APPENDIX 5

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

INTRODUCTION AND SCOPE OF ANALYSIS

Delmarva Power & Light (Delmarva) has been asked to provide an Integrated Resource Plan (IRP) that describes its current view of the likely costs and risk characteristics of projected 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 current supply portfolio includes a blend of the existing and 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 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). As of June of 2011, none of the existing or future FSAs will provide the renewable energy necessary to meet this obligation. To meet this rapidly escalating obligation and to hedge the risk of price volatility it creates, Delmarva implemented a portfolio of long-term contracts with renewable resources including up to 150 MWs of land-based wind resources, the BlueWater Wind (BWW) off-shore wind project (200 MWs[1] with deliveries beginning in 2016), and the Dover Sun Park. Delmarva's will receive 70% of the Renewable Energy Credits (RECs) created by this 10 MW Dover Sun Park which is expected to be in-service in the summer of 2011. The renewable portfolio is bundled with the FSAs to provide for the electrical needs of Delmarva's SOS customers.

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[1] Of which approximately 50% will be dedicated to 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 2011 through 2020). The Portfolio Model serves to demonstrate prevailing and forecasted market characteristics, and the price uncertainty associated with SOS supply.

The Reference Case (RC) consists of the existing and new FSA contracts, plus the already contracted for renewable resources. 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
Delmarva Delaware SOS

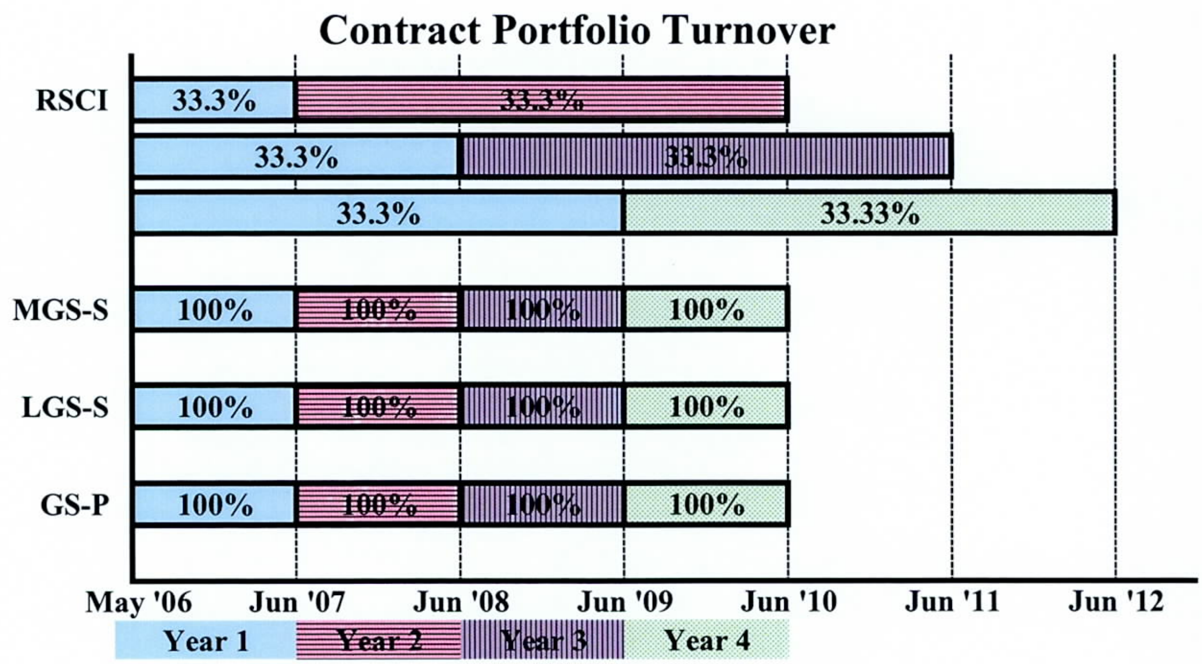


Table 1 provides the blended cost of existing FSA contracts and the percentage of SOS customer requirements covered for the planning years 2010, 2011 and 2012. These costs are included in calculating the expected FSA supply costs and the projection of customer rates provided in the Attachment E.

Table 1: 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	
2010	104.41	92.22	100.00%	83.32	82.61	100.00%
2011	100.91	94.35	66.67%	-	-	-
2012	93.35	88.11	33.33%	-	-	-

For the 2011 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 tranches (one in November and one in January) for 3-year contracts, each for a fraction of its expected RSCI SOS load. It will concurrently solicit 1-year contracts for a fraction of expected LC load in each tranche. 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 document also presents impacts on SOS customers of three additional scenarios which could add new resources to the Resource Portfolio (RP). These scenarios include adding:

- 150 MW off-shore wind resources assumed to come online in 2016 and coming ashore , in Delmarva South with characteristics similar to BWW,
- 150 MW land-based wind resources added in 2014 in western PJM with characteristics of existing land-based wind contracts, and

– gas-fired generation, in the form of a 135 MW combined cycle (CC) facility located in Delmarva South, assumed to come online in 2014[2]

Later in this document, a number of sensitivities, including a larger CC facility located in the northern part of Delmarva service territory, are also evaluated.

This report does <u>not</u> assess the attractiveness of these resources on a present value, full-life basis. Rather, it looks at their impacts on the range of likely average annual portfolio costs per nominal MWh for select years over the IRP planning horizon: 2011, 2013, 2015, 2017, and 2020.

The analysis contained herein is based on market conditions that prevailed in July of 2010. At that time, Delmarva and its advisors (ICF International and *The Brattle Group*) had obtained or developed comprehensive market and forecast information for the planning period. The primary purpose of this report is to compare the relative attractiveness of different scenarios, not to make a precise forecast of what expected future prices will actually be.

All of the wind facilities will have energy output that is both uncertain and not closely related to the shape of the RSCI or LC customer load. (In fact, the output of the existing AES wind farm, which tends to be highest at night and during the winter and early spring, has shown little correlation with customer load and PJM location marginal costs (LMP)). Accordingly, these contracts are simulated as being added financially to the portfolio, rather than as displacing other purchases in it. This method of simulation more accurately reflects what is being done with the physical scheduling and accounting of existing wind resources.

The evaluation conducted herein uses the portfolio simulation approach similar to that described in previous Delmarva IRP submittals, with the most recent description of which was provided in Delmarva's November 3, 2008 Revised Update to IRP. The approach was deployed by Delmarva's Power Procurement group, which also designed and tested a number of additional

[2] With capital cost modeled as a levelized (constant nominal) charge per MW for fixed-cost recovery.

generation alternatives described in this report. *The Brattle Group* reviewed the current results for methodological correctness and internal data consistency and concluded that the modeling technique is properly applied. This report briefly describes the model, interprets the results in light of typical risk patterns in the electric industry, and comments on Delmarva's preference for particular procurement alternatives. This report demonstrates detailed results for SOS customers segmented by RSCI and LC customer groups. Results presented in this report are in real dollars (2010$) except where otherwise noted and are for the most part presented for RSCI customer supply. Where applicable, alternative versions of figures and tables for RSCI presented in this report expressed in nominal or out-year dollars are provided in Attachment A of this document. In addition, a set of results for Large Commercial customers in both real and nominal dollars is provided in Attachment B. This report uses 2.5% inflation rate for consistency with ICF's inflation forecast. Inflation is expected to be about 2.2-2.3% over the coming decade, based on the long-range macroeconomic outlook summarized in the latest Blue Chip Consensus.[3]

KEY FINDINGS

Table 2 presents the expected and likely ranges of costs from the Reference Case ("RC") portfolio and three scenario portfolios for 2011, 2013, 2015, 2017 and 2020. 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 scenarios per year, in which the possible outcomes are drawn from distributions that describe forward financial market expectations and volatility as of July 15, 2010. In Table 2, it is important to note that the additional off-shore wind is evaluated at the prices in the existing BWW contract and that the addition land-based wind at prices similar to that of the existing AES contract.

The risk exposure of the RC portfolio changes somewhat over time. In 2011, its costs and risks are set 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

[3] Blue Chip Economic Indicators, pp.14-15, October 10, 2010.

there is more time for conditions to change, hence more forecasting error. In addition, there is more load uncertainty (e.g., due to the success of conservation programs) and industry-wide policy uncertainty affecting future power market conditions (e.g. coal plant retirements due to tightening EPA regulations, and a potential renewal of climate protection policies).

Table 2: Supply Cost Projections - RSCI Customers

Confidential Material Omitted

Real Dollars (2010$)

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)	**Difference as Percent of Average**
Settlement Period: Planning Year 2011							
Reference Case	2,985,002						
Settlement Period: Planning Year 2013							
Reference Case	2,909,270						
Settlement Period: Planning Year 2015							
Reference Case	2,887,191	$96.41		$123.07	$74.81	$48.26	**50.06%**
Reference Case and CC South	2,887,191	$97.72	**1.4%**	$120.27	$78.00	$42.27	**43.26%**
Reference Case with Wind (Land Based)	2,887,191	$98.21	**1.9%**	$123.96	$76.42	$47.54	**48.41%**
Settlement Period: Planning Year 2017							
Reference Case	2,897,693	$114.50		$148.24	$87.38	$60.86	**53.15%**
Reference Case and CC South	2,897,693	$114.62	**0.1%**	$145.20	$89.85	$55.35	**48.29%**
Reference Case with Wind (Land-Based)	2,897,693	$116.06	**1.4%**	$148.14	$88.88	$59.26	**51.06%**
Reference Case with Wind (Off-Shore)	2,897,693	$120.00	**4.8%**	$150.95	$93.37	$57.58	**47.98%**
Settlement Period: Planning Year 2020							
Reference Case	2,912,189	$127.64		$177.41	$89.42	$87.99	**68.93%**
Reference Case and CC South	2,912,189	$126.37	**-1.0%**	$169.00	$91.55	$77.46	**61.29%**
Reference Case with Wind (Land-Based)	2,912,189	$126.98	**-0.5%**	$172.01	$89.05	$82.96	**65.33%**
Reference Case with Wind (Off-Shore)	2,912,189	$131.75	**3.2%**	$175.68	$94.34	$81.33	**61.73%**

Table 3: Supply Cost Projections - LC Customers

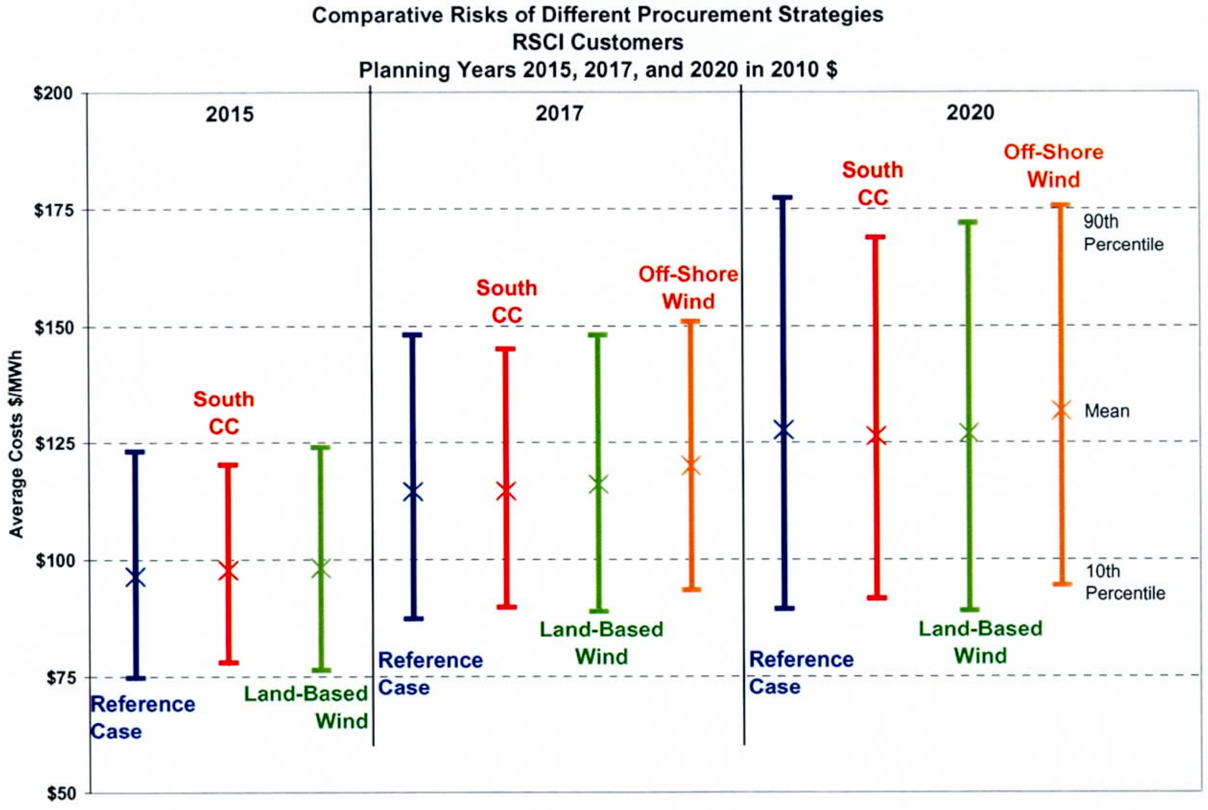
Confidential Material Omitted

Real Dollars (2010$)

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)	**Difference as Percent of Average**
Settlement Period: Planning Year 2011							
Reference Case	980,369						
Settlement Period: Planning Year 2013							
Reference Case	880,585						
Settlement Period: Planning Year 2015							
Reference Case	828,339	$86.92		$118.11	$61.80	$56.31	**64.79%**
Reference Case and CC South	828,339	$88.22	**1.5%**	$116.35	$65.20	$51.15	**57.97%**
Reference Case with Wind (Land Based)	828,339	$88.71	**2.1%**	$118.20	$63.86	$54.33	**61.25%**
Settlement Period: Planning Year 2017							
Reference Case	819,893	$102.26		$138.62	$72.77	$65.84	**64.38%**
Reference Case and CC South	819,893	$102.38	**0.1%**	$135.19	$75.30	$59.89	**58.49%**
Reference Case with Wind (Land-Based)	819,893	$103.84	**1.5%**	$139.14	$74.70	$64.44	**62.05%**
Reference Case with Wind (Off-Shore)	819,893	$107.84	**5.5%**	$141.96	$79.28	$62.68	**58.13%**
Settlement Period: Planning Year 2020							
Reference Case	743,029	$119.09		$172.47	$77.92	$94.55	**79.40%**
Reference Case and CC South	743,029	$117.82	**-1.1%**	$165.12	$80.04	$85.08	**72.21%**
Reference Case with Wind (Land-Based)	743,029	$118.43	**-0.6%**	$168.91	$78.27	$90.64	**76.54%**
Reference Case with Wind (Off-Shore)	743,029	$123.20	**3.5%**	$173.25	$83.67	$89.58	**72.71%**

As can be seen in Figure 2, each of the scenario portfolios provides reduced price uncertainty versus the RC, and the expected average cost relative to the reference case generally improves by the latter half of the coming decade – though off-shore wind increases supply costs relative to the RC in all future periods.

Figure 2: Comparative Risk of the RC and Scenario Portfolios



On a stand alone basis, the CC installed in the Southern Delmarva does not appear to be attractive because it would not recover its expected costs from likely market revenues. Therefore, it cannot improve the expected cost of the RC portfolio. Although its attractiveness increases over time, the expected revenues from CC operation are not high enough over the decade analyzed in this study to break-even with the annual carrying and operating costs. Owning a CC, however, would provide a hedge against uncertain capacity prices and (to a lesser extent) CO_2 prices. (Note that the gas resources evaluated herein are specific to actual sites and facilities that should be available to Delmarva.)

