BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF DELAWARE

IN THE MATTER OF INTEGRATED RESOURCE PLANNING FOR THE PROVISION OF STANDARD OFFER SERVICE BY DELMARVA POWER & LIGHT COMPANY UNDER 26 DEL C. § 1007(c) & (d): REVIEW AND APPROVAL OF THE REQUEST FOR PROPOSALS FOR THE CONSTRUCTION OF NEW GENERATION RESOURCES UNDER 26 DEL. C. § 1007(d)

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INTERIM REPORT ON DELMARVA POWER IRP IN RELATION TO RFP

PREPARED FOR:

Delaware Public Service Commission
Delaware Office of Management and Budget
Delaware Energy Office
Delaware Controller General

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I. Introduction

A. Background

On November 1, 2006, Delmarva Power & Light Company ("Delmarva" or "DP&L") issued a Request for Proposals ("RFP") for the purchase of power under long-term contracts from new generation resources to be built within the State of Delaware for the purpose of supplying standard offer service, as required under the Electric Utility Retail Customer Supply Act of 2006 ("EURCSA" or the "Act"). Three bidders submitted proposals in response to the RFP on or by December 22, 2006: (1) Bluewater Wind, LLC ("Bluewater") submitted multiple bids from two 600 MW proposed offshore wind projects; (2) Conectiv Energy Supply, Inc. ("Conectiv"), an affiliate of Delmarva, proposed alternative bids from a planned 177 MW natural gas-fired plant; and (3) NRG Energy, Inc. ("NRG"), proposed multiple bids from a planned 600 MW coal-fired integrated gasification combined cycle ("IGCC") facility.

On February 21, 2007, New Energy Opportunities, Inc. and its subcontractors, the consulting team retained by the Delaware Public Service Commission ("Commission"), the Energy Office (an office of the Department of Natural Resources and Environmental Control), the Office of Management and Budget, and the Controller General ("State Agencies") to assist in overseeing the RFP (the "Independent Consultant" or "IC"), and DP&L submitted their evaluation reports with respect to the proposals bid in response to the RFP. While the evaluation reports differed in a variety of respects, the ranking of the bids was the same — Conectiv, Bluewater and then NRG — although each of the bids was projected to increase standard offer service rates based on reference case assumptions.

Previously, on December 1, 2006, Delmarva filed an Integrated Resource Plan ("IRP") with the State Agencies.[1] Under the Act, Delmarva is required in its IRP to "systematically evaluate all available supply options" in order to "acquire sufficient, efficient and reliable resources over time to meet its customers' needs at a minimal cost."[2] On February 6, 2007, the State Agencies directed the Commission staff to retain a consultant for the purpose of conducting an initial review of the IRP and providing an interim report to the State Agencies "for the purpose of providing a framework within which to consider the results of the RFP evaluation."[3] This report is being submitted by the New Energy Opportunities consulting team pursuant to that directive.

B. Issues Addressed in this Report

The central issue for the State Agencies at this time is whether they should direct Delmarva to negotiate a long-term power purchase contract with any of the bidders in the RFP process and if so, which proposal should they select. Our report will address the

[1] Delmarva Power & Light Company Integrated Resource Plan 2007 to 2016 Compliance Filing, PSC Docket No. 06-241 ("IRP Compliance Filing").
[2] 26 Del C. § 1007(c)(1).
[3] Order No. 7131at 3-4.

risks and benefits of a decision to go forward with or not to go forward with one of the bids in the RFP process in the context of important assumptions, recommendations and alternatives considered or required to be considered in Delmarva's IRP.

Our review of the IRP encompasses the following areas:

1. *Demand Side Management ("DSM").* Is the level of DSM proposed by Delmarva reasonable? If not, what might be reasonable ranges of DSM that might be cost-effective? What is the impact, if any, on the economic attractiveness of the bids if the proposed level of DSM is not implemented or implemented at a higher level?

2. *Sufficiency of Generation and Transmission Capacity in the Delmarva Zone to Prevent Upward Shift in Capacity and Energy Prices and Potential Reliability Issues*. Has Delmarva adequately considered the risk that insufficient generating capacity and/or transmission capacity would be in place (due to lack of new builds or retirements) to prevent shortage-induced upward price shifts or spikes? Has the Company developed a plan to manage these risks? Would selection of any of the bids be a cost-effective way to manage these risks? In this regard, does it appear reasonably likely that the Mid-Atlantic Pathway Project ("MAPP") will be built and be built within the timeframe proposed? If MAPP is not built or not built within the timeframe proposed, what is the impact on the economic attractiveness of the bids?

3. *General Shift Upward in Energy Prices; Long-Term Power Purchases; Renewables*. Has Delmarva adequately considered the risk that natural gas prices could shift or spike upward increasing regional energy prices substantially above projected levels? Has the Company developed a plan to manage these risks? Would selection of any of the bids be a cost-effective way to manage these risks? Are long-term power purchase contracts from regional sources of generation, especially onshore wind projects, a reasonable alternative to the bids submitted in the RFP process either alone or in connection with other actions? Are self-build generation projects a reasonable alternative? Has Delmarva systematically evaluated these alternatives? Is there a reasonable likelihood that onshore wind projects in Delaware will be built at some level over the next 10 years, as suggested in the IRP? If not, what is the impact on the evaluation of the bids in the RFP?[4]

4. *Resource Management and Regulatory Issues Associated With Long-Term Power Purchases and/or Self-Build Generation.* DP&L contends that long-term purchase contracts and self-build generation are incompatible with customer choice.[5] Is the Company's position valid? If Delmarva is to be directed to enter into a long-term

[4] In this report, we had planned to address some of the risk issues as they relate to the price stability evaluation and its various scenarios. However, additional scenarios that we had requested to be modeled in this regard have not yet been completed by Delmarva's consultant, ICF International. We plan to file an addendum to this report following receipt of those additional model runs.

[5] See IRP Compliance Filing at 11-13, 23-27.

power purchase agreement, how should it manage the contract and SOS requirements purchases and what should be the regulatory treatment?

Key issues intended to be addressed by the IRP and RFP processes are the long-term price and reliability risks associated with having sufficient generation capacity on the Delmarva peninsula (and/or regionally) to mitigate spikes in locational capacity prices and congestion, which increases locational energy prices, as well as the overall level of energy prices, which is affected by both natural gas prices and a regional need for sufficient generating capacity. At the same time, environmental issues are critically important, both in terms of mitigating climate change, improving air quality and other impacts, as well as their impact on electricity prices.

Delmarva's position is that the market will take care of these risks with little, if any, intervention by the Company or the State Agencies. However, as we understand it, EURCSA requires or suggests a substantial degree of responsibility for active recognition and management of these risks by Delmarva, at least on behalf of its Standard Offer Service customers.

Ultimately, the question is whether the issue to manage energy, capacity and congestion risks should be addressed by (a) selecting one of the bids, (b) not selecting one of the bids and not pursuing long-term generation alternatives, or (c) not selecting one of the bids at this time but broadening the alternative approaches or solutions to be considered, including the purchase of long-term capacity, energy and renewable energy credits from regional power supplies.

C. Executive Summary

We have reviewed Delmarva's IRP, including some of the key assumptions and recommendations, and some additional scenarios conducted by Delmarva's consultant at our request. In addition, we have conducted an informal telephone survey of developers of wind project in the region and large wholesale energy marketers and generation owners. Our major conclusions and recommendations are as follows:

- Delmarva did not conduct a risk assessment that would address the potential for retirement of Indian River units 1 and 2 and its consequences if NRG's proposed coal IGCC plant is not built. This is a possibility in light of recent emissions control regulations promulgated by the Delaware Department of Natural Resources and Environmental Control ("DNREC") that would require substantial capital investment in these units. A decision on the bids pursuant to the RFP should await the results of a study by PJM at the Commission staff's request that would address the impact on reliability if these units are retired. If substantial issues are raised, it should then be determined whether selecting one of the bids is a cost-effective means of addressing the associated risks.

- Delmarva should be responsible as a general matter for assessing the need for additional generating capacity on the Delmarva peninsula from a reliability and economic standpoint and for conducting a risk assessment. Unless obviated by the selection of one of the bids, the Company should be directed to prepare a contingency plan to obtain required generation on the Delmarva pensinsula if circumstances warrant either through a power purchase agreement or a self-build alternative, subject to Commission approval.

- Delmarva did not evaluate any long-term power purchase opportunities from regional generation sources. Based on a telephone survey, the purchase of energy and Renewable Energy Credits from developers of regional onshore wind generation projects appears to provide the potential for cost-effective hedging of systemic energy price risk and Renewable Portfolio Standards ("RPS") compliance cost risks, hence contributing to price stability.

- DSM and the proposed MAPP transmission line, whether they are implemented or not, would not appear to have a material impact on evaluation of the bids.

- Based on a risk assessment, analysis of additional scenarios, and evaluation of market information, we do not recommend a change in our ranking of bids or recommend that Delmarva be directed to sign a power purchase agreement with one of the bidders at this time in the absence of a market test.

- In order to conduct a "market test," we recommend that Delmarva be directed to canvas in a broader way opportunities for adding one or more long-term power purchase agreements to provide long-term price stability for its residential and small commercial ("RSCI") standard offer service ("SOS") customers (alternatively, this could be pursued directly on behalf of the State Agencies). This can be accomplished through one of two approaches:

    - Obtaining proposals through a "short form" all-source RFP for long-term power supplies that would not be limited to new generation within Delaware. The bidders in the current RFP process would be allowed to keep their bids in place or rebid. This would allow the Company to assess the economic and other benefits of regional generators or power supplies and ultimately compare these other alternatives to the bid projects; or

    - A renewables-only RFP for energy, capacity and RECs as a means to hedge energy and RPS compliance risk in the event that the State Agencies determine that one of Bluewater's bids is the most attractive of those submitted pursuant to the current RFP. Regional renewable generators would be entitled to participate. Bluewater would be allowed to keep its bids in place or rebid.

It should be pointed out that our evaluation of the IRP was preliminary and focused on providing guidance to the State Agencies for purposes of their upcoming decision as to whether they should direct Delmarva to negotiate a long-term power purchase agreement with one of the bidders. We also understand that the Commission staff is exploring separately both the reliability issues referenced above as well as the economic potential of self-build generation.

II. EURCSA Requirements Applicable to Delmarva IRP; Delmarva's Compliance; Relationship to RFP

A. Statutory Requirements

Under the Act, Delmarva is required to conduct integrated resource planning on a biennial basis, commencing with a filing on December 1, 2006. In its IRP, Delmarva is required to "*systematically* evaluate *all available supply options* during a 10-year planning period in order to acquire sufficient, efficient and reliable resources over time to meet its customers' needs at a minimal cost."[6] DP&L is required to "*explore in detail* all reasonable short- and long-term procurement or demand-side management strategies, even if a particular strategy is ultimately not recommended by the company."[7] The Legislature reiterated that "all potential opportunities for a more diverse supply at the lowest reasonable cost" must be investigated.[8] Among the resources to be considered are generation and transmission resources that the Company itself would build.

