference Case Total	2,190,268	$161.96			$210.26	$122.12	$88.14
Reference Case and CC	2,190,268	$140.94	**-$21.03**	**-12.98%**	$171.29	$115.18	$56.11
High Gas Case							
Reference Case	2,190,268	$183.18		**13.10%**	$244.00	$132.99	$111.01
Reference Case and CC	2,190,268	$153.42	**-$29.76**	**8.86%**	$194.84	$118.79	$76.05
Low Gas Case							
Reference Case	2,190,268	$140.75		**-13.10%**	$176.52	$111.25	$65.27
Reference Case and CC	2,190,268	$124.99	**-$15.76**	**-11.32%**	$149.11	$104.97	$44.13

Panel B: Real 2012 $

Sensitivity Analysis Real Dollars - 2022 Planning Year

Electricity Hedging Option	Total Expected Electricity Volume (MWh)	Total Average Costs ($/MWh)	**Difference ($) within Sensitivity**	**Delta (%) to Base Case**	High Average Costs 90.0% ($/MWh)	Low Average Costs 10.0% ($/MWh)	Difference between High and Low Average Costs ($/MWh)
Reference Case							
Reference Case Total	2,190,268	$126.53			$164.26	$95.40	$68.86
Reference Case and CC	2,190,268	$110.10	**-$51.86**	**-32.02%**	$133.81	$89.98	$43.83
High Gas Case							
Reference Case	2,190,268	$143.10		**13.10%**	$190.62	$103.90	$86.72
Reference Case and CC	2,190,268	$119.85	**-$63.33**	**8.86%**	$152.21	$92.80	$59.41
Low Gas Case							
Reference Case	2,190,268	$109.95		**-13.10%**	$137.90	$86.91	$50.99
Reference Case and CC	2,190,268	$97.64	**-$43.11**	**-11.32%**	$116.48	$82.01	$34.48

ATTACHMENT B

RESULTS FOR LARGE COMMERCIAL CUSTOMERS
(NOMINAL $ AND REAL 2012 $)

Table 4: Supply Cost Projections (LC Customers)

Panel A: Nominal $

CONFIDENTIAL MATERIAL OMITTED

LC
Nominal Dollars

Electricity Hedging Option	Total Expected Electricity Volume (MWh)	Total Average Costs ($/MWh)	Delta (%)	High Average Costs 90.0% ($/MWh)	Low Average Costs 10.0% ($/MWh)	Difference between High and Low Average Costs ($/MWh)	Delta ($/MWh)	Difference as Percent of Average
Settlement Period: Planning Year 2013								
Reference Case	1,122,176							
Settlement Period: Planning Year 2015								
Reference Case	1,097,128							
Settlement Period: Planning Year 2017								
Reference Case	1,117,347	$84.67		$116.69	$59.33	$57.36		**67.75%**
Reference Case and CC	1,117,347	$76.83	**-9.3%**	$99.77	$57.04	$42.73	**-$14.64**	**55.61%**
Settlement Period: Planning Year 2019								
Reference Case	1,081,056	$96.20		$137.31	$61.26	$76.06		**79.06%**
Reference Case and CC	1,081,056	$84.01	**-12.7%**	$112.61	$59.04	$53.57	**-$22.49**	**63.76%**
Settlement Period: Planning Year 2022								
Reference Case	1,051,137	$106.74		$160.56	$63.38	$97.18		**91.04%**
Reference Case and CC	1,051,137	$91.57	**-14.2%**	$130.04	$60.91	$69.13	**-$28.05**	**75.49%**

Panel B: Real 2012 $

CONFIDENTIAL MATERIAL OMITTED

LC
Real Dollars (2012$)

Electricity Hedging Option	Total Expected Electricity Volume (MWh)	Total Average Costs ($/MWh)	Delta (%)	High Average Costs 90.0% ($/MWh)	Low Average Costs 10.0% ($/MWh)	Difference between High and Low Average Costs ($/MWh)	Delta ($/MWh)	Difference as Percent of Average
Settlement Period: Planning Year 2013								
Reference Case	1,122,176							
Settlement Period: Planning Year 2015								
Reference Case	1,097,128							
Settlement Period: Planning Year 2017								
Reference Case	1,117,347	$74.84		$103.14	$52.44	$50.70		**67.75%**
Reference Case and CC	1,117,347	$67.91	**-9.3%**	$88.18	$50.42	$37.76	**-$12.94**	**55.61%**
Settlement Period: Planning Year 2019								
Reference Case	1,081,056	$80.93		$115.52	$51.53	$63.98		**79.06%**
Reference Case and CC	1,081,056	$70.68	**-12.7%**	$94.73	$49.67	$45.06	**-$18.92**	**63.76%**
Settlement Period: Planning Year 2022								
Reference Case	1,051,137	$83.38		$125.43	$49.52	$75.92		**91.04%**
Reference Case and CC	1,051,137	$71.53	**-14.2%**	$101.59	$47.58	$54.00	**-$21.91**	**75.49%**

Figure 2: Comparative Risk of the RC and Scenario Portfolios

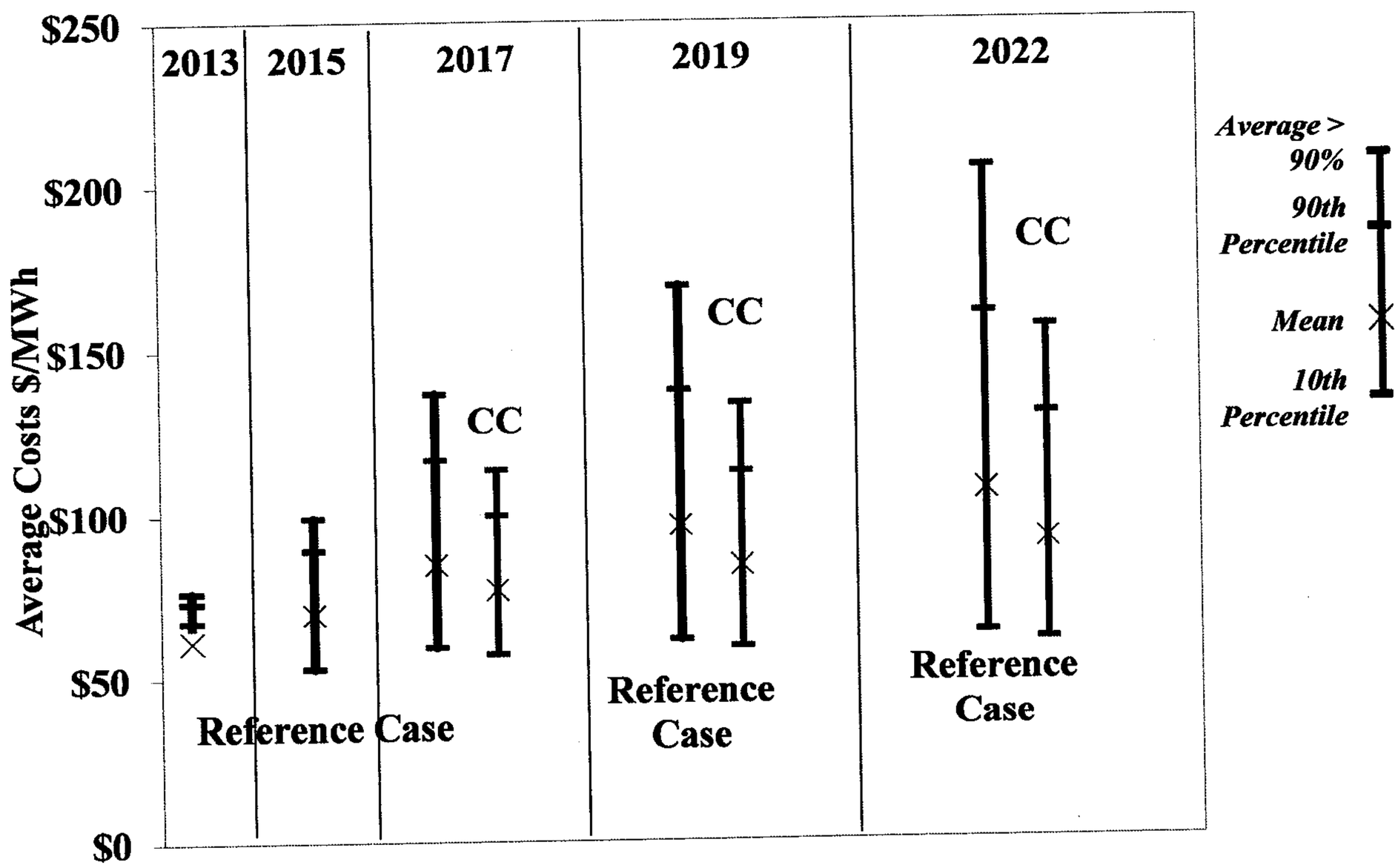

Table 5: Tariff Rate Projections
Panel A: Nominal $

CONFIDENTIAL MATERIAL OMITTED

Planning Year	Residential Rates (Tariff "R")				MGT-S Rates			
	Demand ($/KW)		Energy(Cents/kWh)		Demand ($/KW)		Energy(Cents/kWh)	
	Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter
Currently Effective			9.55	9.56	11.7	7.4	4.01	4.96
2013/14	-	-						
2014/15	-	-						
2015/16	-	-						
2016/17	-	-	11.53	11.47	12.7	7.8	4.31	5.19
2017/18	-	-	12.45	12.34	13.8	8.5	4.68	5.64

Panel B: Real 2012 $

CONFIDENTIAL MATERIAL OMITTED

Planning Year	Residential Rates (Tariff "R")				MGT-S Rates			
	Demand ($/KW)		Energy(Cents/kWh)		Demand ($/KW)		Energy(Cents/kWh)	
	Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter
Currently Effective			9.55	9.56	11.7	7.4	4.01	4.96
2013/14	-	-						
2014/15	-	-						
2015/16	-	-						
2016/17	-	-	10.45	10.39	11.5	7.1	3.91	4.71
2017/18	-	-	11.00	10.90	12.2	7.5	4.14	4.99

Table 6: Sensitivity Results (LC Customers)
Panel A: Nominal $

Sensitivity Analysis Nominal Dollars - 2022 Planning Year

Electricity Hedging Option	Total Expected Electricity Volume (MWh)	Total Average Costs ($/MWh)	**Difference ($) within Sensitivity**	**Delta (%) to Base Case**	High Average Costs 90.0% ($/MWh)	Low Average Costs 10.0% ($/MWh)	Difference between High and Low Average Costs ($/MWh)
Reference Case							
Reference Case Total	1,051,137	$106.74			$160.56	$63.38	$97.18
Reference Case and CC	1,051,137	$91.57	**-$15.17**	**-14.21%**	$130.04	$60.91	$69.13
High Gas Case							
Reference Case	1,051,137	$127.70		**19.64%**	$195.54	$73.06	$122.48
Reference Case and CC	1,051,137	$106.23	**-$21.47**	**16.01%**	$154.24	$67.16	$87.08
Low Gas Case							
Reference Case	1,051,137	$85.78		**-19.64%**	$125.59	$53.71	$71.88
Reference Case and CC	1,051,137	$74.41	**-$11.37**	**-18.74%**	$102.25	$51.61	$50.64

Panel B: Real 2012 $

Sensitivity Analysis Real Dollars - 2022 Planning Year

Electricity Hedging Option	Total Expected Electricity Volume (MWh)	Total Average Costs ($/MWh)	**Difference ($) within Sensitivity**	**Delta (%) to Base Case**	High Average Costs 90.0% ($/MWh)	Low Average Costs 10.0% ($/MWh)	Difference between High and Low Average Costs ($/MWh)
Reference Case							
Reference Case Total	1,051,137	$83.38			$125.43	$49.52	$75.92
Reference Case and CC	1,051,137	$71.53	**-$35.20**	**-32.98%**	$101.59	$47.58	$54.00
High Gas Case							
Reference Case	1,051,137	$99.76		**19.64%**	$152.75	$57.07	$95.68
Reference Case and CC	1,051,137	$82.99	**-$44.71**	**16.01%**	$120.49	$52.47	$68.03
Low Gas Case							
Reference Case	1,051,137	$67.01		**-19.64%**	$98.11	$41.96	$56.15
Reference Case and CC	1,051,137	$58.13	**-$27.65**	**-18.74%**	$79.88	$40.32	$39.56

ATTACHMENT C

ENERGY AND PEAK LOAD OBLIGATION FORECAST

Attachment C

Load Forecast (GWH)
DPL Delaware Unrestricted
Calendar Year

	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Standard Offer Service												
Residential	2,960	2,811	2,684	2,698	2,716	2,734	2,750	2,765	2,780	2,793	2,805	2,819
Small Commercial	142	150	154	154	155	156	156	157	157	158	158	158
Street Lighting	28	28	28	28	28	28	28	28	28	28	29	29
RSCI Subtotal	*3,129*	*2,989*	*2,866*	*2,880*	*2,899*	*2,918*	*2,934*	*2,950*	*2,965*	*2,979*	*2,992*	*3,006*
LC&I	858	911	930	935	939	942	945	949	952	955	957	958
Hourly Service	331	352	359	361	362	364	365	366	368	369	370	370
Large Commercial & Industrial	1,189	1,263	1,289	1,296	1,301	1,306	1,310	1,316	1,319	1,323	1,327	1,328
Subtotal	4,318	4,251	4,155	4,176	4,200	4,223	4,245	4,266	4,285	4,302	4,318	4,334
Third-Party Suppliers												
Residential	111	105	101	101	102	103	103	104	104	105	105	106
Small Commercial	36	38	39	39	39	39	39	39	39	40	40	40
Street Lighting	10	10	10	10	10	10	10	10	10	10	10	11
RSCI Subtotal	*157*	*153*	*149*	*150*	*151*	*152*	*153*	*153*	*154*	*155*	*155*	*156*
Large Commercial & Industrial	4,106	4,360	4,453	4,475	4,494	4,509	4,525	4,543	4,557	4,569	4,581	4,588
Subtotal	4,263	4,513	4,603	4,626	4,645	4,660	4,678	4,697	4,711	4,724	4,737	4,744
Total Distribution Load												
Residential	3,071	2,916	2,785	2,799	2,818	2,837	2,853	2,869	2,884	2,898	2,910	2,924
Small Commercial	177	188	192	193	194	195	195	196	197	197	198	198
Street Lighting	38	38	38	38	38	38	38	39	39	39	39	39
Large Commercial & Industrial	5,295	5,623	5,743	5,771	5,795	5,814	5,835	5,859	5,876	5,892	5,908	5,916
Total	8,581	8,765	8,758	8,802	8,845	8,884	8,923	8,962	8,996	9,026	9,055	9,078
Migration (%)												
Residential	3.6%	3.6%	3.6%	3.6%	3.6%	3.6%	3.6%	3.6%	3.6%	3.6%	3.6%	3.6%
Small Commercial	20.1%	20.1%	20.1%	20.1%	20.1%	20.1%	20.1%	20.1%	20.1%	20.1%	20.1%	20.1%
Street Lighting	26.8%	26.8%	26.8%	26.8%	26.8%	26.8%	26.8%	26.8%	26.8%	26.8%	26.8%	26.8%
RSCI Subtotal	*4.8%*	*4.9%*	*5.0%*	*5.0%*	*5.0%*	*4.9%*	*4.9%*	*4.9%*	*4.9%*	*4.9%*	*4.9%*	*4.9%*
Large Commercial & Industrial	77.5%	77.5%	77.5%	77.5%	77.5%	77.5%	77.5%	77.5%	77.5%	77.5%	77.5%	77.5%
Total	49.7%	51.5%	52.6%	52.6%	52.5%	52.5%	52.4%	52.4%	52.4%	52.3%	52.3%	52.3%

Attachment C

DSM Projectons (GWH)
DPL Delaware
Calendar Year

	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Standard Offer Service												
Residential	168	276	367	452	503	551	587	646	700	730	762	792
Small Commercial	8	14	20	25	24	23	22	26	29	31	32	34
Street Lighting	0	0	0	0	0	0	0	0	0	0	0	0
RSCI Subtotal	*177*	*290*	*387*	*478*	*527*	*574*	*609*	*672*	*729*	*761*	*794*	*826*
Large Commercial & Industrial	71	122	168	212	201	190	186	216	246	259	273	281
Subtotal	248	412	555	690	728	764	795	888	975	1,020	1,067	1,107
Third-Party Suppliers												
Residential	6	9	13	16	18	20	21	23	25	27	28	29
Small Commercial	2	3	5	6	6	5	5	6	7	7	8	8
Street Lighting	0	0	0	0	0	0	0	0	0	0	0	0
RSCI Subtotal	8	13	18	22	24	25	26	30	32	34	36	37
Large Commercial & Industrial	244	384	544	697	657	620	607	711	816	862	907	936
Subtotal	253	397	561	719	681	645	633	741	849	896	942	973
Total Distribution Load												
Residential	175	285	379	469	521	571	608	670	725	757	789	821
Small Commercial	11	18	25	31	30	28	27	32	36	38	40	42
Street Lighting	0	0	0	0	0	0	0	0	0	0	0	0
RSCI Subtotal	185	303	404	500	551	599	636	702	762	795	830	863
Large Commercial & Industrial	315	505	712	909	858	810	793	927	1,062	1,121	1,179	1,217
Total	500	808	1,116	1,409	1,409	1,409	1,428	1,629	1,824	1,916	2,009	2,080

Attachment C

Load Forecast (GWH)
DPL Delaware less DSM
Calendar Year

Page 3

	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Standard Offer Service												
Residential	2,792	2,535	2,318	2,245	2,213	2,183	2,163	2,119	2,080	2,062	2,043	2,027
Small Commercial	133	136	134	129	131	133	134	131	128	127	126	125
Street Lighting	28	28	28	28	28	28	28	28	28	28	29	29
RSCI Subtotal	*2,953*	*2,699*	*2,479*	*2,402*	*2,372*	*2,344*	*2,325*	*2,278*	*2,236*	*2,218*	*2,198*	*2,180*
LC&I	806	823	809	782	794	805	811	793	774	767	760	756
Hourly Service	311	318	312	302	307	311	313	306	299	296	294	292
Large Commercial & Industrial	1,118	1,141	1,121	1,084	1,101	1,116	1,124	1,099	1,073	1,064	1,054	1,047
Subtotal	4,070	3,840	3,600	3,486	3,472	3,460	3,450	3,378	3,310	3,282	3,252	3,227
Third-Party Suppliers												
Residential	105	96	88	85	84	83	82	80	79	78	77	77
Small Commercial	33	34	34	33	33	34	34	33	32	32	32	32
Street Lighting	10	10	10	10	10	10	10	10	10	10	10	11
RSCI Subtotal	*148*	*141*	*132*	*128*	*127*	*127*	*126*	*124*	*122*	*121*	*120*	*119*
Large Commercial & Industrial	3,862	3,976	3,910	3,779	3,837	3,889	3,918	3,832	3,741	3,708	3,675	3,651
Subtotal	4,010	4,117	4,042	3,907	3,964	4,015	4,044	3,956	3,862	3,828	3,794	3,770
Total Distribution Load												
Residential	2,897	2,631	2,405	2,330	2,296	2,265	2,245	2,199	2,159	2,141	2,121	2,103
Small Commercial	167	170	168	162	164	167	168	164	160	159	157	156
Street Lighting	38	38	38	38	38	38	38	39	39	39	39	39
RSCI Subtotal	*3,101*	*2,839*	*2,611*	*2,530*	*2,499*	*2,470*	*2,451*	*2,402*	*2,358*	*2,338*	*2,317*	*2,299*
Total	8,080	7,956	7,642	7,393	7,437	7,475	7,494	7,333	7,172	7,110	7,046	6,998

Attachment C

Load Forecast (GWH)
DPL Delaware less DSM
Planning (Compliance) Year

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	2012/13	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23
Standard Offer Service											
Residential	2,685	2,444	2,287	2,232	2,200	2,174	2,145	2,103	2,073	2,055	2,036
Small Commercial	134	135	132	130	132	133	133	130	127	126	125
Street Lighting	28	28	28	28	28	28	28	28	28	29	29
RSCI Subtotal	*2,847*	*2,607*	*2,447*	*2,390*	*2,360*	*2,336*	*2,306*	*2,261*	*2,229*	*2,209*	*2,190*
LC&I	813	817	798	787	799	808	804	785	772	765	758
Hourly Service	314	316	308	304	308	312	310	303	298	295	293
Large Commercial & Industrial	1,128	1,133	1,106	1,091	1,107	1,119	1,114	1,089	1,069	1,060	1,051
Subtotal	3,974	3,740	3,553	3,480	3,467	3,455	3,420	3,349	3,298	3,269	3,241
Subtotal (less hourly)	3,660	3,424	3,245	3,176	3,159	3,144	3,109	3,046	3,000	2,974	2,949
Third-Party Suppliers											
Residential	101	93	87	85	83	82	81	80	79	78	77
Small Commercial	34	34	33	33	33	34	34	33	32	32	32
Street Lighting	10	10	10	10	10	10	10	10	10	10	10
RSCI Subtotal	*145*	*137*	*130*	*128*	*127*	*126*	*125*	*123*	*121*	*120*	*119*
Large Commercial & Industrial	3,909	3,949	3,855	3,803	3,858	3,901	3,882	3,794	3,727	3,694	3,665
Subtotal	4,054	4,085	3,985	3,931	3,986	4,027	4,007	3,917	3,848	3,814	3,784
Total Distribution Load											
Residential	2,786	2,537	2,374	2,316	2,283	2,257	2,226	2,182	2,151	2,132	2,114
Small Commercial	168	169	165	163	165	167	166	163	160	158	157
Street Lighting	38	38	38	38	38	38	39	39	39	39	39
Large Commercial & Industrial	5,037	5,117	5,031	4,862	4,938	5,005	5,043	4,931	4,814	4,771	4,729
Total	8,029	7,825	7,538	7,411	7,453	7,483	7,427	7,266	7,146	7,083	7,026

Attachment C

Peak Demand Forecast (MW)
DPL Delaware Unrestricted
Calendar Year

	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Standard Offer Service												
Residential	986	996	1,014	1,034	1,056	1,075	1,092	1,109	1,128	1,144	1,161	1,178
Small Commercial	23	23	23	24	24	25	25	25	26	26	27	27
Street Lighting	0	0	0	0	0	0	0	0	0	0	0	0
RSCI Subtotal	1,009	1,019	1,038	1,057	1,080	1,100	1,117	1,135	1,154	1,170	1,187	1,205
LC&I	137	138	141	143	146	149	151	154	156	159	161	163
Hourly Service	53	53	54	55	57	58	58	59	60	61	62	63
Large Commercial & Industrial	190	191	195	199	203	207	210	213	217	220	223	226
Subtotal	1,198	1,210	1,233	1,256	1,283	1,307	1,327	1,348	1,371	1,390	1,411	1,431
Third-Party Suppliers												
Residential	37	37	38	39	40	40	41	42	42	43	44	44
Small Commercial	6	6	6	6	6	6	6	6	6	7	7	7
Street Lighting	0	0	0	0	0	0	0	0	0	0	0	0
RSCI Subtotal	43	43	44	45	46	47	47	48	49	49	50	51
Large Commercial & Industrial	655	661	673	686	701	714	725	737	749	760	771	782
Subtotal	697	704	717	731	746	760	772	784	798	809	821	833
Total Distribution Load												
Residential	1,023	1,033	1,052	1,072	1,095	1,116	1,133	1,151	1,170	1,187	1,204	1,222
Small Commercial	28	29	29	30	30	31	31	32	32	33	33	34
Street Lighting	0	0	0	0	0	0	0	0	0	0	0	0
RSCI Subtotal	1,051	1,062	1,081	1,102	1,125	1,146	1,164	1,183	1,203	1,220	1,238	1,256
Large Commercial & Industrial	844	853	868	885	904	921	935	950	966	980	994	1,008
Total	1,896	1,914	1,950	1,987	2,029	2,067	2,099	2,132	2,169	2,199	2,232	2,264
Migration (%)												
Residential	3.6%	3.6%	3.6%	3.6%	3.6%	3.6%	3.6%	3.6%	3.6%	3.6%	3.6%	3.6%
Small Commercial	20.1%	20.1%	20.1%	20.1%	20.1%	20.1%	20.1%	20.1%	20.1%	20.1%	20.1%	20.1%
Street Lighting	-	-	-	-	-	-	-	-	-	-	-	-
RSCI Subtotal	4.1%	4.1%	4.1%	4.1%	4.1%	4.1%	4.1%	4.1%	4.1%	4.1%	4.1%	4.1%
Large Commercial & Industrial	77.5%	77.5%	77.5%	77.5%	77.5%	77.5%	77.5%	77.5%	77.5%	77.5%	77.5%	77.5%
Total	36.8%	36.8%	36.8%	36.8%	36.8%	36.8%	36.8%	36.8%	36.8%	36.8%	36.8%	36.8%

Attachment C

DSM Projectons (MW)
DPL Delaware
Calendar Year

	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Standard Offer Service												
Residential	50	129	187	206	231	236	238	246	253	258	263	267
Small Commercial	2	7	10	11	11	11	10	11	12	12	13	13
Street Lighting	0	0	0	0	0	0	0	0	0	0	0	0
RSCI Subtotal	*52*	*136*	*196*	*217*	*242*	*246*	*248*	*257*	*265*	*270*	*275*	*280*
Large Commercial & Industrial	20	57	81	94	92	88	86	92	99	102	106	109
Subtotal	73	193	277	311	334	335	334	350	364	372	381	388
Third-Party Suppliers												
Residential	2	3	4	5	6	6	6	6	7	7	7	7
Small Commercial	1	1	1	2	2	2	2	2	2	2	2	2
Street Lighting	0	0	0	0	0	0	0	0	0	0	0	0
RSCI Subtotal	2	4	5	6	7	8	8	8	9	9	9	9
Large Commercial & Industrial	71	105	148	199	195	185	178	204	229	239	249	257
Subtotal	73	108	153	205	203	192	186	212	238	248	258	266
Total Distribution Load												
Residential	52	132	191	211	237	242	244	253	260	265	270	274
Small Commercial	3	8	11	13	13	12	12	13	14	14	15	15
Street Lighting	0	0	0	0	0	0	0	0	0	0	0	0
RSCI Subtotal	55	140	201	224	250	254	256	266	274	279	284	289
Large Commercial & Industrial	91	161	229	293	288	273	264	296	328	342	355	366
Total	146	301	430	516	537	527	520	562	602	620	640	655

Attachment C

Peak Demand Forecast (MW)
DPL Delaware less DSM
Calendar Year

	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Standard Offer Service												
Residential	936	866	828	828	824	839	854	863	875	887	898	911
Small Commercial	20	16	14	12	13	14	15	14	14	14	14	14
Street Lighting	0	0	0	0	0	0	0	0	0	0	0	0
RSCI Subtotal	*957*	*882*	*841*	*840*	*838*	*853*	*869*	*877*	*889*	*901*	*912*	*925*
LC&I	122	97	82	75	80	85	90	87	85	85	85	85
Hourly Service	47	37	32	29	31	33	35	34	33	33	33	33
Large Commercial & Industrial	169	135	114	105	111	119	124	121	118	118	117	118
Subtotal	1,126	1,017	955	945	948	972	993	998	1,006	1,018	1,029	1,043
Subtotal (less hourly)	1,079	979	924	916	917	939	958	965	974	985	997	1,010
Third-Party Suppliers												
Residential	35	35	34	34	34	34	35	35	36	36	37	37
Small Commercial	5	5	5	4	4	5	5	5	5	5	5	5
Street Lighting	0	0	0	0	0	0	0	0	0	0	0	0
RSCI Subtotal	*40*	*40*	*39*	*38*	*38*	*39*	*40*	*40*	*40*	*41*	*41*	*42*
Large Commercial & Industrial	584	556	525	488	505	529	547	533	520	521	522	525
Subtotal	624	596	564	526	544	568	586	573	560	561	563	566
Total Distribution Load												
Residential	972	901	862	862	858	874	889	898	910	923	935	948
Small Commercial	25	21	18	17	18	19	20	19	19	19	18	19
Street Lighting	0	0	0	0	0	0	0	0	0	0	0	0
RSCI Subtotal	*997*	*922*	*880*	*878*	*876*	*892*	*908*	*917*	*929*	*941*	*953*	*966*
Large Commercial & Industrial	753	691	639	592	616	648	671	654	638	638	639	643
Total	1,750	1,613	1,519	1,471	1,492	1,540	1,579	1,571	1,567	1,579	1,592	1,609

Attachment C

Peak Demand Forecast (MW)
DPL Delaware less DSM
Calendar Year

PJM Coincident Peak Factor for DPL Zone 96.254%

	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Standard Offer Service												
Residential	901	834	797	797	793	808	822	831	842	853	865	877
Small Commercial	19	15	13	12	13	14	14	14	14	13	13	14
Street Lighting	0	0	0	0	0	0	0	0	0	0	0	0
RSCI Subtotal	921	849	810	809	806	821	836	844	855	867	878	890
LC&I	117	93	79	73	77	82	86	84	82	82	81	82
Hourly Service	45	36	31	28	30	32	33	32	32	32	31	32
Large Commercial & Industrial	163	130	110	101	107	114	120	116	113	113	113	113
Subtotal	1,084	979	920	909	913	935	956	961	969	980	991	1,004
Subtotal (less hourly)	1,038	943	889	881	883	904	922	928	937	948	959	972
Third-Party Suppliers												
Residential	34	33	33	33	33	33	34	34	34	35	35	36
Small Commercial	5	5	4	4	4	4	5	4	4	4	4	4
Street Lighting	0	0	0	0	0	0	0	0	0	0	0	0
RSCI Subtotal	39	38	37	37	37	38	38	38	39	39	39	40
Large Commercial & Industrial	562	536	506	469	486	509	526	513	500	501	502	505
Subtotal	601	574	543	506	523	547	564	551	539	540	541	545
Total Distribution Load												
Residential	935	867	830	829	826	841	856	864	876	888	900	912
Small Commercial	24	20	17	16	17	18	19	18	18	18	18	18
Street Lighting	0	0	0	0	0	0	0	0	0	0	0	0
RSCI Subtotal	959	887	847	845	843	859	874	883	894	906	918	930
Large Commercial & Industrial	725	665	616	570	593	623	646	629	614	614	615	619
Total	1,684	1,553	1,463	1,416	1,436	1,482	1,520	1,512	1,508	1,520	1,532	1,549

ATTACHMENT D

RPS OBLIGATION AND SUPPLY PROJECTIONS

Attachment D

DPL DE
Planning (Compliance) Year

	2012/13	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23
Standard Offer Service (GWH)	3,974	3,740	3,553	3,480	3,467	3,455	3,420	3,349	3,298	3,269	3,241
Third-Party Suppliers	4,054	4,085	3,985	3,931	3,986	4,027	4,007	3,917	3,848	3,814	3,784
Total Distribution Load	8,029	7,825	7,538	7,411	7,453	7,483	7,427	7,266	7,146	7,083	7,026
Transitional Third Party Supplier Load Obligation	1,673	576	147	57	0	0	0	0	0		
RPS Exempt Load	700	900	1,100	1,300	1,500	1,500	1,500	1,500	1,500	1,500	1,500
DPL RPS Load Obligation (GWH)	5,655	6,349	6,291	6,054	5,953	5,983	5,927	5,766	5,646	5,583	5,526
Solar RPS Requirement %	0.40%	0.60%	0.80%	1.00%	1.25%	1.50%	1.75%	2.00%	2.25%	2.50%	2.75%
Preliminary Solar RPS Requirement	22,621	38,093	50,327	60,536	74,406	89,743	103,725	115,323	127,037	139,581	151,960
Bloom ESRECs	5,655	9,523	12,582	0	0	0	0	0	0	0	0
Adjusted Solar RPS Requirement	16,966	28,570	37,745	60,536	74,406	89,743	103,725	115,323	127,037	139,581	151,960
Adjusted Solar RPS Requirement (%)	0.30%	0.45%	0.60%	1.00%	1.25%	1.50%	1.75%	2.00%	2.25%	2.50%	2.75%
Total RPS Requirement %	8.5%	10.0%	11.5%	13.0%	14.5%	16.0%	17.5%	19.0%	20.0%	21.0%	22.0%
Total Requirement less Solar	458,084	596,802	673,138	726,443	788,711	867,523	933,530	980,246	1,002,187	1,032,902	1,063,723
Existing REC Allowance (1%)	56,553	63,489	62,909	60,536	59,525	59,829	59,271	57,661	0	0	0
Preliminary New REC Requirement	401,531	533,313	610,229	665,907	729,186	807,694	874,259	922,585	1,002,187	1,032,902	1,063,723
Bloom ERECs	10,907	218,181	353,595	504,576	504,576	504,576	504,576	504,576	504,576	504,576	504,576
Adjusted New REC Requirement	390,624	315,132	256,634	161,331	224,610	303,118	369,683	418,009	497,611	528,326	559,147
Total RECs	464,143	407,191	357,288	282,403	358,541	452,690	532,679	590,993	624,648	667,907	711,107

Attachment D

DPL DE Solar Portfolio
Planning (Compliance) Year
(Solar Renewable Energy Credits - SRECs)
AS FORECASTED

	2012/13	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23
Preliminary Solar Req'mt	22,621	38,093	50,327	60,536	74,406	89,743	103,725	115,323	127,037	139,581	151,960
Bloom Obligation Reduction (ESRECs)	5,655	9,523	12,582	0	0	0	0	0	0	0	0
Adjusted Solar Requirement	16,966	28,570	37,745	60,536	74,406	89,743	103,725	115,323	127,037	139,581	151,960
SREC Purchases											
Utility Scale											
Total Dover/SEU Contracts	10,127	14,126	17,025	17,835	18,865	13,845	13,776	13,707	13,639	13,571	13,503
Total Solar Pilot Program	6,431	11,472	11,415	11,358	11,301	11,245	11,188	11,132	11,077	11,021	10,966
Total Contracted Purchases	16,558	25,598	28,440	29,193	30,166	25,090	24,964	24,840	24,715	24,592	24,469
Additional SRECs Required	268	2,972	9,305	31,343	44,240	64,653	78,761	90,483	102,322	114,989	127,491
Incremental SRECs Required		2,703	6,333	22,038	12,897	20,413	14,107	11,723	11,838	12,668	12,502
Beginning of Year SREC Bank	140	0	0	0	0	0	0	0	0	0	0
End of Year SREC Bank	0	0	0	0	0	0	0	0	0	0	0
Expiring SRECs	0	0	0	0	0	0	0	0	0	0	0
Price of SREC Purchases ($/REC)											
Dover Solar	$197.00	$197.00	$197.00	$197.00	$197.00	$197.00	$197.00	$197.00	$197.00	$197.00	$197.00
Existing SEU Contract		$210.64	$210.64	$210.64	$210.64						
Total Solar Pilot Program	$240.59	$208.56	$208.86	$209.17	$209.50	$209.83	$210.17	$210.53	$210.90	$140.82	$70.75
Total Dover/SEU Contracts	$179.09	$179.09	$181.25	$181.77	$182.34	$179.09	$179.09	$179.09	$179.09	$179.09	$179.09
DE SREC Financint Program	$240.59	$208.56	$208.86	$209.17	$209.50	$209.83	$210.17	$210.53	$210.90	$140.82	$70.75
Cost of SREC Purchases											
Dover Solar	$1,813,611	$2,529,798	$2,517,149	$2,504,563	$2,492,040	$2,479,580	$2,467,182	$2,454,846	$2,442,572	$2,430,359	$2,418,208
Existing SEU Contract	$0	$0	$568,718	$737,227	$947,864	$0	$0	$0	$0	$0	$0
Total Solar Pilot Program	$1,547,251	$2,392,662	$2,384,144	$2,375,768	$2,367,533	$2,359,448	$2,351,499	$2,343,708	$2,336,072	$1,551,992	$775,840
Total SREC Purchases ($)	$3,360,862	$4,922,460	$5,470,011	$5,617,559	$5,807,437	$4,839,028	$4,818,681	$4,798,554	$4,778,644	$3,982,351	$3,194,047

