(UNSEALED BY DPL REQUEST 3/8/13)

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FILED PURSUANT TO RULE 11 OF THE

COMMISSION RULES OF PRACTICE AND PROCEDURE

APPENDICES TO 2012 INTEGRATED RESOURCE PLAN

APPENDIX 6

DELMARVA POWER AND LIGHT COMPANY BEFORE THE DELAWARE PUBLIC SERVICE COMMISSION CONCERNING PORTFOLIO PERFORMANCE FOR INTEGRATED RESOURCE PLANNING

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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

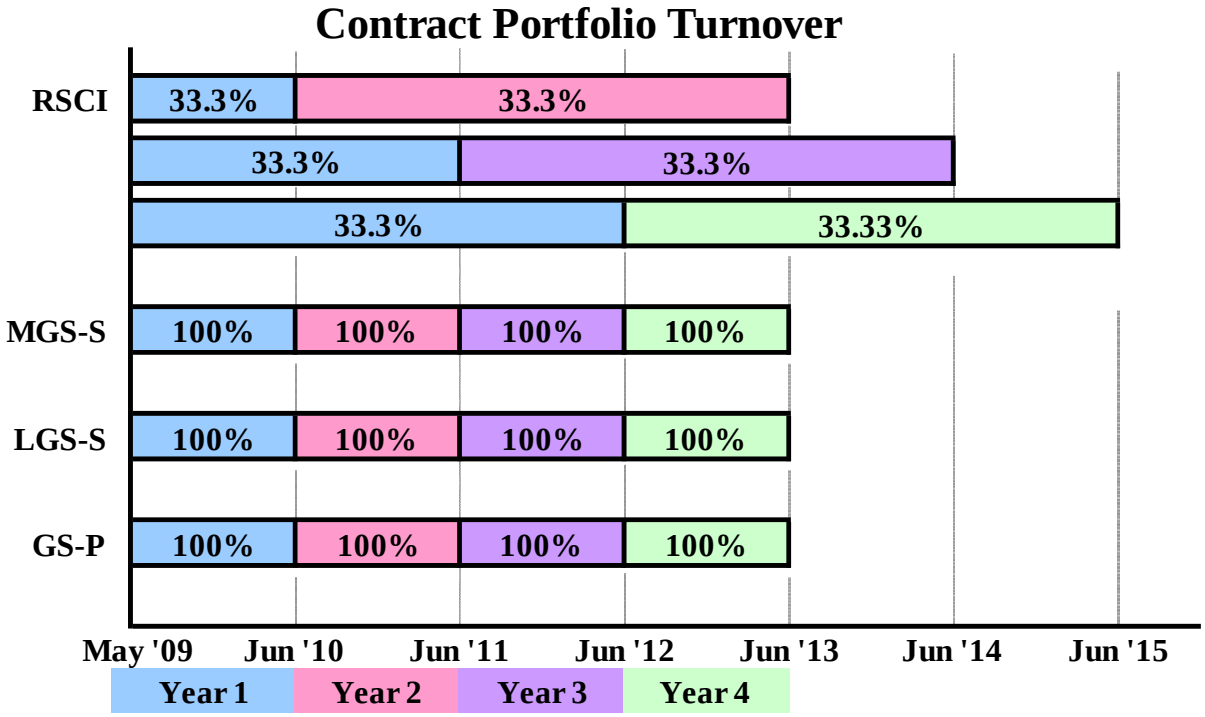


Figure 2 provides the blended cost of existing FSA contracts and the percentage of SOS customer requirements already covered for the planning years 2012, 2013 and 2014 by virtue of past RFPs. These costs are included in calculating the expected FSA supply costs and the projection of customer rates provided 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

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	$96.93	$99.26	$94.55	$100.53

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	$94.00	$106.26	$82.99	$112.41

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

LC 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	1,122,176	$67.34	$73.27	$61.20	$76.37

LC 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	1,097,128	$69.71	$89.24	$53.09	$99.18

LC 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	1,117,347	$84.67	$116.69	$59.33	$136.62
Reference Case and CC	1,117,347	$76.83	$99.77	$57.04	$113.45

LC Customers Planning Year 2019

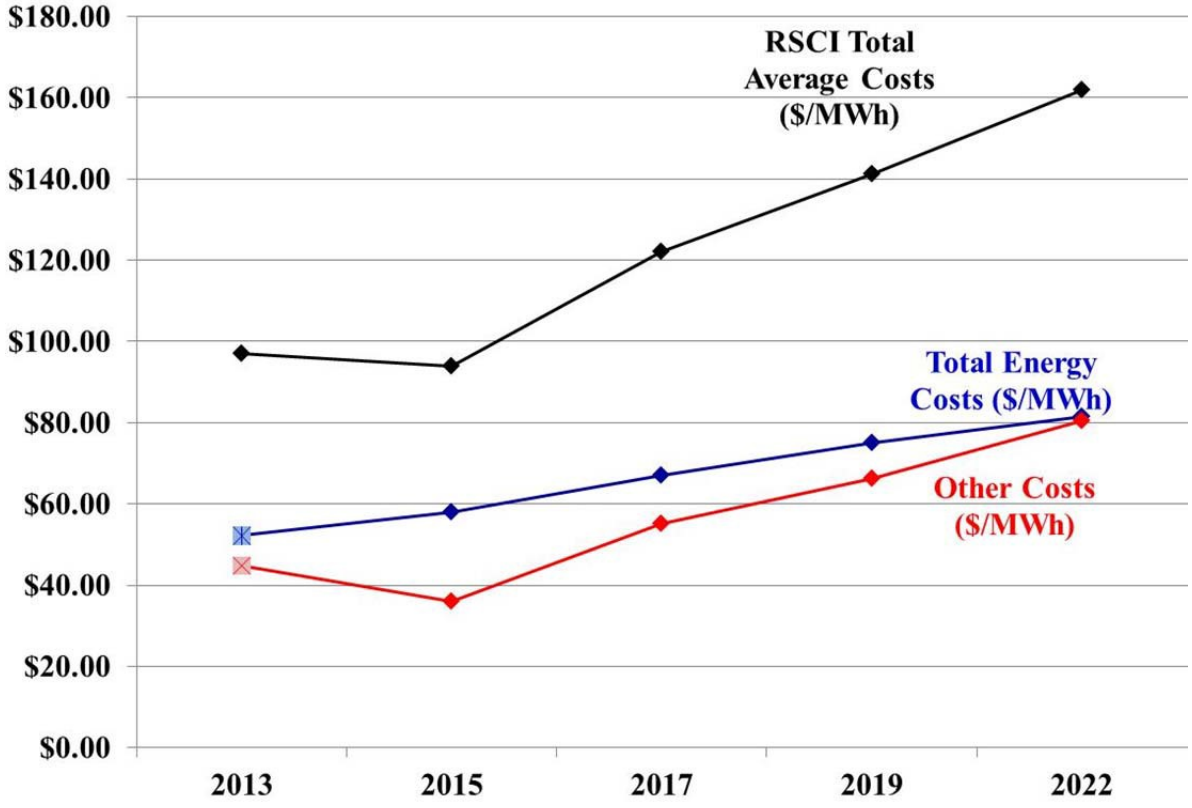
	Total Expected Electricity Volume (MWh)	Total Average Costs ($/MWh)	High Average Costs 90.0% ($/MWh)	Low Average Costs 10.0% ($/MWh)	Average Costs Above 90% ($/MWh)
Reference Case Total	1,081,056	$96.20	$137.31	$61.26	$168.96
Reference Case and CC	1,081,056	$84.01	$112.61	$59.04	$133.44