The pricing of (or restrictions on) CO_2 emissions is a material risk in the long term, with the potential to raise PJM prices by a few $/MWh by 2020 and by more thereafter. Roughly speaking, given the existing PJM resource mix, every $10/ton of CO_2 pricing raises the PJM all-hours average energy price by around $7/MWh. The wind resources Delmarva has already recently obtained provide a useful hedge against this situation. Gas-fired generation produces CO_2, but significantly less than coal generation so a gas CC would also partly hedges Delmarva customers against CO_2 price impacts. And since the CC being considered has a lower heat rate than most of the marginal units in PJM, the introduction of CO_2 prices (especially at the low levels likely over the next 10 years) will tend to improve the attractiveness of these plants, not impair them. The attractiveness of wind resources, of course, would improve with high carbon prices. However, it does not look likely right now that prices as high or higher than the reference case, particularly in 2017-2020 timeframe are going to ensue, absent a major shift in climate policy.

It is assumed herein that additional wind resources may become available on terms similar to the existing land-based and off-shore contracts. If so, the above results show that they would not generally reduce the cost of the RCs supply portfolio. This occurs because both land-based and off-shore wind resources would have contract costs in excess of the expected value of the energy, capacity and REC revenues they generate. This is particularly true for additional off-shore wind, which at current BWW contract prices, would still raise the average price of power in the portfolio by about 5% in 2017 and 3.5% in 2020. Moreover, the risk reductions in 2017 and 2020 due to wind are quite modest, barely reducing the overall range for the RC portfolio. These economics would be even less attractive if the carbon price by 2020 was lower than has been assumed in the reference case (which is almost $30/ton in nominal terms by 2020, but which conceivably could be much less, given the current political stalemate over climate policy).

To test the sensitivity of new resource attractiveness to CO_2 policies and prices, Delmarva analyzed two discrete sensitivities in which the prices of CO_2 are materially higher or lower than in the reference case. In the High CO_2 case, it is assumed that a policy similar to the Waxman-Markey proposal of 2008 (or the McCain-Lieberman proposal of 2009) will be passed in time to start setting prices for CO_2 in 2015 at levels similar to what the US EPA predicted would be the most likely impact of Waxman-Markey. Those prices are about $30/ton in real 2009 dollars by 2019, about $9 higher per ton than in the reference case. In the Low CO_2 case, it is assumed that CO_2 prices are set at a constant, $5/ton in 2015-2020 in real 2009 dollars, a level that would raise about $10 billion if applied to US electric utility generation. This is comparable to the amounts commonly discussed as needed for funding of research programs in carbon mitigation technologies and alternative fuels. Because these are discrete alternatives (not representing a continuum of possibilities drawn from an observable or inferred distribution, unlike forward power or gas prices), Delmarva has not analyzed them in a Monte Carlo fashion. Rather, the 2017 and 2020 sensitivities are shifted right (up in cost) or left (down in cost) by the average effect of the incremental CO_2 on the energy prices in each outcome in the reference case.[4]

Delmarva also recognizes that its access to future wind resources may occur on considerably different terms than have been negotiated in the past. Off-shore wind technology in particular is changing rapidly, with shifts towards larger turbines, new platform designs, and new suppliers (as well as increased competition for access to their equipment). The understanding of O&M complexities and costs is also evolving. Thus, it may be that future wind resources will be available at higher, or lower, investment or operating costs, and/or that such resources may perform better or worse than the existing or contractually committed facilities. Delmarva has developed sensitivity cases that assume a 10% increase in potential capital and operating costs as well as higher capacity factors [34% vs. 32% assumed in the reference case].

It is likely that these sensitivities understate the true degree of uncertainty surrounding the costs or benefits of wind resources, e.g., excluding variation in annual or seasonal wind levels that is

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4 In these alternative CO_2 pricing sensitivities, it has been assumed that overall demand for gas and electricity would be unaffected (so that gas and electric spot prices are only adjusted by the incremental cost of the assumed CO_2 prices, with no other adjustments). It is not likely that this will be the case, as, for instance, increased CO_2 prices are likely to cause greater use of gas-fired generation in lieu of coal, with some upward pressure on gas prices. Likewise, it is possible that higher gas prices would cause higher CO_2 prices, because the price of CO_2 will sometimes depend on how economically gas can be substituted for coal. However, there are also offsetting effects that have not been evaluated, such as reductions in overall demand for energy consumption (due to the carbon penalty). Moreover, the prices of gas and electricity can vary considerably for other reasons. Thus, we have isolated the effects of carbon pricing by itself, without considering potential feedback effects.
It is also likely that variations in CO_2 prices would alter the price of RECs. Generally, higher CO_2 prices should tend to lower REC prices, and vice versa, because the equilibrium price of RECs is the level that makes renewable resources breakeven for cost recovery. Including this effect would tend to make the value of wind resources even less sensitive to CO_2 prices. This dynamic has also not been simulated in this study.

likely to occur periodically over very long periods of time. However, it is clear even without such broader analysis that in general, wind resources have become less attractive since the prior Delmarva IRP, not more, largely because market prices for conventional power have fallen, increased (cleaner) gas-fired generation is likely, and meaningful carbon prices over the next decade look less probable.

If long-term resources such as a CC or wind contracts are added to the portfolio, especially under fixed pricing, it may be appropriate to restrict customer switching, or to place the fixed costs of these assets in a non-bypassable charge, so that there is little risk of future stranded assets or inadequate cost-recovery if/when customer switching should occur. Delmarva has proposed a cost recovery mechanism to mitigate customer migration risk that is provided as Appendix 9 of this IRP.

Table 4 presents a projection of customer rates for Residential and MGT customers for the period 2011 through 2015. The projection are based on the Reference Case portfolio results presented above and are also in real dollars (2010$). Projections for all customer classes are provided in Attachment E.

Table 4: Tariff Rate Projections (2010$)
Confidential Material Omitted

Planning Year	Residential Rates (Tariff "R")				MGT-S Rates			
	Demand ($/kW)		Energy (Cents/KWH)		Demand ($/kW)		Energy (Cents/KWH)	
	Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter
Currently Effective	-	-	11.04	10.07	14.00	9.20	4.59	5.91
2011	-	-						
2012	-	-						
2013	-	-						
2014	-	-	11.49	10.76	15.58	9.68	5.02	6.14
2015	-	-	11.90	11.14	16.20	10.06	5.21	6.38

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 have switched 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. However, electricity market price data is only available for one to two years forward (gas is available for five to six years forward), so long term studies are also required for structural forecasts of future prices based on projected scenarios for market conditions. Once these parameters are quantified, they can be used to project possible future costs of alternative supply portfolios across a broad range of market circumstances that could unfold.

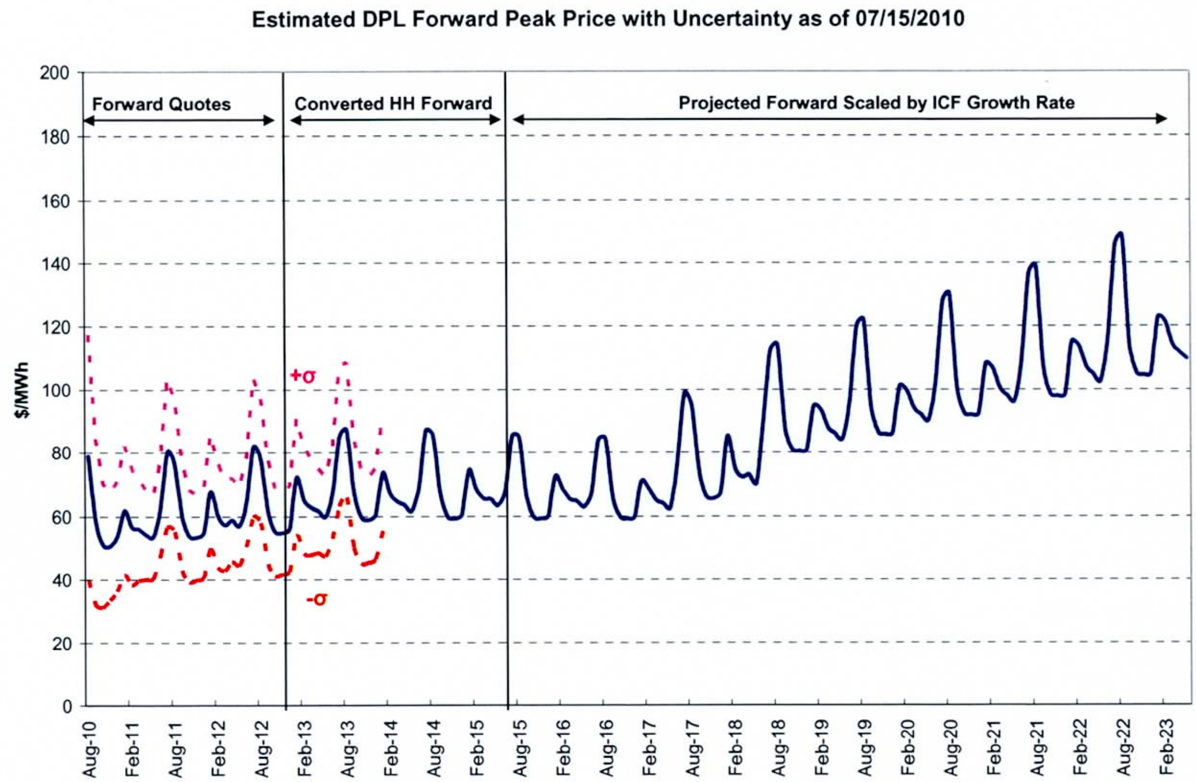
The Brattle Group has developed a model to predict the likely ranges of future electricity costs to RSCI SOS and LC customers under different combinations of financial and physical generation resources over time. This evaluation was conducted using an enhanced version of the portfolio simulation model described in previous Delmarva IRP submittals, with the most recent 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 future costs and risks.

A key input to portfolio planning and risk analysis is the expected prices and uncertainty associated with future power purchases. Market outlooks for both of these can be obtained from broker quotes for forward on-peak monthly sales. As of July 15, 2010, the estimated on-peak

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

forward curve at PJM-West, plus average monthly congestion into the Delmarva zone through 2023, is presented in Figure 3.

Figure 3 (Nominal $)



In this graph, the dark blue line is the on-peak monthly price of power as it was being offered at PJM on July 15, 2010, and adjusted for congestion to Delmarva. Note that the growth rate of the prices increases significantly in 2018 due to the assumed introduction of CO_2 prices beginning in that year.

There are two vertical lines in the above figure, one at January 2013 and the other at June 2015. The first line represents the end of the time frame over which electricity futures with monthly prices were quoted at PJM-West (as of July 2010). Typically, electricity futures are only quoted on a monthly basis for about 12-18 months forward. To obtain market-based forward prices thereafter, we extrapolated the PJM electricity forwards from the Henry Hub natural gas forward prices. To convert these gas prices to electricity, we scaled each monthly Henry Hub price by the forward average heat rate implicit in the ratio between PJM electricity prices and Henry Hub gas prices. This approach is used until 2015, the second vertical line, beyond which we extrapolate the prevailing monthly pattern at the growth rate(s) obtained by ICF in its fundamental modeling of PJM prices. (The Henry Hub natural gas prices are also extrapolated beyond 2015 at the growth rates obtained from ICF.)

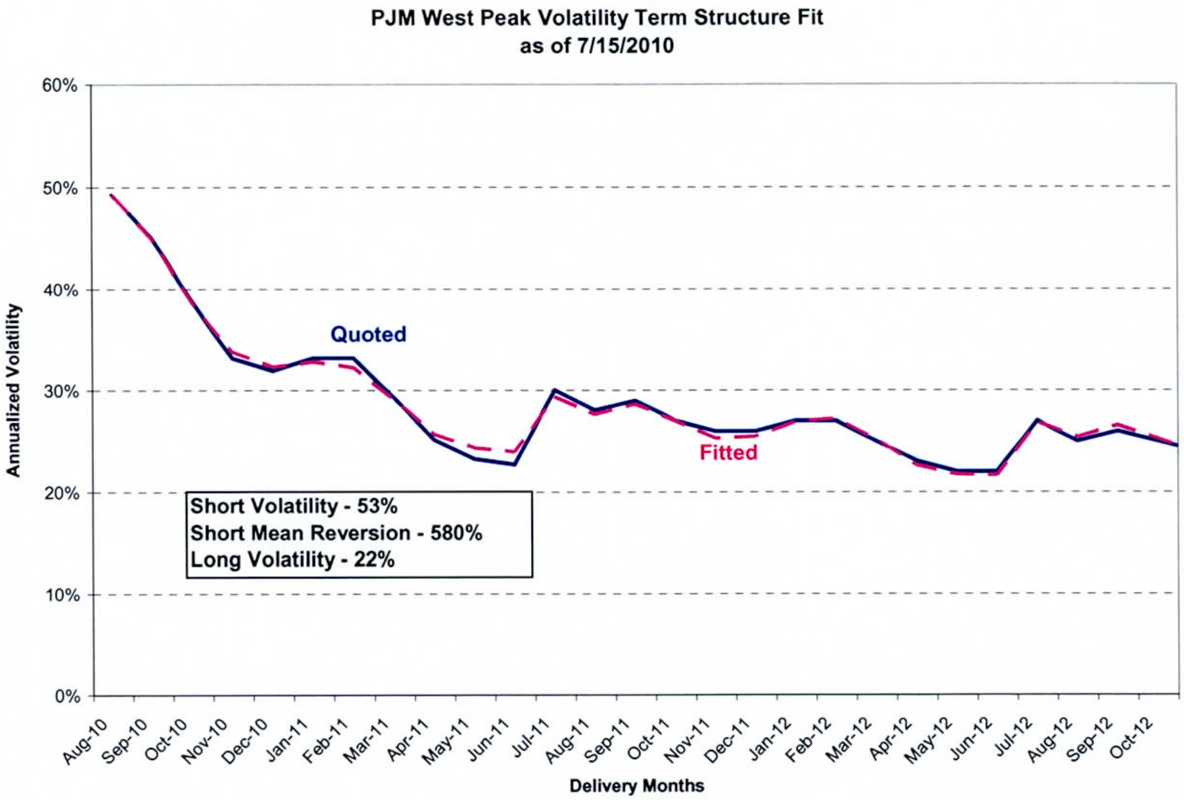
The congestion component for delivery from PJM-West to Delmarva in the above was modeled in the following way: The level of the annual congestion was determined in accordance with ICF's projected LMP differences between PJM-West and the Delmarva zone. Roughly speaking, this projection shows the basis premium for peak Delmarva over peak PJM-West declining from about $7/MWh in 2010 to about $1.5/MWh by 2018, due to transmission expansion and reduction in the cost difference between coal and gas plants. The monthly congestion shape was determined based on the historical monthly average day-ahead LMP differences for those same locations.

The dashed pink and red lines above and below the blue line in Figure 3 depict the ranges around those forward prices that describe the uncertainty power market brokers perceive 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 the appropriate option price. 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 dashed line in Figure 4 below shows the two-factor model results compared to the quoted volatilities depicted by the solid blue line.

The volatility function in Figure 4 is used to simulate 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 the portion of load covered by spot).