DPL DE Wind Portfolio
Planning (Compliance) Year
(Renewable Energy Credits - RECs)
AS FORECASTED

	2012/13	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23
Preliminary REC Requirement	401,531	533,313	610,229	665,907	729,186	807,694	874,259	922,585	1,002,187	1,032,902	1,063,723
Bloom Obligation Reduction (ERECs)	10,907	218,181	353,595	504,576	504,576	504,576	504,576	504,576	504,576	504,576	504,576
Adjusted REC Requirement	390,624	315,132	256,634	161,331	224,610	303,118	369,683	418,009	497,611	528,326	559,147
RECs from Existing Wind Contracts											
AES Armenia Wind	129,210	129,210	129,210	129,210	129,210	129,210	129,210	129,210	129,210	129,210	129,210
Gestamp - Roth Rock	105,120	105,120	105,120	105,120	105,120	105,120	105,120	105,120	105,120	105,120	105,120
Gamesa - Chestnut Flats	99,864	99,864	99,864	99,864	99,864	99,864	99,864	99,864	99,864	99,864	99,864
Total RECs from Wind Contracts	334,194	334,194	334,194	334,194	334,194	334,194	334,194	334,194	334,194	334,194	334,194
Additional RECs Required	**3,882**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**66,708**	**224,953**
BOY REC Bank	52,548	0	19,062	96,622	269,485	379,069	410,145	374,656	290,841	127,424	0
EOY REC Bank	0	19,062	96,622	269,485	379,069	410,145	374,656	290,841	127,424	0	0
Expiring RECs	0	0	0	0	0	0	0	0	0	0	0

Delmarva Solar Compliance Cost

Solar Carve-Out Compliance Cost											
	Projected										
Compliance Year	2012/13	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23
Forecasted SOS Load Obligation GWH*	5,655	6,349	6,291	6,054	5,953	5,983	5,927	5,766	5,646	5,583	5,526
Preliminary Solar RPS Requirement	22,621	38,093	50,327	60,536	74,406	89,743	103,725	115,323	127,037	139,581	151,960
Dover Sun Park & SEU Contract											
SRECs	10,127	14,126	17,025	17,835	18,865	13,845	13,776	13,707	13,639	13,571	13,503
$/SREC	$179.09	$179.09	$181.25	$181.77	$182.34	$179.09	$179.09	$179.09	$179.09	$179.09	$179.09
$	$1,813,611	$2,529,798	$3,085,867	$3,241,791	$3,439,904	$2,479,580	$2,467,182	$2,454,846	$2,442,572	$2,430,359	$2,418,208
DE SREC Financing Program											
SRECs	6,431	11,472	11,415	11,358	11,301	11,245	11,188	11,132	11,077	11,021	10,966
$/SREC	$240.59	$208.56	$208.86	$209.17	$209.50	$209.83	$210.17	$210.53	$210.90	$140.82	$70.75
$	$1,547,251	$2,392,662	$2,384,144	$2,375,768	$2,367,533	$2,359,448	$2,351,499	$2,343,708	$2,336,072	$1,551,992	$775,840
Bloom Purchases											
ESRECs	5,655	9,523	12,582	0	0	0	0	0	0	0	0
/ESREC	$267.56	$97.15	$93.50	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Total $	$1,513,111	$925,153	$1,176,426	$0	$0	$0	$0	$0	$0	$0	$0
Banked SRECs											
SRECs	140	0	0	0	0	0	0	0	0	0	0
$/SREC	$197.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
$	$27,521	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Spot Purchases											
SRECs	268	2,972	9,305	31,343	44,240	64,653	78,761	90,483	102,322	114,989	127,491
/SREC	$42.03	$120.20	$87.04	$103.06	$105.64	$137.39	$155.74	$166.44	$177.59	$189.80	$202.50
Total $	$11,275	$357,207	$809,897	$3,230,387	$4,673,573	$8,882,550	$12,266,099	$15,060,479	$18,171,108	$21,824,451	$25,817,285
Total SREC Retired	22,621	38,093	50,327	60,536	74,406	89,743	103,725	115,323	127,037	139,581	151,960
Total Solar Compliance Costs	$4,912,768	$6,204,820	$7,456,334	$8,847,946	$10,481,010	$13,721,578	$17,084,780	$19,859,033	$22,949,752	$25,806,803	$29,011,333

Delmarva RPS Compliance Cost

RPS Compliance Cost						Projected					
Compliance Year	**2012/13**	**2013/14**	**2014/15**	**2015/16**	**2016/17**	**2017/18**	**2018/19**	**2019/20**	**2020/21**	**2021/22**	**2022/23**
Forecasted SOS Load Obligation * (GWh)	5,655	6,349	6,291	6,054	5,953	5,983	5,927	5,766	5,646	5,583	5,526
Preliminary RPS Req'mt	480,705	634,895	723,465	786,979	863,117	957,266	1,037,255	1,095,569	1,129,224	1,172,483	1,215,683
Total RPS Compliance											
Solar Complinace Cost											
SRECs	22,621	38,093	50,327	60,536	74,406	89,743	103,725	115,323	127,037	139,581	151,960
$/SREC	$217.18	$162.89	$148.16	$146.16	$140.86	$152.90	$164.71	$172.20	$180.65	$184.89	$190.91
$	$4,912,768	$6,204,820	$7,456,334	$8,847,946	$10,481,010	$13,721,578	$17,084,780	$19,859,033	$22,949,752	$25,806,803	$29,011,333
Contracted Wind Portfolio											
RECs	386,742	315,132	256,634	161,331	224,610	303,118	369,683	418,009	497,611	461,618	334,194
$/REC	$24.00	$24.00	$24.00	$24.00	$24.00	$24.00	$24.00	$24.00	$24.00	$25.00	$26.00
$	$9,281,808	$7,563,180	$6,159,216	$3,871,944	$5,390,640	$7,274,832	$8,872,392	$10,032,216	$11,942,664	$11,540,438	$8,689,044
Net Energy Payment $/MWH	$28.76	$32.03	$37.80	$57.35	$38.12	$24.85	$18.32	$15.38	$12.34	$12.87	$17.14
Net Energy Payment $	$11,122,547	$10,095,171	$9,701,992	$9,252,581	$8,562,135	$7,531,860	$6,773,501	$6,430,759	$6,142,510	$5,939,960	$5,728,778
Net REC Payment $/REC	$52.76	$56.03	$61.80	$81.35	$62.12	$48.85	$42.32	$39.38	$36.34	$37.87	$43.14
Net REC Payment $	$20,404,355	$17,658,350	$15,861,208	$13,124,525	$13,952,775	$14,806,692	$15,645,893	$16,462,975	$18,085,174	$17,480,398	$14,417,822
Bloom Fuel Cell Purchases	$72.90	$72.58	$69.44	$64.81	$61.34	$57.43	$60.86	$60.13	$59.58	$59.34	$59.10
ERECS	10,907	218,181	353,595	504,576	504,576	504,576	504,576	504,576	504,576	504,576	504,576
Net Cost $/EREC	$267.56	$97.15	$93.50	$64.20	$61.34	$57.43	$60.86	$60.13	$59.58	$59.34	$59.10
Net Cost $	$2,918,240	$21,195,529	$33,062,050	$32,393,846	$30,948,217	$28,979,131	$30,708,220	$30,338,643	$30,063,021	$29,939,889	$29,821,490
	$4,431,351	$22,120,681	$34,238,476	$32,393,846	$30,948,217	$28,979,131	$30,708,220	$30,338,643	$30,063,021	$29,939,889	$29,821,490
Existing REC Spot Purchases											
RECs	56,553	63,489	62,909	60,536	59,525	59,829	59,271	57,661	0	0	0
$/REC	$1.00	$1.00	$1.00	$1.00	$1.00	$1.00	$1.00	$1.00			
$	$56,553	$63,489	$62,909	$60,536	$59,525	$59,829	$59,271	$57,661	$0	$0	$0
New Spot REC Spot Purchases											
RECs	3,882	0	0	0	0	0	0	0	0	66,708	224,953
$/REC	$5.39	$5.52	$15.81	$26.61	$28.43	$30.34	$32.42	$34.59	$36.97	$39.45	$45.25
$	$20,908	$0	$0	$0	$0	$0	$0	$0	$0	$2,631,505	$10,179,726
Total RECs	480,705	634,895	723,465	786,979	863,117	957,266	1,037,255	1,095,569	1,129,224	1,172,483	1,215,683
Total Compliance Costs	$28,312,824	$45,122,188	$56,442,501	$54,426,852	$55,441,527	$57,567,230	$63,498,165	$66,718,313	$71,097,947	$75,858,595	$83,430,370

BLOOM FUEL CELL

Discount Factor	7.5%
Inflation Rate	2.5%

Year	2012/13	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23
Bloom Fuel Cell											
Capacity (MW)	5	20	30	30	30	30	30	30	30	30	30
Capacity Factor	96%	96%	96%	96%	96%	96%	96%	96%	96%	96%	96%
Energy (MWh)	39,385	166,230	252,288	252,288	252,288	252,288	252,288	252,288	252,288	252,288	252,288
Market Revenus $/millions	1.42	7.12	11.35	13.33	14.89	16.70	18.03	18.63	19.21	19.78	20.37
Bloom Heat Rate mmbtu/MWh	7.50	7.50	7.50	7.50	7.50	7.50	7.50	7.50	7.50	7.50	7.50
Total Gas Cost $/millions	1.14	6.64	10.27	10.89	11.54	10.85	14.41	14.76	15.16	15.67	16.18
Net Energy Revenue ($/millions)	$0.2811	$0.4740	$1.0737	$2.4421	$3.3523	$5.8547	$3.6197	$3.8684	$4.0495	$4.1157	$4.1827
Bloom Bill											
Bloom Price ($/MWh)	$166.87	$166.87	$166.87	$166.87	$166.87	$166.87	$166.87	$166.87	$166.87	$166.87	$166.87
Gross Payment $/millions	$6.57	$27.74	$42.10	$42.10	$42.10	$42.10	$42.10	$42.10	$42.10	$42.10	$42.10
Net Bloom Cost $/millions	$6.29	$27.26	$41.03	$39.66	$38.75	$36.24	$38.48	$38.23	$38.05	$37.98	$37.92
Net Bloom Cost $/MWH	160	164	163	157	154	144	153	152	151	151	150
RECs											
MWh to EREC factor	2	2	2	2	2	2	2	2	2	2	2
ERECs (Potential)	78,770	332,460	504,576	504,576	504,576	504,576	504,576	504,576	504,576	504,576	504,576
Maximum REC Reduction	284,417	401,531	533,313	610,229	665,907	729,186	807,694	874,259	922,585	1,002,187	1,032,902
MWh to ESREC factor	0.17	0.17	0.17	0.17	0.17	0.17	0.17	0.17	0.17	0.17	0.17
ESRECs (Potential)	6,564	27,705	42,048	42,048	42,048	42,048	42,048	42,048	42,048	42,048	42,048
Maximum Solar Obligation Reduction	25%	25%	25%	25%	25%	30%	30%	30%	30%	30%	30%
Maximum SREC Reduction	5,655	9,523	12,582	15,134	18,602	26,923	31,118	34,597	38,111	41,874	42,048
Bloom SREC Obligation Reduction	5,655	9,523	12,582	0	0	0	0	0	0	0	0
Bloom REC Obligation Reduction	10,907	218,181	353,595	504,576	504,576	504,576	504,576	504,576	504,576	504,576	504,576
Market Price Forecasts											
Capacity ($/MW/Day)	$0.00	$40.00	$40.00	$169.46	$232.56	$282.47	$314.58	$319.91	$328.51	$341.83	$355.70
Energy ($/MWh)	$36.02	$41.15	$43.32	$45.77	$49.33	$54.43	$58.36	$60.50	$62.47	$64.16	$65.90
Gas Price ($/mmbtu)	$3.85	$5.33	$5.43	$5.75	$6.10	$5.73	$7.62	$7.80	$8.01	$8.28	$8.55
$/REC	$2.63	$5.39	$5.52	$15.81	$26.61	$28.43	$30.34	$32.42	$34.59	$36.97	$39.45
$/SREC	$42.03	$120.20	$87.04	$103.06	$105.64	$137.39	$155.74	$166.44	$177.59	$189.80	$202.50

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Appendix 7
Generation Interconnection Transmission Planning*

* This was originally presented to the IRP Working group on June 11, 2012. Some material has been updated from the original .

Scott Razze, Manager, Interconnection
Jaclyn Cantler, Manager, Transmission Planning

Pepco Holdings, Inc

Agenda

PJM Interconnection Process

- Overview
- Recent Process Improvements

PJM Regional Transmission Expansion Planning Process

- Overview
- 2012 Process
- Process Changes

PJM Interconnection Process

PJM Interconnection Process

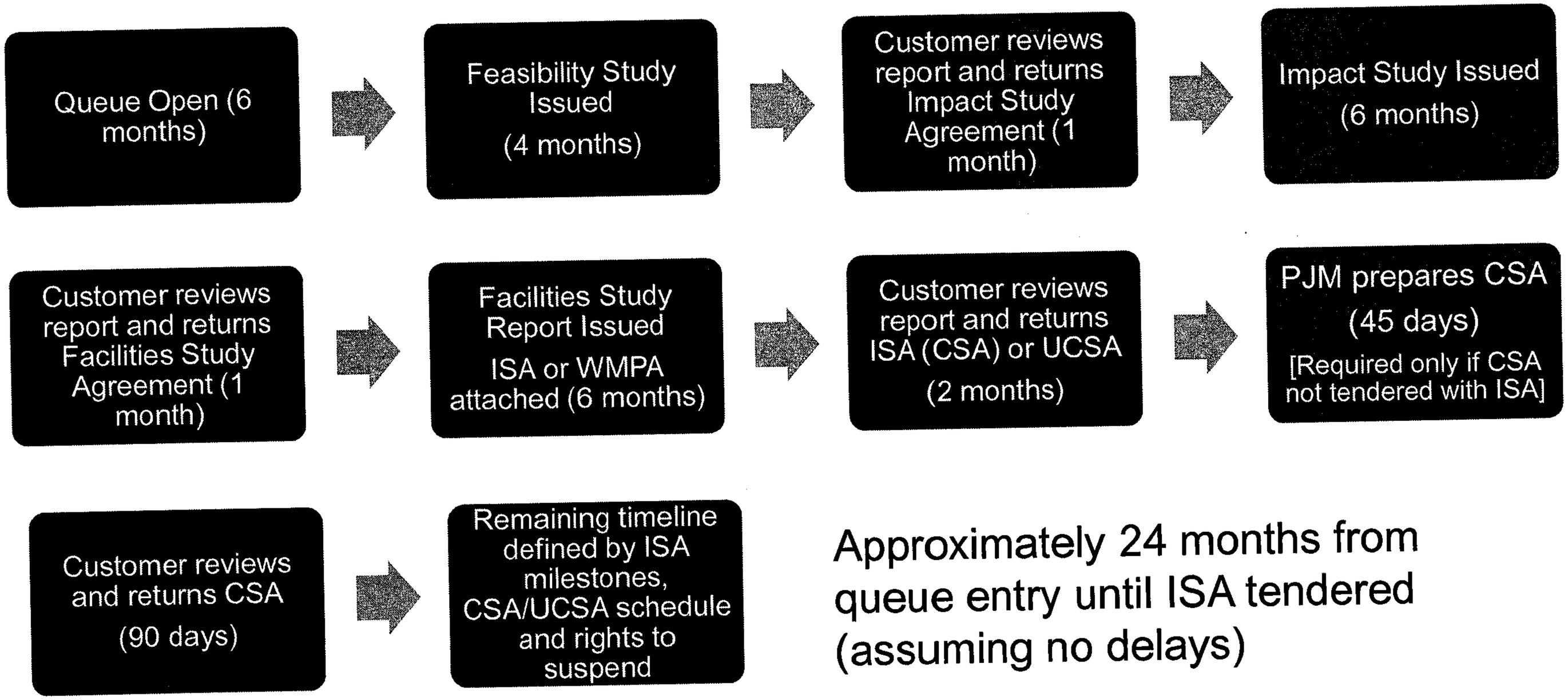
Interconnection Process Overview

Follows FERC Pro Forma Process

- Queues are "Open" for a 6 month period
  - Generation, Merchant Transmission, ARR, and Long-Term Firm Transmission Service project are received
- Rights are Based on Queue Position and Satisfaction of Milestone Requirements
  - Feasibility, System Impact, and Facilities Studies Identify Required Upgrades
  - Studies provide progressively more detail
  - Queue volume and drop-out rate require frequent re-studies
- Required Transmission Upgrades Based on Reliability Criteria – paid by Developer

PJM Interconnection Process

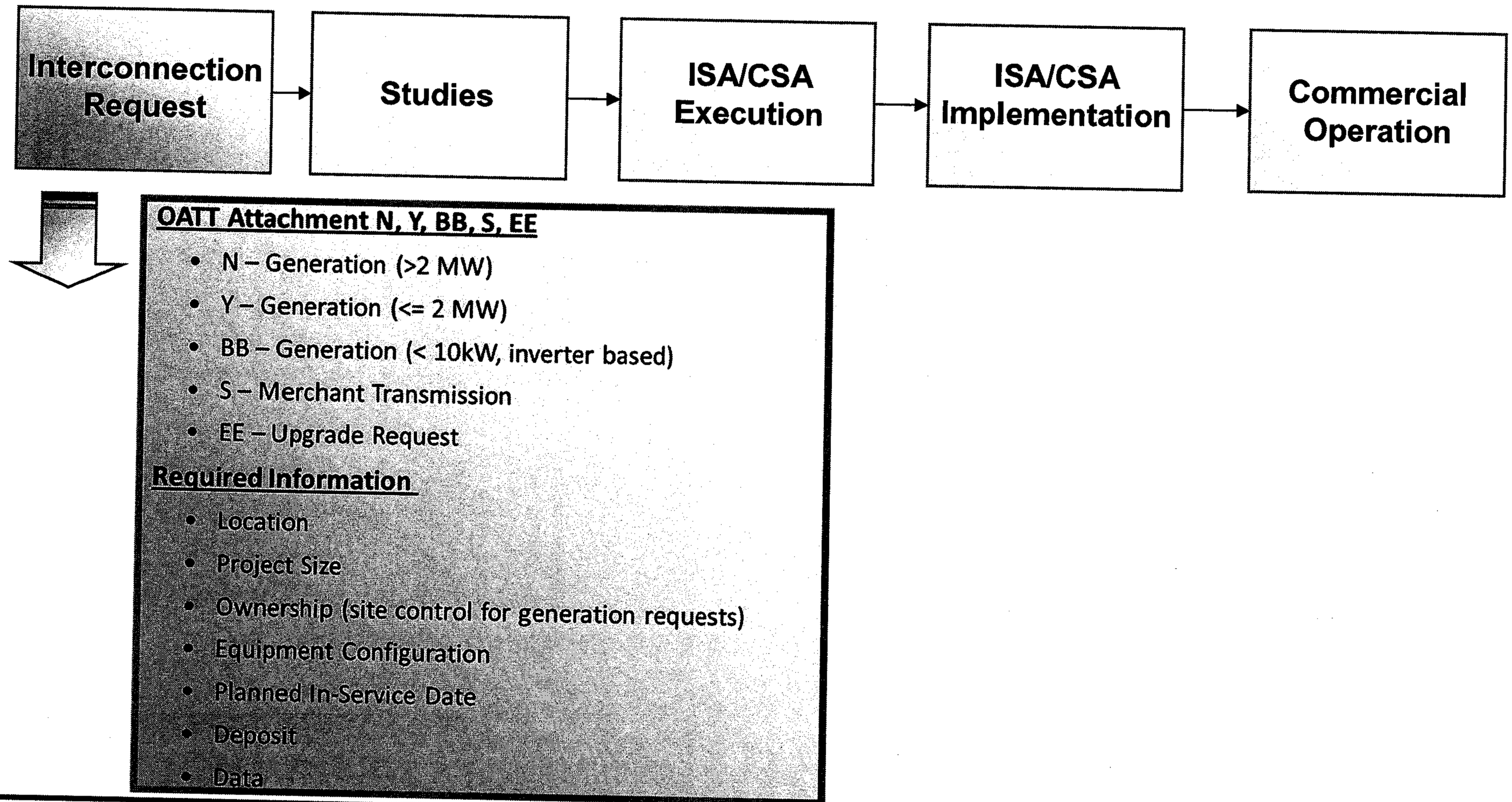
Time line Overview



Approximately 24 months from queue entry until ISA tendered (assuming no delays)

PJM Interconnection Process

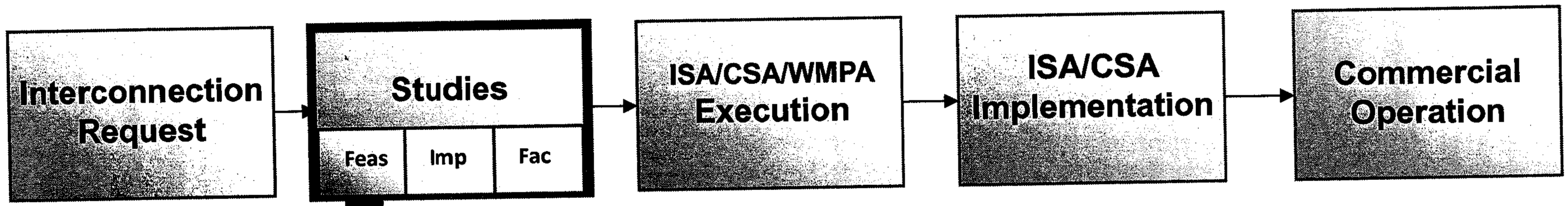
Queue Process Overview



www.pjm.com > Planning > RTEP Development > Expansion Planning Process

PJM Interconnection Process

Queue Process Overview

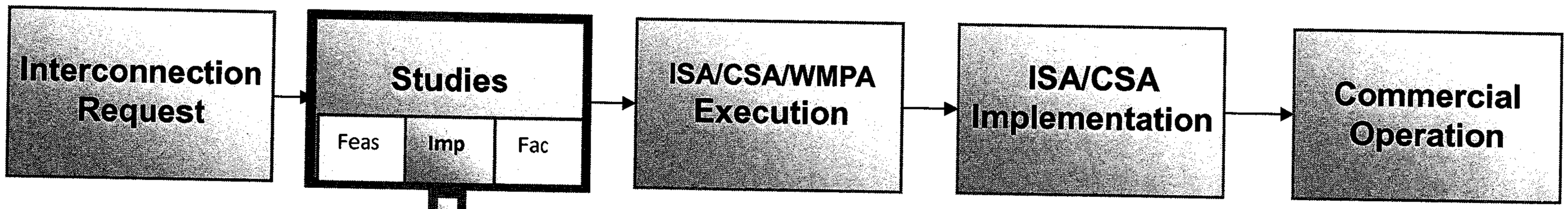


Feasibility Study (Long Term Firm - Initial Study)

- Required
  - Deposit based on request timing and MW/MVA size (later queue month = more money)
  - Site control for generation requests
  - In-service date within 7 years of entering queue (exceptions allowed)
- Study Completion
  - Target 4 months after close of queue
- Study By
  - PJM and TO (Contractor under direction of TO)
- Results
  - Attachment Facilities Needed for Interconnection
  - Identify Transmission Overloads and Required Upgrades (Costs and Construction Schedule Estimates for primary POI)
  - Identify overloads associated with secondary POI (no cost or schedule estimates)
  - Short Circuit Analysis

PJM Interconnection Process

Queue Process Overview

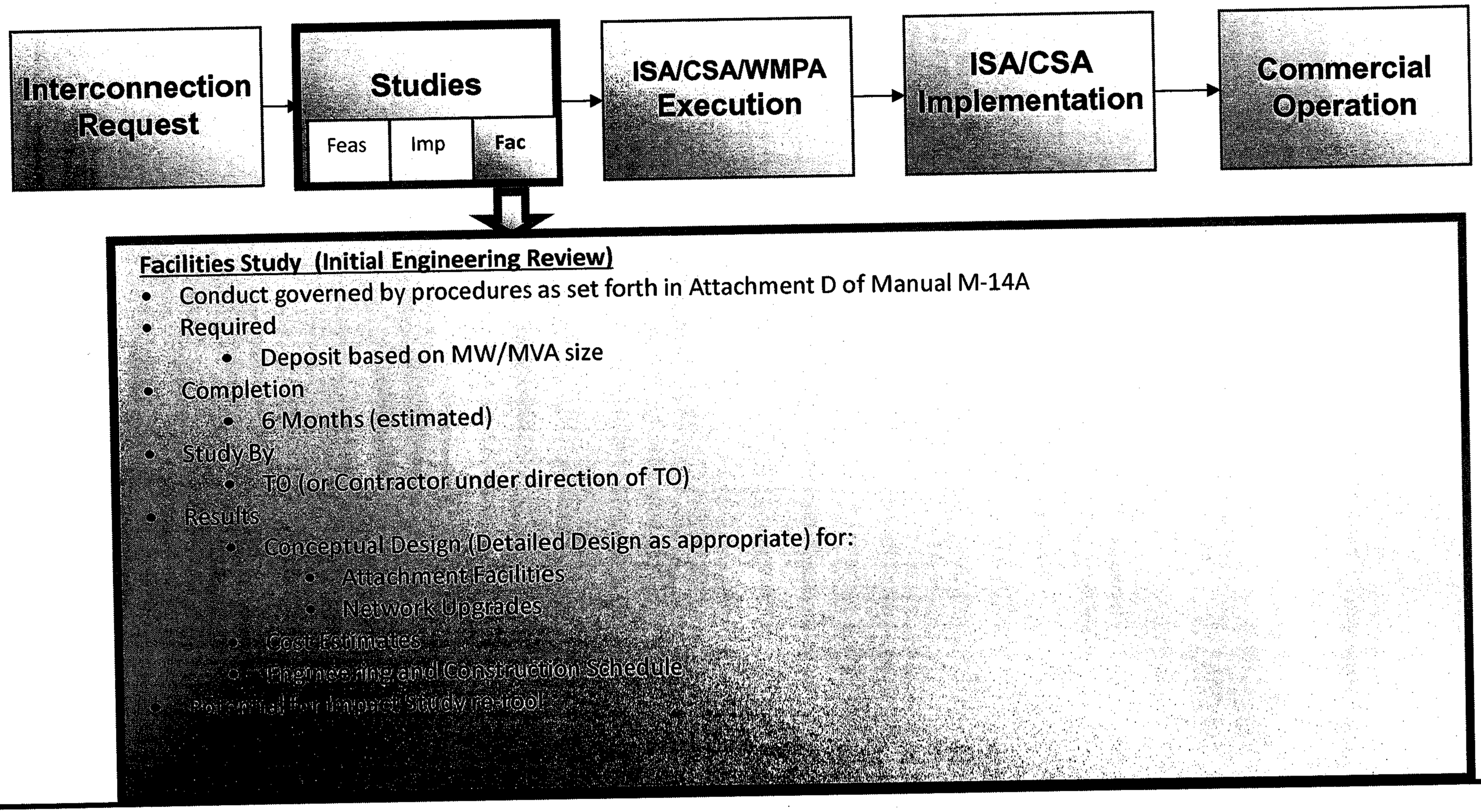


Impact Study (Start of analysis for Upgrade Requests)

- Required
  - Deposit based on MW/MVA size
  - Initial Air Permit Application (N/A for solar/wind projects)
  - Ownership (site control for Transmission Interconnection Requests)
- Study Completion
  - Target 11 months after close of queue
- Study By
  - PJM and TO (Contractor under direction of TO)
- Results
  - Gen & Load Deliverability Analysis
  - Stability Analysis
  - Short Circuit Analysis
  - Cost Estimates and Allocations

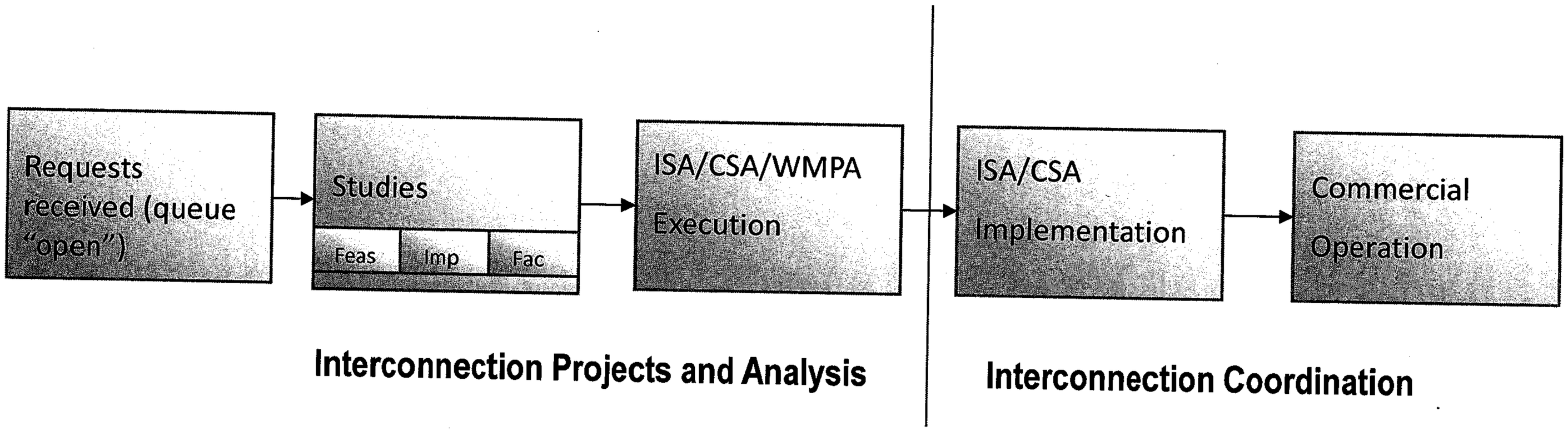
PJM Interconnection Process

Queue Process Overview



PJM Interconnection Process

Interconnection Process Overview



- Projects may drop out of the queue at any time
- Project size may be reduced but not increased
- Projects are withdrawn from the queue if they miss milestones or financial obligations

PJM Interconnection Process

Interconnection Process Overview

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pjm > About PJM > Services > Planning > eTools > Markets > Committees & Groups > Documents

> search
> advanced search

> Home > Planning > Queues, Retirements and Retools > Generation Interconnection Queues > Generation Queues: Active

Generation Queues: Active

- > Queues, Retirements & Retools
- > Generation Interconnection Queues
- > Merchant Transmission Queues
- > ARR Upgrade Queues
- > Long-Term Firm TSRs
- > Generation Retirements
- > Retool Results
- > Wholesale Market Participation Agreements

= In Progress
= Document Posted
= Interim Study
= Not Required

= Under Study
= Under Construction
= Partially In-Service
= In-Service
= Suspended

= Natural Gas
= Methane
= Hydro
= Solar
= Oil
= Other

= Nuclear
= Wind
= Diesel
= Biomass
= Coal
= Wood

MW - Total Energy output of facility
MWC - Capacity component of total energy output of facility

To access the studies please click on the circle icons below.

Note: In order to properly use this page you must have ActiveX enabled for your browser. Click **here** for instructions on how to enable ActiveX for Internet Explorer 6.0 & 7.0.