Delmarva is required to set forth its supply and demand forecast for the next 10-year period. The Company is also required to "set forth the resource mix with which DP&L plans to meet its supply obligations for the 10-year period (i.e., demand side-management programs, long-term purchased power contracts, short-term purchased power contracts, self generation, procurement through wholesale market by RFP, spot market purchases, etc.)."[9] At least 30 percent of the resource mix shall be purchases made pursuant to the existing procurement process for standard offer service requirements service.[10]

In developing its IRP, the Company is authorized to consider the economic and environmental values of a number of specified considerations. These include resources that utilize new or innovative baseload technologies (such as coal gasification), resources that provide environmental benefits (such as renewable resources), facilities with existing fuel and transmission infrastructure, facilities that utilize existing brownfield or industrial sites, resources that promote fuel diversity, resources that support or improve reliability, and resources that encourage price stability.[11] These are basically the same factors to be incorporated in the RFP process for considering bids for long-term contracts for new generation in Delaware.[12]

[6] 26 Del C. § 1007(c)(1) (emphasis added).
[7] 26 Del C. § 1007(c)(1)(a) (emphasis added).
[8] 26 Del C. § 1007(c)(1)(b).
[9] 26 Del C. § 1007(c)(1).
[10] 26 Del C. § 1007(c)(1)(a).
[11] 26 Del C. § 1007(c)(1)(b).
[12] See 26 Del C. § 1007(d).

Fundamentally, the Legislature required DP&L to be responsible for a detailed planning process to provide for supply and demand-side resources that would satisfy its standard offer service obligations in terms of *reliability* and *cost* to consumers. In connection with reliability and cost, the Company is required to plan for having *sufficient* resources available over a 10-year planning horizon.

B. Compliance of Delmarva's IRP

Delmarva's treatment of long-term power purchase contracts (unit or firm wholesale supply contracts with durations of 10 to 25 years) in its IRP is simply a one-sided recitation of what it views as the negative attributes of such contracts.[13] There are numerous problems with Delmarva's approach. First, it reflects a clear predisposition against the bids submitted pursuant to the RFP or for that matter against other long-term power purchase contracts.. Second, Delmarva did no assessment of long-term power purchase opportunities from new regional generation outside of Delaware or from existing generation sources either inside or outside Delaware. Third, Delmarva did not adequately explore, in our view, the need for new generation on the Delmarva peninsula during the planning period to address the risks that PJM's Reliablity Pricing Model may not stimulate new generation, that new environmental regulations may cause retirements of existing in-state generation and/or the proposed Mid-Atlantic Power Pathway project would not be built, or at least built on schedule. The associated risks have both reliability and economic implications (higher locational capacity prices and congestion-induced higher energy prices). Fourth, DP&L did not adequately address, in our view, the potential magnitude of the risk that energy prices would shift higher on a long-term basis, due to higher natural gas prices or a regional shortfall in capacity relative to demand or consider long-term power purchase contracts or self-build generation as mitigation measures. These matters are addressed in Sections IV and V of this report.

C. Relationship to RFP

As part of the first IRP process, Delmarva filed, pursuant to the requirements of EURCSA, a proposed RFP for the purchase under long-term contracts of capacity and energy from new generation resources located in Delaware. The proposed RFP was ordered to be modified by the Commission and the Energy Office in a variety of respects and, with such modifications, was issued on November 1, 2006, a month before the IRP was required to be submitted. The Legislature set a timetable for the RFP process that commenced before the IRP in an effort "to immediately attempt to stabilize the long-term outlook for standard offer supply in the DP&L service territory."[14] Following the evaluation of bids, the State Agencies were authorized to approve one or more proposals in response to the RFP and to direct Delmarva to enter into one or more contracts with the successful bidder or bidders. Alternatively, the State Agencies could decline to approve any proposal.

[13] DP&L IRP Compliance Filing (December 1, 2006) at 23-26.
[14] 26 Del C. § 1007(d).

Evaluation of RFP Bids in Brief

The evaluation of the bids is described in detail in the bid evaluation reports. The evaluations were based on both economic and non-price criteria, with a point scoring system that could be overridden by the State Agencies in their judgment in the context of "supercategories" of economics, favorable characteristics (environmental impact, fuel diversity and innovative technolgy) and project viability.

Conectiv's alternative proposal to sell firm energy backed by capacity from its proposed 177 MW natural gas-fired combined cycle plant at its existing Hay Road power station in northern New Castle County had the highest ranking, with 68.9 points out of a potential 100 points, as assigned by the IC. Conectiv's proposal scored best in pricing, had a minimal score for price stability, scored best in project viability, and had the lowest score for favorable characteristics (although slightly lower than NRG's). While the wholesale market energy and capacity costs associated with residential and small commercial ("RSCI") SOS customers was projected to be $86.20/MWh (levelized in $2005 for the period 2011-38), those costs with the Conectiv bid included were projected to be $87.48/MWh.

Conectiv proposed pricing for base energy during on-peak hours that would be indexed to coal prices and general inflation once the plant is in service.[15] However, the initial level of these energy prices and part of the capacity price would be subject to a one-time adjustment based on movements of forward natural gas prices since the bid was submitted, a price risk that we recommended be contained contractually as a condition of any contract awarded to Conectiv.[16] In addition, all carbon-related costs in excess of regulations enacted pursuant to the Regional Greenhouse Gas Initiative would be passed through to Delmarva.

Bluewater's best ranked bid was its proposal to sell up to 400 MWh per hour of energy (as well as unforced capacity and renewable energy credits) from its proposed 600 MW Atlantic North offshore wind project, with a total score of 57.0 points. Bluewater proposed fixed pricing with a fixed annual escalator of 2.5 percent. Bluewater's bid was ranked after the Conectiv bid in price, had the highest price stability score, scored best for favorable characteristics, but received the lowest score for project viability. With regard to project viability, a major concern of the IC was Bluewater's apparent reliance on obtaining greenhouse gas credits for the output of the plant (and selling them for a large amount of revenue while at the same time it planned to sell renewable energy credits from the same output). We viewed this as being unlikely and speculative, hence raising questions as to the project's financeability.[17] The wholesale market energy and capacity costs associated with RSCI SOS customers was projected to be $98.21/MWh.[18]

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[15] For the off-peak hours and for a 25 MW block of energy above 152 MW, energy is priced off a daily delivered (city-gate) natural gas index, which is a more conventional pricing method for natural gas projects.

[16] Bid Evaluation Report at 55.

[17] See Bid Evaluation Report at 22-23. In addition, permitting an offshore wind project will be a challenge, especially since the rules are evolving and the final rules have not been issued. Bid Evaluation Report at 21.

[18] In preparing this report, we noted an error in our calculations that result in less than a $.20/MWh change (increase), which we view as being immaterial.

NRG proposed several alternative bids associated with its proposed 600 MW IGCC plant at the site of its Indian River power station in Millsboro. NRG offered various alternatives, including options for a 20-year or 25-year contract without carbon capture and sequestration ("CCS") technology and a 25-year contract with CCS. In each variant, there was flexibility in turning down a portion of energy output. NRG's bid for a 25-year contract without CCS received 24.8 points; its bid with CCS received 23.8 points. The NRG bid was evaluated as producing somewhat higher costs than the Bluewater bid, when the projected costs of carbon dioxide allowances were included, resulting in a projected levelized wholesale capacity and energy cost associated with SOS of $101.37/MWh. This was due to a combination of factors, including the capital intensive nature of the project, allowance costs associated with carbon dioxide emissions for which NRG sought a cost passthrough, and a relatively low guaranteed (target) availability factor, especially in the early years of the project. The project received minimal scores in the economic supercategory, which includes price stability, and ranked in the middle for favorable characteristics and project viability.

Based on the reference case analysis, the net present value (8.8% discount rate) above market costs for the bids range from $37 million for Conectiv to $493 million for Bluewater's best bid to $678 million for NRG's 25 year bid without CCS. A comparison of our analysis is set forth in the table below along with Delmarva's analysis of the bids.[19] Since Delmarva's figures are in undiscounted nominal dollars, our above-market price projections are as well. Our estimated above-market value estimates are lower than that of Delmarva due to use of a higher forecast of natural gas transportation prices resulting in a higher estimate of energy market prices and lower estimates of imputed debt impacts. The estimated above-market values are particularly lower for NRG's bids, due to our use of a much lower coal price forecast than that used by Delmarva (which also affected our analysis of Conectiv's bid to a lesser degree).

[19] This information on the above-market costs of the bids is provided in response to the request of Commissioner Clark at the meeting of the State Agencies on February 28, 2007 (Transcript at 69-70). We also explored whether PJM's Reliability Pricing Model might have the impact of increasing capacity prices to the cost of new entry prior to the date assumed by ICF (2015), which would reduce above-market costs, an issue also raised at the same meeting of the State Agencies. The maximum likely impact on the evaluation of any bid would be $7 million, which is not material to our conclusions or recommendations.

TABLE 1: Comparison of Economic Impact

	Market Reference	BW 25 Full	BW 25 Partial	NRG 20	NRG 25	Connectiv Alt Bid
DP&L Bid Evaluation						
Levelized Cost for SOS (2005$/MWh)	85.43	99.45	99.82	106.87	107.56	86.63
Additional Cost Above Market (Sum of Nominal in $billion)		$2.00	$2.10	$3.90	$5.20	$0.10
IC Reference Bid Evaluation						
Levelized Cost for SOS (2005$/MWh)	$86.20	$98.21	$99.42	$101.84	$101.37	$87.48
Additional Cost Above Market (Sum of Nominal in $billion)		$1.78	$2.05	$2.82	$3.37	$0.07
Additional Cost Above Market (NPV of Nominal in $billion)		$0.49	$0.55	$0.68	$0.68	$0.04

The metric used in the price evaluation was the wholesale energy and capacity costs for RSCI SOS customers with and without the bids included, stated in levelized $/MWh in 2005$. The evaluation period starting with the year the first bid project was proposed to go into service (2011) until the last year of the proposed power sale agreement of any of the bid projects (2038). As we had recommended and the Commission and Energy Office approved, a scaling system was developed and agreed to by Delmarva and the IC after the detailed economic methodology had been developed, including the price evaluation metric, and before any of the bids were submitted.[20] Based on our collective view that bids would likely have a range between them of $10-$15/MWh and wanting to exclude the impact of outlier bids that could have the effect of unduly reducing the significance of price differences between bids, Delmarva and the IC agreed on a scaling approach that would give the low bid the maximum 33 points and the high bid 0 points, with in-between bids being scaled proportionately, but in the event that a bid was more than $15/MWh above the low bid, the outlier bid would receive 0 points and the other bids would be scaled proportionately as if the high bid was $15/MWh above the low bid.[21] NRG's bid with CCS was not formally evaluated since its cost was substantially above NRG's other bids (as well as all the other bids) and well over the $15/MWh "outlier" limit. Hence, we scaled the remaining bids — which had a range of $14.36/MWh over the low bid — based on the high/low scaling approach.[22]

[20] See Final Report Regarding Delmarva Power & Light Company's Proposed RFP (Oct. 12, 2006) at 52; Order No. 7081, PSC Docket No. 06-241 (Oct. 17, 2006) at 73.

