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Independent Economic Assessment of the Proposed Bluewater Offshore Wind Farm

Prepared for:

Delmarva Power & Light

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EXECUTIVE SUMMARY

Pace Global Energy Services, LLC ("Pace") was commissioned by Delmarva Power and Light ("Delmarva") to independently assess the economic impacts of the proposed Bluewater Wind off-shore wind farm (the "BWW Project") on Delmarva's Standard Offer Service ("SOS") customers. The review undertaken by Pace was based solely on publicly-available information and data sources. Pace analyzed the expected "Green Premium" for the BWW Project which refers to the excess cost of the BWW Project above a comparable PJM[1] benchmark. The value of the Project was evaluated relative to the cost of an all-hours firm contract in the PJM energy market ("PJM-Market") and an on-shore wind farm in western PJM ("PJM-West Wind").[2] Specific project configurations were evaluated as follows:

1. The BWW Project (without back-up power supply) compared to the PJM-Market;
2. The BWW Project with NRG providing back-up power ("NRG Back-Up") compared to the PJM-Market;
3. The BWW Project with Conectiv providing back-up power ("Conectiv Back-Up") compared to the PJM-Market; and
4. The BWW Project compared to PJM-West Wind (both without back-up power supply).

Analysis of the Green Premium provides a better reflection, to the existing SOS customer, of the true cost of the BWW Project, rather than the "Price to Compare", due to the significant rate instability introduced by the BWW Project which would be borne by the SOS customer base over the contractual term.

Pace has generally expressed the Green Premium in terms of aggregate annual value as well as in dollars per megawatt-hour ("MWh"). Pace also evaluated the substantial BWW Project risk factors facing SOS customers both qualitatively and quantitatively based on the contract terms and market conditions. Pace's scope did not call for any recommendations on the suitability of the Green Premium or other risk factors.

Pace's analysis priced the Bluewater off-shore facility well above market comparable to similar findings for other, recently-proposed off-shore facilities, most notably by LIPA. Pace's analysis revealed a ***substantial*** Green Premium for each option before consideration of the Energy Rate escalation terms (see Exhibit 1) on both a nominal, levelized dollar per MWh basis, and on a cost per month per Delmarva SOS customer for all of the options considered.

- The BWW Project as a stand-alone operation requires a levelized cost, or Green Premium, of $60.95 per MWh ($79 million per year), leading to a $22/month increase in the average cost to each SOS customer.

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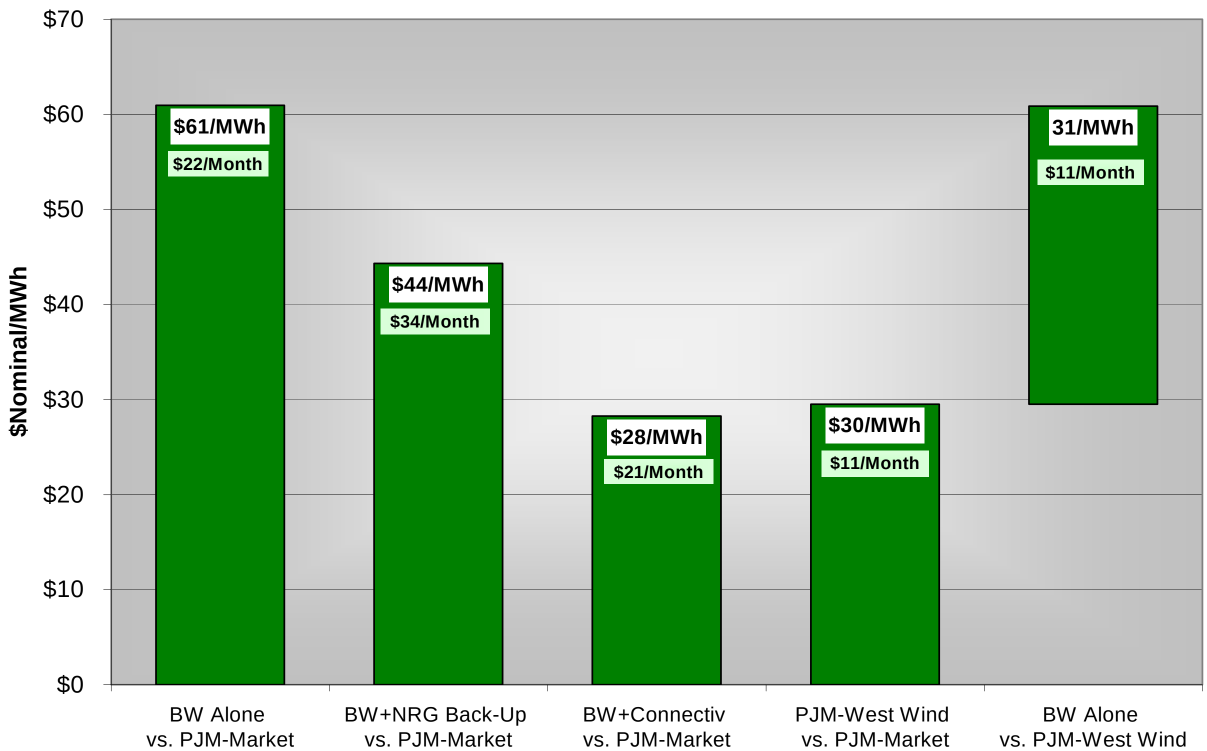
[1] PJM refers to the Pennsylvania, Jersey, Maryland power grid, operated by the PJM Independent System Operator ("PJM ISO").

[2] PJM market prices were derived from the expected price projections based on Pace's 2007Q3 Power Outlook service, with subsequent modeling to evaluate proposed gas-unit dispatch in the presence of the Project and the inclusion of the MAPP transmission power line through the Delmarva peninsula.

- When combined with the NRG Back-Up resource, the levelized Green Premium per MWh is lower, at $44.32 per MWh. However, the overall Green Premium cost to consumers is higher, at $122 million per year, or $34/month per customer.
- The BWW Project combined with the Conectiv Back-Up resource results in a Green Premium of $75 million, or $21/month per customer.
- By way of contrast, purchasing an equivalent amount of wind energy from PJM-West comes at an annual levelized cost of $38 million higher compared to the PJM-Market, or $11/month per customer, i.e., the BWW Project costs $11/month per customer more than an on-shore wind alternative.
- These Green Premiums will likely be much higher upon application of price escalation terms embedded in the contract.
- The Green Premium for the BWW Project without escalation is substantial relative to the value of carbon exposure avoided and no foreseeable estimates of carbon prices would fully offset this cost differential.

Exhibit 1: Levelized Green Premiums Without Escalation Per MWh and Per Customer*



*Comparisons for the BWW Project ("BW") or PJM-West Wind alone are based on anticipated wind-only purchases. Alternatives including back-up generation are based on 195 MW around-the-clock purchasing requirements. Values reflect nominal levelized costs beginning June 1, 2014 assuming 8.96% nominal discount rate (6.3% real rate and 2.5% inflation) and a 25-year payment schedule.
Source: Pace.

By way of comparison, the Green Premium estimated for the proposed Long Island Off-shore Wind Farm would have cost customers an average of approximately $5.75/month on a levelized basis. Although the Green Premium was substantially higher on a $/MWh basis due to the very high installed cost estimates for the wind farm, the LIOWP project was sized at only 144 MW and spread over an estimated 1.095 million customers. The Bluewater wind farm is three times larger, resulting in almost twice the level of investment required, being spread over less than one-third the customer base.

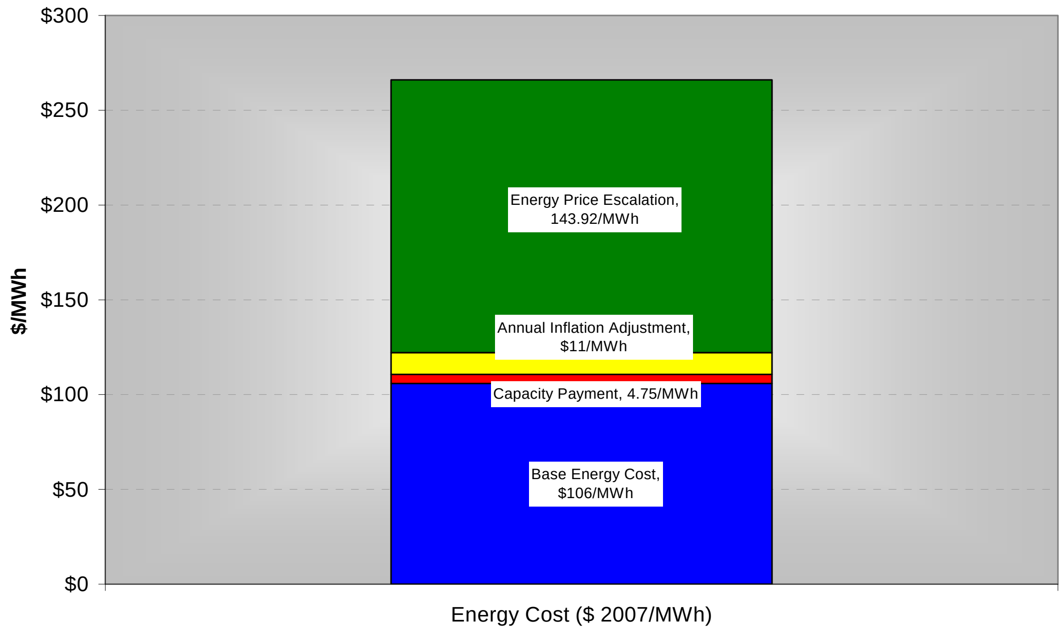
These figures do not reflect the additional, and in some cases asymmetric risks, being borne exclusively by the SOS customers. Introduction of these risks, enumerated below, materially alter the economics of the BWW Project. Specific noteworthy risks include: commercially asymmetric pricing escalators, potential for elimination of the production tax credit, and potential for project delays.