Filter By: Fuel Type: All or Status: All or State: All

A B C D E F G H I J K L M N O P Q R S T U All (baseline reports) XML

www.pjm.com > Planning > Generation Interconnection

PJM Interconnection Process
Recent Improvements

Interconnection Process Senior Task Force Goals

- Timely completion of studies
- Move projects to an ISA more quickly
- Reduce number of re-tools
- Provide greater certainty in results
- Manage changes associated with projects
- Manage process workload

PJM Interconnection Process

Recent Improvements

IPSTF Queue Changes

- 6 Month Queue Cycle
- Sliding Queues
- Alternate Queue
- Rule Changes

PJM Interconnection Process
Recent Improvements

6 Month Queue Cycle

- Take Requests in 6-Month Queues
  - November 1 - April 30
  - May 1 - October 31
- Staggered Deposit Structure
  - First 4 months (lowest), Fifth month, and Sixth month (highest)
- 3-Month Feasibility Studies
  - December 1 – February 28 (29)
  - June 1 – August 31
  - Month following queue close allowed for scoping meetings and case building
  - Month following completion of study for customer response
- 4-Month System Impact Studies
  - June 1 – October 30
  - December 1 – March 30 (or 31)

PJM Interconnection Process

Recent Improvements

Sliding Queues

- Allow Projects which do not make Significant Changes to move forward
  - Require Projects which make large changes to undergo restudy
  - Projects may slide a maximum of 2 times (in aggregate)
- Retain non-Material Modification provisions prior to commencement of Feasibility Study
  - Allows 60% reduction without affect to current Queue Position

PJM Interconnection Process
Recent Improvements

Sliding Queues

- Following Feasibility Study
  - Allows 15% reduction with no queue slide
  - Allows 60% reduction with slide to next queue and new Feasibility Study
    - Requested change cannot be deemed to be a material modification
- Following System Impact Study
  - Allows 5% or 10 MW reduction with no queue slide
  - Allows 20% or 50 MW reduction with slide to next queue and new System Impact Study
    - Requested change cannot be deemed to be a material modification

PJM Interconnection Process

Recent Improvements

Alternate Queue

- Establish Alternate Queue for Projects < 20MW
  - Projects Enter the Interconnection Queue as they do today
  - Project may be assigned to the Alternate Queue based on Established Screening Criteria
    - Cannot be connected to a PJM monitored transmission facility as defined in PJM Manual M-03
    - Cannot be an uprate or addition to an existing facility
    - Distribution Factor (DFAX) for any PJM monitored transmission facility may not exceed 5%
    - May not connect to the same Point of Interconnection as any other project
    - Aggregate impact of all projects connecting on any individual radial connection to a PJM monitored transmission facility shall not exceed 1% of line rating

PJM Interconnection Process
Recent Improvements

Alternate Queue

- Study Phase Highlights
  - Eliminate PJM Deliverability, Short Circuit and Stability Testing for Projects that Qualify
  - TO Identification of Attachment Facilities and any lower voltage impacts
    - Combine Feasibility and Impact Studies, where applicable
    - Facility Study – no change to existing process
  - Projects meeting the screening criteria could be studied outside of the process used for greater than 20 MW projects
  - Phases of the process will adhere to the timeframes and coordination requirements as are in place for the existing process (Feasibility, Impact study)
- Remaining Process is Unchanged (following the Study Phase)

PJM Interconnection Process

Recent Improvements

Rule Changes

- Impact Study Data
  - Data and any supporting information must be received with or before impact study agreement is returned
    - If data and information is not received then 10 days to cure deficiency. Failure to cure deficiency will result in termination and withdrawal of request
- Deactivation – CIR utilization
  - Identification of intent to utilize Deactivation CIRs must be received with the execution of the Impact Study Agreement
    - Requests to utilize CIRs at later date will require withdrawal of project from queue and resubmission of interconnection request

PJM Interconnection Process
Recent Improvements

Rule Changes

- Refundable Deposit Structure
  - Attachment N under subpart G of Tariff (Units 2-20 MWs)
    - Change to a refundable deposit of $10,000 for months one through four, $12,000 for the fifth month, and $15,000 for the sixth month
  - Attachment Y (Units 2MWs or Less)
    - Change to a refundable deposit of $2,000 for months one through four, $3,000 for the fifth month, and $5,000 for the sixth month
- Change the "Suspension" Provision
  - Reduce time allowed for Suspension under Construction Agreements from 3 years to 1 year (where the project has effects on other projects)
  - Retain 3 year allowance for Suspension if the project under suspension does not impact material modification

PJM Regional Transmission Expansion Planning Process

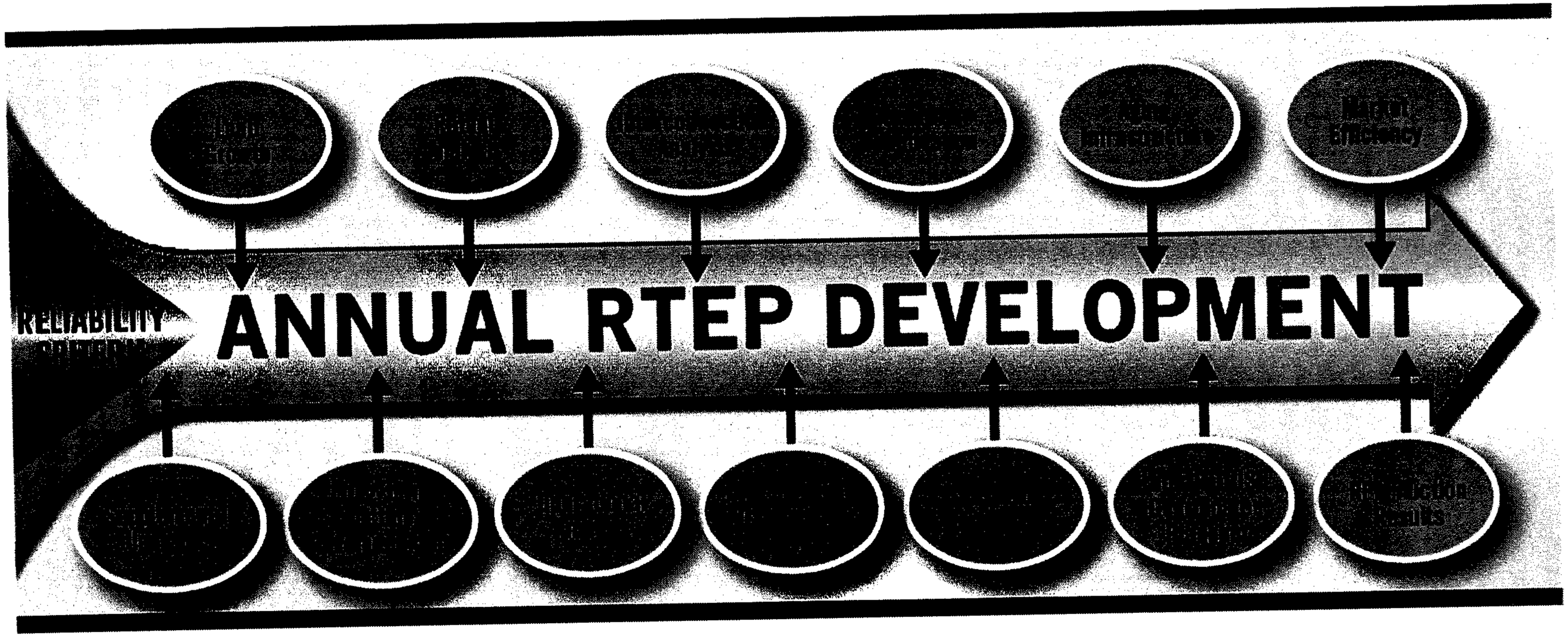
PJM RTEP Process

General Info

- Open process which began in 1997 with the first plan issued in 2000
- Written protocol for the PJM Planning Process outlined in Schedule 6 of OA and Manual 14-B
- 15 year planning horizon to ensure necessary upgrades
- Adherence to NERC reliability standards
- Transmission investments authorized under PJM's RTEP since 2000 total about $23.4 billion

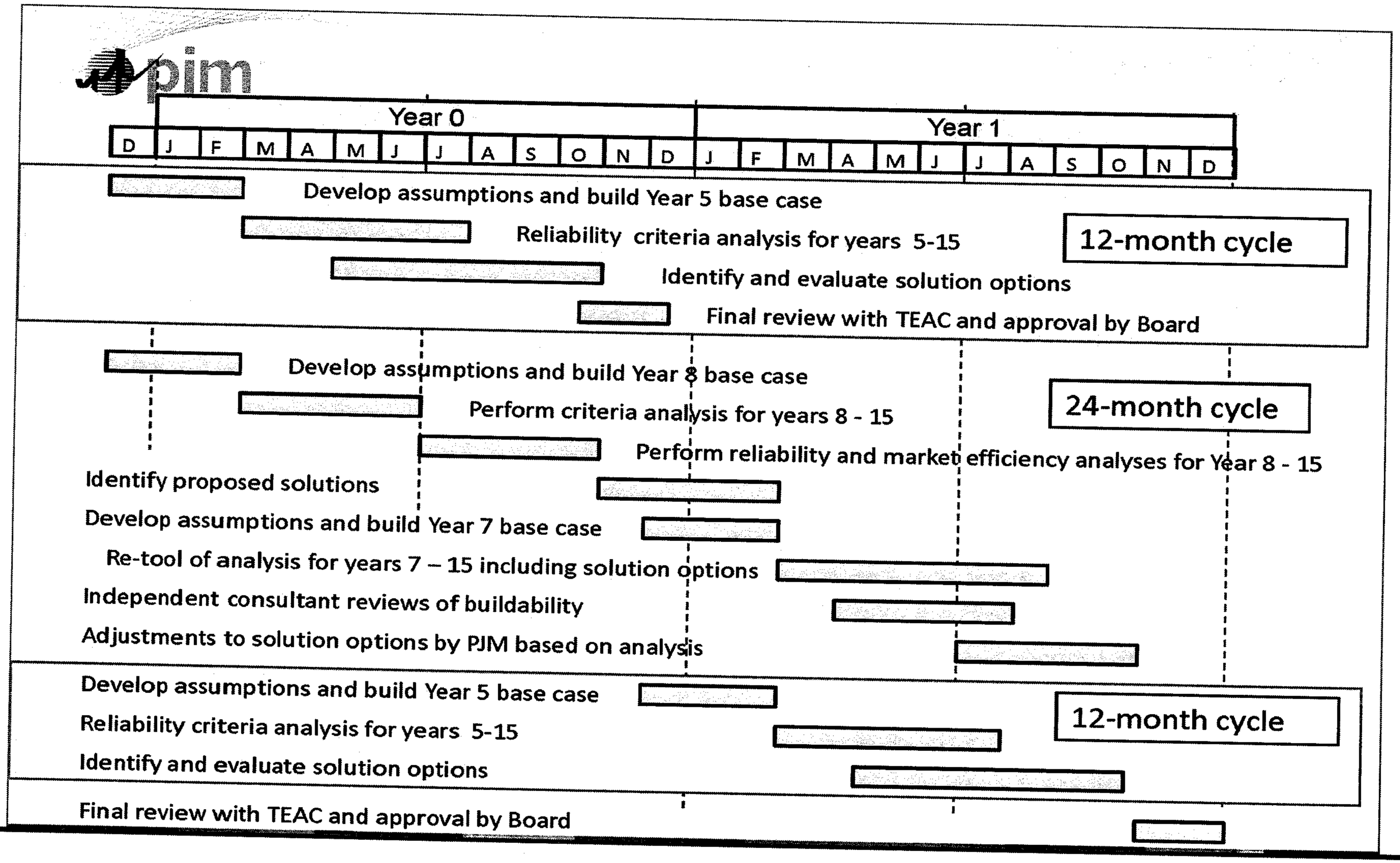
PJM RTEP Process

RTEP Development Drivers



PJM RTEP Process

RTEP Timeline



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PJM RTEP Process

2012 RTEP Process

- Status
  - 2017 summer case reliability analysis in progress, nearly complete
  - 2017 light load and 2020 cases working
- Key Assumptions
  - PJM Load Forecast issued in January of 2012, LM for load deliverability test
  - PJM topology based on the 2016 RTEP case that was used in the 2011 RTEP
    - Include all PJM Board approved upgrades through the December 6, 2011 PJM Board of
  - Generation – existing, generation with signed ISA and associated upgrades, generation with a signed FSA and associated upgrades

PJM RTEP Process

2012 Scenario Analysis

- Renewable Portfolio Standards (RPS)
  - 0 GW offshore
  - 10 GW offshore – study, develop transmission overlay
  - Source a portion of RPS from neighboring entities
- High load growth scenario
- At-risk generation
  - RPM
  - Regulatory

PJM RTEP Process

2012 Scenario Analysis - RPS

- RPS scenario analyses were completed as part of the 2011 RTEP
  - Identified RPS requirements
  - Developed sourcing strategy to meet all PJM state's RPS requirements with resources located in PJM
    - 4 GW Offshore with 38 GW Onshore
    - 20 GW Offshore with 28 GW Onshore
    - Both scenarios included solar carve out consistent with state RPS
- Developed transmission overlays based on combination of reliability analysis and production cost simulations

PJM RTEP Process

2012 Scenario Analysis - RPS

- 2012 RTEP RPS scenario analyses will build on the work completed as part of the 2011 RTEP
  - Utilize the same source for RPS requirements as 2011 RTEP – updated to include latest RPS policies
  - Utilize similar analytic approach as 2011 RTEP
    - Production Cost Analysis
    - Reliability Analysis
      - Generation Deliverability, Common Mode
- 2012 RTEP RPS Scenario Sourcing Strategy
  - 7 GW Offshore
  - Low GW Offshore
  - 40% External Resource Strategy

PJM RTEP Process

2012 Scenario Analysis – High Load

- Develop a high growth load forecast based on a more optimistic economic projection
- Update the 2017 RTEP base case with a high growth load forecast
- Perform reliability analyses using the updated base cases
  - Generation Deliverability
  - Load Deliverability (with initial focus on historically constrained areas)
  - 15 year analyses

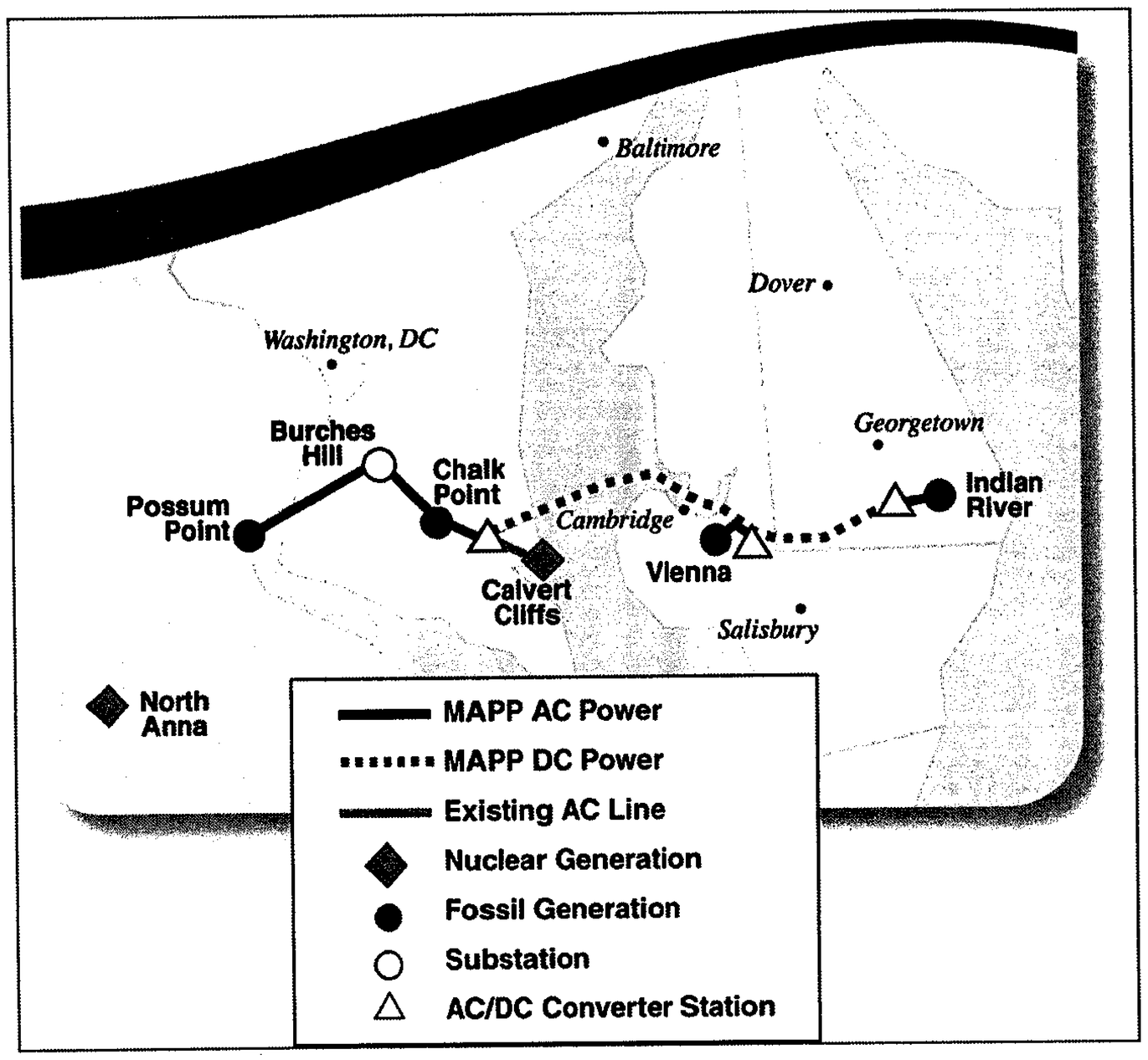
PJM RTEP Process

2012 Scenario Analysis – At Risk Generation

- 2012 RTEP "At-Risk" scenario analyses will build on the work completed in 2011
- Utilize "Coal Capacity at Risk for Retirement in PJM" report
  - http://pjm.com/documents/~/media/documents/reports/20110826-coal-capacity-at-risk-for-retirement.ashx
- Perform reliability analysis on potential impact
  - Load Deliverability analysis of select LDAs (MAAC, EMAAC, SWMAAC, Others)
  - Area CETO will be increased based on the amount of "at-risk" generation located within the area
  - Additional analyses will be done focusing on potential regional issues

PJM RTEP Process

MAPP Status



- On 8/24/12 PJM Board of Managers removed the PATH and MAPP projects from the RTEP stating that reliability drivers necessitating these projects through the 15 year horizon no longer exist
- PJM referenced the following with respect to their decision:
  - Decreasing customer load growth
  - Increasing participation in demand response programs
  - Recent commitment of new generating capacity in eastern PJM

PJM RTEP Process

Planning Process Changes

- FERC Order 1000 is requiring changes to the PJM Planning process
- PJM has been working through the RPPTF to develop revisions to the process. PJM's October Compliance Filing was submitted to FERC on 10/25 and addressed the majority of the below requirements, aside from those otherwise noted
  - Cost Allocation (Transmission Owners)
  - ROFR
  - Planning for Public Policy
  - Regional Planning Process
  - Interregional Planning – *April 2013*
  - PJM will also review multi-driver projects

Delmarva Power & Light

Appendix 8

Air Quality and Health Impacts Assessment for Delmarva Power & Light's 2012 Integrated Resource Plan

29 November 2012

Prepared for
Delmarva Power & Light.
401 Eagle Run Road
Newark, DE 19702

Prepared by
ICF International
101 Lucas Valley Road, Suite 260
San Rafael, CA 94903
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12-055

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Executive Summary

The Delmarva Power & Light (Delmarva) Integrated Resource Plan (IRP) requires a comprehensive assessment of the environmental impacts associated with energy production sources, including how these impacts are expected to change over time. This report summarizes the application of air quality modeling tools to examine the air quality impacts and health-related costs and benefits associated with expected changes in emissions, including emissions from power generation sources, between 2013 and 2022.

In this assessment, the Community Multiscale Air Quality (CMAQ) model was used to quantify the changes in air quality and mercury deposition between 2013 and 2022 and the contribution of emissions from the power generation sector to pollutant concentrations and deposition for those years. The Benefits Mapping and Analysis Program (BenMAP) was used to assess the health impacts and monetized health-related impacts of the simulated changes in ozone and fine particulate matter ($PM_{2.5}$) air quality between 2013 and 2022 as well as the overall health impacts and monetized health-related impacts associated with emissions from the power generation sector, specifically electric generating units (EGUs). Oxides of nitrogen (NO_x) are important precursors to ozone formation. NO_x and sulfur dioxide (SO_2) contribute to the formation of secondary aerosols. Thus the assessment of the health effects and benefits for ozone and $PM_{2.5}$ addresses the effects of changes in NO_x and SO_2 emissions. More qualitative methods were used to estimate the health and economic effects related to mercury deposition and also greenhouse gases. The analysis focused on the Mid-Atlantic states and the State of Delaware. The modeling analysis region is defined by a 4-km resolution grid encompassing Delaware and portions of other Mid-Atlantic and neighboring states.

The core CMAQ simulations include a 2013 Base Case simulation and a 2022 Reference Case simulation. Two additional simulations were conducted in which the CMAQ Particle and Precursor Tagging Methodology (CMAQ/PPTM) was used to examine the contributions of emissions from the major source categories (comprising point [EGU and non-EGU], on-road motor vehicle, non-road, and area sources) to simulated $PM_{2.5}$ concentrations and specifically to quantify the contributions from EGU sources.

EGU emissions for use in the air quality modeling were estimated using ICF's Integrated Planning Model (IPM®) and emissions for all other source sectors were obtained from emission estimates prepared by the U.S. Environmental Protection Agency (EPA). For most regions, NO_x and SO_2 emissions (overall and from EGU sources) are lower for 2022, compared to 2013. One exception is that there is an estimated increase in NO_x emissions for EGUs for the region encompassed by the 4-km grid, reflecting the insertion of additional generation units due to future power demands in some portion of this domain. The EGU emissions from IPM for both 2013 and 2022 reflect estimates of future economic and population growth and corresponding electric generation demand, any planned shutdowns of existing facilities, inclusion of new facilities to meet future generation demands, and application of emission controls on existing facilities associated with applicable state and national rules.

The CMAQ modeling results show both increases and decreases in pollutant concentrations for 2022, compared to 2013. The decreases are fairly widespread, reflecting emissions reductions

for a number of source categories throughout the domain, and are generally greater in magnitude than the increases. The health effects assessment indicates that air quality improvements between 2013 and 2022 are expected to provide significant positive health impacts for both the greater Mid-Atlantic region and the State of Delaware. Estimated monetized health-related benefits range from 13 to 29 billion dollars for the region encompassed by the 4-km grid and from approximately 1 to 2 billion dollars for the State of Delaware.

The CMAQ/PPTM was used to examine the contributions of emissions from the major source categories to simulated $PM_{2.5}$ concentrations and specifically to quantify the contributions from EGU sources. The tagging results indicate that emissions from EGU sources account for approximately 13 percent of the simulated annual average $PM_{2.5}$ concentration for both 2013 and 2022. The EGU contribution from sources located in Delaware is negligible. Monetized health-related costs associated with EGU emissions for 2022 (based on their contribution to simulated $PM_{2.5}$ concentrations for the 2022 Reference Case simulation) range from 36 to 90 billion dollars for the 4-km grid and from 2.5 to 6.8 billion dollars for Delaware.

In summary, the air quality and health effects modeling results indicate improvements in air quality between 2013 and 2022 due to expected changes in emissions from all sources, including EGUs. The simulated improvements in air quality result in a lower incidence of adverse health effects and substantial monetized health-effects benefits for Delaware and the surrounding region.

1. Introduction

This report summarizes the application of air quality modeling tools to examine the air quality impacts and health-related costs and benefits associated with expected changes in emissions, including power generation sources, between 2013 and 2022.

1.1. Background and Objectives

Delmarva Power & Light (Delmarva)'s Integrated Resource Plan (IRP) requires that a comprehensive environmental externalities assessment be conducted on the utilization of specific methods of energy production. This assessment is intended to examine the environmental impacts and benefits associated with energy production sources and to appropriately monetize these benefits or costs for policy decision makers. Included in this IRP is an evaluation of the costs and benefits of expected changes in emissions, including emissions from power generation sources, between 2013 and 2022.

As part of the IRP, an analysis of the environmental costs and benefits, specifically related to air quality, provides a means for assessing the effects of changes in power generation sources over time. The analysis summarized herein was conducted using an air quality modeling system from which information was derived and used as input to a health benefits model to calculate and evaluate health-related costs and benefits.

The core modeling analysis includes a 2010/2013 Base Case simulation and a 2020/2022 Reference Case simulation. The 2010/2013 emissions for the Base Case simulation are comprised of 2013 emission estimates for electric generating unit (EGU) sources and 2010 emission estimates for all other sources; this combination will be referred to throughout the remainder of this document as 2013. The 2020/2022 emissions for the Reference Case simulation are comprised of 2022 emission estimates for EGU sources and 2020 emission estimates for all other sources; this combination will be referred to throughout the remainder of this document as 2022. The emissions for the EGU sources were estimated using ICF International, Inc. (ICF)'s Integrated Planning Model (IPM®). Pollutants of interest in this analysis are oxides of nitrogen (NO_x), sulfur dioxide (SO_2), ozone, fine particulate matter ($PM_{2.5}$), and mercury. The Community Multiscale Air Quality (CMAQ) model, which was developed by the U.S. Environmental Protection Agency (EPA), was used to simulate ozone and $PM_{2.5}$ concentrations and airborne mercury deposition over the approximate ten-year planning horizon. Two additional simulations were conducted in which the Particle and Precursor Tagging Methodology (PPTM), a feature of the CMAQ model, was used to quantify the contribution of emissions from power generation facilities to the simulated concentrations and deposition amounts.

For ozone and $PM_{2.5}$, the Benefits Mapping and Analysis Program (BenMAP) (Abt and Associates, 2008), which was also developed by the U.S. EPA, was used to assess the health impacts and monetized health-related impacts of the simulated changes in ozone and $PM_{2.5}$ air quality between 2013 and 2022 as well as the overall health impacts and monetized health-related impacts associated with emissions from the power generation sector, specifically EGUs. For mercury, qualitative methods were used to estimate the health and economic impacts. For greenhouse gases (CO_2), estimates of costs/benefits were estimated following methodologies

outlined in the 2009 National Academy of Sciences (NAS) report related to the costs of energy production and use.

1.2. Overview of the Methodology

This regional-scale photochemical air quality modeling and health risk assessment was conducted to examine and quantify the air quality and health-related benefits associated with alternative energy generation. Key components of this assessment included:

- Emission inventory preparation
- Air quality model application
- Health impact/benefit assessment

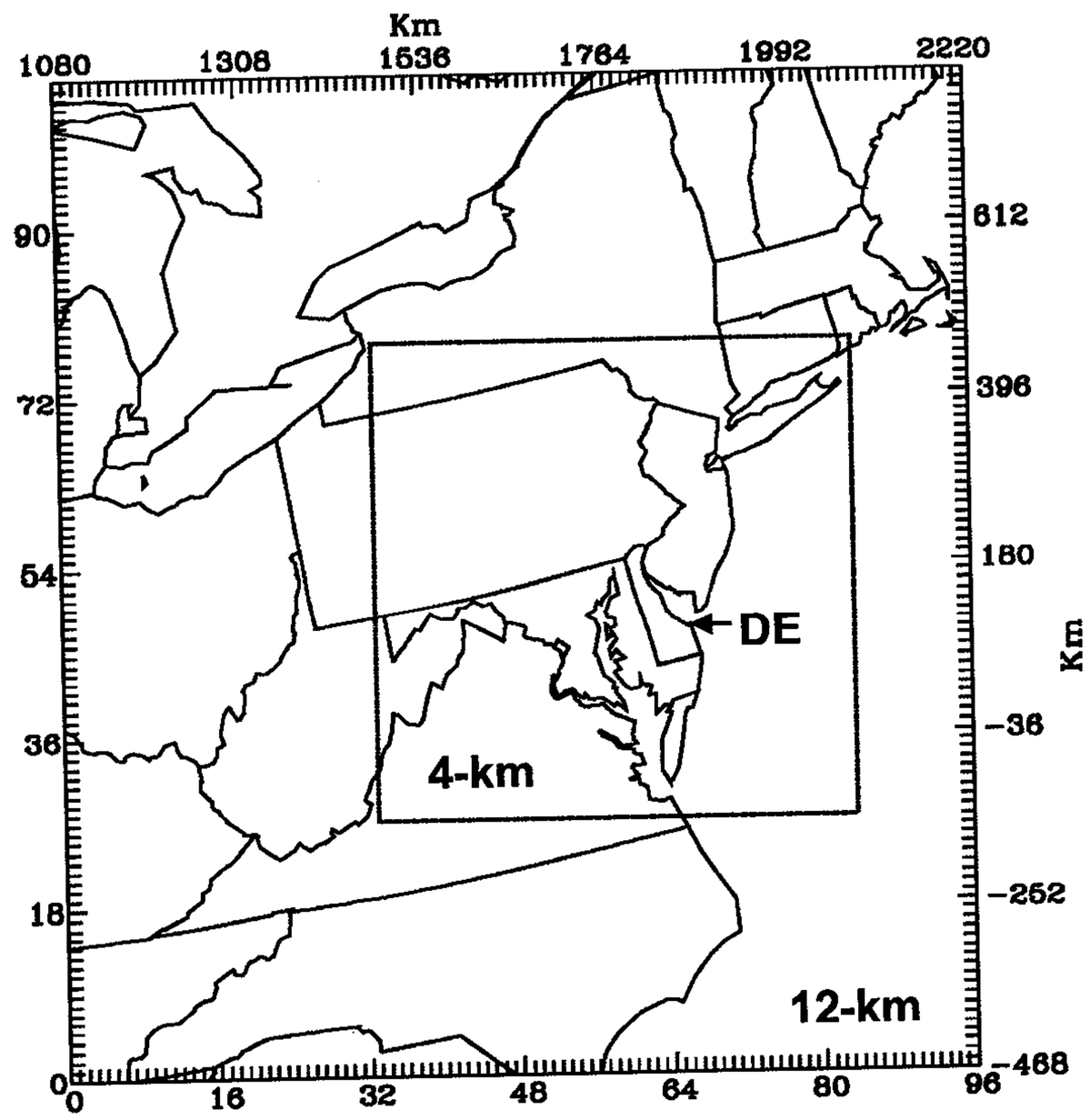
The primary tools that were used for this assessment include:

- Sparse-Matrix Operator Kernel Emissions (SMOKE) processing tool (version 2.5) for the preparation of model-ready emissions;
- Community Multiscale Air Quality (CMAQ) model (version 4.6) for quantifying the air quality changes for the different power generation alternatives; and
- Environmental Benefits Mapping and Analysis Program (BenMAP) tool (version 4.0.43) to assess the health-related impacts of the simulated changes in air quality.

These tools are widely used for conducting air quality and health effects analysis.

The CMAQ modeling domain is depicted in Figure 1-1. It consists of an outer, regional-scale grid that covers the Mid-Atlantic region and portions of some surrounding states and an inner, high-resolution grid that is focused on Delaware. The horizontal resolution is 12 kilometers (km) for the outer grid and 4 km for the inner grid. Air quality impacts and health effects were evaluated for the 4-km grid and specifically for Delaware.

Figure 1-1. CMAQ Modeling Domain for the 2012 IRP Analysis; Horizontal Grid Spacing is 12 km for the Outer Grid and 4 km for the Inner Grid.



Boundary conditions for the 12-km domain were derived from corresponding national-scale simulations run for a 36-km resolution continental U.S. (CONUS) modeling domain.

The CMAQ model was applied for an annual simulation period, using meteorological inputs for a base year of 2001. The meteorological inputs were originally prepared by EPA and have been used for a number of past and recent air quality modeling studies. This simulation period is characterized by typical meteorological conditions for the area of interest, with normal temperatures and precipitation amounts during the summer months (compared to 40 years of climatological data), but less than normal precipitation during the fall period. For these reasons, it was also selected for use in the Virginia Mercury Study (Douglas et al. 2008a) and the 2010 IRP (ICF, 2010).

The future year (2022) was chosen for the analysis to meet the regulatory requirements of the IRP ten-year planning horizon and to realize the environmental impacts and benefits associated with the expected changes in emissions from any alternative energy sources. Emissions for 2022, for all but the EGU sources, were obtained from the latest projected 2020 national-scale emission inventory released by EPA. EGU emissions were estimated using the IPM® (ICF, 2012). The 2022 IPM EGU emissions reflect estimates of future economic and population growth and corresponding electric generation demand, any planned shutdowns of existing

facilities, inclusion of new facilities to meet future generation demands, and application of emission controls on existing facilities associated with applicable state and national rules The resulting model-ready inventories contain emissions for all criteria pollutants (as required for photochemical modeling) for ten source category sectors, including on-road mobile sources, non-road mobile sources (construction equipment, locomotives, ships, aircraft, etc.), EGU point sources, non-EGU point sources, area sources, biogenic sources, and others.

For both the 2013 Base Case and 2022 Reference Case simulations, the CMAQ/PPTM tool was used to quantify the contribution of emissions from power generation facilities to the simulated concentrations. Tags were applied to the EGU facilities in Delaware and also to EGU facilities in the remainder of the modeling domain.

The simulation results for 2013 and 2022 were used to examine the changes in air quality with time and quantify the benefits associated with the expected air quality changes between 2013 and 2022. Following the application of CMAQ, the outputs were processed for input to the BenMAP health effects analysis tool. For both 2013 and 2022, BenMAP was used to quantify the health-related impacts associated with expected improvements in air quality between 2013 and 2022. BenMAP was also used to estimate the health-related impacts and monetized health-related costs associated with power generation in the 4-km grid and Delaware. The BenMAP tool includes health impact functions, which relate a change in the concentration of a pollutant with a change in the incidence of a health endpoint. BenMAP also calculates the economic value of health impacts. For this study, the health effects analysis considered the effects of ozone and $PM_{2.5}$.

For mercury, qualitative methods were used to estimate the health and economic benefits. The benefits assessment for mercury deposition was based on information from a comprehensive study of the benefits of controlling mercury emissions from coal fired power plants (NESCAUM, 2005). Specifically, estimates of monetized benefits per change in mercury deposition for the Mid-Atlantic states from the NESCAUM report were used along with the CMAQ modeling results from this present study to estimate mercury benefits for 2020.

1.3. Scenarios

Four annual CMAQ simulations comprise this study. These include the 2013 Base Case simulations (with and without PPTM) and the 2022 Reference Case simulations (with and without PPTM).

2. Emission Inventory Preparation

This section summarizes the data, methods, and procedures followed in preparing modeling emission inventories for use in the air quality modeling exercise supporting the environmental benefits and health impacts analysis for the 2012 IRP. The analysis examined the expected changes in criteria pollutant emissions from a number of source categories (i.e., electric generation units (EGUs), other industrial point sources, non-point sources (also referred to as area sources), non-road sources, and on-road motor vehicle sources), comparing base year estimates with future year estimates. Specification of emissions for all EGUs was accomplished using the IPM (ICF, 2012), which included base year (Base Case) estimates for 2013 and future year (Reference Case) estimates for 2022. The EGU emissions changes were incorporated into national emission inventories originally developed by EPA for 2010 and 2020, respectively. The impacts for the base (2010/2013) and future year (2020/2022) scenarios were assessed using EPA's CMAQ model (Version 4.6), containing the Carbon Bond 2005 (CB-05) chemical mechanism.

2.1. Emissions Data and Methods

The CMAQ model requires, as input, hourly, gridded criteria pollutant emissions of both anthropogenic and biogenic sources that have been spatially allocated to the appropriate grid cells and chemically speciated for the applicable chemical mechanism used in the model. The modeling inventories were processed and prepared for CMAQ using EPA's Sparse-Matrix Operator Kernel Emissions (SMOKE) software (Version 2.5). The emissions inventories prepared for the IRP modeling analysis were derived, in part, from information developed by EPA for 2010 and 2020 based on the 2002 modeling platform database (EPA, 2008). The SMOKE input files include the following categories:

- Area fugitive dust
- Agricultural
- Aircraft, locomotive and commercial marine vessels
- Average fires
- Non-point (area)
- Non-road
- On-road
- IPM point
- Non-IPM point.

The SMOKE input files for 2010 and 2020 were obtained from the following EPA ftp site: ftp://ftp.epa.gov/EmisInventory/2002v3CAP. Input information was provided in these files for the 50 states and Washington D.C. for a national-scale modeling domain. New biogenic emissions

for the 12- and 4-km grids used in this analysis were generated using the BEIS3.14 model with BELD3 land use and 2001 meteorological data. The gridded surrogate data for the 12-km grid required for SMOKE processing were obtained from EPA, while the surrogates for the 4-km grid required for SMOKE processing were prepared using the Spatial Allocator in the Surrogate Tool and various shape file catalog files provided by EPA.

In addition to these files, emissions for the portions of Canada, Mexico, and offshore areas were obtained for the years 2010 and 2020 from EPA. The modeling inventories include the following pollutants: volatile organic compounds (VOC), oxides of nitrogen (NO_x), carbon monoxide (CO), sulfur dioxide (SO_2), fine particulates ($PM_{2.5}$), coarse particulates (PM_{10}), mercury (Hg), and ammonia (NH_3). The 2010/2013 and 2020/2022 anthropogenic mercury emissions are based on the EPA Clear Skies database which included files for IPM point source, non-IPM point source, and non-point (area source) sectors (EPA, 2003).

2.2. Emissions Processing Procedures

As noted above, SMOKE, version 2.5 was utilized to process the emissions and prepare CMAQ-ready inputs for the 2010/2013 Base Case and the 2020/2022 Reference Case scenarios using source sector files provided by EPA and updated EGU emissions provided by IPM. Emission files were prepared for the 12- and 4-km resolution grids used in the modeling analysis, and included a) processing of all source sectors using various SMOKE programs and inputs, b) substitution of the IPM EGU emissions into the point source file, and c) review and quality assurance checks.

Once the IPM results were obtained, the modified files were processed by SMOKE with the other source category input files to prepare model-ready inputs for CMAQ. The general procedures followed in preparing the modeling inventories, using various programs included with SMOKE, were the following:

- Modify EPA point source file to substitute emissions for all EGUs using estimates from IPM.
- Perform chemical speciation to transform input criteria pollutants into the CB-05 chemical mechanism species, as required by CMAQ.
- Perform temporal distribution to distribute the input annual/monthly emissions into hourly emissions.
- Perform spatial distribution of input emissions to the 12- and 4-km resolution modeling grids.
- Merge emissions from all source categories into the CMAQ model-ready files.
- Conduct a review and quality assurance of the inventory processing.

The emissions inventory processing quality assurance (QA) procedures included the preparation and examination of tabular emissions summaries and graphical display products.

Tabular summaries were used to examine emissions totals for various steps of the emissions processing. Summaries for input emissions are based on the input inventory data: monthly

emissions for the on-road and non-road sectors, and annual emissions for other sectors for criteria pollutants. Summaries for the emissions are based on the SMOKE output reports which include daily emissions for each CB-05 species for each sector. The output daily emissions are summed over all days in the year and the CB-05 species are summed for the criteria pollutants. The emissions summaries were made for each scenario by state and sector, and comparisons were made between the input emissions and output emissions for each sector to assure consistency.

In addition to the tabular summaries, various graphical displays were prepared for one day of each month to examine the spatial distribution and temporal variation for each sector and the final merged emissions using a graphical plotting package.

2.3. Emissions Summaries

Although the processed emission inventories were prepared for the full set of species listed above, most of the presentation and discussion that follows focuses on the NO_x, SO_2, and mercury emissions, since these are the species specified by IPM for EGUs that differed between the 2010/2013 Base Case and the 2020/2022 Reference Case scenarios (referred to throughout the remainder of this section as 2013 and 2022, respectively). NO_x is a precursor for ozone and both NO_x and SO_2 are precursor species for $PM_{2.5}$. Tables 2-1 and 2-2 present emission totals for the 12-km and 4-km resolution grids, respectively, for the 2013 Base Case and the 2022 Reference Case scenario. Tables 2-3 and 2-4 present this same information for the Mid-Atlantic states and the State of Delaware, respectively. The estimated changes in emissions between the Base Case and Reference Case in the various source sectors reflect implementation of emission control technologies in response to state and federal rule requirements, the shutting down of older facilities, fleet turnover of on-road motor vehicles and off-road equipment, the introduction of cleaner engine technologies, the use of cleaner fuels, the development of new electric generation units in response to future electric demand, and the effects of the expected growth in population.