[21] Using a scaling approach that excludes the impact of outlier bids is frequently used in the industry where a point system is used in price evaluation. Moreover, as part of the scaling system, if the range of high and low bids were less than $10/MWh, the bids would be scaled based on the relationship of the bids to $10/MWh above the low bid. For example, a bid that was $5/MWh above the low bid would receive 16.5 out of 33 points, reflecting that even a high bid among bids that are relatively tightly packed should receive some points.

[22] Had we scaled the bids using $15.00/MWh as the bottom of the scale, the impact on Bluewater's bids (increased by 1.1 point) and NRG's bids (increased by 1.3-1.4 points) would not have been material.

Key Assumptions Reviewed

The economic analysis conducted in the bid evaluation assumes a market in equilibrium. Even the scenario analysis used in the price stability evaluation assumes a market where supply and demand are in balance, albeit based on different assumptions regarding fuel costs, carbon dioxide allowance costs, generation capital costs, and transmission builds. Our focus in this report is on the underlying risks from the standpoint of RCSI SOS customers and how to manage these risks. The risks of substantially higher prices than projected, primarily associated with the need for generation and transmission capacity for the Delmarva load zone, and the systemic risk of higher energy prices caused by higher natural gas prices are addressed in the following sections.

Given the evaluation of the bids pursuant to the RFP, important questions are:

- The magnitude of the risk and the consequences to SOS ratepayers if the risks materialize
- Are there other ways to manage these risks more cost-effectively than selecting one of the bids?
- If not, which of the bids manages these risks best and in the most cost-effective manner.

In this report, we will focus on some of the key features and assumptions of the analyses used in both the IRP and RFP evaluation in terms of whether they capture or appropriately reflect certain risks for Delmarva customers. The RFP bids were evaluated using ICF's Integrated Planning Model ("IPM") which operates on the underlying assumption that the market always achieves equilibrium between supply and demand, which may underestimate real market conditions and risks. We will also frame the discussions in light of the recently filed Errata by Delmarva.[23]

The underlying assumptions we are reviewing include the following:

- Since ICF's market model assumes perfectly balanced supply and demand for fuel, electricity, and capacity, IPM does not capture the potential risks associated with short-term supply shortages or unanticipated load growth (it also does not capture potential future capacity surpluses, either).
- ICF's market model also assumes transmission additions, capacity additions and retirements are supported by the market. While this assumption is needed in an equilibrium model, it overlooks the fact that permitting and financing issues may impede needed additions, resulting in inadequate supply for the region.
- In the IRP and RFP, some amount of DSM is "selected" by ICF's market model as economic options for Delaware. Load assumptions were adjusted

[23] Delmarva's Response to Comments on Delmarva's Integrated Resource Plan ("IRP") filed on March 23, 2007 (PSC Docket No. 07-02),

accordingly, but there are risks if the expected DSM solutions do not materialize.

- Additionally, some renewable generation (onshore wind and landfill gas) in Delaware is "selected" by ICF's market model.[24] The actual development potential of these resources, especially onshore wind, is questionable, though the revised results show much lower wind build outs.

- Delmarva points out that the MAPP project will be able to "make even more diverse resources, including renewables, available to SOS customers." The project is included in most scenarios, though a sensitivity that removes the MAPP project appears to have only a minor impact on costs incurred by SOS customers.

- While the RFP evaluation did test a "High Gas" scenario, the scenario does not reflect the potential for long-term fundamental shifts in the crude oil market, which is correlated to that of natural gas, or short-term volatility in gas prices due to imbalanced supply and demand.

- Lastly, several assumptions regarding load and capacity in surrounding states may pose risks for the PJM market in general, which will impact market costs for SOS customers.

In the following sections, we will discuss some of the key assumptions and their underlying risks in the context of relying solely on the continuation of three-year laddered SOS requirements purchases from a power supply standpoint, as Delmarva proposes. Furthermore, we will examine additional model runs that encompass some of these assumptions discussed and their impact on evaluation results. Initially, we will address how DSM is treated in Delmarva's IRP and the relationship to the State Agencies' upcoming decision on the bids submitted pursuant to the RFP for long-term power purchases from new generation in Delaware.

[24] Per Delmarva's Response to Comments on Delmarva's Integrated Resource Plan ("IRP") filed on March 23, 2007 (PSC Docket No. 07-02), Footnote 4: "The Errata to the IRP, attached as IRP Errata 1, represents adjustments made by Delmarva since the IRP was filed on December 1, 2006. This IRP Errata 1 reconciles the filed IRP with the Reference Case used to evaluate the RFP Bids. Additionally, since the RFP Referece Case, further adjustments have been made to renewables, load growth in New Jersey, and nuclear build out parameters. With these adjustments, Delmarva's updated recommendation calls for only 35 MW of generation build out in Delaware through 2016, all of which should be from renewables, wind 30 MW, landfill gas 5 WM. The portion attributable to the SOS Customer Load served by Delmarva would be about 10 MW.

III. DSM

One of the tasks to be undertaken as part of our supplemental workplan is to assess the reasonableness of the Company's assumptions regarding DSM in the IRP and in the evaluation of projects bid in response to the RFP. Our objective here is not to perform an in-depth, detailed review of the Company's DSM projections (as will be done later during the proceeding to review the Company's IRP), but rather to conduct a high level assessment of the process used to develop these estimates, the measures considered, and the compatibility of the level of DSM savings assumed by DP&L relative to industry norms. We will also assess whether the DSM assumptions made or reasonable alternatives to them would likely have any material impact on the evaluation of the bids.

In its IRP, DP&L states that it used a multi-step process to develop its savings assumptions about DSM:

1. Measure identification
2. Review of existing research
3. Estimate measure impact
4. Develop cost estimates of implementing DSM
5. Perform cost-effectiveness screening
6. Estimate market potential

DP&L identified 28 residential and 28 non-residential measures that were considered in the IRP and in the evaluation of RFP bid projects. These measures were provided in Exhibits 3.3 and 3.4

TABLE 2: DP&L Identified Residential and Non-Residential DSM Measures

Exhibit 3.3: Residential DSM Measures Considered

1. Central AC Quality Installation	15. ENERGY STAR Dishwasher
2. Central AC Tune-Up	16. ENERGY STAR Groundsource Heatpump
3. Central Heatpump Quality Installation	17. ENERGY STAR Home
4. Central Heatpump Tune-Up	18. ENERGY STAR Refrigerator
5. Duct Sealing	19. ENERGY STAR Window AC
6. Efficient Basement Insulation	20. High-Efficiency Pool Pump and Timer
7. Efficient Ceiling Insulation	21. High-Efficiency Portable Electric Spas
8. Efficient Domestic Hot Water Heater	22. Home Performance with ENERGY STAR
9. Efficient Wall Insulation	23. Programmable Thermostat
10. Efficient Windows	24. SmartStats
11. ENERGY STAR Central AC	25. Updated Energy Code
12. ENERGY STAR Central Heatpump	26. Water Heater Load Control
13. ENERGY STAR CFL	27. Weatherization Assistance
14. ENERGY STAR Clotheswasher	28. ENERGY STAR Dishwasher

Exhibit 3.4: Non-Residential DSM Measures Considered

1. Building Commissioning	15. High-Efficiency Vending
2. Central Chiller Quality Installation	16. LED Exit Sign (4 W)
3. Compact Fluorescent Poultry Lighting	17. Linear Fluorescent (2L4' F28T8/SS) Lighting
4. Copier Power Management Enabling	18. Network PC Monitor Power Management Enabling
5. Efficient Windows	19. Occupancy Sensors (Lighting)
6. Energy Management System	20. Operator Training and Maintenance Program
7. Heatpump Quality Installation	21. Package AC Quality Installation
8. High Bay T5 (4L4' F28T5/HO) Lighting	22. PC Power Management Enabling
9. High-Efficiency Central Chiller	23. Perimeter Daylighting Controls
10. High-Efficiency Heatpump	24. Printer Power Management Enabling
11. High-Efficiency Motor	25. Screw-In Compact Fluorescent Lighting
12. High-Efficiency Package AC	26. SmartStats
13. High-Efficiency Packaged Terminal AC	27. Split AC Quality Installation
14. High-Efficiency Split AC	28. Updated Energy Code

To estimate the savings that each considered residential DSM measure would generate, baseline usage profiles were developed for building type of different characteristics, such as size (square feet) and HVAC system. For non-residential buildings, six different building types were used to model each of this class of customers' sub-sectors (offices, restaurants, grocery stores, retail stores, hotels/motels, and healthcare). The baseline building types and each DSM measure was simulated utilizing the DOE2.1E energy modeling program. This allowed DP&L to estimate the savings of peak load and energy for each measure over its life.

Measure costs were estimated using other industry studies, adjusted where possible for DP&L specific information.

Cost effectiveness screening was conducted using industry standard benefit costs tests: the total resource cost (TRC) test, the participants' cost test (PCT), and the ratepayer impact (RIM) test. Although all three test ratios were calculated, the Company states that the TRC test is the most meaningful.

The market potential or achievable potential was estimated by projecting the maximum number of annual installations of each measure and applying a technology adoption rate. From this achievable potential, DP&L estimated what portion was economic at $73/kW-yr, the assumed capacity price of a peaking unit. This represented the subset of the achievable potential that was included as options in the IPM simulation results. The IPM model apparently compared these DSM options to supply resource options and selected for inclusion in the IRP only a portion of the DSM that was economic at $73/kW-yr in 2005$.