LC 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	1,051,137	$106.74	$160.56	$63.38	$205.12
Reference Case and CC	1,051,137	$91.57	$130.04	$60.91	$156.33

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



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 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

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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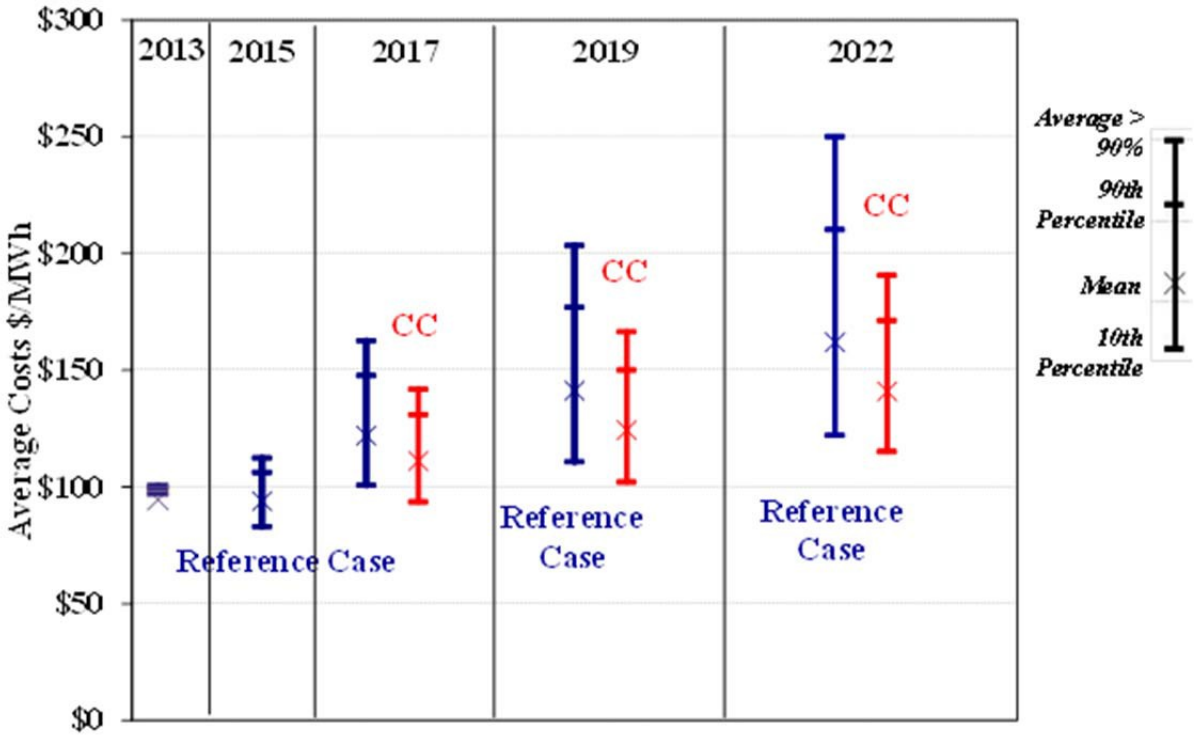
this figure ($96.93 per MWh) is not approximate, because it is based on blending the existing FSA contracts with the 1/3 share of the 2013 incremental cost.

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:

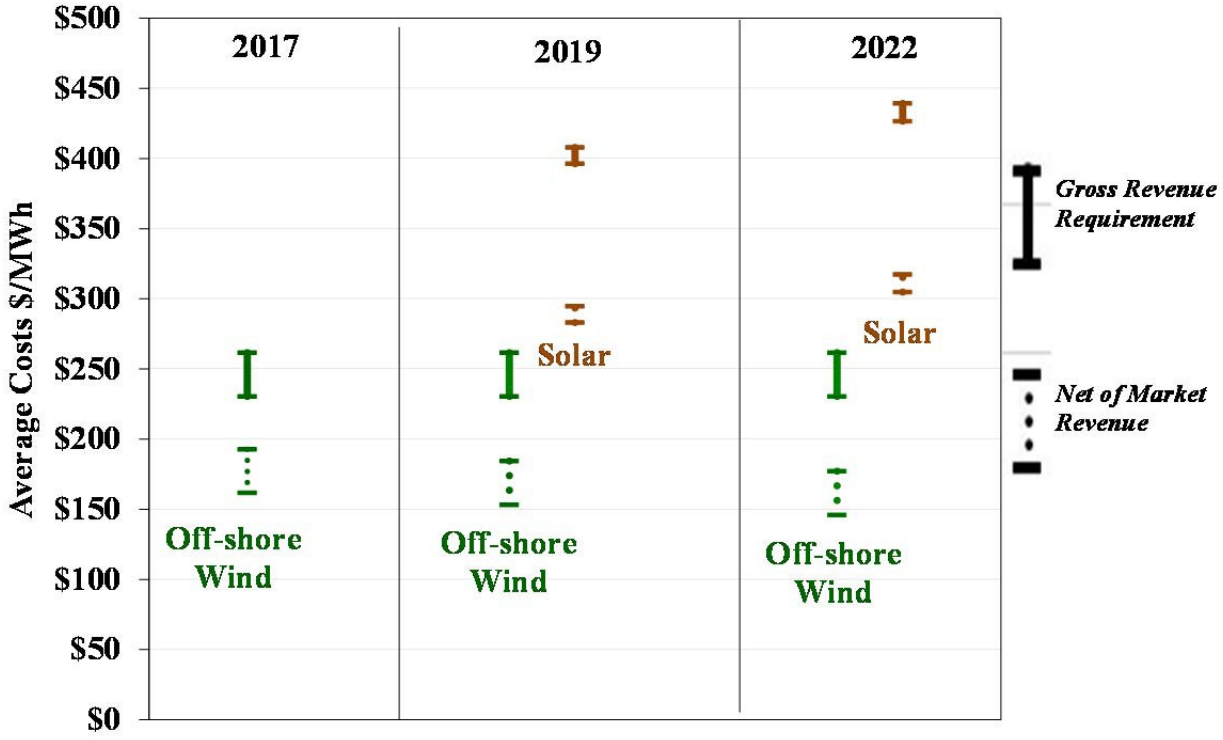
Overnight construction cost per kW (2017$):	$1,135
Full load average heat rate (Btu/kWh):	7,000
Fixed O&M (2017$/kW-year):	$18.89
Useful life (basis for capital recovery):	20 years
After tax weighted average cost of capital:	8.1%

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.

