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November 13, 2007

**VIA E-MAIL**
**VIA HAND DELIVERY**

The Honorable Arnetta McRae
Commission Chair
Delaware Public Service Commission
861 Silver Lake Boulevard
Cannon Building Suite 100
Dover, Delaware 19904

The Honorable Jennifer Wagner Davis
Director
Office of Management and Budget
Haslet Armory
122 William Penn Street
3rd Floor, Suite 301
Dover, Delaware 19901

Russell T. Larson
Controller General
Office of the Controller General, State of Delaware
Legislative Hall
411 Legislative Avenue
Dover, Delaware 19901

The Honorable John A. Hughes
Secretary
Department of Natural Resources and Environmental Control
89 Kings Highway
Dover, Delaware 19901

Re: Docket No. 06-241; Energy Security Analysis, Inc. Report

Dear Chairwoman McRae, Director Davis, Controller General Larson and Secretary Hughes:

Enclosed herein for your review and consideration is a report from Energy Security Analysis, Inc. ("ESAI"), which analyzes the Terms Sheets submitted on September 14, 2007, as amended by Bluewater Wind LLC ("Bluewater") on November 6, 2007. ESAI was retained by Bluewater to provide this analysis.

The ESAI Report is consistent with and compliments in many respects the report issued by the Independent Consultant retained by the State Agencies (the "IC"). However, the ESAI report proffers a credible scenario wherein the ratepayers will save money over the life of the proposed power purchase agreements. This scenario is based, in large part, upon ESAI's predictions of a more costly fossil fuel market and a more robust market for Renewable Energy Credits. In short, we offer this report not to take issue with or challenge the IC's report but

WIL:69866.1/BLU098-239434

rather to provide additional analysis and research to the State Agencies as they make critical decisions in this process.

Thank you for your consideration of this report.

Very truly yours,

Thomas P. McGonigle
For WOLF, BLOCK, SCHORR and SOLIS-COHEN LLP

TPM/kj
Enclosure

# Analysis
# of
# Offshore Wind & Gas Hybrids

*A Study Prepared*

*For*

**Bluewater Wind Delaware LLC**

***November 13, 2007***

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# BLUEWATER WIND ANALYSIS - SUMMARY

## Market Cost Comparison; 2014-2038
## Bluewater Wind Hybrid Combinations Vs. Market Purchase

**25 Year Average, Nominal Dollars**[1]
(Inflation Adjusted)

| | Market | Bluewater NRG | Bluewater Conectiv | |
|---|---|---|---|---|
| **Blended Energy Price, $/MWh** | $142.67 | $138.02 | $148.14 | |
| **Blended Capacity Price, $/MWh** | $17.70 | $25.47 | $14.27 | |
| **RECs, $/MWh (To Consumer)**[2] | $9.12 | $6.25 | $6.25 | |
| **TOTAL $/MWh** | $169.48 | $169.74 | $168.66 | |
| ***TOTAL Cents/kWh*** | ***16.95*** | ***16.97*** | ***16.87*** | |
| | *Hybrid % of DPL Avg Load* | | | |
| ***Add'l Monthly Cost to Consumers*** | *25.6%* | ***$0.07*** | ***-$0.21*** | ***25 Yr Avg*** |
| (1,000 kWh/mo average, nominal dollars) | *34.0%* | ***$7.19*** | ***$5.34*** | ***Year 1*** |
| | *18.6%* | ***-$2.80*** | ***-$2.28*** | ***Year 25*** |
| ***Contract Cost Vs Market (millions)*** | | ***16.8*** | ***(54.1)*** | |

**25 Year Average, Levelized 2007 Dollars**[1]
(No inflation included)

| | Market | Bluewater NRG | Bluewater Conectiv | |
|---|---|---|---|---|
| **Blended Energy Price, $/MWh** | $110.80 | $107.92 | $115.82 | |
| **Blended Capacity Price, $/MWh** | $13.82 | $20.54 | $11.47 | |
| **RECs, $/MWh (To Consumer)** | $7.27 | $4.87 | $4.87 | |
| **TOTAL $/MWh** | $131.89 | $133.33 | $132.16 | |
| ***TOTAL Cents/kWh*** | ***13.19*** | ***13.33*** | ***13.22*** | |
| | *Hybrid % of DPL Avg Load* | | | |
| ***Add'l Monthly Cost to Consumers*** | *25.6%* | ***$0.37*** | ***$0.07*** | ***25 Yr Avg*** |
| (1,000 kWh/mo average, 2007 dollars) | *34.0%* | ***$7.28*** | ***$5.33*** | ***Year 1*** |
| | *18.6%* | ***-$1.77*** | ***-$1.49*** | ***Year 25*** |
| ***Levelized Contract Cost Vs Market (millions)*** | | ***228.5*** | ***121.1*** | |

| | *Nominal Price Avg* | *Levelized (2007 $)* | | |
|---|---|---|---|---|
| ***Transco Zone 6 Non NY Gas Price*** | **$15.65** | **$12.12** | **per MMBtu** | ***25 Yr Avg*** |

1 - Nominal dollars are adjusted for inflation. Levelized dollars are in real terms, in this case, 2007 dollars. Because savings to the Bluewater hybrid projects accrue in later years, they are discounted on a levelized basis to 2007 dollars and the cost appears higher than on a nominal basis. The nominal basis reflects the actual anticipated costs that the consumer would see in each respective year.
2 - Market purchases reflect REC purchases totally from market sources at market prices. Hybrid REC costs represent blended REC costs to meet requirements for the 300 MW block assuming the purchase of Bluewater RECs per the September 14, 2007 Term Sheet combined with market purchases for the balance requirement for the block.

# DISCUSSION OF CONCLUSIONS

### *SUMMARY AND CONCLUSIONS*

ESAI has developed energy, capacity and REC market assessments in order to determine the cost savings or increases associated with a 300 MW Bluewater Wind/NRG combined cycle hybrid project or a Bluewater Wind/Conectiv Peaker hybrid project as compared to pure market purchases. On average, the Bluewater/NRG hybrid would increase the typical retail customer bill by $0.07 per month over the 25 year project period (inflation adjusted). The Bluewater/NRG hybrid price would be higher in the earlier years, but would provide savings to customers in the later years. The Bluewater/Conectiv hybrid would decrease the customer retail monthly bill by $0.21 on average - less expensive than the NRG hybrid - but would provide slightly less savings in the outer years than the NRG hybrid. The project was assessed over a 25 year time period commencing January 1, 2014.

The Bluewater/NRG hybrid provides a total cost above market of $16.8 million over the 25 year life of the project. The Bluewater/Conectiv project would save $54.1 million. These costs are on a normalized or inflated basis. Both projects provide higher costs in Year 1 and savings in the outer years. Both projects are neutral to the market halfway through the life of the project and then begin to accrue savings (see charts on adjoining page).

On a levelized basis, in 2007 dollars, the Bluewater/NRG hybrid project would cost $228.5 million above market and the Bluewater/Conectiv hybrid would cost $121 million compared to market purchases alone. The costs are higher on a levelized basis due to costs being higher in the earlier years and savings being realized in the outer years.

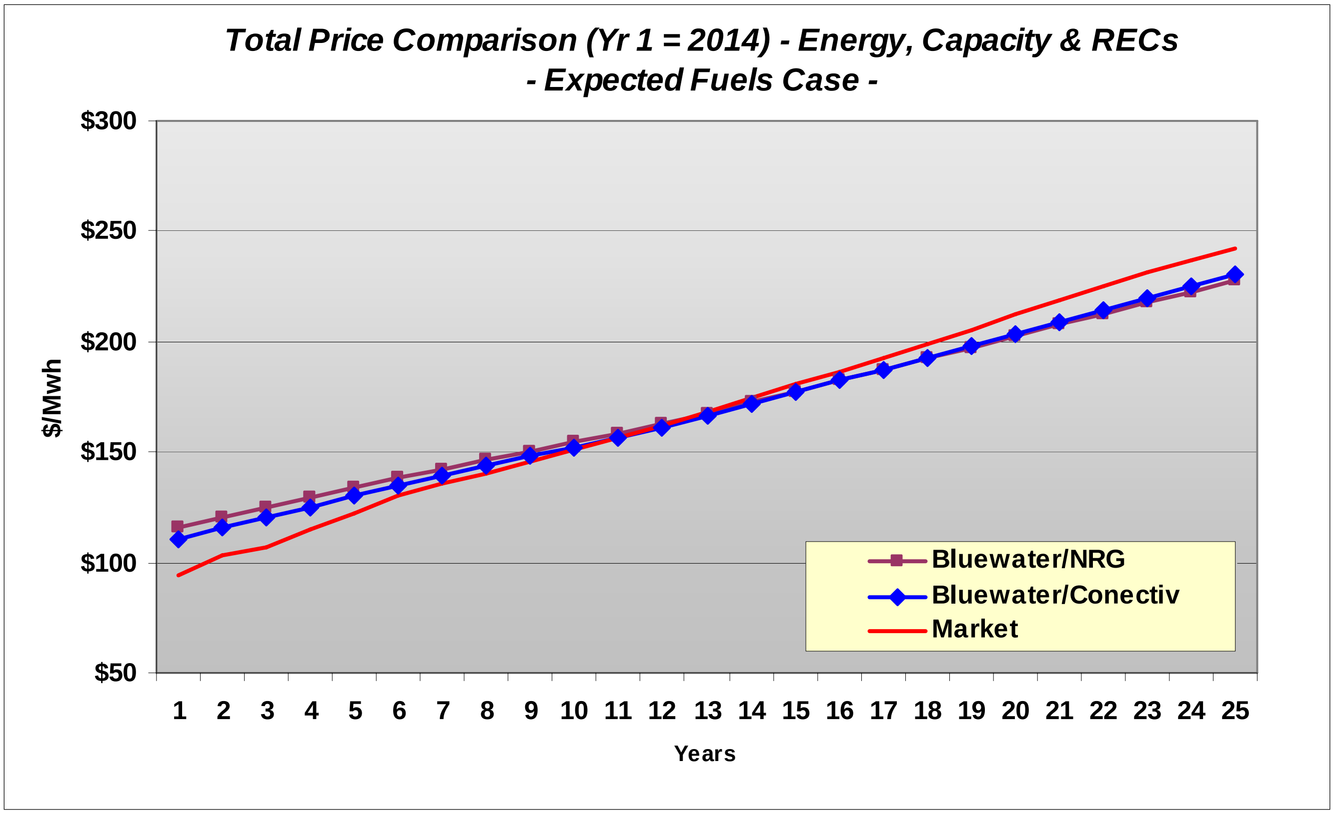
These results are based on ESAI fuels forecasts. Results of a high fuels price scenario show increased savings and are presented in the Appendix. The high fuels case increases fuel prices by 30 percent. The high fuels scenario indicates much lower costs for the Bluewater/NRG and Bluewater/Conectiv hybrid projects than purchases from the market. The Bluewater/NRG hybrid provides a savings below market of $1,991 million over the 25 year life of the project. The Bluewater/Conectiv project would save $1,818 million. These costs are on a normalized or inflated basis.

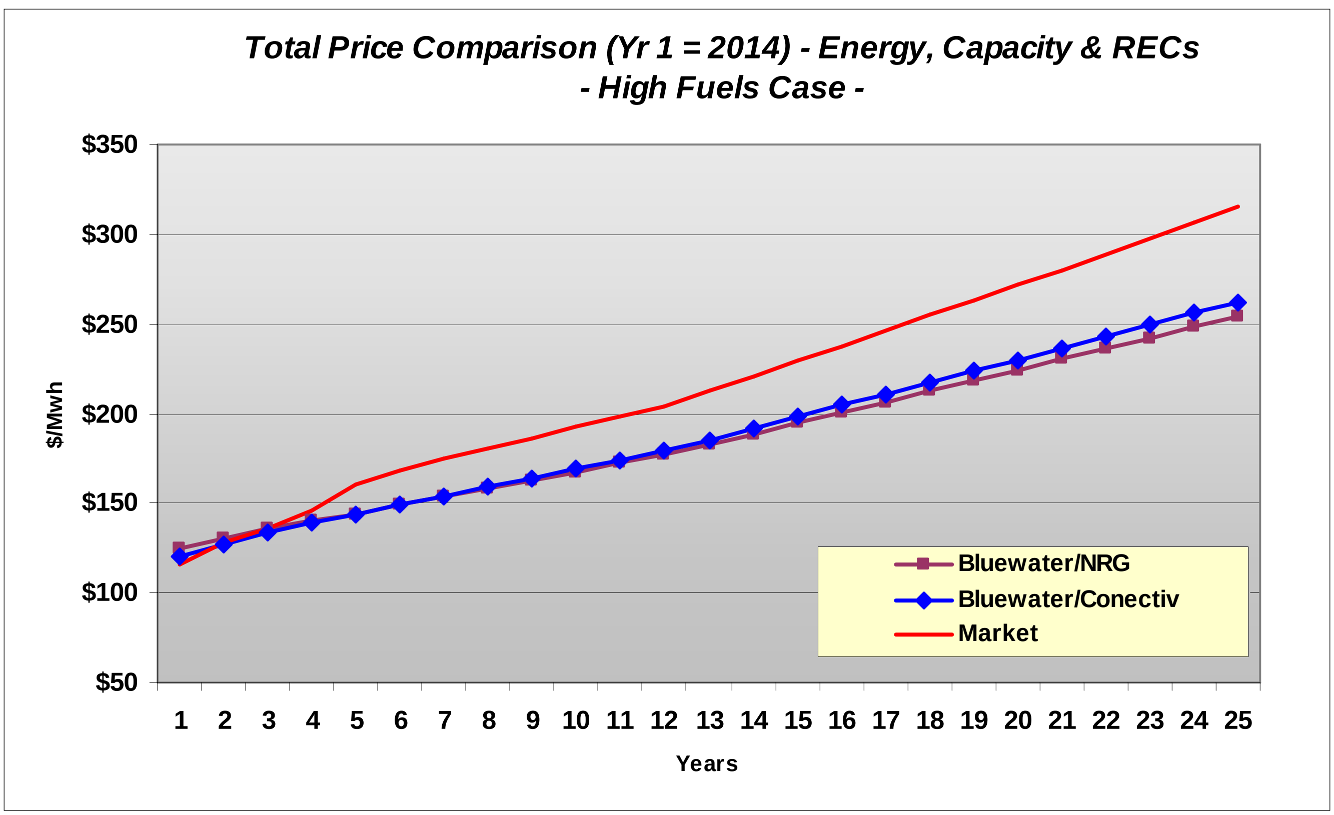
On a levelized basis, in 2007 dollars, the Bluewater/NRG hybrid project high gas scenario would save $1,404 million verses market purchases and the Bluewater/Conectiv hybrid high gas scenario would save $1,297 million compared to market purchases alone. The costs are higher on a levelized basis due to costs being higher in the earlier years and savings being realized in the outer years.

In this analysis, the one time commodity escalator outlined in the September 14, 2007 Bluewater Wind term sheet has been removed. This escalator would have provided a potential one time increase in the energy price due to commodity cost increases associated with turbine manufacturing and currencies during the period ending at financial close.

All other assumptions and methodologies are addressed within the body of this report, including methodologies for hourly energy modeling and capacity price forecasting. The blended energy cost is the weighted average of the Bluewater production with its price and the gas fired plant with its price (as determined by the gas price and heat rate). If the market price is cheaper in any hour than the gas fired plant production cost, then the market price is substituted. The upside price is capped by the production cost of the gas-fired unit in the hybrid combination. This methodology is a key component of ESAI's assessment.

Also included is an analysis of congestion and loss premiums for determining locational marginal prices in the DPL zone and an analysis of ESAI's gas price forecast.


Total Price Comparison (Yr 1 = 2014) - Energy, Capacity & RECs
- Expected Fuels Case -
$300
$250
$200
$150
$100
$50
$/Mwh
1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24 25
Years
Bluewater/NRG
Bluewater/Conectiv
Market


Total Price Comparison (Yr 1 = 2014) - Energy, Capacity & RECs
- High Fuels Case -
$350
$300
$250
$200
$150
$100
$50
$/Mwh
1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24 25
Years
Bluewater/NRG
Bluewater/Conectiv
Market

## *ESAI CAPABILITIES*

Since its inception in 1984, Energy Security Analysis Inc (ESAI) has been dedicated to monitoring, analyzing, and synthesizing information about worldwide energy markets. ESAI has a team of experts that research markets and market dynamics in several key practice areas.

1. **Power markets.** ESAI assists clients in navigating the deregulated US electricity markets with a specific focus on the Northeast markets; PJM, New York and New England. ESAI has built proprietary pricing models that incorporate input fuel forecasts, transmission economics, bidding behavior, and power flow modeling. Our zonal and pool-wide price forecasts provide next week, monthly and long-term (10 year) outlooks.
2. **Natural gas markets.** ESAI provides ongoing assessments of fundamental, technical, and financial market factors that shape short, medium, and long-term natural gas prices in North America. Our analysis measures the impact of market deregulation, electricity demand, and merchant generation development on natural gas demand supply.
3. **Petroleum markets.** With over twenty years of experience, we provide a comprehensive analysis of the global, regional, and national petroleum markets developed from a proprietary country-by-country fundamentals database dating back to 1978. ESAI also provides customized consulting work in such areas as project feasibility and profitability, market access, political and regulatory issues, and expert witness testimony.

The core of ESAI’s practice is to provide clients with updated market research in the form of ongoing research reports. ESAI's power analysis provides an objective, independent view of the increasingly complex and dynamic deregulated power markets. ESAI as a firm has a unique capability in this regard in that our forecasts and related analysis for the Northeast markets are published weekly, monthly and quarterly, providing forecasts for energy and capacity prices over weekly, 6-month, and 10-year intervals.

Other features of our power and gas practice include:

- **Regional Expertise -** Targeted analysis of the three major Northeast U.S. markets - New England, New York and PJM.
- **Pool, Zonal, and Nodal Pricing -** With Locational Marginal Pricing (LMP) at the heart of FERC's Standard Market Design (SMD) rules, ESAI provides clients with forecasts for power prices at the pool-wide (or hub) level, but also at the zonal and nodal level, where our assessment of intra-pool, intra-node, and generator dynamics takes market analysis to a more granular level.
- **Market dynamics -** Exploration and understanding of the distinct elements unique to each regional power market, including regulatory policies and rules, transmission system configuration, capacity markets, generation fuel mix, dispatch stack, and market liquidity in the ISO-administered, as well as over-the-counter (OTC), energy markets.

- **Power flow modeling -** ESAI has developed it's own optimal power flow modeling capability, which utilizes a Power World™ security constrained dispatch and power flow with proprietary economic inputs. Providing a richer analysis than a traditional dispatch stack/production cost model, power flow analysis is used to assess congestion, measure the system impact of capacity additions, outages, and loop flows, and determine locational pricing at the nodal and zonal levels.
- **Capacity assessment -** ESAI's Capacity Watch provides a subjective evaluation of generation and transmission capacity project development. Each project receives a probability of completion weighting and the proprietary capacity outlooks are then used in power flow modeling.
- **Bidding behavior -** Incorporation of generator bidding behavior into power price forecasting and flow modeling. Work includes identification and exploration of various bidding strategies across unit types - including base load, peakers, and hydro facilities.
- **Transmission economics -** Understanding and modeling of transmission economics. Expertise includes dynamic transmission modeling through flow analysis, seams issues and inter-pool flows, congestion, and utilization of transmission rights.
- **Locational input fuel forecasts -** Incorporation of ESAI's proprietary input fuel forecasts for natural gas, fuel oil, and other crude products. Natural gas forecasts include prices for Henry Hub, Transco Zone 6, TETCO M3, and Algonquin City-Gate.

ESAI publishes market reports focused on energy price forecasts by region and zone as well as gas forecasts for the Northeast US. These reports contain relevant market analysis, policy updates, and insights on changes in market design. The combination of the various publications combine to form ESAI’s Northeast Power Service, which we offer to our clients through annual retainer agreements. Ongoing analysis is required to produce these reports, which form the basis for ESAI’s in-depth understanding of the three Northeast markets and their design.

ESAI’s ongoing clients include major investment banks, regulatory organizations, ISO’s, utilities, generators, and hedge funds. ESAI also performs economic analysis of specific power plants for valuation purposes as well as other projects including a study for PJM entitled **“Impacts of the PJM RTO Expansion”** completed in November 2005. This study can be found at ***http://www.pjm.com/documents/documents-archive.html***.

### *SUMMARY OF MODEL APPROACH*

ESAI has developed a bottom-up cost comparison of the gas-fired hybrids (Bluewater-NRG CCGT and Bluewater-Conectiv Peaker) with a pure market based purchase approach. To develop the cost comparisons, costs for the pure market case were built up as follows:

PJM Western Hub
\+ DPL Zonal Congestion & Loss Premium
\+ PJM Capacity Market Cost
\+ Renewable Energy Cost
Total Market Cost for Comparison

The hybrid costs are built up by blending the production and costs of the Bluewater Wind project (energy, capacity and RECs) with the corresponding production and costs of the NRG unit or the Conectiv unit. Total production capacity of the NRG unit is 300 MW and of the Conectiv unit is 200 MW.

A 'block' of energy is produced for purchase by DPL totaling 300 MW. The starting point for the blended hybrid costs and total production is the Bluewater production of energy from wind. The Bluewater production schedule is based upon a 12 x 24 analysis of hourly production - a 24 hour MW production profile is utilized for each day of a given month with a different 24 hour profile for each of the 12 months. The Bluewater production is subtracted from the 300 MW total to determine the need for energy production from the gas-fired plant.

For NRG, the total production capacity of the plant is 300 MW. The NRG plant will be able to provide the balance of the 300 MW above the Bluewater production, even when the wind is not blowing and there is no production in that hour. The Conectiv plant is only 200 MW and would not be able to provide the full 300 MW block during times when the Bluewater plant is producing below 100 MW. When the Conectiv plant and Bluewater combination cannot provide the full 300 MW block, a market purchase is applied to make up the balance. These calculations assume dispatch during all hours as a backup, however, as described later, our models assume economic dispatch of these units. The production calculations are described below.