Pace analyzed the proposed transaction and takes note of the commercially unusual pricing escalator features found in the contract. These terms impose an asymmetric risk upon the SOS customers and shift all risk from the developer to the SOS customer. These terms enhance the likelihood of the SOS customer seeing a higher price. SOS customers aware of magnitude of the price hike would be expected to risk mitigate by migrating to another provider. However, elimination of the risk-shifting pricing escalators from the commercial language does not eliminate or reduce the price/risk profile to the SOS customer. Bluewater absorbs this commodity price risk. The SOS customer then takes this cost shifting in the form of Bluewater's increased credit risk profile.

Exhibit 2 demonstrates that even if the escalators were removed the SOS customer is bearing potentially $143.92/MWhr in credit risk. Contractually, the Bluewater risk profile cannot be changed by elimination of the pricing escalator language which would only shift the escalator price risk into other types of risks, which may not be capable of being hedged. By removing the pricing escalators the SOS customer, through Delmarva, would need to hedge Bluewater credit exposure through use of Credit Default protection. Retaining the price escalators in the contract exposes the SOS customer to commodity price risk which is poorly correlated to energy prices. In this situation the SOS customer has an incentive to over-hedge as Bluewater has an incentive to delay. Removing price escalators without strong credit protections imposes severe rate instability upon the SOS customer, as Bluewater is carrying risk far above its capacity, and potentially well in excess of its base energy cost.

Elimination of the production tax credit would expose Bluewater to material financial stress as no recovery mechanism is contained within the contractual terms. Production Tax Credit exposure could cause Bluewater to seek financial recovery through alternate means: contractual renegotiation, bankruptcy, etc. Loss of Production Tax Credits could also be mitigated by means of a surcharge, fee, or assessment. Ultimately, prices to the SOS customer increase by $11.00/month per customer if the tax credit were not renewed and Bluewater made whole financially.

Exhibit 2: Bluewater Energy Cost Estimate



Source: Pace

Engineering, Procurement, and Construction ("EPC") costs for off-shore wind projects have been rising steadily in recent years due to elevated metals prices and increased wind turbine demand versus supply. Vestas is the proposed supplier of the Bluewater off-shore wind turbines; however no turbine supplier is well-mobilized to provide offshore turbines to the North American market. Further, Vestas has recently ceased production of the wind turbine proposed by Bluewater as the turbines are experiencing material failures in their European off-shore installations. Recent European off-shore wind installations have experienced some operational difficulties that appear to be reasonable for an embryonic application. It should be noted that given all suppliers' tepid interest in selling off-shore wind turbines in the undeveloped North American market, there is some risk that the current estimates may increase to more unfavorable levels over time.

Pace Global evaluated the economics of the proposed Bluewater wind farm[3] without escalation against three benchmarks. We compared the present value costs of:

1. The BWW Project (without back-up power supply) compared to the PJM-Market;
2. The BWW Project with NRG providing back-up power ("NRG Back-Up") compared to the PJM-Market;
3. The BWW Project with Conectiv providing back-up power ("Conectiv Back-Up") compared to the PJM-Market; and
4. The BWW Project compared to PJM-West Wind on-shore

[3] Wind values were evaluated in the context of a broader generation portfolio of equal installed capacity value per rules of the PJM market.

For the BWW Project versus each benchmark, the analysis compared the aggregate costs in present value terms as well as a levelized cost per MWh over a 25-year horizon. The levelized cost per MWh reflects a representative price differential over 25 years after consideration of the fact that near-term dollars are more valuable than future dollars.

For each of those comparisons, Pace Global made independent assessments of fuel prices, capacity values, emissions and carbon cost burdens, and numerous other assumptions that are documented in the following report. ***No attempt was made to value externalities beyond those assumptions.*** For example, the potential health benefits of wind generation versus fossil-fuel generation are only represented inasmuch as our emissions and carbon values are explicitly incorporated in the assumptions.

BWW PROJECT BACKGROUND

The BWW Project is a proposed 450 MW wind farm off the coast of Rehoboth Beach, Delaware. In March 2006 the Delaware General Assembly introduced House Bill 6 which required Delmarva to develop an IRP plan and "investigate all possible opportunities for a more diverse supply at the lowest reasonable cost." On or before August 1st Delmarva was required to file a proposal for obtaining new long term contracts. On December 21st and 22nd, respectively, Conectiv and Bluewater submitted bids.

Delmarva also received qualified proposals for an Offshore Wind project from Bluewater. On February 21st both Delmarva and an Independent Consultant filed bid evaluation reports. The reports were consistent in ranking the bid responses in the following order: (1) Conectiv; (2) Bluewater; and (3) NRG. Both the Independent Consultant and Delmarva concluded that all bids were above market; however, Conectiv's bid was $1.28/MWhr above market while Bluewater's and NRG's bids were $12.01 and $15.17 above market, respectively.

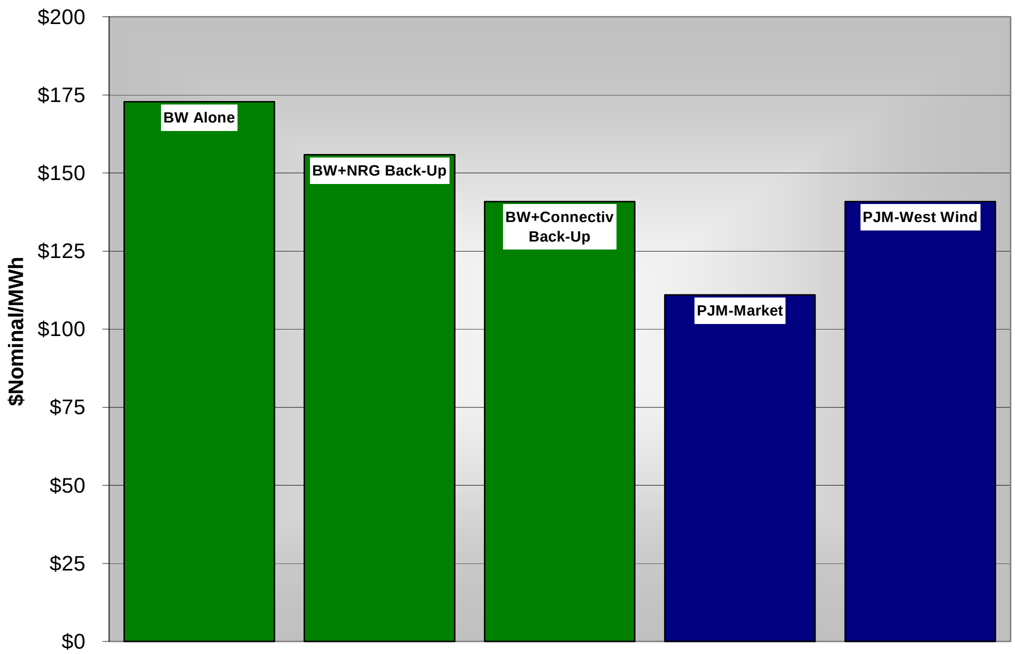
The May 2007 Delaware Public Service Commission ("PSC") order required that Delmarva negotiate with Bluewater, Conectiv, and NRG. Delmarva has concluded term-sheet negotiations with Bluewater, during which process the contract terms changed dramatically. Under Bluewater's new proposal they would develop the offshore wind project utilizing Vestas equipment, and then sell the output of that wind farm to Delmarva. The BWW Project calls for 150 3 MW units, constituting a total maximum generating capacity of 450 MW.

ANALYSIS OF BLUEWATER OFF-SHORE WIND PROJECT

GREEN PREMIUM ASSOCIATED WITH BLUEWATER PROPOSAL

The Green Premium associated with the BWW Project without escalation is significant. The levelized costs (Exhibit 3) and resulting Green Premiums (Exhibit 1) reveal that SOS customers will experience a substantial increase in the their bill for power received from the BWW Project, regardless of whether the backup resource is combined with the BWW Project or not, relative to the PJM-West Wind alternative. The BWW Project without escalation as a stand-alone operation requires a levelized cost, or Green Premium, of $60.95 per MWh ($79 million per year), leading to a $22/month increase in the average cost to each SOS customer.[4] Over the 25-year life of the project, the value of the Green Premium totals $1,857 million in nominal terms, with a net present value ("NPV") of $780 million as of June 1, 2014.

Exhibit 3: Levelized Costs by Option



*Values reflect levelized costs beginning June 1, 2014 assuming 8.96% nominal discount rate (6.3% real rate and 2.5% inflation) and a 25-year payment schedule.
Source: Pace.

When combined with the NRG Back-Up resource, the levelized Green Premium (without BWW Project escalation) per MWh is lower, at $44.32 per MWh. However, the overall Green

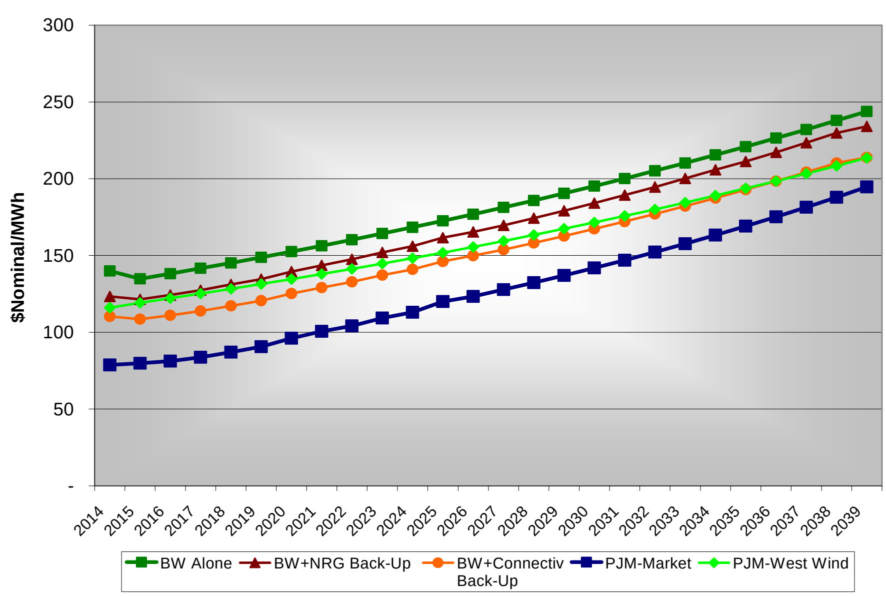
[4] Levelized rates and costs are similar to a home mortgage payment. The values are based on the 25-year payment term called for in the proposals and an 8.96% nominal discount rate based on the assumption of a real discount rate of 6.3% and an inflation rate of 2.5%. The value per customer is based on the assumption of 300,000 SOS customers.