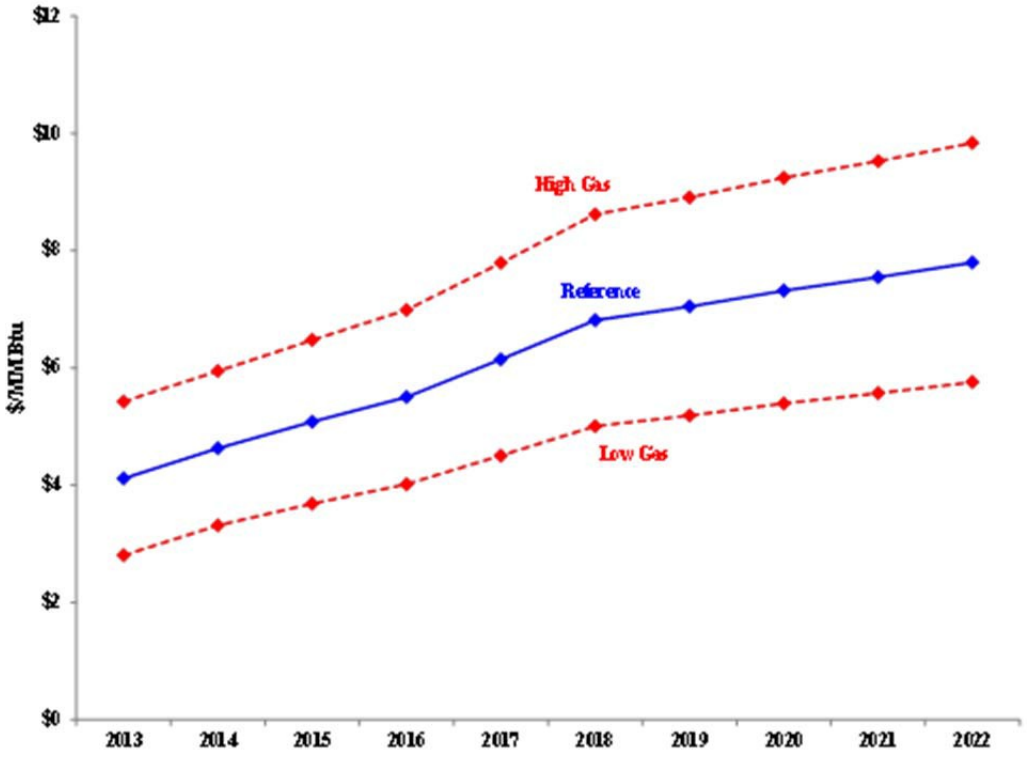
This same figure shows that neither an offshore wind plant nor an additional solar project would be economically useful to FSA costs. The paired bars shown for wind and solar are for the gross and net costs of such resources, not for their costs folded into the FSA portfolios. The top of these bars indicates 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.

[4] 2012 Quarterly State of the Market Report for PJM, January through September, p.29.

Figure 8: Tariff Rate Projections (Nominal $)

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	-	-	9.24	9.31	10.9	6.7	3.76	4.52
2014/15	-	-	11.11	11.06	11.2	6.9	3.84	4.62
2015/16	-	-	11.10	11.07	11.5	7.1	3.93	4.73
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

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, electricity market price data is only available for a few years forward (gas is available for up to

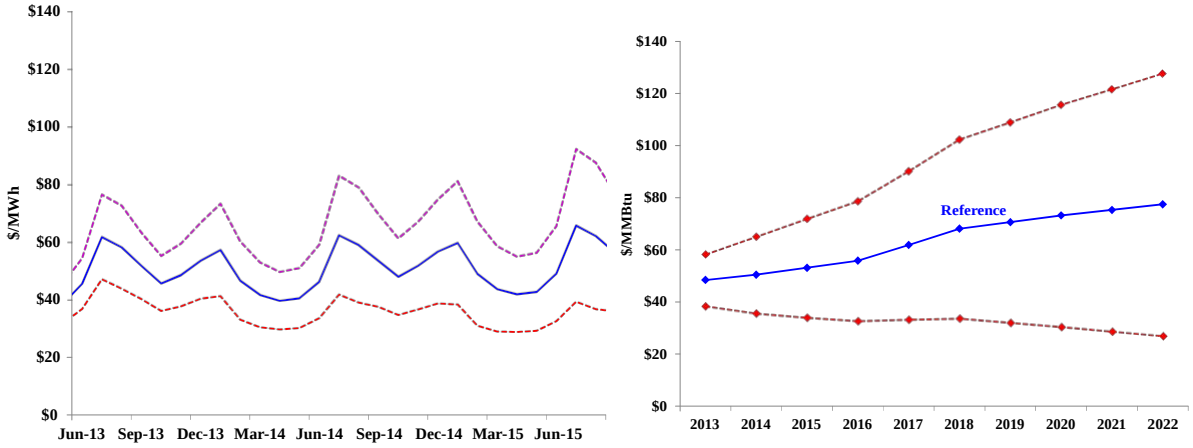
[5] Correlation is a statistical measure of the extent to which uncertain factors tend to change in the same direction.

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.