From 2013 to 2022, there are major reductions estimated for NO_x emissions from the on-road motor vehicle sector for all areas, modest reductions in EGUs, other industrial point sources, and non-road sources, and little or no change in non-point (area) sources in all areas. One exception is that there is an estimated increase in NO_x emissions for EGUs for the 4-km domain, reflecting the insertion of additional generation units due to future power demands in some portion of this domain.

For SO_2 emissions, major reductions are estimated for EGU's between the base and future year for the 12- and 4-km domain and the State of Delaware, but EGU emissions in the Mid-Atlantic states are reduced only slightly. The SO_2 emissions for all other source categories show slight reductions, with the exception of non-road sources, which show slight increases for all areas, likely due to the expected increase in population and activity associated with these sources.

For mercury emissions, the EGU sector shows a significant decrease while other industrial point sources show a slight increase and non-point sources remain relatively unchanged in the future year.

Table 2-1. Emission Inventory Totals (tons/yr) by Sector for the 2013 Base Case and 2022 Reference Case for the IRP Modeling for the 12-km Grid.

Pollutant	Sector	2013 Base Case	2022 Reference Case
NOx	EGU	373,330	342,982
	Non-EGU/Point	411,826	408,745
	Non-point	441,012	440,212
	Non-road	798,882	662,304
	On-road Vehicle	1,279,712	491,344
SO_2	EGU	1,102,071	830,739
	Non-EGU/Point	582,052	567,749
	Non-point	453,637	453,554
	Non-road	70,559	72,978
	On-road Vehicle	10,997	10,733
Hg	EGU	6.4019	2.8165
	Non-EGU/Point	9.7821	10.7567
	Non-point	3.6571	3.8610

Table 2-2. Emission Inventory Totals (tons/yr) by Sector for 2013 the Base Case and 2022 Reference Case for the IRP Modeling for the 4-km Grid.

Pollutant	Sector	2013 Base Case	2022 Reference Case
NOx	EGU	94,911	98,424
	Non-EGU/Point	145,021	142,595
	Non-point	205,407	205,095
	Non-road	324,163	268,106
	On-road Vehicle	491,757	182,117
SO_2	EGU	187,019	135,776
	Non-EGU/Point	158,247	152,253
	Non-point	218,050	218,010
	Non-road	38,838	39,998
	On-road Vehicle	4,636	4,721
Hg	EGU	1.3425	0.5298
	Non-EGU/Point	3.9888	4.3576
	Non-point	1.6078	1.6975

Table 2-3. Emission Inventory Totals (tons/yr) by Sector for the 2013 Base Case and 2022 Reference Case for the IRP Modeling for the Mid-Atlantic States (New Jersey, Pennsylvania, Maryland, D.C., Delaware, and Virginia).

Pollutant	Sector	2013 Base Case	2022 Reference Case
NOx	EGU	135,606	129,190
	Non-EGU/Point	161,304	159,026
	Non-point	162,173	161,700
	Non-road	302,452	253,926
	On-road Vehicle	448,253	167,917
SO_2	EGU	286,423	285,404
	Non-EGU/Point	201,114	195,277
	Non-point	160,541	160,472
	Non-road	35,113	37,725
	On-road Vehicle	3,998	4,004
Hg	EGU	1.8259	0.6434
	Non-EGU/Point	4.7052	5.2918
	Non-point	0.9741	1.0194

Table 2-4. Emission Inventory Totals (tons/yr) by Sector for the 2013 Base Case and 2022 Reference Case for the IRP Modeling for the State of Delaware.

Pollutant	Sector	2013 Base Case	2022 Reference Case
NOx	EGU	2,492	1,524
	Non-EGU/Point	4,678	4,678
	Non-point	3,265	3,253
	Non-road	15,144	15,173
	On-road Vehicle	11,893	4,334
SO_2	EGU	9,702	3,332
	Non-EGU/Point	11,530	11,530
	Non-point	5,797	5,796
	Non-road	3,315	3,672
	On-road Vehicle	112	110
Hg	EGU	0.0265	0.0229
	Non-EGU/Point	0.5395	0.5423
	Non-point	0.0166	0.0182

To illustrate and check the reasonableness of the spatial distribution of emissions throughout the modeling domain, daily emission density plots for a selected day were prepared and examined. Figures 2-1 through 2-3 present daily emissions for the 2013 Base Case and the 2022 Reference Case for July 15th for NO_x, SO_2, and mercury, respectively, for the 4-km grid. As noted above, the meteorological inputs for the modeling exercise are for 2001, while the

emissions correspond to 2010/2013 and 2020/2022. The plots show the highest emissions corresponding to the locations of the major cities (Richmond, Washington, D.C., Baltimore, Philadelphia, and New York) and transportation corridors (freeways) as well as locations of large industrial facilities.

Figure 2-2-1. Daily NO_x Emissions (July 15, 2001) for the (a) 2013 Base Case and (b) 2022 Reference Case for the 4-km Grid.

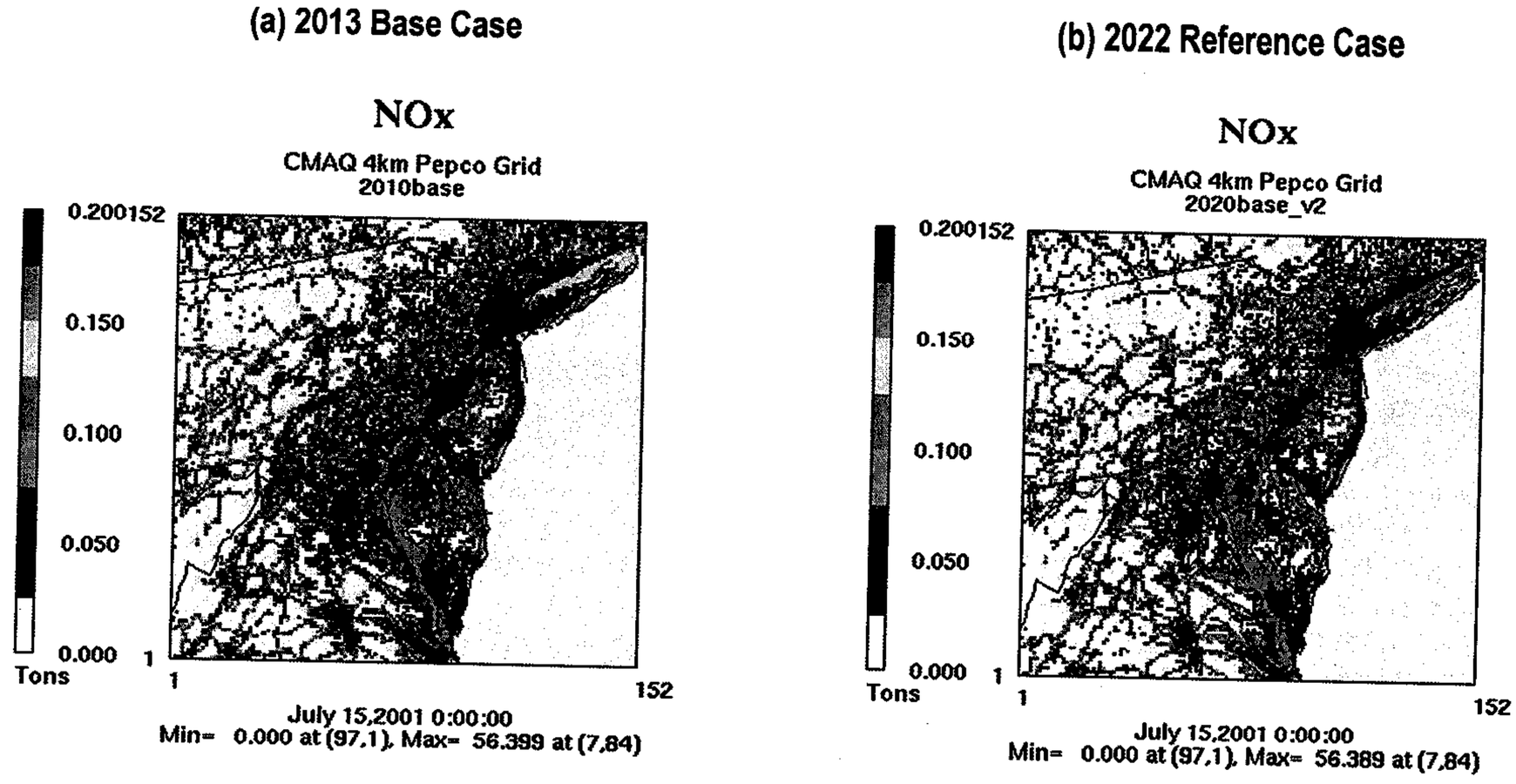


Figure 2-2. Daily SO_2 Emissions (July 15, 2001) for the (a) 2013 Base Case and (b) 2022 Reference Case for the 4-km Grid.

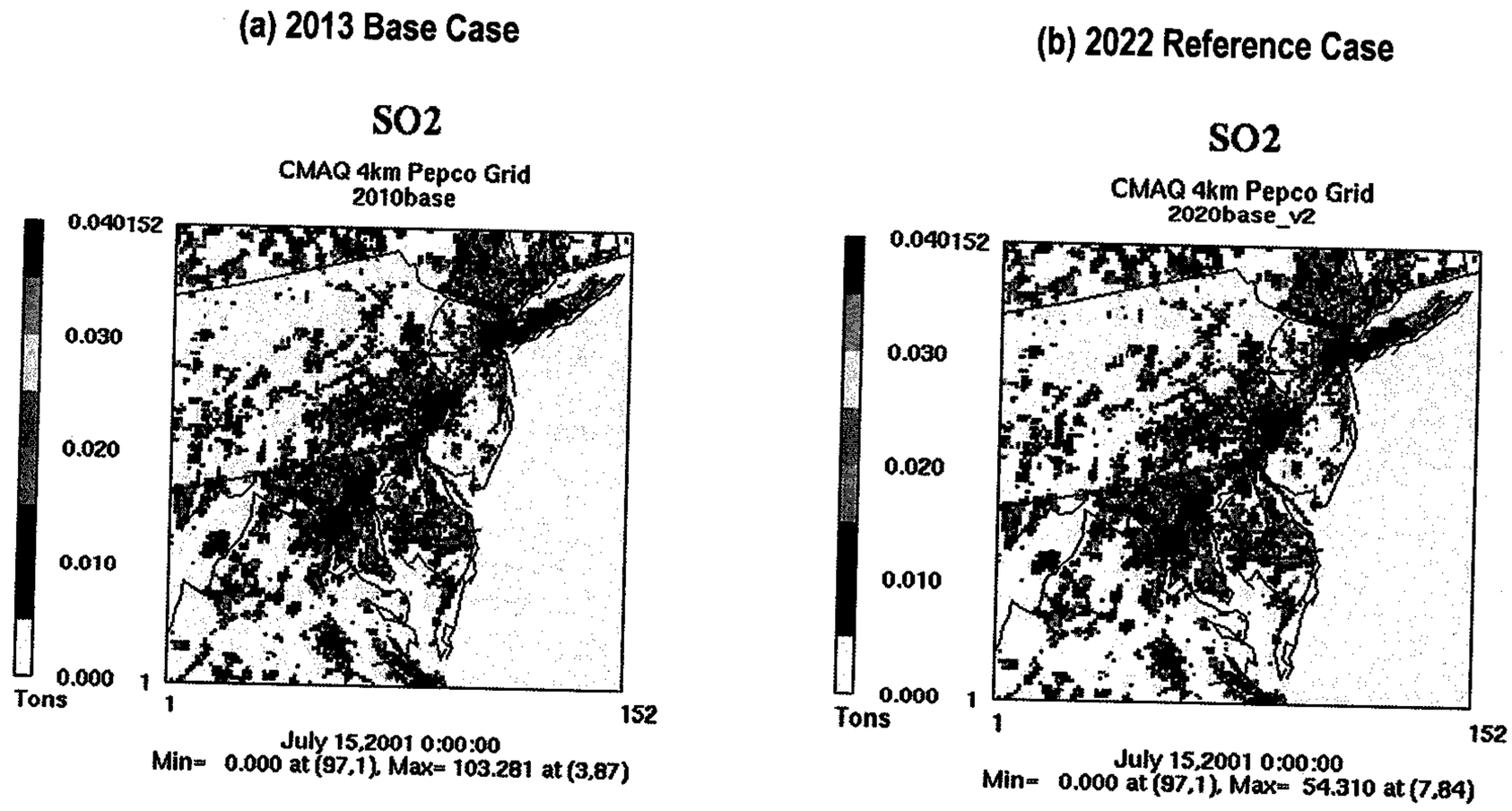


Figure 2-3. Daily Total Mercury Emissions (July 15, 2001) for the (a) 2013 Base Case and (b) 2022 Reference Case for the 4-km Grid.

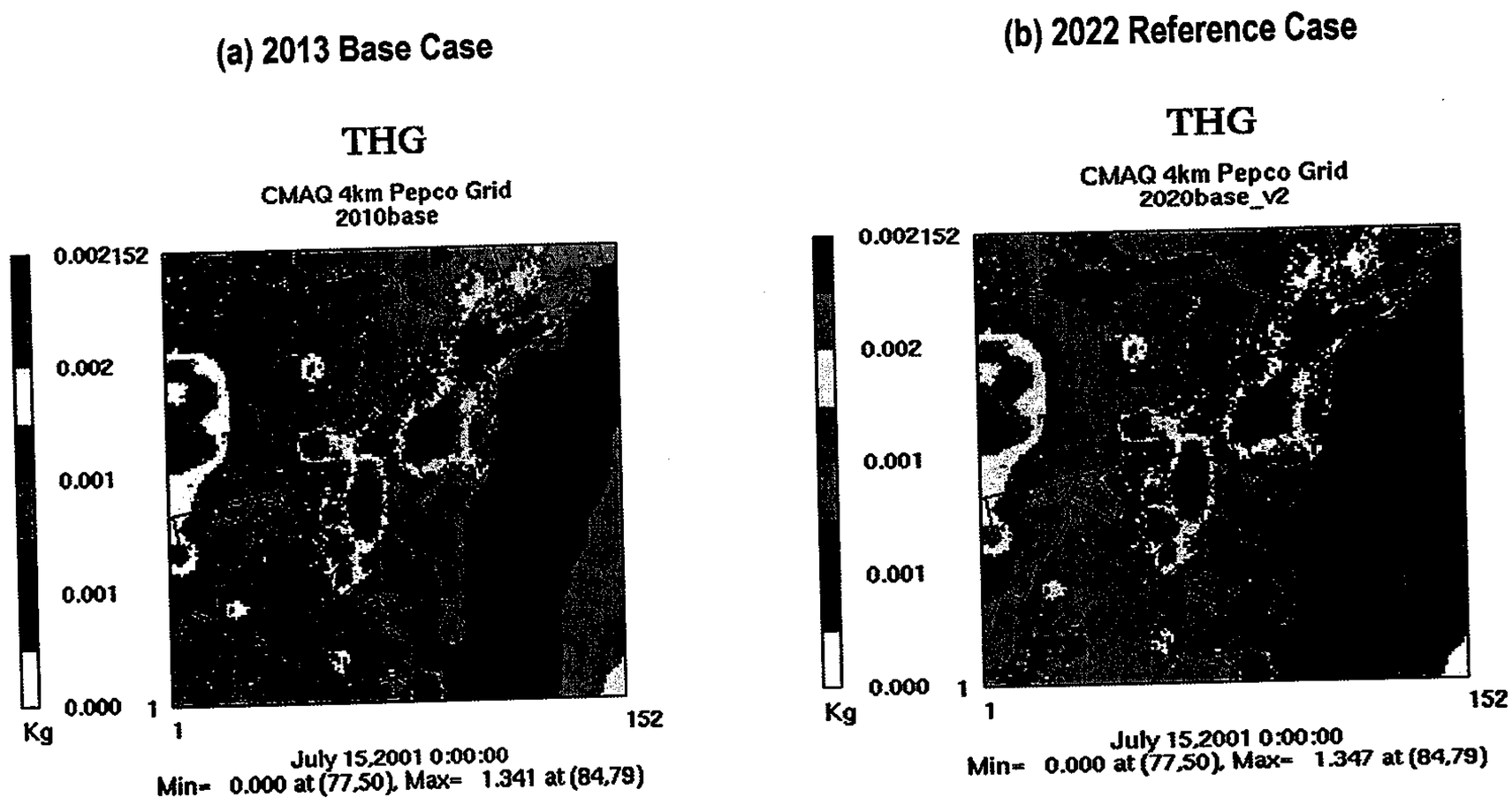


Table 2-5 presents state-by-state net changes in total EGU NO_x and SO_2 emissions for the Mid-Atlantics states comparing the 2013 Base Case with the 2022 Reference Case estimates. The information reflects a mix of estimated increases and decreases in emissions at a number of facilities throughout the Mid-Atlantic states. This includes the introduction of a few new generation facilities to meet future power demands.

For the State of Delaware, EGU NO_x and SO_2 emissions are expected to decrease significantly by 2022, while EGU emissions in the State of Maryland are expected to increase significantly. Within the State of New Jersey, EGU emissions increase slightly. Within the State of Pennsylvania, EGU NO_x emissions are forecast to decrease by about 10 percent while SO_2 emissions are expected to increase by over 20 percent. Finally, for the Commonwealth of Virginia, EGU NO_x emissions are expected to decrease slightly but SO_2 emissions are expected to decrease significantly.

Table 2-5. Summary of EGU NO_x and SO_2 Emissions (tons/year) for the Mid-Atlantic States: 2013 vs. 2022.

State	2013 EGU		2022 EGU		Diff: 2020 EGU - 2013 EGU	
	NO_X (tpy)	SO_2 (tpy)	NO_X (tpy)	SO_2 (tpy)	NO_X (tpy)	SO_2 (tpy)
Delaware	2,496	9,702	1,524	3,332	-972	-6,371
Maryland	10,205	23,443	15,492	26,532	5,288	3,089
New Jersey	6,320	6,282	6,657	8,059	338	1,777
Pennsylvania	91,923	176,602	81,640	217,995	-10,283	41,393
Virginia	24,666	70,395	23,877	29,486	-790	-40,908
Total	**135,610**	**286,423**	**129,190**	**285,404**	**-6,419**	**-1,019**

Figure 2-4a through c present emissions estimates by source sector for the 4-km grid for the 2013 Base Case and the 2022 Reference Case for NO_x, SO_2, and mercury, respectively. Figures 2-5a through c present similar emission totals by source sector for the State of Delaware. The figures show the expected reductions in emissions between 2013 and 2022.

Figure 2-4a. Emission Totals by Source Category for the 4-km Grid for the IRP Modeling Analysis 2013 Base Case and 2022 Reference Case: NO_x.

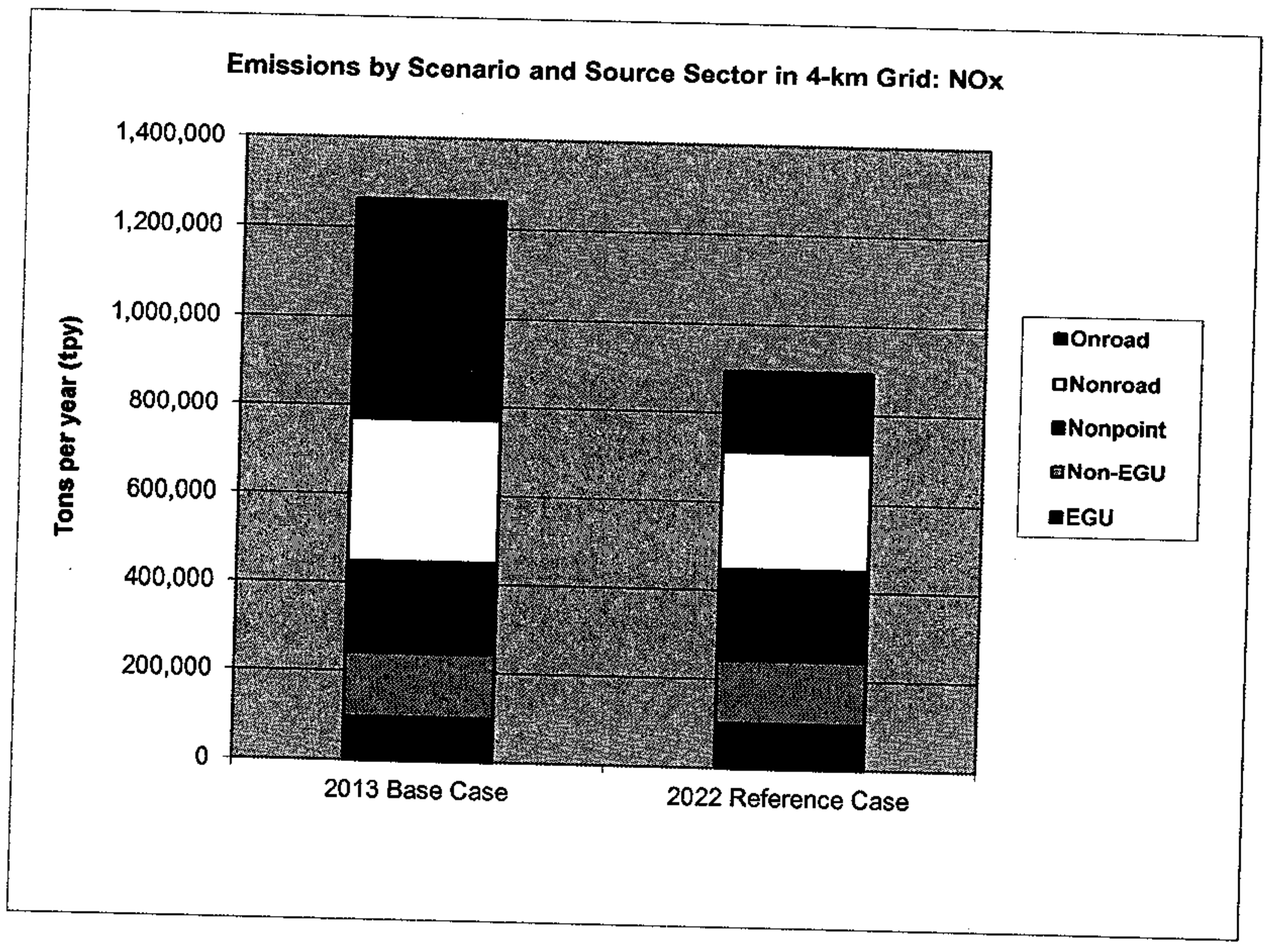


Figure 2-4b. Emission Totals by Source Category for the 4-km Grid for the IRP Modeling Analysis 2013 Base Case and 2022 Reference Case: SO_2.

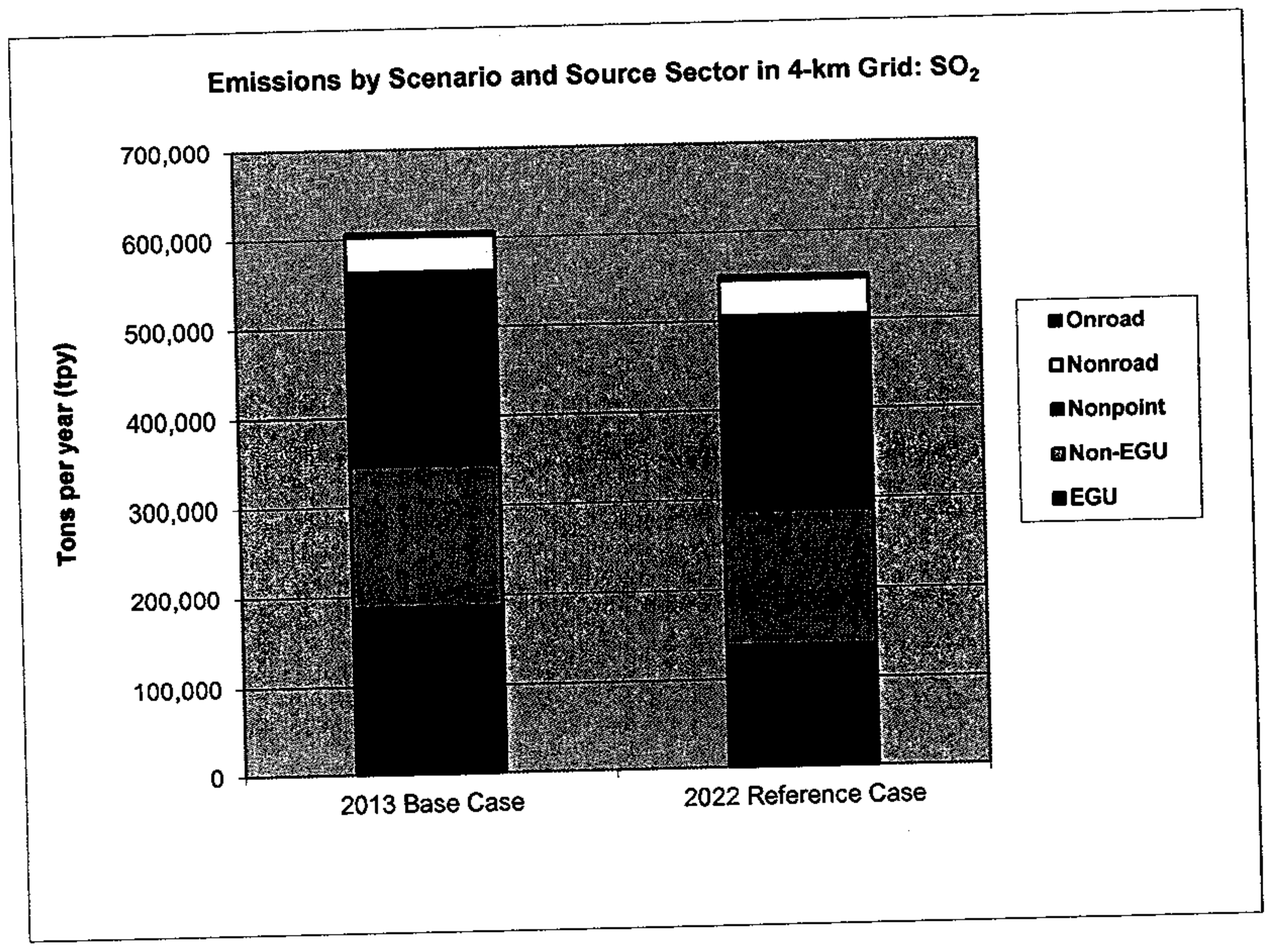


Figure 2-4c. Emission Totals by Source Category for the 4-km Grid for the IRP Modeling Analysis 2013 Base Case and 2022 Reference Case: Hg.

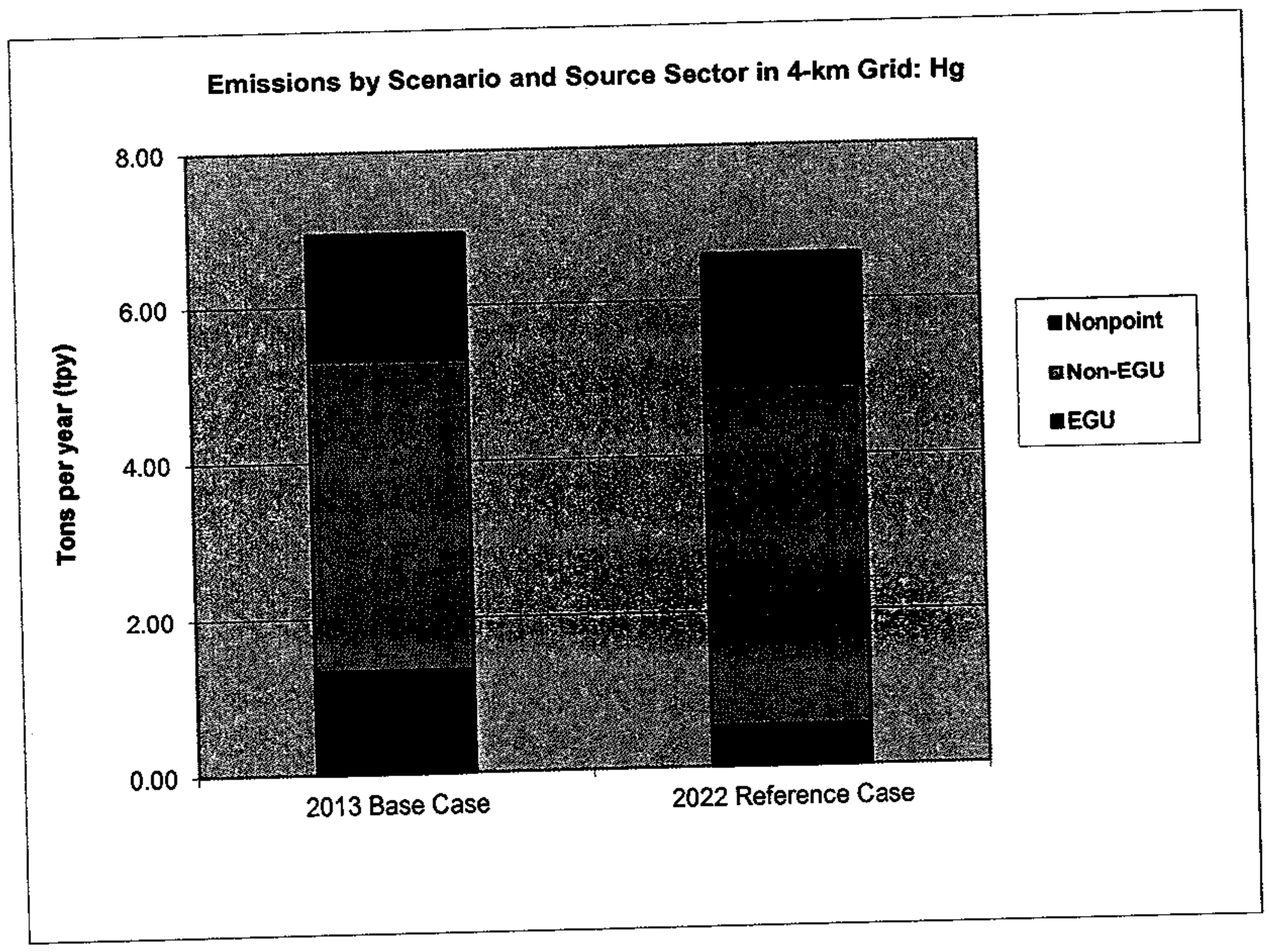


Figure 2-5a. Emission Totals by Source Category for Delaware for the IRP Modeling Analysis 2013 Base Case and 2022 Reference Case: NO_x.

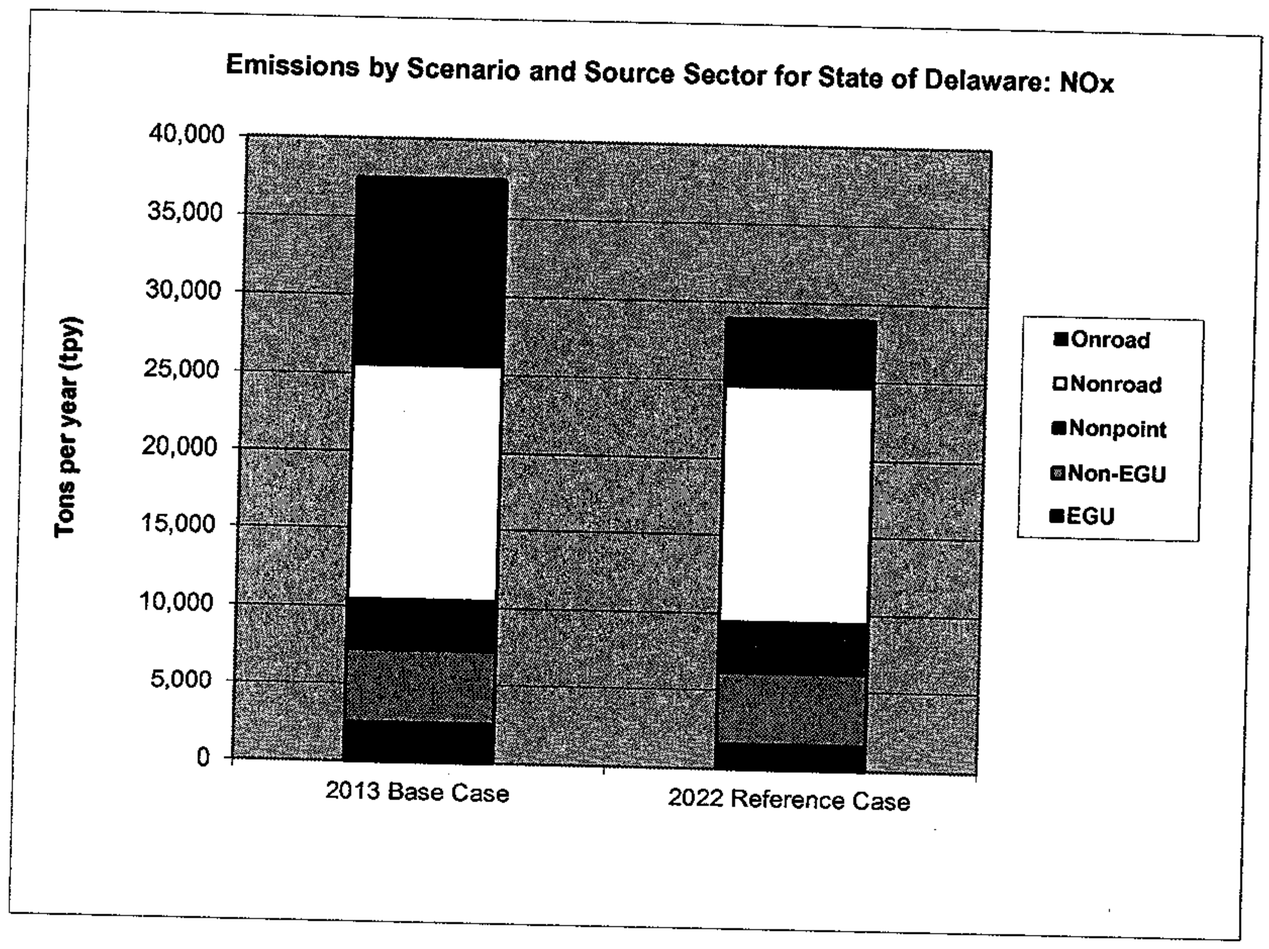


Figure 2-5b. Emission Totals by Source Category for Delaware for the IRP Modeling Analysis 2013 Base Case and 2022 Reference Case: SO_2.