Premium cost to consumers is higher, at $122 million per year, or $34/month per customer, due to the valuation of purchases at a cost above the unit price and the volumetric purchases required, exclusively from the NRG unit, when the BWW Project is unable to meet is energy delivery requirements due to lack of wind. Delmarva is obligated to procure energy from NRG under the contract terms. This raises the amount of energy purchased at above-unit costs, increasing the overall cost of power purchases for SOS customers. Over the 25-year life of the project, the value of the Green Premium totals $2,914 million in nominal terms, with a NPV of $1,204 million as of June 1, 2014.

The BWW Project without escalation combined with the Conectiv Back-Up resource results in a Green Premium of $75 million, or $21/month per customer, as the proposed back-up supply is valued just slightly above the PJM-Market. Over the 25-year life of the project, the value of the Green Premium totals $1,862 million in nominal terms, with a NPV of $801 million as of June 1, 2014.

By contrast, the selection of the PJM-West Wind alternative as a stand-alone option would result in a levelized $29.52/MWh Green Premium relative to the PJM-Market, or $31.35/MWh less than the BWW Project. The PJM-West Wind annual levelized cost is expected to be $38 million higher compared to the PJM-Market, or $11/month per customer. Over the 25-year life of the project, the value of the Green Premium totals $860 million in nominal terms, with a NPV of $378 million as of June 1, 2014. The PJM-West Wind alternative provides lower capital and operating costs and meets Delmarva's requirement under the Delaware Renewable Portfolio Standard requirements. Exhibit 4 depicts the PJM market forecast, as well as nominal price forecast prices for each of the alternatives. The results are presented in nominal dollars to account for the mix of escalation for inflation as applied to specific pricing components in each of the alternatives. A complete summary of the Green Premiums is provided in Exhibit 5.

Exhibit 4: PJM-Market and Alternative BWW Project Power Price Forecasts, 2014-2039



Source: Pace

Exhibit 5: Summary of Green Premiums by Alternative (Without BWW Project Escalation)

Bluewater Wind Alone vs. Market Value		
Total Green Premium	$MM	**1,857**
Net Present Value of Green Premium	$MM	**780**
Levelized Annual Green Premium	$MM	**79**
Levelized Annual Green Premium Per MWh	*$/MWh*	***60.95***
Impact on Monthly Household Bill	*$/Month/Cust.*	***22***
Average Annual Generation Base	GWh	1,237
Bluewater Wind + NRG Back-Up vs. Market Value		
Total Green Premium	$MM	**2,914**
Net Present Value of Green Premium	$MM	**1,204**
Levelized Annual Green Premium	$MM	**122**
Levelized Annual Green Premium Per MWh	*$/MWh*	***44.32***
Impact on Monthly Household Bill	*$/Month/Cust.*	***34***
Average Annual Generation Base	GWh	2,628
Bluewater Wind + Connectiv Back-Up vs. Market Value		
Total Green Premium	$MM	**1,862**
Net Present Value of Green Premium	$MM	**801**
Levelized Annual Green Premium	$MM	**75**
Levelized Annual Green Premium Per MWh	*$/MWh*	***28.27***
Impact on Monthly Household Bill	*$/Month/Cust.*	***21***
Average Annual Generation Base	GWh	2,628
Bluewater Wind vs. PJM-West Wind		
Total Green Premium	$MM	**993**
Net Present Value of Green Premium	$MM	**401**
Levelized Annual Green Premium	$MM	**41**
Levelized Annual Green Premium Per MWh	*$/MWh*	***31.35***
Impact on Monthly Household Bill	*$/Month/Cust.*	***11***
Average Annual Generation Base	GWh	1,237
PJM-West Wind vs. Market Value		
Total Green Premium	$MM	**861**
Net Present Value of Green Premium	$MM	**378**
Levelized Annual Green Premium	$MM	**38**
Levelized Annual Green Premium Per MWh	*$/MWh*	***29.52***
Impact on Monthly Household Bill	*$/Month/Cust.*	***11***
Average Annual Generation Base	GWh	1,289

*Assumes Guaranteed Initial Delivery Date ("GIDD") of June 1, 2014 and a 25-year project life.
Net Present Value ("NPV") and levelized values are nominal values as of the date of GIDD assuming an 8.96% nominal discount rate (6.3% real rate and 2.5% inflation) and a 25-year payment schedule. Household bill calculation assumes 300,000 SOS customer base.
Source: Pace.

SUMMARY OF RISK FACTORS

Acceptance of the project exposes the SOS customers to high levels of rate instability over the 25-year term of the power purchase agreement. The SOS customer is exposed to rate instability due to the BWW Project's tenor, terms, and structure, including:

- Contractual Energy Price Escalation
- Elimination of Federal Production Tax Credit ("PTC")
- Wholesale Energy and Gas Market Price Volatility
- Pattern of Hourly Wind Generation vs. Market Pricing
- PJM Locational Marginal Pricing ("LMP")
- PJM Scheduling Penalties
- REC Market Exposure
- Stranded Cost Potential
- Project Termination or Downsizing

Contractual Energy Price Escalation

Attachment 4 to the Bluewater Wind contract term sheet allows for escalation of the initial Energy Rate based on an aggregate of the overall percentage changes in key commodity price indices between the Execution Date and date of Financial Closing. This represents a period of approximately 50 months, assuming that a Power Purchase Agreement ("PPA") is executed by January 1, 2008 and that Financial Closing occurs by February 29, 2012 per the Critical Project Milestone Schedule in Attachment 2. Price escalation is asymmetric in that the contract does not allow for a price decrease in the event the percentage change in the aggregate Energy Price Adjustment term is negative.

Unlike capital cost true-up and performance-based measures, the proposed structure exposes SOS customers to an unlimited potential increase in the Energy Rate with no corresponding potential for a lower Energy Rate. This could lead to over-hedging by Bluewater to capture the upside embedded in this real option value. Thus the proposed contract terms shift risk asymmetrically to the SOS ratepayers. However, were Bluewater to absorb all price escalation price risk, Delmarva would be exposed to increased credit risk exposure coming from the contractual terms of the Bluewater contract as credit risk mitigation is not addressed in the publicly-available terms reviewed by Pace.

The aggregate Energy Price Adjustment term is based on a Turbine Supply Adjustment ("TSA") and a Balance of Plant ("BOP") Adjustment which attempt to account for increases in the cost of manufacturing and installation of the wind turbines and steel poles, respectively. Recent history demonstrates that the commodity indices, upon which the adjustment factors are based, have become increasingly volatile. Consequently, the potential for a significant increase in the Energy Rate clearly exists. Looking back at the past 50 months of historical commodity prices (see Exhibit 6), comparable to the timeframe contemplated by Bluewater Wind, reveals a material rise in the prices of the commodities included in the adjustment terms. A summary of the indices and weights used to derive the Energy Price Adjustment factor is provided in Exhibit 7.

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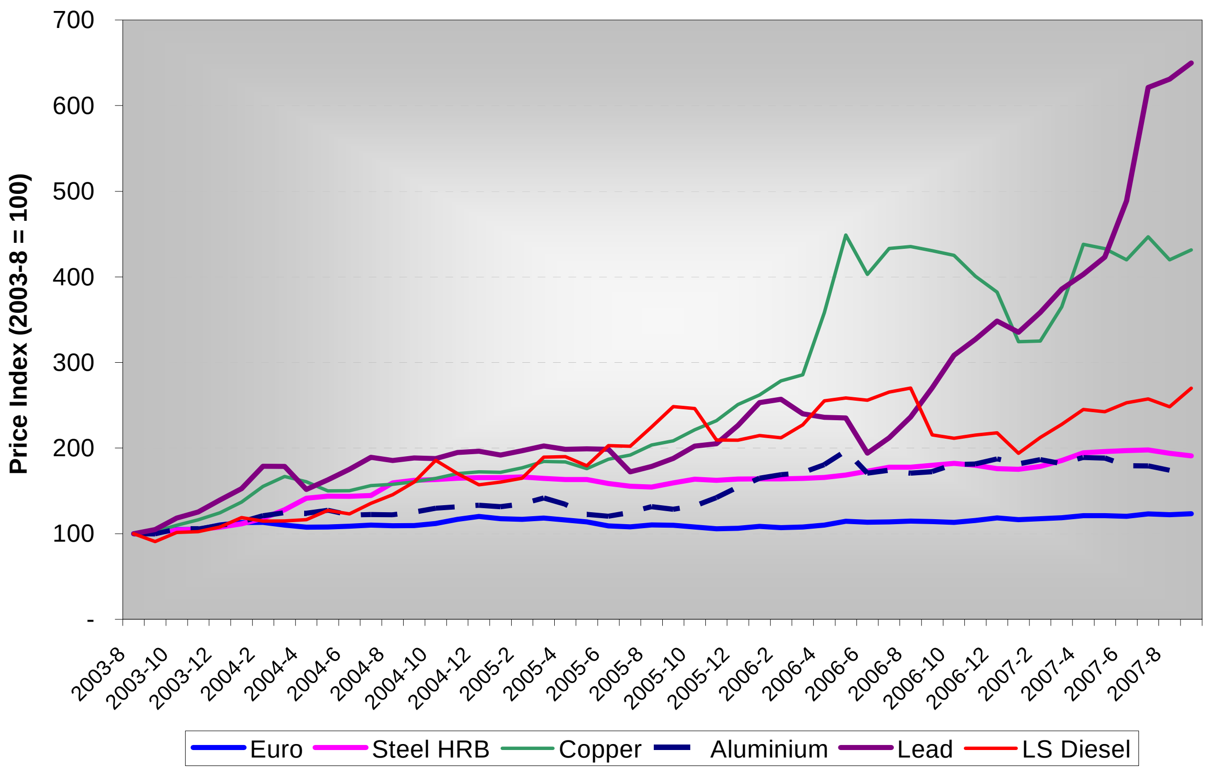
Two examples demonstrate how the Energy Price Adjustment will negatively impact SOS customers. Example 1 demonstrates what the impact would be assuming the percentage change in commodity indices over the past 50 months, as shown in Exhibit 8. The effect would be a 136% increase over the base rate of $105.90/MWh to $249.82/MWh, which is then inflated at the contract inflation rate of 2.5% annually from 2007 forward over the term of the contract. The impact on the Green Premium is $273.37/MWh which amounts to an increase in annual costs of $276 million per year, or an extra $77/month per customer. In aggregate, this implies a $99/month per customer cost increase.