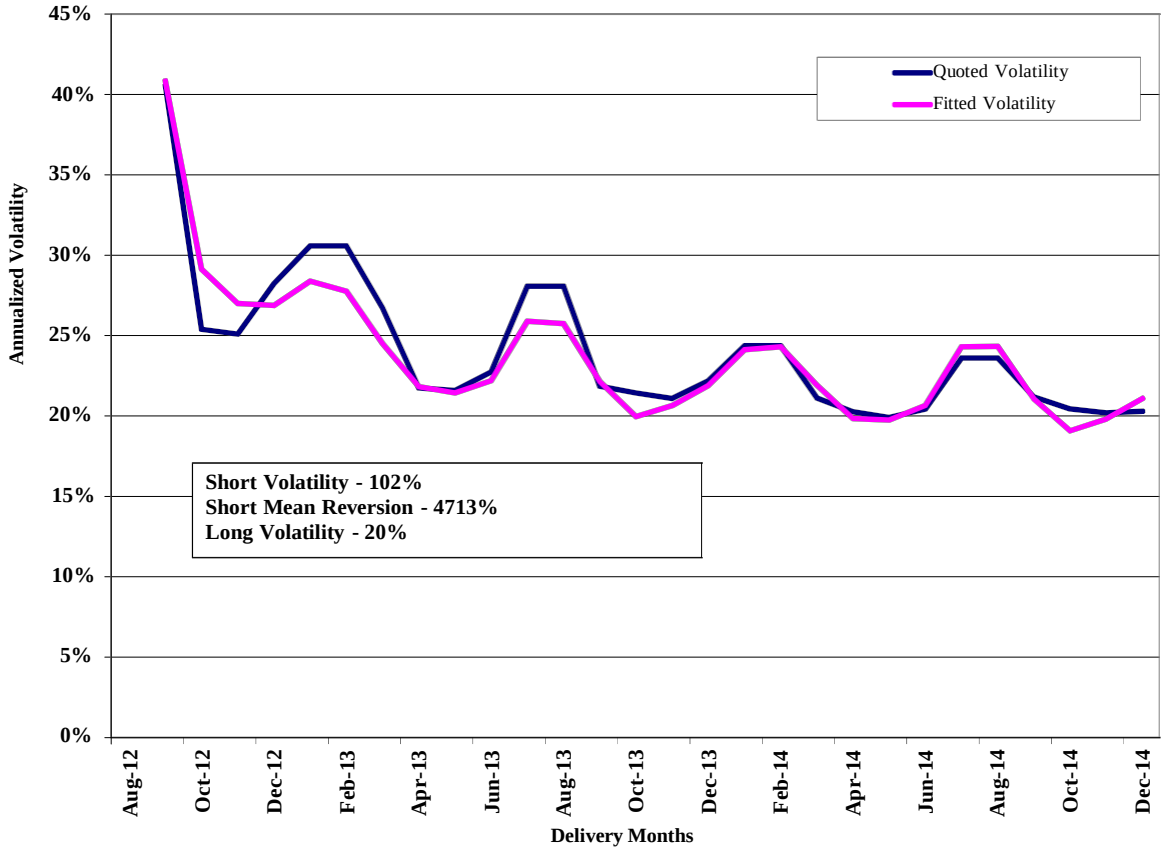
The dashed pink and red lines above and below the solid blue line in Figure 9 depict the ranges around those forward prices that describe the market uncertainty regarding what the actual average monthly spot prices could turn out to be. Like the monthly forward price, the monthly uncertainty has a pattern 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.

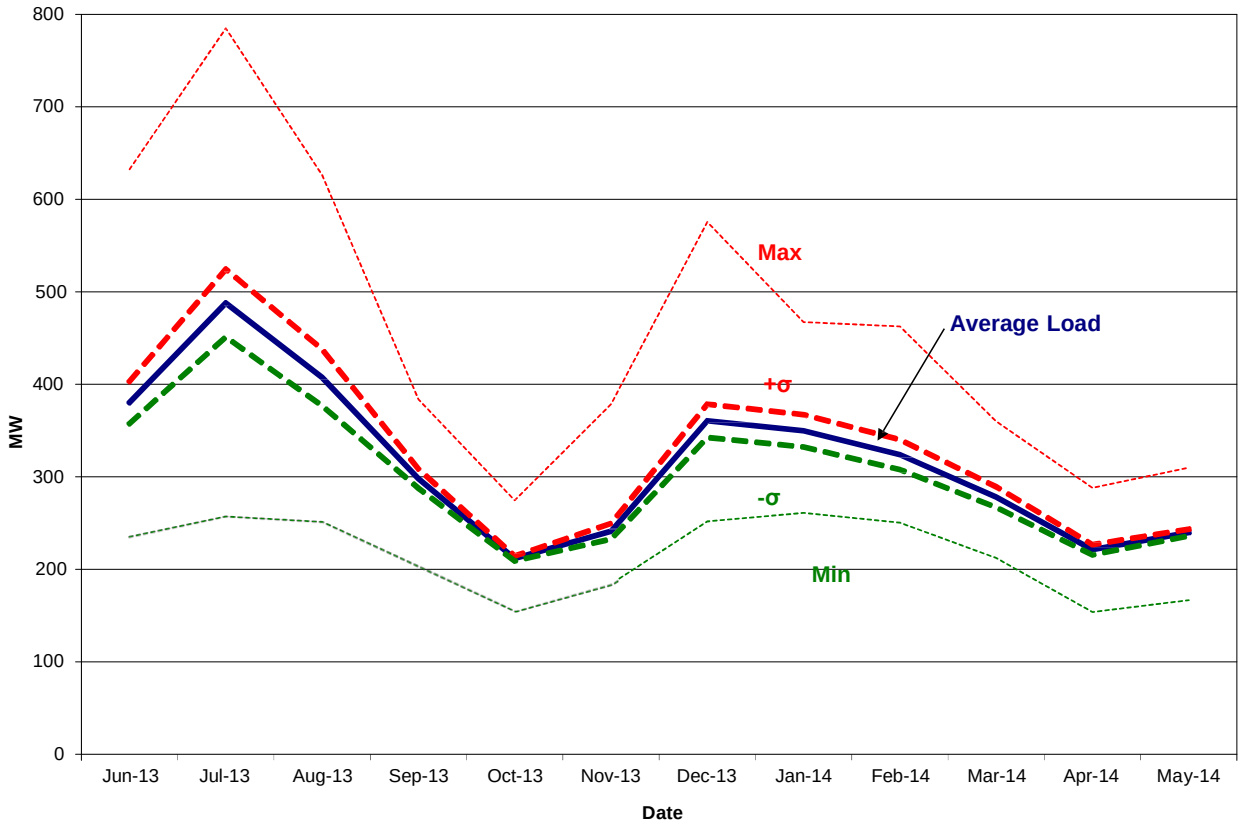
The pink line in **Figure 10** below shows the fitted two-factor model results compared to the quoted volatilities prevailing at the beginning of August 2012 (depicted by the solid blue line). The fit is in very close agreement to the quotes, but it is more useful, as it has restated those volatilities 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