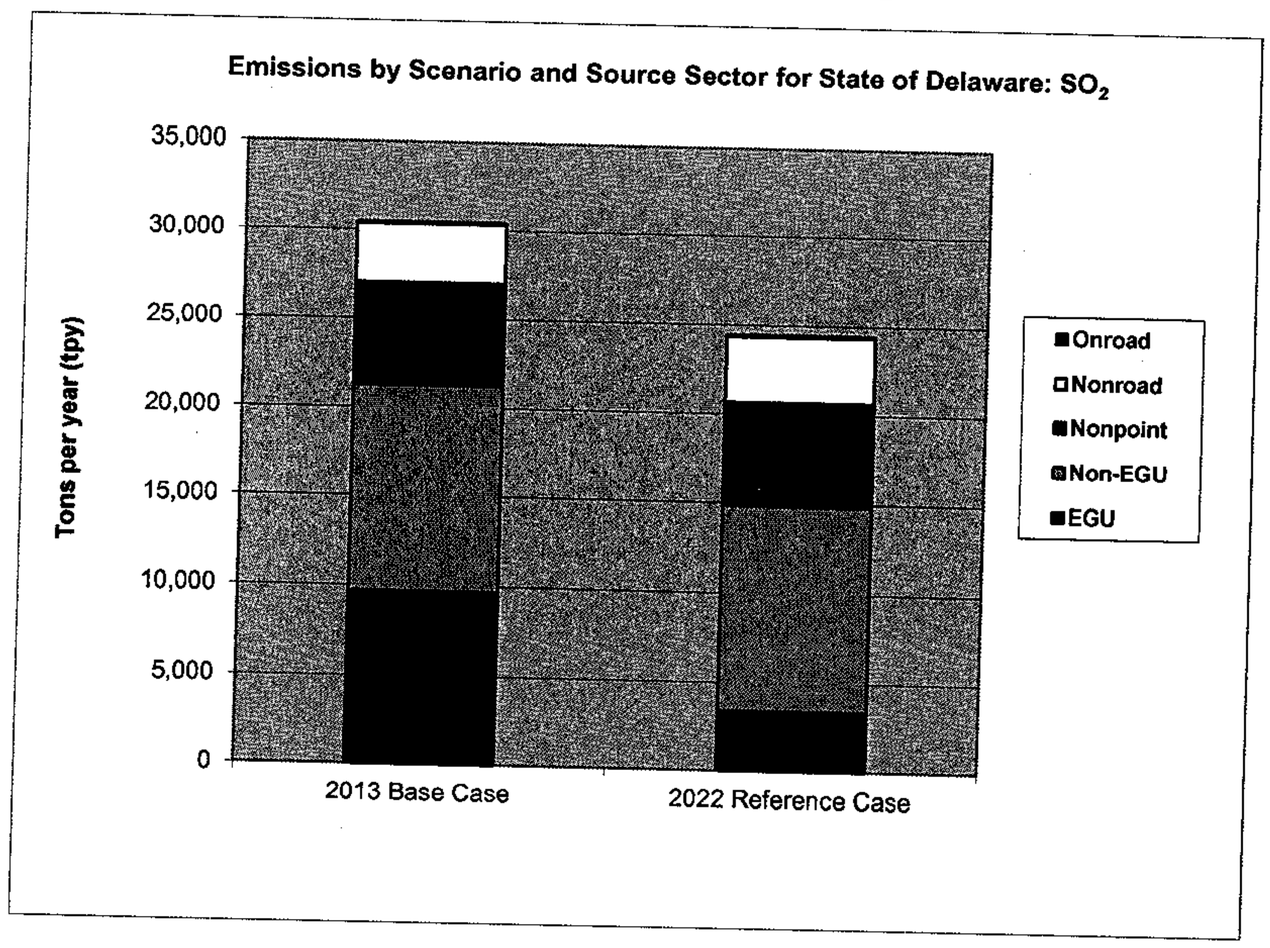
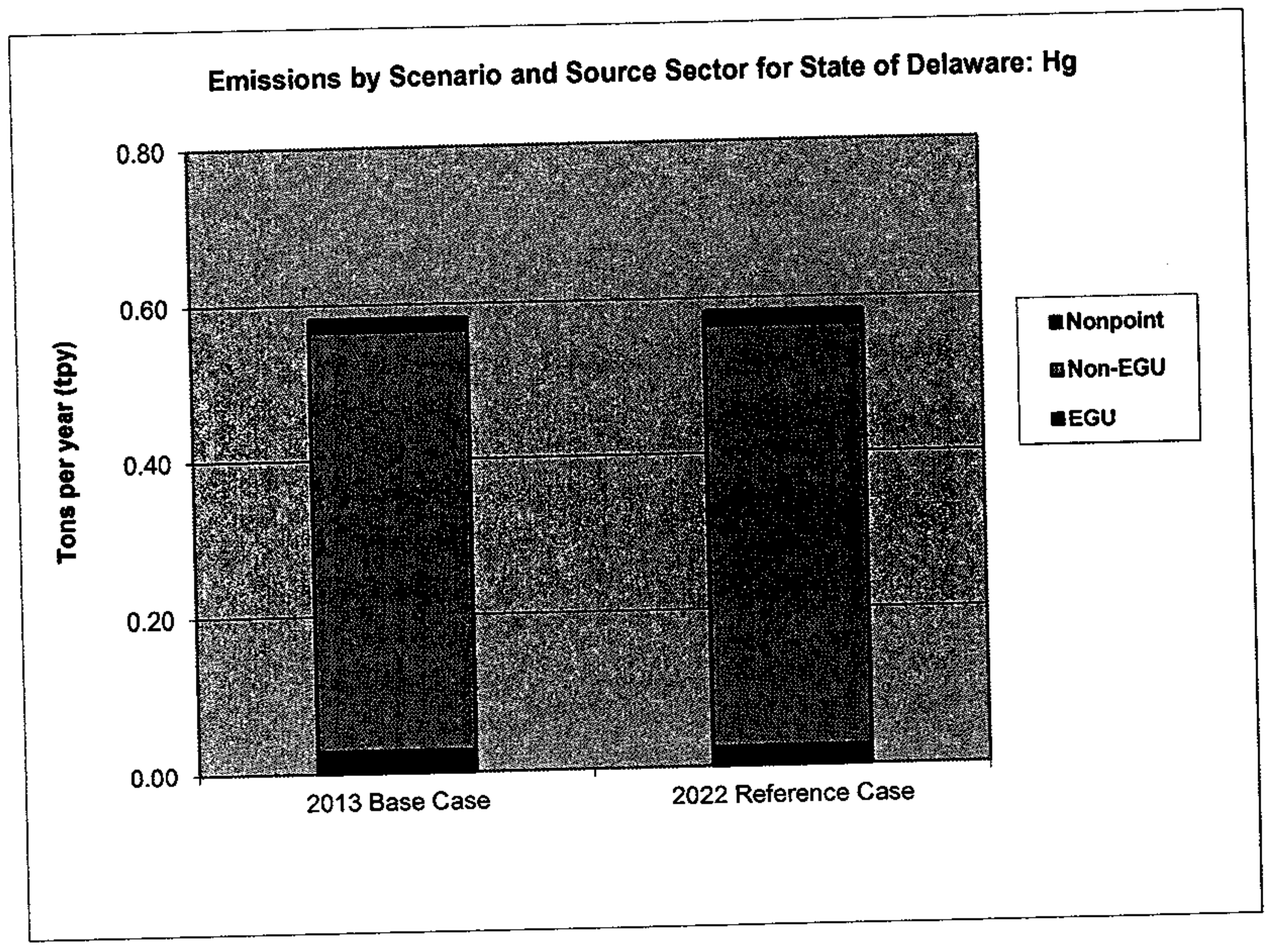


Figure 2-5c. Emission Totals by Source Category for Delaware for the IRP Modeling Analysis 2013 Base Case and 2022 Reference Case: Hg.



3. Air Quality Modeling

The air quality modeling methods and results are presented in this section. The CMAQ model was used to quantify the changes in air quality and mercury deposition between 2013 and 2022 and the contribution of emissions from the power generation sector to pollutant concentrations and deposition for those years. The model was applied at the regional scale for an annual simulation period. The CMAQ model requires information on the emissions, meteorology, and land-use characteristics of the modeling domain. Information about the emissions changes with time were incorporated into the model through the emission input files for the modeled years 2013 and 2022. The CMAQ modeling results provide the basis for the health effects and benefits modeling.

3.1. Overview of the CMAQ Modeling System

The CMAQ model is a state-of-the-science, regional air quality modeling system that can be used to simulate the physical and chemical processes that govern the formation, transport, and deposition of gaseous and particulate species in the atmosphere (Byun and Ching, 1999). The CMAQ tool was designed to improve the understanding of air quality issues (including the physical and chemical processes that influence air quality) and to support the development of effective emission control strategies on both the regional and local scale. The CMAQ model was designed as a "one-atmosphere" model. This concept refers to the ability of the model to dynamically simulate ozone, particulate matter, and other species (such as mercury) in a single simulation. In addition to addressing a variety of pollutants, CMAQ can be applied to a variety of regions (with varying geographical, land-use, and emissions characteristics) and for a range of space and time scales.

Numerous recent applications of the model, for both research and regulatory air quality planning purposes, have focused on the simulation of ozone and $PM_{2.5}$. For example, the CMAQ model was recently used by the U.S. EPA and the National Highway Traffic Safety Administration (NHTSA) to support the development of the Corporate Average Fuel Economy Standards (NHTSA, 2012). It was used by EPA to support the second prospective analysis of the costs and benefits of the Clean Air Act (CAA) (Douglas et al., 2008b) and also by Delmarva Power & Light for the 2010 IRP (ICF, 2010).

The CMAQ model numerically simulates the physical processes that determine the magnitude, temporal variation, and spatial distribution of the concentrations of gaseous and particulate species in the atmosphere and the amount, timing, and distribution of their deposition to the earth's surface. The simulation processes include advection, dispersion (or turbulent mixing), chemical transformation, cloud processes, and wet and dry deposition. The CMAQ science algorithms are described in detail by Byun and Ching (1999).

According to Bullock et al. (2008 and 2009), the CMAQ model reflects the current state-of-the-science in simulating the atmospheric processes that influence the dispersion, advection, chemical transformation, and deposition of mercury. The CMAQ model includes three mercury (Hg) species: elemental mercury (HG0), reactive gaseous mercury (HG2), and particulate-bound mercury (HGP).

The CMAQ model also supports source attribution for ozone, particulate matter, and mercury as described by Douglas et al. (2007). The CMAQ Ozone and Particle Precursor Tagging Methodologies (OPTM and PPTM) are designed to provide detailed, quantitative information about the *contribution* of selected sources, source categories, and/or source regions to simulated ozone and $PM_{2.5}$ concentrations, respectively. Emissions of precursor pollutants from selected sources, source categories, or source regions are (numerically) tagged and then tracked throughout a simulation. The contribution from each tag to the resulting simulated concentration of ozone, $PM_{2.5}$, or any of the $PM_{2.5}$ component species for any given location within the CMAQ modeling domain can be quantified. By tracking the emissions from selected sources or source locations, the methodology also provides information on the fate of the emissions from these sources. PPTM can also be applied for mercury.

The tagging methodology differs from the use of air quality model sensitivity simulations in which the emissions are modified or eliminated (zeroed-out). Sensitivity simulations typically provide information about the effects of changes in the emissions on the simulation results. In contrast, OPTM and PPTM provide information about the contribution of the emissions from the tagged sources, relative to the unmodified simulated conditions.

The CMAQ model requires several different types of input files. Gridded, hourly emission inventories characterize the release of anthropogenic, biogenic, and, in some cases, geogenic emissions from sources within the modeling domain. The emissions represent both low-level and elevated sources and a variety of source categories (including, for example, point, on-road mobile, non-road, area, and biogenic). The amount and spatial and temporal distribution of each emitted pollutant or precursor species are key determinants to the resultant simulated air quality values.

The CMAQ model also requires hourly, gridded input fields of several meteorological parameters including wind, temperature, mixing ratio, pressure, solar radiation, fractional cloud cover, cloud depth, and precipitation. A full list of the meteorological input parameters is provided in Byun and Ching (1999). The meteorological input fields are typically prepared using a data-assimilating prognostic meteorological model, the output of which is processed for input to the CMAQ model using the Meteorology-Chemistry Interface Processor (MCIP). The prescribed meteorological conditions influence the transport, vertical mixing, and resulting distribution of the simulated pollutant concentrations. Certain of the meteorological parameters, such as mixing ratio, can also influence the simulated chemical reaction rates. Rainfall and near-surface meteorological characteristics govern the wet and dry deposition, respectively, of the simulated atmospheric constituents.

Initial and boundary condition (IC/BC) files provide information on pollutant concentrations throughout the domain for the first hour of the first day of the simulation, and along the lateral boundaries of the domain for each hour of the simulation. Photolysis rates and other chemistry-related input files supply information needed by the gas-phase and particulate chemistry algorithms.

CMAQ version 4.6 was used for this study (primarily for consistency with the previous IRP and to accommodate the use of the PPTM tool). This version of the model supports several options for the gas-phase chemical mechanism, particle treatment, aerosol deposition, and cloud treatment. All simulations conducted as part of this study used the CB-05 chemical mechanism. For particles, the AERO4 particle treatment, which includes sea salt, was applied. For the both the 2013 Base Case and 2022 Reference Case simulations, the CMAQ PPTM feature was used to quantify the contribution of EGU emissions to the simulated $PM_{2.5}$ concentrations.

3.2. CMAQ Application Procedures

The application of CMAQ, including the modeling domain, simulation period, input files (with the exception of the emission inventories), and post-processing and quality assurance procedures are discussed in this section. Preparation of the emission inventories for the application of CMAQ was discussed in detail in the previous section. Model performance evaluation for CMAQ for this simulation period (for a base year of 2001) was conducted as part of the Virginia Mercury Study (Douglas et al., 2008a) as well as several other EPA studies, and the results were found to be acceptable for use in air quality analysis.

Modeling Domain and Simulation Period

The modeling domain used for this analysis was presented in Figure 1-1. The domain consists of an outer, regional-scale grid that covers the Mid-Atlantic region and portions of some surrounding states and an inner, high-resolution grid that is focused on Delaware. The horizontal resolution is 12 km for the outer grid and 4 km for the inner grid. Air quality impacts and health effects were calculated for the 4-km grid and Delaware.

The CMAQ model was applied for an annual simulation period, using meteorological inputs for a base year of 2001. This simulation period is characterized by typical meteorological conditions for the area of interest, with normal temperatures and precipitation amounts during the summer months, but less than normal precipitation during the fall period. For these reasons, it was also selected for use in the 2010 IRP and the Virginia Mercury Study (Douglas et al. 2008a). In running the model, the annual simulation period was divided into two parts covering January through June and July through December, respectively. Each part of the simulation also included an additional five start-up simulation days, which were intended to reduce the influence of uncertainties in the initial conditions on the simulation results.

Meteorological Input Files

The 12-km resolution meteorological input files for the annual (2001) simulation period were originally prepared by EPA using the Pennsylvania State University/National Center for Atmospheric Research (PSU/NCAR) Fifth Generation Mesoscale Model (MM5) (EPA, 2005). The MM5 outputs were postprocessed by EPA for input to CMAQ using the MCIP program. The meteorological input preparation methodology and some information on MM5 model

performance are provided by McNally (2003). The meteorological fields for the 12-km study domain were extracted from a larger 12-km domain used by EPA.

The 12-km meteorological inputs were also used as the basis for the 4-km meteorological fields. Interpolation and reanalysis methods were used to adapt the input files to the 4-km grid. The 12-km fields were interpolated to the 4-km grid. For most parameters, objective analysis (based on bi-linear interpolation) was used to combine the interpolated fields with available observations and thus adjust the 12-km fields to the 4-km grid. Certain parameters such as radiation, rainfall, and land-use-based quantities, which are not expected to exhibit smooth variations in space, were not interpolated and the values used for the 4-km sub-cells were the same as for the encompassing 12-km grid cell.

Initial and Boundary Conditions and Geophysical Input Files

As part of the air quality modeling exercise to support the prior (2010) IRP, CMAQ was run once for 2010 and once for 2020 for the 36-km CONUS domain and the output from these runs was used to generate boundary conditions for the 12-km grid. For the current study, the same (2010 and 2020) boundary conditions were used for the 12-km grid for the 2013 and 2022 simulations. For each CMAQ scenario, the output from the 12-km grid was used to generate boundary conditions for the 4-km grid (one-way nesting). Gridded land-use and photolysis rate input files were prepared for the 12- and 4-km grids and the simulation period using standard CMAQ utility programs (CMAS, 2008).

Post-processing and Quality Assurance Procedures

Quality assurance of the CMAQ runs included the following steps:

- Scripts were routinely checked to ensure that the correct input files and output file names were used. Any error messages generated by CMAQ were checked and reconciled.
- For each simulation, plots of average $PM_{2.5}$ concentration, selected particulate species (e.g., sulfate, nitrate, organic carbon, and elemental carbon), and mercury deposition for each month and for the annual simulation period were prepared. In addition, plots of daily maximum 8-hour average ozone for the 15th day of each month were prepared. These were examined and compared with the results for other runs. The concentration patterns and values were checked for reasonableness.
- Difference plots comparing $PM_{2.5}$ and ozone concentrations and mercury deposition for the scenarios were also prepared. Checks were done to ensure that differences in the CMAQ results were consistent with the emissions changes.

Following the quality assurance of the modeling results, the CMAQ results were post-processed for input to the health impacts and benefits modeling, as discussed in Section 4 of this report. The CMAQ modeling results are presented in the remainder of this section.

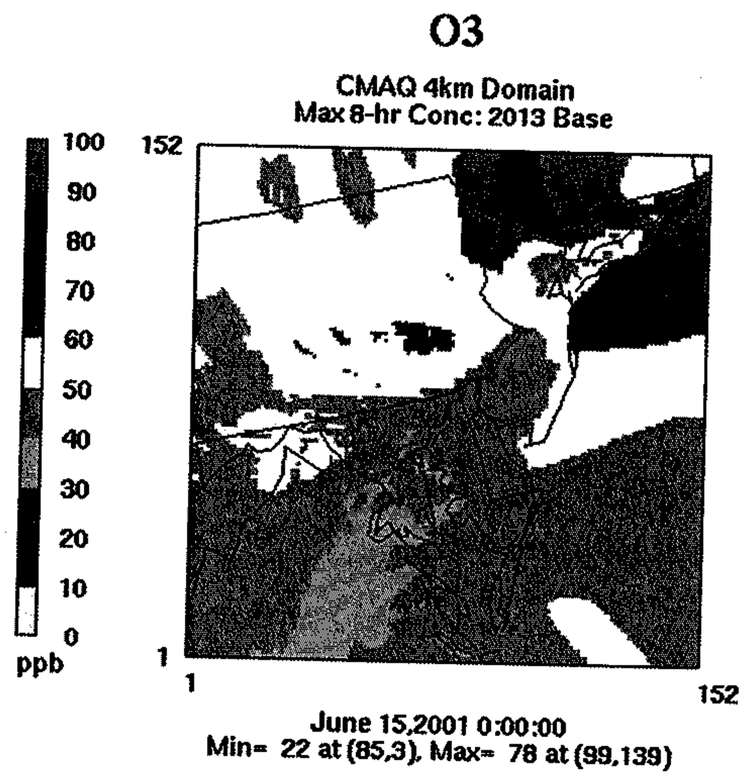
3.3. Air Quality Modeling Results for the 2013 Base and 2022 Reference Cases

Ozone

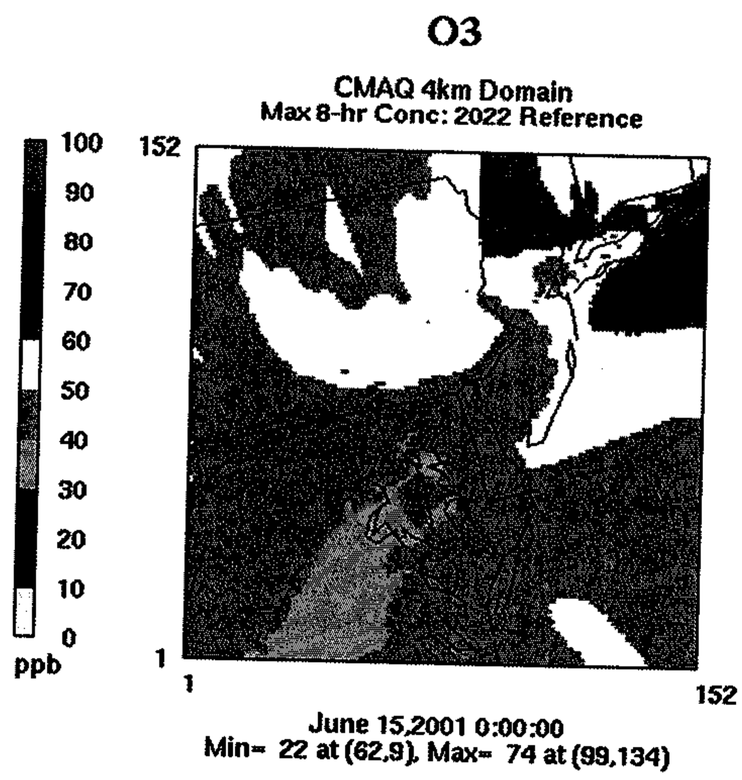
Figure 3-1 through 3-3 display simulated daily maximum 8-hour ozone concentration (ppb) for the 4-km grid for the 2013 Base Case and 2022 Reference Case simulations and the difference in daily maximum 8-hour ozone concentration (ppb) between the two simulations. The results are shown for the 15th of June, July, and August, which represent the peak ozone season months for the Mid-Atlantic states. These days were selected as example ozone-season days for display of the ozone concentrations, primarily because of relatively higher ozone concentrations compared to other days comprising the simulation period. The date and time given on these and all subsequent figures refer to the meteorological base year and start hour for the selected day or averaging period. The minimum and maximum values for any location within the domain are also provided, along with their grid cell (x,y) locations. The differences are calculated as 2022 Reference Case minus the 2013 Base Case.

Figure 3-1. Simulated Daily Maximum 8-Hour Ozone Concentration (ppb) for the 4-km Grid for the 2013 Base Case and 2022 Reference Case Simulations and Difference in Simulated Daily Maximum 8-Hour Ozone Concentration (ppb) for the 2022 Reference Case Minus the 2013 Base Case: June 15th.

(a) 2013 Base Case



(b) 2022 Reference Case



(c) Reference Case—Base Case

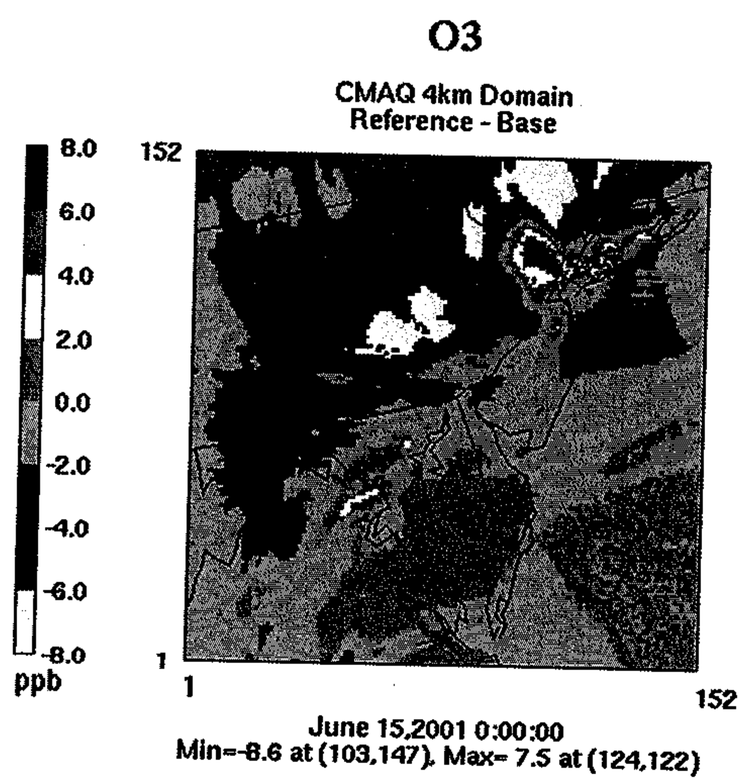
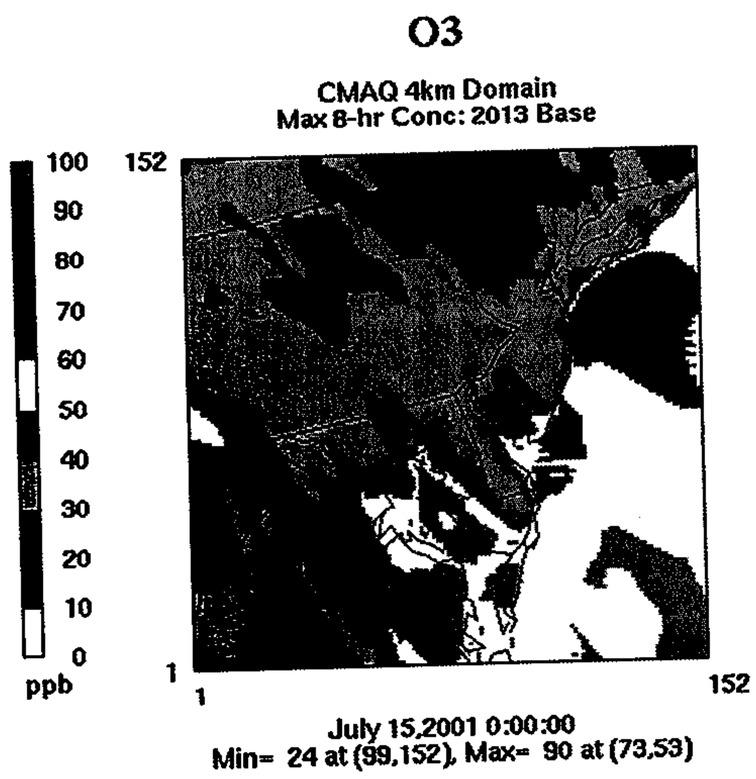
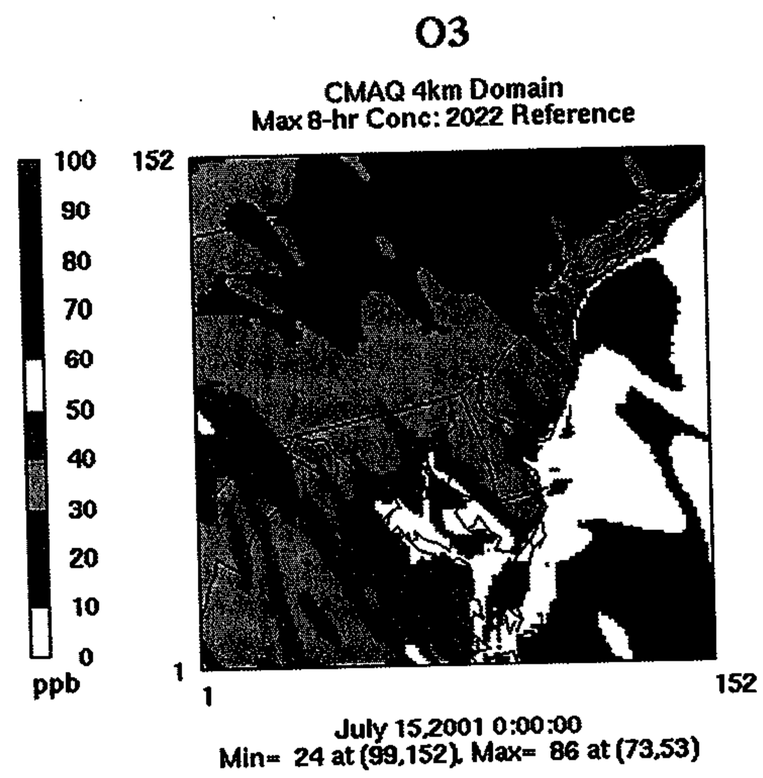


Figure 3-2. Simulated Daily Maximum 8-Hour Ozone Concentration (ppb) for the 4-km Grid for the 2013 Base Case and 2022 Reference Case Simulations and Difference in Simulated Daily Maximum 8-Hour Ozone Concentration (ppb) for the 2022 Reference Case Minus the 2013 Base Case: July 15th.

(a) 2013 Base Case



(b) 2022 Reference Case



(c) Reference Case—Base Case

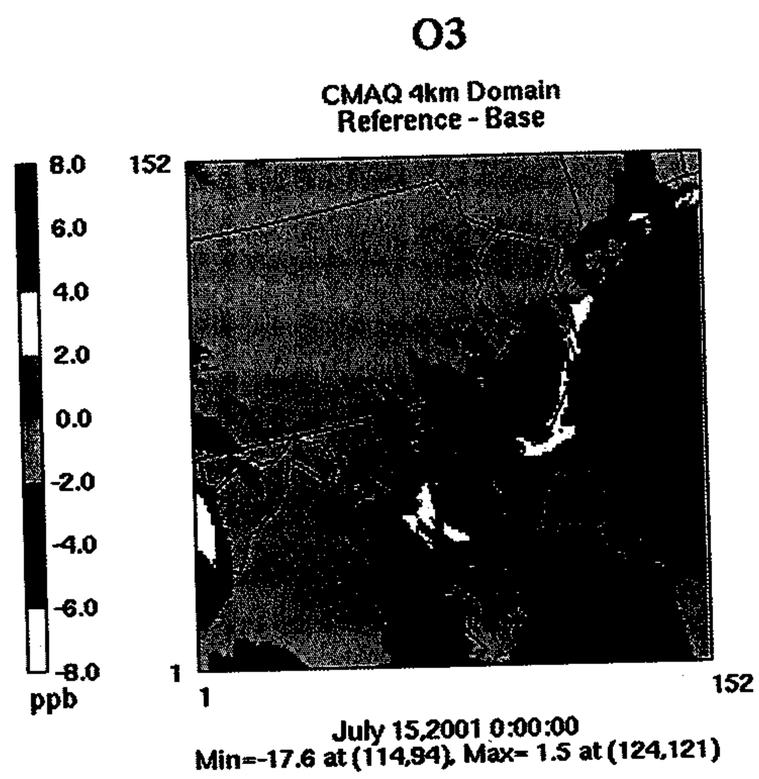
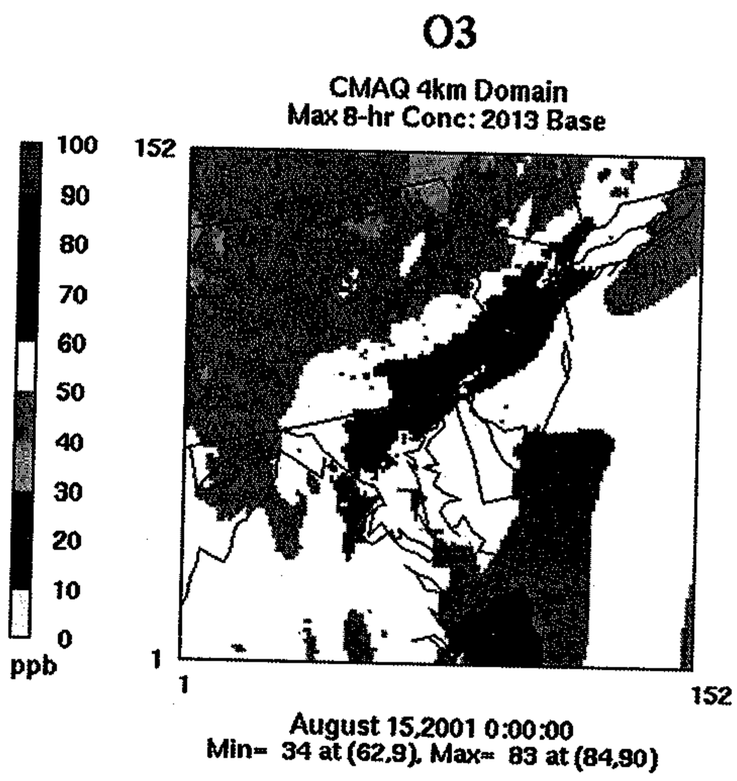
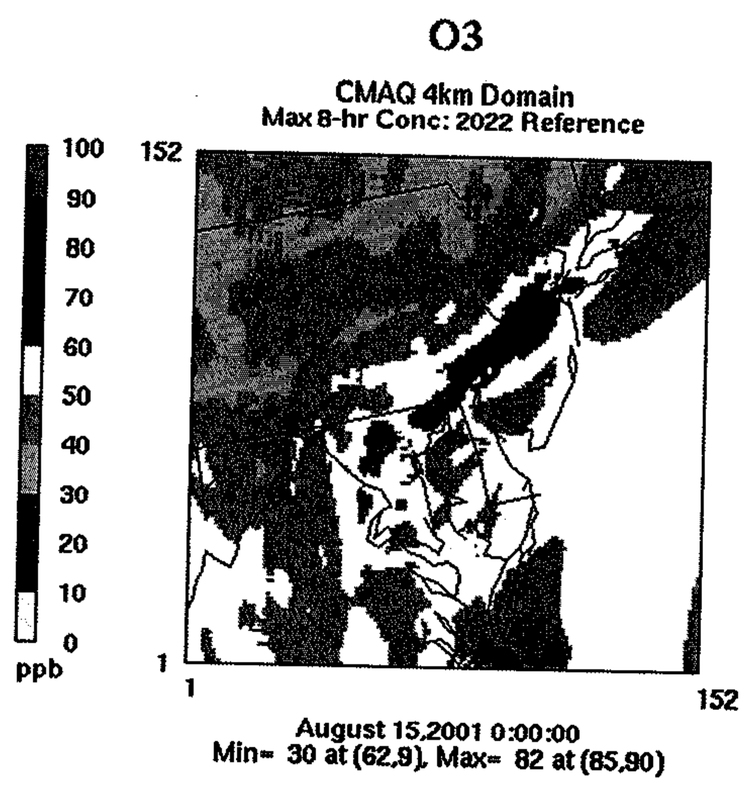


Figure 3-3. Simulated Daily Maximum 8-Hour Ozone Concentration (ppb) for the 4-km Grid for the 2013 Base Case and 2022 Reference Case Simulations and Difference in Simulated Daily Maximum 8-Hour Ozone Concentration (ppb) for the 2022 Reference Case Minus the 2013 Base Case: August 15th.

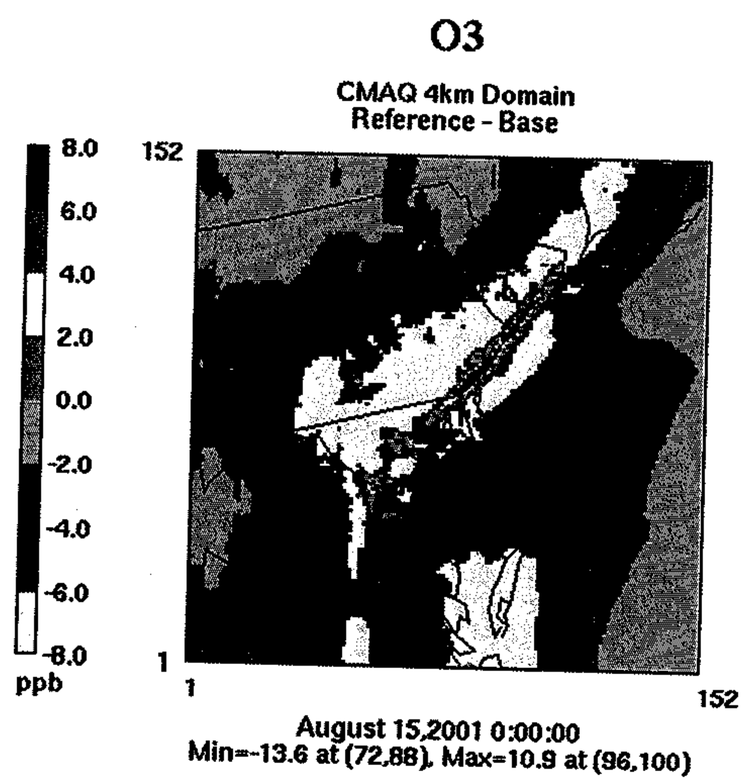
(a) 2013 Base Case



(b) 2022 Reference Case



(c) Reference Case—Base Case



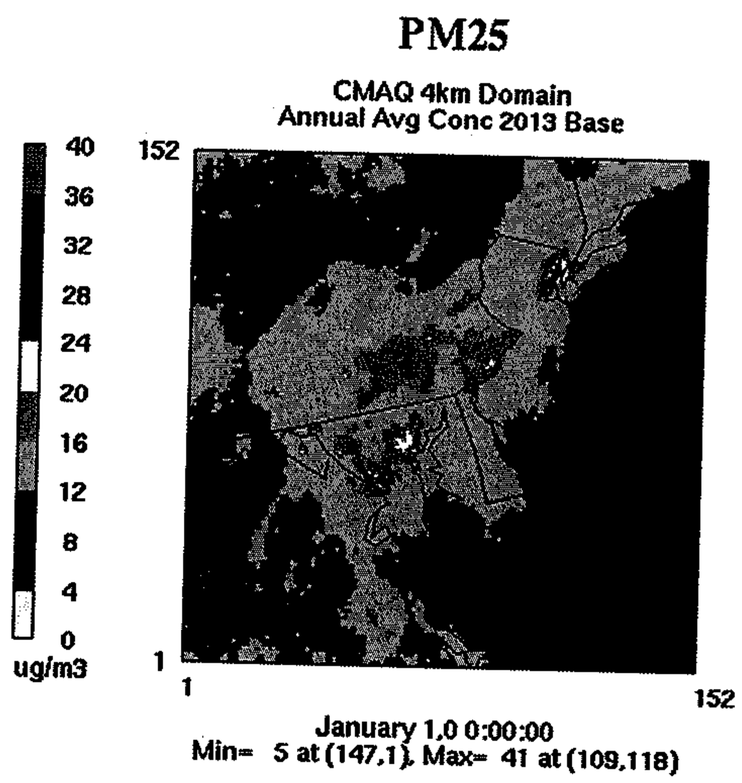
The daily maximum 8-hour ozone concentration patterns are quite different among the three days, with the highest ozone concentrations occurring in different portions of the grid on different days. For 2013, the highest overall simulated daily maximum 8-hour average concentration (90 ppb) occurs on July 15th. Ozone concentrations are highest for Delaware on August 15th. There are both increases and decreases in ozone concentration for 2022, compared to 2013. The decreases are fairly widespread, reflecting emissions reductions for a number of source categories throughout the domain, and are generally greater in magnitude than the increases. The increases are more isolated and reflect increases in emissions from specific sources.