Example 2 assumes that all of the indices increase at an annual inflation rate of 2.5%. The resulting rate increase is 11% which increases the initial Energy Rate to $117.38/MWh which is inflated by 2.5% through the term of the contract from 2007, as seen in Exhibit 9. The impact on the Green Premium is $77.97/MWh which amounts to an increase in annual costs of $22 million per year, or $6/month per customer more than at the original pricing. These examples illustrate the potential for significant, and potentially exponential, increases in the Energy Rate quoted by Bluewater, even under relatively modest percentage changes in the proposed indices.

Exhibit 6: Indexed Prices for Commodities Over Previous 50 Months (2003-8 = 100)



Source: Pace; Bloomberg; U.S. Bureau of Labor.

Exhibit 7: Energy Price Adjustment Parameters

Index	Source	BOP Weighting[2]		TSA Weighting[2]		Energy Price Adjustment
		Sub-Adj.	BOP Adj.	Sub-Adj.	TSA Adj.	
		BOP Wgt.:	**0.47**	*TSA Wgt.:*	**0.38**	
Steel	CRU Group Steel Plate	0.24	0.11	0.56	0.21	**0.33**
Copper	COMEX Copper Avg. Mth. Spot Price	0.32	0.15	0.08	0.03	**0.18**
Aluminum	COMEX Aluminium Avg. Mth. Spot Price	0.08	0.04	0.16	0.06	**0.10**
Lead	London Metal Exchange Lead[1]	0.08	0.04	NA	NA	**0.04**
Fuel	Diesel Fuel (No. 5, NY Harbor Low Sulfur)	0.08	0.04	NA	NA	**0.04**
Exchange Rate	Euro Per Dollar	NA	NA	0.80	0.30	**0.30**
Totals		**0.80**	**0.38**	**1.60**	**0.61**	**0.98**

[1]The change in the price of lead is multiplied by one plus the change in the exchange rate which is not represented here.

[2]Weights as specified in Attachment 4 as revised October 15, 2007.

Source: Pace.

Exhibit 8: Energy Rate Increase Assuming Previous 50-Month Price Evolution

	Estimates	Steel	Copper	Aluminum	Lead	Fuel	Euro
New Energy Price $2007/MWh[1]	249.82						
Base Energy Price $2007/MWh	105.90						
Energy Price Adjustment[2]	135.90%						
BOP Adjustment[3]	94.82%						
BOP Adjustment Weight	47%						
BOP Sub-Adjustment[4]	201.74%						
Actual Percent Change[5]		91.0%	331.4%	74.0%	550.0%	169.8%	23.5%
Weighting in BOP Adj.		0.24	0.32	0.08	0.08	0.08	NA
Weighted Percent Change		21.8%	106.1%	5.9%	44.0%	13.6%	NA
Turbine Supply Adjustment[6]	41.08%						
Turbine Supply Adjustment Weight	38%						
Turbine Supply Sub-Adjustment[7]	108.11%						
Actual Percent Change[5]		91.0%	331.4%	74.0%	550.0%	169.8%	23.5%
Weighting in BOP Adj.		0.56	0.08	0.16	NA	NA	0.80
Weighted Percent Change		51.0%	26.5%	11.8%	NA	NA	18.8%

[1]New Energy Price $2007/MWh = Base Energy Price $2007/MWh x (1 + Energy Price Adjustment)

[2]Energy Price Adjustment = BOP Adjustment + Turbine Supply Adjustment (If the Sum is >= 0)

[3]BOP Adjustment = BOP Adjustment Weight x BOP Sub-Adjustment

[4]BOP Sub-adjustment = % Growth in Steel x Weighting in BOP + % Growth in Copper x Weighting in BOP + % Growth in Aluminum x Weighting in BOP + % Growth in Lead x Weighting in BOP x % Growth in the Euro to Dollar Exchange Rate x Weighting in BOP + % Growth in Fuel x Weighting in BOP

[5]% Growth as Measured for the Period from 8/2003 to 9/2007 to Simulate a Similar Period of Time as Envisioned for the financial close date for the Project.

[6]Turbine Supply Adjustment = Turbine Supply Adjustment Adjustment Weight x Turbine Supply Adjustment Sub-Adjustment

[7]Turbine Supply Sub-adjustment = % Growth in Steel x Weighting in Turbine Supply + % Growth in Copper x Weighting in Turbine Supply + % Growth in Aluminum x Weighting in Turbine Supply + % Growth in the Euro to Dollar Exchange Rate x Weighting in Turbine Supply

Source: Pace.

Exhibit 9: Energy Rate Increase Assuming a 2.5% Annual Inflation Rate

	Estimates	PPI Steel	Copper	Aluminum	Lead	Fuel	Euro
New Energy Price $2007/MWh[1]	117.38						
Base Energy Price $2007/MWh	105.90						
Energy Price Adjustment[2]	10.84%						
BOP Adjustment[3]	4.17%						
BOP Adjustment Weight	47%						
BOP Sub-Adjustment[4]	8.87%						
Actual Percent Change[5]		11.0%	11.0%	11.0%	11.0%	11.0%	11.0%
Weighting in BOP Adj.		0.24	0.32	0.08	0.08	0.08	NA
Weighted Percent Change		2.6%	3.5%	0.9%	0.9%	0.9%	NA
Turbine Supply Adjustment[6]	6.67%						
Turbine Supply Adjustment Weight	38%						
Turbine Supply Sub-Adjustment[7]	17.55%						
Actual Percent Change[5]		11.0%	11.0%	11.0%	11.0%	11.0%	11.0%
Weighting in BOP Adj.		0.56	0.08	0.16	NA	NA	0.80
Weighted Percent Change		6.1%	0.9%	1.8%	NA	NA	8.8%

[1]New Energy Price $2007/MWh = Base Energy Price $2007/MWh x (1 + Energy Price Adjustment)

[2]Energy Price Adjustment = BOP Adjustment + Turbine Supply Adjustment (If the Sum is >= 0)

[3]BOP Adjustment = BOP Adjustment Weight x BOP Sub-Adjustment

[4]BOP Sub-adjustment = % Growth in Steel x Weighting in BOP + % Growth in Copper x Weighting in BOP + % Growth in Aluminum x Weighting in BOP + % Growth in Lead x Weighting in BOP x % Growth in the Euro to Dollar Exchange Rate x Weighting in BOP + % Growth in Fuel x Weighting in BOP

[5]% Growth as Measured for the Period from 8/2003 to 9/2007 to Simulate a Similar Period of Time as Envisioned for the financial close date for the Project.

[6]Turbine Supply Adjustment = Turbine Supply Adjustment Adjustment Weight x Turbine Supply Adjustment Sub-Adjustment

[7]Turbine Supply Sub-adjustment = % Growth in Steel x Weighting in Turbine Supply + % Growth in Copper x Weighting in Turbine Supply + % Growth in Aluminum x Weighting in Turbine Supply + % Growth in the Euro to Dollar Exchange Rate x Weighting in Turbine Supply

Source: Pace.

Pace understands that Bluewater has filed to seek removal of these pricing escalators. Exhibit 6 through Exhibit 9 demonstrate the commodity price uncertainty existing in the wind turbine manufacturing and installation environment. Removal of the pricing escalators cannot remove the underlying price uncertainty. Removal of the pricing escalators only shifts the risks of rising commodity costs onto Bluewater. The potential exists, as seen in Exhibit 2, for this increase in commodity costs to far exceed Bluewater's base energy cost. Were commodity price increases to continue, Bluewater's financial condition would be materially adversely changed. This material adverse change in Bluewater's financial condition increases the SOS customer's credit exposure to Bluewater in direct proportion to the rising commodity costs.

This relationship can be shown in Bluewater's initial price escalation terms which provided for: a price escalator adjustment of up to 98% of the Bluewater energy price representing 92% of the totality of payments made from Delmarva to Bluewater. Consequently, if Bluewater is not recovering 98% of its commodity price exposure through the price escalator then it is carrying this risk or potentially hedging the risk. Regardless, Bluewater's financial condition will have materially adversely changed. Thus, insertion or removal of the price escalation contract language is ineffective in reducing the underlying commodity-based price exposure.

Elimination of Federal Production Tax Credit ("PTC")

The current BWW Project pricing includes the value of the present federal PTC escalated for inflation. The PTC is a provision that allows developers of wind resources to receive a tax credit of $19/MWh escalating with inflation for the first 10 years of a wind project. The PTC is currently authorized to cover projects coming on line before the end of 2008 and must be re-authorized by Congress through the end of 2014 in order to be available to the BWW Project. The requirement for re-authorization introduces substantial regulatory risk. Further, several factors may diminish the perceived acceptability of this subsidy in the future, including:

- Stricter carbon regulations that increase the demand and market pricing for energy from renewable resources;
- Technological improvements to improve the performance and capacity factors of wind turbines;
- Increasing wind turbine size and other efficiencies leading to lower capital costs per unit of capacity
- Lower wind turbine production and installation costs; or the
- Perception that the market is sufficiently developed to sustain itself in the absence of the PTC.

