APPENDIX 4

APPENDIX 4

Supporting Documentation for the Delmarva Delaware IRP Filing Resource Modeling

December 1, 2010

TABLE OF CONTENTS

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.

CHAPTER ONE - ANALYTICAL AND MODELING APPROACH

ANALYTIC APPROACH

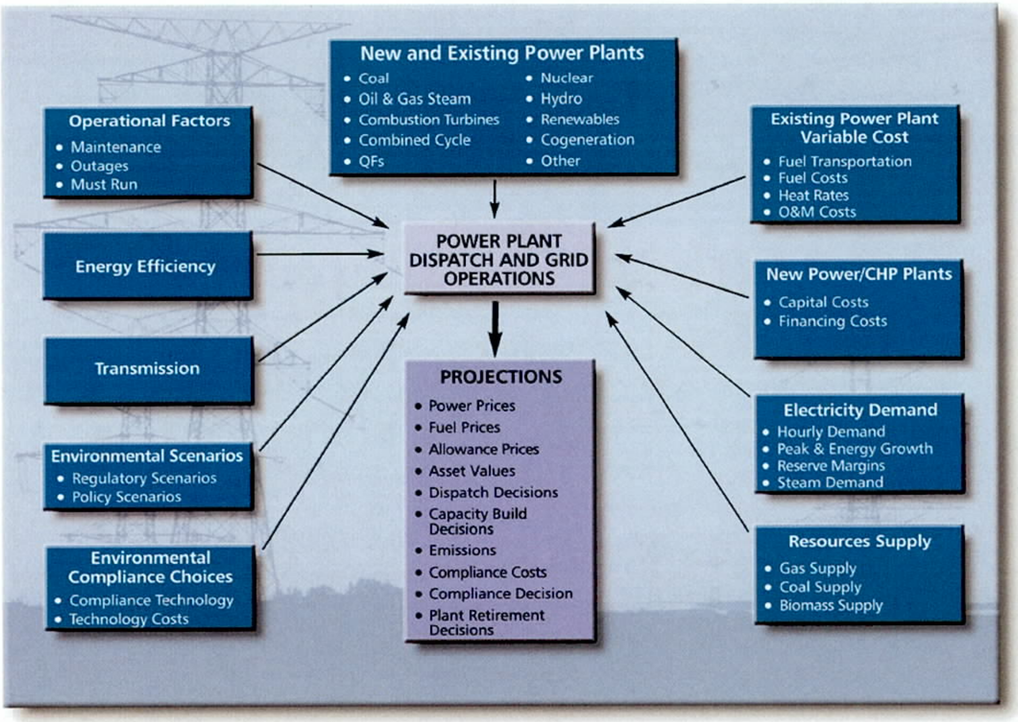
ICF's Integrated Planning Model™ (IPM®) was used to develop a fundamentals based, long-term forecast for Delmarva Power and Light. IPM® simulates power market operations at the wholesale level for energy generation and installed capacity requirements in order to determine the most cost effective service 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.

In terms of size and demand, the PJM marketplace is the largest in the US and certainly among the largest in the world, with the 2010 projected peak load of roughly 136 GW. This constitutes roughly 18 percent of total US peak load. The overall size of and membership in the PJM market has grown significantly in the last several years and the PJM footprint has expanded to reflect this growth.

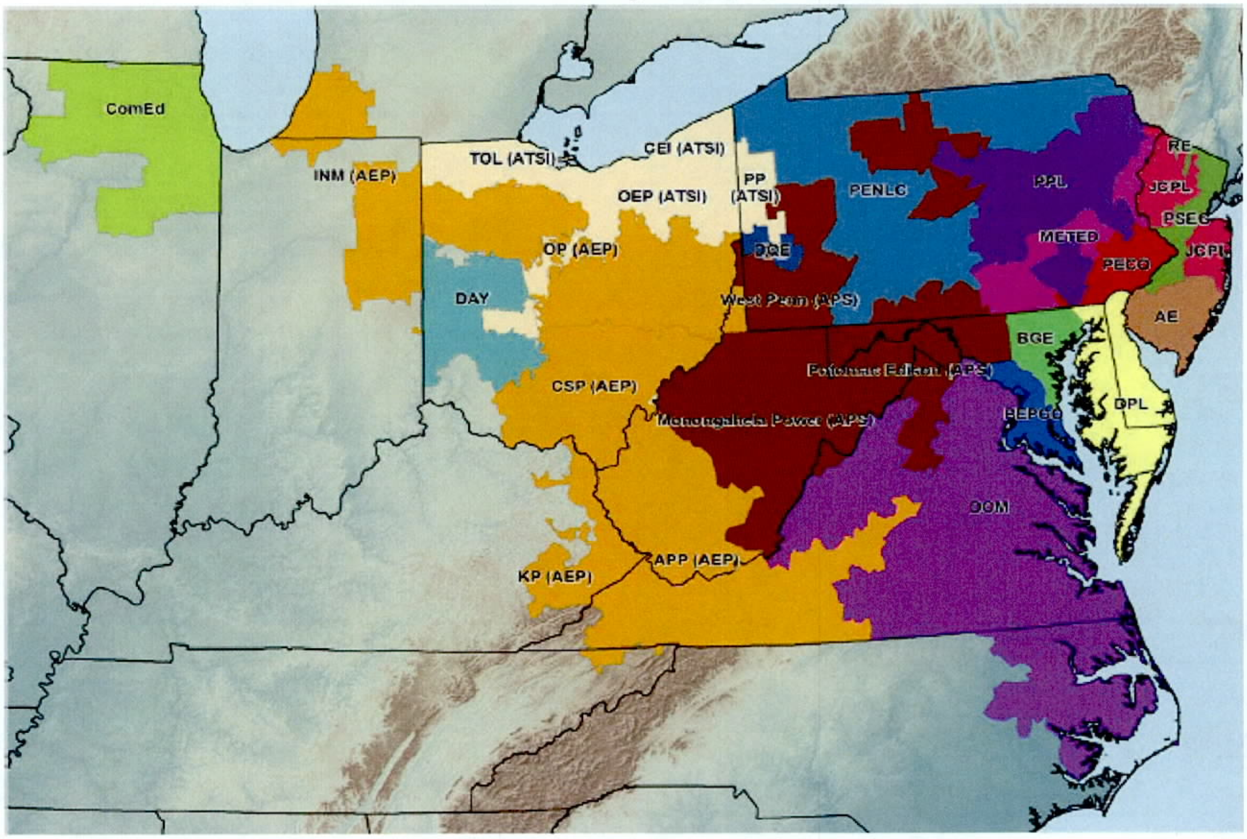
In its original form, the PJM Independent System Operator (ISO) comprised 10 control zones: Atlantic Electric Company (AECO), Baltimore Gas & Electric (BGE), Delmarva Power and Light (Delmarva Power), Jersey Central Power & Light Company (JCPL), Metropolitan Edison Company (Met-Ed), PECO Energy Company (PECO), Pennsylvania Electric Company (PENELEC), 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 late 2009, the FERC issed an order approving the integration of the American Transmission Systems, Inc. with PJM as of June 1, 2011. In addition, in October

2010, the FERC conditionally approved the move of Duke Energy Ohio, Inc. and Duke Energy Kentucky, Inc PJM as of January 1, 2012.