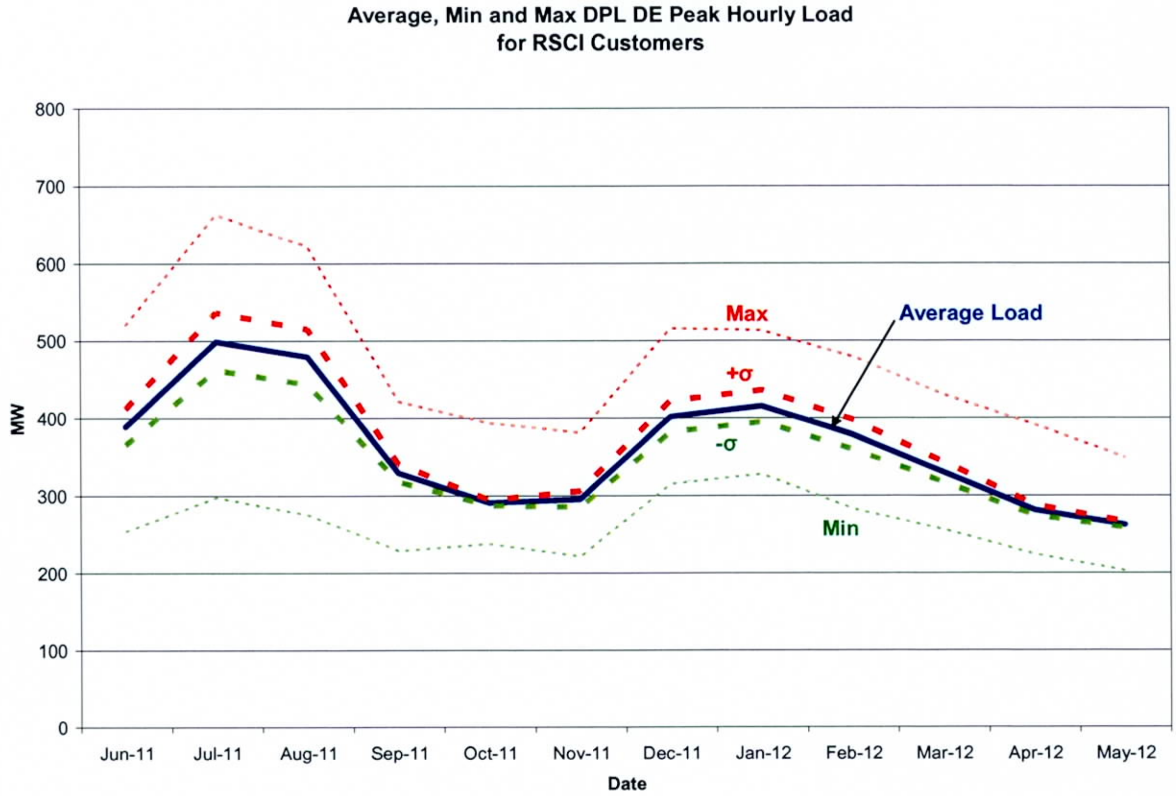
Figure 4



Brattle and Delmarva have reviewed the history of implied volatility in quoted option prices over the past two years, out of concern that the current outlook may not be typical or representative of "normal" market conditions – given that we are in a recession. However, that review has shown the fitted volatility function to be remarkably stable over the recent past, with no evident trend towards a different risk term structure.

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 2011, along with the associated typical weather uncertainty considered, are shown in Figure 5 below.

Figure 5

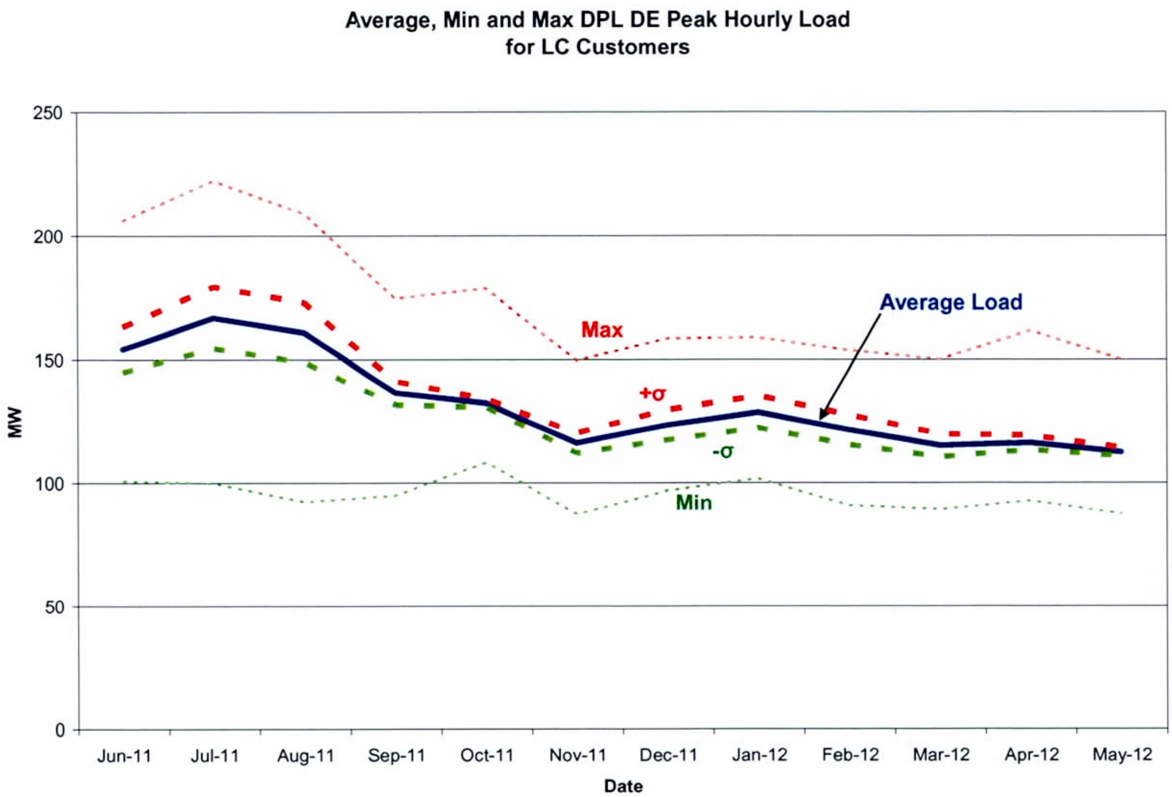


This figure reflects only the load during on-peak hours for residential and small commercial customers projected from historical load experienced over January 2007 through December 2009, and adjusted for potential conservation impacts, which are based on Delmarva's own cost/benefit analyses of conservation and demand management similar to what the Sustainable Energy Utility (SEU) would conclude and pursue. Note that the average load is around 360 MW, while the minimum hourly load is around 200 MW (again, for peak hours). The minimum hourly load for off-peak hours is about 170 MW. The weather uncertainty surrounding average monthly loads is not very large, a few percent.[6] Maximum hourly loads can be almost 1.4 times the average for any given month, with an annual peak of almost 700 MW. However, high load levels occur in relatively few of the hours in a month.

[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.

The average projected hourly load levels (by month, in MWs) for Delmarva's LC customers for the twelve months beginning June 2011 along with the associated typical weather uncertainty considered, are shown in Figure 6 below.

Figure 6



This figure reflects only the load during on-peak hours for LC customers projected from historical load experienced over January 2007 through December 2009, 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 almost three time less than the average load for RCSI customers, around 130 MW, while the minimum hourly load is around 90 MW (again, for peak hours). The minimum hourly load for off-peak periods is about 60 MW. Maximum hourly loads can be 1.4 times the average for any given month, with an annual peak of over 220 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, along with the corresponding information on natural gas prices and wind plant performance, 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 will be pertinent for purchase dates in the future. Based on weather-related load uncertainty, the loads for each month are also "drawn" by the simulation model. Only the level of monthly load is uncertain in the model. 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. Scaling factors are applied to reflect the positive correlations between intraday spot prices and load requirements. Future FSA price ranges are simulated based on their exposure to market factors, like monthly price and load uncertainty and intraday price and load shapes. Other uncertainties, like customer switching risk, are captured by the risk premium of 8% added to the FSA price. This premium is itself an uncertain factor, which may change over time. That uncertainty has not been represented in this analysis, but it would tend to widen the distributions of possible costs from the FSA (while having no effect on the risk ranges for the physical resources that could be added to the RC portfolio).

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 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 obligations derived from Delaware's Renewable Portfolio Standards is presented in Attachment D of this document. The average cost of supplying Renewable Energy Credits calculated in Attachment D was included in the portfolio supply costs projections included in this study.

For the land-based and off-shore wind scenarios, the RECs generated by these additional facilities are in excess of Delmarva's requirements to meet the State's RPS. Therefore, the RECs generated by these facilities are assumed to be resold into the market and thus increasing the uncertainty of cost of supply to Delmarva's SOS customers. Delmarva simulated this increased risk by adjusting the portfolio model results in the following manner. For the expected value (reference case) calculations, Delmarva assumed that the RECs are resold at the price at which they are purchased, i.e. at the prices implicit in current wind contracts. Under this assumption, there is no net gain or loss on RECs from wind – it is a neutral aspect to the risks of these contracts. For the sensitivity case involving lower average RC costs, RECs are assumed to be priced and resold at higher levels predicted by the IPM model as being necessary to breakeven on a new wind facility, i.e. at REC prices that cover the shortfall between wind revenue requirements and the expected revenues from market energy and capacity sales. For the high average cost calculation, Delmarva assumed the additional RECs are sold at just $2 per REC. This results in a larger net cost to customers, since the wind contracts cost more than they yield. A surplus of REC supply in the market place (as is currently the case) could cause such a depressed market for RECS.

RESULTS – INITIAL PERIOD, 2011, 2013 AND 2015

The simulation model calculates the energy-only costs of an FSA portfolio, which depends on the price of the existing and new FSA contracts. Existing wind resources are simulated using hourly generation patterns specific to each month, received from the land-based wind and BWW providers under contract to Delmarva. These hourly profiles are used to simulate revenues from wind resources, which are used to off-set corresponding costs of the portfolio.

The non-energy costs for PJM capacity, ancillary services and RECs are added to the portfolio to get the full costs of the Reference Case. {Confidential Material Omitted}

Capacity prices after 2013 are projected by ICF (since RPM auctions for those dates have not yet occurred). These prices are about $97/kW-year in 2015 and $137/kW-year in 2020, i.e., about enough to cover the fixed costs of a new gas CC. The range of expected supply costs of the Reference Case in 2011, 2013 and 2015 is depicted in Figure 7. This figure shows the cumulative probability distribution for the Reference Case outcomes for 2011, 2013, and 2015 as S shaped curves.

Figure 7 (Nominal $)

Confidential Material Omitted

Over time the S-curve shifts to the right (portfolio becomes more costly) and becomes less vertical (portfolio becomes more risky). The shift to the right is smaller in magnitude than the increase in non-energy costs, because the average costs of the energy-only portfolio decrease over the first couple of years as existing FSA contracts expire, and are replaced at lower market prices (largely due to the sustainable, dramatic reduction in natural gas prices in the past year).

Gas-fired Generation Asset

Because of the projected rising capacity prices in PJM (as well as uncertainty over the completion of announced transmission projects), it is worthwhile to evaluate whether a gas-fired generation plant could reduce the costs or risks of RSCI SOS and LC service. This prospect has been evaluated by considering the addition of a 135 MW Combined Cycle (CC) facility in Delmarva South in 2014. The cost associated with this CC facility are simulated as the levelized nominal carrying charges for a new CC plus fuel costs incurred at the monthly spot prices of natural gas delivered to the southern part of Delmarva's service territory[7].

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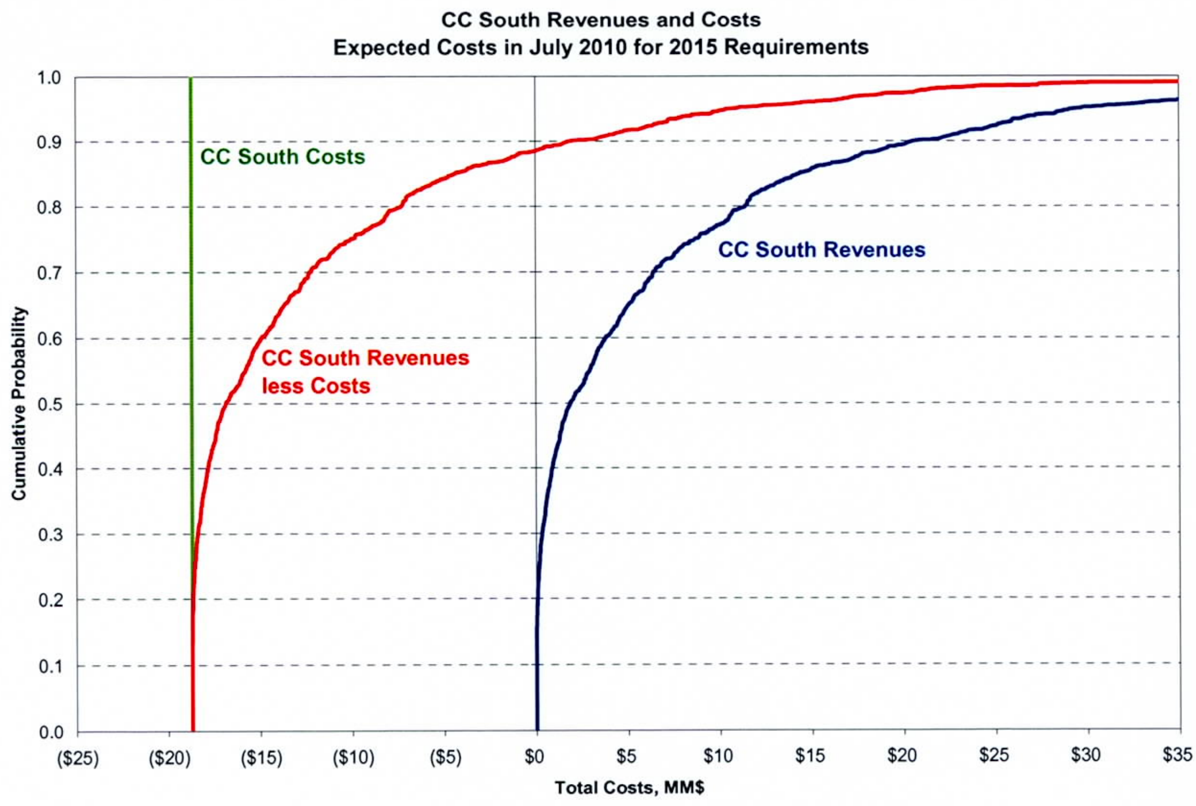
[7] The CC is assumed to have an installed cost of $1,430/kW in 2009$ and a full load heat rate of 8,332 MMBtu/kWh.

The initial year stand-alone economics of the CC facility are shown in Figure 8. They compare the annual fixed costs of the CC to the revenues foreseeable in the Delmarva zone from its spot energy sales and capacity (under the same simulated market conditions as experienced by the RC). The net revenue curve is in the middle, and it is rarely positive. On average, the small CC in the South Delmarva would not recover its expected annual costs in 2015. Instead, it would incur a wholesale loss of about $11.8 million in 2015, and recovering this shortfall would raise the average price of the RSCI supply portfolio by $1.49/MWh. Since the energy production from a CC is fairly small, it does not have a large effect on portfolio energy risk, reducing the difference between 90[th] and 10[th] costs percentile by $6.62/MWh or about 12%. Adding a CC to the supply portfolio would provide a hedge against uncertain capacity prices. However, capacity price-risk has not been modeled in this study. In addition, it is not projected that PJM capacity prices will equal CC fixed costs until sometime after 2015.

Figure 8 (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 40% capacity factor in 2015.

If the CC were priced as an owned asset, under cost of service regulation, its capital recovery charges would be slightly higher in the early years, making it slightly less attractive in the earlier years (although eventually more attractive, due to the declining capital charges). However, a CC does reduce the risk of the RC significantly, because it produces profitable energy in peak hours, thereby providing savings over the spot power purchases costs.