#### *NRG Hybrid Production*

The NRG combined cycle production would be calculated as follows:

*At 150 MW Bluewater production*:

NRG Production = 300 MW - 150 MW = 150 MW

*At 50 MW Bluewater production*:

NRG Production = 300 MW - 50 MW = 250 MW

### *Conectiv Hybrid Production*

The Conectiv peaker production would be calculated as follows:

*At 150 MW Bluewater production*:

Conectiv Production = 300 MW - 150 MW = 150 MW

*At 50 MW Bluewater production*:

Conectiv Production = 300 MW - 50 MW = 250 MW needed

Conectiv would produce at 200 MW max capacity

Balance of 50 MW would be purchased from the market.

### *Economic Dispatch*

To minimize costs for ratepayers, the gas-fired units would only be operated when it was economically feasible to do so. When the market price is below the production cost, the unit will not operate and the buyer (DPL) will be supplied with power from the market. When the market price is higher than the production cost, then the actual production cost applies, providing a savings to the actual market cost.

Typically, the market cost is lower than production costs during off-peak hours and is often higher than production costs during on-peak hours. The NRG unit has a higher efficiency with a heat rate of 7,200 Btu/kWh and therefore a lower production cost. The Conectiv plant has a heat rate of 9,000 Btu/kWh.

At a $7.00/MMBtu gas price, the production cost of the NRG plant is $50.40/MWh and the production cost for the Conectiv plant is $63.00/MWh, before adding variable costs.

### *ESAI Models*

Four models were utilized to build up these cost comparisons as described below. Further details on the energy price models are provided in the following section of the this report.

1) **Production Cost Model** - This model is a proprietary ESAI marginal cost production cost model and it develops the PJM Western Hub market price for every hour during the forecast period. This is the largest component of the market price.

2) **Power Flow Model** - Calculates the DPL Zonal Congestion & Loss Premiums that are added to the PJM Western Hub price to determine the energy price in Delaware. This is a security constrained optimal power flow model that includes the impacts of all transmission lines (existing and projected), generators and other system components.

3) **Blending Model** - A SQL database model which determines the production for each hour for wind and each gas fired generator and also determines whether or not market purchases apply for the applicable hour. The correct purchase price for the 300 MW block is then determined by weighting the

Bluewater price, the gas fired production costs, and market prices. The model calculates different 300 MW block prices for the Bluewater-NRG hybrid, the Bluewater-Conectiv hybrid, and the pure market purchase.

4) **Total Cost Model** - ESAI has developed a spreadsheet based model which inputs the hybrid energy prices, and calculates blended capacity prices and blended REC prices to develop the total blended hybrid cost to compare with the pure market costs. Forward market capacity and REC prices are determined by ESAI as outlined later in this report.

Through the process of building up prices through these various models, ESAI develops an economically driven, cost optimized solution for each of the two hybrid solutions to compare with the pure market purchase option.

## *NATURAL GAS PRICES*

ESAI develops its own natural gas price forecasts as on ongoing part of its Power and Natural Gas practice. ESAI has a fundamentally based approach to forecasting natural gas prices that includes assessing future production, demand, imports and LNG regasification capability as well as storage dynamics. This approach provides visibility for 6 years in our outlook, after which time prices are escalated at 4.3 percent per year (years 7 - 10).

As ESAI's natural gas forecast only goes out 10 years, we have escalated natural gas prices beyond our 10 year forecast at 4.0 percent annually or slightly lower. Core inflation on a future basis is widely accepted to be assessed in the range of 2.5 - 3.25 percent. We believe that natural gas prices will escalate at a pace that is higher than the core inflation rate due to the very high utilization of natural gas productive capacity. Since 2003, natural gas production capacity has been utilized at close to 100 percent as new productive capacity is offset by production declines at existing wells. With capacity utilization at 95 percent or higher, we would expect natural gas prices to climb at a pace that is above the core inflation rate.

Natural gas prices and other fuel prices such as #2 oil, #6 oil and coal are input to the ESAI models on a monthly basis for each of our forecast years. A high fuels price scenario is outlined in Appendix B where the fuels prices are escalated by 30 percent.

## *CAPACITY COSTS*

While capacity supplied by the Bluewater project and the respective back-up facility will vary throughout the term of the respective power purchase agreements (but will always total 300 MW), for the purposes of simplification, ESAI's analysis assumes an average of 105 MW of capacity supplied by the Bluewater project. The market capacity clearing price is based upon ESAI forecasts and the capacity prices for the Bluewater project and the gas fired plants are based upon the prices in the contract term sheets. Notably, the capacity prices for the Bluewater Wind and market capacity prices escalate over time. The NRG and Conectiv capacity prices are fixed.

### *INTRODUCTION*

ESAI has developed the energy and capacity forecasts that form the basis of this evaluation. Energy forecasts have been developed through the use of ESAI's natural gas and fuels forecasts that are input to ESAI's production cost and powerflow models. The methodologies for the energy forecasts are provided later in this report. Also provided are details of ESAI's long term assessment of natural gas prices and an overview of expected market conditions over the next ten years.

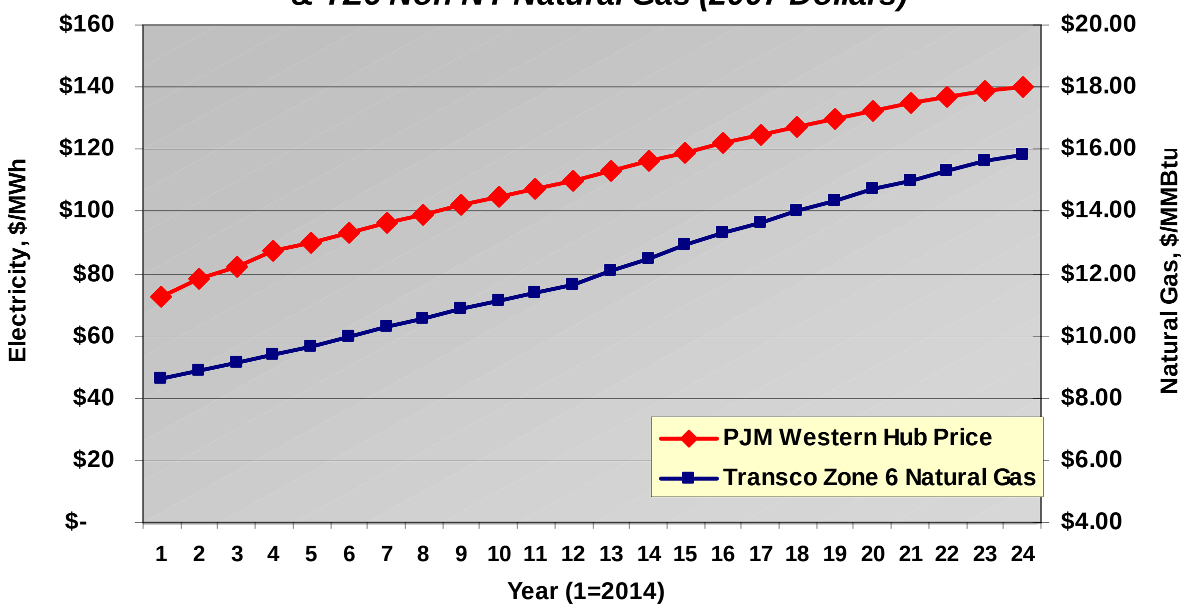
Capacity forecasts are developed using ESAI's models of the PJM RPM capacity construct including the use of the Variable Resource Requirement, VRR, demand curves. ESAI develops projections of capacity surpluses in the PJM RTO and specific locational areas consistent with PJM's published CETO and CETL limits.

### *ENERGY PRICE FORECAST METHODOLOGY*

ESAI utilizes a production cost model to determine the PJM Western Hub clearing price for every hour (8760 basis) over the forecast period. From the results of this analysis, the PJM Western Hub on-peak price is determined. ESAI utilizes weather normalized load forecasts, existing generation with actual heat rates, new generator additions and retirements, and in-house fuel forecasts.

After calculating the PJM Western Hub pricing, the congestion and loss premiums for the DPL zone the prices must be evaluated to determine the zonal LMP price. ESAI has run its security constrained optimal power flow transmission model of the PJM RTO to determine the congestion pricing impacts for the DPL zone. Based on an analysis of the expected transmission upgrades from 2007 to 2011 as outlined in the PJM RTEP, the system topology as of 2011 has been fixed. Additional transmission upgrades beyond 2011 are uncertain and we assume the 2011 system topology remains in place. The PEPCO

***Figure 1 - ESAI Price Forecasts - PJM Western Hub Electricity & TZ6 Non NY Natural Gas (2007 Dollars)***



MAPP project was approved Oct 17, 2007 as part of the PJM RTEP transmission upgrade process. This project has been approved but the final disposition of this project as well as the timing are unknown, but if built, we expect the commissioning date to be near 2015 or later. As this project is well beyond the 2011 date for our transmission analysis, it was not included in our models.

Peak load growth for the PJM RTO is assumed at 1.7 percent per year, consistent with the PJM outlook. Average load growth for the RTO is assumed at 1.5 percent per year.

### ESAI'S PRODUCTION COST DISPATCH MODEL

ESAI has developed a proprietary SQL-based production cost dispatch stack model that is used for long term forecasts. The PJM model includes each system generator within the Mid-Atlantic and APS regions and each unit is assigned a heat rate and fuel type based on its configuration. A forecast for each fuel type on a delivered basis is provided for each month over the term of the forecast. For every hour, the model calculates the production cost for each unit and then ranks the units in cost from lowest to highest. In this manner, the model develops a production cost ranking or 'dispatch stack' in which the lowest cost units are dispatched first and the highest cost units last.

An hourly load profile is input to the model for the duration of the forecast period. The load for a given hour is matched up against the corresponding unit in the dispatch stack according to the cumulative capacity required to match the load. This unit is the marginal unit for the hour and its production cost is assigned as the energy clearing price for that hour. The model then stores the hourly production cost information for each hour in an output file.

Other inputs are required to model seasonal generator maintenance outages, generation additions and retirements, and system imports and exports. These inputs are all included in the normal operation of the model.

### ESAI POWER FLOW MODELING

To assess the congestion and loss pricing components at the DPL zone, ESAI utilizes a modeling system from PowerWorld Corporation. This model contains all of the modeling algorithms to define the transmission and generation systems and more importantly, to calculate power flows and prices across the system. ESAI inputs all generator information and other system data such as interface constraints and import/export flows. ESAI utilizes proprietary fuel forecasts, generator heat rates, and bid behavior to develop the economic information required for the generator bid curves embedded in the model.

ESAI uses PowerWorld's Security Constrained Optimal Power Flow (SCOPF) tool to achieve an economical operation of the system while considering not only normal operating limits, but also violations due to line overloads that would occur during contingencies. The SCOPF changes the system pre-contingency operating point so that the total operating cost is minimized, and at the same time no security limit is violated if contingencies occur.

The SCOPF has the ability to produce bus locational marginal prices that fully and simultaneously model the economics and the security of the network. This function is indispensable to simulate the performance of a system, region, utility, or individual generator in a market environment, and to analyze the system conditions that result in high marginal prices. The SCOPF is also used to study the effects and economic impact of network congestion. The computation of security-constrained locational marginal prices in the model closely emulates PJM's Day Ahead Market dispatch model.

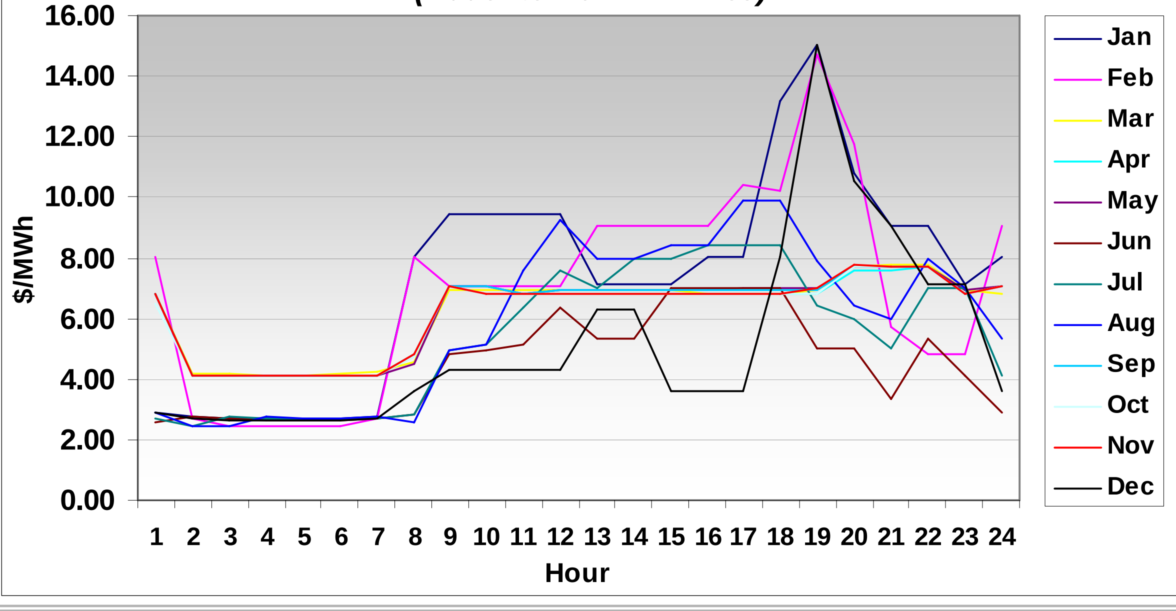
ESAI uses the model in a DC mode with loss factors embedded that have been calculated from AC simulations with the same base case. This is consistent with the PJM operation of the Day Ahead Market models and allows for an equal comparison with results expected from the actual Day Ahead Market.

ESAI uses over 1,100 contingencies in its N-1 security constrained dispatch analysis. This means that the model takes each of the specified lines and transformers out of service, one at a time, and then re-dispatches the system on an optimal basis such that no line transformer capacities are exceeded. The contingencies represented are on the 138 kV systems and higher.

The PJM system is modeled under expected conditions for each year at varying load levels. Each model run represents a 'snapshot' of the system at the assumed conditions of system load, outages and imports/exports. ESAI ran the model at intervals of load (Mid-Atlantic basis) from 30,000 MW to 55,000 MW in 5,000 MW increments. The nodal and zonal price results can be load weighted for the expected load distribution for any given period.

A 12 x 24 profile was developed for the DPL congestion and loss components. These price premiums for each hour were added to the PJM Western Hub prices calculated from the production cost model to arrive at the final DPL zonal price for each hour. The congestion and loss premiums developed are consistent with historical values as adjusted for the RTEP transmission upgrades. The 12x24 profiles are shown below in Figure 2.

***Figure 2 - DPL Congestion & Loss Profile, 12 x 24 (Adder to PJMWH Price)***



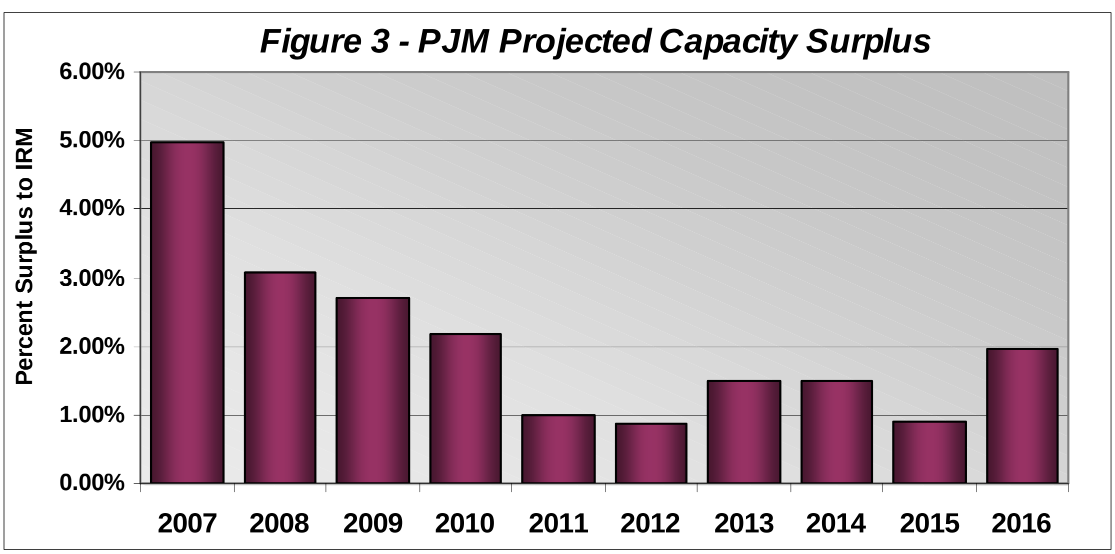
## *CAPACITY FORECAST METHODOLOGY*

ESAI's forecast for forward RPM clearing prices for the market outlook was undertaken prior to the final posting of the 2009/10 capacity year results. ESAI's forecast is consistent with the results posted for the 2009/10 capacity year and remains unchanged. ESAI's forecast of RPM clearing prices is based upon the Reliability Pricing Model parameters and the Variable Resource Requirement demand curve. Key parameters for the forecast included the following:

- PJM defined RPM demand curves
- Peak load growth at 1.7 percent per year
- Low surplus scenario – surplus to IRM (Installed Reserve Margin - reliability requirement above peak load) does not move above 1.0 percent
- Required RTO capacity based on load growth is greater than 2,500 MW per year
- PJM defined CONE (Cost of New Entry) for Years 1-3, 15 percent CONE increase applied in Year 4
- CONE escalates at 3.5 percent annually after Year 4
- All available capacity was assumed to clear in the auction
- EMAAC converges with RTO due to transmission upgrades and increases to CETL capabilities

Figure 3 provides ESAI's view of the surpluses to the reserve margin requirement (15 percent above peak load). The low surpluses beyond 2010 drive prices higher on the demand curve and are the main driver for capacity prices. It is possible that PJM's capacity could move below the reserve margin requirement, however, we believe that an equilibrium level representing a small surplus will develop.

Table 1 provides the ESAI forecast for PJM RTO and EMAAC[3]. The CETL (Capacity Emergency Transfer Limits) have been increased significantly for 2008 but less




3 - EMAAC - Eastern Mid-Atlantic Area Council is a defined LDA, or Locational Deliverability Area.

**Table 1 - ESAI RTO & EMAAC RPM FORECAST**

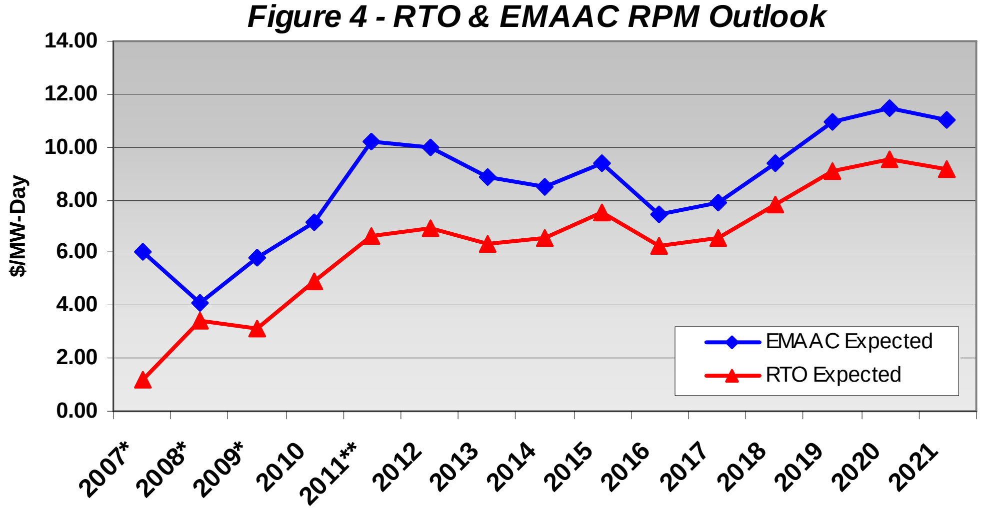
| RPM | RTO Expected | | EMAAC Expected | | |
|---|---|---|---|---|---|
| | ($/MW-Day) | ($/kW-mo) | EMAAC Premium to RTO | ($/MW-Day) | ($/kW-mo) |
| **2007*** | 40.00 | 1.22 | 394% | 197.70 | 6.01 |
| **2008*** | 111.46 | 3.39 | 33% | 133.81 | 4.07 |
| **2009*** | 102.04 | 3.10 | 87% | 191.32 | 5.82 |
| **2010** | 161.95 | 4.93 | 45% | 234.82 | 7.14 |
| **2011**** | 216.98 | 6.60 | 55% | 336.33 | 10.23 |
| **2012** | 226.69 | 6.90 | 45% | 328.70 | 10.00 |
| **2013** | 207.80 | 6.32 | 40% | 290.93 | 8.85 |
| **2014** | 214.25 | 6.52 | 30% | 278.53 | 8.47 |
| **2015** | 247.20 | 7.52 | 25% | 309.00 | 9.40 |
| **2016** | 204.87 | 6.23 | 20% | 245.85 | 7.48 |
| **2017** | 215.89 | 6.57 | 20% | 259.07 | 7.88 |
| **2018** | 256.43 | 7.80 | 20% | 307.71 | 9.36 |
| **2019** | 299.62 | 9.11 | 20% | 359.54 | 10.94 |
| **2020** | 313.85 | 9.55 | 20% | 376.62 | 11.46 |
| **2021** | 301.87 | 9.18 | 20% | 362.24 | 11.02 |

* - Cleared Values; ** - Over 900 MW capacity export to NYC (Linden VFT and Hudson DC tie)

so for 2009. Further transmission upgrades in PJM East should keep EMAAC and eastern zonal prices from developing increasing premiums to the RTO capacity prices. There will be zonal capacity prices from 2011 and beyond, and we believe that the Eastern zones will see decreasing premiums to the RTO as an overall trend. However, starting in 2010, there will be significant capacity exports from PJM with the commencement of the Linden VFT project (2010) and the Hudson Transmission Partners Bergen to Manhattan tie line (2011). These projects will export over 900 MW of capacity from JCPL and PSEG. This may cause the JCPL and PSEG premiums to increase significantly above our EMAAC average projections.

The capacity transfer limits between zones and areas have not yet been released for

**Figure 4 - RTO & EMAAC RPM Outlook**




* - Cleared Values, ** - Over 900 MW capacity export to NYC (Linden VFT & Hudson DC tie)

the capacity years starting in 2010. In advance of receiving this data, we conservatively assume that the 2010 capacity premium will be lower than the last two years average. ESAI projects a 45 percent premium against the 2008/2009 average of 60 percent. The addition of the Linden VFT project and the Hudson Transmission Bergen to Manhattan project will draw over 900 MW of capacity from Eastern PJM and will be bullish for capacity prices. We assume only a slight increase in the EMAAC premium to 55 percent. (The Linden VFT project intends to supply capacity to New York City, but may be disallowed due to deliverability constraints.)