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 with the exception of the recently approved Duke areas.

Exhibit 1.2: PJM Transmission Zones



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.

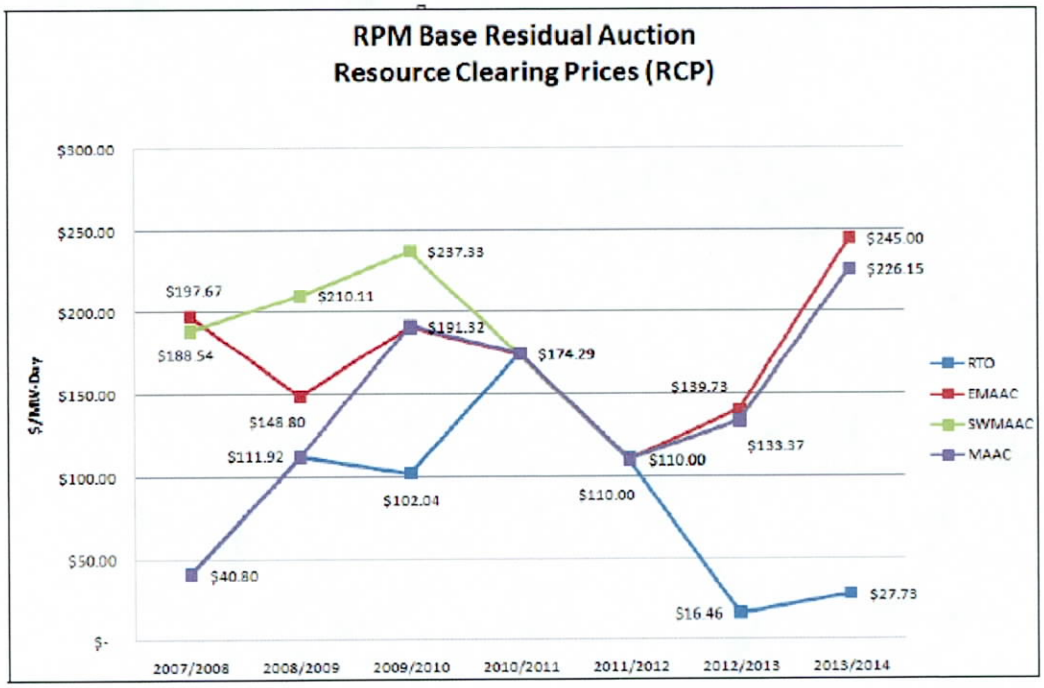
- Transmission Access – The energy markets employ Locational Marginal Pricing (LMP) in which each location's price reflects not only marginal bid prices, but also transmission congestion and loss effects. The crucial feature is that the most competitive bid that takes into account other generation as 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.

- 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 1.3: PJM RPM Base Residual Auction Results (Nominal $/MW-day)



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 (LM6000s and LMS100s) - Similar to peaking combustion turbines, aeroderivative capacity offers short construction times, quick start capability, and have lower capital costs than combined cycles. LM6000s and 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 (SO2), nitrogen oxides (NOx), 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.

Integrated Gasification Combined Cycle with Carbon Capture Sequestration (IGCC CCS) - The IGCC with carbon capture includes a water-shift process for concentrating CO2, Selexol absorption of CO2 and CO2 compression for pipeline injection. Selexol is currently considered the state of the art sorbent for CO2 capture for IGCC.

Supercritical Pulverized Coal with Carbon Capture Sequestration (IGCC CCS) - The supercritical coal unit carbon capture includes the cost of a MEA (monoethanolamine) absorber-stripper system and CO2 compression for pipeline injection. Amine based sorbents are currently considered state of the art for CO2 removal for supercritical coal units.

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 analysis assumes that no completely new facilities will be able to be online within the next ten years. However, uprates at existing facilities are directly accounted for in this period.

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

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.

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 2009 dollars.

Exhibit 2.1: Delaware Conventional Resource Options Capital Cost Assumptions

Resource Type	Earliest Online Year	Capital Cost (2009$/kW)	Fixed O&M Cost (2009$/kW)	Forced Outage Rate
Combustion Turbine	2011	893	7.4	2.4%
Combined Cycle	2014	1,218	10.5	1.3%
Aeroderivatives (LM6000)	2010	1,262	10.2	1.3%
Aeroderivatives (LMS100)	2010	1,041	10.2	1.3%
Supercritical Pulverized Coal	2015	2,815	28.9	6.3%
Integrated Gasification Combined Cycle	2016	3,595	33.8	6.3%
Supercritical Pulverized Coal with Carbon Capture Sequestration	2020	6,275	42.1	6.3%
Integrated Gasification Combined Cycle with Carbon Capture Sequestration	2020	5,704	44.0	6.3%
Nuclear	2019	5,330	116.5	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 2013 unless they are already under construction and will be available prior to 2010. New coal plants including IGCC plants are assumed to be available after 2015, unless in an advanced stage of development. New nuclear options become available in 2019. 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.

Exhibit 2.2 Higher Heating Value Heat Rate (BTU/kWh)

Vintage	Combined Cycle Gas	Simple Cycle Gas	Nuclear	Advanced Coal (IGCC)	Supercritical Coal
2013	7,100 (F tech)	10,905			
2015	7,100	10,905		8,602	9,110
2020	6,800 (G tech)	10,905	10,400	8,257	9,110
2025	6,800	10,448	10,400	8,257	9,110

Exhibit 2.3 presents reduction factors for different pollution control techonologies.

Exhibit 2.3 Reduction Factors by Control Technology

Pollutant Type	Combined cycle (CC)	Combustion turbine (CT)	Integrated Gasification Combined Cycle	Integrated Gasification Combined Cycle with Carbon Capture Sequestration	Supercritical Pulverized Coal	Supercritical Pulverized Coal with Carbon Capture Sequestration
SO2	N/A	N/A	Claus Desulfurization Process – 99.9%	Claus Desulfurization Process – 99.9%	Wet FGD – 98%	Dry FGD + Baghouse – 95%
NOx	SCR – 98% (0.02 lb/MMBtu)	LNB - 95% (0.05 lb/MMBtu)	SCR – 98% (0.02 lb/MMBtu)	SCR – 98% (0.02 lb/MMBtu)	SCR – 95% (0.05 lb/MMBtu)	SCR – 95% (0.05 lb/MMBtu)
Hg	N/A	N/A	Co-Benefits – 98%	Co-Benefits – 98%	Co-Benefits – 90%	ACI – 90%

Exhibit 2.4 presents the capital, fixed and variable operating expenses for renewable techonologies considered in modeling.