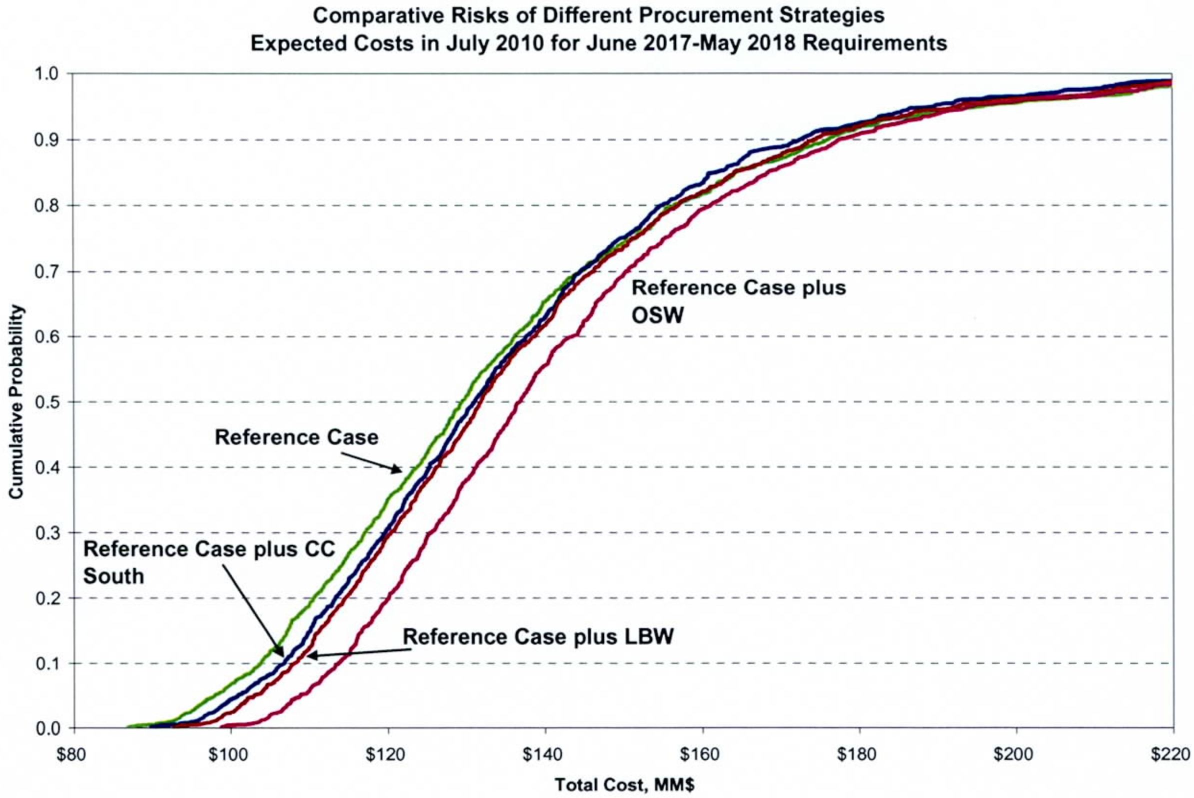
Land-Based Wind Generation Assets

Adding 150 MW of onshore wind in 2014 to the western region of PJM with characteristics of the existing land-based wind contracts causes an <u>increase</u> in the average cost of supply by \$1.64/MWh and a decrease in the uncertainty of the costs measured by the difference between 90th and 10th percentile of \$1.96/WMh, or 3.6% decrease. This is a small effect of less interest by itself than in comparison to off-shore wind, discussed in the next section (since off-shore wind would not be online by 2014).

RESULTS – 2017

2017 is investigated in order to determine if gas-fired generation becomes more or less attractive by then and how it compares to adding more land-based or off-shore wind. Figure 9 depicts the cost per MWh distributions for the RC in 2017 with and without the CC facility and with and without additional land-based or off-shore wind. Note that these S-curves are roughly ten times as wide as the similar curves for 2011, for two reasons. First, there is no existing fixed price FSA contract in place for 2017, unlike 2011. In addition, these curves now depict the degree of uncertainty surrounding those 2017 prices as of 2010, with seven years to go before delivery of that power.

Figure 9 (Nominal $)[8]



As can be seen from the fact that these curves are so tightly overlapping, there is very little average net benefit or cost from either the CC or land-based wind in 2017. In fact, both would increase the average cost of the RC in 2017 by only a trivial amount -- less than $1/MWh. They would also reduce risk a bit, as seen by the slightly more vertical curves above when they are included, with the gas unit having a larger impact. The off-shore wind increase the RC's average costs by $6.53/MWh, or by about 5% while providing a small reduction in risk of about 6%.

RESULTS – 2020

The reference case in this study reflects the assumption that U.S. CO_2 pricing will begin in 2018, and by 2020 this could become a material factor in energy prices. A $10/ton CO_2 price can be expected to raise the average wholesale price of power in PJM by about $7/MWh. This occurs

[8] This figure does not include adjustments for high and low RECs for the wind scenarios.

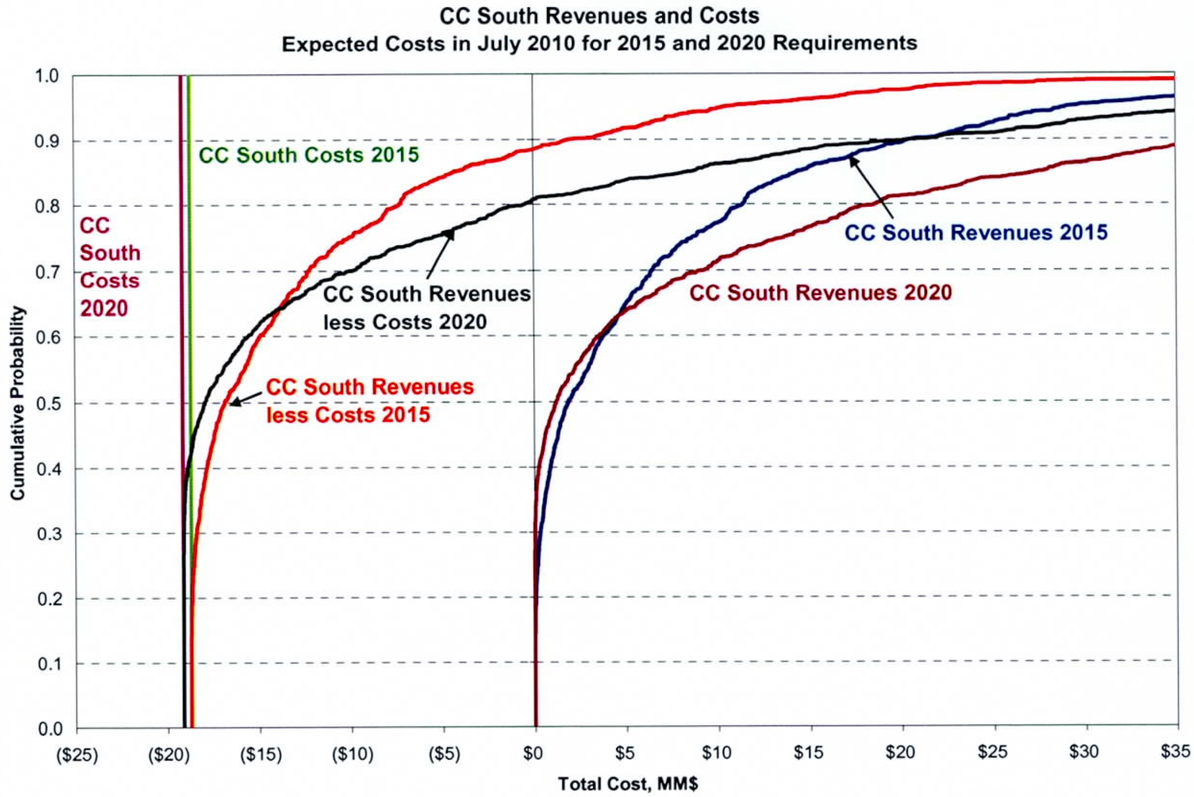
because the dispatch price of coal-fired generation (at a 10,000 Btu/kWh heat rate) increases by about \$10/MWh per \$10/ton CO_2, while the cost of generation from natural gas rises by about \$4/MWh for a CC (depending on heat rate). Since slightly more coal than gas is generally on the margin in PJM dispatch, their increased costs for CO_2 will raise the wholesale market energy price by about \$7. (Transitional CO_2 allowances, if allocated efficiently, should not alter this impact on energy prices, even though such allowances would restore much of the lost income to customers and certain producers from paying the higher energy charges.)

ICF's reference price forecast assumes CO_2 will be regulated for utilities beginning in 2018, expanding to other sectors by 2023. Prices quickly reach over \$30/ton in nominal dollars by 2020. These values are in the middle of the range seen in many studies of recent congressional proposals for carbon cap and trade or taxation programs, such as the Lieberman Warner 2007 proposal.[9] ICF projects 2020 gas prices to be almost \$9./MMBtu under those conditions. The combined effect of CO_2 plus higher gas prices (due to coal to gas dispatch switching) are responsible for the material increase in projected prices beginning in 2018.

The wind resources Delmarva already has under contract should provide a nice hedge against high CO_2 and gas prices, should they occur. Gas resources are a source of CO_2, but they may well be the most economical expansion alternative for a while, unless and until CO_2 prices become quite high. Figure 10 shows the annual cost and net revenue curves for the gas-fired CC facility in 2020 relative to 2015. By 2020, the CC operational in 2014 in Delmarva South increases its attractiveness but still not enough to break-even with the costs.

[9] See "EPA Analysis of the Lieberman-Warner Climate Security Act of 2008, S. 2191 in 110th Congress," U.S. EPA Office of Atmospheric Programs, March 14, 2008. It is available at www.epa.gov/climatechange/economics/economicanalyses.html

Figure 4 (Nominal $)



Both of the additional land-based and off-shore wind resource scenarios reduce risk of the RC portfolio by 7% and 9% correspondingly. Land-based wind reduces the average costs of the RC portfolio by about $1/MWh, while off-shore wind increases the average costs by $5.26/WMh.

SENSITIVITIES

In addition to the ICF's references case forecast for CO_2 prices, two sensitivities are considered: one in which CO_2 prices would remain at just $5/ton in real 2009 dollars in 2020 (Low CO_2 Prices Sensitivity) and one in which CO_2 prices are assumed to follow EIA's reference case allowance price estimate under the Lieberman Warner 2007 proposal (High CO_2 sensitivity).[10]

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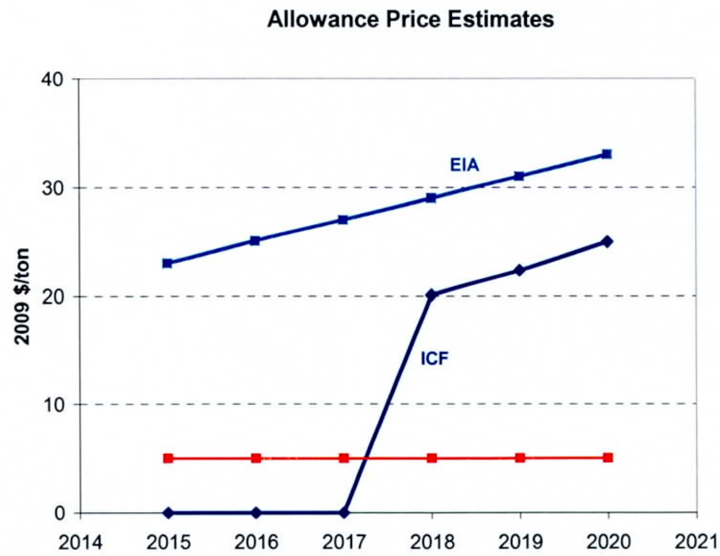
[10] See "EPA Analysis of the Lieberman-Warner Climate Security Act of 2008, S. 2191 in 110th Congress," U.S. EPA Office of Atmospheric Programs, March 14, 2008. It is available at www.epa.gov/climatechange/economics/economicanalyses.html

Figure 11



There is no statistical or market-based evidence for these particular CO_2 sensitivities. Rather, they simply reflect alternative hypotheses about how the political view of climate policy could develop. In the low case, a \$5/ton fee on utility CO_2 emissions might be used to fund R&D programs in potential CO_2-limiting technologies, such as renewables, alternative nuclear designs, biofuels, and carbon capture and sequestration. Alternatively, one can think of a \$5/ton CO_2 fee as a surrogate for a policy that simply restricts CO_2 via command and control rules, or via increasing environmental restrictions on coal plants. This could have the effect of driving up the demand for natural gas and/or increasing the operating costs of existing plants, thereby raising power prices somewhat like a \$5/ton CO_2 fee would accomplish. The High CO_2 sensitivity is included in the event that the political view reverts to a 2008 outlook. At present, this seems much less likely than the Low CO_2 sensitivity.

In addition to CO_2 price variations, we considered the effect of lower gas prices, which might occur if the current boom in gas shale production continues and proves as successful as its proponents argue.. While it is difficult to determine what the marginal cost of gas will be in a world of very extensive shale gas development (whose own marginal costs can vary from around \$3/MMBtu to \$10 or more, depending on the type and depth of shale involved), it is possible that prices would stay around $6-7/MMBtu in real terms for the next decade or beyond. Since much of the US shale gas resource base is in the PA and NY areas, it is also possible that continued shale gas development will reduce the basis differential from Henry Hub to eastern PJM. We have modeled this as a case where the natural gas prices stay at $7/MMBtu after 2018 as shown on the figure below.

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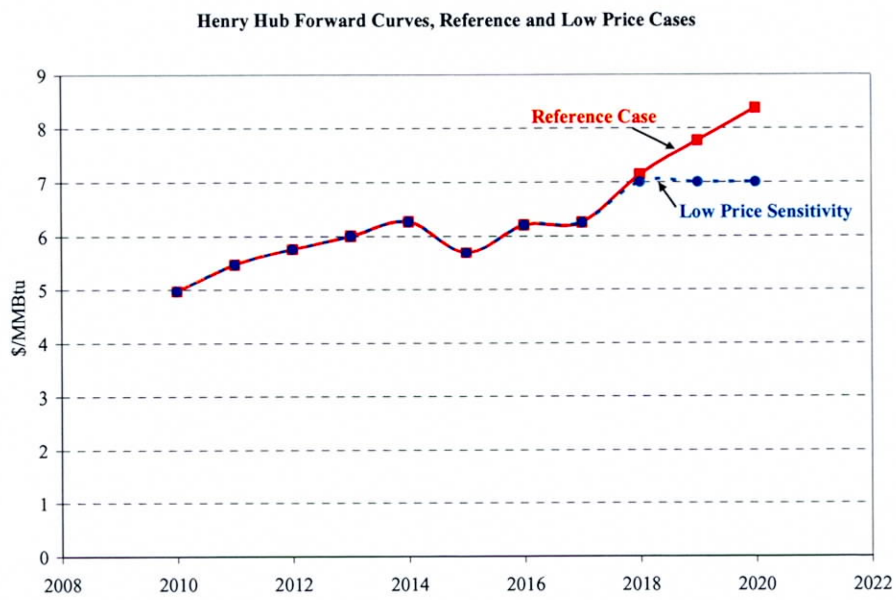
Figure 12



Results of the above described sensitivities are summarized in the table below.