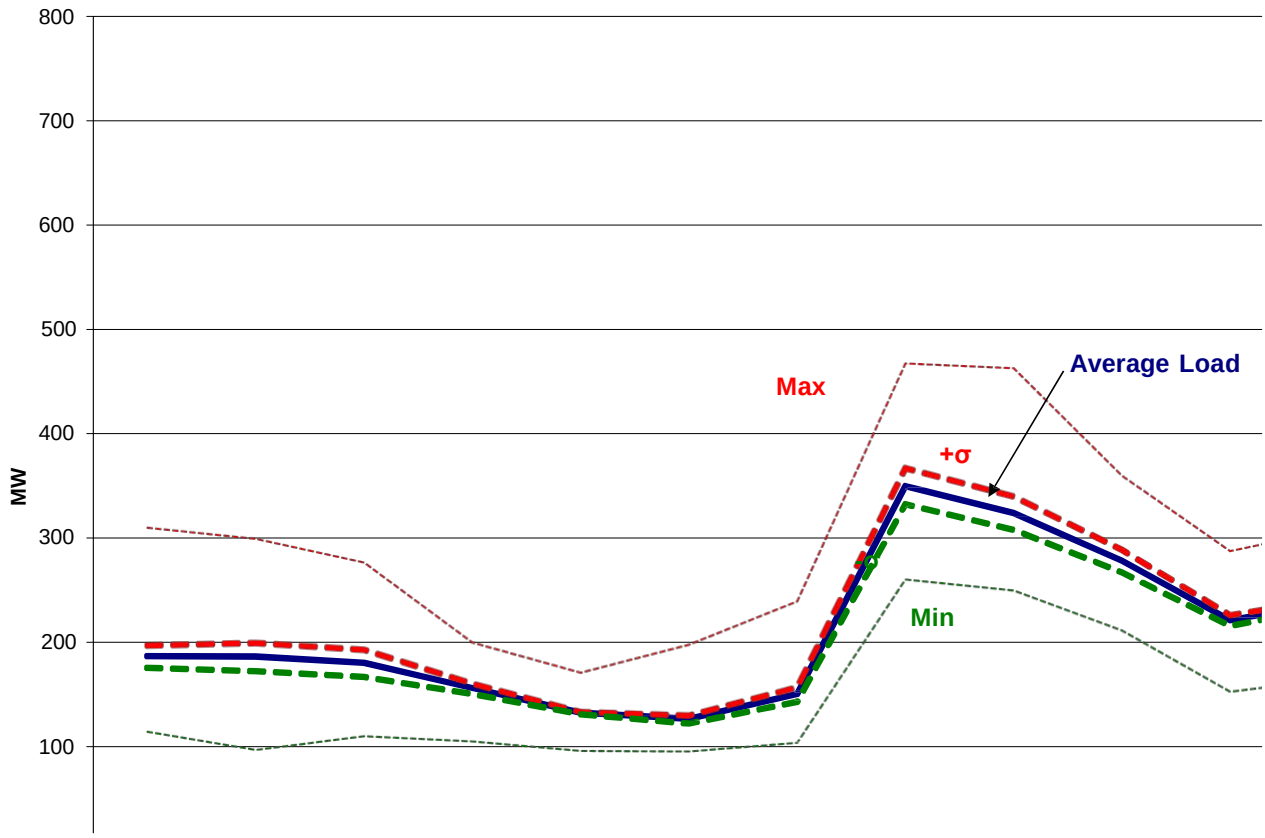
This figure reflects only the load during on-peak hours for RSCI customers projected from historical load experienced over January 2009 through December 2011, as adjusted for potential conservation impacts based on Delmarva's cost/benefit analyses of conservation and demand management activities similar 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.

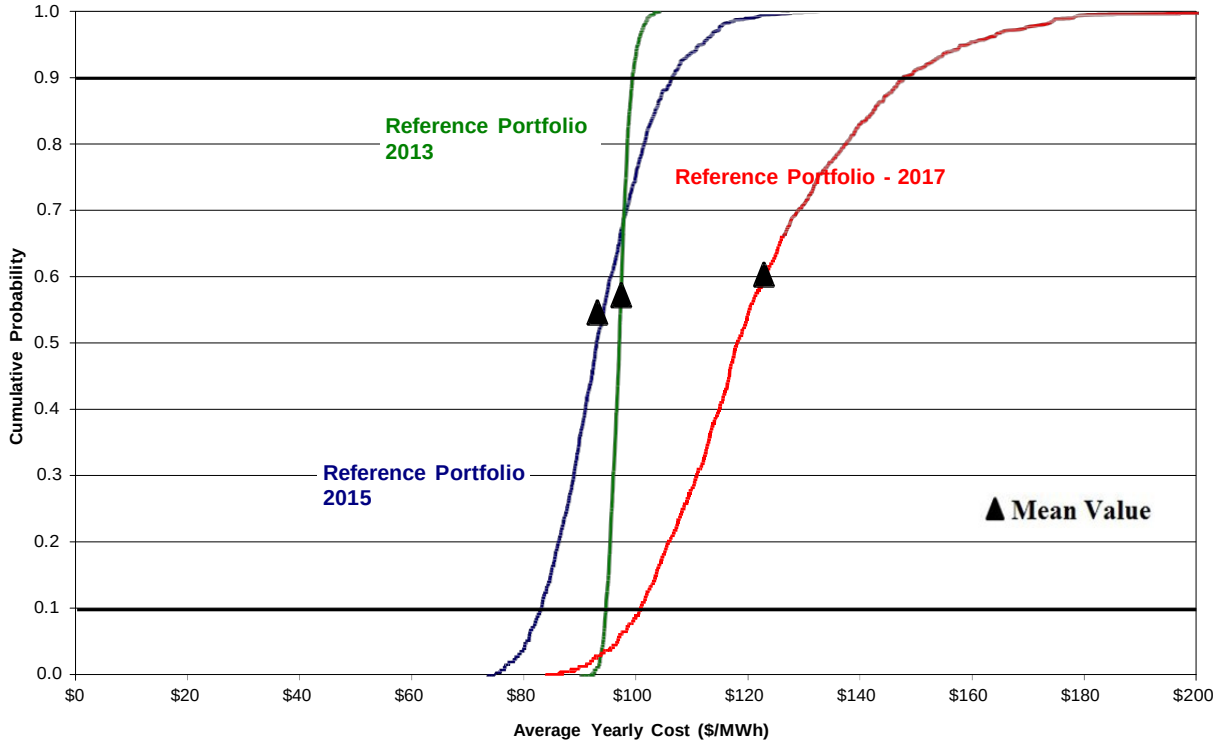
RESULTS – INITIAL PERIOD, 2013, 2015 AND 2017

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 $44.8/MWh[7] to the 3 year forward retail energy cost of about $77.1/MWh. However, this will be averaged in with prior FSA costs for a total of about $96.93/MWh for RSCI customers and about $67.34/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