Exhibit 2.4: Delaware Renewable Resource Options Assumptions Summary

Resource Type	Earliest Online Year	Capital Cost ($/kW)	Fixed O&M Cost ($/kW-yr)	Variable O&M Cost ($/MWh)	Heat Rate (Btu/kWh)
Onshore Wind Step 1	2011	2,665	30.8	0	-
Onshore Wind Step 2	2011	3,200	30.8	0	-
Onshore Wind Step 3	2011	4,000	30.8	0	-
Offshore Wind	2016	3,956	56.97	0	-
Solar Photovoltaic-Distributed	2011	7,592	11.23	0	-
Biomass	2013	4,785	52.78	3.37	9,520
Landfill Gas	2011	2,851	113.47	0.01	13,648

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) to encourage wind and other renewable generation development. The PTC is assumed to be in effect at 50% level through 2015. Exhibit 2.5 presents the capital costs after applicable poduction tax credit for wind, biomass, and landfill and investment tax credit for solar are accounted for.

Exhibit 2.5: Delaware Renewable Resource Options Assumptions Summary with PTC/ITC

Resource Type	Earliest Online Year	Capital Cost ($/kW)
Onshore Wind Step 1	2011	1,825
Onshore Wind Step 2	2011	2,321
Onshore Wind Step 3	2011	3,063
Offshore Wind	2016	3,427
Solar Photovoltaic-Distributed	2011	4,998
Biomass	2013	3,863
Landfill Gas	2011	1,859

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 cCsts, 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 4 capacity factors roughly 33% 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.
4. Costs reflect production and investment tax credits. Applicable production tax credit for wind, biomass, and landfill and investment tax credit for solar are 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.

Levelized costs are useful metrics to compare different types of generation resources on a similar basis. Exhibit 2.6 presents the levelized costs for the technology types in IPM for Delaware. The levelized costs in Exhibit 2.6 are calculated based on the indicated capacity factors. Capacity factor reflects the number of hours a plant is expected to operate in a given year. The total cost is then spread over the number of hours to calculate a dollar per MWh cost.

Exhibit 2.6: Levelized Costs by Generation Resource Type for Delaware

Assumptions	Combined Cycle	Combustion Turbine	Nuclear	SCPC	IGCC	Wind	Solar
Total Levelized Cost ($/MWh)	99.0	175.5	112.8	107.4	142.3	136.7	433.5
Captial Cost ($/kW)	1,374	1,007	6,345	3,448	5,990	3,289	7,592
Capital Charge Rate (%)	12.1%	12.8%	10.6%	11.1%	11.0%	10.7%	10.7%
Capital Cost ($/kW-yr)	166	129	673	383	661	352	812
FOM ($/kW-yr)	10.5	7.4	116.5	39.0	55.0	31.4	11.7
Fixed Charges($/kW-yr)	176.7	136.2	789.1	421.7	715.7	383.3	824.0
Capacity Factor (%)	70%	23%	90%	85%	85%	32%	22%
Dispatch Hours (000 hours)	6.13	2.01	7.88	7.45	7.45	2.80	1.90
Fixed Costs ($/MWh)	28.8	67.6	100.1	56.6	96.1	136.7	433.5
VOM ($/MWh)	3.5	8.7	1.3	4.1	2.8	0.0	0.0
Fuel Cost ($/MMBtu)	8.0	7.7	1.1	2.5	2.5	0.0	0.0
Heat Rate (btu/kWh)	7,100	10,905	10,400	9,110	8,602	0	0
Fuel Cost ($/MWh)	56.5	83.5	11.4	23.1	21.8	0.0	0.0
VOM Cost excluding Emissions Costs ($/MWh)	60.0	92.2	12.7	27.1	24.7	0.0	0.0
SO2 Fuel content (lb/MMBtu)	0.00	0.00	0.00	0.90	0.90	0.00	0.00
SO2 Reduction Factor (%)	0%	0%	0%	95%	98.0%	0%	0%
SO2 Emission Rate (lb/MMBtu)	0.00	0.00	0.00	0.045	0.02	0.00	0.00
Levelized SO2 Allowance Price ($/ton)	62	62	62	62	62	62	62
S02 Allowance Cost ($/MWh)	0.000	0.000	0.000	0.013	0.005	0.000	0.000
Nox Emission Rate (lb/MMBtu)	0.02	0.05	0.00	0.28	0.02	0.00	0.00
Nox Allowance Price ($/ton)	638	638	638	638	638	638	638
Nox Allowance Cost ($/MWh)	0.05	0.17	0.00	0.83	0.05	0.00	0.00
CO2 Emission Rate (lb/MMBtu)	117.1	117.1	0.0	205.3	205.3	0.0	0.0
CO2 Allowance Price ($/ton)	24.4	24.4	24.4	24.4	24.4	24.4	24.4
CO2 Allowance Cost ($/MWh)	10.1	15.6	0.0	22.8	21.5	0.0	0.0
Total Variable Cost ($/MWh)	70.2	107.9	12.7	50.8	46.2	0.0	0.0
Levelized Cost w/o Emissions Costs	88.8	159.8	112.8	83.8	120.8	136.7	433.5

Notes:
Equipment acquisition costs assumed for same year.
Levelization was done for the period of 2015 through 2034.
Production Tax Credit (PTC) and Investment Tax Credit (ITC) are not included in the levelized costs.
All monetary figures are expressed in 2009 Real Dollars.

FINANCING ASSUMPTIONS FOR NEW RESOURCE OPTIONS

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

Exhibit 2.7: New Resource Options Financing Assumptions for Delaware

Financial Assumptions	Combustion Turbine	Combined Cycle/Cogeneration	Coal/Nuclear	Renewables
Debt/Equity Ratio (%)	42.5/57.5	50/50	57.5/42.5	50/50
Nominal Debt Rate (%)	7.63	7.13	7.13	7.13
Nominal After Tax Return on Equity (%)	12.75	12.75	12.75	12.75
Income Taxes[1]	40.6	40.6	40.6	40.6
Other Taxes[2] (%)	1.55	1.55	1.55	1.55
General Inflation Rate (%)	2.5	2.5	2.5	2.5
Levelized Real Capital Charge Rate (%)	12.8	12.1	10.6	10.5

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 Base 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	NOx	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
	SO2	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]	CO2	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, is scheduled to retire 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 Environmental Regulation Assumptions Affecting Multiple Market Areas