Post 2011, we allow the premiums to drop with anticipated regional transmission upgrades. The PEPCO sponsored MAPP transmission project will provide power transfers between Possum's Point in Northern Virginia to the Salem Nuclear Station in New Jersey via Maryland and the Delmarva peninsula. This project has just been approved in PJM's RTEP process, but must start the long process of gaining permitting, siting and other approvals. We assume that this project could be energized in 2015, and that eastern PJM capacity premiums will drop to 20 percent and stabilize at that time. Due to the uncertainty of the timing of completion of this project, it has not been included in this analysis.

### *Cost of New Entry Considerations*

Under the current EPC cost and investment environment, the capacity clearing prices needed in PJM to support the cost of a new entry combined cycle unit is above $8.00/kw-mo. ESAI's average RTO capacity clearing price forecast from 2010 to 2012 is $7.10/kw-mo, less than needed to support new entry. ESAI's Eastern MAAC clearing price forecast averages $9.20/kw-mo. This level is in line with what is required to attract new capacity into the eastern zones.

Overall, the forecast for the RTO assumes a highly competitive market with new entrants providing cost effective solutions to building new capacity. In Eastern PJM, gas fired combined cycle plants may be the best option considering the difficulty that is associated with building coal or nuclear assets in that region. The $9.20/kw-mo average is actually below the 2010-2020 inflation adjusted equilibrium cost of new entry for a new combined cycle plant. Assuming a $8.50/kw-mo capacity payment in 2007 dollars to support the entry of a new combined cycle unit, the required payment in 2010 would be $9.15/kw-mo in 2010 and $11.70/kw-mo in 2020 (2.5 percent escalator). The average over the 2010-2020 time period would be $10.35/kw-mo, over $1.00/kw-mo higher than the more conservative ESAI forecast levels.

### *Project Capacity Prices*

The capacity prices for the Bluewater, NRG and Conectiv projects are outlined below:

- Bluewater - capacity price $65.23/kw-yr in 2007 dollars escalating at 2.5 percent per year.
- NRG - capacity price is $19.25/kw-mo or $231.00/kw-yr fixed over the term of the contract.
- Conectiv - capacity price is $10.65/kw-mo or $231.00/kw-yr fixed over the term of the contract plus $0.62/kw-mo to allow for interconnection costs of $22.3 million.

The Bluewater project supplies 105 MW of capacity and the gas fired plants supply 195 MW for a total of 300 MW of purchased capacity. The blended capacity cost for each hybrid is based upon the MW contributions and costs outlined above.

### *Variable Operating Costs*

Variable operating costs are assessed in several areas of the analysis. We assess variable costs in the ESAI models and we assess variable costs to the NRG and Conectiv plants as outlined in the September 14, 2007 DPL term sheets.

- Modeled units - ESAI assesses a $2.00/MWh variable operating cost to combined cycle units in the production cost and dispatch stack models. Other unit type operating costs are also consistent with industry averages.
- NRG - Variable operating cost is $2.00/MWh in 2007 dollars, escalated at 2.5 percent per year.
- Conectiv - Variable operating cost is $5.50/MWh in 2013 dollars ($4.61 in 2007 dollars) and escalates in accordance with the schedule in the term sheet at 2.5 percent per year.

### *Blended Energy Costs*

There are three components to the hybrid energy costs:

1) Bluewater Wind energy cost; as specified in the term sheets.
2) Hybrid cost equals gas times heat rate for each unit; NRG - 7,200 Btu/kwh; Conectiv - 9,000 Btu/kwh; plus variable costs.
3) Market cost - determined by ESAI models.

The blended energy cost is the weighted average of the Bluewater production and its price and the gas fired plant and its price (as determined by the gas price and heat rate). If the market price is cheaper in any hour than the gas fired plant production cost, then the market price is substituted. This analysis is a key component of ESAI's assessment.

Wind energy production was modeled based on a 12 x 24 production schedule provided by Bluewater. No significant differences were found when applying wind energy production on an 8760 hour basis. Gas fired production or market purchase volumes are determined by subtracting the wind energy production from the total required 300 MW. Regardless of the wind production, the modeling results provide a 300 MW total supply in each hour from wind production, gas fired production and/or market purchases.

## *FURTHER COMMENTS*

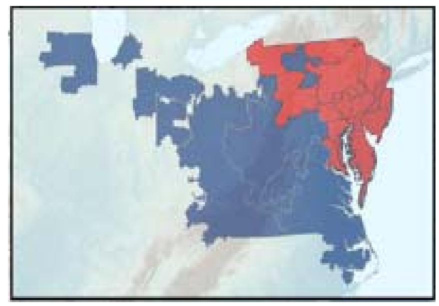
There are a number of drivers in the outlook for PJM power markets that are important and are highlighted below:

- **Generator Retirements -** Only the announced retirements have been included in the energy forecasts provided. It is certain that additional retirements will be forthcoming as older units face emissions pressures and high costs due to inefficient design.
- **Installed Capacity Outlook** - The PJM RTO capacity surplus is dwindling and is expected to just meet installed reserve margin requirements in 2011. Further, our projections assume that sufficient capacity will be built to maintain reserve margins. It is possible that the 15,000 MW of new capacity required during the period 2012 to 2015 will not be built (more with retirements) and that PJM's installed capacity could fall below the 15 percent installed reserve margin requirement.
- **Peak Load Growth** - The 2006 record peak load of 144,796 MW for the PJM RTO was well above expectations. While peak load growth is assumed to be 1.5 to 1.7 percent (1.7 percent in this analysis), ESAI's studies indicate that actual historical peak load growth is slightly above 2.0 percent. This is a significant difference from current planning assumptions.
- **Transmission to New York** - The Neptune DC transmission tie from New Jersey to Long Island will pull 660 MW capacity and energy from PJM to Long Island. Additional DC ties have been included in this analysis, including the 300 MW VFT at Linden (early 2010) and the 600 MW Hudson Transmission Partners DC tie from Bergen to New York City (2011). Development of new transmission ties to New York will be bullish for both capacity and energy prices in PJM, particularly eastern PJM.
- **Long Distance Transmission** - PEPCO, AEP and APS and others have filed their intentions to build long distance and high capacity transmission infrastructure that could bring as much as 5,000 MW of lower cost power from the west into PJM East. One phase of this West to East infrastructure upgrade has just received approval in the RTEP process; the MAPP project. This would have a bearish impact on energy and congestion premiums in Eastern PJM. However, the timeline for the development of this project is on the order of ten years and is not specifically included in this analysis. We note that AEP's recently commissioned Jacksons Ferry to Wyoming 765 kV line took almost twenty years to develop, permit and construct.
- **Fuel Prices** - Further escalations in natural gas prices or oil prices beyond the forecasts presented in this analysis will tend to drive prices higher at the DPL zone. Likewise, a decline in energy prices could have a depressing impact on market prices.

### *PJM - AN EXPANDING MARKET*

The PJM electric market has undergone a significant expansion from its original footprint encompassing Pennsylvania, New Jersey, Maryland, Delaware, Virginia and the District of Columbia electric markets, now known as 'PJM Classic'. PJM has become a Regional Transmission Organization (RTO) and has expanded from its PJM Classic footprint to a much larger area including additional markets from Virginia, West Virginia, Kentucky, Ohio, Indiana, Illinois, and Michigan. PJM now oversees the transmission grids of an area that encompasses 5.6 percent of the territory of the lower 48 states but consumes 17.5 percent of the total power generated. It is the largest power market in the world.

Moreover, PJM is the only power market created since the seminal Federal Energy Policy Act of 1992 and the subsequent Order 888 of the Federal Energy Regulatory Commission (FERC) that has expanded so substantially from its initial core membership. PJM has admitted new members such as American Electric Power, Dayton Power and Light, Commonwealth Edison and Virginia Electric. In doing so, the areas served by these utilities have become part and parcel of a market designed to promote competition in an industry that had been comprehensively regulated since 1935.



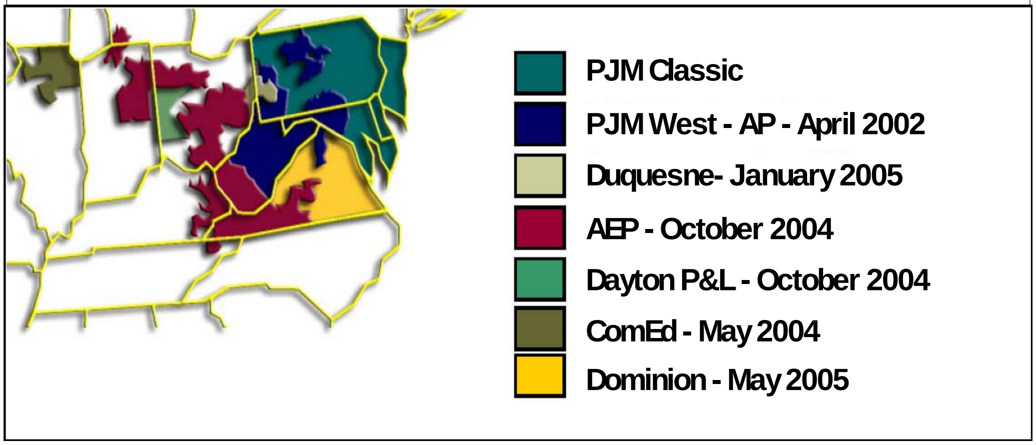
The original PJM market had a footprint defined in the graphic above that encompassed five states - Pennsylvania, New Jersey, Maryland, Delaware, and Virginia - as well as the District of Columbia. At the outset of PJM operations in 1998, the market had

**PJM RTO - SUMMARY OF KEY STATISTICS - 1998-2005**

| | Original Footprint | PJM Merges With: | | | | |
|---|---|---|---|---|---|---|
| ***PJM STATISTICS*** | **PJM Classic** | **Allegheny Power** | **ComEd** | **AEP & Dayton** | **Duquesne** | **Dominion** |
| *DATE OF PJM MARKET ENTRY* | 1998 Basis | Apr 1, 2002 | May 1, 2004 | Oct 1, 2004 | Jan 1, 2005 | May 1, 2005 |
| *PEOPLE SERVED, millions* | 22 | 25 | 35 | 44 | 45.3 | 51 |
| *PEAK LOAD, megawatts* | 49,400 | 61,200 | 87,000 | 107,400 | 110,700 | 131,300 |
| *GENERATING CAPACITY*, megawatts* | 56,000 | 67,000 | 106,000 | 134,000 | 137,500 | 163,800 |
| *TRANSMISSION LINES, miles* | 14,500 | 20,000 | 25,000 | 49,300 | 49,970 | 56,070 |
| *NUMBER OF GENERATORS* | 600 | 660 | 800 | 984 | 1,001 | 1,082 |
| *TERRITORY, square miles* | 48,700 | 79,000 | 91,000 | 137,700 | 138,510 | 164,260 |
| *AREA SERVED, no. of states* | 5 + D.C. | 7 + D.C. | 8 + D.C. | 12 + D.C. | 12 + D.C. | 13 + D.C. |

* - RTO capacity on integration date

**2006 PJM MARKET AREA**




56,000 MW of generation capacity, a peak load of 49,400 MW, 14,500 miles of transmission lines, and covered a population of 22 million. When Allegheny Power joined PJM on April 1, 2002, the RTO grew by 60 generating plants, and 10,000 MW of generating capacity.

In less than three years, PJM more than doubled in size from 67,000 MW of generation capacity to 164,000 MW. In May 2004, Commonwealth Edison, serving markets in Illinois, joined PJM adding 130 generators with 26,000 MW of capacity. In October 2004, the market areas served by American Electric Power and Dayton Power & Light joined (AEP, 130 generating plants and 32,000 MW of capacity – DPL, 45 power plants and 4,800 MW). In January 2005, Duquesne added 14 power plants and 3,000 MW and in May 2005 Dominion added 115 power plants and another 21,000 MW of capacity.

With these additions, the PJM market now encompasses 1,100 generating units, 164,000 MW of generation capacity, a 2006 peak load of 144,000 MW, more than 55,000 miles of transmission lines, and serves a population of more than 50 million. The footprint, as seen in the chart below, now extends far into the Midwest and the South, making PJM the largest power market in the world.

***PJM Generation Assets***

The PJM RTO has a very diverse mix of generation. As the PJM area extends over much of the Appalachian and Central coal regions, coal fired generation comprises a major portion of the PJM generation portfolio. The majority of this coal fired generation is located in Western Pennsylvania, West Virginia and in the AEP service territory.

The total PJM RTO installed capacity is 165,440 MW. Coal comprises 40.6 percent of the total capacity, but coal fired power plants provided 66.6 percent of the total energy output of PJM generators in 2005. Nuclear capacity makes up 18.6 percent of the PJM portfolio and PJM's nuclear facilities generated 25.6 percent of the pool's 2005 energy output. Coal and nuclear combined make up just under 60 percent of the pool's installed capacity, but together accounted for 91.8 percent of the total PJM RTO energy generation. The coal and nuclear base load capacity in PJM is quite large in PJM relative to the other Northeast power pools - New York and New England.

Natural gas fired capacity makes up 27.4 percent of the total installed capacity, but generated only 5.6 percent of the total pool energy production in 2005. The total gas fired capacity of 45,000 MW is comprised of combined cycle capacity and combustion turbine peaking units. Table 2 provides a more detailed breakdown of capacity types and shows that combined cycle capacity is just over 20,000 MW on a pool-wide basis.

Oil fired units make up only a small portion of the total generation portfolio, 3.7 percent, and provide less than 1.0 percent of the total energy production. Most of these units are located in the eastern zones. Because they are steam units and most of them are old and inefficient, the production costs tend to be high. As discussed later, the higher production costs of these units are an important component of the congestion costs seen in the eastern zones.

In the western zones, the generation portfolios are heavily weighted towards coal

***Table 2 - PJM RTO Installed Capacity & Energy Generation; 2005 Basis***

| | Installed Capacity, MW | Installed Capacity, % | 2005 Energy Generation, % |
|---|---|---|---|
| Coal | 67,248 | 40.6% | 66.6% |
| Nuclear | 30,765 | 18.6% | 25.2% |
| Hydro | 7,406 | 4.5% | 1.3% |
| Natural Gas | 45,402 | 27.4% | 5.6% |
| Oil | 6,186 | 3.7% | 0.9% |
| Other | 8,433 | 5.1% | 0.4% |
| | 165,440 | 100.0% | 100.0% |

Figure 5 - PJM RTO Installed Capacity

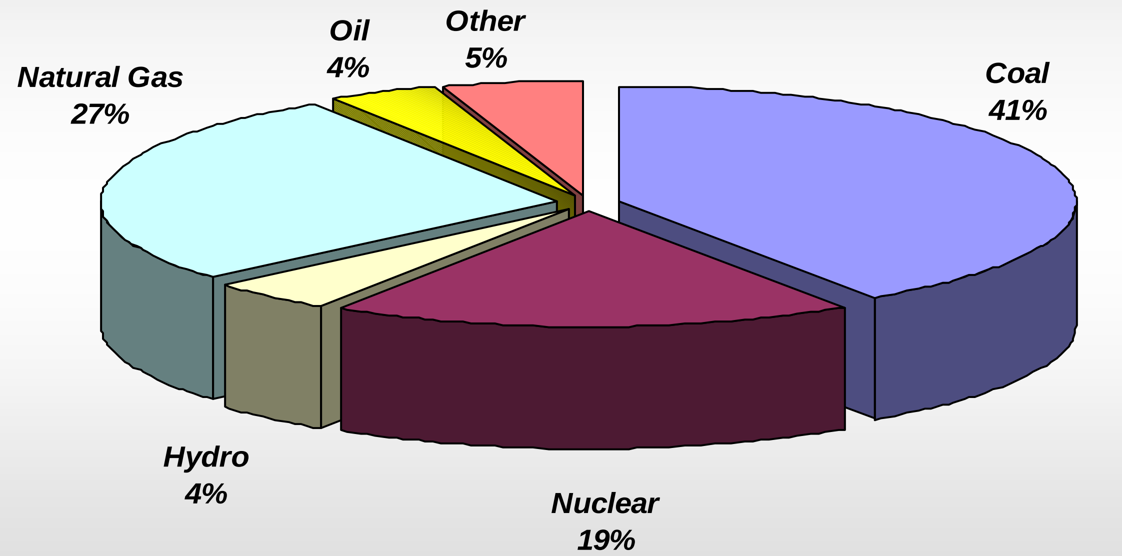



Figure 6 - PJM Energy Generation, 2005

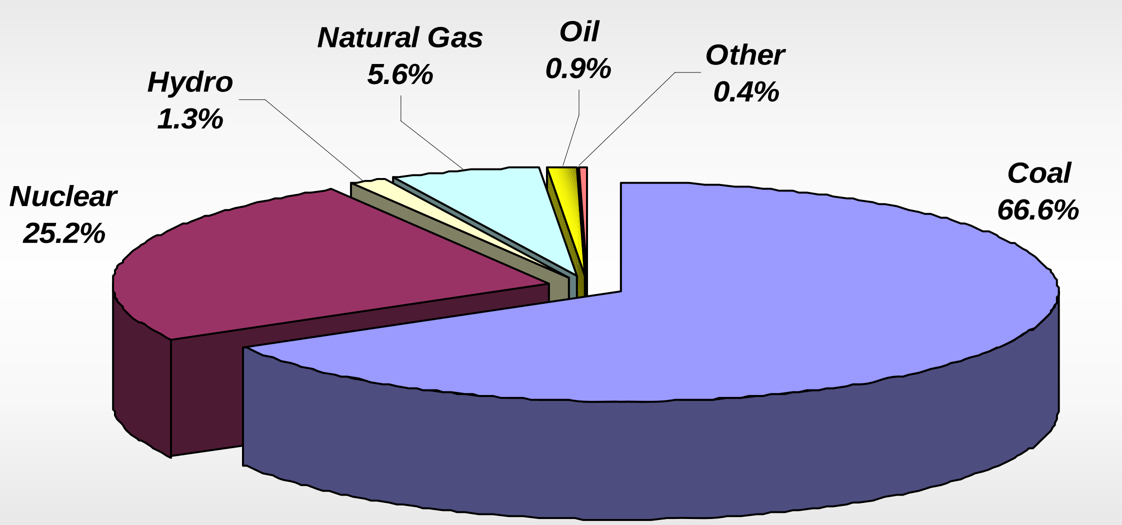


**Table 3 - PJM Installed Capacity Detail**

| | Installed Capacity, MW | Installed Capacity, % |
|---|---|---|
| Nuclear | 30,765 | 18.6% |
| Hydro | 2,300 | 1.4% |
| Hydro Pumped Storage | 5,106 | 3.1% |
| Subtotal | 7,406 | 4.5% |
| Coal | 67,248 | 40.6% |
| Gas, Combined Cycle | 20,172 | 12.2% |
| Gas, Combustion Turbine | 21,112 | 12.8% |
| Gas, Steam | 3,269 | 2.0% |
| Gas, Other | 849 | 0.5% |
| Subtotal | 45,402 | 27.4% |
| Oil, Steam | 6,186 | 3.7% |
| Diesel | 5,847 | 3.5% |
| Kero | 1,580 | 1.0% |
| Wind | 362 | 0.2% |
| Other | 644 | 0.4% |
| TOTAL | 165,440 | 100.0% |

and nuclear capacity. AEP, for example, has a 2006 planned peak load of 23,290 MW and has a combined coal and nuclear capacity is 23,345 MW (coal - 21,245 MW; nuclear - 2,100 MW). The coal and nuclear capacity in AEP could meet all of the zone's internal demand. Additional capacity in the AEP zone is 3,765 MW of gas fired combined cycle and 3,400 MW of gas fired combustion turbines and allows for outages as well as exports to other areas.

The eastern zones tend to have a more diverse mix of generating plants, which under recent market conditions also means that this region has a wider array of capacity with higher production costs. The western zones have much higher percentages of lower cost coal and nuclear capacity. In addition, the cost of coal in the western zones is significantly cheaper than in the east due to the closer proximity to the coal production areas. Under load levels experienced by the pool for the great majority of the year, the western zones have a surplus of lower cost energy that can be exported from the pool or to the eastern zones within PJM. However, the amount of lower cost energy that can be flowed to eastern PJM is limited by constraints on the transmission system. It is this combination of the distribution of generation assets and the constraints on the transmission grid that define the price patterns within PJM.

### *PJM TRANSMISSION OVERVIEW*

PJM operates the high voltage transmission system on behalf of the transmission owners whose assets comprise the grid. PJM dispatches all generation on the system on an economic basis; the unit needed to serve the next MW of load is referred to as the marginal unit and sets the energy clearing price for the pool. Prices can vary by location due to congestion charges which are determined as a function of the transmission constraints on the system.