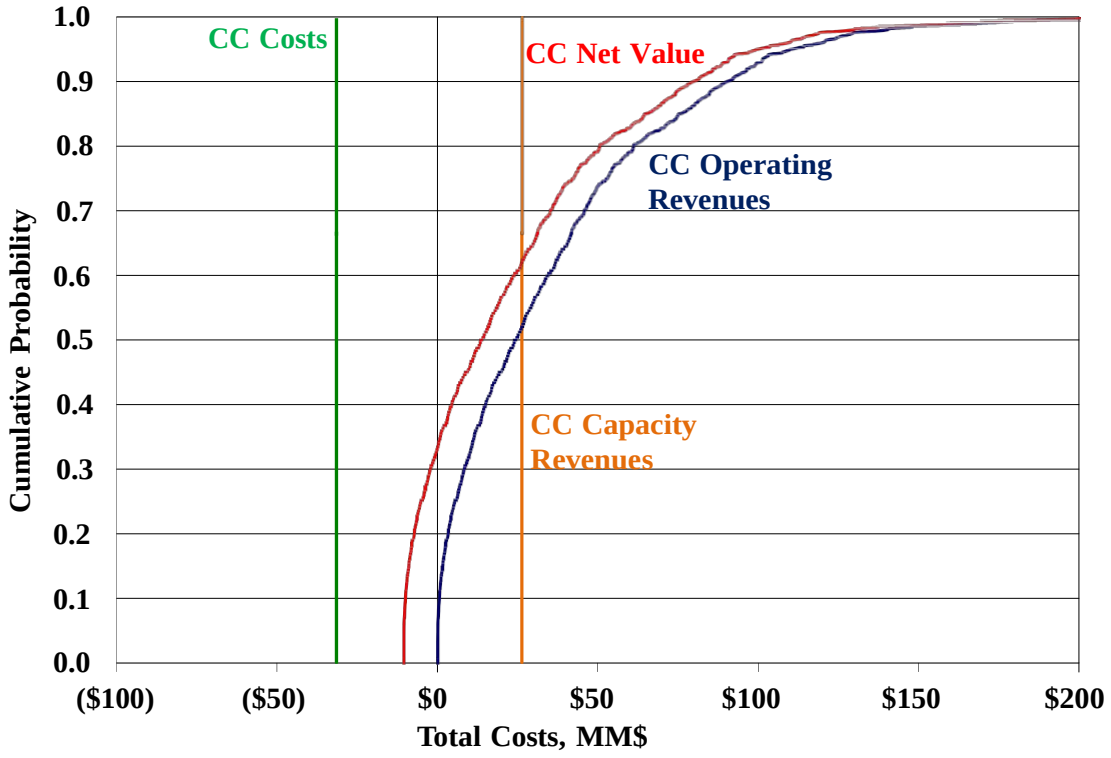
Based upon stakeholder input received during the IRP Working Group process, Delmarva agreed to evaluate whether a gas-fired generation plant could reduce the costs or risks of RSCI and LC service. This prospect has been evaluated by considering the addition of a 300 MW Combined Cycle (CC) facility in 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 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 6 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

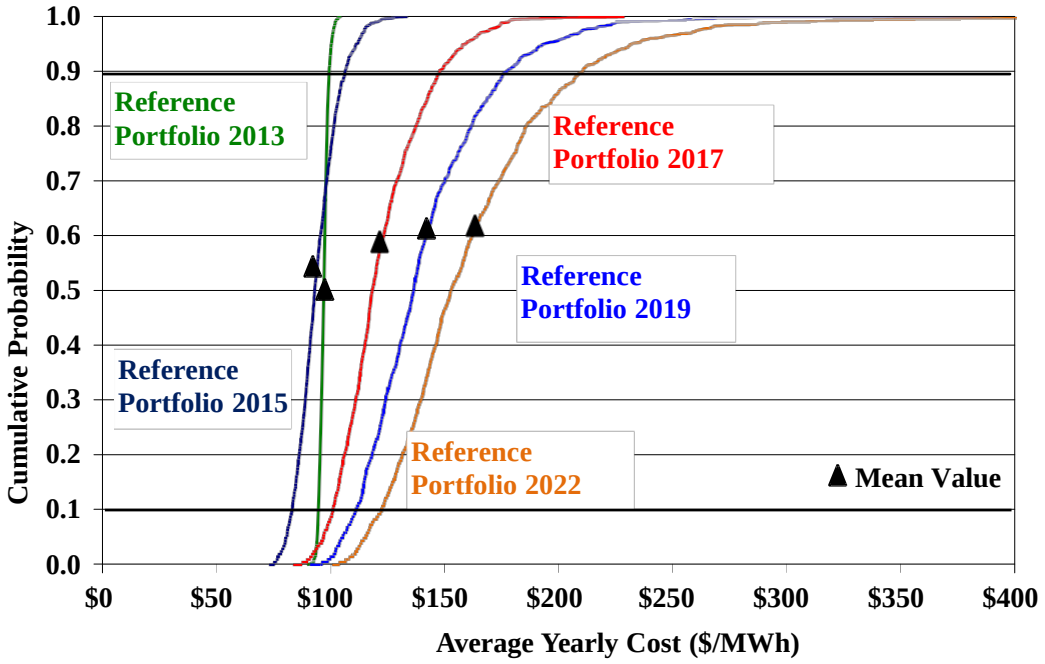
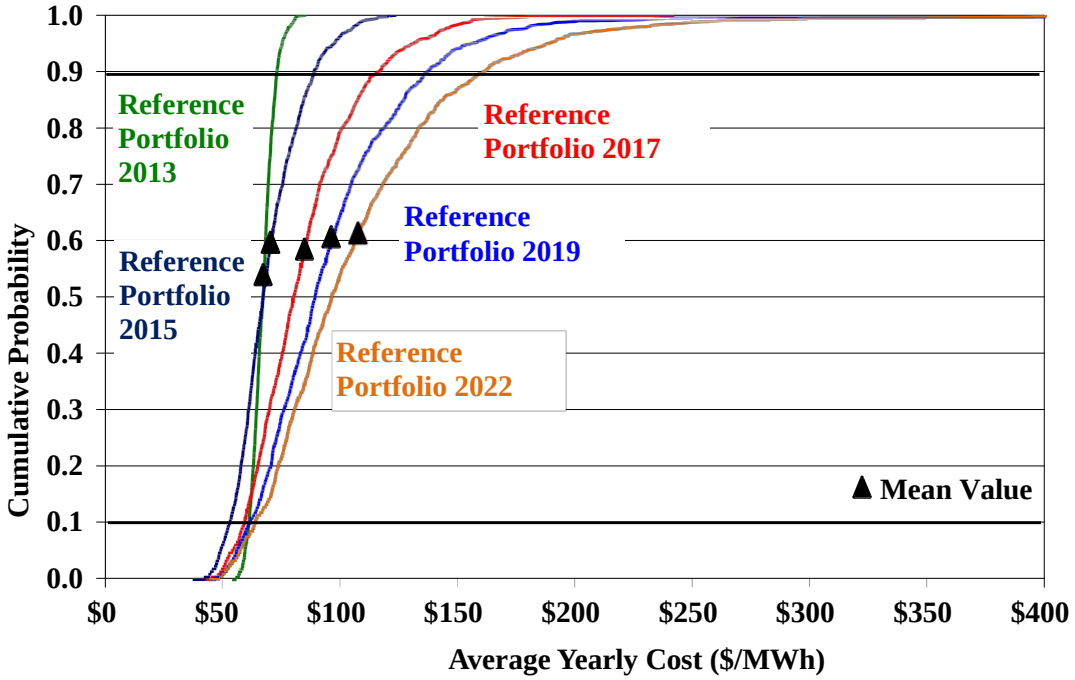


Figure 16: LC FSA Costs in 2013 - 2022



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.