	SO2 Programs	NOX Programs		Hazardous Air Pollutants (HAPs) Program	CO2 Program
		Annual	Ozone Season		
CAIR for SO2 and NOX (2010-2011)	25 States + DC Retirement ratio: 2:1 Existing Title IV for unaffected	25 States + DC 1.522 million tons	25 States + DC 0.568 million tons	2015: Federal MACT standards similar to those for coal-fueled units in EPA's Industrial Boiler MACT program Units must be controlled with scrubber, fabric filter and ACI to continue operation Regulatory Relief: Units excused from compliance with HAPs if commit to retirement by 2018 States with existing Hg rules proceed as planned, so long as they meet minimum requirement as defined by federal MACT	2018: National Multi-sector Cap and Trade Sectoral coverage 2018: Electric power and transportation sectors 2023: Industrial sector 3% below 2005 levels for covered sectors in 2018; 83% below in 2050 Domestic and international offsets based on ICF's projections
Clean Air Transport Rule (CATR) for SO2 and NOX (2012 onward)	28 States and DC State emission budgets, with in-state and limited interstate trading in each of 2 groups Group 1 2012: 3.1 MMTons 2014: 1.7 MMTons Group 2 2012: 0.776 MMTons Existing Title IV for unaffected states	28 States and DC State emission budgets, with in-state and limited interstate trading 2012: 1.376 MMTons	26 States and DC State emission budgets, with in-state and limited interstate trading 2012: 0.642 MMTons		

Overview of Federal Green Air, Waste and Water Regulatory Requirements

A high level of uncertainty characterizes 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.

In keeping with this view, it is assumed that Congress legislatively establishes a national cap-and-trade program for GHG emissions covering most sectors of the US economy that is similar in design to what has been proposed by Senators Kerry and Lieberman. The implementation of the program begins in 2018 to reflect the continuing lack of consensus in Congress.

The Reference Case also 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 consistent with EPA's preferred approach in its proposal for the Clean Air Transport Rule (CATR). States outside of the CATR region remain under the Title IV Acid Rain program requirements.
- 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.
- Consistent with recent proposals in Congress, regulatory relief from HAPs regulation is assumed for units committing to retirement by 2018. Units not committing to retirement must retrofit by 2015.

- In addition to the assumed regulations on air pollutants, units comply with coal combustion byproduct and water withdrawal requirements that are under development by EPA.

Reference Case CO_2 Regulatory Requirements

National CO2 Program

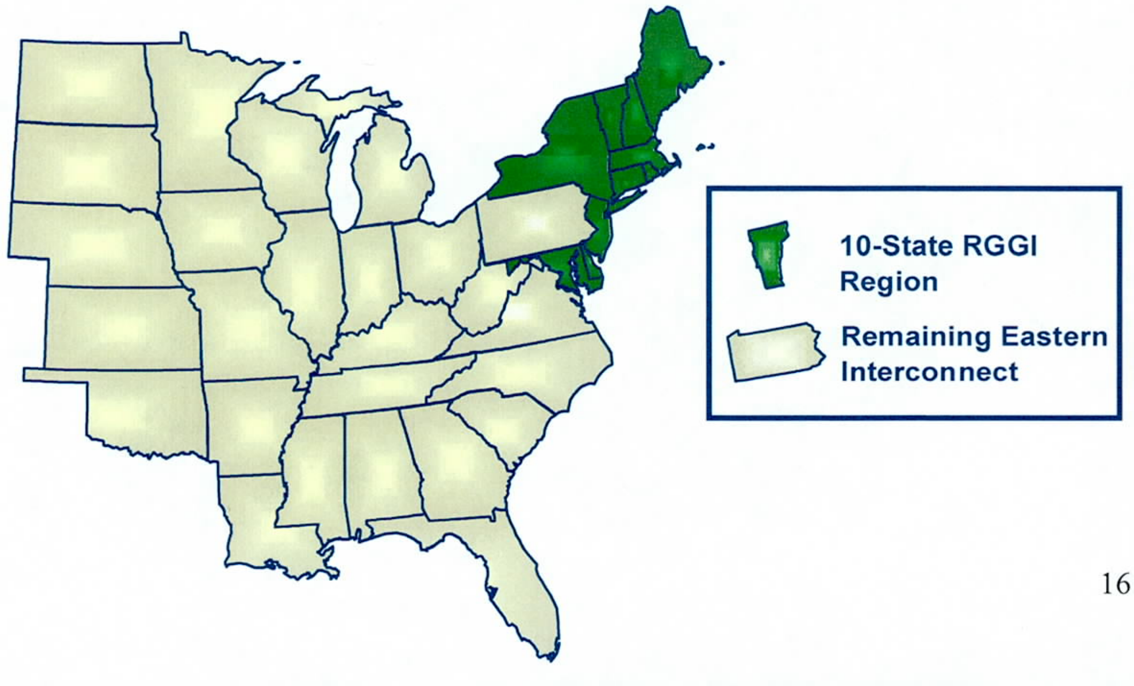
The federal CO_2 legislation considered is modeled afer the 2010 Kerry Lieberman proposal and includes the following details:

- Cap – The cap starts in 2018 at 3% below 2005 levels for affected sources and declines (straight-line) to 83% below 2005 levels in 2050. In 2018, we include the electric and transportation sectors as affected. The cap for those sectors starts at 3% below their 2005 levels in 2018 and gets to 83% below in 2050. We assume the industrials roll into the program in 2023. Its reduction target starts in 2023 at 3% below and straight-lines to 83% below by 2050. We sum those two trajectories together to get to our total cap. The actual compliance obligation is put on the group of affected entities.
- Reserve (backstop) price – The Kerry-Lieberman reserve price is set to start at $25 per metric ton in 2009$ and grow at 5% real per year. Converting that to short tons and 2006$ gets us a reserve price of $21.33/ton in 2018. It then grows at 5% real. In the legislation, the reserve is funded with 4 billion allowances out of the cumulative cap and is intended to control against volatility. This price reflects the marker of what some in Congress might view as a politically viable CO2 price.
- Floor price – The Kerry-Lieberman auction floor price starts at $12 per metric tonne in 2009$ and grows at 3% real per year.