PJM runs a security constrained optimal power flow dispatch model which calculates the price for each node (location) on the grid. The transmission system is dispatched in a manner that meets load demand throughout the system and also accounts for the eventuality of major transmission or generator outages. At moderate to high on-peak load levels, the PJM transmission system experiences flow constraints across individual transmission lines and transmission interfaces (limits on a collection of two or more lines). When flows into an area are constrained, additional generation on the sink side of the constraint must be dispatched to meet load in that area. Typically, the generation on the sink side of the constraint is more expensive and this area will have higher costs to meet load. The

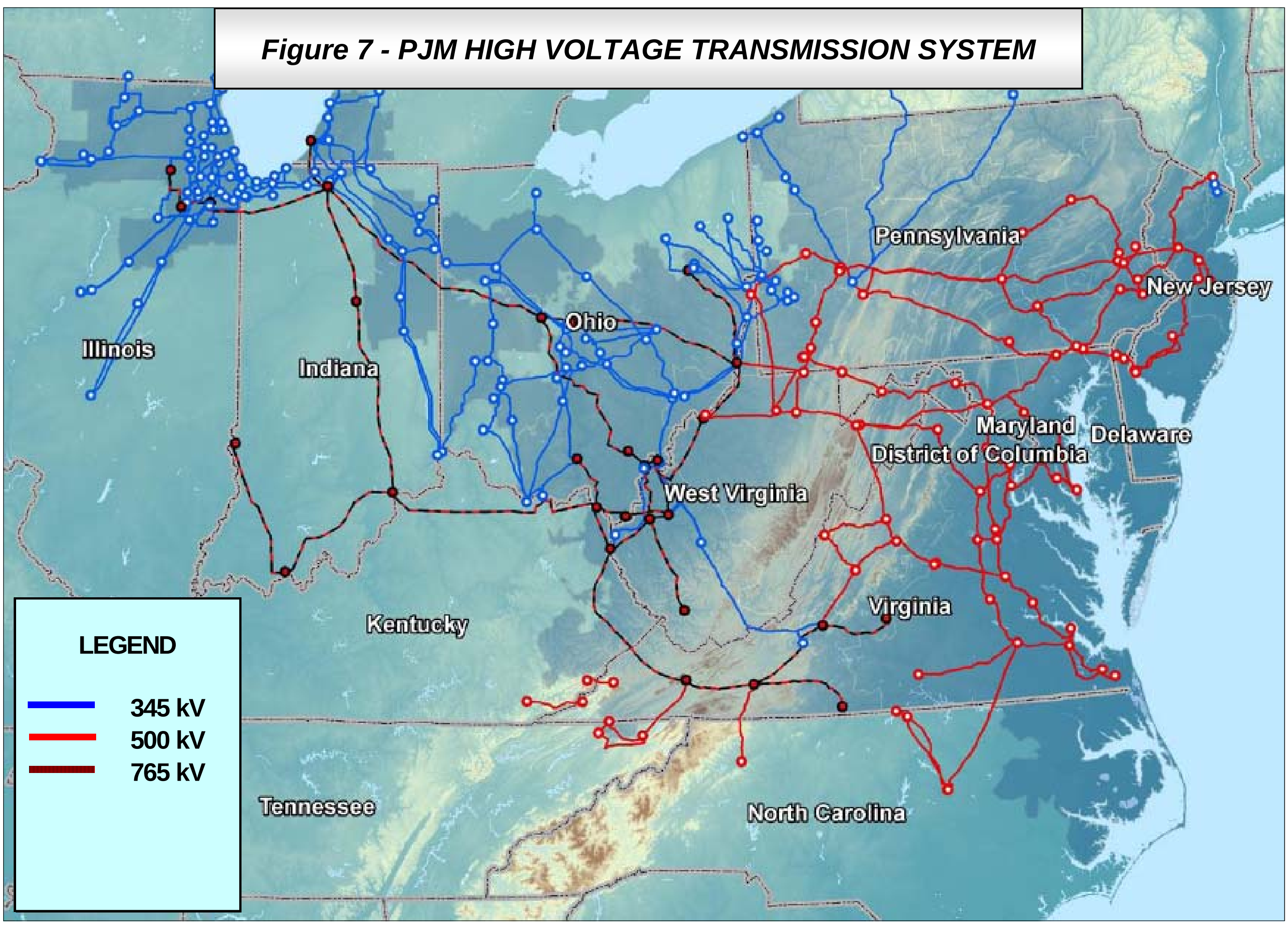



***Figure 7 - PJM HIGH VOLTAGE TRANSMISSION SYSTEM***

PJM models calculate the costs of congestion throughout the system and apply prices consistent with the constraints and load demands. Constrained areas receive price premiums and surplus areas are discounted.

The PJM transmission system has evolved into its current configuration from the plans and designs of the utilities who developed and built their systems. As can be seen in Figure 7, the western portion of the grid from Northern Illinois (ComEd) to Ohio (AEP) has a 345 kV high voltage infrastructure. AEP has further developed a 765 kV backbone of transmission which also runs from Northern Illinois to Ohio and south into Virginia.

The eastern half of PJM has a 500 kV infrastructure which extends through most of the original PJM footprint (PJM Classic) and through the Dominion service area (PJM South). Power is transferred along the 500 kV system in PJM and into 230 kV and lower voltage systems.

Under a non-constrained system, PJM would transfer large amounts of electricity from the lower cost western zones to the east. However, there are a number of constraints on the system that limit the flows from west to east. Figure 8 highlights a number of the more restrictive transmission constraints within the PJM system. These tend to restrict flows from the west to the east. There are three interfaces that restrict flows to the east

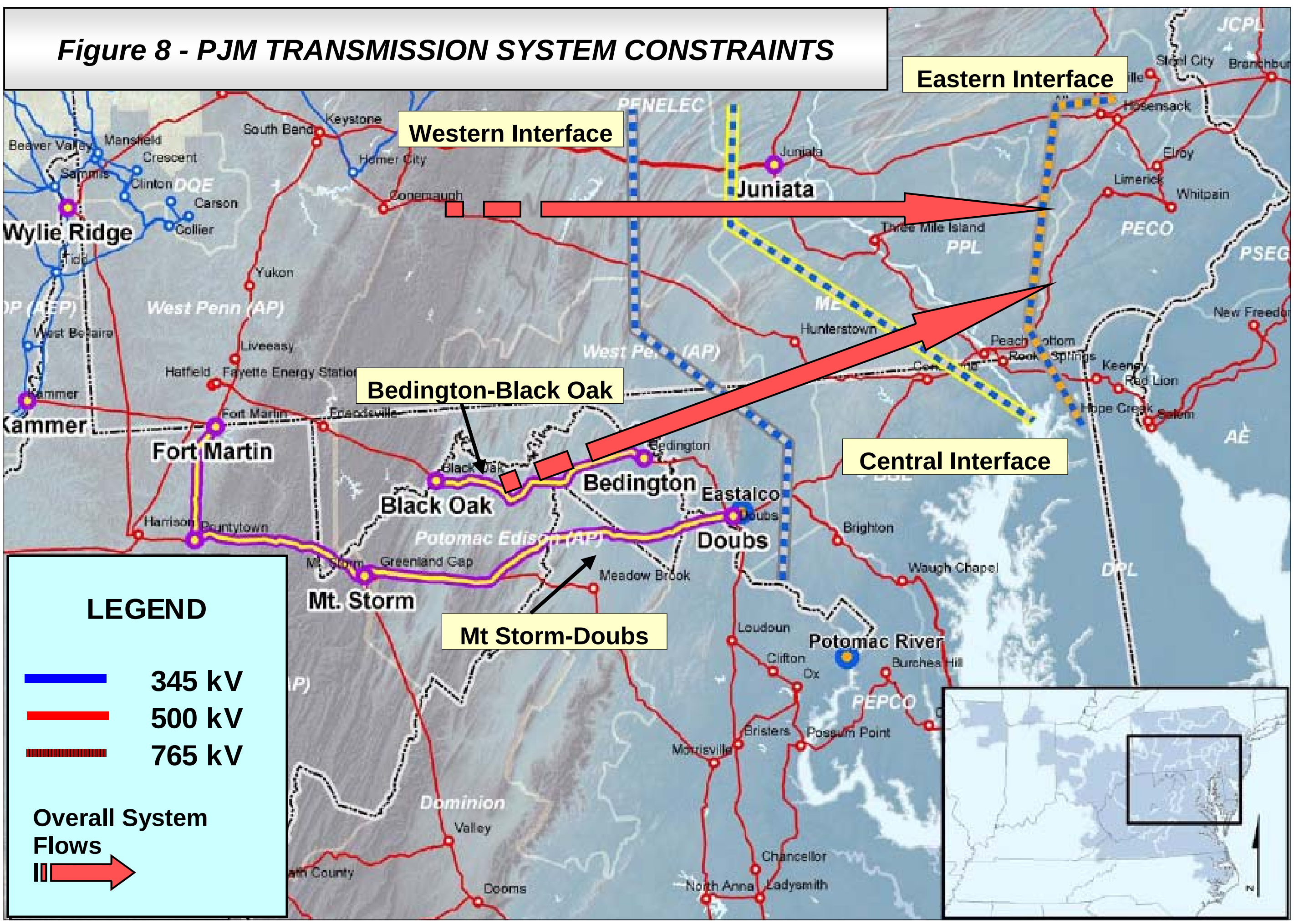



*Figure 8 - PJM TRANSMISSION SYSTEM CONSTRAINTS*

across Pennsylvania and Maryland. These are the western, central and eastern interfaces.

The eastern interface is the most restrictive of these three, although they each contribute to PJM congestion. As these interfaces become binding, more generation in the eastern zones needs to be dispatched as system loads increase, and imports into the eastern zones from the west can no longer be increased. The restricted flows and higher cost generation dispatch result in pricing premiums in the eastern zones. There are other localized constraints within this easternmost region that further increase congestion, particularly in zones such as PSEG and PEPCO.

Flows along the 500 kV southern transmission corridor from West Virginia towards Maryland are constrained by flow limits along the Bedington-Black Oak lines and the Mt Storm to Doubs lines. These constraints are largely dictated by voltage concerns within the PEPCO area.

Other major constraints on flows from west to east occur at the Wylie Ridge and Kammer transformers. Some upgrades were made to the Wylie Ridge facilities, but the transformer has since been derated, erasing the upgrade benefits.

As discussed in the next section, a number of upgrades to these constraining interfaces and lines have been planned, some of which have been recently completed.

### *NEW TRANSMISSION PROJECTS IN PJM*

ESAI has conducted an impact study of pending transmission and generation changes in the Eastern PJM markets over the period 2007-2011. ESAI has simulated the Day Ahead Market security constrained dispatch across the PJM RTO to include the major transmission upgrade projects, changes in the PJM generator dispatch stack and expected load profiles. Major PJM system changes include upgrades of existing transmission transformers and transmission lines, installation of new transmission lines and substations, commissioning of merchant transmission projects, generation retirements and uprates of nuclear generating capacity. The transmission projects are summarized in Table 4 by year on the following page.

### *Table 4 - Approved RTEP Projects Impacting PJM East*

***By 2007:***

New Essex – Aldene 230 kV cable, and new PAR at Essex (PSEG)
Replace de-rated Branchburg 500/230 kV transformers (PSEG)
Replace de-rated New Freedom 500/230 kV transformers (PSEG)
Reconductor Kittatiny-Newton 230 kV circuit (PSEG)
Reconductor Portland-Kittatiny 230 kV circuit (JCPL)
Build two new 230 kV circuits between Palmers Corner and Blue Plains (PEPCO)
Neptune merchant transmission project: Sayreville 230 kV, 660 MW withdrawal (JCPL)

***By 2008:***

Install third and fourth Wylie Ridge 500/345 kV transformer (AP)
Install fourth Meadowbrook 500/138 kV transformer (AP)
Install -100/+525 MVAR dynamic reactive device at Black Oak (AP)
Convert Bergen-Leonia 138 kV circuit to 230 kV (PSEG)
Close Sunnymead bus tie (PSEG)
Build new Branchburg-Flagtown 230 kV section (PSEG)
Reconductor Flagtown-Somerville-Bridgewater 230 kV circuit (PSEG)
Reconductor Laurel-Woodtown 69 kV circuit (AE)
Build new Cumberland-Dennis 230 kV circuit (AE)
New 500/230 kV substation in AE
Build new Dennis-Corson 138 kV circuit (AE)
Build new Cardiff-Lewis 138 kV circuit (AE)
Merchant transmission project: Linden VFT, 330 MW withdrawal (PSEG)
Retire Martins Creek 1, 2, D1-D2 and Brunot Island 4 generating units
Nuclear capacity uprates at Hope Creek, Susquehanna 1, Beaver Valley 1 and 2

***By 2009:***

Reconductor Doubs-Dickerson and Doubs-Aqueduct 230 kV circuits (AP)
Install fourth Bedington 500/138 kV transformer (AP)
Install second Brighton 500/230 kV transformer (PEPCO)
Replace both Conastone 500/230 kV transformer (BGE)
Upgrade Edison-Meadow Road 230 kV “Q” and “R” circuits (PSEG)
Build new Airydale 500 kV substation (PENELEC)
Retire Sewaren 1-4 and Hudson 1 generating units
Nuclear capacity uprates at Susquehanna 2

***By 2010:***

Build new 500 kV substation in PECO
Build second Whitpain-Heaton 230 kV circuit (PECO)
Build new Prexy 500 kV substation (AP)
Merchant transmission project: Hudson, 500 MW withdrawal (PSEG)

***By 2011:***

Build new Meadowbrook-Louden 500 kV circuit (AP)
Replace Doubs 500/230 kV transformers #2, #3, #4 (AP)
Build new 502 Junction 500 kV substation (AP)
Build new Mt. Storm-502 Junction 500 kV circuit (AP)
Build new Mt. Storm-Meadowbrook 500 kV circuit (AP)
Build new Linden-South Waterfront 230 kV circuit (PSEG)
Install second Burches Hill 500/230 kV transformer (PEPCO)

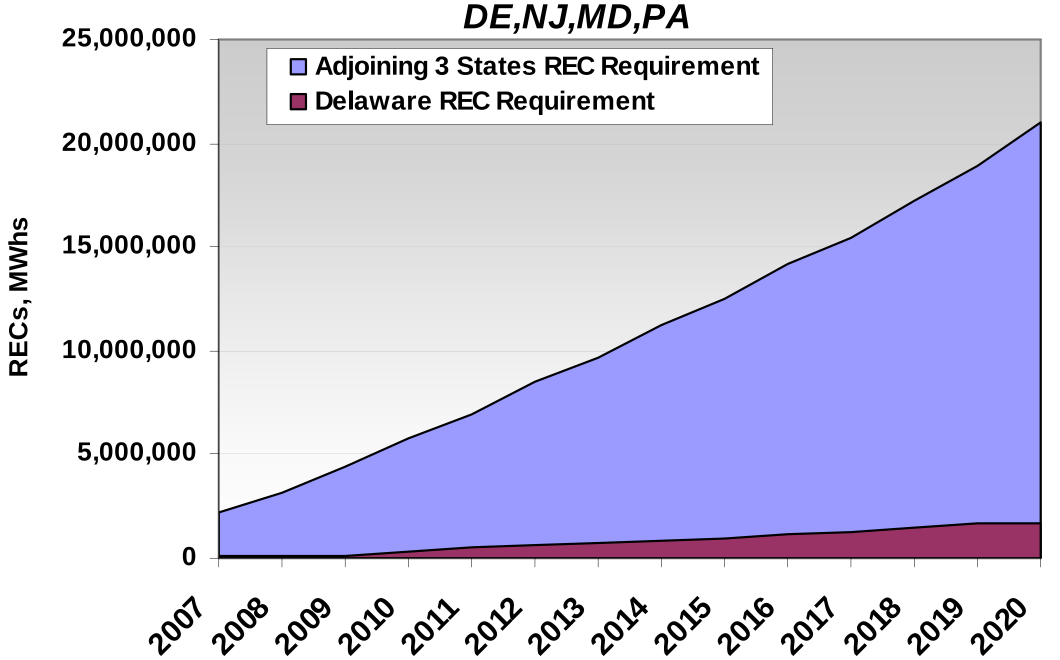
### *RENEWABLE ENERGY CREDIT SUPPLY/DEMAND BALANCE*

ESAI has developed a projection of the required Renewable Energy Credits (RECs) for Delaware based upon the RSCI (Retail and Small Commercial & Industrial) retail load and the Renewable Portfolio Standards set in place by the Delaware legislature. The load is based upon the DOE 2005 reported total retail and commercial sales of 6.67 million MWhs and is escalated at a conservative Delaware load growth of 2.0 percent per year. The renewable energy requirement is based upon a percentage of the total MWh; this percentage is 1.0 percent in 2007 and increases annually to a maximum of 20.0 percent in 2019. ESAI has also developed a projection of the REC requirements for a four state region including the three states adjacent to Delaware - Maryland, New Jersey and Pennsylvania. Because trading will occur on a regional basis, we are evaluating this four state region as representative of a single market, rather than evaluating the Delaware market alone. On the basis of growing demand in this region and relatively low expectations of renewable energy production relative to this demand, we project robust markets for RECs.

Figure 9 below provides a graphic representation of the growth in renewable energy requirements in Delaware and the surrounding states of Maryland, New Jersey and Pennsylvania from 2007 to 2020. In 2007, the REC requirement for the region is only 2.2 million MWh. However, by 2010 the requirement accelerates to over 6.0 million MWh and by 2014 the total requirement is 12.1 million MWh.

With the current supply outlook, we anticipate that there will be a significant shortfall of RECs in the four state region by 2014. An analysis of the PJM generator interconnection queue shows that a total of 6,814 MW of wind projects (nameplate capacity) exist in the queues for the four states in the region. If it is assumed that the Bluewater project will be built in Delaware and the other projects are assessed a historical probability of

***Figure 9 - Regional REC Requirements; DE,NJ,MD,PA***



completion - 19 percent - then 1,659 MW of wind projects could be completed by 2014.

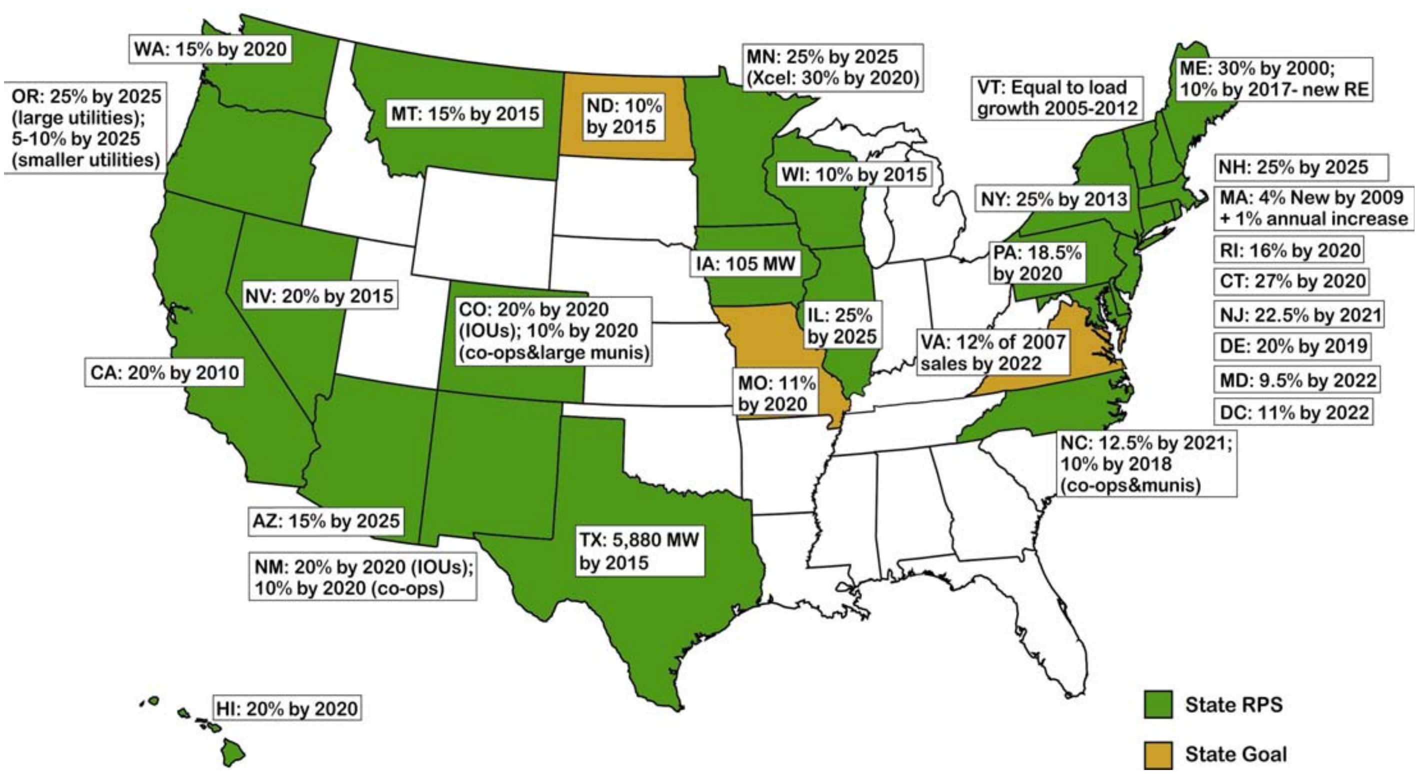
Assessing a capacity factor of 20 percent for the average wind farm results in a MW output of 415 MW of wind generated energy (30 percent capacity factor is assumed for off-shore wind). This equates to 3.63 million MWh of wind generated energy that would qualify for RECs in the four state region, far short of the anticipated 12.0 million requirement in 2014. Under this scenario, the market will continue to develop new wind projects where possible to meet this growing demand.

The 19 percent historical completion factor for projects in the PJM queues applies to all project types over the past five years. Given the actual pace of new wind project construction relative to development interests, the completion rate of 19 percent of project applications in the queue may be high.

### *COMPETITIVE ENVIRONMENT*

The six New England states, New York and four states in PJM (DE, NJ, MD, and PA) all have RPS regulations in place. This will place the buyers of RECs in Delaware in a competitive situation as there is not only a REC shortfall in Delaware, but also in every other region. It is beyond the scope of this analysis to do a detailed East Coast supply and demand balance for RECs, however, we have calculated the total demand for Delaware and the three adjoining states, Pennsylvania, New Jersey and Maryland. In 2010, the Delaware REC requirement is 0.34 million MWh. The total requirement from the four state

***Figure 11 - Renewable Portfolio Standards***
***(29 States and the District of Columbia)***



region exceeds 6.0 million MWh in 2010. By 2014, the first year of Bluewater production, the four state REC requirement will be 12.1 million MWhs compared to the Delaware requirement of 1.6 million MWhs.

RECs are easily deliverable within PJM, and we limit the scope of the competitive discussion to PJM only, however, we do note that it is possible to export RECs from pool to pool (depending on each state's specific standards). Bluewater Wind has committed 175,000 MWhs of RECs to DPL during the potential term of their contract. As such, 262,500 MWhs of RECs have potentially been purchased by DPL when the 50 percent credit is included[4]. The balance of the Bluewater Wind RECs will be supply available to the market, not only to Delaware, but to Pennsylvania, Maryland and New Jersey. Each of these states will be facing shortfalls as well and the load serving entities there will be potential buyers for the Bluewater Wind RECs as well as for RECs generated by other projects in the region.

## ASSESSING THE DELAWARE REC MARKET

As mentioned above, the Delaware REC market is best understood in the context of the PJM REC market with the three adjoining states in PJM that have REC requirements. Each of these PJM states have their own standards and rules, but all states will qualify wind resources as suitable under their RPS programs. Each state has different methods for enforcing compliance for those load serving entities that do not purchase RECs or supply their own.