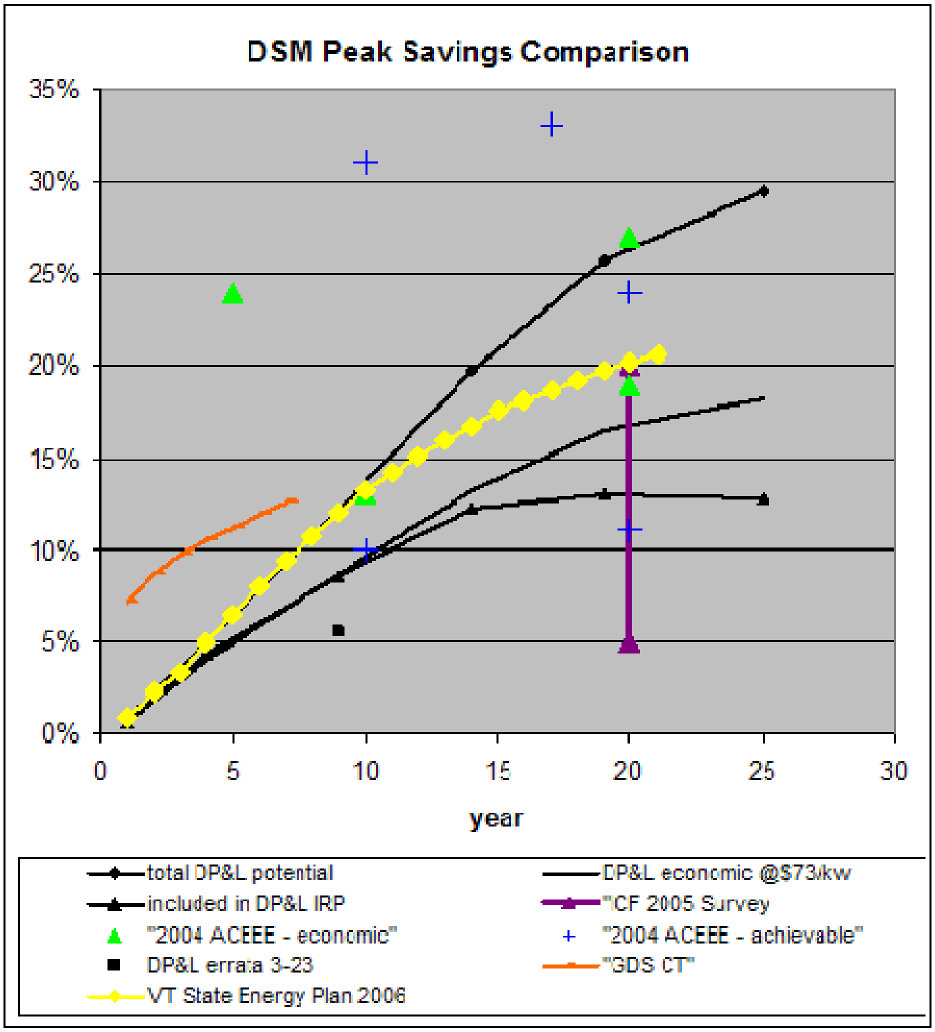
The results of the DSM assumptions and their effect on peak load are summarized in the following table. By 2031, the Company estimates a potential of 876 MW of peak load reductions, or 29% of the 2031 projected peak without DSM. Of this amount, 543 MW were economic at $73/kW-yr. However, the Company has included only 381 MW or a 13% peak load reduction in its IRP. In an errata sheet attached to comments filed by DP&L on March 23, 2007, the Company stated that it has revised its projection of the amount of DSM to be included in the IRP. The peak savings level in 2016 dropped to 126 MW from 198 MW. This latest projection calls for DSM to contribute approximately 5% toward meeting the 2016 peak load, which represents only 45% of the achievable potential for that year.

TABLE 3: DPL Peak and Energy Growth

year	DPL peak (MW)	DPL energy (GWH)	peak potential (MW)	% of peak (%)	peak economic at $73/kw (MW)	% of peak (%)	peak IPM selected (MW)	% peak IPM selected (%)
2007	1,939	7,733	17	1%	13	1%	13	1%
2010	2,069	8,256	103	5%	82	4%	90	4%
2015	2,299	9,173	278	12%	199	9%	198	9%
2020	2,493	9,944	492	20%	330	13%	306	12%
2026	2,702	10,780	694	26%	444	16%	350	13%
2031	2,977	11,876	876	29%	543	18%	381	13%

To assess the high reasonableness of the Company's DSM plan, we examined other recent studies of DSM achievable and economic potential and compared those results as a percent of peak to the DP&L results above. This comparison is shown in the following graph. DSM potential is often defined differently by different utilities and, consequently, there may be differences in the manner in which cost-effectiveness tests are performed. Therefore, this comparison, while adequate and useful for our purposes here, does not eliminate the need for a more detailed assessment of the Company's DSM efforts as will be done later in the IRP proceeding.

FIGURE 1: DSM Peak Savings



When all selected DSM measures are aggregated together, the overall benefit/cost ratio using the TRC test was 2.0, and the levelized cost was $5.53/MWh.

In its IRP analysis, DP&L did include a sensitivity case where there were no DSM options included in the IRP. The capacity expansion in Delaware was the same as the base case, and market prices were only slightly higher ($58.2/MWh in 2016 without DSM versus $58.1/MWh) in the reference case. This outcome would imply that DSM reduced the amount of imports into the DPL zone while having minimal effect on prices in Delaware.

Conclusions

Based upon our experience with DSM programs of other utilities, we offer the following preliminary conclusions regarding DP&L's DSM assumptions.

- The process utilized by DP&L is similar to that used by others in the industry.
- The DSM measures that the company considered are reasonable.
- The appropriate tests for cost-effectiveness were utilized.
- The achievable potential as a percent of peak load is roughly comparable to other DSM potential studies.
- At a high level, the 2.0 benefit/cost ratio and the cost per MWH is typical of DSM programs deployed by other utilities.
- The amount of DSM selected by the IPM model appears to be very conservative, especially after the reduction provided in the March 23rd errata sheet. In 2016, it represents only 45% of the total potential and 63% of the amount that is economic at $73/kW-yr.
- The DSM assumptions do not appear to have a material effect on the evaluation of bid projects in the RFP.

Regardless of how much of the DSM potential estimated by the Company is implemented, the DP&L peak load remains above the 2007 level throughout the 25-year planning horizon. Thus, the Company will still face issues of when and how to procure power supplies for its SOS customers and how to manage long-term power market price risks. We do not believe that even a doubling of the projected DSM or its elimination entirely would have a material impact on the evaluation of bids in the RFP. While we believe that the Company should implement all cost-effective DSM for all of its customers, we do not recommend that the State Agencies defer a decision on whether to direct Delmarva to sign a power purchase contract with one of the bidders pursuant to the RFP due to a concern regarding the potential direction or effectiveness of Delmarva's DSM initiative.

IV. Generation and/or Transmission Capacity Shortfall-Induced Price and Reliability Risks

As stated previously, Delmarva relies on ICF's IPM model in developing the forecasts used in the IRP and RFP evaluation. This model optimizes the amount and type of resources needed over time to meet a particular forecast of resource needs, given cost and performance assumptions regarding available resources. This model allows new resource options, such as new power plants, to be added in one MW increments. Because supply is always assumed to be in perfect balance with demand, and the amounts and types of resources is optimized each year, the model produces market prices that are relatively stable compared to what will likely be experienced. In the real world, market prices will likely be higher than projected if there are shortfalls of supply relative to demand, other things being equal. Conversely, if there is a surplus of supply relative to demand, market prices will likely be lower, other things being equal. There are risks and uncertainty associated with constructing any new electric resources (generation and transmission). It does not appear that the Company has explicitly considered these risks or uncertainties.

In this section, we discuss some of those risks that may not be apparent from the modeled results. Since all of the bids in the RFP process have been evaluated as being above market, our focus is on the risk that there is a shortfall in supply and/or transmission transfer capacity for the Delmarva zone relative to demand, which would have the effect of shifting market prices higher than the projections utilized in the bid evaluation process.

A. Generation Supply and Demand Imbalance Risks

Due to the nature of ICF's market model, it is unable to capture the potential risks associated with short-term supply shortages or unanticipated load growth in one or all of the markets. ICF's market model also assumes transmission additions, capacity additions and retirements are economically motivated. As long as the market forecast supports their existence, the capacity and transmission will be in place. While this assumption is needed in an equilibrium model, it overlooks the fact that a variety of issues may result in inadequate supply for the region, at least on a temporary basis.

PJM Capacity Additions Assumed

The following graph and table illustrate the load and capacity outlook for all of PJM. These figures rely upon the latest PJM 411 Report, which addresses the time period through 2015, but which we have extrapolated out to 2036, the end of the evaluation period utilized by the Company in its IRP and in the bid evaluations. These figures also assume no retirements of existing generating capacity. By the year 2035, PJM will need to add nearly 65,000 MW of new capacity, net of any retirements, in order to meet capacity obligations, based on assumed load growth of 1.4 percent per year.

FIGURE 2: PJM Load & Capacity Outlook

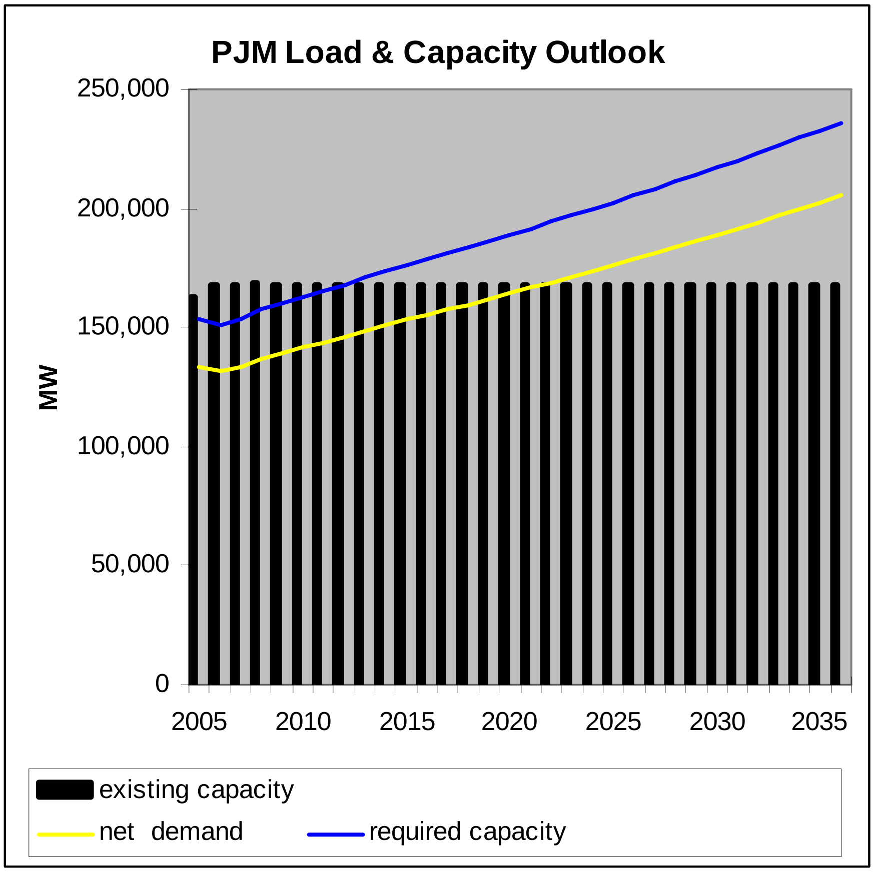


TABLE 4: PJM Load and Capacity Outlook

PJM Load & Capacity Outlook (MW)			
	Existing Capacity	Required Capacity	Surplus/ Deficiency
2010	168,027	162,802	5,225
2015	168,027	176,223	(8,196)
2020	168,027	188,908	(20,881)
2025	168,027	202,507	(34,481)
2030	168,027	217,085	(49,059)
2035	168,027	232,713	(64,686)

PJM maintains lists of generation projects that have applied for interconnection. The following two tables summarize the projects in the current queues that are in service, under construction, or still active.