The Regional Greenhouse Gas Initiative

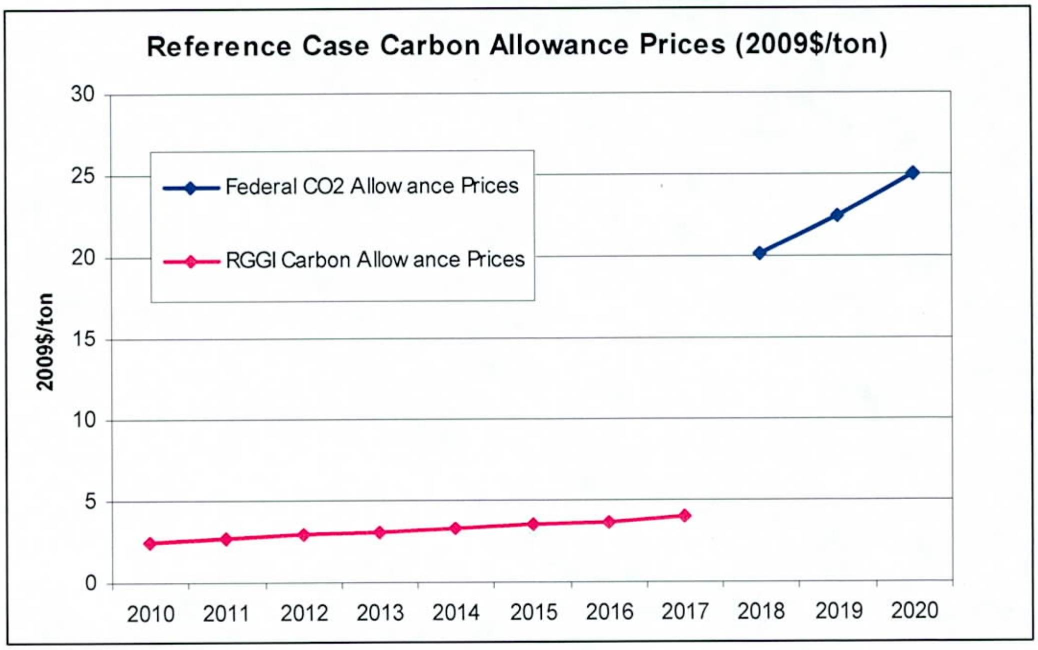
The Regional Greenhouse Gas Initiative (RGGI) is a market-based program to reduce emissions of carbon dioxide (CO_2). Ten states participating in RGGI established a regional cap on CO_2 emissions from the power sector and are requiring power plants to possess a tradable CO_2 allowance for each ton of CO_2 they emit.

Exhibit 3.3: Regional Greenhouse Gas Initiative



The carbon allowance prices for the reference case are shown in Exhibit 3.4.

Exhibit 3.4: Carbon Allowance Pricing Outlook (2009$/ton)



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. NOx 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.

Key Environmental Control Cost Assumptions

The capital cost for SCRs shown below does not include the up-front catalyst cost, which is accounted for in variable O&M assumptions. Capital costs for SCRs and SNCRs include adjustments for interest during construction and difficulty factors.

ICF assumes that SCR catalyst is a variable cost of operation. Consequently, variable O&M estimates for SCR are considerably higher than most other estimates. This operating assumption is based on the view that a plant operator will optimize the rate of catalyst replacement based on the NOX market, and that if the market does not provide sufficient revenues (or forgone costs), that catalyst will be replaced less frequently.

ICF assumes that combustion controls will be in place once a unit becomes subject to a NOX policy. Thus, only the SNCR portion of a layered NOX reduction process (e.g., RJM and Mobotech) is needed.

Exhibit 3.5: Illustrative NOx Retrofit Cost and Performance based on Unit Size

	SCR			SNCR		
Unit Size (2009$)	**200**	**500**	**800**	**100**	**200**	**300**
2015 Capital Cost ($/kW)	$193	$161	$161	$35	$27	$22
2020 Capital Cost ($/kW)	$242	$201	$201	$33	$26	$21
2025 Capital Cost ($/kW)	$230	$192	$192	$32	$24	$20
Fixed O&M ($/kW-yr)	$1.27	$0.79	$0.79	$0.32	$0.23	$0.20
Variable O&M ($/MWh)*	$0.68	$0.68	$0.68	$0.77	$0.77	$0.77
% Capacity Penalty	0.50%	0.50%	0.50%	0%	0%	0%
% NOx Removal	85%	85%	85%	30%	30%	30%

ICF models only the Lime Spray Dryer (LSD) technology on units that have announced plans to install this type of technology. Units that install this type of scrubber must also install a fabric filter. The additional capital cost that is incurred with the fabric filter makes the LSD uneconomic when compared to a wet FGD. In addition, the installation of a LSD is very site-specific, making a universal application within IPM® impracticable.

Exhibit 3.6: Illustrative Scrubber Retrofit Costs Based on Unit Size

	Wet FGD		
Unit Size (2009$)	**200**	**500**	**800**
2015 Capital Cost ($/kW)	$681	$524	$457
2020 Capital Cost ($/kW)	$843	$647	$565
2025 Capital Cost ($/kW)	$801	$615	$537
Fixed O&M ($/kW-yr)	$13.07	$9.08	$7.53
Variable O&M ($/MWh)	$1.90	$1.90	$1.90
% Capacity Penalty	2.10%	2.10%	2.10%
% SO2 Removal	95%	95%	95%
% Mercury Removal - Bituminous	40%	40%	40%
% Mercury Removal – Subbituminous & Lignite	15%	15%	15%

Activated Carbon Injection (ACI) assumptions are based on a variety of public sources. The costs are then adjusted to account for the recent rise commodities costs (e.g. steel, concrete, etc).

The ACI1 option is applied to units with an existing fabric filter burning any type of coal. The capital, fixed O&M and variable O&M costs assume a sorbent injection system (SIS) and sorbent disposal system (SDS). Bituminous units are assumed to achieve a 90 percent removal using conventional Powdered Activated Carbon (PAC), while the subbituminous units are assumed to achieve 90 percent removal using Halogenated Powdered Activated Carbon (HPAC).

The ACI2 option is applied to units with an ESP that do not have an existing fabric filter burning any type of coal. The ACI2 includes the installation of the SIS, SDS, as well as a pulse jet fabric filter (PJFF). This option represents EPRI's TOXECONTM technology. ACI2 is assumed to have a capacity penalty of 0.5 percent due to back pressure drop. Bituminous units are assumed to achieve a 90 percent removal using conventional Powdered Activated Carbon (PAC), while the subbituminous units are assumed to achieve 90 percent removal using Halogenated Powdered Activated Carbon (HPAC).

The ACI3 is applied to units with an ESP that do not have an existing fabric filter burning any type of coal. The ACI3 option includes the installation of a SIS and SDS and does not include a PJFF. ACI3 is not offered to units with SO3 conditioning. Low sulfur bituminous units are assumed to achieve a 90 percent removal using PAC, while the subbituminous units are assumed to achieve 90 percent removal using HPAC. High sulfur bituminous is assumed to not be able to achieve 90 percent removal. Due to the assumed MACT requirements, high sulfur bituminous is not offered ACI3. ACI3 is only offered to units burning bituminous coals with an online year after 1977 due to the size of their ESPs.

Units installing ACI3 to meet near-term state level regulations will be required to install a FF or retire under HAPs. The FF costs represent the delta between ACI2 and ACI3.

Units that are currently selling their fly ash will receive an additional \$0.44-\$1.17/MWh (2009\$) variable O&M adder on their ACI1 and ACI3 options to account for lost fly ash sales and additional disposal costs. These plants were determined using EIA Form 767 data.