### Alternative Compliance Payment

The Alternative Compliance Payment, ACP, is the $/MWh penalty for not purchasing RECs in the marketplace and is one benchmark for the potential market value of RECs. In Delaware, the ACP is $25/MWh for the first year of non-compliance for an individual entity and then increases by $10.00 per year until it reaches a maximum of $50.00/MWh in the fourth year. Pennsylvania has an ACP of $45/MWh and Maryland has a $20/MWh ACP, each on an ongoing basis. The New Jersey ACP has not yet been defined, but will be assessed as a premium to the level required to produce RECs by a qualifying project.

If the market value of RECs is higher than the ACP for that state, then the load serving entity would be expected to pay the ACP rather than committing to higher cost resources to supply RECs. If the market value of the RECs is lower than the ACP, then the LSE would purchase from the market.

### Massachusetts - An Example of Current Trading Activity

In Massachusetts, the market is deficit RECs and is projected to remain that way for quite some time, especially if the Cape Wind project does not move forward. The current ACP is $57.12/MWh in Massachusetts and most entities are forced to pay this penalty. Currently, there is limited forward trading activity for RECs in Massachusetts with discussions in the $30-$45 range. At least one transaction for RECs has been completed for a five year period at above $35.00/MWh. This reflects a level at which the supplier (wind based) can meet his financial obligations and provides the buyer with a significant

4 - Suppliers will receive 150% credit toward RPS compliance for energy generated by wind turbines sited in Delaware on or before December 31, 2012. This likely means that the project must receive state and federal permits to build the project before this date.

discount to the ACP; 35 percent.

### RECs - An Equilibrium Cost Based Approach Based on Merchant Wind

ESAI believes that an equilibrium will develop for forward trading in most REC markets in which the market price is at a significant discount to the ACP, but supports the cost of new entry for pure merchant wind projects that will be required to produce the RECs. ESAI has developed a high level assessment of the REC price required to support a new merchant land-based wind project in PJM.

The proxy project would be a land-based merchant wind project within PJM existing as a price taker in the energy and capacity markets (no PPA for energy or capacity). The parameters include a 7x24 energy price of $50.00/MWh produced at a 25 percent capacity factor. The capacity revenue assumed is $6.00/kw-mo which is reflective of eastern PJM, (Rest of Pool is much lower at $3.00/kw-mo). A production tax credit of 2.1 cents per kilowatt for 10 years was also included. The financial parameters included a 15 percent overall return over a 20 year time span. Three scenarios were looked at for the cost of construction[5]; $1,800/kw, $2,000/kw and $2,200/kw. These costs are consistent with recent announcements of land-based projects.

The $1,800/kw case resulted in a requirement of $37.00/MWh revenue from the REC market. We assume that a seller may be willing to discount this somewhat for a few years in order to get the project moving, but that on average, he would look to recover the $37.00/MWh price level or higher. When shifting the cost basis to $2,000/kw, the REC revenue requirement in PJM moves to slightly above $50.00/MWh. Every project will of course have its own particular economics, and may have REC revenue requirements that are different than described here.

We believe that due to the large deficit potential in the PJM market, the REC suppliers are in a good position to receive their revenue targets, as long as they are below ACP levels. In Pennsylvania, with the ACP at $45.00/MWh, it is likely that buyers will be willing to pay close to $30.00/MWh, using the 35 percent discount to ACP that has traded in Massachusetts. It is unclear whether REC producers would sell at that level, as this represents a 20 percent discount to target levels. Assuming that developers in PJM are innovative and creative in this competitive marketplace, we believe that many developers may find a way to make the $30.00/MWh level work.

### The Delaware REC Outlook - Base Case (Lower REC Prices)

The base case for the ESAI REC outlook assumes the very competitive environment for REC suppliers and the $30.00/MWh benchmark is assumed rather than the $37.00/MWh level actually needed to support new entry. This base case forecast is utilized for all scenarios in which the Bluewater project is constructed and operating. For the market only case, we use the equilibrium (high) case.

From 2007 to 2009, we make the simplifying assumption that Delaware REC buyers will be able to source RECs at below the ACP level of $25.00/MWh. However, by 2010, the Delaware REC shortfall is 290,000 MWh (after accounting for existing supply at Amresco) and we believe that it is unlikely that the market can secure RECs at below the

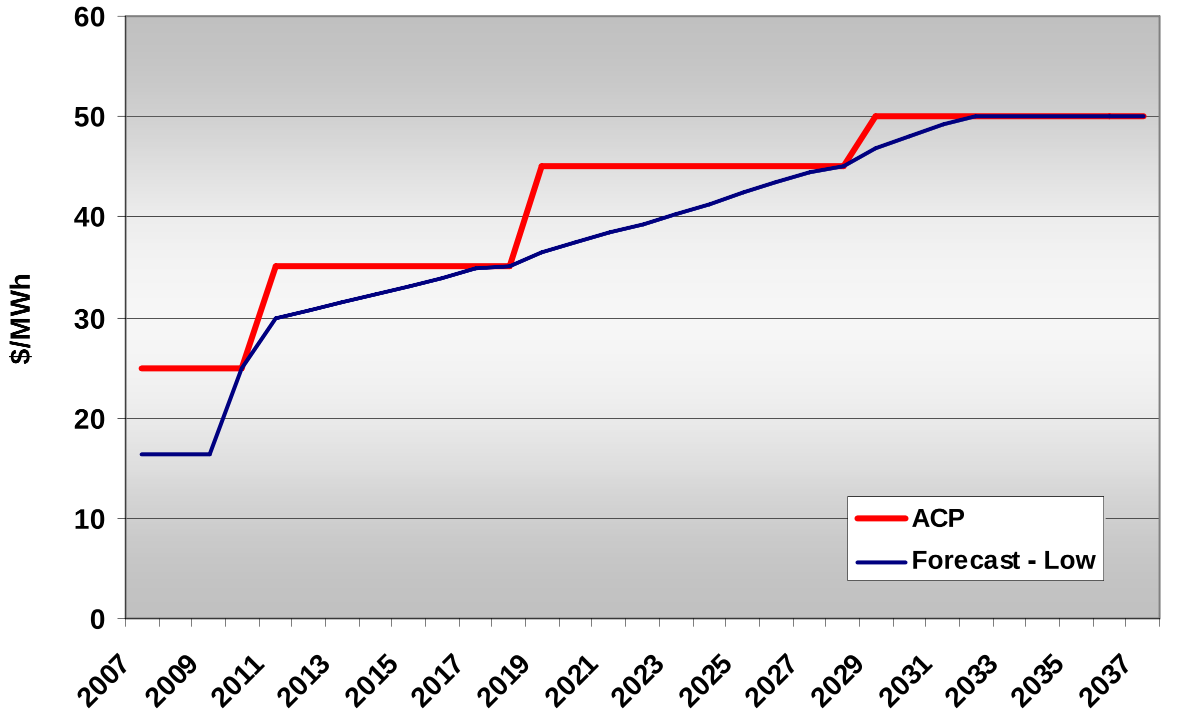
5 - We note that the land-based wind project costs have no relevance to the off-shore wind project costs such as the 450 MW subject project. Land-based projects are typically much smaller and often generate lower capacity factors than the larger off-shore projects. Land-based projects however, are likely to be the major supply source for RECs.

$30.00/MWh most competitive merchant level. For 2010, Delaware LSEs will then choose to pay the ACP at $25.00/MWh.

In 2011, the ACP moves to $35.00/MWh as the LSE would have paid the 2010 penalty of $25.00 rather than source from the market. The $30.00/MWh merchant wind REC competitive benchmark can then set the market price in 2011 as it is below ACP.

Assuming a cost escalator of 2.5 percent per year, the $30.00/MWh merchant wind benchmark will escalate over time as shown in Figure 12. The ACP will get triggered again in 2019 and again in 2029 when the REC value would reach the maximum ACP of $50.00/MWh.

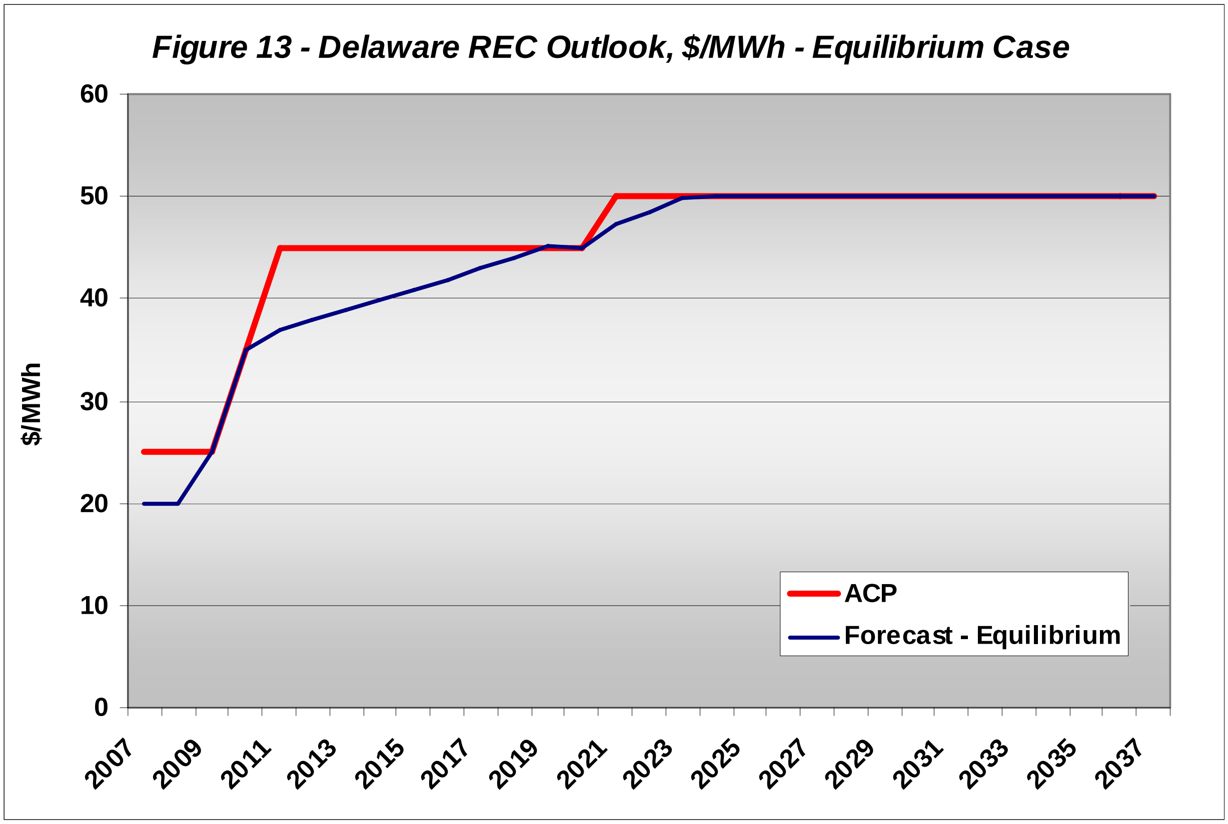
***Figure 12 - Delaware REC Outlook, $/MWh - Low Case***




***The Delaware REC Outlook - Equilibrium Case***

ESAI considered the higher equilibrium outlook in a similar manner as the forego-ing. Without the Bluewater project, the ACP would be triggered sooner in the early years - 2009. The 2010 ACP is then $35.00 which is below the $37.00/MWh merchant wind sell-ing price (no discounted pricing in this case, the merchant seller looks to recover costs fully). The 2010 price would then be at the $35.00 ACP which then triggers the $45.00 ACP for 2011. The $37.00/MWh equilibrium price then sets price for 2013 and escalates at 2.5 percent per year until the $45.00 ACP is utilized again in 2020. Finally, the max ACP is reached in 2024.

This case shows a reasonable increase from the base case assumptions in the low or competitive case and we utilize this for the market purchase only scenario in which no Bluewater project exists.




*Note: The forecasts of REC supply and demand in Delaware do not incorporate demand side management projects that will achieve important energy savings. Nevertheless, we do not anticipate that these savings will materially impact our outlook for significant deficits in REC supplies in 2012 and beyond.*

### *EMISSIONS AND CO2 CONSIDERATIONS*

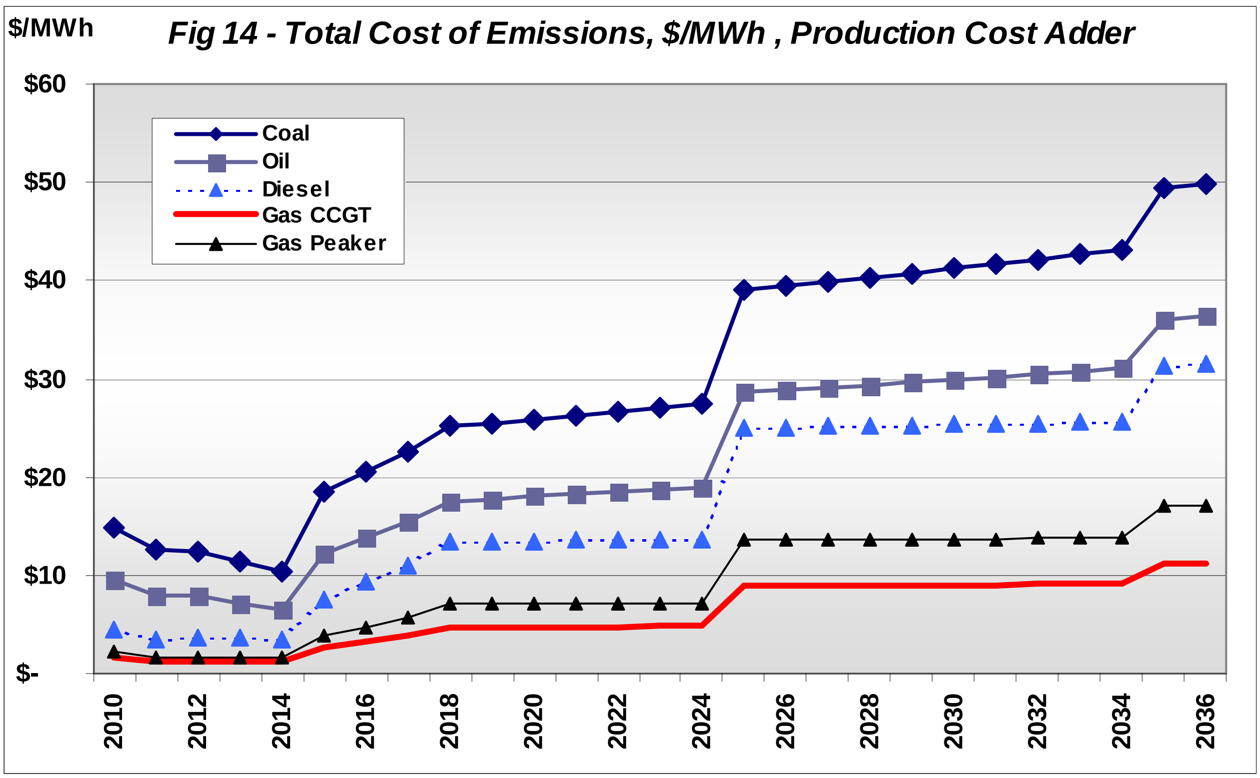
Although the U.S. has not signed on to the Kyoto protocols, there is a groundswell developing at the state level towards implementing CO2 emission standards. In the Northeast, nine states are considering an initiative that would limit CO2 emissions by power generators. The Regional Greenhouse Gas Initiative (RGGI) is a cooperative venture by the governors of the six New England states plus New York, New Jersey, and Delaware. Pennsylvania, Maryland and Washington, D.C. are observers. RGGI's goal is to reduce GHG to 1990 levels. RGGI has developed a database and has contracted with an outside firm to develop a model of the effects of different GHG rule paradigms. The goal is to develop a cap and trade program for CO2 emissions.

The uncertainty inherent in these CO2 emissions discussions will also tend to favor gas-fired combined cycle units for future capacity additions over coal units. Even the newer technology coal plants will have to find a way to sequester the CO2 in order to circumvent the potential high costs of purchasing CO2 credits. It is very likely that any renewable resources will have little or no net CO2 emissions, providing an additional boost to the potential for these resources to be pursued.

The success of a CO2 program may hinge on the penalty for non-compliance. A $5 or $10/MWh penalty may not be enough incentive to coerce generators into making investments or buying credits. Such a penalty would then amount to a tax on the higher CO2 emitters such as coal plants.

A good example of this phenomenon can be seen in the implementation of the renewable portfolio standards in Massachusetts. In that state, the $55/MWh penalty for not

**Fig 14 - Total Cost of Emissions, $/MWh , Production Cost Adder**



meeting RPS portfolio requirements (2005) is gladly paid by marketers and end-users to meet the 2005 requirement of 2.0 percent. The net penalty is a $1.00/MWh charge on net energy consumption that is not particularly onerous. As a result, Massachusetts is falling very short in meeting their in-state renewable capacity targets.

The industry is approaching the CO2 challenge with caution. Most participants will acknowledge that some sort of CO2 legislation will begin to be passed eventually. ESAI believes that the strong political resistance to the possibility of high CO2 prices will result in fairly low price caps, should legislation be enacted. Although, to have any viable impact on fuel consumption patterns, the penalty for non-compliance needs to be on the order of $15-$20/ton CO2 or higher. This will not force a widespread retirement of coal plants, but it would have the effect of narrowing the competitive gap between coal and gas fired plants.

***Figure 15 - CO2 Emissions Credit Cost, $/ton***

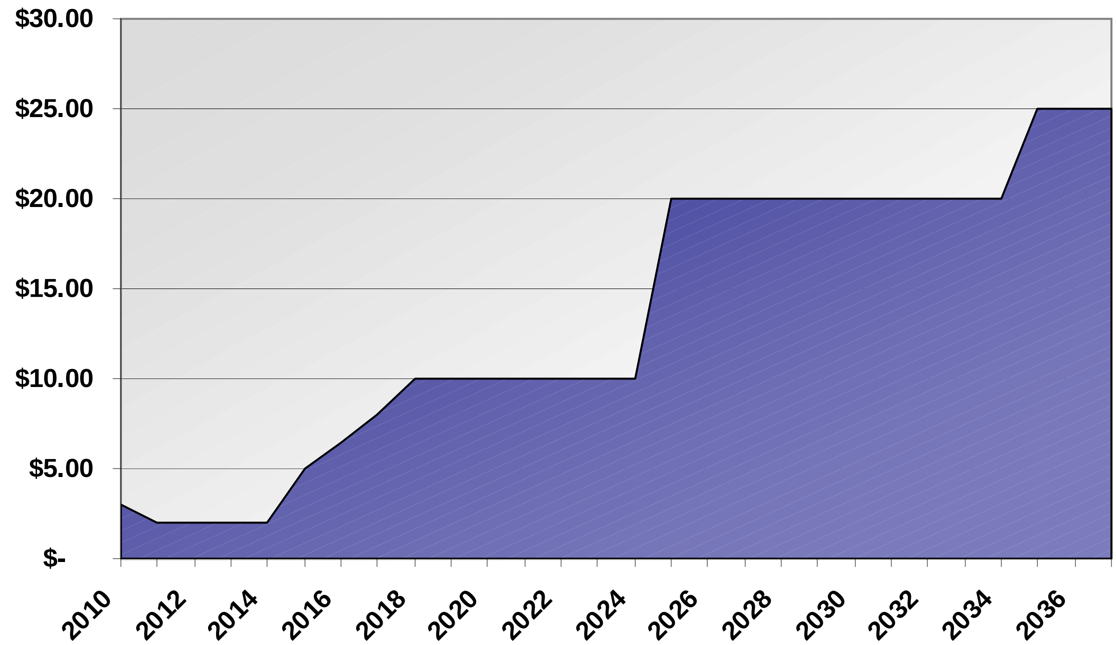
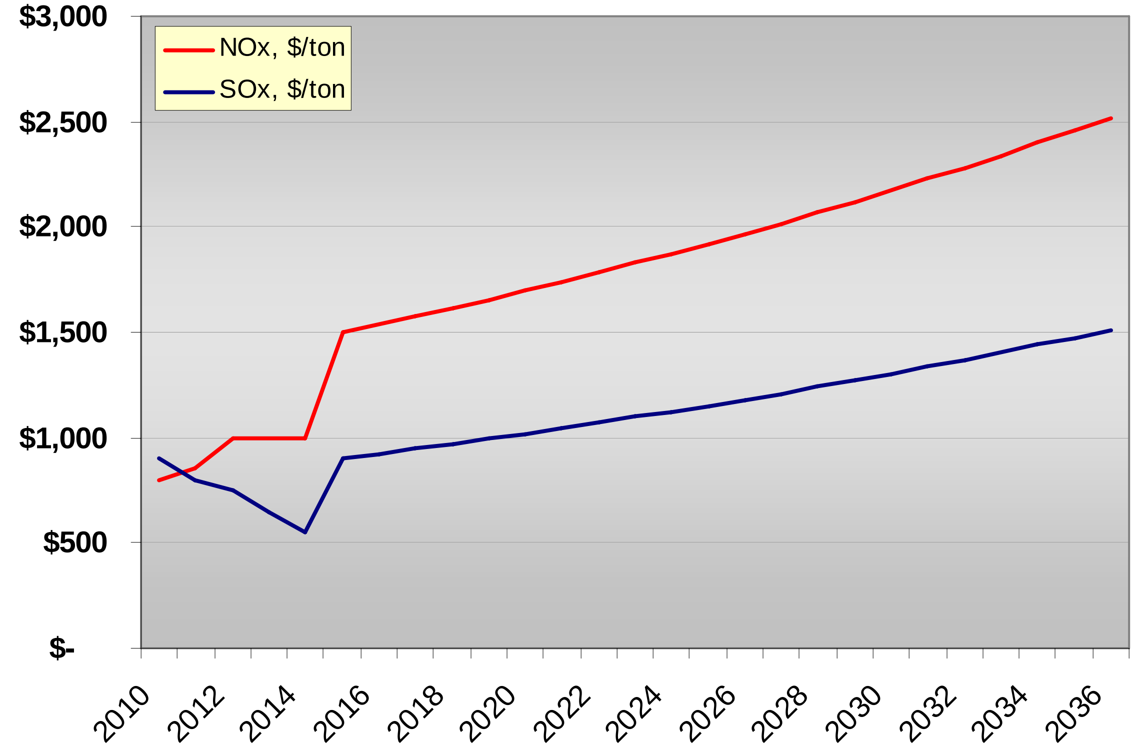



Figure 15 provides ESAI's outlook for CO2 emissions credits. Prices will be low under the RGGI regime until 2015 when more stringent standards apply. Due to the ability to bank credits prior to 2015, prices should move up slowly to the $10/ton 'safety valve' price. If this price level, or higher, persists, emissions credits from other markets can be purchased and applied to the RGGI program.