TABLE 5:
PJM Generation Queue Projects by State and Fuel Type

Sum of MW	FuelType												
State	Biomass	Coal	Diesel	hydro	Methane	natural-gas	nuclear	Oil	Waste	Waste Coal	wind	Wood	Grand Total
DC						10							10
DE	1	630			7	806		142			1,749		3,335
IL	50	765	22		57	629	0		20		7,892		9,435
IN		30				0					1,782		1,812
KY		765											765
MD		10		36	20	2,976	3,343	25			208		6,618
MI							84						84
NC					12							78	90
NJ	30	650	8	1	44	6,531	331	600			8		8,203
OH	185	2,075	7			0					642		2,909
PA	42	9,156	39	339	93	9,501	2,206	7		329	3,182		24,894
TN	50	75											125
VA	50	553		99	41	2,308	1,594	315			37	4	5,001
WV		2,820		100		360					1,730		5,010
Grand Total	408	17,529	76	575	274	23,121	7,558	1,089	20	329	17,230	82	68,291

TABLE 6:
PJM Generation Queue Projects by Status & In-Service Year

Sum of MW	StatusCode				
IS year	ACTIVE	IS	ISP	UC	Grand Total
1989				5	5
1999		38			38
2000		422			422
2001		1,029			1,029
2002		5,344	3		5,347
2003		3,743	166		3,909
2004		3,151			3,151
2005		2,757	157		2,914
2006	623	1,847	11	701	3,182
2007	5,189	3	148	1,396	6,736
2008	8,127		115	1,852	10,094
2009	5,295			752	6,047
2010	7,892			107	7,999
2011	7,675				7,675
2012	3,269				3,269
2013	1,600				1,600
2015	3,234				3,234
2016	1,640				1,640
Grand Total	44,544	18,334	600	4,813	68,291

While it would appear that there is more than ample capacity on tap to meet future needs, such a conclusion would not necessarily be correct. Only 4,800 MW of queue capacity that is not yet in service is under construction. There is no assurance that a sufficient amount of active projects will actually get built. There is also some double-counting in the queue. For example, the 1,749 MW of wind projects in Delaware represents all three of the Bluewater bids in the RFP. It is highly unlikely that more than one of the wind projects would be built, and if Bluewater is not awarded a PPA, it will likely not be built, at least in the foreseeable future. It's important to note that of the 120,000 MW of proposed capacity additions in PJM queues A through R, nearly 90,000 MW or 75% have been withdrawn.

A more realistic approach to address the adequacy of supply is to conduct a "bottom up" analysis of the generation projects under active development with a probability assessment of their likelihood of construction and the timing of construction. Delmarva and ICF did not conduct this type of analysis. Shortfalls of generation supply relative to demand have happened in the past, most notably during the California crisis of 2000-01 (although there were other contributing causes in addition to a demand/supply imbalance). It is also true that there have been periods of excess supply relative to demand due to companies willing to build generation given the perceived market opportunities. Over the past several decades, the wholesale power market has been characterized by a series of "boom-bust" cycles. However, in all of the scenarios analyzed by DP&L, the model inherently assumes that whatever capacity is needed actually gets built (and in 1 MW increments).

The following table shows the selected DP&L build-outs of new capacity for the IC reference case that was requested during the RFP evaluation process. This information is for PJM Classic, a subset of total PJM.

TABLE 7: IPM Capacity Additions for PJM-E and PJM Classic for IC Case

	2007	2008-2009	2010	2012-2015	2016-2020	2021-2025	2026-2031	2031-2037	Total
PJM-E									
Coal (MW)	-155	-2	-7	-1	-1	1	-3	-1	-169
Biomass / IGCC (MW)	0	0	0	0	0	0	0	0	0
Combined Cycle + Cogen (MW)	0	0	0	0	0	0	0	0	0
Combustion Turbine (MW)	0	0	0	0	0	0	384	605	989
Jet (MW)	0	0	0	0	0	0	0	0	0
Wind (MW)	0	45	37	174	186	180	228	216	1066
Geothermal (MW)	0	0	0	0	0	0	0	0	0
Nuclear(MW)	0	111	131	0	0	1000	0	0	1242
Landfill Gas(MW)	0	19	32	42	0	0	0	0	93
Solar TH (MW)	0	130	5	10	786	1291	117	0	2339
Oil/Gas (MW)	0	0	0	0	0	0	0	0	0
Non-wind/solar Renewables (MW)	0	0	0	0	0	0	0	0	0
Total	-155	303	198	225	971	2472	726	820	5560
PJM Classic									
Coal (MW)	-155	149	-133	-1	-20	-9	-485	-1	-655
Biomass / IGCC (MW)	0	0	366	96	80	167	455	0	1164
Combined Cycle + Cogen (MW)	-153	153	0	0	0	0	257	1728	1985
Combustion Turbine (MW)	0	0	0	448	318	588	384	2265	4003
Jet (MW)	0	0	0	0	0	0	0	0	0
Wind (MW)	0	142	85	225	188	231	228	459	1558
Geothermal (MW)	0	0	0	0	0	0	0	0	0
Nuclear(MW)	0	327	155	0	0	1000	0	0	1482
Landfill Gas(MW)	0	40	66	156	0	0	0	0	262
Solar TH (MW)	0	132	35	245	1211	1489	135	0	3247
Oil/Gas (MW)	0	0	0	0	0	0	0	0	0
Non-wind/solar Renewables (MW)	0	0	0	0	0	0	0	0	0
Total	-308	943	574	1169	1777	3466	974	4451	13046

A number of high capital cost generating plants are projected to be built over the time period covered by the bid evaluation analysis, including a 1,000 MW nuclear plant addition (installments during the 2008-10 period reflect anticipating upgrades at existing sites), a variety of wind projects, biomass and IGCC. These are the types of projects that developers generally require long-term contracts in order to support their construction (although a number of wind projects have been built recently in certain markets without traditional long-term contracts). Moreover, there are also significant permitting risks associated with many of these projects. The current regional market structure raises questions about the ability of these types of projects to obtain long-term contracts or to be built in the required scale in the absence of long-term contracts. [25]

RPM

The Federal Energy Regulatory Commission has recently approved PJM's Reliability Pricing Model ("RPM"), a type of forward capacity market to address reliability concerns in PJM sub-regions.[26] The stated purpose of RPM is to create sufficient stability in capacity prices to provide incentives to generators to invest in new plants as well as to retain existing plants in operation in the Locational Delivery Areas ("LDA's") within PJM where they are needed.

PJM's capacity delivery year begins June 1st and runs through May 31st. RPM will become effective on June 1, 2007 and replace PJM's existing capacity market on that date. When fully implemented, the process for the RPM will be to commence capacity procurement three years in advance of a delivery year, as shown in the following timeline. The process will begin with a Base Residual Auction, and will continue with three annual incremental auctions. Delivery year June 1, 2010 through May 31 , 2011 will be the first year of a fully implemented RPM. In that year, there will be 23 LDAs, as shown in the table below. [27]

[25] To a lesser extent the same issues apply to gas-fired combined cycle plants and peakers.
[26] PJM, Interconnection, L.L.C., Order Denying Rehearing and Approving Settlement Subject to Conditions, Docket No. ER 05-1410-001, et al. (Dec. 22, 2006).
[27] See http://www.pjm.com/services/courses/downloads/rpm-training-module-a.pdf

FIGURE 3: Description of Timing of RPM Acutions from PJM

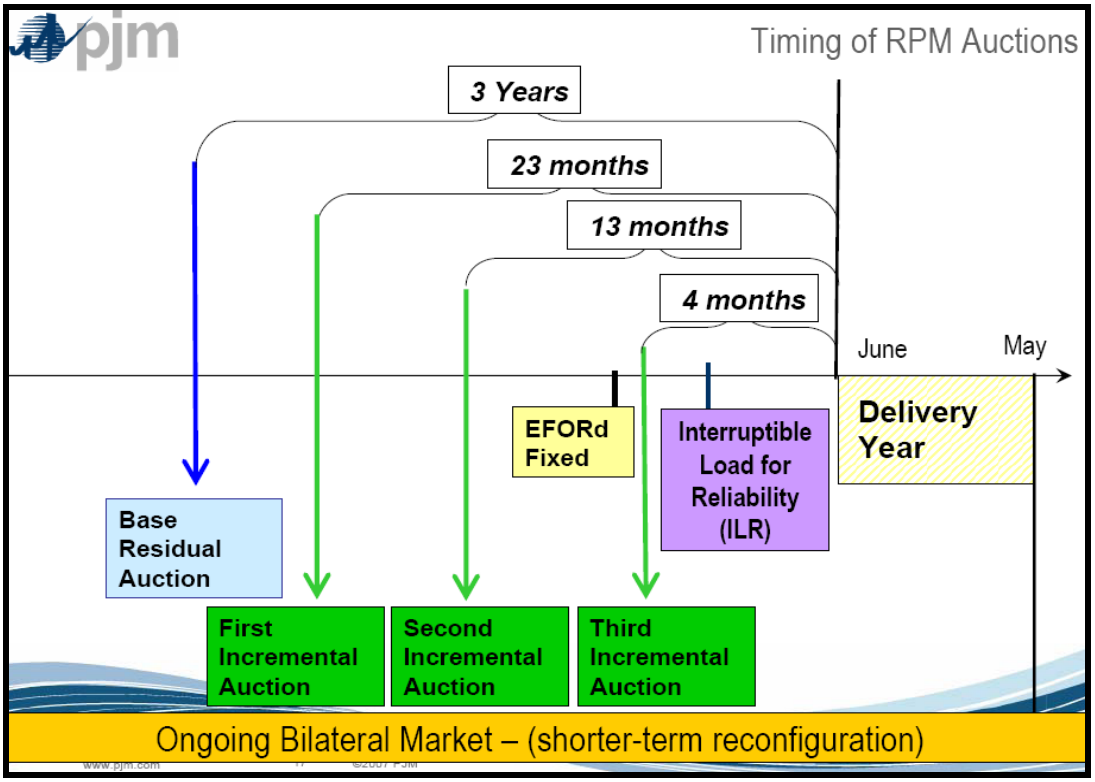
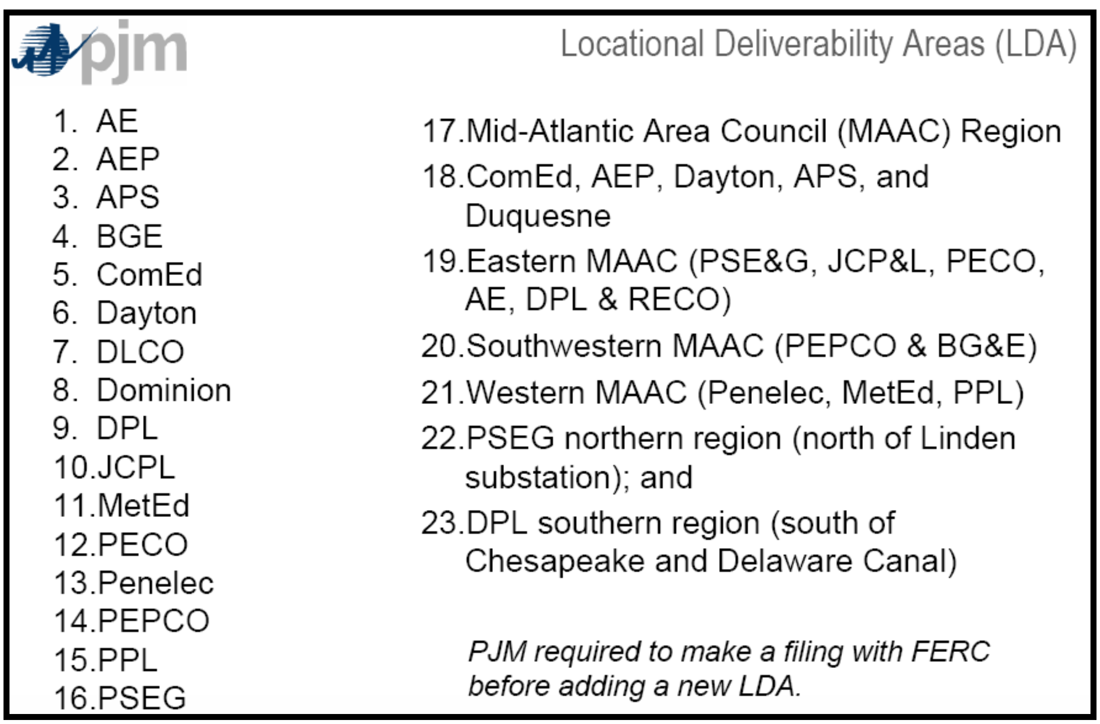