Exhibit 3.7: Mercury Control Technologies Cost Assumptions Based on Size

	ACI on existing Fabric Filter (ACI1)			ACI on units without an existing Fabric Filter with an existing ESP (ACI2)		ACI on units without an existing Fabric Filter with an existing ESP (ACI3)		
Unit Size (2009\$)	**200**	**500**	**800**	**200**	**500**	**200**	**500**	**800**
Configuration	SIS + SDS			SIS + SDS + PJFF		SIS + SDS		
2015 Capital Cost (\$/kW)1	\$10.92	\$10.11	\$6.32	\$239	\$211	\$10.92	\$10.11	\$6.32
2020 Capital Cost (\$/kW)1	\$10.39	\$9.62	\$6.01	\$228	\$200	\$10.39	\$9.62	\$6.01
2025 Capital Cost (\$/kW)1	\$9.88	\$9.14	\$5.72	\$216	\$191	\$9.88	\$9.14	\$5.72
Fixed O&M (\$/kW-yr) – Bit./Sub.2	\$0.63	\$0.26	\$0.16	\$1.22	\$0.79	\$0.63	\$0.26	\$0.16
Variable O&M (\$/MWh) – Bit./Sub.3	\$0.26	\$0.26	\$0.26	\$0.65	\$0.65	\$2.39 / \$0.59	\$2.39 / \$0.59	\$2.39 / \$0.59
% Capacity Penalty	0%	0%	0%	0.50%	0.50%	0%	0%	0%
% Mercury Removal (from input)4	90%	90%	90%	90%	90%	90%	90%	90%

All coal units are assumed to require installation of ACI, fabric filter and scrubber in response to HAPs. Should these not be installed, the unit would be retired.

CCS retrofits on existing coal units are limited to those with a nameplate capacity of 350 MW and above and with an online date of 1970 and later. The capital cost basis is the post-retrofit net capacity "Carbon Dioxide Capture from Existing Coal-fired Power Plants" DOE/NETL November 2007. The storage costs will vary based on the location of the plant and the rank of coal (higher CO_2 content of sub-bituminous vs. bituminous). No variation in costs are assumed based on the mine source of the coal consumed.

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 3.8 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.

Exhibit 3.8: Delaware Renewable Portfolio Standard Annual Targets (%)

Year	Eligible Resources Other than Solar	Solar
2010	4.982	0.018
2011	6.8	0.2
2012	8.1	0.4
2013	9.4	0.6
2014	10.7	0.8
2015	12	1
2016	13.25	1.25
2017	14.5	1.5
2018	15.75	1.75
2019	17	2
2020	17.75	2.25
2021	18.5	2.5
2022	19.25	2.75
2023	20	3
2024	20.75	3.25
2025	21.5	3.5

CHAPTER FOUR - FUEL

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 caoacity and generation mix forPJM as of the beginning of 2010. PJM capacity and generation is dominated by coal, nuclear and natural gas-fired technologies.

Exhibit 4.1: PJM Capacity Mix as of Dec 31, 2009

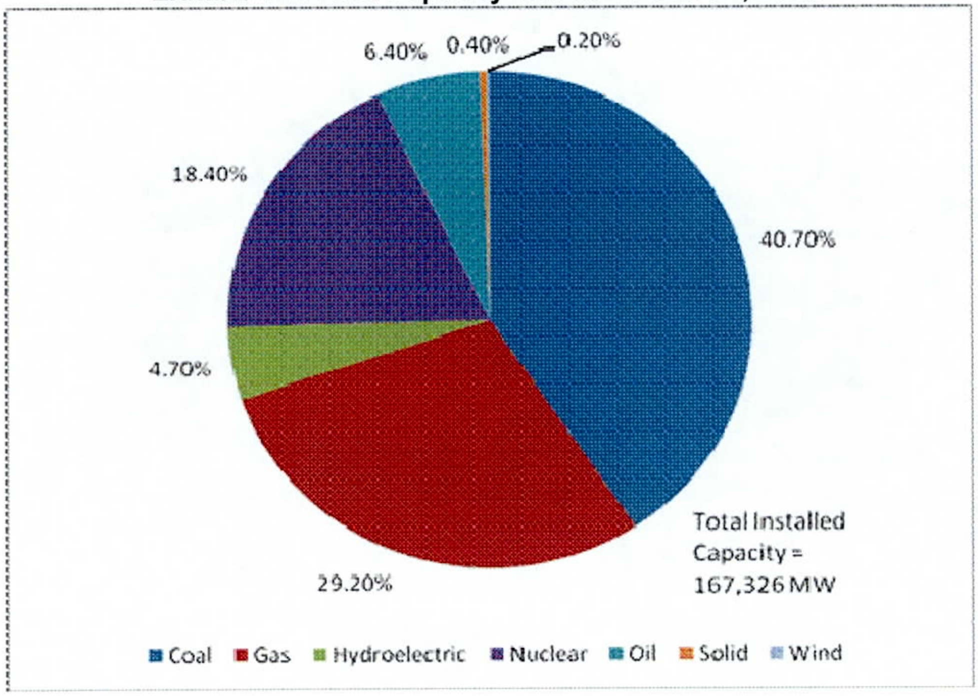
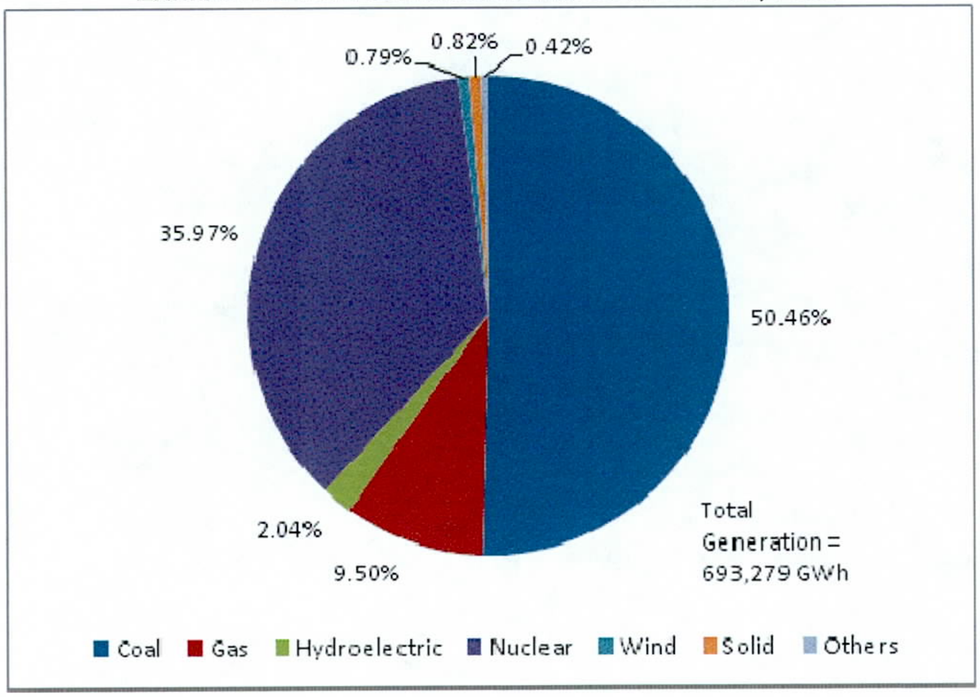


Exhibit 4.2: PJM Generation Mix as of Dec 31, 2009



FUEL TYPES ANALZED

The Base 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 SO2 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 gird were gas-fired resources.