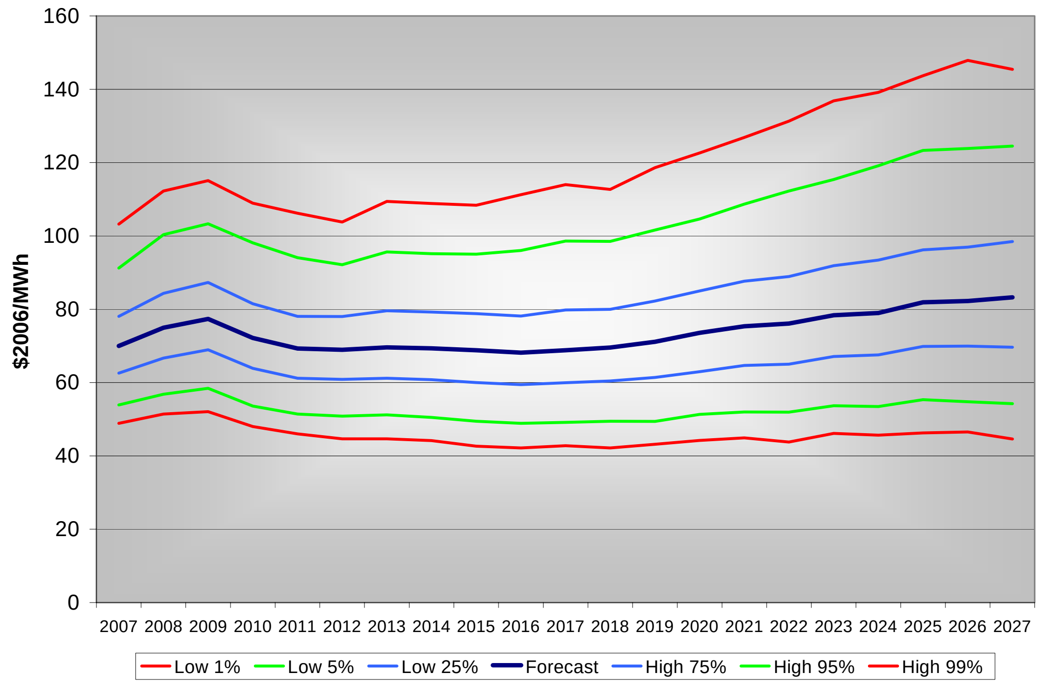
The present contract does not allow Bluewater to capture any true-up for elimination of the production tax credit. However, Bluewater may walk away from the contract were elimination to occur. SOS customers face risks from Bluewater should the PTC fail to be re-authorized and Bluewater be made whole, contractually or via regulatory means. Pace estimates that the levelized Green Premium would increase by $29.88 per MWh, or $39 million per year ($11/month per customer) if this situation were to occur. The impact of the PTC is substantial as it allows for additional up-front cost recovery after-taxes.

The value for Renewable Energy Credits ("RECs") would likely increase in the absence of the PTC as other wind producers would face a similar impact on their costs. RECs price increases, though imperfectly correlated with PTC values, should be expected to increase with the elimination of the PTC. Thus, PTC elimination would expose SOS customers to covering *both* Bluewater's recovery of the PTC on the BWW Project *and* the increase in the cost of purchasing RECs in the market for compliance with the Renewable Portfolio Standard ("RPS"), given the proposed contract terms.

Wholesale Energy and Gas Market Price Volatility

The BWW Project with back-up energy provision is essentially a contract for 300 MW of "around-the-clock" energy and capacity. 53% of the power is expected to come from either the back-up, gas-fired resource or the PJM market depending upon which backup option is utilized. In the event of BWW Project delays or termination, the back-up resource would be under contract to provide all 195 MW of energy in every hour for a term of years up to and including 25 years. The back-up power contracts therefore represent a market-based contract with a price cap supported by the physical asset behind the contract, thus limiting Delmarva's exposure to extreme market conditions in PJM with respect to day-ahead scheduling. Exhibit 10 demonstrates the degree of price stability in spot power prices within any given year away from the forecast for the PJM Delmarva region.

Exhibit 10: Anticipated Spot Power Price Variability from Expected Prices in PJM Delmarva



*The price bands around the forecast represent the estimated distribution of prices around the forecast, e.g., there is a 1% probability that the price will exceed $145/MWh in 2037.

Source: Pace.

The NRG facility is contractually bound to meet any shortfalls, or surpluses, in day-ahead commitments through sales at the real-time nodal price at the generation source. Any curtailments of the BWW Project to alleviate LMP congestion would also be covered in this manner. This contractual terminology implies that load following is accomplished by market-based purchases which are not limited by the real asset price. The Conectiv offering, on the other hand, envisions coverage of shortfalls at the lesser of the unit's Run Cost or the Day-Ahead LMP, or nodal price, and surpluses at the Day-Ahead LMP. The Conectiv offer continues to offer cost protection from the asset for shortfalls, while allowing upside on surpluses in each hour. In both cases, deviations in wind generation from the day-ahead schedules increase the exposure of the project to volatility in gas and power market prices.

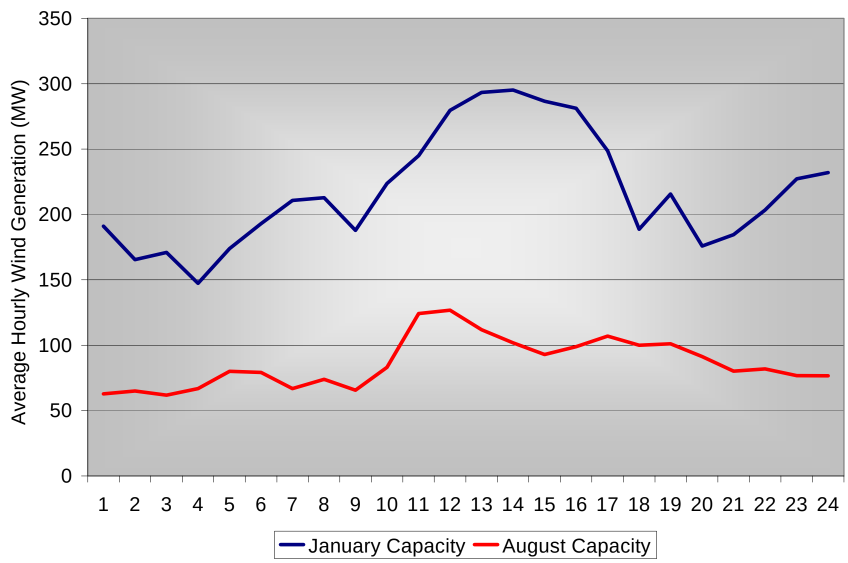
The contract provisions allow for pass-through of all carbon compliance costs associated with both back-up options, whether the value of carbon is reflected in the price of power purchased or produced by the physical asset. The power market projections are based on Pace's base case carbon scenario price projections. Should carbon policy be stricter than Pace Global's expectations, the cost of the back-up power will also increase.

Pattern of Hourly Wind Generation vs. Market Prices

Hourly power market prices in Delmarva are poorly correlated with the expected availability of energy derived from the BWW Project. Further, winter and summer seasonal average hourly generation (see Exhibit 11) vary materially, with the lowest availability in the summer when peak power prices reach their highest levels in PJM. The BWW Project's expected winter availability is higher and is projected to follow load more closely than expected summer generation.

Pace measured the degree to which the weighted-average annual market-based hourly energy prices and wind unit generation tracked the average annual regional price. The result showed that BWW Project revenues without escalation, on a stand-alone basis, would be 3% lower if based on the actual hourly pattern of results. Pace estimates that the resulting levelized Green Premium would increase by $2.94 per MWh, or $4 million per year ($1/month per customer) over the base result.

Exhibit 11: Average Hourly Wind Generation Patterns for January and August 2006



Source: Pace; NOAA.

PJM Locational Marginal Pricing ("LMP")

Locational marginal pricing ("LMP"), as defined by PJM, is "the cost to serve the next MW of load at a specific location, using the lowest production cost of all available generation, while observing all transmission limits." The LMP is composed of the system energy price, the transmission congestion cost, and the cost of marginal losses. The recognition of transmission congestion costs differentiates LMP pricing from zonal prices. These congestion costs reflect the cost of transmission constraints. For instance, a positive congestion cost means that the node at the load center is congested, while the node at the generation point is relatively unobstructed. In such a scenario, the load pays the congestion cost and the generator receives it. A negative congestion cost, on the other hand, means that the node at the generation point is congested. In this scenario, the generator pays the congestion cost. Thus, the marginal costs of dispatch become localized in an LMP system.

Pace has performed an LMP analysis to study the effects on local prices of adding the wind project at the Bethany node in Delaware. Given current system conditions and assuming that the necessary transmission upgrades required for this project, Pace concludes that the influx of additional power at the Bethany node results in a slight increase in congestion at the Bethany substation, but, overall, no significant wind unit curtailment or negative LMP issues are anticipated. Pace's analysis suggests that, on an annual average basis, the LMP at the Bethany node will be slightly less than the zonal energy price for all of Delmarva. This average difference is forecast to be approximately $1.50/MWh. Since Delmarva will sell energy to PJM at this node and buy energy to serve its load at nodes across all of the Delmarva Peninsula, these results suggest that Delmarva could face a financial loss under such circumstances.