$PM_{2.5}$

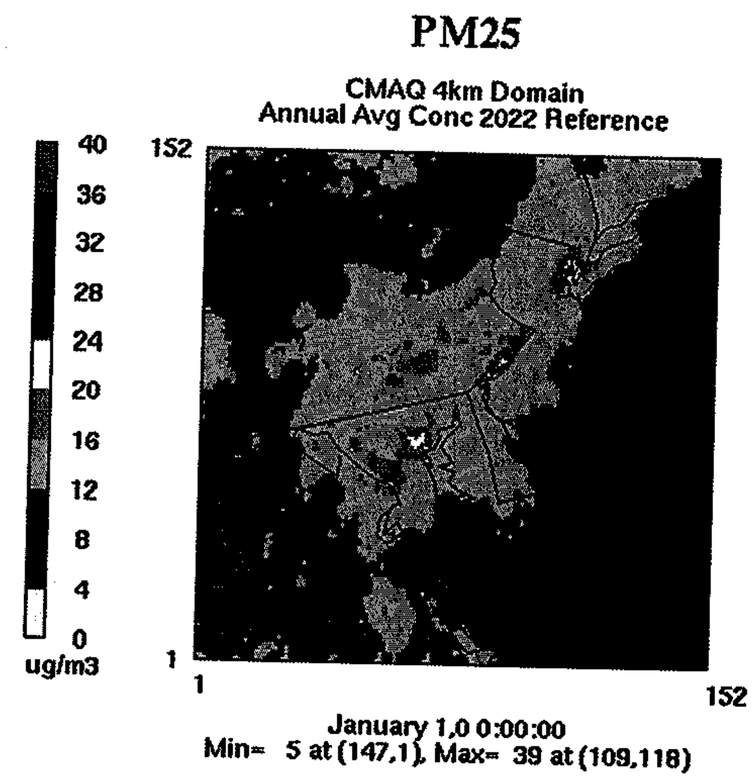
Figure 3-1 displays simulated annual average $PM_{2.5}$ concentration (μgm^{-3}) for the 4-km grid for the 2013 Base Case and 2022 Reference Case simulations and the difference in annual average $PM_{2.5}$ concentration (μgm^{-3}) between the two simulations. $PM_{2.5}$ is a year-round pollutant of concern. The differences are calculated as 2022 Reference Case minus the 2013 Base Case.

Figure 3-4. Simulated Annual Average $PM_{2.5}$ (μgm^{-3}) for the 4-km Grid for the 2013 Base Case and 2022 Reference Case Simulations and Difference in Simulated Annual Average $PM_{2.5}$ (μgm^{-3}) for the 2022 Reference Case Minus the 2013 Base Case.

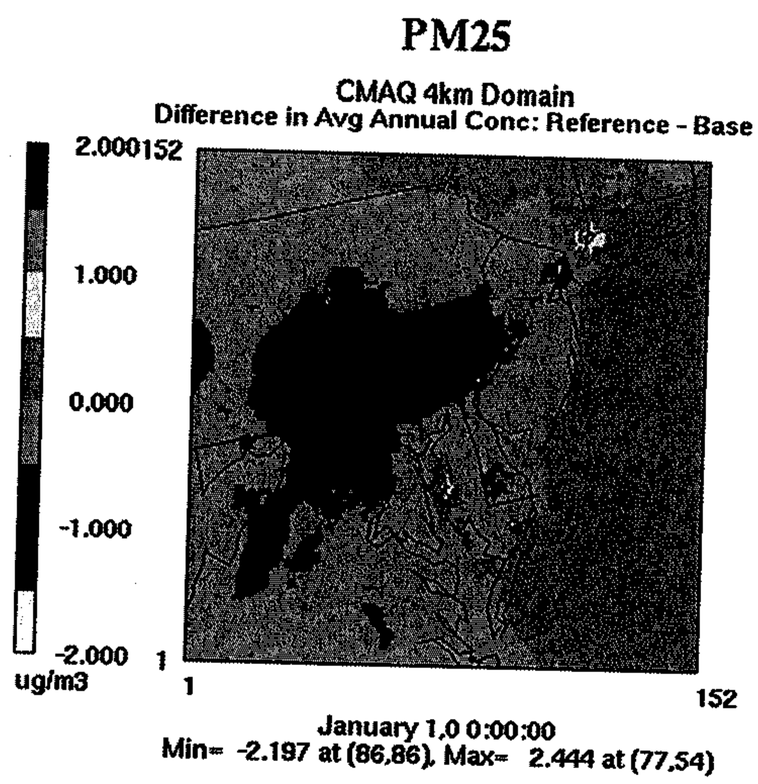
(a) 2013 Base Case



(b) 2022 Reference Case



(c) Reference Case - Base Case



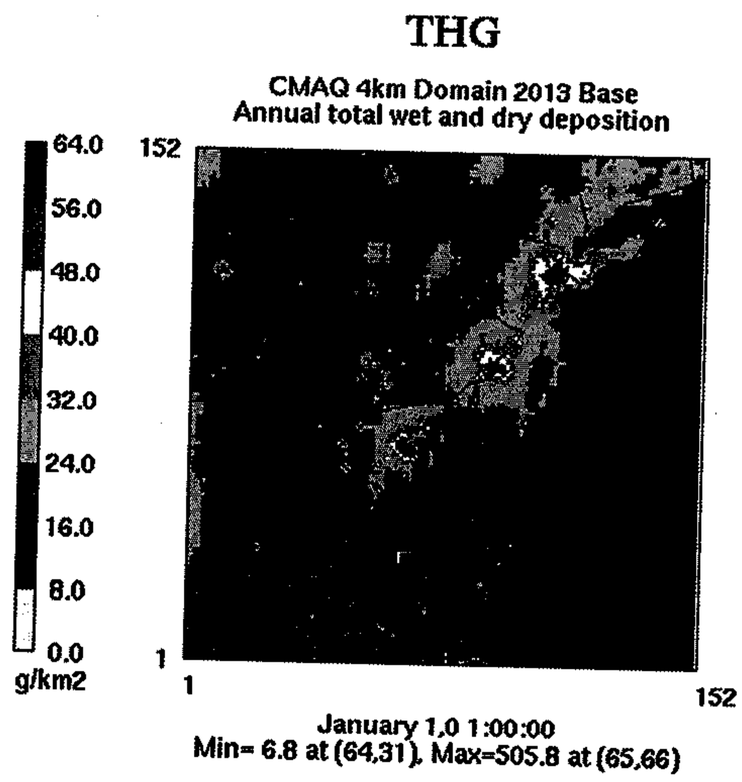
For the 2013 Base Case, annual average $PM_{2.5}$ concentrations for most of the grid are generally less than 16 $\mu g/m^3$. Higher concentrations are simulated over portions of Maryland and eastern Pennsylvania and near New York City, with peak concentrations near Baltimore and New York City. For the 2022 Reference Case, the area over which concentrations are greater than 16 $\mu g/m^3$ is smaller. Focusing on the difference plots, the simulated $PM_{2.5}$ concentrations for 2022 are lower than those for 2013 throughout much of the region. Concentrations are especially lower over southeastern Pennsylvania, central Maryland, and northern Virginia. Concentrations over Delaware are lower by as much as 1.5 $\mu g/m^3$. The maximum decrease is approximately 2.2 μgm^{-3}. The difference pattern shows widespread decreases in $PM_{2.5}$ and these are consistent with reductions in emissions from a variety of source categories throughout the region between 2013 and 2022.

Mercury

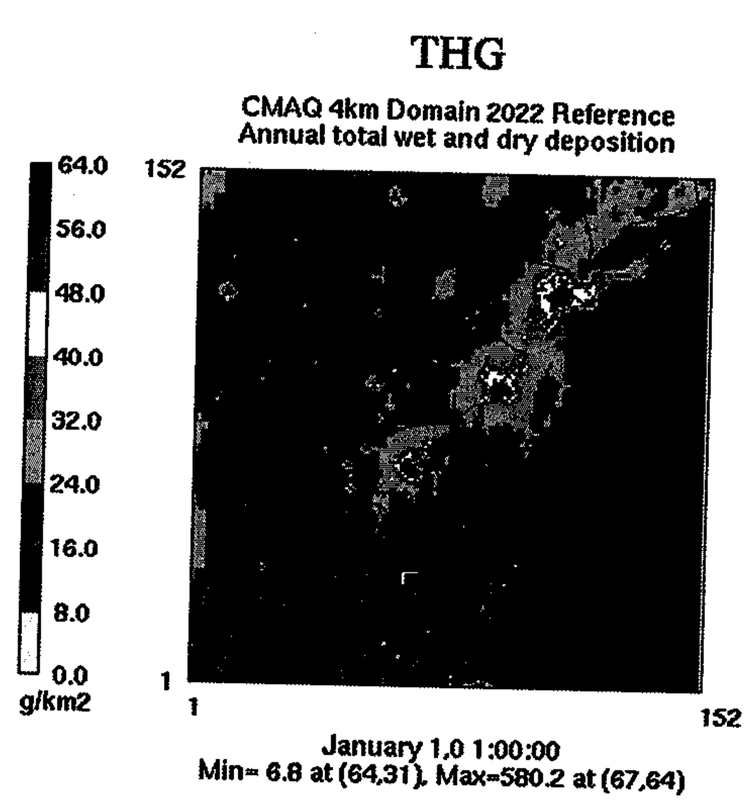
Figure 3-1 displays simulated annual mercury deposition (g km^{-2}) for the 4-km grid for the 2013 Base Case and 2022 Reference Case simulations and the difference in total annual mercury deposition (g km^{-2}) between the two simulations. The differences are calculated as 2022 Reference Case minus 2013 Base Case.

Figure 3-5. Simulated Total Annual Mercury Deposition (g km^{-2}) for the 4-km Grid for the 2013 Base Case and 2022 Reference Case Simulations and Difference in Simulated Total Annual Mercury Deposition (g km^{-2}) for the 2022 Reference Case Minus the 2013 Base Case.

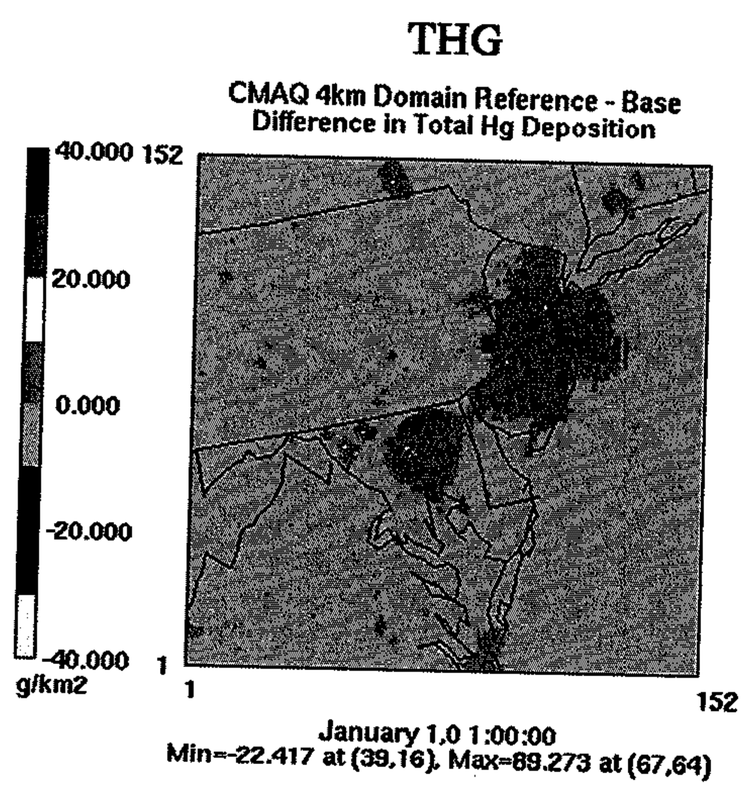
(a) 2013 Base Case



(b) 2022 Reference Case



(c) Reference Case—Base Case



Simulated mercury deposition is highest near the urban areas of Baltimore, Philadelphia, and New York. There is also an area of high deposition in northern Delaware. The difference pattern is characterized by small areas of increases and decreases in mercury deposition for 2022, compared to 2013. Averaged across the domain, the simulated decrease in mercury deposition is less than 1 g km^{-2}.

3.4. $PM_{2.5}$ Source Contribution Analysis

As noted earlier, the CMAQ Ozone and Particle Precursor Tagging Methodologies (OPTM and PPTM) are designed to provide detailed, quantitative information about the *contribution* of selected sources, source categories, and/or source regions to simulated ozone and $PM_{2.5}$ concentrations, respectively. CMAQ/PPTM was used in this study to examine the contributions of emissions from the major source categories to simulated $PM_{2.5}$ concentrations and specifically to quantify the contributions from EGU sources.

CMAQ/PPTM was applied for the 12-km grid only for both the 2013 Base Case and the 2022 Reference Case simulations and the contributions from sources within the 12-km grid to specified receptor areas were estimated. Specifically, PPTM was used to examine the contributions to simulated $PM_{2.5}$ for the following major emissions source categories/source areas:

- EGU point sources in Delaware
- EGU point sources in New Jersey, Pennsylvania, Maryland, Virginia, and Washington, D.C.
- EGU point sources in the remainder of the 12-km grid
- Non-EGU point sources in the 12-km grid
- All other emission sources in the 12-km grid combined (including on-road mobile, non-road, and area sources)
- Biogenic emissions
- Initial conditions and boundary conditions (IC/BCs).

Two key receptor areas were defined as follows: 1) the area encompassed by the 4-km grid (refer to Figure 1-1) and 2) the State of Delaware. Figure 3-6a displays the simulated contribution from each of the seven tagged source categories/regions to annual average $PM_{2.5}$ for the 4-km grid. Figure 3-6b displays the simulation contribution from each of the tagged source categories/regions to annual average $PM_{2.5}$ for Delaware. The units for $PM_{2.5}$ concentration are micrograms per cubic meter (μgm^{-3}).

Figure 3-6a. CMAQ/PPTM-Derived Contributions to Annual Average $PM_{2.5}$ Concentration for the 2013 Base Case and 2022 Reference Case Simulations: 4-km Grid.

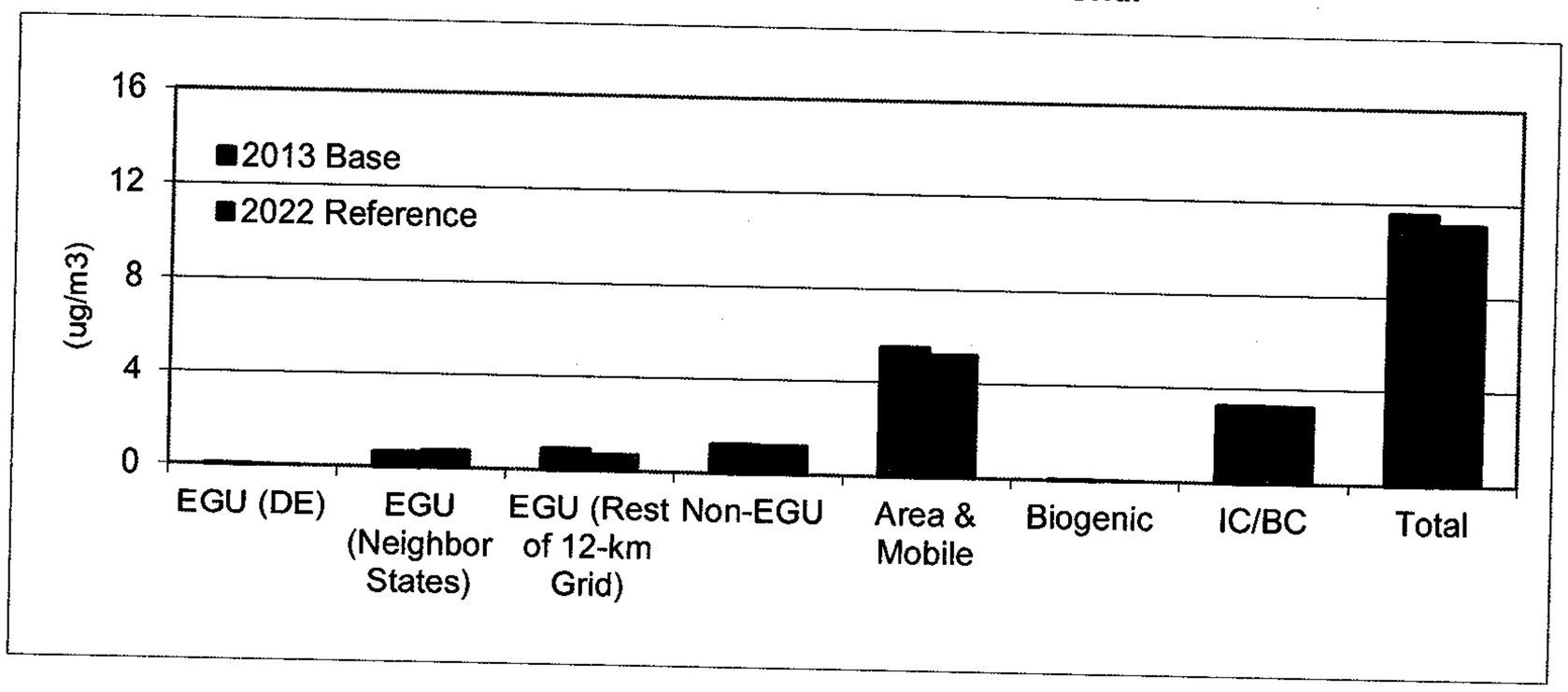
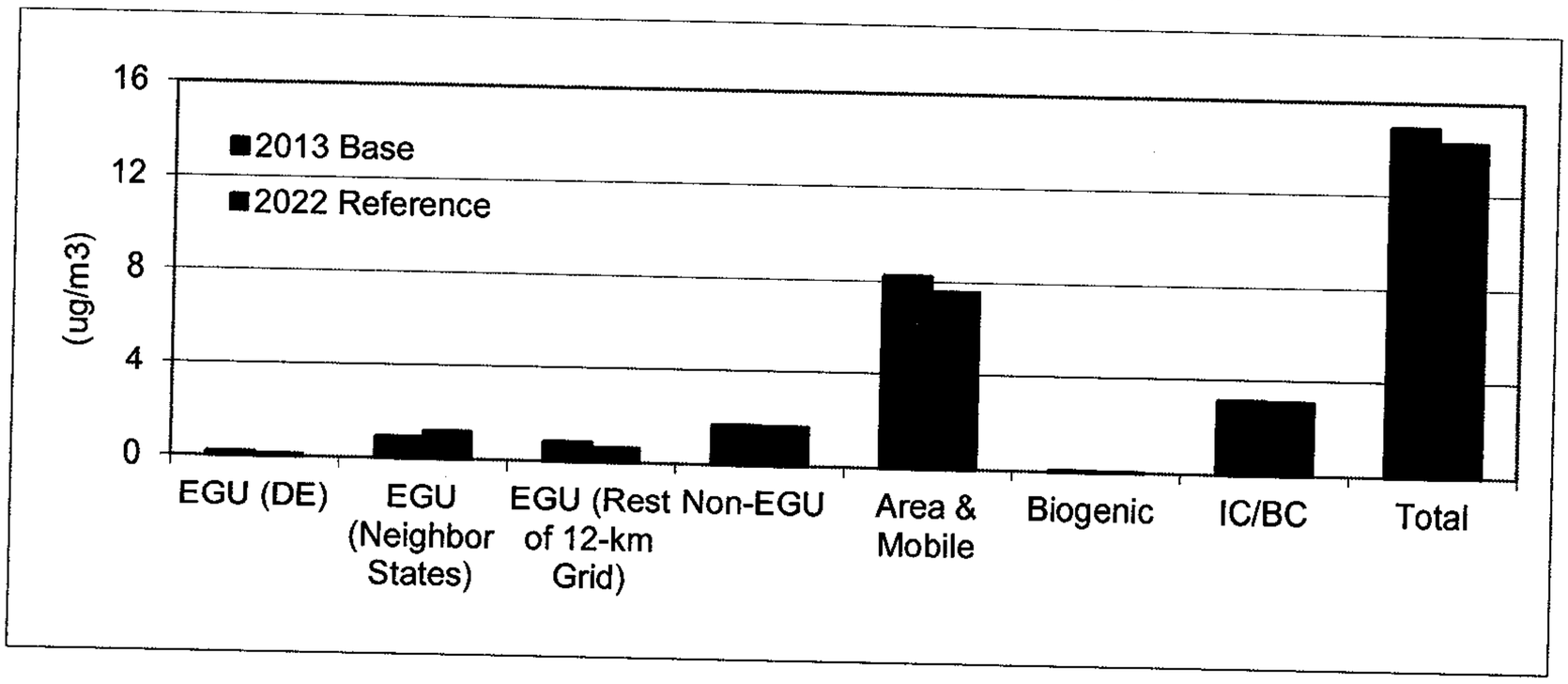


Figure 3-6b. CMAQ/PPTM-Derived Contributions to Annual Average $PM_{2.5}$ Concentration for the 2013 Base Case and 2022 Reference Case Simulations: Delaware.



For both receptor regions and both years, the tagging results indicate that among the tagged categories the area, on-road mobile, and non-road sources (combined) are the largest contributor to the overall $PM_{2.5}$ concentration. They account for about 50 percent of the overall simulated concentration. IC/BCs, non-EGU sources, and EGU sources also contribute. For the 4-km grid, the EGU sources (first three tags combined) account for 13 percent of the simulated annual average $PM_{2.5}$ concentration for both 2013 and 2022. For Delaware, the EGU sources (first three tags combined) account for 12 and 13 percent, respectively, of the simulated annual average $PM_{2.5}$ concentration for 2013 and 2022.

The EGU contribution from sources located in Delaware is negligible when considering annual average $PM_{2.5}$ for the 4-km grid and very small when considering annual average $PM_{2.5}$ for Delaware. There is a slight reduction in contribution from these sources between 2013 and

2022. The EGU contribution is larger for sources in neighboring states and the remainder of the grid. There is an increase in contribution from sources in the neighboring states between 2013 and 2022 and a reduction in contribution from sources in the remainder of the 12-km grid between 2013 and 2022.

Note that the IC/BC contribution represents the contribution from all sources outside the 12-km grid (including EGUs located outside of the region), so the total EGU contribution may be slightly higher.

To further illustrate the EGU contributions, spatial plots of the simulated annual average $PM_{2.5}$ concentration (all sources) and the corresponding contribution from EGU sources are provided in Figures 3-7 and 3-8 for the 2013 Base Case and 2022 Reference Case, respectively. Note that different scales are used to display the contributions from all sources and EGU sources.

Figure 3-7. CMAQ/PPTM Contribution to Simulated Annual Average $PM_{2.5}$ Species Concentration (μgm^{-3}) for the 2013 Base Case Simulation and the 4-km Grid from Emissions from (a) All Sources and (b) EGU Sources.

(a) Annual Average $PM_{2.5}$ (All Sources) **(b) Annual Average $PM_{2.5}$ Contribution (EGU Sources)**

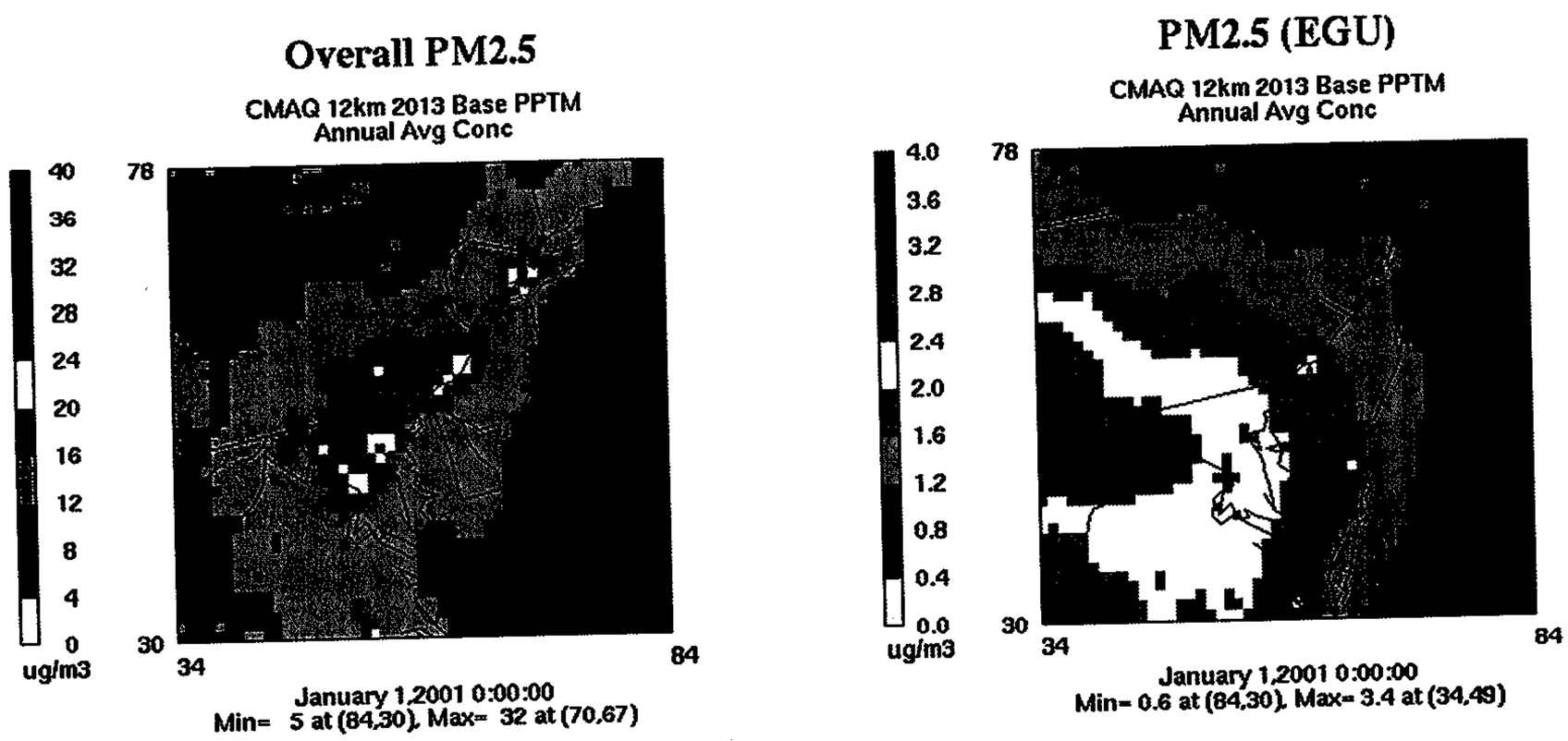
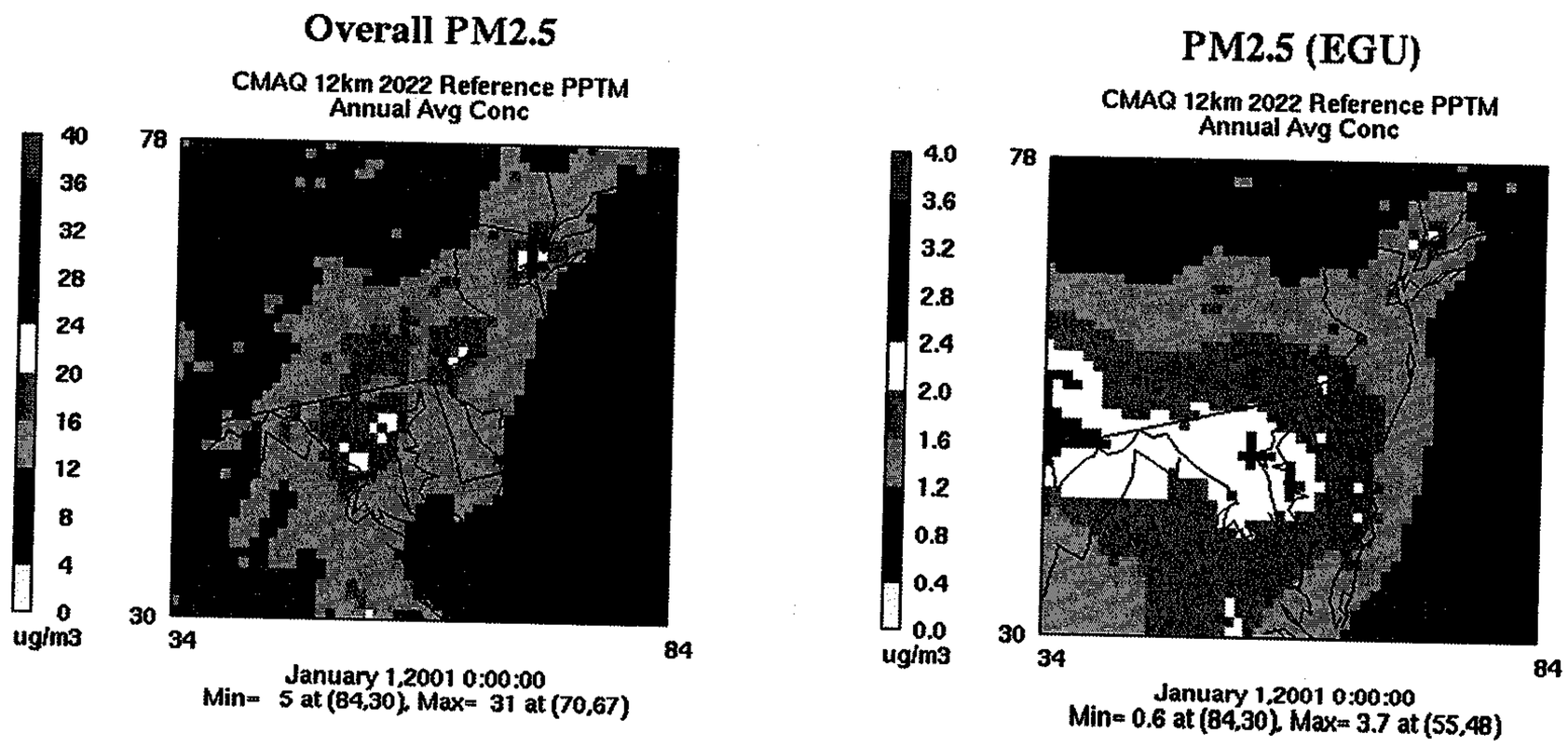


Figure 3-8. CMAQ/PPTM Contribution to Simulated Annual Average $PM_{2.5}$ Species Concentration (μgm^{-3}) for the 2022 Reference Case Simulation and the 4-km Grid from Emissions from (a) All Sources and (b) EGU Sources.

(a) Annual Average $PM_{2.5}$ (All Sources) **(b) Annual Average $PM_{2.5}$ Contribution (EGU Sources)**



For 2013, the overall maximum simulated annual average $PM_{2.5}$ concentration from all sources is 32 μgm^{-3}. The maximum contribution from EGU sources is 3.4 μgm^{-3}. There is a relatively broad area in the west-central portion of the grid with contributions greater than 2.4 μgm^{-3}. The greatest contributions occur in western Pennsylvania, western Maryland, and West Virginia.

For 2022, the overall maximum simulated annual average $PM_{2.5}$ concentration from all sources is 31 μgm^{-3}. The maximum contribution from EGU sources is 3.7 μgm^{-3}. The spatial extent of contributions greater than 2.4 μgm^{-3} is much less than for 2013. The greatest contributions are localized and occur in Maryland along the northwestern and eastern portions of the Chesapeake Bay. This is due to a net increase in both NO_x and SO_2 emissions for EGUs in Maryland between 2013 and 2022, most of which occurs at facilities in this part of the state. This results in a slight increase in contribution from EGUs to $PM_{2.5}$ concentrations in Delaware that is just noticeable in Figure 3-8b and also appears in Figure 3-6b as an increase in contribution from emissions from neighboring states.

The estimated contributions were used to estimate the overall health-related costs associated with EGUs within the region encompassed by the 4-km modeling grid; the EGU-related costs are presented in Section 4 and are compared with results from a recent report by the National Academy of Sciences (NAS, 2009)

3.5. Discussion of Attributes and Limitations

The CMAQ air quality modeling system provides a reliable platform for evaluating the expected responses to changes in precursor emissions. The detailed, quantitative modeling results

provide an excellent basis for examining the effects of the changes in emissions on air quality and provide the requisite input for the health effects and benefits modeling.

CMAQ is a three-dimensional, regional-scale, multi-pollutant model that simulates a) the emissions of precursor species (NO_x, SO_2, VOC, Hg, etc.) from various anthropogenic and biogenic sources, b) the transport, dispersion, and chemical transformation of these constituents into secondary products (ozone and particulate matter), and c) the deposition of such species to land surfaces. It is well suited for use with IPM since the emissions changes estimated using IPM typically 1) involve point sources (with varying stack-height and plume-rise parameters) that require a three-dimensional representation of the atmosphere, 2) are distributed regionally (within the power grid), and 3) simultaneously affect multiple precursor species. All of these factors can be taken into account in a CMAQ simulation. CMAQ is also able to accommodate temporal variations in the emissions and changes to the temporal profiles of the emissions. In addition to a spatially and temporally detailed treatment of the emissions, CMAQ is also designed to account for other factors that affect air quality and the resulting health impacts at any given location, such as meteorology, topography, land-use, and atmospheric chemistry processes.

An important attribute of this application of CMAQ is the use of 4-km horizontal grid resolution. This grid resolution is consistent with current EPA modeling guidance and practice for urban-scale ozone modeling and exceeds that typically used for $PM_{2.5}$ and mercury modeling. This grid resolution should be sufficiently detailed to resolve both near-source and regional processes that influence point source emissions and provide an accurate response to small changes in precursor emissions.

All air quality modeling exercises are affected by inherent uncertainties that derive from model formulation (including numerical approximations and the parameterization of physical and chemical processes), and inaccuracies in the input fields (including the meteorological inputs and emission inventory estimates). A number of key limitations and uncertainties, both general and specific to this analysis, are discussed below.

Pollutants such as ozone and $PM_{2.5}$ are secondary pollutants that are formed through atmospheric chemical processes. There are many different reaction pathways and there are uncertainties associated with each pathway as represented in the CMAQ model.

There are inherent uncertainties in the regional-scale emission inventories as well as in the IPM emission estimates. Key areas of uncertainty in the emissions include the accuracy and completeness of the National Emissions Inventory (NEI) base-year emission estimates, the methods and assumptions used to project the emissions (e.g., economic indicators and forecasts), the use of spatial surrogates (e.g., population, land use) to allocate the emissions by grid cell, the use of estimated annual, seasonal, monthly, and diurnal temporal profiles to allocate the emissions temporally, and the use of chemical speciation profiles that are based on limited data to speciate the data for use in the model (particularly hydrocarbon data). Key areas of uncertainty in the IPM emission estimates are uncertainties in a) forecasting future economic growth and associated demands in electricity, b) changes in the future regulatory environment,

c) market pricing, and d) the costs associated with construction and maintenance of electric generation facilities operated in a marine environment.