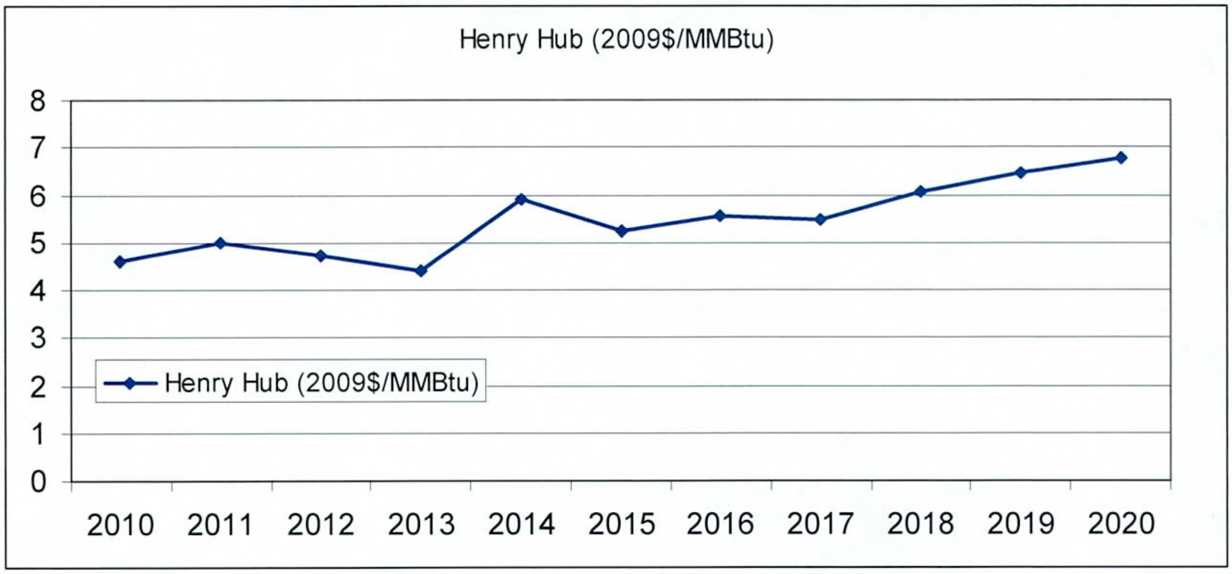
- **Oil** – Oil-fired generation comprises a very small share of the generation resource mix in PJM and throughout the US. PJM does have several older steam generators which can rely on either residual fuel oil or natural gas. In addition, peaking capacity can often fire on distillate fuel or natural 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

The forecast utilized for natural gas prices reflect a combination of the Henry Hub NYMEX futures price in the near term and the ICF July 2010 GMM Reference Case in the mid-and long-terms. The 2011 Henry Hub price projection reflects the average of the 2011 NYMEX forward monthly traded contracts between July 1 and July 31, 2010. The 2010 price is a combination of historical forwards between January 1-July 31 2010 and contracts maturing between August 2010 and December 2010. The 2012 projection reflects the average of 2011 forward derived price and beginning in 2013, we use a fundamentals-based forecast. The forecast of Henry Hub prices are shown in Exhibit 4.3 below.

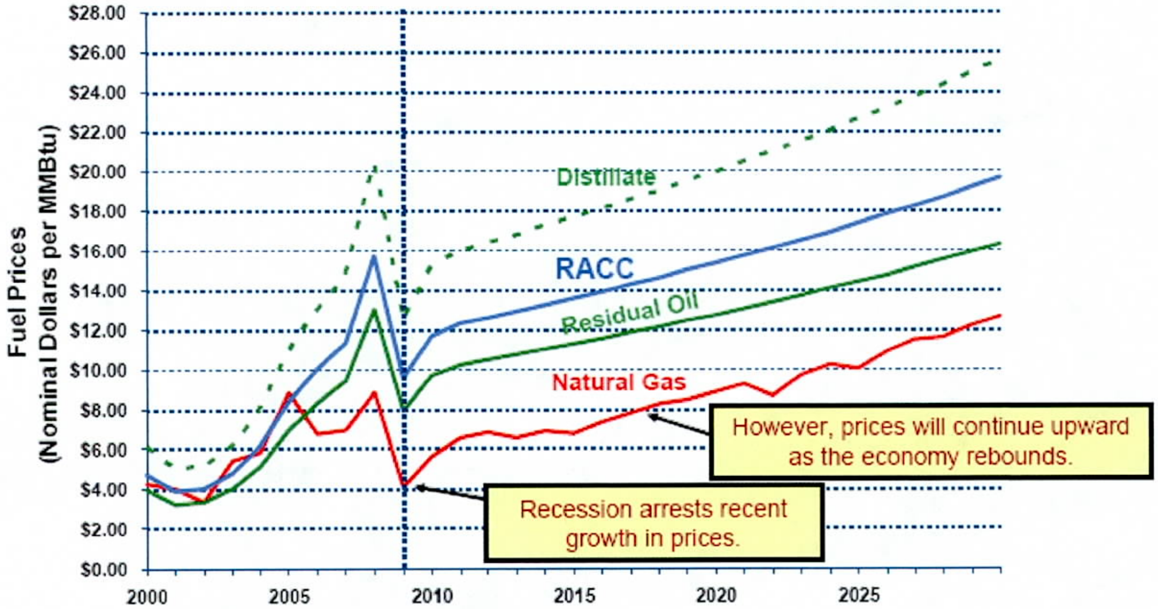
Exhibit 4.3: Henry Hub Natural Gas Price Forecast



OIL FORECASTS

The oil price forecast (Exhibit 4.4) indicates crude prices are expected to remain flat on a real dollar basis at $76.78/bbl. The sharp increase in the crude oil prices in the 2007/08 period has been assumed to be nullified by the increase in demand elasticity for oil over time and a steady increase in supply.