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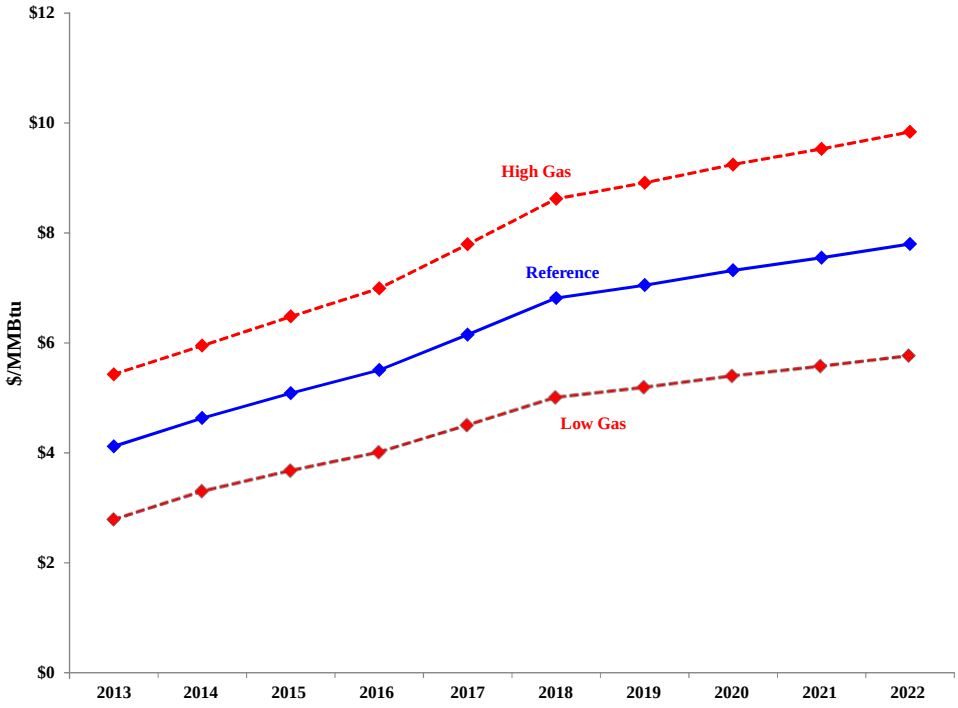
Figure 17: Natural Gas Price Sensitivities For Delivered Prices to PJM Transco Zone 6, Non-NY



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

Panel A – FSA Portfolio

RSCI FSA Results ($/MWh)

	Low Gas	Reference	High Gas
2013	$91.81	$96.93	$102.05
2015	$78.15	$94.00	$109.84
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 $

RSCI
Nominal Dollars

Electricity Hedging Option	Total Expected Electricity Volume (MWh)	Total Average Costs ($/MWh)	**Delta (%)**	High Average Cos ts 90.0% ($/MWh)	Low Average Cos ts 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	$96.93		$99.26	$94.55	$4.71		**4.86%**
Settlement Period: Planning Year 2015								
Reference Case	2,378,072	$94.00		$106.26	$82.99	$23.27		**24.76%**
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 $

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	$94.56		$96.84	$92.25	$4.59		**4.86%**
Settlement Period: Planning Year 2015								
Reference Case	2,378,072	$87.29		$98.67	$77.06	$21.61		**24.76%**
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 $)

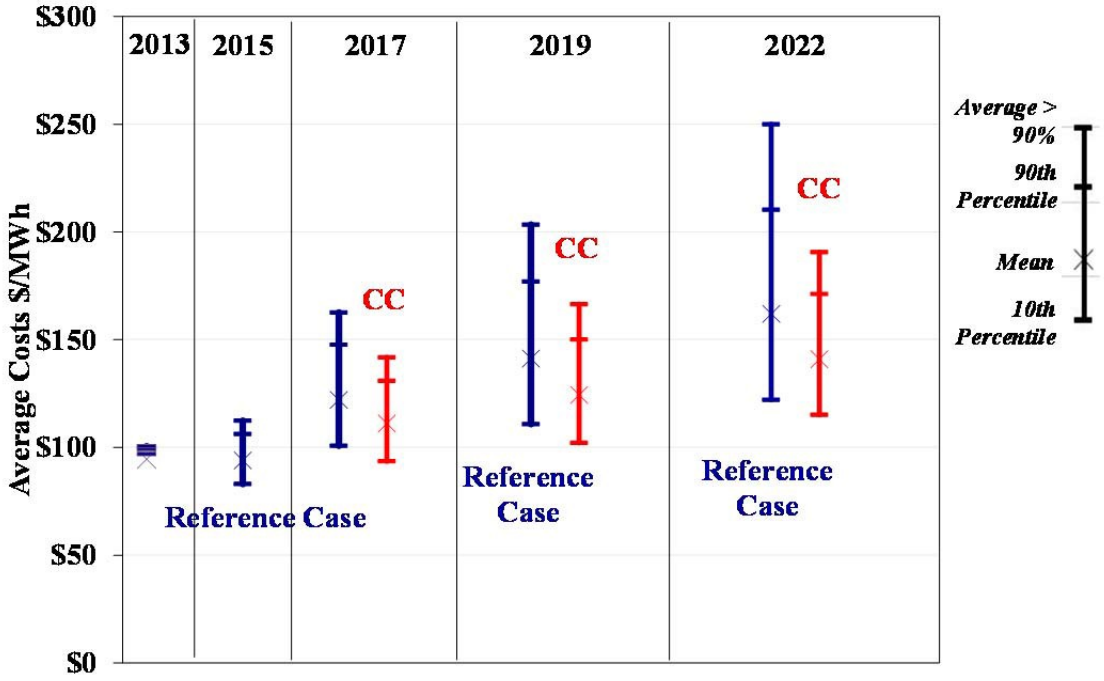


Table 2: Tariff Rate Projections
Panel A: Nominal $

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	-	-	9.24	9.31	10.9	6.7	3.76	4.52
2014/15	-	-	11.11	11.06	11.2	6.9	3.84	4.62
2015/16	-	-	11.10	11.07	11.5	7.1	3.93	4.73
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 $

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	-	-	9.01	9.08	10.6	6.6	3.67	4.41
2014/15	-	-	10.58	10.53	10.6	6.6	3.66	4.40
2015/16	-	-	10.31	10.28	10.7	6.6	3.65	4.40
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 $

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	$67.34		$73.27	$61.20	$12.07		**17.93%**
Settlement Period: Planning Year 2015								
Reference Case	1,097,128	$69.71		$89.24	$53.09	$36.15		**51.86%**
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 $

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	$65.70		$71.49	$59.71	$11.78		**17.93%**
Settlement Period: Planning Year 2015								
Reference Case	1,097,128	$64.73		$82.87	$49.30	$33.57		**51.86%**
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