Table 5 – Sensitivity Results (RSCI Customers)

Sensitivity Analysis Real 2010 Dollars - 2020 Planning Year

Electricity Hedging Option	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 Total	$127.64			$177.41	$89.42	$87.99
Reference Case and CC South	$126.37	-$1.27	-1.00%	$169.00	$91.55	$77.46
Reference Case with Wind (Land-Based)	$126.98	-$0.66	-0.52%	$172.17	$92.42	$79.75
Reference Case with Wind (Off-Shore)	$131.75	$4.11	3.22%	$175.84	$93.44	$82.40
High Carbon Case						
Reference Case	$130.90		2.55%	$183.10	$90.82	$92.29
Reference Case and CC South	$129.50	-$1.40	2.48%	$174.12	$92.94	$81.17
Reference Case with Wind (Land-Based)	$129.95	-$0.95	2.34%	$178.64	$90.32	$88.32
Reference Case with Wind (Off-Shore)	$134.68	$3.78	2.22%	$182.30	$91.11	$91.20
Low Carbon Case						
Reference Case	$120.43		-5.65%	$164.64	$86.37	$78.27
Reference Case and CC South	$119.45	-$0.99	-5.47%	$157.59	$88.48	$69.10
Reference Case with Wind (Land-Based)	$120.49	$0.05	-5.11%	$162.50	$86.30	$76.20
Reference Case with Wind (Off-Shore)	$125.37	$4.94	-4.84%	$166.72	$87.13	$79.59
Flat Henry Hub						
Reference Case	$123.98		-2.87%	$170.68	$88.09	$82.58
Reference Case and CC South	$123.04	-$0.94	-2.63%	$163.42	$90.22	$73.21
Reference Case with Wind (Land-Based)	$123.72	-$0.26	-2.57%	$167.77	$87.85	$79.93
Reference Case with Wind (Off-Shore)	$128.57	$4.59	-2.42%	$171.68	$88.69	$82.99

Finally, an additional set of sensitivity cases was modeled to test the sensitivity of the scenario cases to the many of the assumptions that went into creating them. The results of these sensitivities on RSCI customer supply costs are presented in Table 6.

Table 6 – Sensitivity Results (RSCI Customers)

Sensitivity Analysis Real 2010 Dollars - 2020 Planning Year

Electricity Hedging Option	Total Average Costs ($/MWh)	Difference ($) From Reverence Case	Difference ($) within Sensitivity	Difference ($) From Related Scenario	High Average Costs 90.0% ($/MWh)	Low Average Costs 10.0% ($/MWh)	Difference between High and Low Average Costs ($/MWh)
Reference Case	$127.64				$177.41	$89.42	$87.99
Reference Case and CC South	$126.37	-$1.27			$169.00	$91.55	$77.46
Reference Case with Wind (Land-Based)	$126.98	-$0.66			$172.17	$92.42	$79.75
Reference Case with Wind (Off-Shore)	$131.75	$4.11			$175.84	$93.44	$82.40
Reference Case with Larger CC in DPL North	$120.41	-$7.23	-5.66%	-$5.95	$153.91	$90.47	$63.44
Low Capacity Factor Reference Case with Wind (Land-Based)	$127.38	-$0.26	-0.21%	$0.40	$174.34	$85.82	$88.52
Low Capacity Factor Reference Case with Wind (Off-Shore)	$132.20	$4.56	3.57%	$0.45	$178.62	$90.93	$87.69
High Capacity Factor Reference Case with Wind (Land-Based)	$126.58	-$1.06	-0.83%	-$0.40	$172.90	$85.57	$87.32
High Capacity Factor Reference Case with Wind (Off-Shore)	$131.31	$3.67	2.87%	-$0.45	$176.58	$90.60	$85.98
Reference Case and CC South 10% Increase in Capital Costs	$126.88	-$0.76	-0.60%	$0.51	$169.52	$92.06	$77.46
Reference Case with Wind (Land-Based) 10% Cost Increase	$127.51	-$0.13	-0.10%	$0.53	$174.55	$89.58	$84.96
Reference Case with Wind (Off-Shore) 10% Cost Increase	$132.93	$5.29	4.14%	$1.18	$178.80	$91.55	$87.25

Discussion of Sensitivity Results

The above tables confirm the directionally expected effects of the risk factors being isolated. In particular, higher CO_2 prices raise the RC average price by around 2.5% for all resource combinations, and low carbon prices lower them (here by about 5 to 6%, because the low CO_2 sensitivity is quite a bit below the reference case). High CO_2 prices also reduce the expected cost disadvantage of the wind resources, while low CO_2 prices increase their disadvantage relative to the straight FSA portfolio. And the overall range of portfolio costs attributable to CO_2 price exposure is slightly smaller when wind is included that when it is not – as expected. Thus, wind resources provide a modest hedge against CO_2 prices, providing a benefit especially in the event of high CO_2 prices. However, they do so at the expense of raising the overall cost of the portfolio in every scenario in 2020, while a gas CC lowers the portfolio cost and risk range in every scenario.

A large, northern gas CC appears to be attractive by 2020 in every sensitivity compared to a portfolio without it. This is an expected result from its heat rate advantages over the marginal units setting the price in PJM, provided it is also true that it is possible to develop one for relatively low construction costs. Here, it is assumed that a 290 MW CC can be built with an overnight construction cost of $1050/kW in 2010 dollars. That is based on studies of a specific potential site, so it has more foundation than a generic estimate, but of course there would be construction cost and performance uncertainty. The reason a gas CC also decreases the risk range so much more than wind resources is because the gas CC is deployed only when (and whenever) it is economic to do so as a means of avoiding higher spot prices for power (or equivalently, as an opportunity to obtain a positive profit margin that can be credited back to customers.) A wind unit, though having no fuel cost, has intermittent output that cannot be dispatched to offset or match the highest cost power that is trading in PJM. Thus, its risk reduction benefits are more random, less concentrated on critical peak hours.

Low gas prices reduce the overall costs of the market by around the same amount regardless of the supply portfolio, largely because gas is on the margin during nearly all of the on-peak hours in PJM (and more so by 2020 than today) Thus, the portfolio average price is quite insensitive to the addition of an additional CC unit. Low gas costs slightly impair the wind resources, since their contract costs remain the same while their energy value declines. However, this could be an artifact of not modeling how REC prices might change with lower gas prices. If REC prices then rose, the loss in value from energy sales would be offset by the gain in value in wind REC sales, for no net exposure to gas costs. For resource planning purposes, this is probably the best assumption to make.

The reference case assumes new wind costs and performance equal to the corresponding wind resources in the existing DE supply contract mix. However, no specific resources with these terms and conditions have been identified by or offered to Delmarva. Accordingly, we simulated the impacts of 10% (?) higher contract costs and higher or lower capacity factors (+/- 2 percentage points) for the new wind alternatives. Higher costs naturally degrade the attractiveness of the resource, but the effect on the RSCI portfolio is fairly dilute. Specifically, a 10% increase in the new land-based wind scenario raises the RSCI average price by 0.4%, while the same percentage increase in the new off-shore wind scenario raises it by 0.9%. An increase in the capacity factor of the wind makes both kinds more attractive than in the corresponding reference cases, but the off-shore wind does not overcome its cost disadvantages with the higher capacity factor. A lower capacity factor makes both more expensive, i.e., increasing the RSCI portfolio average cost. However, the land based wind still is attractive enough to very slightly reduce the cost of the RSCI portfolio -- just not as much as it would have at a higher capacity factor.

ATTACHMENT A

RESULTS FOR RSCI CUSTOMERS
(NOMINAL $)

Table 5: Supply Cost Projections - RSCI Customers

Confidential Material Omitted

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)	Difference as Percent of Average
Settlement Period: Planning Year 2011							
Reference Case	2,985,002						
Settlement Period: Planning Year 2013							
Reference Case	2,909,270						
Settlement Period: Planning Year 2015							
Reference Case	2,887,191	$109.08		$139.25	$84.64	$54.61	**50.06%**
Reference Case and CC South	2,887,191	$110.57	**1.4%**	$136.08	$88.25	$47.83	**43.26%**
Reference Case with Wind (Land Based)	2,887,191	$111.12	**1.9%**	$140.25	$86.46	$53.79	**48.41%**
Settlement Period: Planning Year 2017							
Reference Case	2,897,693	$136.11		$176.21	$103.86	$72.35	**53.15%**
Reference Case and CC South	2,897,693	$136.25	**0.1%**	$172.60	$106.80	$65.80	**48.29%**
Reference Case with Wind (Land-Based)	2,897,693	$137.96	**1.4%**	$176.09	$105.65	$70.44	**51.06%**
Reference Case with Wind (Off-Shore)	2,897,693	$142.64	**4.8%**	$179.43	$110.99	$68.44	**47.98%**
Settlement Period: Planning Year 2020							
Reference Case	2,912,189	$163.39		$227.10	$114.47	$112.63	**68.93%**
Reference Case and CC South	2,912,189	$161.76	**-1.0%**	$216.34	$117.19	$99.15	**61.29%**
Reference Case with Wind (Land-Based)	2,912,189	$162.54	**-0.5%**	$220.19	$113.99	$106.20	**65.33%**
Reference Case with Wind (Off-Shore)	2,912,189	$168.65	**3.2%**	$224.88	$120.77	$104.11	**61.73%**

Figure 2: Comparative Risk of the RC and Scenario Portfolios

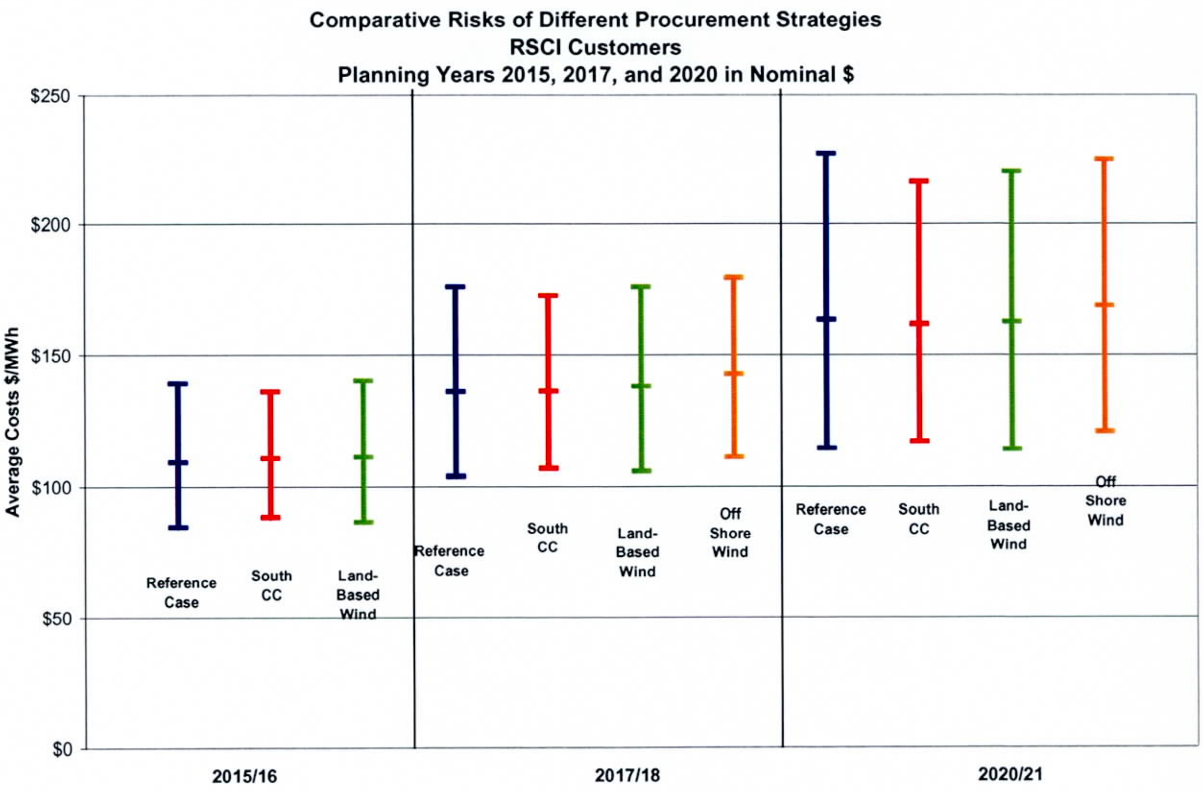


Table 4: Tariff Rate Projections (Nominal $)

Confidential Material Omitted

Planning Year	Residential Rates (Tariff "R")				MGT-S Rates			
	Demand ($/kW)		Energy (Cents/KWH)		Demand ($/kW)		Energy (Cents/KWH)	
	Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter
Currently Effective	-	-	11.04	10.07	14.00	9.20	4.59	5.91
2011	-	-						
2012	-	-						
2013	-	-						
2014	-	-	12.68	11.87	17.20	10.68	5.54	6.78
2015	-	-	13.47	12.60	18.32	11.38	5.90	7.22

Table 5 – Sensitivity Results (RSCI Customers)

Sensitivity Analysis Nominal Dollars - 2020 Planning Year

Electricity Hedging Option	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 Total	$163.39			$227.10	$114.47	$112.63
Reference Case and CC South	$161.76	-$1.63	-1.00%	$216.34	$117.19	$99.15
Reference Case with Wind (Land-Based)	$162.54	-$0.85	-0.52%	$220.39	$118.30	$102.08
Reference Case with Wind (Off-Shore)	$168.65	$5.26	3.22%	$225.09	$119.62	$105.48
High Carbon Case						
Reference Case	$167.56		2.55%	$234.39	$116.26	$118.13
Reference Case and CC South	$165.77	-$1.79	2.48%	$222.88	$118.97	$103.91
Reference Case with Wind (Land-Based)	$166.35	-$1.21	2.34%	$228.67	$115.61	$113.06
Reference Case with Wind (Off-Shore)	$172.40	$4.84	2.22%	$233.36	$116.62	$116.74
Low Carbon Case						
Reference Case	$154.17		-5.65%	$210.75	$110.56	$100.19
Reference Case and CC South	$152.90	-$1.26	-5.47%	$201.73	$113.27	$88.46
Reference Case with Wind (Land-Based)	$154.23	$0.07	-5.11%	$208.01	$110.47	$97.54
Reference Case with Wind (Off-Shore)	$160.49	$6.32	-4.84%	$213.42	$111.53	$101.89
Flat Henry Hub						
Reference Case	$158.71		-2.87%	$218.48	$112.77	$105.72
Reference Case and CC South	$157.50	-$1.21	-2.63%	$209.20	$115.49	$93.71
Reference Case with Wind (Land-Based)	$158.37	-$0.34	-2.57%	$214.76	$112.45	$102.31
Reference Case with Wind (Off-Shore)	$164.58	$5.87	-2.42%	$219.77	$113.53	$106.24

Table 6 – Sensitivity Results (RSCI Customers)

Sensitivity Analysis Nominal Dollars - 2020 Planning Year

Electricity Hedging Option	Total Average Costs ($/MWh)	Difference ($) From Reverence Case	Difference ($) within Sensitivity	Difference ($) From Related Scenario	High Average Costs 90.0% ($/MWh)	Low Average Costs 10.0% ($/MWh)	Difference between High and Low Average Costs ($/MWh)
Reference Case	$163.39				$227.10	$114.47	$112.63
Reference Case and CC South	$161.76	-$1.63			$216.34	$117.19	$99.15
Reference Case with Wind (Land-Based)	$162.54	-$0.85			$220.39	$118.30	$102.08
Reference Case with Wind (Off-Shore)	$168.65	$5.26			$225.09	$119.62	$105.48
Reference Case with Larger CC in DPL North	$154.14	-$9.25	-$172.65	-$7.62	$197.02	$115.81	$81.21
Low Capacity Factor Reference Case with Wind (Land-Based)	$163.06	-$0.34	-$163.73	$0.51	$223.18	$109.86	$113.31
Low Capacity Factor Reference Case with Wind (Off-Shore)	$169.23	$5.83	-$157.56	$0.57	$228.65	$116.40	$112.25
High Capacity Factor Reference Case with Wind (Land-Based)	$162.03	-$1.36	-$164.75	-$0.51	$221.32	$109.54	$111.78
High Capacity Factor Reference Case with Wind (Off-Shore)	$168.08	$4.69	-$158.70	-$0.57	$226.04	$115.98	$110.06
Reference Case and CC South 10% Increase in Capital Costs	$162.42	-$0.98	-$164.37	$0.66	$216.99	$117.84	$99.15
Reference Case with Wind (Land-Based) 10% Cost Increase	$163.23	-$0.16	-$163.56	$0.68	$223.43	$114.67	$108.76
Reference Case with Wind (Off-Shore) 10% Cost Increase	$170.16	$6.77	-$156.62	$1.51	$228.88	$117.19	$111.68