Exhibit 4.4: Historical and Projected Annual Average Fuel Prices



Sources: Historical data from Platts Gas Daily and EIA

COAL FORECASTS

Coal continues to be an important determinant of power prices particularly in the off peak hours. Coal prices have risen in the spot markets on a commodity basis – i.e., at or near the mine. This increase has been driven by higher demand for coal which in turn has in part been driven by higher oil and natural gas prices. There also has been rising international demand for US coal. However, these increases have still left coal at a discount to natural gas prices.

Coal prices have been determined internally within the IPM® model based on a linear optimization using detailed supply characteristics at the mining level. Coal resources for each of 40 coal supply basins are disaggregated into the following categories:

- Rank[1]
- Sulfur content
- Existing and new
- Surface: Overburden Ratio, Size, Mining Method
- Underground: Depth, Seam Thickness, Mining Method

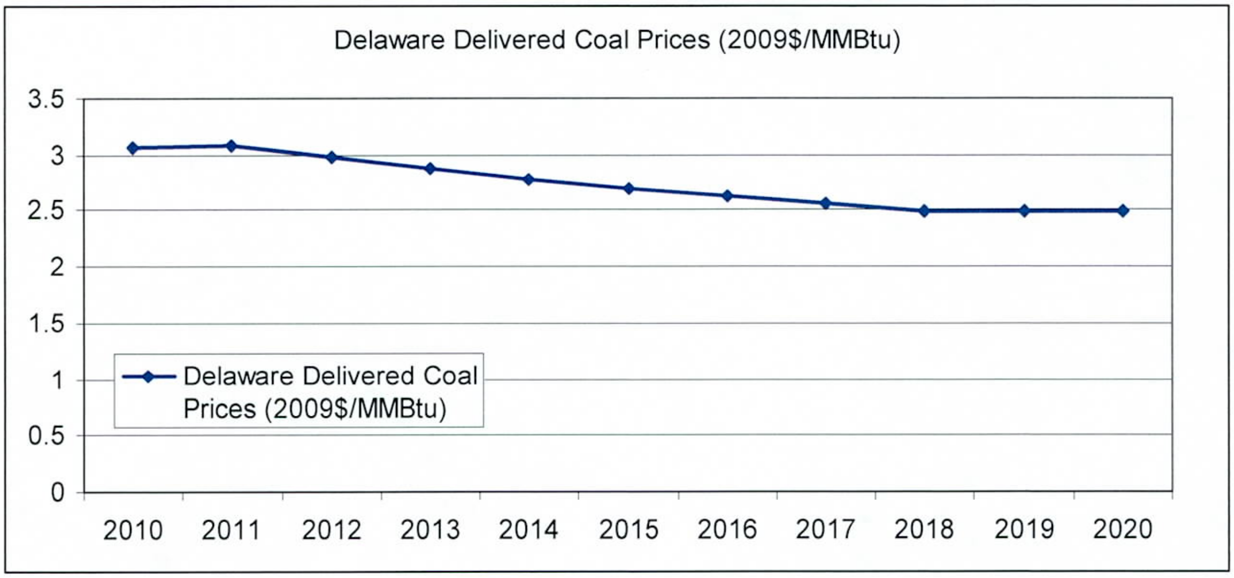
Coal supply curves for each of the 40 supply basins are created by applying disaggregated coal resources assigned to one of 16 prototype coal costing models. The coal supply curves are then used as inputs to IPM® and transportation paths are defined to individual coal plants through identified modes of delivery and associated transportation costing.

[1] Coal "rank" refers to the degree of alteration or "coalification" that the organic source material in coal has attained. Coal is formed by the decomposition of plant matter without free access to air and under the influence of moisture, pressure, and temperature. Over the course of the geologic process that forms coal—coalification—the chemical composition of the coal gradually changes to compounds of lower hydrogen content and higher carbon content. There are four major ranks of coal in the U.S. classification scheme, from highest to lowest: anthracite, bituminous, subbituminous, and lignite.

Supply costs assumptions include continued low productivity at mining location and increasing real coal transportation costs.

Exhibit 4.5 reflects the delivered coal prices for Delaware.

Exhibit 4.5: Representative Delivered Coal Prices for Delaware, 2009$/ton



CHAPTER FIVE – REFERENCE CASE RESULTS

Chapter Five presents results of the long-term Reference Case including the resource mix that would optimally serve the PJM market.

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	2011	2012	2014	2016	2018	2020
Coal	81,192	80,904	75,447	74,684	65,599	65,592
Biomass	477	477	826	1,936	2,990	4,140
Nuclear	33,620	33,648	33,648	33,648	33,648	33,648
Cogen	3,000	3,000	2,255	1,492	1,492	1,027
Combined Cycle	22,295	22,295	28,236	33,362	38,960	39,620
Combustion Turbine	31,446	31,445	31,205	31,205	33,286	34,365
Oil/gas	7,187	6,374	8,454	8,578	8,578	8,578
Hydro	2,312	2,312	2,437	2,437	2,437	2,437
Pumped Storage	4,966	4,966	4,966	4,966	4,966	4,966
Wind	5,680	8,493	9,997	10,197	10,197	13,253
Solar PV	265	427	1,246	2,475	2,507	3,229
Landfill Gas	532	532	648	1,137	1,633	1,956
Other	541	541	541	541	541	541
Total	193,513	195,414	199,906	206,658	206,834	213,352

Note: Duke Ohio & Kentucky and First Energy (ATSI) generation is included in all years.

Exhibit 5.2: Expected Generation (GWh) by Type – PJM Wide

Capacity Types	2011	2012	2014	2016	2018	2020
Coal	470,136	476,214	468,224	481,219	441,183	446,176
Biomass	3,775	3,775	6,439	14,903	22,976	31,766
Nuclear	261,447	255,706	260,207	257,945	254,864	260,094
Cogen	18,725	19,926	13,579	8,275	9,275	6,317
Combined Cycle	78,792	90,408	113,583	132,829	187,317	184,507
Combustion Turbine	4,067	5,365	4,801	3,429	5,264	5,510
Oil/gas	3,993	5,236	2,553	680	694	4
Hydro	7,417	7,417	7,739	7,739	7,739	7,739
Pumped Storage	8,604	8,604	8,604	8,369	7,361	7,459
Wind	14,480	22,855	27,166	27,454	27,724	36,610
Solar PV	439	717	1,996	3,960	4,029	5,169
Landfill Gas	3,747	3,759	4,706	8,694	12,736	15,370
Other	4,279	4,279	4,279	4,279	4,279	4,279
Total	879,901	904,261	923,876	959,775	985,441	1,011,000

Note: Duke Ohio & Kentucky and First Energy (ATSI) generation is included in all years.

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 and 5.4 present the all-hours energy prices and annual capacity prices for DPL North and DPL South zones, respectively.

Exhibit 5.3: All-hours Wholesale Energy Price (2009$/MWh)

Confidential Material Omitted

Exhibit 5.4: Capacity Price (2009$/kW-yr)

Confidential Material Omitted