FIGURE 4: Description of LDA from PJM



In the three interim years (2007/08, 2008/09, and 2009/10), RPM will be implemented on abbreviated schedules, and will include only four LDAs.

FIGURE 5: Description of LDA Timing from PJM

pjm

LDAs for Transition Period

Transition Delivery Year	Locational Deliverability Areas
2007/2008, 2008/2009, & 2009/2010	•PJM Mid-Atlantic Region and APS •Eastern MAAC (PSE&G, JCP&L, PECO, AE, DPL, and RECO) •Southwestern MAAC (PEPCO & BG&E) •Rest of Market - ComEd, AEP, Dayton, Dominion and Duquesne
2010/2011	All 23 LDAs

RPM was developed to address perceived shortcomings in PJM's existing capacity markets, which were deemed too volatile and unpredictable to facilitate a sufficient amount of new generating capacity to be built and financed. The existing capacity market effectively had a "vertical demand curve", where relatively small changes in installed capacity from slightly deficient to slightly surplus caused market capacity prices to go from very high prices to very low prices. RPM attempts to introduce added stability and predictability to PJM capacity markets by deploying a gradually sloping demand curve, where prices would theoretically adjust to changes in installed capacity relative to required capacity. RPM is also intended to encourage new capacity in LDAs where it is needed most by having separate demand curves for different LDAs.

Delmarva, in its IRP, states that it is relying on RPM to stimulate the required amount of generating capacity: "Delmarva anticipates that [RPM] will provide the proper signal to the competitive resource supply providers such that capacity additions will be determined efficiently by the market, in a competitive fashion."[28] The key question facing PJM stakeholders and the Commission is whether RPM will be sufficient in stimulating sufficient generation in the right place at the right time. It is unclear at this point whether it will be successful in this regard. Under RPM, Capacity prices are capped at 1.5 times the cost of a new peaking unit, reduced by any applicable ancillary services revenues and net energy revenues. Capacity prices set by RPM are not long-term prices, as have historically been typically included in power purchase agreements for capital intensive power plants. Thus, there is considerable risk and uncertainty as to whether or nor RPM

[28] IRP Compliance Filing at 14.

will be successful in facilitating capital intensive projects such as wind, coal, and nuclear to be built. It is possible that the developers of such new capacity will find RFP and market incentives to sufficient to build new generation of this type or that they may be able to obtain long-term contracts with other market participants as buyers. However, if this does not occur, the capital intensive projects included as "optimal" generation in ICF's modeling may not materialize, and the result will be energy prices that are significantly higher than presently forecast by DP&L.

Retirements

There are two risk issues involving retirements of generating units—(1) retirement of generating units on the Delmarva peninsula, with attendant reliability and economic impacts, and (2) retirement of generating units within PJM as a whole.

Delmarva Peninsula

On November 15, 2006, the DNREC promulgated regulations that impose stricter limits on emissions of nitrogen oxides, sulfur dioxide and mercury from eight coal-fired and residual oil-fired generating units within the state.[29] The regulations limit both emission rates and annual emissions. The generators subject to the regulation, including NRG and Conectiv, two of the bidders pursuant to the RFP, have appealed the regulation. In its comments during the rulemaking process, NRG suggested that shutting down one or more of the units at its Indian River generating station might be the result if the emissions regulations would require investments in emissions control that would make it uneconomical for the units to continue to operate.[30]

In connection with the IRP and RFP evaluation, ICF, based on generic pollution control retrofit cost assumptions, determined that all of the Delaware generating units subject to DNREC's new regulations would continue to operate, albeit at a substantially reduced capacity factor.[31] All of these units, including Indian River Unit 1 (81 MW, built in 1957) and Indian River Unit 2 (81 MW, built in 1959), were assumed to continue to operate throughout the RFP evaluation period (through 2038) in ICF's transmission reliability and economic modeling analysis. As indicated previously, NRG has proposed to shut down Indian River Units 1 and 2 if it is awarded a contract pursuant to the RFP and it builds the planned IGCC unit.[32]

The IRP (and the RFP bid evaluation) did not evaluate the reliability or cost impact risk associated with retirement of Indian River units 1 and 2 prior to the compliance date for the new regulations. Currently, PJM at the Commission's request is evaluating this prospect from a reliability perspective. Additional analysis will be conducted from an economic perspective. If this analysis suggests significant adverse impact, especially on reliability, then may be a need to reconsider the bid evaluation. An aspect of such

[29] See http://www.awm.delaware.gov/NR/rdonlyres/0FFE2E3D-1DC3-49E5-B65B-4EC44994E925/0/SecOrd2006A0056.pdf and http://www.awm.delaware.gov/NR/rdonlyres/3B571C5A-080A-43D7-A3F2-032AE9748BD7/1312/Reg1146final.pdf.
[30] See http://www.dnrec.state.de.us/air/aqm_page/documents/DNRECRulemakingMeeting030906Final.pdf at 8.
[31] The reduction in coal-fired generation (GWh) is reflected in the IRP Supporting Documentation at 73.
[32] ICF inadvertently left out these proposed retirements in the runs associated with the NRG bids. ICF has indicated that this omission should have a minimal impact, but is performing some additional analysis on this issue. Upon receipt and review of ICF's analysis, we will address this matter in the addendum that we plan to file to this report.

reconsideration could be assessing other cost-effective solutions to the issues raised by retirements.

PJM Region

Upon review of retirements from model runs, we found very few retirements in PJM overall. IPM assumes that if a unit is economical to run with appropriate emissions retrofits, it will not be retired in the model. Therefore, despite a queue of over 2,000 MW of generation that have submitted applications to PJM for deactivation and the fact that half of the generation in PJM will reach 60 years of life sometime during the years modeled, none are "selected" to retire by IPM. PJM lists 1,092 generating units with an aggregate summer capacity rating of 164,400 MW.[33] Nearly 83,000 MW (50%) were placed in service on or before 1975, meaning that they will be more than 60 years old by the end of the study horizon in the bid evaluations. In the State of Delaware, there is a total 3,100 MW of summer rated capacity, with 1,340 MW (43%) placed in service on or before 1975. Looking only at units less than or equal to 200 MW, PJM has 59,500 MW, with 23,940 (40%) placed in service on or before 1975. Delaware has 2,240 MW of capacity of units less than or equal to 200 MW, with 900 MW (40%) placed in service on or before 1975.

In today's market environment, some units that have sought to retire have been retained through Reliability Must Run ("RMR") contracts for reliability purposes, which impose additional costs. With the development of RPM, these units needed for reliability should be appropriately compensated, but the existence of RPM does not necessarily mean that retirements will not occur. If a portion of these units are retired, there are risks associated with insufficient supply coming on-line to make up for the shortfall, despite the existence of RPM.

The generators that have applied for retirement with PJM often cite lack of market incentives to continue operation or emissions retrofits to meet impending regulations make their units uneconomic. According to IPM results (see Table 8), very little retirements in PJM Classic (none after 2007, except for 498 MW of coal around 2026-2031) occur because they are determined to be economic, even with appropriate emissions control retrofits.

PJM Load

In the reference case assumptions, ICF assumed that New Jersey achieves the 20% reduction by 2020 set out in the state's Energy Plan. However, this is, in fact, a 45% reduction of the expected energy consumption for 2020. In the IRP Errata 1 filing, there is a correction to load level post-2020, where load growth of 1.4% is assumed instead of no load growth. Even though New Jersey's Energy Plan has recommended a goal of 20% reduction of energy consumption by 2020, there is a substantial risk that New Jersey does not achieve that goal, which may be reflected in market prices for Delaware. Furthermore, over 3,000 MW of solar thermal installations were assumed to be built in New Jersey in accordance with the state's Renewable Portfolio Standard in the ICF Reference case for RFP evaluations. That amount has been removed and solar

[33] Data taken from List of PJM Generating Units (2006-pjm-411.xls) from www.pjm.com

photovoltaics (PV) potential adjusted according to the IRP Errata 1 filing. The details of the changes were not clear in the filing.