ATTACHMENT B

RESULTS FOR LARGE COMMERCIAL CUSTOMERS
REAL (2010$) & NOMINAL $

Table 6: Supply Cost Projections - LC Customers

Confidential Material Omitted

Real Dollars (2010$)

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)	Difference as Percent of Average
Settlement Period: Planning Year 2011							
Reference Case	980,369						
Settlement Period: Planning Year 2013							
Reference Case	880,585						
Settlement Period: Planning Year 2015							
Reference Case	828,339	$86.92		$118.11	$61.80	$56.31	**64.79%**
Reference Case and CC South	828,339	$88.22	**1.5%**	$116.35	$65.20	$51.15	**57.97%**
Reference Case with Wind (Land Based)	828,339	$88.71	**2.1%**	$118.20	$63.86	$54.33	**61.25%**
Settlement Period: Planning Year 2017							
Reference Case	819,893	$102.26		$138.62	$72.77	$65.84	**64.38%**
Reference Case and CC South	819,893	$102.38	**0.1%**	$135.19	$75.30	$59.89	**58.49%**
Reference Case with Wind (Land-Based)	819,893	$103.84	**1.5%**	$139.14	$74.70	$64.44	**62.05%**
Reference Case with Wind (Off-Shore)	819,893	$107.84	**5.5%**	$141.96	$79.28	$62.68	**58.13%**
Settlement Period: Planning Year 2020							
Reference Case	743,029	$119.09		$172.47	$77.92	$94.55	**79.40%**
Reference Case and CC South	743,029	$117.82	**-1.1%**	$165.12	$80.04	$85.08	**72.21%**
Reference Case with Wind (Land-Based)	743,029	$118.43	**-0.6%**	$168.91	$78.27	$90.64	**76.54%**
Reference Case with Wind (Off-Shore)	743,029	$123.20	**3.5%**	$173.25	$83.67	$89.58	**72.71%**

Figure 2: Comparative Risk of the RC and Scenario Portfolios

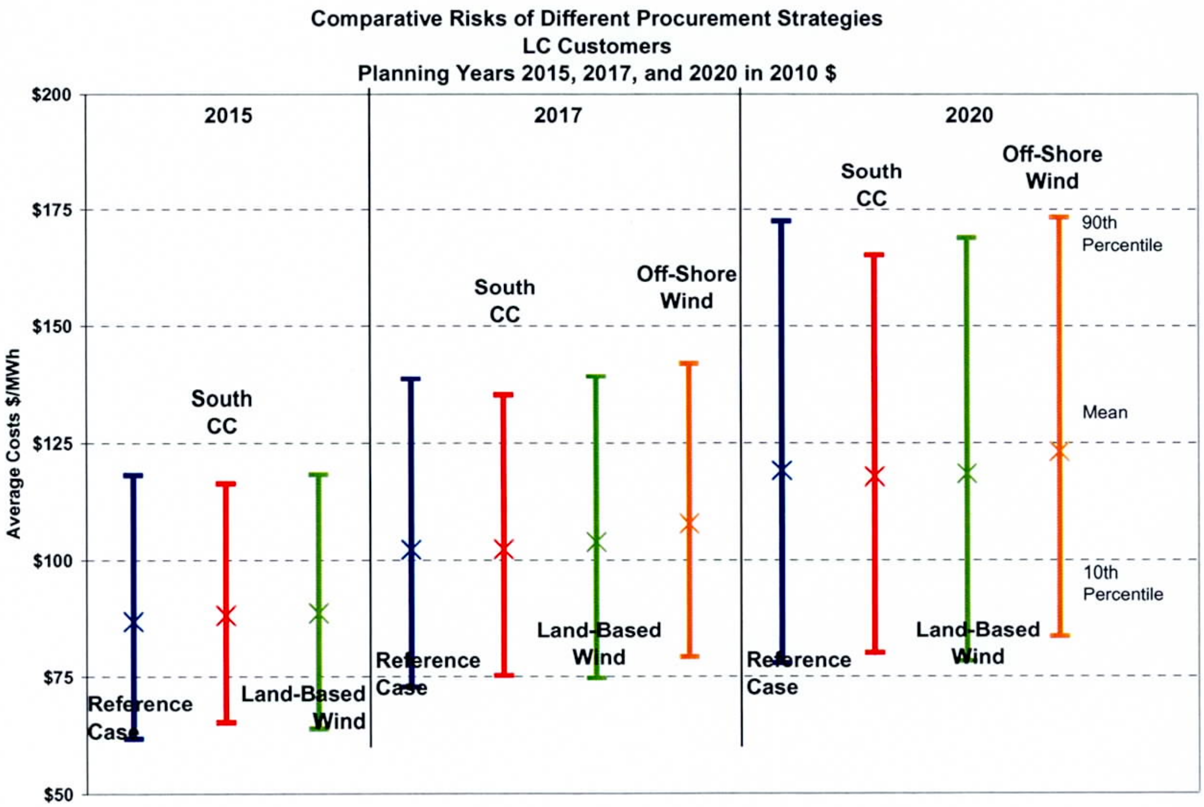


Table 4: Tariff Rate Projections (2010$)

Confidential Material Omitted

Planning Year	Residential Rates (Tariff "R")				MGT-S Rates			
	Demand ($/kW)		Energy (Cents/KWH)		Demand ($/kW)		Energy (Cents/KWH)	
	Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter
Currently Effective	-	-	11.04	10.07	14.00	9.20	4.59	5.91
2011	-	-						
2012	-	-						
2013	-	-						
2014	-	-	11.49	10.76	15.58	9.68	5.02	6.14
2015	-	-	11.90	11.14	16.20	10.06	5.21	6.38

Table 5 – Sensitivity Results (Large Commercial Customers)

Sensitivity Analysis Real 2010 Dollars - 2020 Planning Year

Electricity Hedging Option	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 Total	$119.09			$172.47	$77.92	$94.55
Reference Case and CC South	$117.82	**-$1.27**	**-1.07%**	$165.12	$80.04	$85.08
Reference Case with Wind (Land-Based)	$118.43	**-$0.66**	**-0.56%**	$169.07	$81.64	$87.43
Reference Case with Wind (Off-Shore)	$123.20	**$4.11**	**3.45%**	$173.41	$82.77	$90.65
High Carbon Case						
Reference Case	$121.98		**2.43%**	$177.74	$78.98	$98.76
Reference Case and CC South	$120.58	**-$1.40**	**2.35%**	$170.05	$81.10	$88.95
Reference Case with Wind (Land-Based)	$121.04	**-$0.95**	**2.20%**	$175.21	$79.25	$95.96
Reference Case with Wind (Off-Shore)	$125.76	**$3.78**	**2.08%**	$179.57	$80.14	$99.43
Low Carbon Case						
Reference Case	$111.88		**-6.05%**	$159.34	$75.28	$84.06
Reference Case and CC South	$110.90	**-$0.99**	**-5.87%**	$152.97	$77.41	$75.56
Reference Case with Wind (Land-Based)	$111.93	**$0.05**	**-5.49%**	$158.62	$75.83	$82.79
Reference Case with Wind (Off-Shore)	$116.82	**$4.94**	**-5.18%**	$163.23	$76.76	$86.47
Flat Henry Hub						
Reference Case	$114.13		**-4.16%**	$163.08	$76.32	$86.76
Reference Case and CC South	$113.19	**-$0.94**	**-3.93%**	$156.97	$78.45	$78.53
Reference Case with Wind (Land-Based)	$113.87	**-$0.26**	**-3.85%**	$161.99	$76.78	$85.21
Reference Case with Wind (Off-Shore)	$118.72	**$4.59**	**-3.64%**	$166.55	$77.70	$88.84

Table 6 – Sensitivity Results (Large Commercial Customers)

Sensitivity Analysis Real 2010 Dollars - 2020 Planning Year

Electricity Hedging Option	Total Average Costs ($/MWh)	**Difference ($) From Reverence Case**	**Difference ($) within Sensitivity**	**Difference ($) From Related Scenario**	High Average Costs 90.0% ($/MWh)	Low Average Costs 10.0% ($/MWh)	Difference between High and Low Average Costs ($/MWh)
Reference Case	$119.09				$172.47	$77.92	$94.55
Reference Case and CC South	$117.82	**-$1.27**			$165.12	$80.04	$85.08
Reference Case with Wind (Land-Based)	$118.43	**-$0.66**			$169.07	$81.64	$87.43
Reference Case with Wind (Off-Shore)	$123.20	**$4.11**			$173.41	$82.77	$90.65
Reference Case with Larger CC in DPL North	$111.86	**-$7.23**	**-6.07%**	**-$5.95**	$149.23	$79.40	$69.84
Low Capacity Factor Reference Case with Wind (Land-Based)	$118.83	**-$0.26**	**-0.22%**	**$0.40**	$171.01	$75.01	$96.00
Low Capacity Factor Reference Case with Wind (Off-Shore)	$123.65	**$4.56**	**3.83%**	**$0.45**	$175.51	$80.19	$95.32
High Capacity Factor Reference Case with Wind (Land-Based)	$118.03	**-$1.06**	**-0.89%**	**-$0.40**	$169.82	$74.80	$95.02
High Capacity Factor Reference Case with Wind (Off-Shore)	$122.76	**$3.67**	**3.08%**	**-$0.45**	$174.19	$79.95	$94.24
Reference Case and CC South 10% Increase in Capital Costs	$118.33	**-$0.76**	**-0.64%**	**$0.51**	$165.63	$80.56	$85.08
Reference Case with Wind (Land-Based) 10% Cost Increase	$118.96	**-$0.13**	**-0.11%**	**$0.53**	$171.45	$78.80	$92.65
Reference Case with Wind (Off-Shore) 10% Cost Increase	$124.38	**$5.29**	**4.44%**	**$1.18**	$176.37	$80.87	$95.49

Table 7: Supply Cost Projections - LC Customers

Confidential Material Omitted

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)	Difference as Percent of Average
Settlement Period: Planning Year 2011							
Reference Case	980,369						
Settlement Period: Planning Year 2013							
Reference Case	880,585						
Settlement Period: Planning Year 2015							
Reference Case	828,339	$98.34		$133.63	$69.92	$63.71	**64.79%**
Reference Case and CC South	828,339	$99.82	**1.5%**	$131.64	$73.77	$57.87	**57.97%**
Reference Case with Wind (Land Based)	828,339	$100.37	**2.1%**	$133.73	$72.26	$61.47	**61.25%**
Settlement Period: Planning Year 2017							
Reference Case	819,893	$121.56		$164.77	$86.51	$78.27	**64.38%**
Reference Case and CC South	819,893	$121.70	**0.1%**	$160.69	$89.50	$71.19	**58.49%**
Reference Case with Wind (Land-Based)	819,893	$123.43	**1.5%**	$165.39	$88.80	$76.59	**62.05%**
Reference Case with Wind (Off-Shore)	819,893	$128.19	**5.5%**	$168.75	$94.24	$74.51	**58.13%**
Settlement Period: Planning Year 2020							
Reference Case	743,029	$152.45		$220.78	$99.74	$121.04	**79.40%**
Reference Case and CC South	743,029	$150.81	**-1.1%**	$211.37	$102.46	$108.91	**72.21%**
Reference Case with Wind (Land-Based)	743,029	$151.60	**-0.6%**	$216.22	$100.19	$116.03	**76.54%**
Reference Case with Wind (Off-Shore)	743,029	$157.71	**3.5%**	$221.77	$107.10	$114.67	**72.71%**

Figure 2: Comparative Risk of the RC and Scenario Portfolios

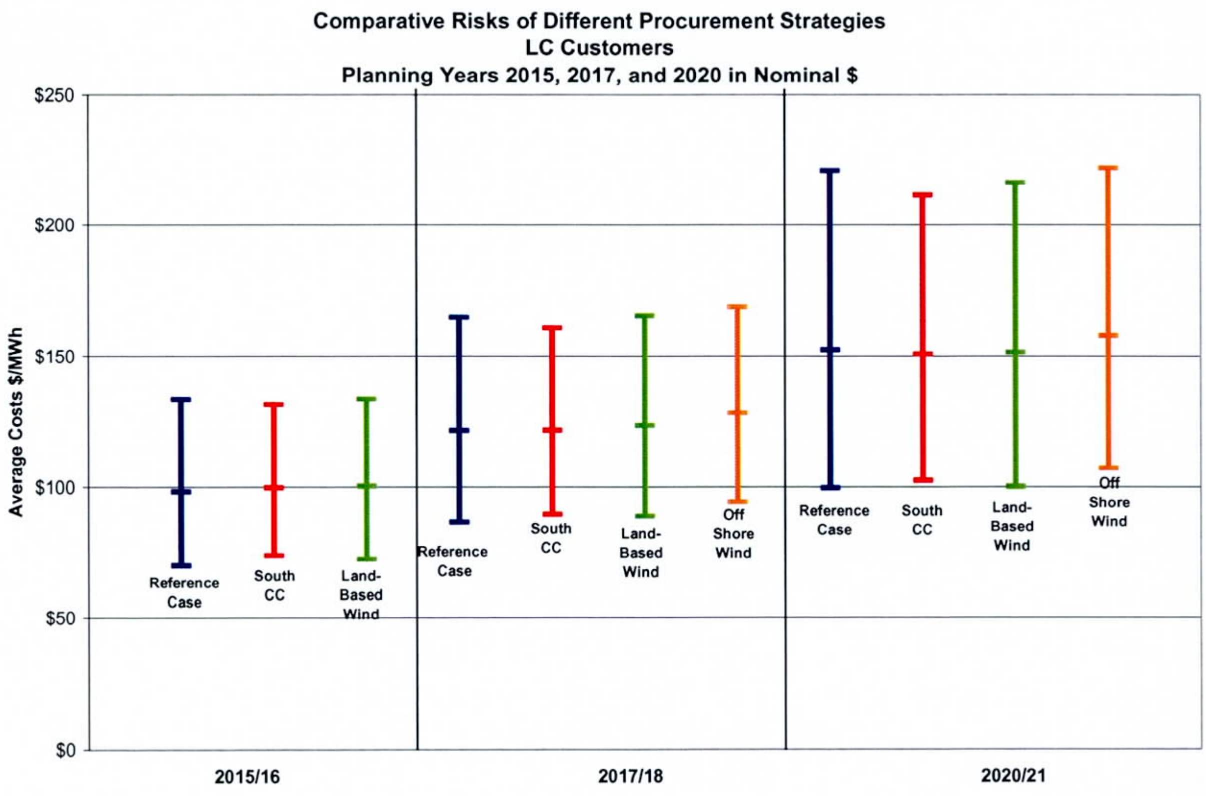


Table 4: Tariff Rate Projections (Nominal $)
Confidential Material Omitted

Planning Year	Residential Rates (Tariff "R")				MGT-S Rates			
	Demand ($/kW)		Energy (Cents/KWH)		Demand ($/kW)		Energy (Cents/KWH)	
	Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter
Currently Effective	-	-	11.04	10.07	14.00	9.20	4.59	5.91
2011	-	-						
2012	-	-						
2013	-	-						
2014	-	-	12.68	11.87	17.20	10.68	5.54	6.78
2015	-	-	13.47	12.60	18.32	11.38	5.90	7.22

Table 5 – Sensitivity Results (Large Commercial Customers)