It is expected that there are also uncertainties in the other inputs that also contribute to biases in the CMAQ results; these have not been specifically examined or quantified as part of this analysis. In addition, there are uncertainties associated with modeling a future year. As noted above, the 2022 emissions are based on future estimates of population and economic and industrial activity and contain uncertainties due to potential unknown social, political, and/or economic factors that could affect growth/activity and future emissions. Also, the meteorological inputs might be representative of 2001 conditions but may not reflect any effects of potential climate change in 2022.

4. Health Effects and Benefits Assessment

The methods and results of the health effects and benefits modeling related to ozone, $PM_{2.5}$, and mercury are presented in this section. Ozone and $PM_{2.5}$ are secondary pollutants that are formed in the atmosphere. Ozone is formed in the atmosphere by a series of reactions involving ultra violet radiation and precursor emissions of NO_x and VOCs. Fine particulates in the atmosphere consist of primary particles that are emitted directly from sources and secondary particles that form in the atmosphere through chemical and physical processes. Pollutants that contribute to the formation of secondary aerosols include SO_2, NO_x, and other species. Thus this assessment of the health effects and benefits for ozone and $PM_{2.5}$ addresses the effects of changes in NO_x and SO_2 emissions.

For ozone and $PM_{2.5}$, the BenMAP health effects analysis tool was used to quantify the health impacts and monetized health impacts associated with EGU emissions and specifically with the changes in emissions from 2013 to 2022. For mercury, a more qualitative assessment is provided.

4.1. Ozone and $PM_{2.5}$

Following the application of CMAQ, the CMAQ-derived air quality estimates were processed for input to the BenMAP health effects analysis tool, and BenMAP was used to estimate the health effects and monetized health-related effects associated with the changes in air pollution simulated by CMAQ. The BenMAP tool includes health impact functions, which relate a change in the concentration of a pollutant to a change in the incidence of a health endpoint. BenMAP also calculates the economic value of health impacts.

Overview of the BenMAP Modeling System

BenMAP is a computer program developed by EPA that uses interpolation functions, population projections, health impact functions, and valuation functions to translate simulated changes in air pollution concentration into changes in health-related incidences and monetized health-related costs/benefits. BenMAP is primarily intended as a tool for estimating the human health effects and economic costs/benefits associated with changes in ambient air pollution. EPA originally developed this tool to analyze national-scale air quality regulations. The health-related monetary values derived using BenMAP are intended to inform policy makers by enabling the comparison of the benefits and costs of various regulatory measures (Abt Associates, 2008).

BenMAP relies on the input of air quality information that can be used to calculate the change in ambient air pollution associated with a change in emissions. Typically, the results from two air quality modeling simulations (with different emission inputs) are used. In some cases, measured ambient air quality data can also be used.

BenMAP calculates health effects based on expected relationships between the change in concentration and certain health effects (also known as health endpoints), using concentration-response (C-R) functions from epidemiology studies (Abt Associates, 2008). The response functions are used together with population data to estimate health effects. For a model-based application, health effects are calculated on a grid cell-by-grid cell basis and then summed to

obtain regional and national-scale estimates. In its most basic form, the health effect for a given health endpoint is a function of the change in air concentration, concentration-response estimates, and population. Primary health endpoints include premature mortality, heart attacks, and chronic respiratory illnesses.

After estimating the change in adverse health effects associated with a given change in air quality, BenMAP calculates the monetary benefits associated with those changes (Abt Associates, 2008). Simply, the economic value is based on the change in the incidence of a certain adverse health effect multiplied by the value of the health effect (on a per-incident or per-case basis). For example, the value associated with avoided premature mortality is typically calculated using the Value of Statistical Life (VSL), which is the monetary amount that people are willing to pay to slightly reduce the risk of premature death. For other health effects, the medical costs of the illness are typically used to estimate value. The BenMAP database includes valuation functions for VSL and other health endpoints.

BenMAP Application Procedures

Prior to the application of BenMAP, the CMAQ model output files were reformatted for input into the BenMAP tool. The analysis period for ozone for the application of BenMAP is a subset of the CMAQ simulation period and includes only April through October. The input files for ozone contain 214 days of daily maximum 8-hour average ozone concentrations for each grid cell in the CMAQ modeling domain. The analysis period for $PM_{2.5}$ for the application of BenMAP is the full annual CMAQ simulation period. The input files for $PM_{2.5}$ contain 365 days of 24-hour average $PM_{2.5}$ concentration for each grid cell. BenMAP was applied for both the 4-km CMAQ modeling domain and for the area covering the State of Delaware. BenMAP includes population data at the census-tract level and algorithms for characterizing demographic changes (age distribution) over time. For this analysis, population estimates for 2020 were used. This is the closest year currently available in BenMAP to the CMAQ simulation year of 2022. BenMAP was applied separately for ozone and $PM_{2.5}$.

BenMAP calculates the changes in health impacts and monetized health-related costs/benefits by comparing the results of two simulations. For this study, BenMAP was used to assess the health impacts and monetized health-related impacts of the simulated changes in ozone and $PM_{2.5}$ air quality between 2013 and 2022. For both years, BenMAP was also to estimate the overall health impacts and monetized health-related impacts associated with emissions from all EGUs in the analysis region. For reference, difference plots of the CMAQ-derived ozone and $PM_{2.5}$ concentrations for each pair of simulations were presented in Section 3.

For each pollutant and simulation couple, the application of BenMAP included four steps:

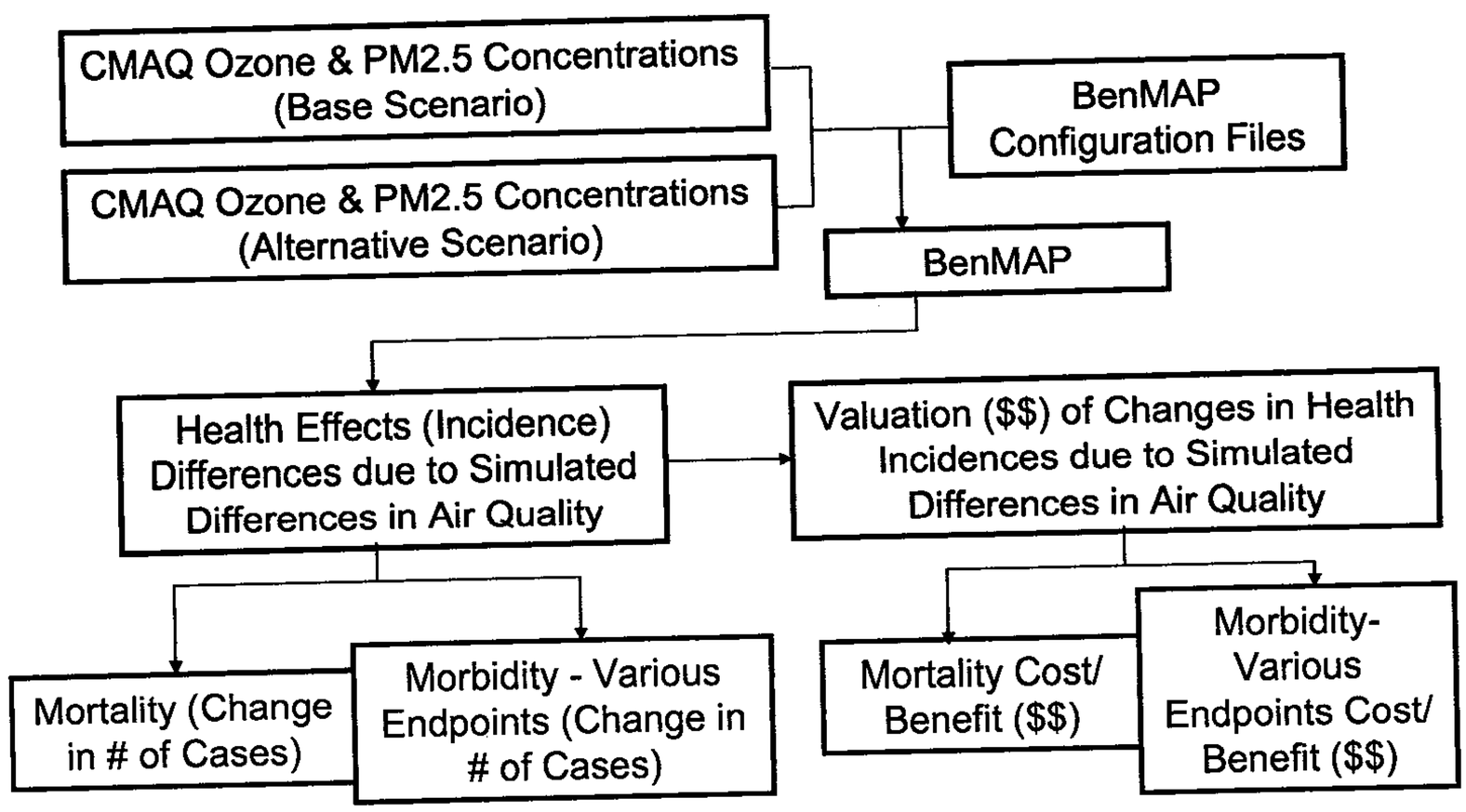
- Incorporation of the CMAQ modeling results into the air quality grid files required by BenMAP (air quality grid creation);

- Calculation of the change in the incidence of adverse health effects based on the differences in the CMAQ-derived ozone and $PM_{2.5}$ concentrations between the two simulations;
- Aggregation of the incidence results and calculation of the economic value of the aggregated incidences; and
- Preparation of tabular and graphical summaries; quality assurance and analysis of the results.

In the air quality grid creation step, the CMAQ model results were used directly.

Figure 4-1 illustrates the steps and components of the BenMAP application procedure.

Figure 4-1. Schematic Diagram of the BenMAP Health Effects and Benefits Analysis



Health Impact Functions

BenMAP was used to calculate reductions in both mortality and a range of non-fatal health effects (morbidity), based on epidemiological studies of a number of U.S. and non-U.S. (Canadian) populations.

BenMAP can estimate changes in a wide range of health impact "endpoints" associated with changes in ozone and $PM_{2.5}$ exposure. The endpoints are grouped broadly as "mortality" and "morbidity." Mortality endpoints include changes in "all-cause" mortality, as well as mortality due to specific causes, such as cardiopulmonary disease. Morbidity endpoints include specific illnesses and symptoms ("asthma exacerbations"); events requiring medical care (emergency room visits and hospital admissions); and adverse effects that involve lost work or restricted activity days.

EPA has evaluated the literature related to the adverse effects of ozone and particulate exposures and identified a set of endpoints for which the associations are considered to be well established, and for which reliable exposure-response relationships have been developed (Abt Associates, 2008). For this analysis, the EPA-recommended set of health endpoints for use with the latest version of BenMAP was used. These endpoints are listed in Table 4-1 and Table 4-2 for ozone and $PM_{2.5}$, respectively. The endpoints include changes in mortality (for both adults and infants), as well as a range of morbidity endpoints related to respiratory and cardiovascular diseases and symptoms, hospital admissions, and lost work or lost activity days. The age range for each endpoint, if available, is provided in the tables.

Table 4-1. Health Impact Functions Used in the BenMAP Application to Estimate Ozone-Related Health Effects.

Endpoint	Author/Study Location	Age Range	Notes
Mortality, Non-Accidental	Ito et al. (2005)	0–99	a, b
Mortality, Non-Accidental	Schwartz (2005) (14 U.S. cities)	0–99	a,c
Mortality, Non-Accidental	Bell et al. (2004) (95 U.S. Cities)	0–99	a,b
Mortality, All Cause	Levy et al. (2005) (US & non-U.S.)	0–99	a,c
Mortality, All Cause	Bell et al. (2005) (US & non-U.S.)	0–99	a,b
Mortality, Cardiopulmonary	Huang et al. (2005) (19 U.S. cities)	0–99	a,b
Emergency Room Visits, Asthma	Jaffe et al. (2003) (Ohio cities)	5-34	a
Emergency Room Visits, Asthma	Peel et al. (2005) (Atlanta, GA)	0–99	a
Emergency Room Visits, Asthma	Wilson et al. (2005) (Portland, ME)	0–99	a
Emergency Room Visits, Asthma	Wilson et al. (2005) (Manchester, NH)	0–99	a
Hospital Admissions, All Respiratory	Burnett et al. (2001) (Toronto, CAN)	0–1	a,c
Hospital Admissions, All Respiratory	Schwartz ((New Haven, CT)	65–99	a,b
Hospital Admissions, All Respiratory	Schwartz (Tacoma, WA)	65–99	a,b
Hospital Admissions, Chronic Lung Disease	Moolgavkar et al. (1997) (Minneapolis, MN)	65–99	a,d
Hospital Admissions, Pneumonia	Moolgavkar et al. (1997) (Minneapolis, MN)	65–99	a,d
Hospital Admissions, Pneumonia	Schwartz (1994) (Detroit, MI)	65–99	a,d
Hospital Admissions, Pneumonia	Schwartz (1994)(Minneapolis, MN)	65–99	a,d
Hospital Admissions, Chronic Lung Disease (less Asthma)	Schwartz (1994) (Detroit, MI)	65–99	a,d
School Loss Days, All	Chen et al. (2000) (Washoe Co, NV)	5–17	a,f
School Loss Days, All	Gilliland et al. (2001) (So. CA)	5–18	a,e
Worker Productivity	Crocker & Horst (Nationwide)	18–64	a,d
Minor Restricted Activity Days	Ostro & Rothschild (1989) (Nationwide)	18–64	a,g

a/ Metric is daily maximum 8-hour ozone.
b/ Metric is daily maximum 8-hour ozone. Warm season. 8-hour max from 24-hour mean.
c/ Metric is daily maximum 8-hour ozone. Warm season. 8-hour max from 1-hour mean.
d/ Metric is daily maximum 8-hour ozone. All year. 8-hour max from 24-hour mean.
e/ Metric is daily maximum 8-hour ozone. All year. 8-hour max from 8-hour mean.
f/ Metric is daily maximum 8-hour ozone. All year. 8-hour max from 1-hour mean.
g/ Metric is daily maximum 8-hour ozone. 8-hour max from 1-hour mean.

Table 4-2. Health Impact Functions Used in the BenMAP Application to Estimate PM2.5-Related Health Effects.

Endpoint	Author/Study Location	Age Range	Notes
Mortality, All Cause	Laden et al. (2006) (6 cities)	25–99	
Mortality, All Cause	Pope et al. (2002) (51 cities)	30–99	
Mortality, All Cause	Woodruff et al. (2006) (204 counties)	0–1	
Mortality, All Cause	Pope et al. (2002) (51 cities)	30–99	a
Mortality, All Cause	Pope et al. (2002) (51 cities)	30–99	b
Mortality, All Cause	Pope et al. (2002) (51 cities)	30–99	c
Mortality, All Cause	Pope et al. (2002) (51 cities)	30–99	d
Mortality, All Cause	Expert Elicitation (2006)	30–99	e
Mortality, All Cause	Expert Elicitation (2006)	30–99	f
Mortality, All Cause	Expert Elicitation (2006)	30–99	g
Mortality, All Cause	Expert Elicitation (2006)	30–99	h
Mortality, All Cause	Expert Elicitation (2006)	30–99	i
Mortality, All Cause	Expert Elicitation (2006)	30–99	j
Mortality, All Cause	Expert Elicitation (2006)	30–99	k
Chronic Bronchitis	Abbey et al. (1995)	27–99	
Acute Bronchitis	Dockery et al. (1996) (24 communities)	8–12	
Acute Myocardial Infarction, Nonfatal	Peters et al. (2001) (Boston, MA)	18–24	
Acute Myocardial Infarction, Nonfatal	Peters et al. (2001) (Boston, MA)	25–44	
Acute Myocardial Infarction, Nonfatal	Peters et al. (2001) (Boston, MA)	45–54	
Acute Myocardial Infarction, Nonfatal	Peters et al. (2001) (Boston, MA)	55–64	
Acute Myocardial Infarction, Nonfatal	Peters et al. (2001) (Boston, MA)	65–99	
Hospital Admissions, Chronic Lung Disease	Moolgavkar (2003) (Los Angeles, CA)	65–99	
Hospital Admissions, Chronic Lung Disease	Ito (2003) (Detroit, MI)	65–99	
Hospital Admissions, Chronic Lung Disease (less Asthma)	Moolgavkar (2000) (Los Angeles, CA)	18–64	
Hospital Admissions, Pneumonia	Ito	65–99	
Hospital Admissions, Asthma	Sheppard (2003) (Seattle, WA)	0–64	
Hospital Admissions, All Cardiovascular (less Myocardial Infarctions)	Moolgavkar	18–64	
Hospital Admissions, All Cardiovascular (less Myocardial Infarctions)	Moolgavkar	65–99	
Hospital Admissions, Ischemic Heart Disease (less Myocardial Infarctions)	Ito (2003) (Detroit, MI)	65–99	
Hospital Admissions, Dysrhythmia	Ito (2003) (Detroit, MI)	65–99	
Hospital Admissions, Congestive Heart Failure	Ito (2003) (Detroit, MI)	65–99	
Emergency Room Visits, Asthma	Norris et al. (1999) Seattle, WA	0–17	
Minor Restricted Activity Days	Ostro and Rothschild (1989) (Nationwide)	18–64	
Lower Respiratory Symptoms	Schwartz and Neas (2000) (6 U.S. Cities)	7–14	
Asthma Exacerbation, Cough	Ostro et al. (2001) (Los Angeles)	6–18	
Asthma Exacerbation, Wheeze	Ostro et al. (2001) (Los Angeles)	6–18	
Asthma Exacerbation, Shortness of Breath	Ostro et al. (2001) (Los Angeles)	6–18	
Work Loss Days	Ostro (1987) (Nationwide)	18–64	
Upper Respiratory Symptoms	Pope et al. (1987) (Utah Valley)	9–11	

a/ Adjusted Coefficient With 10 µg Threshold

b/ Adjusted Coefficient With 12 µg Threshold

c/ Adjusted Coefficient With 15 µg Threshold
d/ Adjusted Coefficient With 7.5 µg Threshold
e/ Full Range
f/ Range from > 10 to 30 µg
g/ Range from >16 to 30 (no threshold)
h/ Range from >7 to 30
i/ Range from 4 to 7 µg
j/ Range from 4 to 10 µg
k/ Range from 4 to 16 µg (no threshold)

The results options for this study include the mean value, incremental percentile values, and the standard deviation.

Valuation Metrics

BenMAP was also used to estimate reductions in monetized health-related benefits (based on value of statistical life studies, lost wages, and health care expenses) associated with the health impacts. These estimates are derived using a set of monetary surrogates for the various health effects developed by EPA and public health researchers. BenMAP also tracks changes over time in willingness-to-pay for reductions in health risks, and includes adjustment factors that incorporate the effect of inflation on health-related costs.

The assessment of monetized health-related benefits involves assigning monetary values to each health endpoint, and totaling the overall benefits associated with changes in pollutant exposures. Different valuation methods are used for the various health endpoints. The monetary surrogate value for mortality is derived using a Value of Statistical Life (VSL) approach, that is, the monetary cost of a single "statistical" death (Abt Associates, 2008). The VSL used for this analysis is $6.3 million (in 2000-equivalent dollars).

Valuation methods for morbidity endpoints (non-fatal health effects) include approaches referred to as cost-of-illness (COI), willingness-to-pay (WTP), and lost wages or productivity (Abt Associates, 2008). COI estimates comprise a range of approaches, which account for the costs of medical care, and in some cases lost wages. WTP approaches refer to methods where voluntary payments to avoid disease are directly or indirectly estimated and used to estimate monetized health-related benefits. Finally, lost productivity methods value the time lost to illness using wage rates or the estimated value of leisure or school time (Abt Associates, 2008). For all endpoints, the total monetized health-related benefit for a given endpoint is estimated by multiplying the monetary values for that endpoint by the estimated change in the number of "cases" of the endpoint. For most studies, morbidity values are small compared to the mortality values. Thus, the specific valuation methods used for morbidity have only a small effect on the overall monetized health-related benefits estimates.

For this analysis, the EPA-recommended set of valuation methods for the latest version of BenMAP was used. The endpoints and methods for the valuation portion of the analysis are

listed in Table 4-3 and 4-4 for ozone and $PM_{2.5}$, respectively. The endpoints include monetized health-related benefits associated with changes in mortality, as well as a range of morbidity endpoints. All monetized health-related benefits results for this analysis are presented in 2010-equivalent U.S. dollars.

Table 4-3. Valuation Functions Used in the BenMAP Application to Estimate Ozone-Related Monetized Health-Related Benefits.

Endpoint	Author/Study Location	Valuation Method	Notes
Mortality, Non-Accidental	Ito et al. (2005)	VSL	a,c
Mortality, Non-Accidental	Schwartz (2005) (14 U.S. cities)	VSL	a,c
Mortality, Non-Accidental	Bell et al. (2004) (95 U.S. Cities)	VSL	a,c
Mortality, All Cause	Levy et al. (2005) (U.S. & non-U.S.)	VSL	a,c
Mortality, All Cause	Bell et al. (2005) (U.S. & non-U.S.)	VSL	a,c
Mortality, Cardiopulmonary		VSL	a,c
Hospital Admissions, Respiratory		COI	b,d
Hospital Admissions, Respiratory		COI	b,e
Emergency Room Visits, Respiratory	Smith et al. (1997)	COI	c
Emergency Room Visits, Respiratory	Stanford et al. (1999)	COI	c
School Loss Days			f
Worker Productivity			g
Acute Respiratory Symptoms	Cardio-vascular studies	WTP	h

a/ Based on 26 value-of life studies
b/ Med costs + wage loss
c/ Ages: 0-99
d/ Ages: 65-99
e/ Ages: 0-2
f/ Ages: 0-17
g/ Ages: 18-65
h/ Ages: 18-99

Table 4-4. Valuation Functions Used in the BenMAP Application to Estimate PM2.5-Related Monetized Health-Related Benefits.

Endpoint	Author/Study Location	Valuation Method	Notes
Mortality	Laden et al. (2006) (6 cities)	VSL	a, i
Mortality	Pope et al. (2002) (51 cities)	VSL	a, i
Mortality	Woodruff et al. (1997) (86 cities)	VSL	a, i
Chronic Bronchitis	Abbey et al. (1995) (CA)	WTP	b, k
Acute Myocardial Infarction	Peters et al. (2001) (Boston, MA)	COI	c,j,q
Hospital Admissions, Chronic Lung Disease	Ito (2003) (Detroit, MI)	COI	d,i
Hospital Admissions, Pneumonia	Ito (2003) (Detroit, MI)	COI	d,i
Hospital Admissions, Respiratory	Ito (2003) (Detroit, MI)	COI	d,p
Hospital Admissions, Cardiovascular	Moolgavkar (2000) (Los Angeles)	COI	d,p
Hospital Admissions, Cardiovascular	Moolgavkar (2000) (Los Angeles)	COI	d,i
Emergency Room Visits, Respiratory	Norris et al (1999) (Seattle, WA)	COI	i,s
Acute Bronchitis	Dockery et al. (1996) (24 communities)	WTP	e,f,m
Lower Respiratory Symptoms	Schwartz and Neas (2000) (6 U.S. cities)	WTP	e,f,m
Upper Respiratory Symptoms	Pope et al. (1991) (Utah Valley)	WTP	e,f,m
Acute Respiratory Symptoms	Ostro (2001) (Los Angeles)	WTP	e,f,n
Work Loss Days	Ostro (1987) (Nationwide)		g,o
Asthma Exacerbation	Ostro (2001) (Los Angeles)	WTP	h,m,r
Mortality, All Cause	Expert Elicitation (2006)	VSL	a,j

a/ Based on 26 value-of-life studies.
b/ Average severity
c/ 5 yrs med, 5 yrs wages, 3% DR
d/ med costs + wage loss
e/1 day illness
f/ CV studies
g/ Median daily wage, county-specific
h/ bad asthma day
i/ 0-99
j/ 30-99 k/ 0-24
l/ 65-99
m/ 0-17
n/ 18-99
o/ 18-65
p/ 20-64
q/ Russell (1998)
r/ Rowe Chestnut (1986)
s/ Stanford (1999)

In the aggregation and valuation step, the results were aggregated for the 4-km grid and for the State of Delaware. Default options were applied in the aggregation and pooling of the results. Similarly, EPA standard inflation values (defaults) were used for the valuation. The results are given in 2010-equivalent U.S. dollars.

Post-processing and Quality Assurance Procedures

As a first step in the quality assurance of the BenMAP application procedures and results, a protocol document outlining each step in the application of BenMAP was prepared. This was subsequently used as a checklist for each application and for quality assurance. Following the application of BenMAP for each pair of simulations, a subset of the BenMAP runs was duplicated by a second modeler using another computer and the results were confirmed to be the same. Finally, the results for each simulation pair were checked for consistency with emissions and the CMAQ modeling results.

Tabular summaries of the results were then prepared, as presented in the following sections. The contents of the tables were systematically checked by comparing the values with the raw BenMAP report files.

Health Effects and Monetized Health Effects Attributable to Emission Changes (2013-2022)

BenMAP was used to estimate the change in the incidence of various health-related endpoints, as well as a monetized health-related benefits associated with improvements in ozone and $PM_{2.5}$ air quality between 2013 and 2022. The incidence and valuation results are presented in the remainder of this section. The health incidence results presented in this section are the BenMAP-derived mean values. The valuation estimates reflect both an income growth adjustment and a time lag between exposure and $PM_{2.5}$ mortality.

The income growth adjustment accounts for expected growth in real income over time. Economic theory suggests that WTP for most goods and services (such as environmental protection) will increase if income increases. To account for growth in income through 2022, BenMAP applied the following factors to the valuation results: 1.23 for long-term mortality, 1.27 for chronic health impacts, and 1.08 for minor health impacts.

The valuation results for $PM_{2.5}$ assume that there is a time lag between changes in $PM_{2.5}$ concentration and changes in $PM_{2.5}$ mortality. To account for this, monetized health-related benefits occurring in the future are discounted. For this analysis, the BenMAP-derived reductions were multiplied by 0.91 to achieve a 3% "discount rate" and by 0.82 to achieve a 7% "discount rate." Similar adjustments do not exist for ozone.

All of the incidence and valuation results are rounded to two significant figures (and also limited to a maximum of two decimal places).

Ozone

BenMAP results for ozone mortality, based on epidemiology literature, are presented in Table 4-5.

Table 4-5. BenMAP Pooled Incidence Results for Ozone-Related Mortality: Reduction in Premature Mortality Associated with the Changes in Air Quality from 2013 to 2022.

Epidemiology Literature	Greater Mid-Atlantic Region (4-km Grid)	Delaware
	No. of Cases Avoided	No. of Cases Avoided
Mortality, Non-Accidental (Ito et al.)	370	30
Mortality, Non-Accidental (Schwartz)	130	10
Mortality, Non-Accidental (Bell et al.)	82	7
Mortality, All Cause (Levy et al.)	370	31
Mortality, All Cause (Bell et al.)	260	22
Mortality, Cardiopulmonary (Huang et al.)	120	10

The reduction in the mortality rate ranges from 82 to approximately 370 cases for the 4-km grid and from 7 to 31 for Delaware.

BenMAP results for other ozone-related health effects and associated endpoints (morbidity) are presented in Table 4-6.

Table 4-6. BenMAP Pooled Incidence Results for Ozone-Related Morbidity: Reduction in Various Morbidity Endpoints Associated with the Changes in Air Quality from 2013 to 2022.

Epidemiology Literature	Greater Mid-Atlantic Region (4-km Grid)	Delaware
	No. of Cases Avoided	No. of Cases Avoided
Emergency room visits for asthma (all ages)	230	23
Hospital admissions for respiratory symptoms	760	70
School loss days (age 5–17)	140,000	12,000
Minor restricted-activity days (age 18–65)	470,000	38,000
Work loss days (age 18–65)	3.2.E+06	3.7.E+05

There are also some reductions in the morbidity endpoints due to the change in ambient ozone from 2013 to 2022.

BenMAP valuation results for ozone related mortality are presented in Table 4-7. The monetized health-related benefits represent regional benefits, in millions of 2010-equivalent U.S. dollars.

Table 4-7. BenMAP-Derived Monetized Health-Related Benefits for Ozone-Related Mortality: Estimated Monetized Benefits (Millions U.S. Dollars) Related to Premature Mortality Associated with the Changes in Air Quality from 2013 to 2022.

Epidemiology Literature	Greater Mid-Atlantic Region (4-km Grid)	Delaware
Non-accidental (Ito et al.)	3,600	300
Non-accidental (Bell et al. (U.S. cities))	810	67
Non-accidental (Schwartz et al.)	1,200	100
All causes (Levy et al.)	3,700	300
All causes (Bell et al.)	2,600	220
Cardiopulmonary	1,200	98

Monetized health-related benefits for mortality range from 810 million to 3.7 billion dollars for the 4-km grid and from 67 to 300 million dollars for Delaware, depending on the study used to calculate the benefits.

BenMAP valuation results for other ozone-related health effects and associated endpoints (morbidity) are presented in Table 4-8.

Table 4-8. BenMAP-Derived Monetized Health-Related Benefits for Ozone-Related Morbidity: Estimated Monetized Benefits (Millions U.S. Dollars) Related to Various Morbidity Endpoints Associated with the Changes in Air Quality from 2013 to 2022.

Epidemiology Literature	Greater Mid-Atlantic Region (4-km Grid)	Delaware
Emergency room visits for respiratory symptoms	0	0
Hospital admissions for respiratory symptoms	17	2
School loss days (age 0–17)	14	1
Work loss days (age 18–65)	4	0
Acute respiratory symptoms (age 18–99)	32	3

For other health effects associated with ozone, the monetized benefits for mortality range from 0 to 32 million dollars for the 4-km grid and from 0 to 3 million dollars for Delaware.

$PM_{2.5}$

BenMAP results for $PM_{2.5}$ mortality are presented in Table 4-9. The mortality estimates are based on both epidemiology literature and expert elicitation.

Table 4-9. BenMAP Pooled Incidence Results for $PM_{2.5}$-Related Mortality: Reduction in Premature Mortality Associated with the Changes in Air Quality from 2013 to 2022.

Epidemiology Literature	Greater Mid-Atlantic Region (4-km Grid)	Delaware
	No. of Cases Avoided	No. of Cases Avoided
Harvard six-city study (Laden et al.)	2,900	200
ACS study (Pope et al.)	1,100	78
Infant mortality study (Woodruff et al.)	4	0
Expert Elicitation		
Expert A	3,000	210
Expert B	2,500	170
Expert C	2,500	180
Expert D	1,700	120
Expert E	3,800	270
Expert F	2,200	150
Expert G	1,300	93
Expert H	1,700	120
Expert I	2,300	160
Expert J	2,100	150
Expert K	400	28
Expert L	1,800	130

For the 4-km grid, the reduction in mortality rate due to emissions changes from 2013 to 2022 ranges from 1,100 to 2,900 based on epidemiological studies and from 400 to 3,800 for the expert elicitation estimates. For Delaware, the reduction ranges from 78 to 200 based on epidemiological studies and from 28 to 270 for the expert elicitation estimates.

BenMAP results for other $PM_{2.5}$-related health effects and associated endpoints (morbidity) are presented in Table 4-10.

Table 4-10. BenMAP Pooled Incidence Results for $PM_{2.5}$-Related Morbidity: Reduction in Various Morbidity Endpoints Associated with the Changes in Air Quality from 2013 to 2022.

Epidemiology Literature	Greater Mid-Atlantic Region (4-km Grid)	Delaware
	No. of Cases	No. of Cases
Chronic bronchitis (age>=25)	800	50
Emergency room visits for asthma (age<19)	1,300	53
Acute bronchitis (age 8–12)	1,700	100
Asthma exacerbation (age 6–18)	35,000	2,200
Lower respiratory symptoms (age 7–14)	21,000	1,300
Upper respiratory symptoms (asthmatic children age 9–18)	16,000	1,000
Minor restricted-activity days (age 18–65)	890,000	54,000
Work loss days (age 18–65)	150,000	9,000
Nonfatal myocardial infarction (age>17)	1,300	99
Hospital admissions—respiratory (all ages)	270	16
Hospital admissions—cardiovascular (age>17)	540	37

The BenMAP results indicate reductions for all of the morbidity endpoints due to emissions changes from 2013 to 2022.

BenMAP valuation results for $PM_{2.5}$ related mortality are presented in Table 4-11. The monetized health-related benefits represent regional benefits, in millions of 2010-equivalent U.S. dollars.

Table 4-11. BenMAP-Derived Monetized Health-Related Benefits for $PM_{2.5}$-Related Mortality with 3% and 7% Discount Rates: Estimated Monetized Benefits (Millions U.S. Dollars) Related to Premature Mortality Associated with the Changes in Air Quality from 2013 to 2022.

Epidemiology Literature	Greater Mid-Atlantic Region (4-km Grid)		Delaware	
	3% Discount Rate	7% Discount Rate	3% Discount Rate	7% Discount Rate
Harvard six-city study (Laden et al.)	26,000	23,000	1,800	1,600
ACS study (Pope et al.)	10,000	9,000	700	630
Infant mortality study (Woodruff et al.)	36	32	2	2
Expert Elicitation				
Expert A	27,000	24,000	1,900	1,700
Expert B	22,000	20,000	1,500	1,300
Expert C	22,000	20,000	1,400	1,300
Expert D	15,000	13,000	1,000	900
Expert E	34,000	31,000	2,400	2,100
Expert F	20,000	18,000	1,300	1,200
Expert G	12,000	11,000	840	750
Expert H	15,000	13,000	1,100	960
Expert I	21,000	19,000	1,400	1,300
Expert J	19,000	17,000	1,000	1,000
Expert K	3,500	3,200	250	230
Expert L	16,000	15,000	1,100	990

For the 3% discount rate, the calculated monetized health-related benefits for the 4-km grid region range from 10 to 26 billion dollars for premature mortality (not including infant mortality) based on epidemiological studies and from 3.5 to 34 billion dollars for the expert elicitation estimates. The calculated monetized health-related benefits for Delaware range from 700 million to 1.8 billion dollars for the premature mortality (not including infant mortality) based on epidemiological studies and from 250 million to 2.4 billion dollars for the expert elicitation estimates.

For the 7% discount rate, the calculated monetized health-related benefits for the 4-km grid region range from 9 to 23 billion dollars for premature mortality (not including infant mortality) based on epidemiological studies and from 3.2 to 31 billion for the expert elicitation estimates. The calculated monetized health-related benefits for Delaware range from 630 million to 1.6 billion dollars for the premature mortality (not including infant mortality) based on epidemiological studies and from 230 million to 2.1 billion for the expert elicitation estimates.

BenMAP valuation results for other $PM_{2.5}$-related health effects and associated endpoints (morbidity) are presented in Table 4-12.

Table 4-12. BenMAP-Derived Monetized Health-Related Benefits for $PM_{2.5}$-Related Morbidity: Estimated Monetized Benefits (Millions U.S. Dollars) Related to Various Morbidity Endpoints Associated with the Changes in Air Quality from 2013 to 2022.

Epidemiology Literature	Greater Mid-Atlantic Region (4-km Grid)	Delaware
Chronic bronchitis (age>=25)	440	27
Emergency room visits for asthma (age<19)	1	0
Acute bronchitis (age 8–12)	1	0
Asthma exacerbation (age 6–18)	2	0
Lower respiratory symptoms (age 7–14)	0	0
Upper respiratory symptoms (asthmatic children age 9–18)	1	0
Minor restricted-activity days (age 18–65)	61	4
Work loss days (age 18–65)	24	1
Nonfatal myocardial infarction (age>17)	150	12
Hospital admissions—respiratory (all ages)	4	0
Hospital admissions—cardiovascular (age>17)	10	1

The monetized health-related benefits associated with morbidity total approximately 690 million dollars for the 4-km grid and 45 million dollars for Delaware, with the majority of the benefits associated with a reduction in the incidence of chronic bronchitis and nonfatal myocardial infarctions.