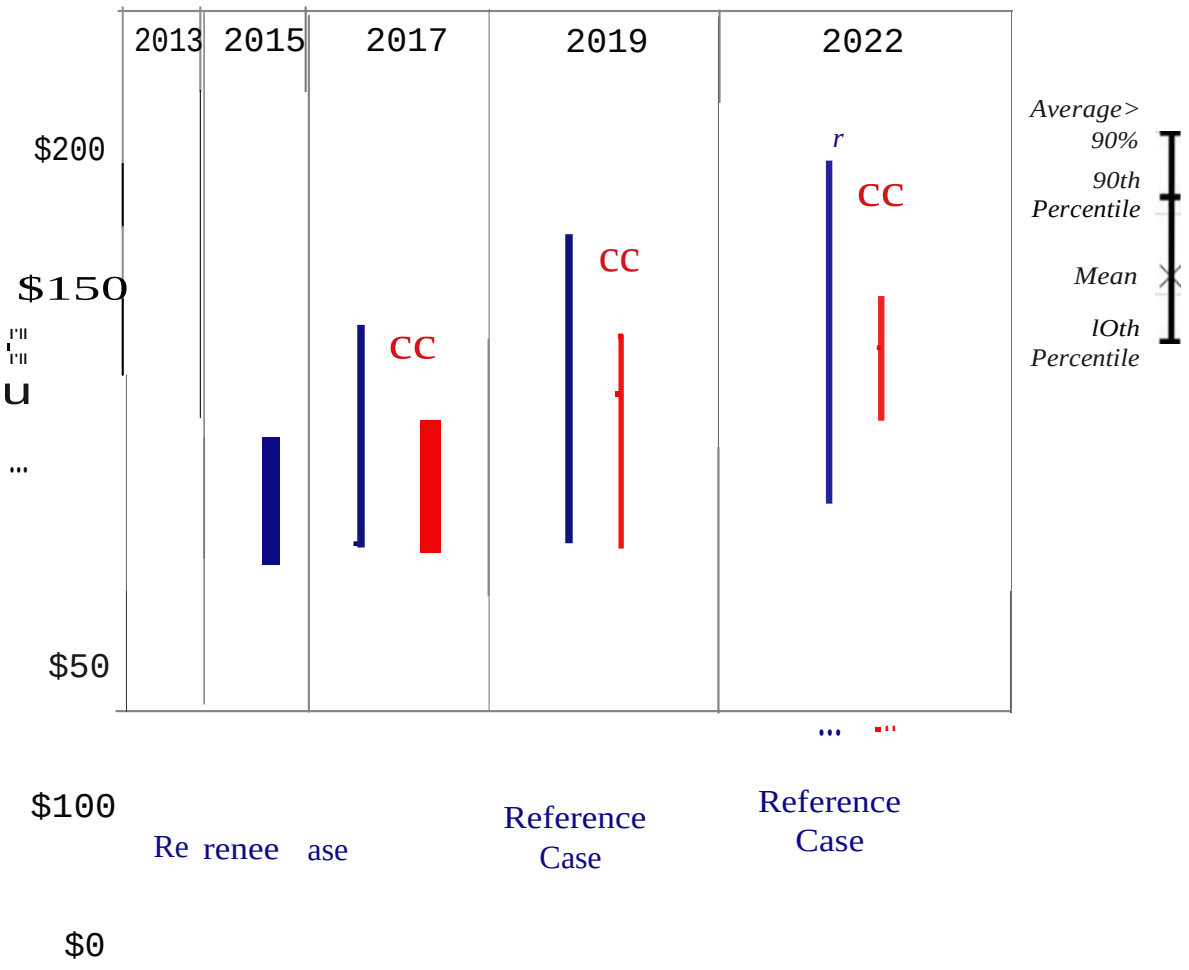


Table 5: Tariff Rate Projections
Panel A: Nominal $

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	-	-	9.24	9.31	10.9	6.7	3.76	4.52
2014/15	-	-	11.11	11.06	11.2	6.9	3.84	4.62
2015/16	-	-	11.10	11.07	11.5	7.1	3.93	4.73
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 $

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	-	-	9.01	9.08	10.6	6.6	3.67	4.41
2014/15	-	-	10.58	10.53	10.6	6.6	3.66	4.40
2015/16	-	-	10.31	10.28	10.7	6.6	3.65	4.40
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 **Page 1**

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%

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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

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Load Forecast (GWH)
DPL Delaware less DSM
Calendar Year

	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

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Load Forecast (GWH)
DPL Delaware less DSM
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											
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

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Peak Demand Forecast (MW)
DPL Delaware Unrestricted
Calendar Year

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	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%

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DSM Projectons (MW)
DPL Delaware
Calendar Year

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	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

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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

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 ES RECs	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

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 (ES RECs)	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 9 - ~~Confidential Version~~

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
Demand ($/kW)												
Summer		$ 7.353866								$10.912791	$12.617523	$12.332350
Winter		$ 5.195718								$ 6.735063	$ 8.204237	$ 7.862365
Energy ($/MWH)												
Summer - all hrs	$0.092362			$0.090862	$0.090138	$0.088207	$0.085271	$0.054818	$0.070797	$ 0.037572		
DP&L On pk		$ 0.051762	$0.150309								$ 0.042539	$ 0.056135
DP&L Off pk		$ 0.039021	$0.053024								$ 0.028211	$ 0.045799
Winter - all hrs	$0.093073			$0.079687	$0.079992	$0.078945	$0.071441	$0.066580	$0.062167	$ 0.045178		
DP&L On pk		$ 0.039563	$0.142324								$ 0.046938	$ 0.058742
DP&L Off pk		$ 0.030221	$0.058568								$ 0.031281	$ 0.047871

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
Demand ($/kW)												
Summer		$ 8.932688								$11.185896	$12.933767	$12.641094
Winter		$ 6.293342								$ 6.903597	$ 8.409111	$ 8.059507
Energy ($/MWH)												
Summer - all hrs	$0.111118			$0.109618	$0.108893	$0.106963	$0.104027	$0.054818	$0.089553	$ 0.038437		
DP&L On pk		$ 0.067375	$0.185028								$ 0.043726	$ 0.057395
DP&L Off pk		$ 0.050153	$0.063789								$ 0.029040	$ 0.046801
Winter - all hrs	$0.110638			$0.097252	$0.097557	$0.096509	$0.089006	$0.066580	$0.079732	$ 0.046234		
DP&L On pk		$ 0.053542	$0.174028								$ 0.048233	$ 0.060069
DP&L Off pk		$ 0.040226	$0.070291								$ 0.032184	$ 0.048926

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
Demand ($/kW)												
Summer		$ 8.923752								$11.469345	$13.261454	$12.961748
Winter		$ 6.294925								$ 7.078411	$ 8.622650	$ 8.263869
Energy ($/MWH)												
Summer - all hrs	$0.111011			$0.109511	$0.108787	$0.106857	$0.103920	$0.054818	$0.089446	$ 0.039336		
DP&L On pk		$ 0.067286	$0.184831								$ 0.044957	$ 0.058704
DP&L Off pk		$ 0.050090	$0.063728								$ 0.029899	$ 0.047841
Winter - all hrs	$0.110663			$0.097277	$0.097583	$0.096535	$0.089031	$0.066580	$0.079757	$ 0.047330		
DP&L On pk		$ 0.053562	$0.174074								$ 0.049581	$ 0.061447
DP&L Off pk		$ 0.040241	$0.070308								$ 0.033125	$ 0.050021

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