Sensitivity Analysis Nominal Dollars - 2020 Planning Year

Electricity Hedging Option	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 Total	$152.45			$220.78	$99.74	$121.04
Reference Case and CC South	$150.81	**-$1.63**	**-1.07%**	$211.37	$102.46	$108.91
Reference Case with Wind (Land-Based)	$151.60	**-$0.85**	**-0.56%**	$216.42	$104.51	$111.92
Reference Case with Wind (Off-Shore)	$157.71	**$5.26**	**3.45%**	$221.98	$105.95	$116.04
High Carbon Case						
Reference Case	$156.15		**2.43%**	$227.52	$101.10	$126.43
Reference Case and CC South	$154.36	**-$1.79**	**2.35%**	$217.68	$103.82	$113.87
Reference Case with Wind (Land-Based)	$154.94	**-$1.21**	**2.20%**	$224.28	$101.45	$122.83
Reference Case with Wind (Off-Shore)	$160.99	**$4.84**	**2.08%**	$229.87	$102.59	$127.28
Low Carbon Case						
Reference Case	$143.22		**-6.05%**	$203.97	$96.37	$107.60
Reference Case and CC South	$141.96	**-$1.26**	**-5.87%**	$195.81	$99.09	$96.72
Reference Case with Wind (Land-Based)	$143.28	**$0.07**	**-5.49%**	$203.05	$97.07	$105.98
Reference Case with Wind (Off-Shore)	$149.54	**$6.32**	**-5.18%**	$208.95	$98.26	$110.69
Flat Henry Hub						
Reference Case	$146.10		**-4.16%**	$208.76	$97.70	$111.06
Reference Case and CC South	$144.89	**-$1.21**	**-3.93%**	$200.94	$100.42	$100.52
Reference Case with Wind (Land-Based)	$145.76	**-$0.34**	**-3.85%**	$207.36	$98.29	$109.07
Reference Case with Wind (Off-Shore)	$151.97	**$5.87**	**-3.64%**	$213.19	$99.47	$113.72

Table 6 – Sensitivity Results (Large Commercial Customers)

Sensitivity Analysis Nominal Dollars - 2020 Planning Year

Electricity Hedging Option	Total Average Costs ($/MWh)	**Difference ($) From Reverence Case**	**Difference ($) within Sensitivity**	**Difference ($) From Related Scenario**	High Average Costs 90.0% ($/MWh)	Low Average Costs 10.0% ($/MWh)	Difference between High and Low Average Costs ($/MWh)
Reference Case	$152.45				$220.78	$99.74	$121.04
Reference Case and CC South	$150.81	**-$1.63**			$211.37	$102.46	$108.91
Reference Case with Wind (Land-Based)	$151.60	**-$0.85**			$216.42	$104.51	$111.92
Reference Case with Wind (Off-Shore)	$157.71	**$5.26**			$221.98	$105.95	$116.04
Reference Case with Larger CC in DPL North	$143.19	**-$9.25**	**-$161.70**	**-$7.62**	$191.03	$101.63	$89.40
Low Capacity Factor Reference Case with Wind (Land-Based)	$152.11	**-$0.34**	**-$152.78**	**$0.51**	$218.90	$96.01	$122.89
Low Capacity Factor Reference Case with Wind (Off-Shore)	$158.28	**$5.83**	**-$146.61**	**$0.57**	$224.66	$102.65	$122.02
High Capacity Factor Reference Case with Wind (Land-Based)	$151.09	**-$1.36**	**-$153.81**	**-$0.51**	$217.38	$95.74	$121.64
High Capacity Factor Reference Case with Wind (Off-Shore)	$157.14	**$4.69**	**-$147.76**	**-$0.57**	$222.98	$102.35	$120.63
Reference Case and CC South 10% Increase in Capital Costs	$151.47	**-$0.98**	**-$153.42**	**$0.66**	$212.03	$103.12	$108.91
Reference Case with Wind (Land-Based) 10% Cost Increase	$152.28	**-$0.16**	**-$152.61**	**$0.68**	$219.47	$100.87	$118.60
Reference Case with Wind (Off-Shore) 10% Cost Increase	$159.22	**$6.77**	**-$145.68**	**$1.51**	$225.76	$103.53	$122.24

ATTACHMENT C

ENERGY AND PEAK LOAD OBLIGATION FORECAST

Load Forecast (GWH)
DPL Delaware Unrestricted
Calendar Year

	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Standard Offer Service											
Residential	2,901	2,961	3,005	3,052	3,094	3,144	3,177	3,219	3,261	3,313	3,348
Small Commercial	143	143	144	144	145	145	146	146	147	147	148
Street Lighting	37	37	37	37	37	37	38	38	38	38	38
RSCI Subtotal	*3,081*	*3,142*	*3,186*	*3,233*	*3,276*	*3,326*	*3,361*	*3,403*	*3,446*	*3,498*	*3,534*
LC&I	1,050	1,052	1,057	1,061	1,063	1,067	1,071	1,075	1,078	1,082	1,086
Hourly Service	264	264	266	267	267	268	269	270	271	272	273
Large Commercial & Industrial	1,314	1,317	1,322	1,327	1,330	1,335	1,340	1,345	1,348	1,354	1,359
Subtotal	4,395	4,458	4,509	4,561	4,606	4,661	4,700	4,748	4,794	4,851	4,893
Third-Party Suppliers											
Residential	87	89	90	91	93	94	95	96	98	99	100
Small Commercial	21	21	21	21	21	21	21	21	21	21	22
Street Lighting	1	1	1	1	1	1	1	1	1	1	1
RSCI Subtotal	*109*	*111*	*112*	*114*	*115*	*116*	*118*	*119*	*120*	*122*	*123*
Large Commercial & Industrial	3,906	3,914	3,932	3,947	3,955	3,969	3,984	3,998	4,009	4,025	4,041
Subtotal	4,015	4,025	4,044	4,060	4,070	4,085	4,101	4,117	4,129	4,147	4,164
Total Distribution Load											
Residential	2,988	3,050	3,095	3,143	3,187	3,238	3,273	3,316	3,359	3,412	3,448
Small Commercial	164	164	165	166	166	166	167	168	168	169	169
Street Lighting	38	38	38	38	38	39	39	39	39	39	39
RSCI Subtotal	*3,190*	*3,252*	*3,299*	*3,347*	*3,391*	*3,443*	*3,478*	*3,522*	*3,566*	*3,619*	*3,657*
Large Commercial & Industrial	5,220	5,231	5,254	5,274	5,285	5,304	5,323	5,342	5,357	5,379	5,400
Total	8,410	8,483	8,553	8,621	8,676	8,746	8,802	8,864	8,923	8,998	9,056
Migration (%)											
Residential	2.9%	2.9%	2.9%	2.9%	2.9%	2.9%	2.9%	2.9%	2.9%	2.9%	2.9%
Small Commercial	12.7%	12.7%	12.7%	12.7%	12.7%	12.7%	12.7%	12.7%	12.7%	12.7%	12.7%
Street Lighting	2.9%	2.9%	2.9%	2.9%	2.9%	2.9%	2.9%	2.9%	2.9%	2.9%	2.9%
RSCI Subtotal	*3.4%*	*3.4%*	*3.4%*	*3.4%*	*3.4%*	*3.4%*	*3.4%*	*3.4%*	*3.4%*	*3.4%*	*3.4%*
Large Commercial & Industrial	74.8%	74.8%	74.8%	74.8%	74.8%	74.8%	74.8%	74.8%	74.8%	74.8%	74.8%
Total	47.7%	47.4%	47.3%	47.1%	46.9%	46.7%	46.6%	46.4%	46.3%	46.1%	46.0%

DSM Projectons (GWH)
DPL Delaware
Calendar Year

	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Standard Offer Service											
Residential	51	160	238	309	376	407	439	476	518	557	572
Small Commercial	4	9	15	21	27	26	25	28	32	36	38
Street Lighting	0	0	0	0	0	0	0	0	0	0	0
RSCI Subtotal	*54*	*169*	*253*	*330*	*402*	*433*	*463*	*505*	*550*	*593*	*610*
Large Commercial & Industrial	32	80	134	191	244	236	228	258	297	335	349
Subtotal	87	249	387	520	646	669	692	763	847	928	959
Third-Party Suppliers											
Residential	2	5	7	9	11	12	13	14	16	17	17
Small Commercial	1	1	2	3	4	4	4	4	5	5	6
Street Lighting	0	0	0	0	0	0	0	0	0	0	0
RSCI Subtotal	*2*	*6*	*9*	*12*	*15*	*16*	*17*	*18*	*20*	*22*	*23*
Large Commercial & Industrial	96	238	400	567	726	702	679	768	882	996	1,037
Subtotal	98	244	409	579	741	718	696	787	902	1,018	1,059
Total Distribution Load											
Residential	52	165	245	318	387	419	452	491	533	574	589
Small Commercial	4	10	17	24	30	29	28	32	37	42	43
Street Lighting	0	0	0	0	0	0	0	0	0	0	0
RSCI Subtotal	*56*	*175*	*262*	*342*	*417*	*449*	*480*	*523*	*570*	*615*	*633*
Large Commercial & Industrial	129	318	534	757	970	939	907	1,027	1,178	1,331	1,385
Total	185	493	796	1,099	1,388	1,388	1,388	1,549	1,748	1,946	2,018

Load Forecast (GWH)
DPL Delaware less DSM
Calendar Year

	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Standard Offer Service											
Residential	2,850	2,801	2,767	2,743	2,718	2,736	2,739	2,743	2,744	2,756	2,775
Small Commercial	139	135	129	124	118	120	121	118	114	111	110
Street Lighting	37	37	37	37	37	37	38	38	38	38	38
RSCI Subtotal	*3,026*	*2,973*	*2,934*	*2,904*	*2,874*	*2,893*	*2,897*	*2,899*	*2,896*	*2,904*	*2,923*
LC&I	1,018	972	922	870	819	831	842	816	781	747	737
Hourly Service	264	264	266	267	267	268	269	270	271	272	273
Large Commercial & Industrial	1,281	1,237	1,188	1,137	1,086	1,099	1,111	1,086	1,052	1,019	1,010
Subtotal	4,308	4,209	4,121	4,041	3,960	3,992	4,009	3,985	3,948	3,923	3,934
Third-Party Suppliers											
Residential	85	84	83	82	81	82	82	82	82	83	83
Small Commercial	20	20	19	18	17	17	18	17	17	16	16
Street Lighting	1	1	1	1	1	1	1	1	1	1	1
RSCI Subtotal	*107*	*105*	*103*	*101*	*100*	*101*	*101*	*101*	*100*	*100*	*100*
Large Commercial & Industrial	3,810	3,677	3,532	3,380	3,229	3,266	3,305	3,230	3,127	3,029	3,004
Subtotal	3,917	3,781	3,635	3,481	3,329	3,367	3,405	3,330	3,227	3,129	3,104
Total Distribution Load											
Residential	2,935	2,885	2,850	2,825	2,800	2,818	2,821	2,825	2,826	2,838	2,859
Small Commercial	160	154	148	142	135	137	139	135	131	127	126
Street Lighting	38	38	38	38	38	39	39	39	39	39	39
RSCI Subtotal	*3,133*	*3,077*	*3,036*	*3,005*	*2,974*	*2,994*	*2,998*	*2,999*	*2,996*	*3,004*	*3,024*
Large Commercial & Industrial	5,092	4,913	4,720	4,517	4,315	4,365	4,416	4,316	4,179	4,048	4,014
Total	8,225	7,990	7,756	7,522	7,289	7,359	7,414	7,315	7,175	7,052	7,038

Load Forecast (GWH)
DPL Delaware less DSM
Planning (Compliance) Year

Page C-4

	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Standard Offer Service										
Residential	2,830	2,787	2,757	2,733	2,726	2,737	2,740	2,743	2,749	2,764
Small Commercial	137	132	127	121	119	120	120	117	113	110
Street Lighting	37	37	37	37	37	37	38	38	38	38
RSCI Subtotal	*3,004*	*2,956*	*2,921*	*2,891*	*2,882*	*2,895*	*2,898*	*2,898*	*2,899*	*2,912*
LC&I	999	951	901	849	824	836	832	802	767	743
Hourly Service	264	265	266	267	267	268	269	270	271	272
Large Commercial & Industrial	1,263	1,216	1,167	1,116	1,091	1,104	1,101	1,072	1,038	1,015
Subtotal	4,267	4,173	4,088	4,007	3,973	3,999	3,999	3,969	3,937	3,927
Subtotal (less hourly)	4,003	3,908	3,822	3,740	3,706	3,730	3,729	3,699	3,666	3,655
Third-Party Suppliers										
Residential	85	84	83	82	82	82	82	82	82	83
Small Commercial	20	19	18	18	17	18	17	17	16	16
Street Lighting	1	1	1	1	1	1	1	1	1	1
RSCI Subtotal	*106*	*104*	*102*	*101*	*100*	*101*	*101*	*100*	*100*	*100*
Large Commercial & Industrial	3,754	3,616	3,469	3,317	3,245	3,282	3,273	3,187	3,086	3,019
Subtotal	3,860	3,720	3,571	3,418	3,345	3,383	3,374	3,287	3,186	3,119
Total Distribution Load										
Residential	2,914	2,870	2,840	2,815	2,808	2,819	2,823	2,825	2,831	2,847
Small Commercial	157	152	145	139	136	138	137	134	129	127
Street Lighting	38	38	38	38	39	39	39	39	39	39
RSCI Subtotal	*3,110*	*3,060*	*3,023*	*2,992*	*2,982*	*2,996*	*2,999*	*2,998*	*2,999*	*3,012*
Large Commercial & Industrial	5,092	4,913	4,720	4,517	4,315	4,365	4,416	4,316	4,124	4,034
Total	8,127	7,893	7,659	7,425	7,318	7,382	7,373	7,257	7,124	7,046

Load Forecast (MW)
DPL Delaware Unrestricted
Calendar Year

	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Standard Offer Service										
Residential	834	840	847	861	881	900	919	935	951	966
Small Commercial	22	22	23	23	23	24	24	25	25	26
Street Lighting	0	0	0	0	0	0	0	0	0	0
RSCI Subtotal	857	863	869	884	904	924	944	960	977	991
LC&I	169	170	171	174	178	182	186	189	193	196
Hourly Service	42	43	43	44	45	46	47	48	48	49
Large Commercial & Industrial	211	213	215	218	223	228	233	237	241	245
Subtotal	1,068	1,076	1,084	1,103	1,128	1,152	1,177	1,196	1,218	1,236
Third-Party Suppliers										
Residential	25	25	25	26	26	27	28	28	29	29
Small Commercial	3	3	3	3	3	3	4	4	4	4
Street Lighting	0	0	0	0	0	0	0	0	0	0
RSCI Subtotal	28	28	29	29	30	30	31	32	32	33
Large Commercial & Industrial	629	633	638	649	664	678	693	704	717	727
Subtotal	657	662	667	678	694	709	724	736	749	760
Total Distribution Load										
Residential	859	866	872	887	907	927	947	963	980	994
Small Commercial	25	26	26	26	27	27	28	29	29	29
Street Lighting	0	0	0	0	0	0	0	0	0	0
RSCI Subtotal	885	891	898	913	934	954	975	991	1,009	1,024
Large Commercial & Industrial	840	846	852	867	887	906	926	941	958	972
Total	1,725	1,738	1,750	1,781	1,821	1,861	1,901	1,932	1,966	1,996