While energy efficiency and solar installations may help New Jersey move toward its goal, we believe a reliance on 45% reduction to future energy use (in 2020) and the inclusion of over 3000 MW of solar applications pose risks for forecasted energy prices. The risk with this assumption is that if New Jersey does not achieve its reduction and solar installation goals, market prices for electricity would be higher than they might otherwise be. Of the sensitivities that ICF conducted for the IRP, the case with Higher New Jersey Load resulted in both the highest energy and capacity prices of the IRP cases.[34]

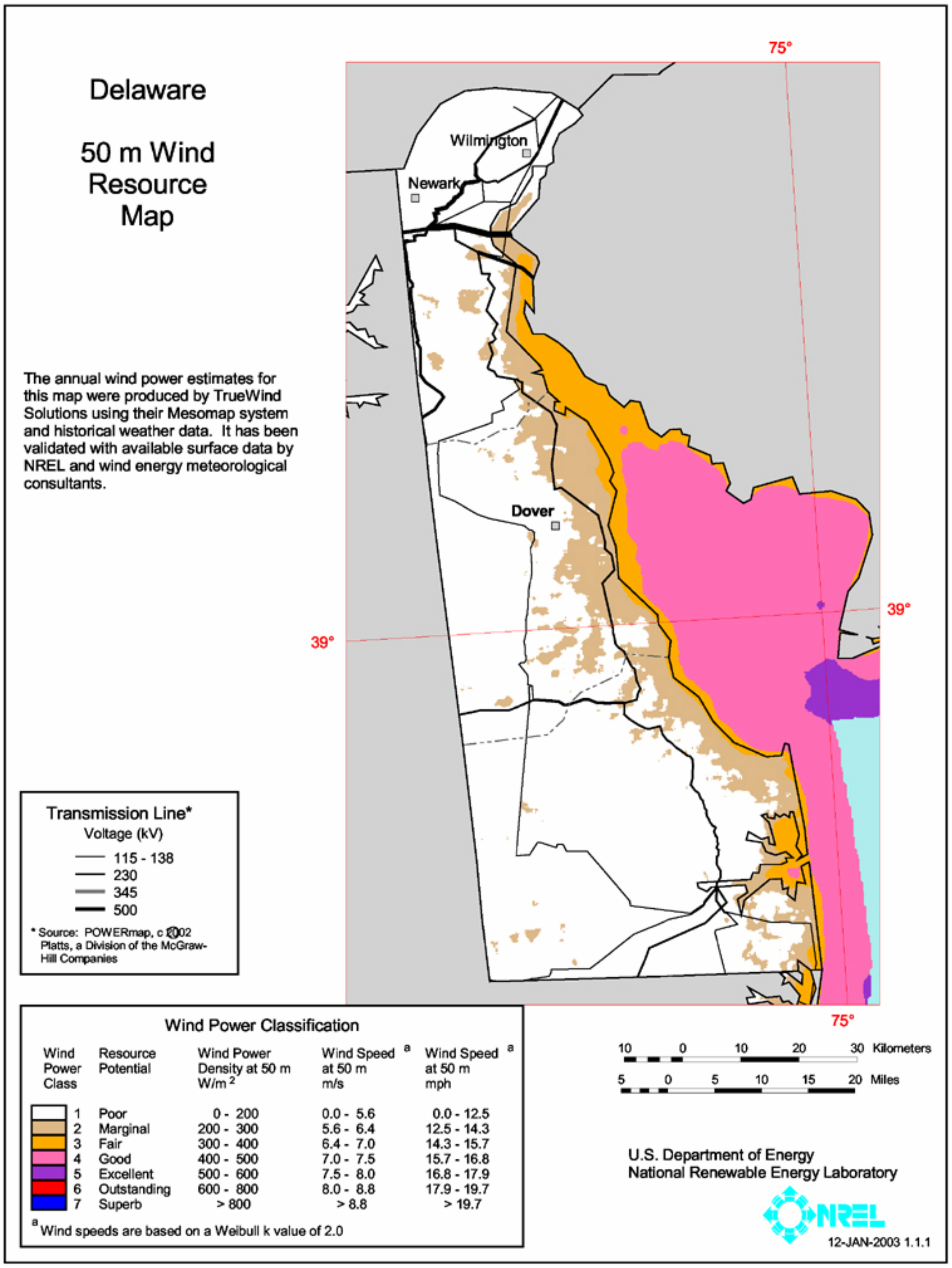
Delaware Renewables (On-Shore Wind)

On March 23, 2007, Delmarva filed an errata to its IRP indicating that since the RFP bid evaluation, "further adjustments have been made to renewables, load growth in New Jersey, and nuclear build out parameters."[35] In conversations with ICF consultants during and after the RFP review process, ICF disclosed an error in classifying Delaware wind resources which resulted in higher classes (higher capacity factors) for wind located in Delaware than their actual potential. In correcting this error, ICF found that less wind resources (30 MW by 2016) would be developed in Delaware.

Upon review of National Renewable Energy Laboratory map and resource assessment of Delaware's on-shore potential, there is very limited potential on-shore for wind development. The areas that show some marginally feasible (Class 3 at 50 meters) wind sites are located along the coast towards the southern portion of Delaware. Our view is that these are not optimal sites for development of on-shore wind projects by wind developers, especially when there are far better wind regimes and easier to permit sites in neighboring states, despite an in-state multiplier for renewable energy certificates (RECs) provided by Delaware's RPS. Additionally, there are no on-shore wind projects in Delaware being proposed in PJM's transmission interconnection queue.

[34] See IRP Supporting Documentation at 75.
[35] Delmarva Power & Light Company's Response to Comments on the Integrated Resource Plan, March 23, 2007 at 3, n.4.

FIGURE 6: Delaware Wind Resources



Source: www.eere.energy.gov

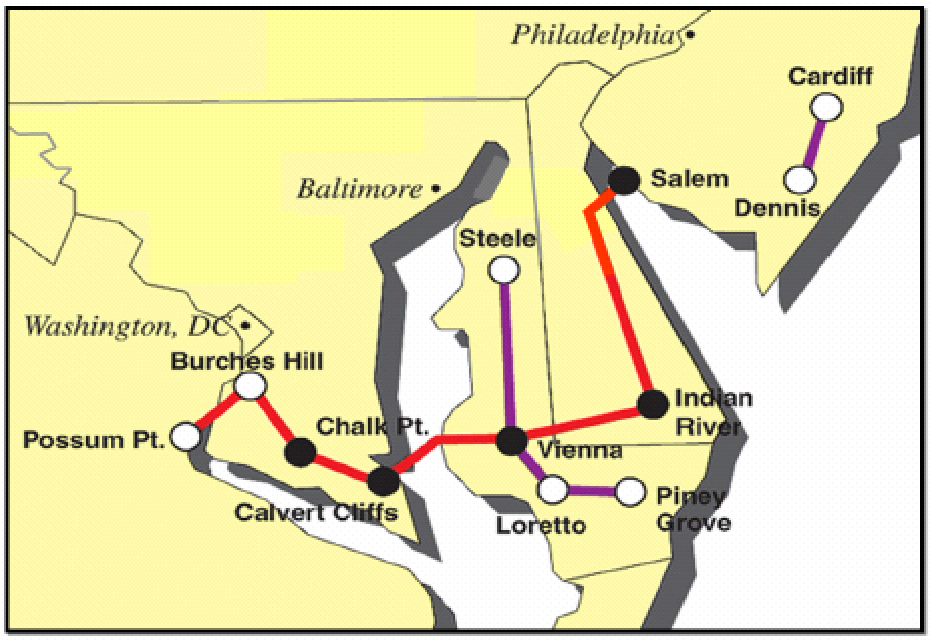
In all, we believe very little, if any, on-shore wind projects will be built in Delaware. However, while there may be minimal wind potential on-shore, the presence of wind generation in Delaware as part of ICF's modeling of available resources on the peninsula is likely to have little impact on energy market prices for Delaware.[36]

[36] If we examine the total energy contribution from the wind resource as presented in Delmarva's IRP Errata 1, it is 30 MW by 2016 (or about 80 GWh) compared to the total energy served by Delmarva of 21,198 GWh (3,966 GWh for Delmarva Delaware SOS and 17,232 GWh for The Rest of Delmarva) by 2016. This constitutes 0.36% of the energy needed to serve Delmarva's load. Therefore, while the assumption of on-shore wind potential in Delaware may be flawed, we do not expect the RFP results to be significantly altered by this assumption.

B. MAPP Transmission Project

As one element of its IRP, DP&L has included the Mid-Atlantic Power Pathway (MAPP) project, a $1.2 billion proposed transmission upgrade connecting Virginia, Maryland, Delaware, and New Jersey. This project involves a 230-mile, 500KV transmission line from Possum Point to Calvert Cliffs to Vienna to Indian River to Salem Stations. It also involves the construction of 230 kV transmission lines within the DPL zone and in New Jersey. This estimated completion date is 2014, although the Company states that some segments of this project would be completed as early as 2010.

FIGURE 7: MAPP Transmission Map



Source: DP&L IRP Filing December 1, 2006, page 15

On May 15, 2006, Pepco Holdings Inc., (PHI), the parent company of DP&L, sent a letter to PJM describing the proposed MAPP project and requesting that PJM include this "PHI-sponsored project" in PJM's transmission expansion plans. Thus, it would appear that the MAPP project was proposed by PHI and does not appear to be a solution to regional transmission needs that was identified by PJM through its stakeholder process. In this request, PHI states that the MAPP project is "ideally suited to meet the demands of the rapid growth and chronic transmission congestion throughout the area traversed and beyond".

As of the initial writing of this report, it does not appear that PJM has included the MAPP project in its list of approved transmission upgrades in the Regional Transmission Expansion Planning process ("RTEP"). This project is not listed in the approved project list that is posted on the PJM web site as of March 1, 2007. It does appear that PJM has performed some analysis of the project. In a presentation at the October 30, 2006 Transmission Expansion Advisory Committee ("TEAC"), PJM describes the results of evaluating transmission alternatives to mitigate western and central PJM interface overloads out through 2019.[37] This evaluation was used to eliminate some proposed projects from further consideration in the RTEP stakeholder process. For each project considered, PJM calculated a $ per KW transfer ratio by dividing the project's estimated cost by the increase it provides in transfer capability. The lower this ratio is, the more effective the project. Of the 16 alternatives identified for continued consideration in the RTEP process, the MAPP project had the highest ratio of project cost to increased transfer capability. The MAPP project ratio was more than twice the next worst project and nearly 7.5 times the best project listed.[38] This would indicate that this project is less effective than other options in eliminating interface overloads.

The MAPP project was included in DP&L's IRP. The Company also tested a sensitivity case without the MAPP project and other proposed transmission upgrades within PJM. In the sensitivity case without these transmission improvements, the amount and type of capacity added in Delaware and the in-state generation by type and by year was exactly the same as the reference case with the transmission improvements included. The all-hours market prices changed very little. Prior to 2014, when the MAPP was not yet in service, the market prices in the reference case and the case without transmission improvements were identical. After 2013, the change in market energy prices is shown in the following table, which includes data taken directly from the Company's IRP filing.

TABLE 8: Market Price Impact of MAPP

All-hours Market Price (2005$/MWH)			
	Base Case	w/o transmission upgrades	difference
2014	$54.20	$54.50	$0.30
2015	$57.00	$57.30	$0.30
2016	$58.10	$58.40	$0.30

Because the DPL zone experiences congestion, we would have thought that the addition of a 500 kV transmission line would have had a greater benefit in lowering market energy prices, and its removal would have caused a larger increase in market prices. With a savings of $0.30 per MWH, it will take a very long time to pay back a $1.2 billion investment in new transmission facilities or even a substantial share in that investment. It is important that the MAPP project undergo a more detailed review during the IRP process. This would be especially true if the project qualified for FERC incentive ratemaking for new transmission investments, and those higher incentive costs were paid for by Delaware consumers.

[37] See http://www.pjm.com/committees/teac/downloads/20061030-teac-presentation.PPT.
[38] Id. at 49-53.