Health Effects and Monetized Health Effects Attributable to Energy Generation

The overall health effects and costs attributed to emissions from EGUs located within the modeling domain (the 12-km grid) were estimated for the greater Mid-Atlantic region (the 4-km grid) and Delaware using the CMAQ/PPTM results summarized in Section 3. For this analysis, only the health effects and costs associated with $PM_{2.5}$ were calculated. The ozone effects were not calculated, but are expected to be much smaller than those for $PM_{2.5}$ (as demonstrated earlier in this section). BenMAP was applied for both 2013 and 2022.

BenMAP results for $PM_{2.5}$ mortality are presented in Table 4-13. The mortality estimates are based on both epidemiology literature and expert elicitation in which experts were asked to develop estimates of the increment in mortality that would be associated with increments of $PM_{2.5}$ exposures, based on their understanding of the epidemiological literature taken as a whole (Abt Associates, 2008). Differences among the studies and the experts are primarily due to the use of different study populations and exposure-response relationships.

Table 4-13. BenMAP Pooled Incidence Results for $PM_{2.5}$-Related Mortality: Premature Mortality Associated with EGU Emissions Located within the Modeling Domain.

Epidemiology Literature	Greater Mid-Atlantic Region (4-km Grid)		Delaware	
	No. of Cases (2013)	No. of Cases (2022)	No. of Cases (2013)	No. of Cases (2022)
Harvard six-city study (Laden et al.)	11,000	11,000	740	740
ACS study (Pope et al.)	4,200	4,100	290	290
Infant mortality study (Woodruff et al.)	14	13	1	1
Expert Elicitation				
Expert A	11,000	11,000	790	800
Expert B	9,200	9,200	650	650
Expert C	9,500	9,400	650	660
Expert D	6,200	6,100	430	430
Expert E	14,000	14,000	1,000	1,000
Expert F	8,200	8,200	570	580
Expert G	5,000	5,000	350	350
Expert H	6,200	6,100	430	430
Expert I	8,900	8,700	610	610
Expert J	7,800	7,700	540	540
Expert K	1,500	1,500	110	100
Expert L	6,500	6,600	470	470

The incidence results for mortality for 2013 and 2022 are very similar, especially after rounding to two significant figures. For the 4-km grid, the number of incidences of mortality (not including infant mortality) attributed to EGU emissions ranges from 1,500 to 14,000 for both years. However, for a number of studies/experts the values for 2022 are lower. For Delaware, the

number of incidences of mortality (not including infant mortality) attributed to EGU emissions ranges from 110 to 1,000 for 2013 and from 100 to 1,000 for 2022. Considering all of the studies/experts, the values for 2022 are in some cases higher and in some cases lower than those for 2013.

BenMAP results for other $PM_{2.5}$-related health effects and associated endpoints (morbidity) are presented Table 4-14.

Table 4-14. BenMAP Pooled Incidence Results for $PM_{2.5}$-Related Morbidity: Morbidity Endpoints Associated with EGU Emissions Located within the Modeling Domain.

Epidemiology Literature	Greater Mid-Atlantic Region (4-km Grid)		Delaware	
	No. of Cases (2013)	No. of Cases (2022)	No. of Cases (2013)	No. of Cases (2022)
Chronic bronchitis (age>=25)	3,000	2,900	190	190
Emergency room visits for asthma (age<19)	3,800	3,800	190	190
Acute bronchitis (age 8–12)	6,300	6,200	390	390
Asthma exacerbation (age 6–18)	130,000	130,000	7,800	7,800
Lower respiratory symptoms (age 7–14)	80,000	79,000	5,000	5,000
Upper respiratory symptoms (asthmatic children age 9–18)	58,000	58,000	3,600	3,600
Minor restricted-activity days (age 18–65)	3,200,000	3,200,000	200,000	200,000
Work loss days (age 18–65)	540,000	540,000	33,000	33,000
Nonfatal myocardial infarction (age>17)	5,300	5,100	380	380
Hospital admissions—respiratory (all ages)	900	900	63	63
Hospital admissions—cardiovascular (age>17)	2,100	2,100	140	140

The incidence results for morbidity for 2013 and 2022 are very similar, especially after rounding, with some lower values for 2022 for the 4-km grid.

BenMAP valuation results for $PM_{2.5}$ related mortality incorporating 3 and 7 percent discount rates are presented in Table 4-15 and Table 4-16. The monetized health-related costs represent regional costs, in millions of 2010-equivalent U.S. dollars.

Table 4-15. BenMAP-Derived Monetized Health-Related Costs for $PM_{2.5}$-Related Mortality with a 3% Discount Rate: Estimated Monetized Costs (Millions U.S. Dollars) Related to Premature Mortality Associated with EGU Emissions Located within the Modeling Domain.

Epidemiology Literature	Greater Mid-Atlantic Region (4-km Grid)		Delaware	
	Millions U.S. $2010 (2013)	Millions U.S. $2010 (2022)	Millions U.S. $2010 (2013)	Millions U.S. $2010 (2022)
Harvard six-city study (Laden et al.)	96,000	95,000	6,600	6,600
ACS study (Pope et al.)	37,000	37,000	2,600	2,600
Infant mortality study (Woodruff et al.)	120	120	8	8
Expert Elicitation				
Expert A	100,000	100,000	7,100	7,100
Expert B	82,000	82,000	5,800	5,800
Expert C	85,000	83,000	5,800	5,800
Expert D	55,000	54,000	3,800	3,800
Expert E	130,000	130,000	8,900	9,000
Expert F	73,000	73,000	5,100	5,100
Expert G	45,000	44,000	3,100	3,100
Expert H	55,000	54,000	3,800	3,800
Expert I	79,000	78,000	5,400	5,500
Expert J	70,000	69,000	4,800	4,800
Expert K	13,000	13,000	930	900
Expert L	58,000	59,000	4,200	4,200

The incidence results for mortality for 2013 and 2022 are very similar, especially after rounding. Using the 3% discount rate, the calculated monetized health-related costs for 2013 for the 4-km grid region range from 37 to 96 billion dollars for premature mortality (not including infant mortality) based on epidemiological studies (Pope et al., 2002 and Laden et al., 2006 in Abt Associates) and from 13 to 130 billion dollars for the expert elicitation estimates. The calculated monetized health-related costs for Delaware range from 2.6 to 6.6 billion dollars for the premature mortality (not including infant mortality) based on epidemiological studies and from 930 million to 8.9 billion dollars for the expert elicitation estimates. For 2022, the calculated monetized health-related costs for the 4-km grid region range from 37 to 95 billion dollars for premature mortality (not including infant mortality) based on epidemiological studies and from 13 to 130 billion dollars for the expert elicitation estimates. The calculated monetized health-related costs for Delaware range from 2.6 to 6.6 billion dollars for the premature mortality (not including infant mortality) based on epidemiological studies and from 900 million to 9 billion dollars for the expert elicitation estimates.

Table 4-16. BenMAP-Derived Monetized Health-Related Costs for $PM_{2.5}$-Related Mortality with a 7% Discount Rate: Estimated Monetized Costs (Millions U.S. Dollars) Related to Premature Mortality Associated with EGU Emissions Located within the Modeling Domain.

Epidemiology Literature	Greater Mid-Atlantic Region (4-km Grid)		Delaware	
	Millions U.S. $2010 (2013)	Millions U.S. $2010 (2022)	Millions U.S. $2010 (2013)	Millions U.S. $2010 (2022)
Harvard six-city study (Laden et al.)	87,000	85,000	6,000	6,000
ACS study (Pope et al.)	34,000	33,000	2,300	2,300
Infant mortality study (Woodruff et al.)	110	110	7	7
Expert Elicitation				
Expert A	92,000	91,000	6,400	6,400
Expert B	74,000	74,000	5,200	5,200
Expert C	76,000	75,000	5,200	5,300
Expert D	50,000	49,000	3,400	3,400
Expert E	120,000	115,000	8,000	8,100
Expert F	66,000	66,000	4,600	4,600
Expert G	40,000	40,000	2,800	2,800
Expert H	50,000	49,000	3,400	3,400
Expert I	71,000	70,000	4,900	4,900
Expert J	63,000	62,000	4,300	4,400
Expert K	12,000	12,000	840	810
Expert L	53,000	53,000	3,800	3,800

Using the 7% discount rate, the calculated monetized health-related costs for 2013 for the 4-km grid region range from 34 to 87 billion dollars for premature mortality (not including infant mortality) based on epidemiological studies (Pope et al., 2002 and Laden et al., 2006 in Abt Associates) and from 12 to 120 billion dollars for the expert elicitation estimates. The calculated monetized health-related costs for Delaware range from 2.3 to 6 billion dollars for the premature mortality (not including infant mortality) based on epidemiological studies and from 840 million to 8 billion dollars for the expert elicitation estimates. For 2022, the calculated monetized health-related costs for the 4-km grid region range from 33 to 85 billion dollars for premature mortality (not including infant mortality) based on epidemiological studies and from 12 to 115 billion dollars for the expert elicitation estimates. The calculated monetized health-related costs for Delaware range from 2.3 to 6 billion dollars for the premature mortality (not including infant mortality) based on epidemiological studies and from 820 million to 8.1 billion dollars for the expert elicitation estimates.

BenMAP valuation results for other $PM_{2.5}$-related health effects and associated endpoints (morbidity) are presented in Table 4-17.

Table 4-17. BenMAP-Derived Monetized Health-Related Costs for $PM_{2.5}$-Related Morbidity: Estimated Monetized Costs (Millions U.S. Dollars) Related to Various Morbidity Endpoints Associated with EGU Emissions Located within the Modeling Domain.

Epidemiology Literature	Greater Mid-Atlantic Region (4-km Grid)		Delaware	
	Millions U.S. $2010 (2013)	Millions U.S. $2010 (2022)	Millions U.S. $2010 (2013)	Millions U.S. $2010 (2022)
Chronic bronchitis (age>=25)	1,600	1,600	100	100
Emergency room visits for asthma (age<19)	2	2	0	0
Acute bronchitis (age 8–12)	3	3	0	0
Asthma exacerbation (age 6–8)	7	7	0	0
Lower respiratory symptoms (age 7–14)	2	2	0	0
Upper respiratory symptoms (asthmatic children age 9–18)	2	2	0	0
Minor restricted-activity days (age 18–65)	220	220	14	14
Work loss days (age 18–65)	88	87	5	5
Nonfatal myocardial infarction (age>17)	610	600	44	44
Hospital admissions—respiratory (all ages)	15	14	1	1
Hospital admissions—cardiovascular (age>17)	35	34	2	2

For both regions, the greatest costs in monetized health-related benefits are associated with chronic bronchitis and non-fatal myocardial infarctions.

Cost per Kilowatt Hour (kWh)

The costs associated with EGU emissions can also be presented in terms of dollars per kilowatt hour (kWh). For this analysis, the costs associated with EGU emissions from states located in the 4-km grid (DE, MD, NJ, PA, VA, and DC) were calculated based on the CMAQ/PPTM results for Tags 1 and 2. The monetized health-related costs from EGU emissions from these states range from $22 to 56 billion (2010-equivalent U.S. dollars) for 2022. The range is based on different epidemiological studies and discount rates (that account for the time lag between changes in $PM_{2.5}$ concentration and changes in $PM_{2.5}$ mortality). Specifically, the lower bound is based on the ACS study mortality estimate with a 7% discount rate and the upper bound is based on the Harvard 6-city study mortality estimate with a 3% discount rate. In both cases, morbidity costs were added to the mortality cost estimate to obtain a total cost. The kWh estimates for these same states were obtained from the IPM and the cost per kWh was calculated. Note that the generation totals for the future year was estimated based on generation levels projected for individual Locational Delivery Areas (LDAs). The calculation was done for 2022. Total costs and costs per kWh are summarized in Table 4-18.

Table 4-18. BenMAP-Derived Total Monetized Health-Related Costs for the 4-km Grid and Costs per kWh Associated with EGU Emissions Located within the 4-km Grid.

This	Overall Cost (Millions $2010)	Cost per KWh ($)
Lower Bound	22,000	0.04
Upper Bound	56,000	0.10

This estimate is in line with the estimate provided in the recent NAS report (NAS, 2009), which indicates that the cost per kWh associated with coal and natural-gas fired utilities on a national scale is approximately 3.3 cents ($0.03) in 2007-equivalent U.S. dollars. In the NAS study, the costs were inclusive of health, vegetative, and other damages. Although a direct comparison of the results from the two studies is not appropriate given that the costs represent different endpoints, it is expected that health effects comprise a majority of the costs for the NAS study. Thus, this comparison provides some assurance that the results of present study are quantitatively consistent ("in the ballpark") with the recent findings of the NAS.

Cost per Ton

The costs associated with EGU emissions can also be presented in terms of dollars per ton of emissions. Again, the costs associated with EGU emissions from states located in the 4-km grid (DE, MD, NJ, PA, VA, and DC) were calculated based on the CMAQ/PPTM results for Tags 1 and 2. Use of the CMAQ/PPTM results allowed the further breakdown of costs according to emission species. Contributions and associated monetized health-related costs were calculated for SO_2 and NO_x. The PPTM results indicate that 63 percent of the overall cost associated with EGU emissions is attributable to SO_2 emissions and 6 percent is attributable to NO_x emissions. The remaining costs are attributable to other species such as (directly emitted) primary $PM_{2.5}$ emissions.

For both species, the total cost range was estimated based on both mortality and morbidity and the range of applicable epidemiological studies and discount rates. The emissions total estimates for the states listed above were obtained from the IPM and the cost per ton was calculated. The calculation was done for 2022. Costs per ton are summarized in Table 4-19.

Table 4-19. BenMAP-Derived Total Monetized Health-Related Costs for the 4-km Grid and Costs per Ton Associated with EGU Emissions Located within the 4-km Grid.

This	Cost per Ton SO_2 ($2022)	Cost per Ton NO_x ($2022)
Lower Bound	43,000	9,500
Upper Bound	110,000	25,000

4.2. Mercury

The benefits assessment for mercury deposition was based on information from a comprehensive study of the benefits of controlling mercury emissions from coal fired power plants (NESCAUM, 2005). Compared to the application of BenMAP, the approach is much more qualitative.

Mercury Effects Estimation Methodology

The basis of the benefits calculations for this analysis are results obtained by NESCAUM (2005) for the Mid-Atlantic region, which is defined in the NESCAUM report as Delaware, Maryland, New Jersey, Pennsylvania, Virginia, West Virginia, and Washington, D.C. From the information provided in the NESCAUM report, the monetized benefit per μgm^{-2} reduction of mercury deposition was calculated for the Mid-Atlantic region. Details of this calculation are provided in the next section.

For the present analysis, the CMAQ-derived change in total mercury deposition rate for the Mid-Atlantic region, relative to the Reference Case scenario was calculated for both scenarios. This change in deposition rate was then multiplied by the benefit per μgm^{-3} for the Mid-Atlantic region (from the NESCAUM report). The resulting estimated benefits are summarized in the next section.

A key assumption in the NESCAUM study is that "...changes in mercury deposition rates result in proportional changes in human methylmercury intakes." The study provides estimated benefits for both neurotoxic and cardiotoxic effects. However, the report notes that the degree of confidence differs between the neurotoxic and cardiotoxic effects. According to this report, the neurological (e.g., IQ) effects associated with *in utero* methylmercury exposures have been thoroughly evaluated. In addition, there is no evidence of a threshold for neurotoxicity. Studies "...evaluating the association of cardiovascular events with adult methylmercury exposures have, as a group, not been as thoroughly evaluated. While high doses of methylmercury are clearly associated with neurological decrements, they have not been repeatedly shown to be associated with adverse cardiac events; in fact, fish consumption, which implies some methylmercury exposure, is recommended as protective of cardiovascular disease." Thus, the authors urge caution in interpreting the results related to monetized benefits associated with the cardiovascular endpoint.

For the present analysis, loss of IQ points with no neurotoxicity threshold is used to estimate the benefits.

Monetized Health Effects Attributable to Mercury Emission Changes (2013-2022)

Using the methodology outlined in the previous section for the calculation of monetized benefits associated with a reduction in mercury deposition, the estimated value for the Mid-Atlantic states is approximately 0.3 million dollars (in 2010-equivalent U.S. dollars). If we assume that Delaware represents about 5% of the total (based roughly on the BenMAP results) the estimated benefit for Delaware is less than approximately 15 thousand dollars.

4.3. Discussion of Attributes and Limitations

The BenMAP tool incorporates a wide variety of recent studies that can be used to quantify and monetize health effects. The epidemiological studies address a variety of different health endpoints and, in some cases, multiple studies (involving different populations or concentration-response functions) are available allowing for some comparison. BenMAP includes up-to-date valuation methods and data for the monetization of health impacts. BenMAP also incorporates advanced statistical methods for aggregating and weighting the results to obtain both mean values as well as information about the likelihood (probability) that the value will be within a given range. A primary advantage of BenMAP is that it can incorporate the change in air quality directly from air quality model output files and thus takes into account spatial and temporal differences in the changes in air quality, and relates these to population. For this analysis, selection of the health effects studies and valuation methods were based on the latest BenMAP (configuration and aggregation, pooling and valuation) input files provided by EPA (which reference the studies and methods that EPA considers to be the most relevant and applicable to the U.S. population as a whole.)

Nevertheless, there are uncertainties associated with the estimation of changes in health effects and monetized health-related benefits associated with changes in ozone and $PM_{2.5}$ air quality. For the health incidence calculations, BenMAP includes an option to generate an average incidence estimate, as well as a range of results that assume there is variability in the inputs to the health impact functions. Variability is incorporated into most of the BenMAP exposure-response algorithms by prescribing a dose-response parameter that assumes a distribution about the mean value. In calculating the health effects, BenMAP samples this distribution to develop a probability distribution of effect. The result is expressed as the mean value of the distribution. For the $PM_{2.5}$ mortality expert elicitation functions, variability is accounted for in a variety of ways. For the valuation calculation, the valuation function is also specified as a probability distribution, accounting for different methods of estimating health costs and willingness to pay. BenMAP samples from probability distributions from single or multiple cost estimation models, and combines the results through Monte Carlo simulation. The resulting monetized benefit distributions therefore include contributions both from the uncertainty in the exposure-response relationships and in the valuation functions.

Finally, the mercury assessment is qualitative and the results are for the Mid-Atlantic region only. The assessment is based on the results the NESCAUM study, which considers many factors and includes numerous assumptions (see NESCAUM, 2005 for a discussion of the attributes and limitation of this study).

5. Discussion of Climate Change

The assessment and estimation of environmental impacts for electric generation facilities in Delaware related to climate change follow methodologies and recommendations provided by the National Academy of Sciences (NAS) in their recent report entitled "Hidden Costs of Energy: Unpriced Consequences of Energy Production and Use" (NAS, 2009). The report recognizes that the production of energy from electric generation facilities will continue to be a major source of greenhouse gas (GHG) emissions, including CO_2 and methane, and "...damages from these emissions will result as their increased atmospheric concentrations affect climate, which in turn will affect such things as weather, freshwater supply, sea level, biodiversity, and human society and health (NAS, 2009). However, the report further states that because of the complexities of climate change and the different time-scales over which the damages could occur, estimating and quantifying damages, which are based on the prediction of climate-change effects "is an intricate and uncertain process."

To prepare recommendations for how to assess climate change related damages, the NAS committee relied on a review of existing integrated assessment models (IAMs) and associated climate change literature. IAMs attempt to quantify damages of greenhouse gas emissions by estimating physical and monetary impacts associated with three main areas: 1) temperature changes, 2) impacts on weather, 3) impacts on various market sectors, as well as non-market sectors including agriculture, water resources, coastal infrastructure, health, and ecosystems (NAS, 2009). The IAMs examined by NAS include the Regional Integrated Model of Climate and Economy (RICE), the Dynamic Integrated Model of Climate and the Economy (DICE), the Framework for Uncertainty, Negotiation, and Distribution (FUND), and the Policy Analysis of the Greenhouse Effect (PAGE), which differ somewhat in their inputs, assumptions, and marginal damage formulas. Marginal damages are defined as damages per ton of emissions "associated with a particular climate change scenario at a particular future time." One of the difficulties in attempting to quantify damages due to GHG emissions, as opposed to criteria pollutant emissions (SO_2 or NO_x), is that the impacts of GHG's differ greatly in both spatial and atmospheric residence time scales, and the variety of potential impacts related to resulting temperature change. Due to the uncertainties in estimating potential future changes in climate and their effects on physical and economic resources, the NAS concluded that "only rough order-of-magnitude estimates of marginal damages were possible at this time." Their estimates range from $1 to $100 per ton CO_2-eq.

Table 5-1 presents total CO_2 emissions for all EGUs located in the Mid-Atlantic states, comparing emissions for 2013 with those estimated for 2022. The estimated changes in EGUs in 2022 result in an increase of CO_2 emissions of nearly 20 percent or 37,657,372 tons. Using the NAS estimates for costs/benefits, the future year scenario represents costs of $37 million to $3.7 billion due to CO_2 emissions.

Table 5-1. Total CO2 Emissions for the 2013 Base Case and 2022 Reference Case for All EGUs Located within the Mid-Atlantic States.

	2013 Base Case (tpy)	2022 Reference Case (tpy)
Total for All EGUs	**193,882,638**	**231,540,010**
Difference (tpy)		37,657,372
Difference (%)		19.4%

6. Summary and Conclusions

The objective of this analysis was to examine and quantify the air quality impacts and related costs and benefits of expected changes in emissions, including from power generation sources, between 2013 and 2022. The CMAQ air quality model was used to quantify the air quality changes and BenMAP was used to assess the health-related impacts of the simulated changes in air quality over the approximate ten-year planning horizon. The analysis focused on two geographical regions including a 4-km resolution modeling grid covering the Mid-Atlantic states (see Figure 1-1) and the State of Delaware.

The CMAQ simulations included a 2013 Base Case simulation and a 2022 Reference Case simulation. The 2013 emissions for the Base Case simulation are comprised of 2013 emission estimates for EGU sources and 2010 emission estimates for all other sources. The 2022 emissions for the Reference Case simulation are comprised of 2022 emission estimates for EGU sources and 2020 emission estimates for all other sources. Pollutants of interest in this analysis are NO_x, SO_2, ozone, $PM_{2.5}$, and mercury. Two additional simulations were conducted in which the PPTM feature of the CMAQ model was used to quantify the contribution of emissions from power generation facilities to the simulated concentrations and deposition amounts.

The health effects analysis focused primarily on the effects of ozone and $PM_{2.5}$. Ozone and $PM_{2.5}$ are secondary pollutants that are formed in the atmosphere. Ozone is a secondary pollutant that is formed in the atmosphere by a series of reactions involving ultra violet radiation and precursor emissions of NO_x and VOCs. Fine particulates in the atmosphere consist of primary particles that are emitted directly from sources and secondary particles that form in the atmosphere through chemical and physical processes. Pollutants that contribute to the formation of secondary aerosols include SO_2, NO_x, and other species. Thus this assessment of the health effects and benefits for ozone and $PM_{2.5}$ addresses the effects of changes in NO_x and SO_2 emissions. Mercury and greenhouse gases (CO_2) were also considered using qualitative methods.

For the air quality modeling analysis, the EGU emissions were estimated using the IPM®. The emissions totals are summarized in Tables 2-1 through 2-4. For most regions, NO_x and SO_2 emissions (overall and from EGU sources) are lower for 2022, compared to 2013. One exception is that there is an estimated increase in NO_x emissions for EGUs for the 4-km domain, reflecting the insertion of additional generation units due to future power demands in some portion of this domain. The EGU emissions from IPM for both 2013 and 2022 reflect estimates of future economic and population growth and corresponding electric generation demand, any planned shutdowns of existing facilities, inclusion of new facilities to meet future generation demands, and application of emission controls on existing facilities associated with applicable state and national rules.

The CMAQ modeling results show both increases and decreases in ozone concentration for 2022, compared to 2013. The decreases are fairly widespread, reflecting emissions reductions for a number of source categories throughout the domain, and are generally greater in magnitude than the increases. The simulated $PM_{2.5}$ concentrations for 2022 are lower than those for 2013 throughout much of the region, especially over southeastern Pennsylvania, central Maryland, and northern Virginia. The maximum decrease is approximately 2.2 μgm^{-3}.

Simulated mercury deposition is characterized by small areas of increases and decreases in mercury deposition for 2022, compared to 2013. Averaged across the domain, the simulated decrease in mercury deposition is less than 1 g km^{-2}.

Total monetized benefits for 2013 - 2022 (ozone and $PM_{2.5}$) are presented in Table 6-1. The ranges given below encompass the different health-incidence studies used in this analysis (but limited to, in this case, Laden et al. and Pope et al., for $PM_{2.5}$ mortality and Levy for ozone mortality) and different assumptions regarding cessation lag (discount rate) for $PM_{2.5}$ mortality. The monetized health-related benefits are given in 2010-equivalent U.S. dollars. Estimated mercury deposition benefits do not change the totals given here.

Table 6-1. Total BenMAP-Derived Monetized Health-Related Benefits for $PM_{2.5}$ and Ozone (Millions U.S. Dollars) Associated with the Changes in Air Quality from 2013 to 2022. The High End Total Includes $PM_{2.5}$ Mortality from Laden et al. with a 3% Discount Rate and the Low End Total Includes $PM_{2.5}$ Mortality from Pope et al. with a 7% Discount Rate.

	Greater Mid-Atlantic Region (4-km Grid)		Delaware	
	High End	Low End	High End	Low End
2013–2022				
PM-Mortality (Laden, 3% discount rate)	25,000		1,800	
PM-Mortality (Pope, 7% discount rate)		9,000		630
PM-Morbidity	690	690	45	45
Ozone-Mortality (Levy)	3,700	3,700	300	300
Ozone-Morbidity	67	67	6	6
Total	*29,457*	*13,457*	*2,151*	*981*
Total (2 significant figures)	29,000	13,000	2,200	980

As shown in Table 6-1, from 2013 to 2022 health benefits arising from the improving air quality associated with the Reference Case are expected to provide significant positive health impacts for both the greater Mid-Atlantic region and the State of Delaware.

The CMAQ/PPTM was used to examine the contributions of emissions from the major source categories to simulated $PM_{2.5}$ concentrations and specifically to quantify the contributions from EGU sources. The specific tags included:

- EGU point sources in Delaware
- EGU point sources in New Jersey, Pennsylvania, Maryland, Virginia, and Washington, D.C.
- EGU point sources in the remainder of the 12-km grid
- Non-EGU point sources in the 12-km grid
- All other emission sources in the 12-km grid combined (including on-road mobile, non-road, and area sources)
- Biogenic emissions
- Initial conditions and boundary conditions (IC/BCs).

For both receptor regions, the tagging results indicate that among the tagged categories the area, on-road mobile, and non-road mobile sources (combined) are the largest contributors to the overall $PM_{2.5}$ concentration. For the 4-km grid, the EGU sources (first three tags combined) account for 13 percent of the simulated annual average $PM_{2.5}$ concentration for both 2013 and 2022. For Delaware, the EGU sources (first three tags combined) account for 12 and 13 percent, respectively, of the simulated annual average $PM_{2.5}$ concentration for 2013 and 2022. The EGU contribution from sources located in Delaware is negligible when considering annual average $PM_{2.5}$ for the 4-km grid and very small when considering annual average $PM_{2.5}$ for Delaware.

Total costs associated with EGU emissions for 2022 are presented in Table 6-2. The estimated costs include only those associated with $PM_{2.5}$, and costs associated with ozone and mercury were not calculated, but are expected to be much smaller than those for $PM_{2.5}$.

Table 6-2. Total BenMAP-Derived Monetized Health-Related Costs for $PM_{2.5}$ (Millions U.S. Dollars) Associated with EGU Emissions Located within the Modeling Domain. The High End Total Includes $PM_{2.5}$ Mortality from Laden et al. with a 3% Discount Rate and the Low End Total Includes $PM_{2.5}$ Mortality from Pope et al. with a 7% Discount Rate.

	Greater Mid-Atlantic Region (4-km Grid)		Delaware	
	High End	Low End	High End	Low End
2013-2022				
PM-Mortality (Laden, 3% discount rate)	95,000		6,600	
PM-Mortality (Pope, 7% discount rate)		33,000		2,300
PM-Morbidity	2,600	2,600	170	170
Ozone-Mortality (Levy)				
Ozone-Morbidity				
Total	*97,600*	*35,600*	*6,770*	*2,470*
Total (2 significant figures)	**98,000**	**36,000**	**6,800**	**2,500**

The estimated total cost associated with EGU emissions alone (based on their contribution to simulated $PM_{2.5}$ concentrations for the 2022 Reference Case simulation) ranges from 36 to 90 billion dollars for the 4-km grid and from 2.5 to 6.8 billion dollars for Delaware.

In summary, the air quality and health effects modeling results indicate improvements in air quality between 2013 and 2022 due to expected changes in emissions from all sources, including EGUs. The simulated improvements in air quality result in a lower incidence of adverse health effects and substantial monetized health-effects benefits for Delaware and the surrounding region.

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Appendix 9 - Confidential Material Omitted

Forecast of SOS Rates by Customer Class

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

2013-14	R	RTOU	RTOU ND	RSH	SGS-S	GS-SH	GS-WH	OL	ORL	MGS-S	LGS-S	GS-P

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

2014-15	R	RTOU	RTOU-ND	RSH	SGS-S	GS-SH	GS-WH	OL	ORL	MGS-S	LGS-S	GS-P

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

2015-16	R	RTOU	RTOU-ND	RSH	SGS-S	GS-SH	GS-WH	OL	ORL	MGS-S	LGS-S	GS-P

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

2016-17	R	RTOU	RTOU-ND	RSH	SGS-S	GS-SH	GS-WH	OL	ORL	MGS-S	LGS-S	GS-P
Demand ($/kW)												
Summer		$ 9.287728								$12.662107	$14.640862	$14.309411
Winter		$ 6.548156								$ 7.814306	$ 9.519514	$ 9.122965
Energy ($/MWH)												
Summer - all hrs	$0.115335			$0.113835	$0.113111	$0.111180	$0.108244	$0.054818	$0.093770	$ 0.043118		
DP&L On pk		$ 0.070888	$0.192839								$ 0.050139	$ 0.064207
DP&L Off pk		$ 0.052654	$0.066208								$ 0.033514	$ 0.052216
Winter - all hrs	$0.114716			$0.101329	$0.101635	$0.100587	$0.093083	$0.066580	$0.083809	$ 0.051942		
DP&L On pk		$ 0.056791	$0.181393								$ 0.055244	$ 0.067234
DP&L Off pk		$ 0.042546	$0.073011								$ 0.037076	$ 0.054620

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

2017-18	R	RTOU	RTOU-ND	RSH	SGS-S	GS-SH	GS-WH	OL	ORL	MGS-S	LGS-S	GS-P
Demand ($/kW)												
Summer		$10.055997								$13.824869	$15.984900	$15.622260
Winter		$ 7.089319								$ 8.531883	$10.392858	$ 9.960403
Energy ($/MWH)												
Summer - all hrs	$0.124462			$0.122962	$0.122238	$0.120307	$0.117371	$0.054818	$0.102897	$ 0.046805		
DP&L On pk		$ 0.078493	$0.209746								$ 0.055189	$ 0.069569
DP&L Off pk		$ 0.058063	$0.071439								$ 0.037037	$ 0.056476
Winter - all hrs	$0.123376			$0.109989	$0.110295	$0.109247	$0.101743	$0.066580	$0.092469	$ 0.056439		
DP&L On pk		$ 0.063696	$0.197037								$ 0.060758	$ 0.072876
DP&L Off pk		$ 0.047469	$0.078786								$ 0.040923	$ 0.059105

Sensitivity Case Removal of CSAPR

- In its modeling for Delmarva's 2012 Delaware Integrated Resource Plan, ICF assumed that EPA's Cross State Air Pollution Rule (CSAPR) would be in effect beginning January 1, 2013, when the modeling efforts began for the Reference Case in July.
- On August 21, 2012, the U.S. Court of Appeals for the DC Circuit vacated CSAPR, temporarily reinstating the Clean Air Interstate Rule (CAIR).
- In order to study the impact of the of the recent vacatur of CSAPR, ICF has designed a sensitivity case removing CSAPR from the model.
- The details of the sensitivity, which will be discussed in later slides, assumes that CAIR continues as currently designed followed by more stringent SO_2 and NO_X requirements starting in 2018. Results from this sensitivity case can be compared to the Reference Case to evaluate the regulatory change's potential impact.

MODELING ASSUMPTIONS FOR SENSITIVITY

Clean Air Interstate Rule (CAIR)

	SO_2 Programs	NO_X Programs		Air Toxics (MATS) Requirements	CO_2 Program
		Annual	**Ozone Season**		
CAIR for SO_2 and NO_X (2010-2017)	25 States + DC Retirement ratio: 2010: 2:1 2015: 2.86:1 Existing Title IV for unaffected states	25 States + DC 2009: 1.522 million tons 2015: 1.268 million tons (200,000 ton Compliance Supplement Pool (CSP) in 2009	25 States + DC 2009: 0.568 million tons 2015- onwards: 0.485 (Banking from SIP Call allowed)	2016: Federal MACT standards consistent with proposed Air Toxics Rule Mercury (Hg) Units must meet 1.2 lb./TBtu rate standard Hydrogen Chloride (HCl) Units must meet 0.002 lb./MMBtu rate standard Particulate Matter (PM) Units must have fabric filter or upgraded or post-1977 ESP States with existing Hg rules proceed as planned, so long as they meet minimum requirement as defined by federal MACT	2023: CO_2 control program reflecting potential for regulation/legislation covering CO_2 emissions from the power sector; New Source Performance Standards All new fossil fuel-fired electric utility generating units greater than 25 MW to meet an output-based standard of 1,000 pounds of CO_2 per MWh.
CAIR II for SO_2 and NO_X (2018-onwards)	25 States + DC State level emission budgets with intrastate trading only (see table in the next slide)	25 States + DC State level emission budgets with intrastate trading only (see table in the next slide)			

CAIR II Projected State Level Emission Budgets

State	Annual SO2 Projected Budget 2018+ (tons)	Annual NOx Projected Budget 2018+ (tons)
Alabama	93.761	48.889
District of Columbia	0.421	0.102
Delaware	13.334	2.951
Florida	150.803	70.440
Georgia	126.769	46.978
Iowa	38.136	23.157
Illinois	114.639	53.996
Indiana	151.486	77.162
Kentucky	112.320	58.936
Louisiana	35.669	25.154
Maryland	42.065	19.638
Michigan	106.270	46.257
Minnesota	29.742	22.273
Missouri	81.643	42.408
Mississippi	20.089	12.613
North Carolina	81.718	44.046
New Jersey	19.273	8.974
New York	80.407	32.312
Ohio	198.444	76.973
Pennsylvania	164.214	70.160
South Carolina	34.076	23.136
Tennessee	81.643	36.106
Texas	190.963	128.218
Virginia	37.770	25.553
Wisconsin	51.922	28.871
West Virginia	128.449	52.573
Total	2,186.026	1,077.877

CAIR II

- In its ruling, the court required EPA to continue to enforce CAIR. ICF assumes that the EPA will not have a new alternative and that Phase II of CAIR will start as scheduled in 2018.
- Instead of going back and reworking CAIR, which is tied to the 1997 NAAQS for $PM_{2.5}$, the sensitivity case assumes that EPA will proceed with implementation of the proposed 2012 NAAQS for $PM_{2.5}$. This new program (CAIR II) is assumed to start in 2018.
- The table in the previous slide shows the state level budgets for 2018. Given the proposed 2012 annual standard for $PM_{2.5}$ is a 15% reduction from the 1997 annual standard (15μg/m^3 to 12μg/m^3) , the 2018 budgets were derived by reducing the 2015 CAIR budgets by 15%.
- Only intrastate trading is allowed and interstate trading is not allowed.
- Since the assumption is that CAIR II will be a new program with a new currency that is specific to each state, there is no banking allowed into 2018.
- The budgets in the previous slide have not been reduced to account for the New Unit Set Aside (NUSA). The budgets will be reduced by 3% similar to EPA's example method for NOx allowances in CAIR.