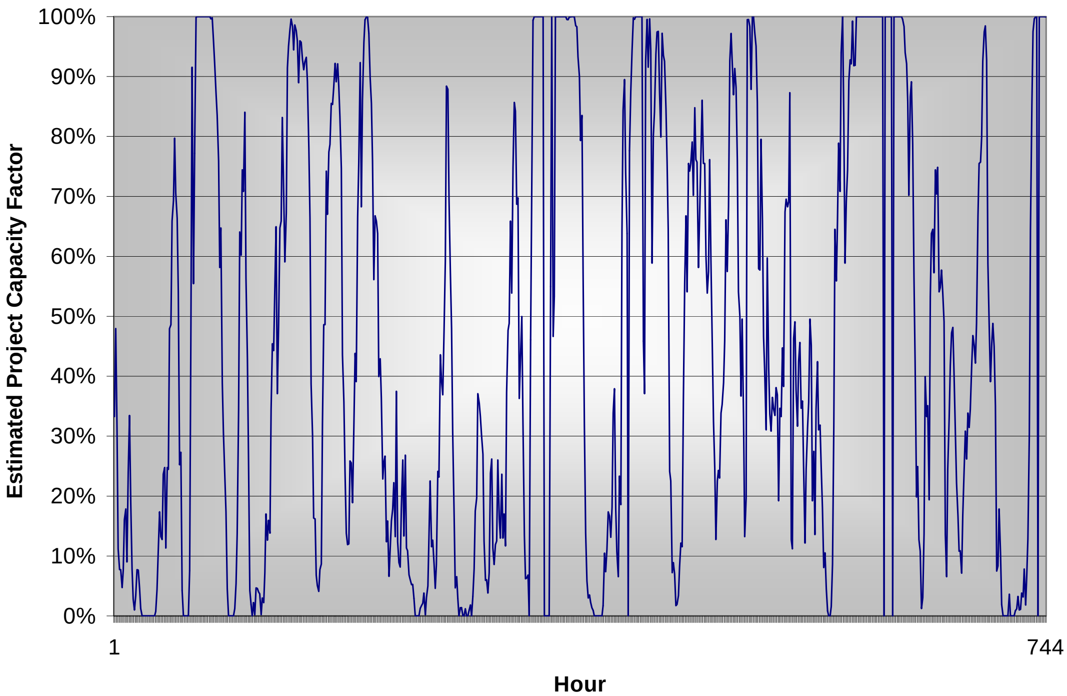
These conclusions ignore any revenues that Delmarva could receive from Financial Transmission Rights ("FTR") or Auction Revenue Rights ("ARR"). FTRs entitle the holder to a portion of the congestion revenue that PJM collects between two nodes in one direction. ARRs are distributed to load serving entities and entitle the holder to receive revenue from the auction of FTRs. Through these products, Delmarva could have the ability to offset some of the congestion charges foreseen at the Bethany node and reduce its potential losses.

PJM Scheduling Penalties

A wind generator may participate in the PJM Reliability Pricing Model ("RPM") if granted capacity deliverability rights by PJM. Wind generators in the RPM are expected to bid energy into the day-ahead market based on best-efforts hourly forecasts for the following day. As an intermittent resource provider, wind generators are not penalized for bidding under capacity value when wind speeds are expected to be low.

The submission of hourly bids is risky for a wind generator, as wind speeds are highly variable hour to hour as demonstrated for January 2006 in Exhibit 12. Should generation deviate from the day-ahead schedule, the wind generator pays the real-time rate for the energy imbalance. In addition, the wind generator must pay operating reserve deviation charges when the unit deviates more than 5 MW or 5% from the day-ahead schedule. Since wind generators produce power intermittently, all energy produced above as well as below the day-ahead tolerance band is assessed operating reserve charges. Operating reserves charges can be quite significant, averaging approximately 3% of the cost of real-time power for the amount over or under the margin of error.

Exhibit 12: Estimated Hourly BWW Project Capacity Factor for January 2006



Source: Pace; Based on wind speed data from NOAA.

REC Market Exposure

Each MWh produced by the BWW Project creates one Renewable Energy Credit ("REC") that can be applied against the Delaware Renewable Portfolio Standard ("RPS"). The RPS established the percentage of energy that must come from renewable energy resources, including wind, in each year to be phased in over a 13-year period starting in 2007 and stabilizing at a long-term requirement of 17.995% by 2019. The standard may be met through the surrender of RECs that may originate from any eligible renewable resource within, or delivered into, the PJM market. Pace included the cost of providing RECs associated with SOS customer load in the cost of each of the options net of any REC purchases specified contractually based on a forecast of REC pricing used in a recent analysis by the Regional Greenhouse Gas Initiative ("RGGI").

The proposed term sheet calls for Delmarva to purchase 175,000 RECs from the BWW Project in each year of the contract term starting in 2015 at $19.75/MWh increasing with inflation from 2007.[5] The acquisition of 175,000 RECs from Blue Water will leave Delmarva with significant RECs exposure. Based on retail sales projections based on the load forecast for Delmarva's Residential and Small General Service/Industrial ("RSCI"), Pace estimates that this exposure will increase from 276,682 to 971,978 RECs between 2014 and 2039.

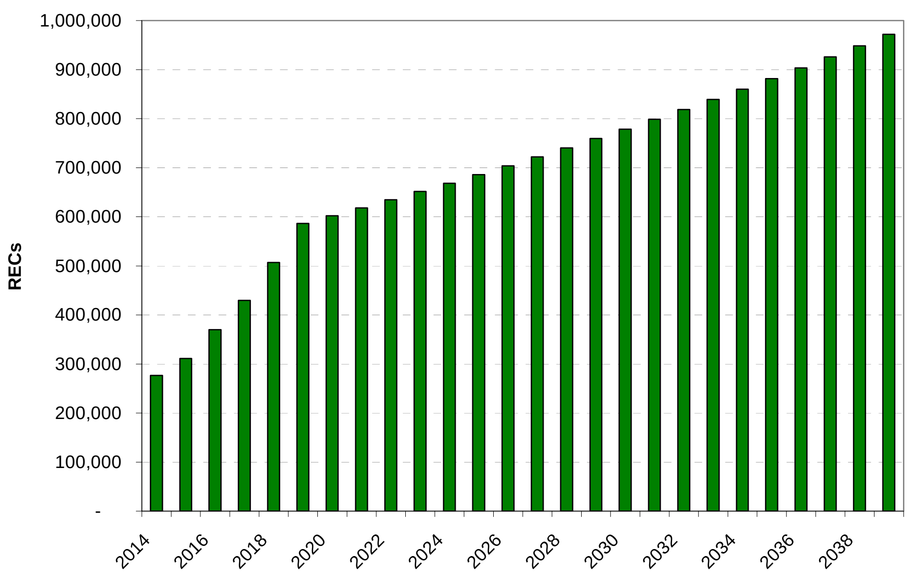
[5] Additional REC purchases of 105,000 in 2012, 135,000 in 2013, and 150,000 in 2014 are also required by the proposed contract terms.

Exhibit 13 depicts Delmarva's remaining RECs exposure for the Study Period that must be purchased in the market for PJM RECs. Bluewater, conversely, will have an expected surplus of 1.23 million RECs from 2015 through 2039 which they may elect to sell to meet remaining in-state demand, where, based on EIA retail sales forecast data, RECs demand will grow from 1.23 million in 2014 to 2.24 million in 2039. The BWW Project's excess RECs may also be sold into the PJM or national markets.

REC markets are in the formative stages of development. Differences in RPS standards and phase-in schedules exist among the states. Further, the anticipated scarcity of RECs and the impact of REC markets on carbon markets is poorly understood. Presently, each state creates REC targets and applies its own REC definition to groups, or tiers, of renewable resources based on classifications of size, vintage, location and deliverability to the state, and other characteristics.

Many resources, such as wind, can be used to satisfy the RPS requirements across PJM, and other regions, that increase the competition for their RECs. SOS customers are being called upon to develop a very high-cost renewable resource while failing to receive the environmental products associated with the BWW Project which the customers paid for. The existing contract terms are unusual for commercial transactions and given the uncertainty in the evolving REC marketplace, these terms increase rate variability significantly. Specifically, SOS customers could enter into a 195-MW ATC contract backed by a gas-fired asset in Delaware while purchasing RECs through a competitive RFP to comply with the standard. This creates an arms-length transaction to potentially minimize renewable project development risk and allows Delmarva, and the SOS customers, to meet their REC needs within the framework of a well-understood, stabilized rate.

Exhibit 13: Delmarva SOS Customer RECs Requirements



*Net of BWW Project REC scheduled amounts and solar requirements; average load per customer per the Integrated Resource Plan used to project requirements.

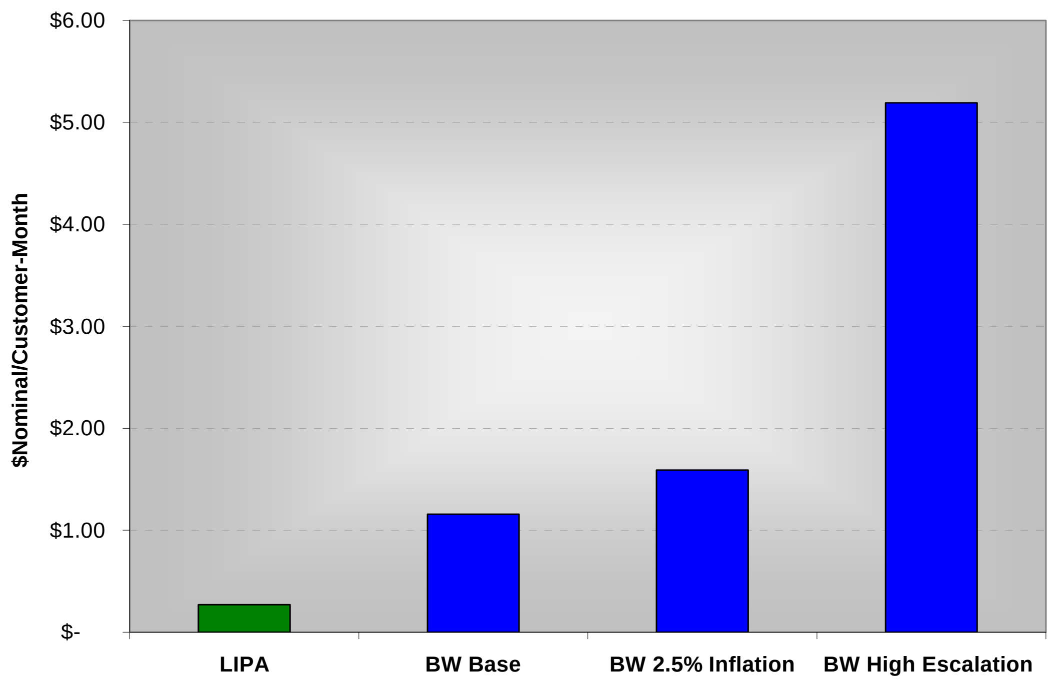
Source: Pace

Stranded Cost Potential

Delmarva SOS customers have the option to select a competitive provider of energy. Any significant increase in the cost of power may lead to a net customer out-migration. Acceptance of the BWW Project forces upon the SOS customer a material price increase. Further, the impact of the price escalators could force an exponential price increase upon the existing SOS customer base. The information examined by Pace revealed no stranded cost mitigation mechanism for Delmarva to recover under. Thus, any decrease in the number of remaining SOS customers will result in the need for financial remediation to cover the increasing cost per customer from the BWW Project. The remediation needs to cover both the direct financial burden, as well as the consequences of managing a smaller portfolio of customers. Options include stranded cost riders on SOS or all transmission and distribution customers or exit fees charged to SOS customers opting out of the program. A third option would require financial asset impairment or write-offs which will impact Delmarva's credit and ability to conduct business at lowest cost.