Beyond 2025, we have assumed an equilibrium price that is consistent with where the European CO2 credits have been trading. ESAI also believes that caps in these ranges would be applied by any Federal CO2 programs to protect industry interests.

Figure 16 provides an overview of ESAI's projections for NOx and SOx emissions credit costs.

**Figure 16 - SOx and NOx Emission Credit Projections, $/ton**




Note: For ease of readership, the summary and conclusions are provided at page 2 of this report.

### *PJM'S RELIABILITY PRICING MODEL*

In its April 20th, 2006 order, FERC made some key determinations regarding the future of PJM's capacity markets. Firstly, FERC determined that the then existing capacity construct was unjust and unreasonable. Secondly, they found that the Reliability Pricing Model proposal put forth by PJM on August 31st, 2005 was a just and reasonable replacement for the existing market design. FERC then ordered a settlement process to proceed among market participants to determine an alternative to RPM or an agreement on a revised RPM solution. After more than four months of settlement discussions, PJM and its stakeholders reached a settlement regarding the structure of a new capacity market for PJM. The settlement discussions, under the direction of a FERC Administrative Law Judge and involving over 150 individuals representing more than 65 parties, yielded a revised Reliability Pricing Model (RPM) for the PJM region.

Importantly, the RPM Settlement did not disturb the major components of the August 31st, 2005 RPM filing as outlined below:

- A forward procurement auction to meet capacity obligations four years in advance,
- Use of a variable resource requirement (VRR) demand curve,
- Establishment of locational capacity requirements,
- Demand response and transmission participation,
- Explicit market power mitigation rules,
- An "opt-out alternative" for LSEs to not participate in the RPM.

#### *PJM Capacity Forecast Design*

The RPM design centers on a Variable Resource Requirement Curve, also known as a demand curve. Figure 17 compares the current RPM VRR curve (in red) with the demand curve in the original PJM filing.

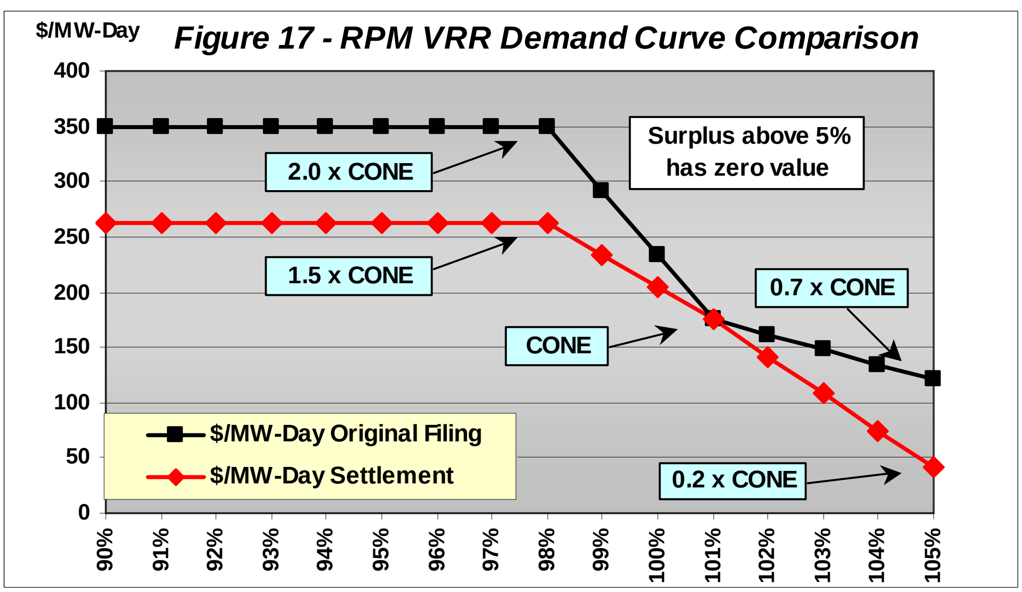



*Figure 17 - RPM VRR Demand Curve Comparison*

There are several key points which define the PJM VRR demand curves as outlined in Figure 18. The rules are extensive and complex, but the demand curve clearing price mechanism as described below is the most important aspect of the RPM construct.

The demand curve is what sets the level of the RTO clearing price. Simply put, increasing the surplus above the 15 percent reserve margin requirement lowers the price by moving to the right along the x-axis (see Figure 18). Increasing the surplus from 1 percent to 5 percent moves the clearing price from point B ($5.20/kw-mo) to Point C ($1.04/kw-mo) - a drop of over $4.00/kw-mo. Conversely, if the market were to move from a generation surplus of 1 percent to a deficit of 3 percent, then the clearing price would move from point B, $5.20/kw-mo, to point A, $7.84/kw-mo - an increase of $2.60/kw-mo.

Under the RPM capacity model, PJM will pay a capacity payment to a generator based on the clearing price and the size of the unit. The total cost paid to generators is paid by load - in most instances, a load serving entity.

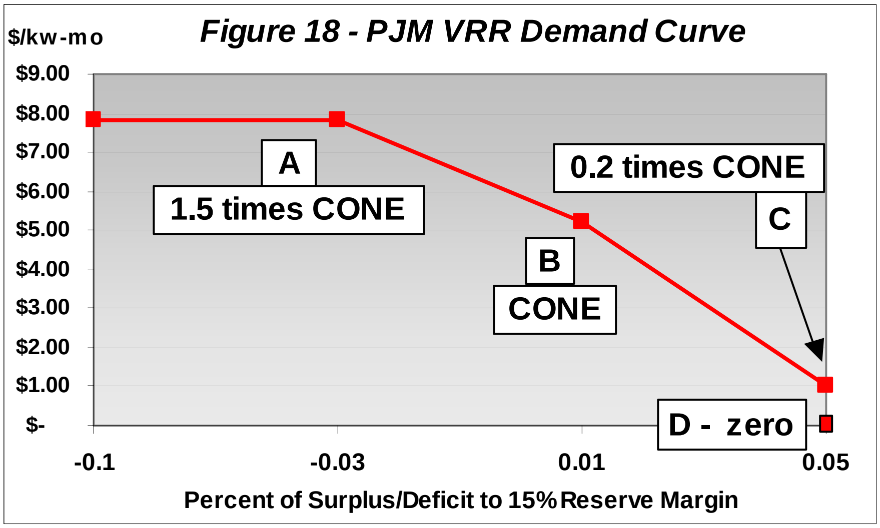
Given the expected surplus conditions for 2008 of approximately 3 percent, the RTO payment simply calculated from this demand curve would be $3.12/kw-mo. If the surplus decreases to 1 percent as expected by 2010, the demand curve based clearing price would be $5.20/kw-mo, an increase of $2.08/kw-mo (not accounting for inflation adjustments). For a typical 300 MW generator, the 2008 payment would be $11.2 million based on the surplus of 3 percent. However, this payment would increase to $18.7 million in 2010 based on an expected surplus of 1 percent.

If a deficit of 3 percent were seen in 2010 due to load growth and no capacity additions, the capacity payment would increase to the maximum of $7.84/kw-mo, resulting in a $28.2 million for the 300 MW generator above the 3 percent surplus case. Load serving entities would then be responsible to pay the corresponding increases based upon their peak load requirements in the pool. This increase of $17 million at the maximum price level equates to $6.50/MWh that would be paid by load under maximum payment conditions above the payment in the 3 percent surplus case.

The demand curve parameters are described below:

**A - Maximum Payment**

The PJM VRR curve reaches a maximum value of $257/MW-day ($7.84/kw-mo) at 97 percent of the installed reserve margin requirement. This point is defined on the y-axis at a price of 1.5 times the capacity price required to support the cost of new entry (CONE). CONE is



defined by PJM as $170/MW-day for the 2007-2009 capacity years and represents the capacity price that is required to support a new power plant entry into the market after deducting energy and ancillary service revenues. If capacity prices are below the cost of new entry, investment in new power plants will theoretically not move forward. Declining surpluses would then push prices higher as defined by the demand curve and then trigger new investment in power plants.

**B - Midpoint**

Point B represents the demand curve price at an x-axis point of 1 percent surplus to the reserve margin requirements and is representative of the capacity price on the y-axis that is equal to the cost of new entry (CONE).

**C - End of Curve**

The PJM VRR curve does not extend to zero on a continuous slope; it stops moving downward at the x-axis supply surplus of 5.0 percent. The basis for point C is 0.2 times CONE.

**Zero Value Point**

The PJM VRR curve reaches a zero value when the generator surplus is more than 5 percent above the installed reserve margin requirement (currently 15 percent above peak load). At capacity surpluses above 5.0 percent, generators receive no capacity payments.

Overall, the PJM VRR curve provides for much higher revenues when capacity surpluses are low, or when the capacity is short of the installed reserve margin target – currently 15 percent in PJM. ESAI has developed forecasts for the PJM RTO based on the demand curve and on ESAI's outlook for capacity surpluses in the RTO and in the Eastern PJM areas.

PJM has used $170/MW-day ($5.20/kw-mo) as the cost of new entry in the capacity years 2007-2009. Due to the significant increases in power plant construction costs, ESAI has assumed a one time increase in the CONE value of 15 percent in 2010 and a 3 percent inflation escalator to CONE starting in 2011. ESAI's forecasts of supply surpluses or deficits for each region are applied to the demand curve to determine the capacity clearing prices. Declining surpluses and increasing CONE values provide for increasing RPM capacity clearing prices going forward.

The Bluewater capacity price as defined in the September 14, 2007 term sheet is $65.23/kw-yr and would be escalated to $73.80/kw-yr in 2012. ESAI's estimate of the cost of new entry is $76.08/kw-yr in 2012, based upon the metrics above. The actual cost of new entry is likely to be higher than this level based upon conservative upward adjustments.

The high fuels case escalates all fuel prices (natural gas, #6 oil, diesel, kerosene, and coal) by 30 percent. In the outer years, from 2017 and beyond, the escalator remains 4.0 percent - the same as in the base case. The impact on consumers is a savings of $7.75 per month for the NRG hybrid case and $7.08 on the Conectiv hybrid case; on average over the 25 year contract period. The first years result in higher net costs to consumers, but

### *Market Cost Comparison - High Fuels Case; 2014-2038*
### *Bluewater Wind Hybrid Combinations Vs. Market Purchase*

**25 Year Average, Nominal Dollars**
(Inflation Adjusted)

| | Market | Bluewater NRG | Bluewater Conectiv | |
|---|---|---|---|---|
| **Blended Energy Price, $/MWh** | $189.71 | $154.49 | $168.33 | |
| **Blended Capacity Price, $/MWh** | $17.70 | $25.47 | $14.27 | |
| **RECs** | $9.12 | $6.25 | $6.25 | |
| **TOTAL $/MWh** | $216.52 | $186.21 | $188.85 | |
| ***TOTAL Cents/kWh*** | ***21.65*** | ***18.62*** | ***18.88*** | |
| | *Hybrid % of DPL Avg Load* | | | |
| ***Add'l Monthly Cost to Consumers*** | *25.6%* | ***-$7.7582*** | ***-$7.0831*** | ***25 Yr Avg*** |
| (1,000 kWh/mo average, nominal dollars) | *34.0%* | ***$4.2706*** | ***$2.3784*** | ***Year 1*** |
| | *18.6%* | ***-$10.2837*** | ***-$8.9158*** | ***Year 25*** |
| ***Contract Cost Vs Market (millions)*** | | ***(1,991)*** | ***(1,818)*** | |

**25 Year Average, Levelized 2007 Dollars**
(No inflation included)

| | Market | Bluewater NRG | Bluewater Conectiv | |
|---|---|---|---|---|
| **Blended Energy Price, $/MWh** | $147.18 | $120.59 | $131.37 | |
| **Blended Capacity Price, $/MWh** | $13.82 | $20.54 | $11.47 | |
| **RECs** | $7.27 | $4.87 | $4.87 | |
| **TOTAL $/MWh** | $168.27 | $146.00 | $147.71 | |
| ***TOTAL Cents/kWh*** | ***16.83*** | ***14.60*** | ***14.77*** | |
| | *Hybrid % of DPL Avg Load* | | | |
| ***Add'l Monthly Cost to Consumers*** | *25.6%* | ***-$5.6996*** | ***-$5.2627*** | ***25 Yr Avg*** |
| (1,000 kWh/mo average, 2007 dollars) | *34.0%* | ***$4.0517*** | ***$2.2565*** | ***Year 1*** |
| | *18.6%* | ***-$7.2269*** | ***-$6.2656*** | ***Year 25*** |
| ***Levelized Contract Cost Vs Market (millions)*** | | ***(1,404)*** | ***(1,297)*** | |

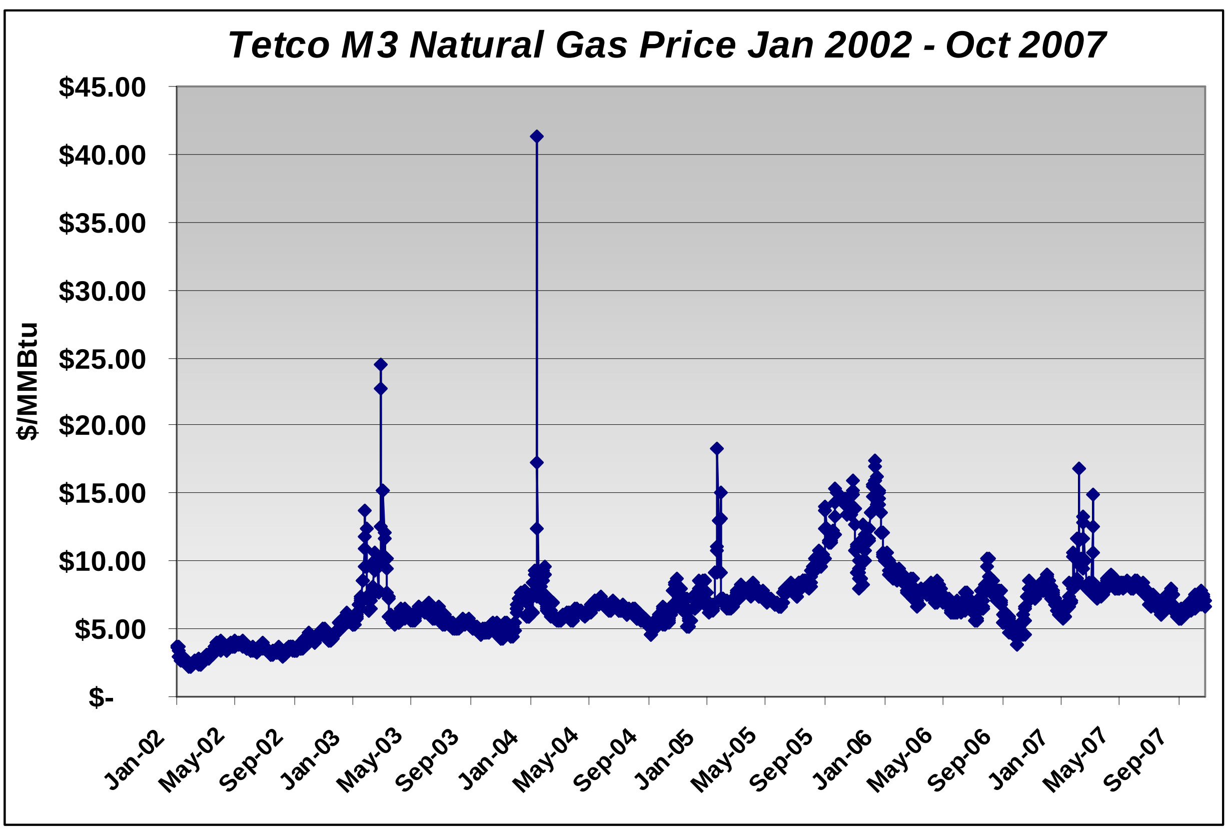
| | *Nominal Price Avg* | *Levelized (2007 $)* | | |
|---|---|---|---|---|
| ***Transco Zone 6 Non NY Gas Price*** | **$20.66** | **$16.26** | **per MMBtu** | ***25 Yr Avg*** |

by year 3 the net cost is breakeven and by year 8 the cumulative costs are recovered and savings begin to accrue.

The 30 percent increase over the expected forecast is used as a high case scenario. This increase of 30 percent is based on the standard deviation of prices at Tetco M3 (and Transco Zone 6 Non-New York) over the period from January 2004 to October 2007. The standard deviation of daily Tetco M3 prices is 30 percent and is the basis for our evaluation. This is a similar high case increase in gas prices as requested by the Independent Consultant in the April 4, 2007 Interim Report.

The standard deviation is a statistical representation of the point of deviation from the mean at which 90 percent of all of the observations are below. For example, if the mean natural gas price was $10.00/MMBtu with a standard deviation of 30 percent, 90 percent of the observed prices would be below $13.00.

Over a longer period of time, the observed standard deviation of actual market prices is higher than 30 percent. From January 2002 to October 2007, the standard deviation was 40 percent. For shorter periods of time, the standard deviation can be higher or lower, depending on the volatility of prices during the specific time period. For the period, January 2006 to October 2007, the standard deviation of Tetco M3 gas daily gas prices was low at only 13 percent. However, in the 2005 time period that saw Hurricanes Katrina and Rita disrupt prices, the volatility was high and the standard deviation for 2005 was 30 percent. The chart below provides the daily Tetco M3 price series from January 2002 to October 2007.



### *COMMODITY ESCALATOR ASSUMPTIONS*

The Bluewater term sheet had included price escalators to reflect price increases in the capital cost expenditures over the time period from the contract execution date until the financial closing. While this analysis does not include the commodity escalator, ESAI developed an analysis of the likely outcome or these escalators as provided below.

The price escalators would have been applied to the energy price and are separate from the 2.5 percent energy price escalation as outlined in the compensation section of the Bluewater-DPL term sheet.

The price escalator formulas are provided in Attachment 4 of the term sheet and utilize the percent escalation over the five year time period until financial closing. Using these formulas, ESAI calculates a net increase in the energy cost of 1.37 percent on the basis of 2010 dollars.

There are futures markets for many of the commodities listed in the Attachment 4 escalator formula. These markets trade generally from two to four years forward and active quotations can be found from publicly accessed websites. Because the metals commodities trade from 18 months to two years forward, we have based this estimate of the escalators on 2010.

The forward structure of all of the commodity markets, with the exception of aluminum, are 'backwardated'. This means that the current spot month trading level is higher than the future prices. In other words, the forward prices are trading at a discount to the current spot month trading prices.

The assumptions utilized are outlined below and price quotation indications from October 18, 2007 are provided below:

- Copper - Trades on the NYMEX exchange. The October 2007 contract was trading at 3.62 cents per pound. The September 2009 contract was trading lower at 3.298 cents per pound.
- Aluminum - Trades on the NYMEX exchange. The October 2007 contract was trading at 1.105 cents per pound. The September 2009 contract was trading slightly higher at 1.12 cents per pound.
- #2 Heating Oil (diesel) - Trades on the NYMEX exchange. The October 2007 contract was trading at $2.34 per gallon. The October 2010 contract was trading lower at $2.15 per gallon.
- WTI Crude Oil - While not specifically in the formula, it acts as a benchmark for oil and oil products in general. WTI crude oil trades on the NYMEX exchange. The November 2007 contract was trading at $87.61 per barrel. The November 2011 contract was trading lower at $75.44 per barrel.
- Lead - Trades on the London Metals Exchange. The current spot price was US$3798 per tonne. The price for a contract 18 months forward was trading at $3390 per tonne.

- Steel - No futures exchanges are trading steel. The CRU posted global steel index has risen by an average rate of 9.5 percent from 2002 to 2007. The rate of price increase of the global steel index has slowed somewhat since mid-2004. We assume that prices will rise by 9.5 percent over the evaluation period.
- Currency futures - At this point, it is unclear whether the project will have currency exposure, and if it does, it is unclear which currency would be the basis for evaluation in the escalator formulas. ESAI examined the forward markets for $/Euro and $/Krone and found that the markets were trading flat, i.e., no premiums or discounts for currency exchange 18 months forward.

The escalator formulas were evaluated using the figures outlined above. The forward trading values are not necessarily an indicator of actual future prices, but rather they are a concrete indicator of the price at which these commodities can be bought or sold in the markets today, for delivery some time in the future. This is particularly relevant to this evaluation as a turbine supplier could 'lock in' the costs of his materials against delivery of his turbines to Bluewater using forward contracts as outlined above. If a supplier were to utilize these contracts, his costs would be lower than the prices obtained by purchasing these commodities for prompt delivery in the current market conditions.

In undertaking this escalator analysis, ESAI used the revised price escalator formula provided to the PSC Independent Consultant on October 16, 2007. This formula would reduce the overall impact of commodity price increases on the Energy price as compared with the proposal included in the September 14, 2007 term sheet.