DSM Projectons (MW)
DPL Delaware
Calendar Year

	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Standard Offer Service										
Residential	26	33	43	46	50	55	54	53	52	51
Small Commercial	0	0	0	1	1	1	1	1	1	1
Street Lighting	0	0	0	0	0	0	0	0	0	0
RSCI Subtotal	*26*	*33*	*43*	*47*	*51*	*56*	*55*	*54*	*53*	*52*
Large Commercial & Industrial	0	1	4	7	8	8	8	8	8	9
Subtotal	26	34	47	54	59	64	63	62	61	60
Third-Party Suppliers										
Residential	1	1	1	1	2	2	2	2	2	2
Small Commercial	0	0	0	0	0	0	0	0	0	0
Street Lighting	0	0	0	0	0	0	0	0	0	0
RSCI Subtotal	1	1	1	1	2	2	2	2	2	2
Large Commercial & Industrial	0	2	13	22	22	23	24	24	25	26
Subtotal	0	0	0	0	0	0	0	0	0	0
Total Distribution Load										
Residential	27	34	44	47	52	57	56	55	53	52
Small Commercial	0	0	1	1	1	1	1	1	1	1
Street Lighting	0	0	0	0	0	0	0	0	0	0
RSCI Subtotal	*27*	*34*	*44*	*48*	*53*	*58*	*57*	*56*	*54*	*53*
Large Commercial & Industrial	0	3	17	29	30	31	32	33	34	34
Total	28	37	62	77	83	89	89	88	88	88

Load Forecast (MW)
DPL Delaware less DSM
Calendar Year

	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Standard Offer Service										
Residential	808	807	804	815	831	845	865	882	899	915
Small Commercial	22	22	22	22	23	23	24	24	24	25
Street Lighting	0	0	0	0	0	0	0	0	0	0
RSCI Subtotal	*830*	*830*	*826*	*838*	*853*	*868*	*889*	*906*	*924*	*940*
LC&I	169	170	167	167	171	174	178	181	184	187
Hourly Service	42	43	43	44	45	46	47	48	48	49
Large Commercial & Industrial	211	212	210	211	216	220	225	229	233	236
Subtotal	1,042	1,042	1,036	1,048	1,069	1,088	1,114	1,134	1,156	1,176
Subtotal (less hourly)	999	999	993	1,005	1,024	1,042	1,067	1,087	1,108	1,127
Third-Party Suppliers										
Residential	24	24	24	24	25	25	26	26	27	27
Small Commercial	3	3	3	3	3	3	3	4	4	4
Street Lighting	0	0	0	0	0	0	0	0	0	0
RSCI Subtotal	*27*	*27*	*27*	*28*	*28*	*29*	*29*	*30*	*31*	*31*
Large Commercial & Industrial	628	631	625	627	641	655	669	680	692	702
Subtotal	656	659	652	655	669	684	698	710	722	733
Total Distribution Load										
Residential	832	831	828	840	856	870	891	908	926	942
Small Commercial	25	26	25	25	26	27	27	28	28	28
Street Lighting	0	0	0	0	0	0	0	0	0	0
RSCI Subtotal	*858*	*857*	*853*	*865*	*882*	*896*	*918*	*936*	*954*	*971*
Large Commercial & Industrial	840	843	835	838	857	875	894	908	924	938
Total	1,698	1,700	1,688	1,703	1,738	1,772	1,812	1,844	1,878	1,909

ATTACHMENT D

RPS OBLIGATION AND SUPPLY PROJECTIONS

RPS Requirement Projection
DPL DE SOS excluding Hourly Service
Planning (Compliance) Year

		2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Standard Offer Service (GWH)											
Residential & Small Commercial		3,004	2,956	2,921	2,891	2,882	2,895	2,898	2,898	2,899	2,912
Large Commercial & Industrial (Non-Hourly)		999	951	901	849	824	836	832	802	767	743
Large Commercial & Industrial (Hourly)		264	265	266	267	267	268	269	270	271	272
Subtotal		4,267	4,173	4,088	4,007	3,973	3,999	3,999	3,969	3,937	3,927
Existing FSA Coverage											
Residential & Small Commercial		0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
Large Commercial & Industrial (Non-Hourly)		0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
Uncovered SOS RPS Requirements (GWH)											
Residential & Small Commercial		3,004	2,956	2,921	2,891	2,882	2,895	2,898	2,898	2,899	2,912
Large Commercial & Industrial (Non-Hourly)		999	951	901	849	824	836	832	802	767	743
Large Commercial & Industrial (Hourly)		264	265	266	267	267	268	269	270	271	272
Subtotal		4,267	4,173	4,088	4,007	3,973	3,999	3,999	3,969	3,937	3,927
Solar RPS Requirement	%	0.200%	0.400%	0.600%	0.800%	1.000%	1.250%	1.500%	1.750%	2.000%	2.250%
	SRECs	8,533	16,690	24,526	32,056	39,732	49,985	59,981	69,463	78,747	88,367
Total RPS Requirement	%	7.0%	8.5%	10.0%	11.5%	13.0%	14.5%	16.0%	17.5%	19.0%	20.0%
Total Requirement less Solar	RECs	290,142	337,986	384,254	428,754	476,797	529,851	579,817	625,177	669,359	697,125
Existing REC Allowance (1%)		42,667	41,726	40,877	40,070	39,732	39,988	39,987	39,693	39,373	0
Total Requirement less Existing	RECs	247,475	296,260	343,377	388,684	437,065	489,863	539,830	585,484	629,986	697,125

DPL DE Wind Portfolio
Planning (Compliance) Year
(Renewable Energy Credits - RECs)

	Capacity MW	Capacity Factor	Inservice Date
AES Armenia Wind	50	27.9%	12/1/2009
Synergics Roth Rock	40	34.8%	12/31/2010
Synergics Eastern Wind	60	35.0%	12/31/2010
Bluewater Wind	200	31.9%	6/1/2017
New Land-Based Wind	0	30.0%	6/1/2014
New Off-Shore Wind	0	32.0%	6/1/2017

	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Total SOS Requirement	247,475	296,260	343,377	388,684	437,065	489,863	539,830	585,484	629,986	697,125
RECs from Existing Wind Contracts										
AES Armenia Mountain	122,000	122,000	122,000	122,000	122,000	122,000	122,000	122,000	122,000	122,000
Synergics Roth Rock	122,000	122,000	122,000	122,000	122,000	122,000	122,000	122,000	122,000	122,000
Synergics Eastern Wind	184,000	184,000	184,000	184,000	184,000	184,000	184,000	184,000	184,000	184,000
Blue Water Wind	0	0	0	0	0	0	303,184	305,775	308,971	311,582
New Land-Based Wind Facilities	0	0	0	0	0	0	0	0	0	0
New Off-Shore Wind Facilities	0	0	0	0	0	0	0	0	0	0
Total	428,000	428,000	428,000	428,000	428,000	428,000	731,184	733,775	736,971	739,582
Blended Additions to New REC Bank	$24.00	$24.00	$24.00	$24.00	$24.00	$24.00	$22.18	$22.38	$22.58	$22.79
Additional RECs Required	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
BOY REC Bank	118,113	298,638	430,378	515,001	554,317	545,252	483,389	674,743	823,034	930,019
EOY REC Bank	298,638	430,378	515,001	554,317	545,252	483,389	674,743	823,034	930,019	972,476
Expiring RECs	0	0	0	0	0	0	0	0	0	0
Blended Additions to New REC Bank ($)										
BOY REC Bank	2,834,712	7,167,312	10,329,072	12,360,024	13,303,608	13,086,048	11,601,336	14,965,846	18,398,200	20,957,453
EOY REC Bank	7,167,312	10,329,072	12,360,024	13,303,608	13,086,048	11,601,336	14,965,846	18,398,200	20,957,453	22,110,080
Blended Additions to New REC Bank ($/REC)										
BOY REC Bank	$24.00	$24.00	$24.00	$24.00	$24.00	$24.00	$24.00	$22.18	$22.35	$22.53
EOY REC Bank	$24.00	$24.00	$24.00	$24.00	$24.00	$24.00	$22.18	$22.35	$22.53	$22.74
Blended Annual Usage ($/REC)	$24.00	$24.00	$24.00	$24.00	$24.00	$24.00	$23.81	$22.18	$22.35	$22.52

DPL DE Solar Portfolio
Planning (Compliance) Year

		2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Solar Requirement	SRECs	8,533	16,690	24,526	32,056	39,732	49,985	59,981	69,463	78,747	88,367
RECs from Existing Solar Contracts											
SEU Dover Purchase		7000	3700	0	0	0	0	0	0	0	0
Dover Solar		2,846	6,096	9,747	9,699	9,650	9,602	9,554	9,506	9,459	9,411
Existing SEU Contract _Early		0	0	0	0	0	0	0	0	0	0
Existing SEU Contract		0	0	0	2,700	3,500	4,500	0	0	0	0
Other	Utility Scale	0	0	1,402	2,859	5,833	10,412	18,206	20,117	20,520	20,930
Other SEU	Customer-Sited	5,688	10,594	13,377	16,798	20,749	25,471	32,222	39,840	48,769	58,026
	Total	8,533	16,690	24,526	32,056	39,732	49,985	59,981	69,463	78,747	88,367
Additional SRECs Required		**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
BOY SREC Bank		0	0	0	0	0	0	0	0	0	0
EOY SREC Bank		0	0	0	0	0	0	0	0	0	0
Expiring SRECs		0	0	0	0	0	0	0	0	0	0
Price of RECs from Solar Contracts ($/REC)											
Dover Solar		$216.70	$216.70	$216.70	$216.70	$216.70	$216.70	$216.70	$216.70	$216.70	$216.70
Existing SEU Contract _Early		$216.70	$216.70								
Existing SEU Contract				$231.70	$231.70	$231.70	$231.70	$231.70	$231.70	$231.70	$231.70
Other	Utility Scale	$216.70	$211.28	$206.00	$200.85	$195.83	$190.93	$186.16	$181.51	$176.97	$172.54
Other SEU	Customer-Sited	$263.00	$259.95	$257.89	$255.01	$251.71	$248.00	$243.38	$238.96	$234.54	$230.53
Cost of RECs from Solar Contracts ($)											
Dover Solar		$616,620	$1,321,062	$2,112,238	$2,101,677	$2,091,168	$2,080,713	$2,070,309	$2,059,957	$2,049,658	$2,039,409
Existing SEU Contract _Early		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Existing SEU Contract		$0	$0	$0	$625,590	$810,950	$1,042,650	$0	$0	$0	$0
Other	Utility Scale	$0	$0	$288,730	$581,503	$1,163,827	$2,038,078	$3,488,995	$3,835,960	$3,907,163	$3,977,973
Other SEU	Customer-Sited	$1,495,813	$2,753,892	$3,449,777	$4,283,712	$5,222,712	$6,317,031	$7,842,112	$9,520,294	$11,438,099	$13,376,586
	Total	$3,608,245	$6,828,846	$9,300,523	$11,876,193	$14,511,369	$17,795,502	$21,243,528	$24,936,506	$28,833,019	$32,770,556
Blended Cost of SRECs ($/REC)		$423	$409	$379	$370	$365	$356	$354	$359	$366	$371

ATTACHMENT E

TARIFF RATE PROJECTIONS (2011-2015)

Confidential Material Omitted

Table #16 — **2014 Proposed Uniform Residential and Small Commercial FP-SOS Rates and large Commercial and Industrial Rates Including Revenue Taxes (= Rates from Table #14 + PCA)**

	R	RTOU	RTOU-ND	RSH	SGS-S	GS-SH	GS-WH	OL	ORL	MGS-S	LGS-S	GS-P
Demand ($/kW)												
Summer		6.827164								15.584571	17.773881	17.779337
Winter		6.377197								9.675600	12.024111	11.232535
Energy ($/MWH)												
Summer - all hrs	0.114871			0.114871	0.114871	0.114871	0.114871	0.063452	0.114871	0.050183		
DP&L On pk		0.106818	0.206299								0.073464	0.059452
DP&L Off pk		0.078267	0.069040								0.053281	0.044552
Winter - all hrs	0.107557			0.107557	0.107557	0.107557	0.107557	0.075316	0.107557	0.061405		
DP&L On pk		0.086038	0.188176								0.082612	0.062521
DP&L Off pk		0.063040	0.073874								0.059664	0.046991
Annual								0.071347	0.111815			

Table #16 — **2015 Proposed Uniform Residential and Small Commercial FP-SOS Rates and large Commercial and Industrial Rates Including Revenue Taxes (= Rates from Table #14 + PCA)**

	R	RTOU	RTOU-ND	RSH	SGS-S	GS-SH	GS-WH	OL	ORL	MGS-S	LGS-S	GS-P
Demand ($/kW)												
Summer		7.082667								16.195122	18.471100	18.475847
Winter		6.614256								10.057807	12.494674	11.676948
Energy ($/MWH)												
Summer - all hrs	0.119025			0.119025	0.119025	0.119025	0.119025	0.065680	0.119025	0.052119		
DP&L On pk		0.110711	0.214000								0.076083	0.062296
DP&L Off pk		0.081020	0.071414								0.055108	0.046812
Winter - all hrs	0.111410			0.111410	0.111410	0.111410	0.111410	0.077972	0.111410	0.063800		
DP&L On pk		0.089121	0.195131								0.085583	0.065515
DP&L Off pk		0.065218	0.076431								0.061737	0.049370
Annual								0.073860	0.115844			

Confidential Material Omitted

Table #16 **2014 Proposed Uniform Residential and Small Commercial FP-SOS Rates and large Commercial and Industrial Rates Including Revenue Taxes (= Rates from Table #14 + PCA)**

	R	RTOU	RTOU-ND	RSH	SGS-S	GS-SH	GS-WH	OL	ORL	MGS-S	LGS-S	GS-P
Demand ($/kW)												
Summer		$ 7.535912								$ 17.202450	$ 19.619039	$ 19.625061
Winter		$ 7.039232								$ 10.680052	$ 13.272369	$ 12.398617
Energy ($/MWH)												
Summer - all hrs	$ 0.126796			$ 0.126796	$ 0.126796	$ 0.126796	$ 0.126796	$ 0.070039	$ 0.126796	$ 0.055393		
DP&L On pk		$ 0.117907	$ 0.227715								$ 0.081091	$ 0.065624
DP&L Off pk		$ 0.086392	$ 0.076207								$ 0.058812	$ 0.049177
Winter - all hrs	$ 0.118723			$ 0.118723	$ 0.118723	$ 0.118723	$ 0.118723	$ 0.083135	$ 0.118723	$ 0.067780		
DP&L On pk		$ 0.094970	$ 0.207711								$ 0.091188	$ 0.069012
DP&L Off pk		$ 0.069584	$ 0.081543								$ 0.065858	$ 0.051870
Annual								$ 0.078754	$ 0.123423			

Table #16 **2015 Proposed Uniform Residential and Small Commercial FP-SOS Rates and large Commercial and Industrial Rates Including Revenue Taxes (= Rates from Table #14 + PCA)**

	R	RTOU	RTOU-ND	RSH	SGS-S	GS-SH	GS-WH	OL	ORL	MGS-S	LGS-S	GS-P
Demand ($/kW)												
Summer		$ 8.013388								$ 18.323294	$ 20.898354	$ 20.903725
Winter		$ 7.483424								$ 11.379485	$ 14.136577	$ 13.211395
Energy ($/MWH)												
Summer - all hrs	$ 0.134666			$ 0.134666	$ 0.134666	$ 0.134666	$ 0.134666	$ 0.074311	$ 0.134666	$ 0.058968		
DP&L On pk		$ 0.125259	$ 0.242121								$ 0.086081	$ 0.070483
DP&L Off pk		$ 0.091666	$ 0.080798								$ 0.062350	$ 0.052964
Winter - all hrs	$ 0.126050			$ 0.126050	$ 0.126050	$ 0.126050	$ 0.126050	$ 0.088218	$ 0.126050	$ 0.072184		
DP&L On pk		$ 0.100832	$ 0.220773								$ 0.096829	$ 0.074125
DP&L Off pk		$ 0.073788	$ 0.086474								$ 0.069850	$ 0.055858
Annual								$ 0.083566	$ 0.131067			