Net customer migration is compared to an analysis undertaken of the LIPA project and customer base. Exhibit 14 shows the impact of 5% net customer migration of Delmarva SOS customers relative to the impact of 5% net customer migration of LIPA customers. Additionally, Pace demonstrates the impact of price escalation on 5% net customer migration, both in the case of full materials pricing escalation through financial close with 2.5% annual inflation over the 25 year term of the contract and in the case assuming only the 2.5% annual inflation over the 25 year term.

Exhibit 14: Impact of 5% Customer Migration on Remaining Customer Base



Source: Pace.

Pace analyzed the impact of imputed debt. The cost of imputed debt is less than $1.00/MWhr based upon a 25% risk factor. Inability to recover imputed debt by Delmarva should be expected to impact Delmarva's credit rating and access to liquidity. Liquidity concerns are as important as the contract terms, as they give Bluewater an economic incentive to delay the project. If the project is delayed Delmarva will be purchasing spot gas based power from either of the back-up facilities thus injecting significant rate instability onto the SOS customer base.

Pace sees the price escalation as commercially unique and contributing to potential stranded cost issues. The uncapped price adjustment mechanism may create sharp price increases over the entire term of the PPA with particular exposure to price spikes in the underlying commodities prior to financial close. Pace also views the contract terms as asymmetric to the SOS rate payer. Understanding that the contract terms provide an incentive for Bluewater to delay the project, and understanding that delays increase the exposure to commodity cost and increase rate instability through required purchases of spot gas based power, SOS customers will see increasing rates and rate instability. Thus project delays and commodity costs may influence existing SOS ratepayers to exist by choosing another provider.

BWW Project Termination or Downsizing

This section describes how downsizing or terminating the BWW Project leaves Delmarva with a 195 MW round the clock, spot gas priced unit backed market contract supply Delmarva's SOS customers. BWW Project termination or delay reasons include Vestas turbine availability delays, cancellation of turbine production, inability to acquire alternative turbines, non-renewal of the production tax credit, delays in Minerals Management Service permitting, and operational risk associated with installation and operation of the first wind turbine off the coast of the United States.

According to Forbes, Vestas Wind Systems is in the process of re-modeling the offshore turbine V90 3MW in response to damages to gear boxes at offshore European locations. As a result of these operational problems, Vestas recently ceased sales of the V90 3 MW turbine as the company attempts to resolve the issue. Although the cause of the malfunction is currently unknown, it is speculated that the problem stems from the increasing size of wind turbines placing a greater strain on gear boxes.

Vestas has not stated that production of the turbines chosen by Bluewater is being cancelled.

Were Vestas to continue with the sales halt, Bluewater would be required to choose an alternative turbine provider. Present turbine production facilities are experiencing a significant backlog which should be expected to delay the financial close. Further, were another turbine manufacturer to be chosen the price escalators chosen by Bluewater may be uncorrelated with the actual developers costs, potentially over-leveraging either Bluewater or the SOS customers.

The production tax credit is due for renewal during the contract term. If the production tax credit is not renewed project financial viability may be materially impacted. Pace reviewed no contract terms mitigating this risk to potential project termination or downsizing.

Delays in MMS permitting, based upon rules which are currently under development, will delay the BWW Project and hence increase the SOS customers exposure to commodity prices and/or spot gas based power purchases. Thus, delays introduce rate instability to the SOS customer.

Operational off-shore wind turbines have not been built, installed, or operated anywhere in North America. Operational risks and delays are reasonable to expect with an existing technology employed in a new geographic area. Delays or turbine unavailability, to the extent it occurs, expose the SOS customers to commodity price risk and spot gas based power purchase risk.

Rates: Wholesale vs. Retail

Retail customers of Delmarva see a retail bill which tends to show somewhere on the average of 11.1 cents per kilo watt hour. That is their retail rate. The retail rate contains the wholesale rate plus additional factors:

- The retail rate includes some supplier premiums. Specifically, it allows for a full service requirement or load following. Load following is not generation dumped into the wholesale market thus, it comes at a higher cost and must be included into the retail rate.

- The retail rate also includes volumetric risks associated with retail choice. Customers have the choice to go to other providers for their supply. This is volumetric risk which is assumed by the supplier.

- Retail rates include ancillary services:, voltage regulation; black start; and all other items which fall under the definition of ancillary services. The cost of ancillary services is not included in the wholesale rate but is included in the retail rate.

- The return on retail margin is another factor which is not included in the wholesale numbers.

- A number of mandated fees and assessments are included in the retail rate and not included in the wholesale rate.

The analysis undertaken by Pace represents prices evaluated for comparison with the prevailing wholesale rate for electricity and capacity. The above mentioned fees would have to be additive to the wholesale energy and capacity cost to undertake a comparison of retail to retail rates. Any comparison of retail rates to wholesale rates would otherwise create a gross mischaracterization of the actual cost to the consumer.

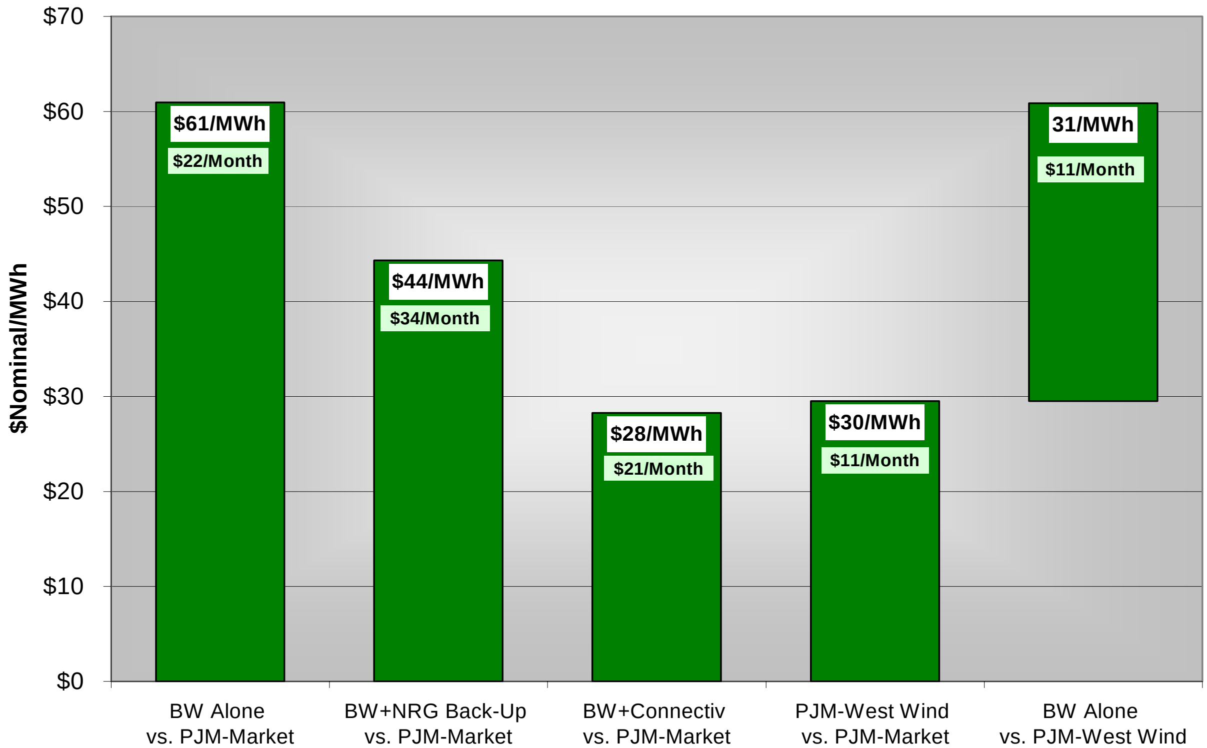
CONCLUSIONS

In reviewing publicly-available data on the BWW Project, Pace evaluated the market conditions and conducted its economic analysis regarding the energy and capacity prices. We undertook an analysis of the risk factors associated with the Bluewater Wind farm, including the price escalation adjustment mechanism, the impact of project delays, and other factors. Pace looked at the impact upon the SOS customer, including rate stability, and the overall project economics and variability in these factors.

Pace's analysis priced the Bluewater off-shore facility well above market comparable to similar findings for other, recently-proposed off-shore facilities, most notably by LIPA. Pace's analysis revealed a ***substantial*** Green Premium for each option before consideration of the Energy Rate escalation terms (see Exhibit 15) on both a nominal, levelized dollar per MWh basis, and on a cost per month per Delmarva SOS customer for all of the options considered.