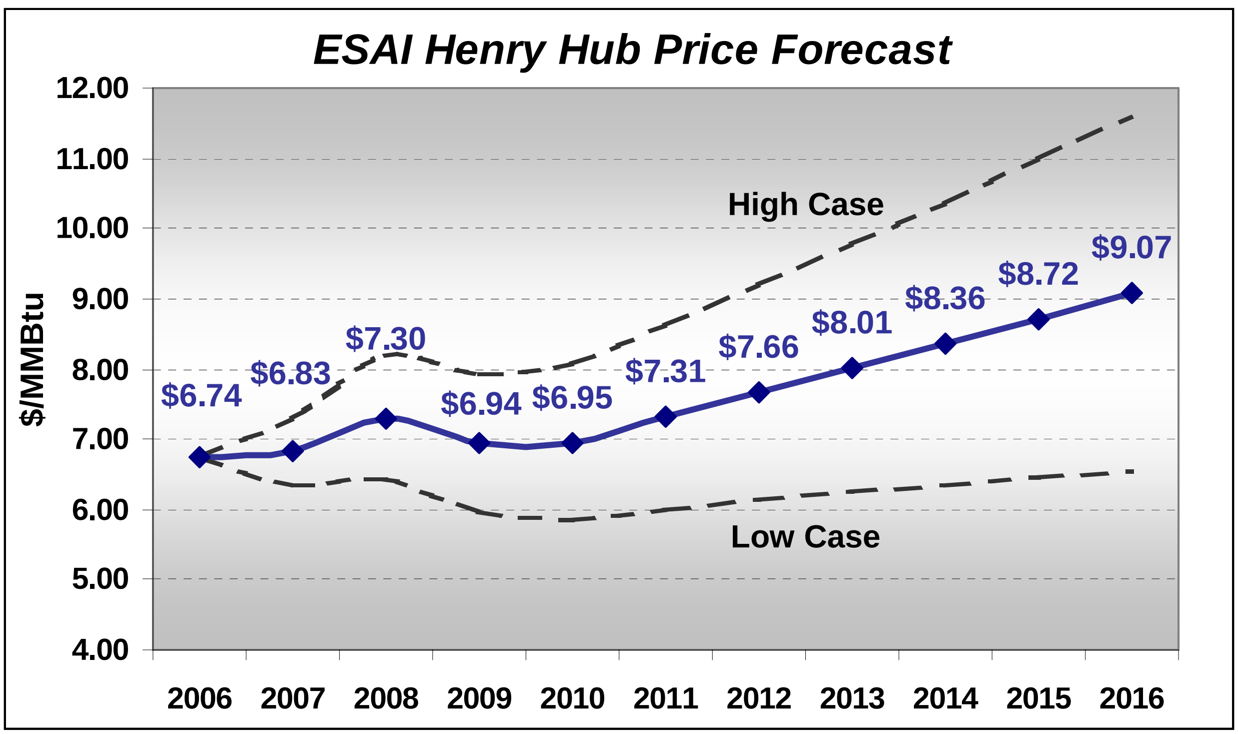
### *Long Term Outlook—North American Natural Gas*

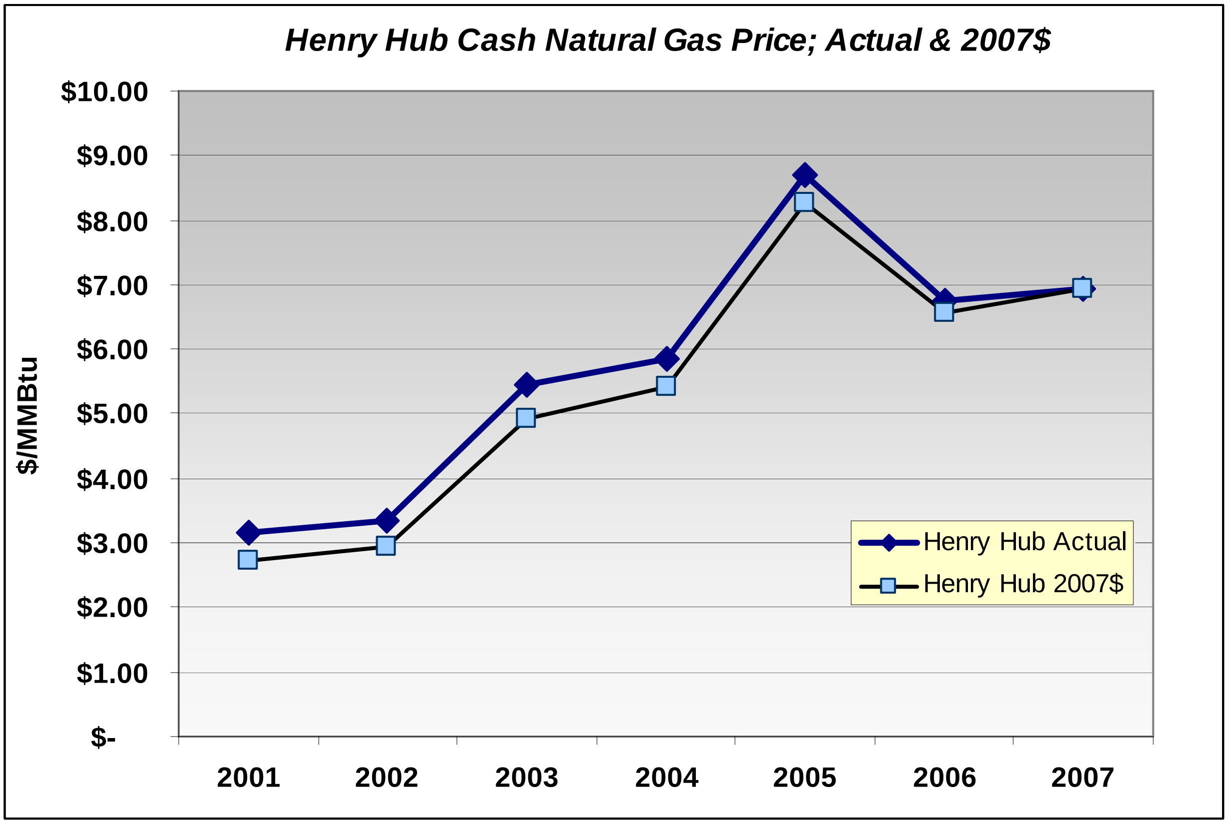
ESAI's 10-year natural gas outlook is stable to bullish due to our expectation that gas-fired power generation will grow at a rate of 5.0 percent per year, pushing total U.S. demand to 26.0 Tcf by 2016. At the same time, reserve depletion in the Gulf of Mexico and in Alberta has caused a permanent shift to the left for the U.S. gas supply curve - causing further upside pricing pressures. However, deepwater production increases in the Gulf of Mexico and increases in LNG imports will stabilize supply for the next three to four years and prices are expected to stabilize in the $6.00 to $8.00/MMBtu range during the 2008 to 2011 period. Longer term, prices are expected to rise at a rate of approximately 4.0 percent per year, slightly above inflation due to the lack of spare production capacity as described below.

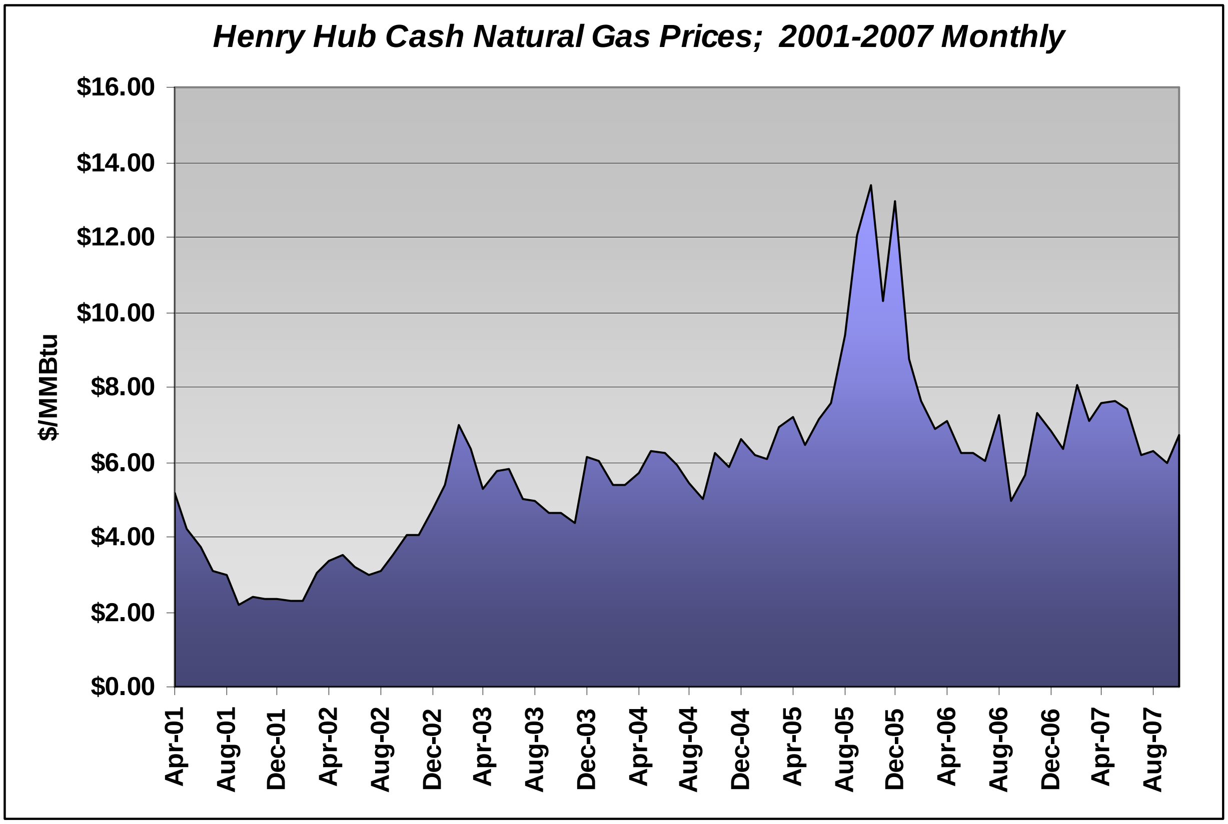
Deepwater production increases in the Gulf of Mexico are being seen with the introduction of the Independence Hub, a gathering point for deepwater production rigs. The Independence Hub is currently producing up to 0.25 Bcf/d and will increase to 1.0 Bcf/d by early 2008. Other large deepwater finds will begin producing in 2008 and 2009, notably BP's Atlantis and Thunder Horse projects which will help offset Gulf of Mexico production declines.

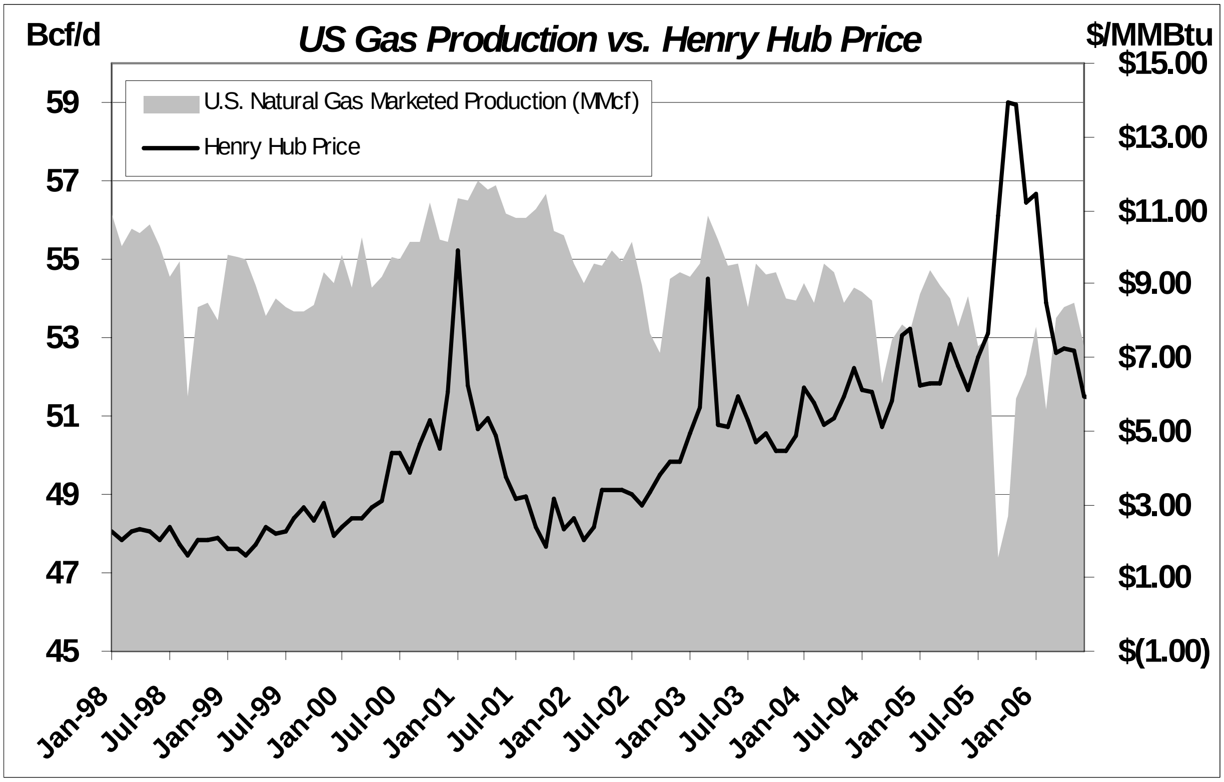
There are a number of factors that underpin ESAI's outlook on the natural gas market. We highlight these factors below, most of which are bullish:

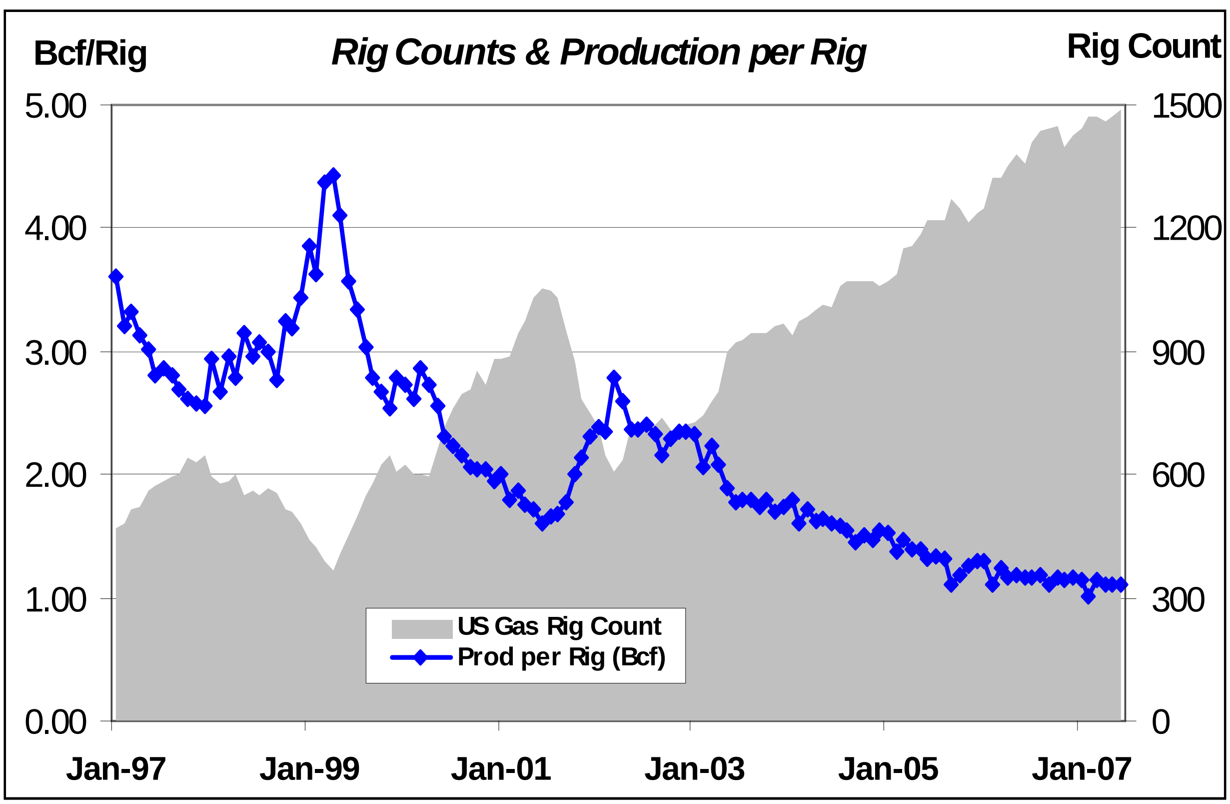
1) **Natural gas production** is declining on a long term basis, particularly in the offshore Gulf of Mexico. Recent deepwater finds may stabilize the declines in the near term.
2) **Rockies Express**, the large transcontinental pipeline from Wyoming to Missouri originally, and its extension to Ohio is expected to bring stranded reserves to key markets.
3) **Production capacity utilization** is maxed out. There is no buffer of spare capacity against

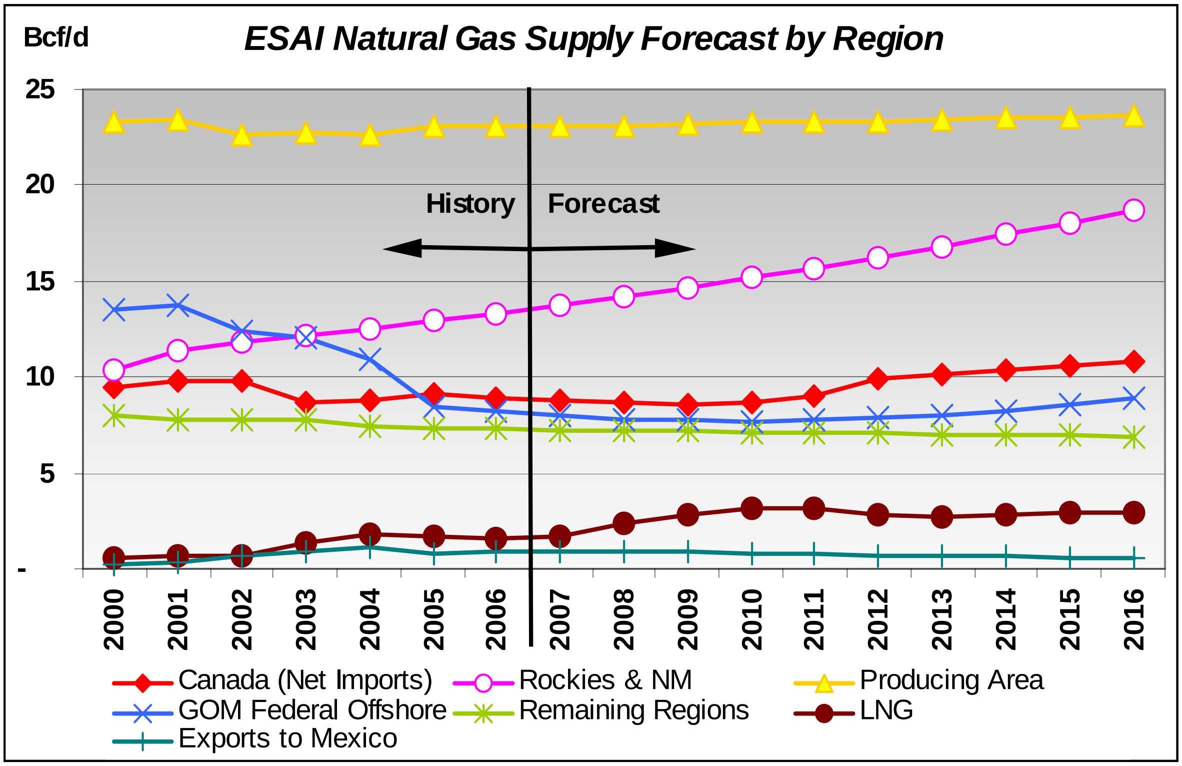


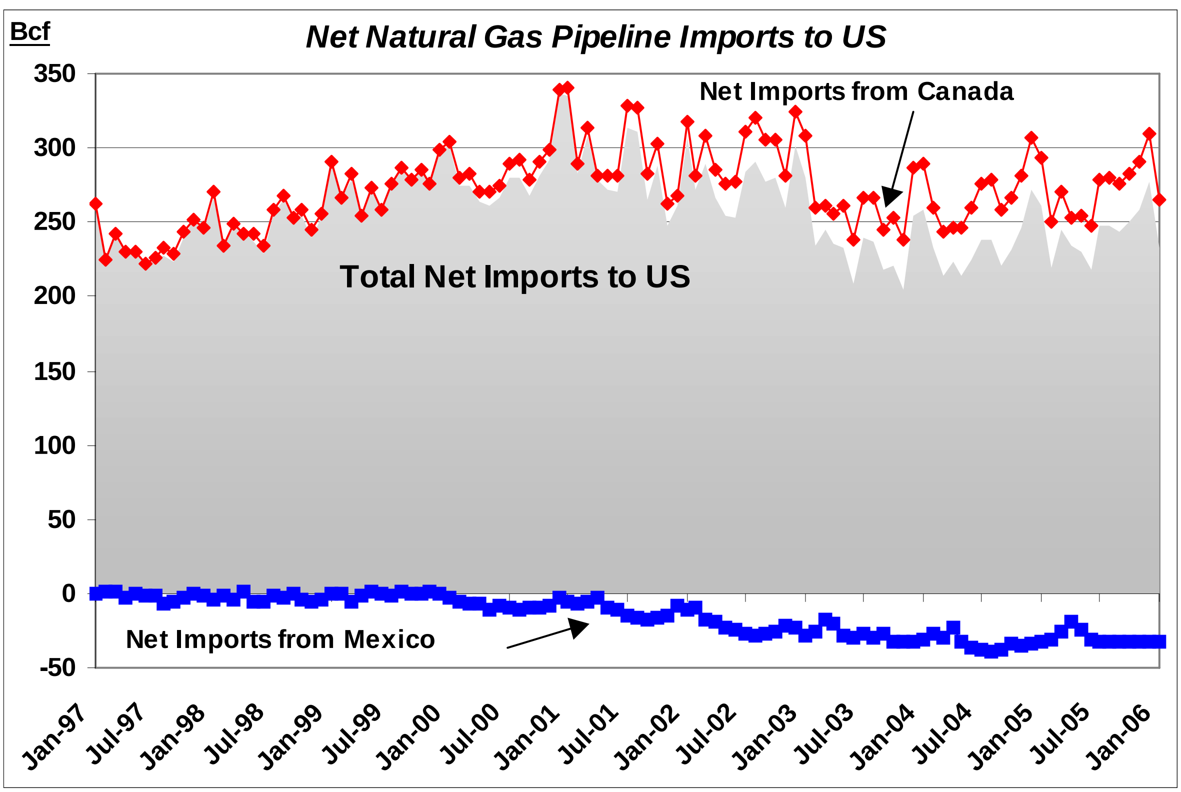

Henry Hub Cash Natural Gas Price; Actual & 2007$
$/MMBtu
$10.00
$9.00
$8.00
$7.00
$6.00
$5.00
$4.00
$3.00
$2.00
$1.00
$-
2001
2002
2003
2004
2005
2006
2007
Henry Hub Actual
Henry Hub 2007$