- The BWW Project as a stand-alone operation requires a levelized cost, or Green Premium, of $60.95 per MWh ($79 million per year), leading to a $22/month increase in the average cost to each SOS customer.
- When combined with the NRG Back-Up resource, the levelized Green Premium per MWh is lower, at $44.32 per MWh. However, the overall Green Premium cost to consumers is higher, at $122 million per year, or $34/month per customer.
- The BWW Project combined with the Conectiv Back-Up resource results in a Green Premium of $75 million, or $21/month per customer.
- By way of contrast, purchasing an equivalent amount of wind energy from PJM-West comes at an annual levelized cost of $38 million higher compared to the PJM-Market, or $11/month per customer, i.e., the BWW Project costs $11/month per customer more than an on-shore wind alternative.
- These Green Premiums will likely be much higher upon application of price escalation terms embedded in the contract.
- The Green Premium for the BWW Project without escalation is substantial relative to the value of carbon exposure avoided and no foreseeable estimates of carbon prices would fully offset this cost differential.

Exhibit 15: Levelized Green Premiums Without Escalation Per MWh and Per Customer*



*Comparisons for the BWW Project ("BW") or PJM-West Wind alone are based on anticipated wind-only purchases. Alternatives including back-up generation are based on 195 MW around-the-clock purchasing requirements. Values reflect nominal levelized costs beginning June 1, 2014 assuming 8.96% nominal discount rate (6.3% real rate and 2.5% inflation) and a 25-year payment schedule.

Source: Pace.

By way of comparison, the Green Premium estimated for the proposed Long Island Off-shore Wind Farm would have cost customers an average of approximately $5.75/month on a levelized basis. Although the Green Premium was substantially higher on a $/MWh basis due to the very high installed cost estimates for the wind farm, the LIOWP project was sized at only 144 MW and spread over an estimated 1.095 million customers. The Bluewater wind farm is three times larger, resulting in almost twice the level of investment required, being spread over less than one-third the customer base.

The critical factor in project economics and SOS customer rate stability is the price escalation mechanism. This price formula is asymmetric against the interests of SOS customers over the 25 year term of the contract. The price adjustment varies up to 98% of the Bluewater energy price representing 92% of the totality of payments made from Delmarva to Bluewater. However, price volatility associated with commodities used in the manufacture of wind turbines should be assumed to continue. Therefore, if Bluewater were to assume the commodity price risk this would shift Delmarva's risk profile from energy price risk based upon underlying commodity prices to credit risk based upon Bluewater's financials. Given the contractual mitigation measures available to Delmarva, and evaluated by Pace, a material adverse change in the financial condition of Bluewater would leave Delmarva exposed to the same commodity price risks. This creates a large and uncapped risk for Delmarva.

Pace has not seen commercial pricing terms in a contractual setting as Bluewater is proposing: asymmetric risks contractually shifted to the ratepayer where the developer carries none of the risk, without caps or limitations. The terms analyzed by Pace remove Bluewater's incentive to burden-share, potentially delaying the financial close of the project. Any delays in the financial close expose SOS ratepayers to commodity price escalation. The longer SOS customers are exposed the higher the potential for customer migration. Customer migration impact, on the existing SOS customer base, assuming Bluewater project is approved, result in material adverse financial cost shifting to the remaining SOS customer base.

The Bluewater Wind Farm, as evaluated by Pace, contractually exposes SOS customers to a long-term PPA which carries asymmetric risk. The risks are shifted wholly to the customer resulting in significant rate instability. Lower cost/risk profile risk alternatives exist. Pace has evaluated two such alternatives. Underlying commodity price risks, found in the price escalators, and associated with the Bluewater off-shore wind project can be contractually removed from the contract. However, doing so only exposes the SOS customer to other types of risk, associated with the Bluewater wind project including credit, default, imputed debt, and spot gas based power purchase requirements. These risks increase in direct proportion to the commodity price risks originally contained in the escalators.

Removal of the escalators also creates an incentive for Bluewater to begin the project and seek additional recovery at a later date as underlying commodity price increases financially impair their financial condition. Failure to allow recovery of impairment expenses would have a material adverse affect upon Bluewater while allowing recovery sets in motion a slow process of allowing continual adjustments.

APPENDIX A

PJM WESTERN WIND FARM ANALYSIS

Pace Global performed an analysis comparing the costs of the BWW Project with those of an onshore wind farm in a neighboring region in order to represent a reasonable economic assessment of a renewable alternative. Note that no specific development activities have been undertaken and the values used in this analysis could change significantly upon the selection of a specific site and the conduct of a full due diligence.

Pace performed a high-level examination of the economics of acquiring wind-generated power from Pennsylvania, where onshore wind resource development is viable. The cost was estimated as a 25-year Purchased Power Agreement allowing for full cost recovery assuming standard debt-to-equity ratios and a 14% return on equity to the developer. Pace Global developed the following assumptions for this hypothetical 450 MW project:

- A generic estimate for on-shore wind project development, permitting, construction, and capital costs was developed for the PJM region. A total all-in cost of $2,924 per kW was estimated for the hypothetical project, including costs related to interconnection to the PJM power grid.
- Annual fixed operating and maintenance costs were assumed equal to 2% of EPC costs.
- The PTC was assumed to be available to the developer.
- Onshore capacity receives a 20% capacity recognition value.
- Transmission costs were developed through an analysis of likely rates for the purchase of firm transmission through the PJM system and price differentials into the Delmarva territory estimated at $7.50/MWh (taking into account the impact of the MAPP transmission project on Delmarva prices); analysis of line losses through the system indicated that a 2.36% loss rate should be applied to move power through PJM into Delmarva.
- Pace reviewed historical wind generation for units in Western PJM and made an assumption of technological improvement given the timing of the asset to come on line in 2014 to arrive at a 34% capacity factor for the generic wind farm. We also assume a 1.5% outage rate resulting in a 33.5% effective capacity factor before transmission line losses.

CO2 ASSUMPTIONS

Assumptions regarding the future cost of carbon dioxide (“CO_2”) emissions are important in this assessment because they will affect the price of power and the costs faced by fossil fuel generators. Therefore, Pace has explicitly forecasted CO_2 compliance costs for inclusion in its power market forecast and in its cost estimates for fossil fuel-fired generation.

Indicators of pending U.S. carbon regulation have shifted over the past few months with mandatory, economy-wide carbon caps appearing imminent on the horizon. Numerous federal bills proposed in the 109th and 110th Congresses call for mandatory carbon caps for large stationary source emissions, state-level and regional carbon regulations are increasingly putting pressure on Congress to act, and the Bush administration signaled an important shift in its position with its recent climate change announcement in advance of the G8 summit. With this continual expansion in government support for action, Pace Global sees the passage of national carbon legislation in the United States following the 2008 presidential election sometime between 2009 and 2011.

Pace Global's 2007Q3 forecast reflects carbon compliance costs consistent with recently proposed bills and geopolitical trends. Pace Global anticipates a cap-and-trade greenhouse gas emissions trading program for electric and industrial sectors that will begin implementation early in the next decade with subsequent tiered cap reductions. In the absence of any finalized carbon mandates, many uncertainties make it difficult to definitively predict the market cost of compliance instruments (carbon allowances, credits/offsets). Key cap and trade provisions that will drive costs include:

- **Timing and Cap Level:** The timing and stringency of carbon caps will jointly have the largest implications to compliance costs. Pace Global's view is that initial caps will be phased in beginning in the 2012-2015 timeframe with additional cap reductions (and cost increases) around 2018, 2020, 2025, and/or 2030 (with some proposals extending as far out as 2050). Increasingly stringent caps generally are expected to result in higher compliance costs. Pace Global believes initial cap reductions will aim to stabilize greenhouse gas emissions.
- **Carbon Credit / Offset provisions:** Offset provisions in final carbon legislation will directly impact compliance costs for covered entities. Carbon Credit / Offset provisions allow for emission reductions through projects which are external to the affected source and which can be used for direct compliance purposes in lieu of allowances. The volume of offsets created effectively raises the direct emission cap shared by the affected facilities. It has been observed in international carbon markets that flexible offset provisions allow for more supply to enter the system helping to stabilize prices.
- **Sectors Covered:** Some bills call for reductions through the power sector only, others include power and industrial sectors. The inclusion of more sources generally allows for more flexibility to generate cost effective emissions reductions, therefore stabilizing associated compliance costs.
- **Price Control Measures:** Some proposals include safety valve credit reserves and price caps as policy tools to moderate carbon prices. The use of such controls can provide price ceilings, but if implemented inefficiently can also create unproductive and costly market distortions.
- **Allowance Allocations:** It is expected that a U.S. program would include a hybrid allowance allocation scheme (a mix of auctions, input and output based allocations as well as allocations to set-aside funds) with variations in control measures to keep prices in check.

At the moment, the political support for a CO_2 control program is greater in some states than at the national level. The Regional Greenhouse Gas Initiative ("RGGI"), a cap-and-trade program covering power plant CO_2 emissions, is being launched in the Northeast, with Delaware as a member. Although the first compliance period begins in 2009, reductions below the cap are not required until after 2014. Therefore, Pace Global believes low-cost mitigation efforts, including offsets, will be prevalent through 2014. A more substantial compliance cost is forecast for generators starting in 2015. In its national CO_2 compliance cost forecast, Pace Global assumes the introduction of a \$3/tonne cost in 2013, increasing to \$23 by 2030. Pace Global believes that this expected national CO_2 compliance cost forecast is consistent with the stringency and timing of the RGGI initiatives. Exhibit 16 displays the expected compliance costs.

Exhibit 16: CO_2 Compliance Cost (2006\$/tonne CO_2)

Year	Cost
2013	3.00
2014	4.00
2015	5.00
2016	6.00
2017	7.00
2018	9.00
2019	10.00
2020	13.00
2021	14.00
2022	15.00
2023	16.00
2024	17.00
2025	20.00
2026	20.50
2027	21.00
2028	21.50
2029	22.00
2030	23.00

Source: Pace