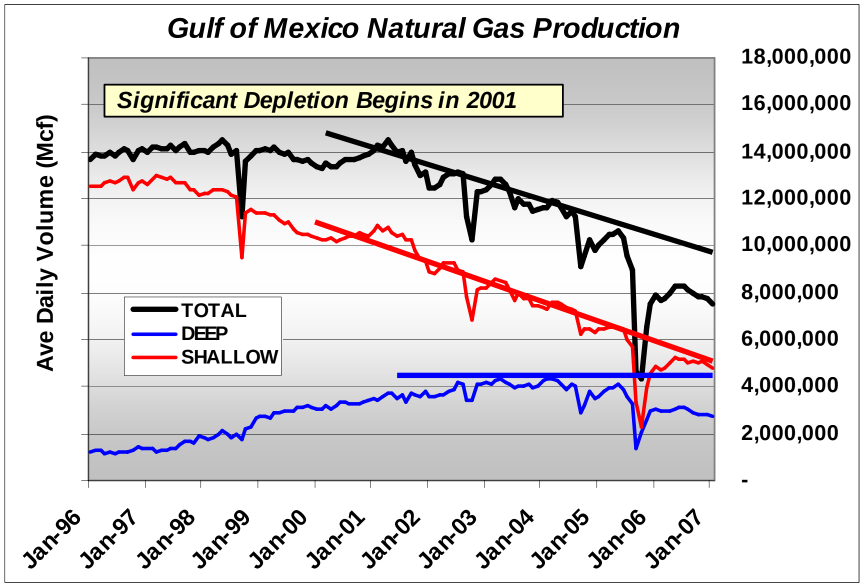

Henry Hub Cash Natural Gas Prices; 2001-2007 Monthly
$/MMBtu
$16.00
$14.00
$12.00
$10.00
$8.00
$6.00
$4.00
$2.00
$0.00
Apr-01
Aug-01
Dec-01
Apr-02
Aug-02
Dec-02
Apr-03
Aug-03
Dec-03
Apr-04
Aug-04
Dec-04
Apr-05
Aug-05
Dec-05
Apr-06
Aug-06
Dec-06
Apr-07
Aug-07


US Gas Production vs. Henry Hub Price
Bcf/d
$/MMBtu
U.S. Natural Gas Marketed Production (MMcf)
Henry Hub Price
59
57
55
53
51
49
47
45
$15.00
$13.00
$11.00
$9.00
$7.00
$5.00
$3.00
$1.00
$(1.00)
Jan-98
Jul-98
Jan-99
Jul-99
Jan-00
Jul-00
Jan-01
Jul-01
Jan-02
Jul-02
Jan-03
Jul-03
Jan-04
Jul-04
Jan-05
Jul-05
Jan-06


Rig Counts & Production per Rig
Bcf/Rig
Rig Count
5.00
4.00
3.00
2.00
1.00
0.00
1500
1200
900
600
300
0
US Gas Rig Count
Prod per Rig (Bcf)
Jan-97
Jan-99
Jan-01
Jan-03
Jan-05
Jan-07


Bcf/d
ESAI Natural Gas Supply Forecast by Region
25
20
15
10
5
-
History
Forecast
2000
2001
2002
2003
2004
2005
2006
2007
2008
2009
2010
2011
2012
2013
2014
2015
2016
Canada (Net Imports)
Rockies & NM
Producing Area
GOM Federal Offshore
Remaining Regions
LNG
Exports to Mexico


Bcf
Net Natural Gas Pipeline Imports to US
350
300
250
200
150
100
50
0
-50
Net Imports from Canada
Total Net Imports to US
Net Imports from Mexico
Jan-97
Jul-97
Jan-98
Jul-98
Jan-99
Jul-99
Jan-00
Jul-00
Jan-01
Jul-01
Jan-02
Jul-02
Jan-03
Jul-03
Jan-04
Jul-04
Jan-05
Jul-05
Jan-06




damages from hurricanes or other events.

4) **Rig counts** are going up, but production per rig is falling dramatically.

5) **The Rockies** is the main area which provides an opportunity for growth. However, new drilling potential is limited by bans on drilling in many areas as well as environmental considerations. Pipeline infrastructure in the region is seeing significant improvement with the commissioning of the Rockies Express pipeline which is in the final stages of Phase II development. This project is expected to push as much as 1.5 Bcf/d of gas eastward from Wyoming to Missouri by January 2008. Phase III, which is expected to be completed by 2009, could eventually provide a total 1.8 Bcf/d of takeaway capacity to stranded production in the Rockies - an increase of 0.3 Bcf/d over Phase II. This final phase of the project will deliver gas directly to Ohio (bypassing the Henry Hub altogether) and will ease basis-pricing in the Midwest. This additional supply should also result in softer Henry Hub prices over the 2-4 year horizon. Other pipeline projects have been announced (Williams, Dominion) that will bring gas further east.

6) **Exploration opportunities** are very limited. The Energy Policy Act of 2005 provides funds for study of opening up additional areas for exploration, but even if the findings of these studies are favorable, it would not be at least until 2010 that drilling could commence in new areas.

7) **Imports from Canada** have been decreasing. While there are some potential increases in production in Canada, we are wary of commitments made, particularly in Ontario to reduce or eliminate coal burning power plants. In Ontario, if the government follows through on its coal elimination plan, Canada's power demand would transfer to gas fired plants for the most part, and demand would increase by 1.0 Bcf/day. To date, Ontario has been delaying the closure of many of these coal plants and Ontario is making strides to increase wind and nuclear capacity, mitigating this concern somewhat. We expect Canadian imports to decline through 2010, when additional production could increase import levels above 9.0 Bcf/day.

8) **LNG imports** are increasing but at a slower pace than originally expected. We anticipate several developments which will keep LNG from developing to the extent that many hope will emerge. Firstly, terminal development has been slow, particularly in California and the East Coast. Terminals in New Brunswick and the Gulf Coast are moving along, but the pace is slow. Imports are likely to reach 2.5 to 3.0 Bcf/day only in 2009, much later than ESAI had earlier anticipated. - Final approvals were received for the Excelerate LNG project in Massachusetts. Excelerate will have the capability to deliver and gasify LNG from

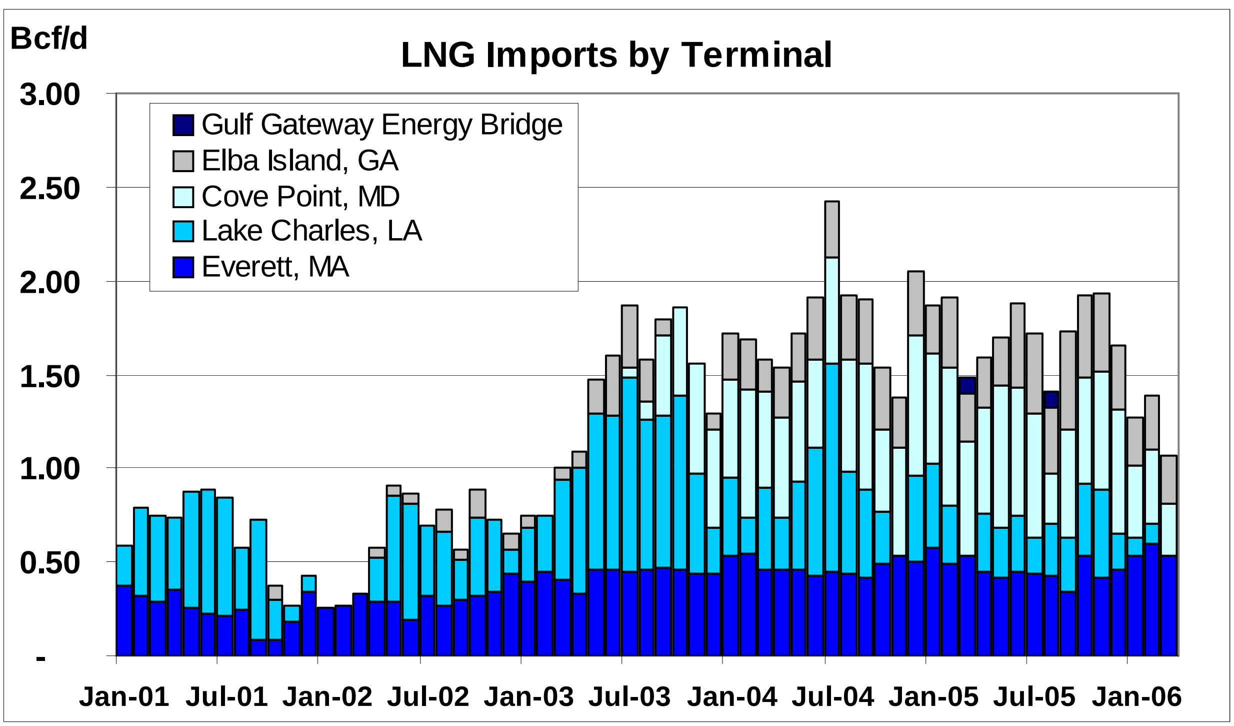
the LNG vessel directly into the Algonquin pipeline system. The project will deliver 0.4 Bcf/d on average with a peak send out of 0.8 Bcf/d. This project will only have a slight impact on basis prices in New England due to its limited transfer capabilities and the lack of any associated storage facility.

9) **LNG Supply** is a major concern. We do not believe that there will be enough LNG supply to meet the full throughput demands of the newly built terminals at least in the near future. There should be enough to meet U.S. market needs for a while, but with domestic production declines likely to continue, LNG is unlikely to meet the supply gap until the 5-10 year horizon. Global competition for LNG already is significant and will continue to be a problem for U.S. importers. Throughputs at existing terminals were lower in 2005 and flat in 2006 despite increased capacity (see chart next page). This is counter to ESAI's previous expectations of an increase in LNG imports from 2004 to 2005.

10) **Demand** is not bullish, however, a 5-6 percent growth from the power sector will provide some overall demand growth. Industrial demand will be flat or decrease slightly. The latest price increases have impacted industrial demand from sectors such as the petrochemical industry. If prices decrease to $5.00 to $6.00, we expect that some of this demand will increase again providing bullish support to prices. Recent drops to $7.00 and below have resulted in some return of demand from the petrochemical sector.

11) **Hydro** in the west is an area of concern with respect to the potential for increased gas demand. There is always a potential for dry periods in the west which will decrease hydro production, resulting in increased generation from gas fired generators and the attendant gas demand.

In summary, the ESAI outlook is somewhat bullish for natural gas going forward. With production capacity fully utilized and no spare production capacity, any supply disruption event



has immediate and bullish consequences as was so well displayed with Hurricane Ivan in 2004 and Hurricanes Katrina and Rita in 2005. If prices do decline, it will be due to moderate weather patterns, as seen following the very mild winters of 2005/6 and 2006/7. At lower prices, some industrial demand will return, providing a price floor of $5.00/MMBtu.

## ESAI Domestic Natural Gas Supply Forecast Through 2016

(in billion cubic feet)

| | 2007 | 2008 | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 |
|---|---|---|---|---|---|---|---|---|---|---|
| **Canada (Net Imports)** | | | | | | | | | | |
| **TOT Forecast/Year** | **3,192** | **3,161** | **3,129** | **3,145** | **3,302** | **3,632** | **3,705** | **3,779** | **3,854** | **3,931** |
| Forecast/Day | 8.3 | 8.6 | 8.6 | 8.6 | 9.0 | 9.9 | 10.1 | 10.4 | 10.6 | 10.8 |
| Net Change | (65) | (32) | (32) | 16 | 157 | 330 | 73 | 74 | 76 | 77 |
| Percent Change | -2% | -1% | -1% | 0% | 5% | 9% | 2% | 2% | 2% | 2% |
| Percent Mkt Served | 14% | 14% | 14% | 13% | 14% | 15% | 15% | 15% | 15% | 15% |
| **Rockies & NM** | | | | | | | | | | |
| Colorado | 1,214 | 1,256 | 1,300 | 1,346 | 1,393 | 1,442 | 1,492 | 1,544 | 1,598 | 1,654 |
| Wyoming | 1,842 | 1,952 | 2,070 | 2,194 | 2,325 | 2,465 | 2,613 | 2,770 | 2,936 | 3,112 |
| Utah | 306 | 309 | 311 | 313 | 316 | 319 | 321 | 324 | 326 | 329 |
| New Mexico | 1,662 | 1,670 | 1,678 | 1,687 | 1,695 | 1,704 | 1,712 | 1,721 | 1,729 | 1,738 |
| **TOT Forecast/Year** | **5,023** | **5,187** | **5,359** | **5,540** | **5,729** | **5,929** | **6,138** | **6,358** | **6,590** | **6,833** |
| Forecast/Day | 13.8 | 14.2 | 14.7 | 15.2 | 15.7 | 16.2 | 16.8 | 17.4 | 18.1 | 18.7 |
| Net Change | 156 | 164 | 172 | 181 | 190 | 199 | 209 | 220 | 231 | 243 |
| Percent Change | 3% | 3% | 3% | 3% | 3% | 3% | 4% | 4% | 4% | 4% |
| Percent Mkt Served | 22% | 23% | 23% | 24% | 24% | 24% | 25% | 25% | 26% | 26% |
| **Producing Area** | | | | | | | | | | |
| Texas | 5,339 | 5,382 | 5,425 | 5,469 | 5,512 | 5,556 | 5,601 | 5,646 | 5,691 | 5,736 |
| Louisiana | 1,245 | 1,220 | 1,195 | 1,172 | 1,148 | 1,125 | 1,103 | 1,081 | 1,059 | 1,038 |
| Oklahoma | 1,678 | 1,683 | 1,687 | 1,691 | 1,695 | 1,700 | 1,704 | 1,708 | 1,712 | 1,717 |
| Arkansas | 181 | 177 | 172 | 168 | 164 | 160 | 156 | 152 | 148 | 144 |
| **TOT Forecast/Year** | **8,444** | **8,461** | **8,480** | **8,499** | **8,519** | **8,541** | **8,563** | **8,586** | **8,610** | **8,635** |
| Forecast/Day | 23.1 | 23.1 | 23.2 | 23.3 | 23.3 | 23.3 | 23.5 | 23.5 | 23.6 | 23.7 |
| Net Change | 17 | 17 | 18 | 19 | 20 | 21 | 22 | 23 | 24 | 25 |
| Percent Change | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% |
| Percent Mkt Served | 38% | 37% | 37% | 36% | 36% | 35% | 35% | 34% | 34% | 33% |
| **GOM Federal Offshore** | | | | | | | | | | |
| Shelf | 1,592 | 1,433 | 1,290 | 1,161 | 1,045 | 940 | 846 | 762 | 686 | 617 |
| Deepwater | 1,311 | 1,416 | 1,529 | 1,652 | 1,784 | 1,926 | 2,080 | 2,247 | 2,427 | 2,621 |
| **TOT Forecast/Year** | **2,903** | **2,849** | **2,819** | **2,812** | **2,828** | **2,867** | **2,927** | **3,009** | **3,112** | **3,238** |
| Forecast/Day | 8.0 | 7.8 | 7.7 | 7.7 | 7.7 | 7.8 | 8.0 | 8.2 | 8.5 | 8.9 |
| Net Change | (80) | (54) | (30) | (7) | 16 | 38 | 60 | 82 | 104 | 126 |
| Percent Change | -3% | -2% | -1% | 0% | 1% | 1% | 2% | 3% | 3% | 4% |
| Percent Mkt Served | 13% | 12% | 12% | 12% | 12% | 12% | 12% | 12% | 12% | 12% |
| **Remaining Regions** | | | | | | | | | | |
| **TOT Forecast/Year** | **2,643** | **2,630** | **2,617** | **2,604** | **2,591** | **2,578** | **2,565** | **2,552** | **2,539** | **2,527** |
| Forecast/Day | 7.2 | 7.2 | 7.2 | 7.1 | 7.1 | 7.0 | 7.0 | 7.0 | 7.0 | 6.9 |
| Net Change | (13) | (13) | (13) | (13) | (13) | (13) | (13) | (13) | (13) | (13) |
| Percent Change | 0% | -1% | -1% | -1% | -1% | -1% | 0% | -1% | 0% | -1% |
| Percent Mkt Served | 12% | 12% | 11% | 11% | 11% | 11% | 10% | 10% | 10% | 10% |
| **LNG** | | | | | | | | | | |
| **TOT Forecast/Year** | **596** | **861** | **1,012** | **1,157** | **1,148** | **1,019** | **1,004** | **1,041** | **1,066** | **1,077** |
| Forecast/Day | 2.0 | 2.4 | 2.8 | 3.2 | 3.1 | 2.8 | 2.8 | 2.9 | 2.9 | 2.9 |
| Net Change | 13 | 265 | 151 | 145 | (9) | (129) | (15) | 37 | 25 | 11 |
| Percent Change | 2% | 44% | 17% | 14% | -1% | -11% | -1% | 4% | 2% | 1% |
| Percent Mkt Served | 3% | 4% | 4% | 5% | 5% | 4% | 4% | 4% | 4% | 4% |
| **Exports to Mexico** | | | | | | | | | | |
| **TOT Forecast/Year** | **344** | **330** | **310** | **291** | **274** | **257** | **242** | **227** | **214** | **201** |
| Forecast/Day | 0.9 | 0.9 | 0.8 | 0.8 | 0.8 | 0.7 | 0.7 | 0.6 | 0.6 | 0.6 |
| Net Change | (3) | (14) | (20) | (19) | (17) | (16) | (15) | (15) | (14) | (13) |
| Percent Change | -1% | -4% | -6% | -6% | -6% | -6% | -6% | -6% | -6% | -6% |
| **Total Supply** | **22,459** | **22,819** | **23,105** | **23,465** | **23,844** | **24,307** | **24,659** | **25,097** | **25,557** | **26,039** |
| Forecast/Day | 61.5 | 62.3 | 63.3 | 64.3 | 65.3 | 66.4 | 67.6 | 68.8 | 70.0 | 71.3 |
| Net Change | 30 | 360 | 286 | 360 | 379 | 464 | 352 | 438 | 460 | 482 |
| Percent Change | 0% | 2% | 1% | 2% | 2% | 2% | 1% | 2% | 2% | 2% |
| Sys. Balance (Strg/Fuel) | (0) | 0 | (0) | 0 | 0 | 0 | (0) | (0) | (0) | 0 |
| **Net Supply** | **22,458** | **22,820** | **23,105** | **23,465** | **23,844** | **24,308** | **24,659** | **25,097** | **25,557** | **26,040** |
| Net Supply/Day | 61.5 | 62.3 | 63.3 | 64.3 | 65.3 | 66.4 | 67.6 | 68.8 | 70.0 | 71.3 |

## ESAI Domestic Natural Gas Demand Forecast Through 2016

(in billion cubic feet)

| | 2007 | 2008 | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 |
|---|---|---|---|---|---|---|---|---|---|---|
| **Power** | | | | | | | | | | |
| **TOT Forecast/Year** | **6,372** | **6,709** | **7,025** | **7,376** | **7,745** | **8,155** | **8,539** | **8,966** | **9,414** | **9,885** |
| Forecast/Day | 17.5 | 18.3 | 19.2 | 20.2 | 21.2 | 22.3 | 23.4 | 24.6 | 25.8 | 27.1 |
| Net Change | 303 | 337 | 316 | 351 | 369 | 410 | 384 | 427 | 448 | 471 |
| Percent Change | 5.0% | 5.3% | 4.7% | 5.0% | 5.0% | 5.3% | 4.7% | 5.0% | 5.0% | 5.0% |
| Percent Mkt Served | 28% | 29% | 30% | 31% | 32% | 34% | 35% | 36% | 37% | 38% |
| **Industrial** | | | | | | | | | | |
| **TOT Forecast/Year** | **6,546** | **6,525** | **6,468** | **6,429** | **6,391** | **6,370** | **6,314** | **6,276** | **6,239** | **6,201** |
| Forecast/Day | 17.9 | 17.8 | 17.7 | 17.6 | 17.5 | 17.4 | 17.3 | 17.2 | 17.1 | 17.0 |
| Net Change | (40) | (21) | (57) | (39) | (39) | (21) | (56) | (38) | (38) | (37) |
| Percent Change | -0.6% | -0.3% | -0.9% | -0.6% | -0.6% | -0.3% | -0.9% | -0.6% | -0.6% | -0.6% |
| Percent Mkt Served | 29% | 29% | 28% | 27% | 27% | 26% | 26% | 25% | 24% | 24% |
| **LDCs** | | | | | | | | | | |
| **TOT Forecast/Year** | **7,949** | **8,010** | **8,028** | **8,068** | **8,109** | **8,172** | **8,190** | **8,231** | **8,272** | **8,313** |
| Forecast/Day | 21.8 | 21.9 | 22.0 | 22.1 | 22.2 | 22.3 | 22.4 | 22.6 | 22.7 | 22.8 |
| Net Change | 40 | 62 | 18 | 40 | 40 | 63 | 18 | 41 | 41 | 41 |
| Percent Change | 0% | 1% | 0% | 0% | 0% | 1% | 0% | 0% | 0% | 0% |
| Percent Mkt Served | 35% | 35% | 35% | 34% | 34% | 34% | 33% | 33% | 32% | 32% |
| **Fuel & other** | | | | | | | | | | |
| **TOT Forecast/Year** | **1,591** | **1,576** | **1,583** | **1,591** | **1,599** | **1,612** | **1,615** | **1,623** | **1,632** | **1,640** |
| Forecast/Day | 4.4 | 4.3 | 4.3 | 4.4 | 4.4 | 4.4 | 4.4 | 4.4 | 4.5 | 4.5 |
| Net Change | (16) | (16) | 8 | 8 | 8 | 12 | 4 | 8 | 8 | 8 |
| Percent Change | -1% | -1% | 0% | 0% | 1% | 1% | 0% | 0% | 0% | 0% |
| Percent Mkt Served | 7% | 7% | 7% | 7% | 7% | 7% | 7% | 6% | 6% | 6% |
| **Total Demand** | **22,458** | **22,820** | **23,105** | **23,465** | **23,844** | **24,308** | **24,659** | **25,097** | **25,557** | **26,040** |
| Total Demand//Day | 61.5 | 62.3 | 63.3 | 64.3 | 65.3 | 66.4 | 67.6 | 68.8 | 70.0 | 71.3 |
| Net Change | 287 | 361 | 285 | 361 | 379 | 464 | 351 | 438 | 460 | 483 |
| Percent Change | 1.3% | 1.6% | 1.3% | 1.6% | 1.6% | 1.9% | 1.4% | 1.8% | 1.8% | 1.9% |