As far as the evaluation of bid projects is concerned, however, it does not appear that the MAPP project's exclusion would materially impact the results of the RFP. It is our understanding that the evaluation of the bids was performed by ICF utilizing modeling assumptions that included the MAPP project. The company also conducted a sensitivity case without the MAPP project during the RFP bid evaluations, which resulted in an increase of levelized SOS costs over the entire period of the evaluation of $0.77/MWh. Based upon a high level assessment of these results, it appears unlikely that if the MAPP project is not built or is substantially delayed that market prices would be increased substantially enough to alter the outcome of the bid evaluations.

C. Request for Additional Model Runs

In light of the perceived risks as described thusfar, we asked Delmarva/ICF (after the bid evaluations were concluded) to conduct several model sensitivity runs that includes changes to assumptions used in the "IC Case" of the bid evaluation (which had higher gas transportation costs and lower forecasted coal costs than in Delmarva's reference case). One model run ("Adjusted Load Case") included two changes to the "IC Case":

- Increased load growth in New Jersey (New Jersey energy efficiency reduces load growth to 1.0% annually rather than the steeper reductions assumed by Delmarva); and
- No onshore wind in Delaware.

The results are shown in Table 9.

In addition, we requested that Delmarva/ICF model a sensitivity case with the same modified assumptions as in the Adjusted Load Case with the following additional modifications:

- Retirement of generating units less than 200 MW in size when they reached an age of 60 years;
- No nuclear additions in PJM classic (1,000 MW was assumed in the 2020-25 period previously);
- The MAPP and proposed AEP transmission additions are not built;

Delmarva declined to run a scenario where coal-fired generation units of less than 200 MW in size would retire when they became 60 years old. These units, generally built in the 1950's and 1960's (which include Indian River units 1 and 2 and Edge Moor units 3 and 4), are not subject to regulation as new sources under the Clean Air Act Amendments of 1970 and are still relatively prevalent in PJM. According to ICF, its analysis suggests that all of these older facilities will continue to be economic to operate throughout the evaluation period, which is through 2038. ICF, however, has not conducted an evaluation on specific generating units. Because generating units were built differently, maintained differently, have differing retrofit costs, are subject to varying environmental requirements, and have differing economic values due to their location and access to coal transportation, there is likely to be a substantial variance as to whether particular units will continue to operate or retire for economic reasons (or operate as reliability must run units). Therefore, we felt it was appropriate to test a scenario where a significant amount of these units retire, using age as a retirement factor. After substantial additional discussion with Delmarva, the Company agreed to run an additional scenario, which we will call the "Additional Retirements Case", based on the changes in assumptions described above, with the following modification to the retirement assumption: [39] retirement of generating units that have applied to PJM for retirement and oil/gas steam and combustion turbine units below 200 MW once they have reached a life of 60 years.

The impact of the Additional Load Case is is that market prices for capacity and energy to serve RSCI SOS load increased $2.50/MWh from $86.20/MWh (levelized in 2005) to $88.70/MWh. However, the impact on the evaluation of the bids was not significant. With regard to the Additional Retirements Case, market prices for capacity and energy increased $3.88/MWh to $89.72/MWh (levelized in 2005$). Again, the impact on the evaluation of bids was not significant. Each bid was evaluated as being above market, with the same ranking, although the Conectiv bid is evaluated as being somewhat closer to the market price. The impact is relatively small on total levelized SOS costs, but does increase market prices in future years. Again, the impact appears small because adequate capacity additions are assumed by the model to meet reserve requirements, so the market is in balance. Below is a table that compares the results of the Additional Load Case and the Additional Retirements Case to the IC Case.

Table 9: Results of Additional Scenarios (Levelized 2005$/MWh)

	Market Reference	NRG 25 Yr	Conectiv Alternative	BW North 25 Yr Full
Adjusted Load Case	$88.51	$103.46	$89.47	$100.34
Additional Retirements	$89.72	$104.22	$90.67	$101.26

Had Delmarva conducted the scenario we originally requested or one in which a substantial amount of older, smaller coal plants in PJM retire once they reach the age of 60, we believe that the results would likely have been that forecasted market prices would have been higher and the bids would have been evaluated as being less uneconomic (above market) than they were evaluated in this scenario. The reason is that as lower operating cost units (baseload generators) are removed from the fleet of generators, marginal energy costs may increase, leading to higher energy market prices.

D. Conclusions

Based on the foregoing analysis, we reach the following conclusions:

- A decision on the bids pursuant to the RFP should await the analysis conducted at the request of the Commission staff that addresses the impact on

[39] This analysis was conducted in response to a request from the IC to Delmarva dated March 14, 2007 (attached as Appendix A).

reliability and system economics if Indian River units 1 and 2 are retired; if substantial issues are presented from this analysis, it should then be determined whether selecting one of the bids pursuant to the RFP is a cost-effective means of addressing the associated risks.

- None of the issues that we have identified appear to dictate any different conclusions than those implicit in our evaluation of bids pursuant to the RFP; specifically, reductions in projected energy efficiency in New Jersey, removing the projected MAPP transmission line, removing onshore wind generation in Delaware, removing nuclear additions in PJM Classic, and injecting additional retirements of generators did not appear to have a material impact on the economic evaluations of the bids using IPM. However, we believe that a more robust set of retirement assumptions would likely have had a larger impact on the analysis.

- Delmarva should be responsible for assessing the need for additional generating capacity on the Delmarva peninsula from a reliability and economic standpoint (based on "bottom up" evaluation and monitoring) and for conducting a risk assessment as part of its IRP obligations. Consistent with the foregoing, the Company should be directed to prepare (and update as needed) a contingency plan to obtain required generation either through a power purchase agreement or through self-build generation as part of its IRP obligation. This might entail installation of a combustion turbine or natural gas-fired combined cycle plant to mitigate increases in locational capacity prices and/or congestion at a favorable site, subject to Commission approval.

Related to the issues of sufficiency of generation and transmission transfer capability are the issues of forecasted energy prices, which are expected to be driven largely by natural gas prices. These matters are addressed in the following section.

V. Risk of Higher than Projected Natural Gas Prices and Mitigation Measures

A. High Natural Gas Prices

The same reference case for natural gas prices (Henry Hub) was used in the IRP and RFP evaluation.[40] In our bid evaluation report, we noted that we had reviewed ICF's forecast against NYMEX futures prices (through 2012) and the Energy Information Administration's comparable long-term forecast and determined the reference natural gas forecast to be reasonable for purposes of the bid evaluation.[41] In this regard, Bluewater's

[40] See Delmarva IRP Supporting Documentation at 62-63.
[41] IC Bid Evaluation Report at 35. We also found ICF's methodology for forecasting carbon dioxide allowance costs to be reasonable (and do not prefer the somewhat higher Synapse mid-case forecast, as some commentors have suggested).

consultant Geller & Associates states that "our [Geller & Associates'] long-term forecast correlates roughly with the outlook presented by both ICF and EIA."[42]

The IRP did not test a high gas price scenario, but the RFP evaluation did test a "High Gas" scenario, which was used in the price stability analysis. In the "High Gas" case, levelized gas prices were increased over the reference case by $0.96/MMBtu in 2005 dollars.[43]. We do not believe that this scenario adequately reflects the potential for strong long-term upward shifts in the natural gas prices due to fundamental shifts in the related oil markets or if LNG is not successfully deployed to the extent projected. Nor does the high gas scenario reflect shorter term volatility in gas prices due to periodic imbalances between supply and demand.

As Delmarva points out in the IRP Supporting Documentation (p. 61), "crude oil price is critical (to natural gas demand) because of inter-fuel competition. Industrials and electric utilities can switch between residual fuel oil and distillate as natural gas prices go up." In general, crude oil prices and natural gas prices are linked due to this switching capability of demand. However, through conversations with ICF on how natural gas cases were developed for the sensitivities and information reported in the IRP Supporting Documentation, we determined that all of the gas price scenarios (High, Reference, and Low) used in sensitivity tests for the IRP and RFP bid evaluations assumed the same crude oil price forecast consistent with that set forth at page 64 of the IRP Supporting Documentation--$54.11/bbl in 2016 (2005$). Current prices are approximately $66/bbl (2007$). We believe this assumption dampens the potential price levels that natural gas prices may reach if crude prices increase dramatically due to fundamental long-term supply shifts.

While there is certainly sharp disagreement among industry participants in the petroleum industry, there are reputable experts and observers who believe that a worldwide peak in crude oil production has already occurred or will occur in the foreseeable future leading to the prospect of sharply increased crude oil prices.[44] Sharply higher oil prices would lead to higher natural gas prices than projected. Moreover, some of the same observers are concerned about peak natural gas on a worldwide basis, which would have the same impact.[45] There is also the question of the extent to which LNG will be successfully deployed in North America to keep supply consistent with demand.

The IC requested that ICF model a scenario with substantially higher gas prices than the High Gas scenario—with assumed natural gas prices approximately 30% above the reference case. However, Delmarva and ICF declined on the basis that they did not have a higher gas price projection than was used in the High Gas case and that such a scenario would have a very low probability. Based on our discussion, we believe that a major concern of Delmarva's was that it did not want to produce a scenario that would create a record to support selection of any of the bids for a long-term contract based on what they

[42] Appendix C to Bluewater Wind Delaware LLC Comments on the Evaluations of Proposals for Consturction of New Generation by the Independent Consultant, ICF and Delmarva dated March 26, 2007 (Geller & Associates, Observations: Integrated Resource Plan and Evaluation Bids) at 1.
[43] See Delmarva Bid Evaluation Report at 32.
[44] See, e.g., Matthew R. Simmons, "Do 'We' Face an Energy Crisis?" February 20, 2007, http://www.simmonsco-intl.com/files/Sandia%20Labs%20BW.pdf.
[45] Id.

perceived to be a very low probability case.[46] However, using robust scenarios is useful, indeed, important, in the resource planning process, and we are disappointed that such a scenario was not produced.

Hence, we modified our request for Delmarva to model a "High Gas" scenario with the other assumptions incorporated in the Additional Load Case. As shown below, the ranking of the bids in the "High Gas" case did not change in this analysis, although all of the bids evaluated above-market costs (difference between SOS cost of bids versus market) were lower than in the reference case.

TABLE 10: Results of Three Requested Scenarios Relative to IC Reference
($/MWh Levelized 2005$)

	Market Reference	NRG 25 Yr	Conectiv Alternative	BW North 25 Yr Full
IC Reference Case	$86.20	$101.37	$87.48	$98.21
Adjusted Load	$88.51	$103.46	$89.47	$100.34
Additional Retirements	$89.72	$104.22	$90.67	$101.26
High Gas	$92.85	$105.98	$93.48	$103.47

While one can debate the scenarios of natural gas prices that should be considered, in our view the more critical consideration is whether there are other more cost-effective opportunities in the market to hedge natural gas driven electric energy price risks.

B. Wind and Renewables as a Hedge

While the availability of onshore wind projects in Delaware is unlikely, wind and other renewable generation in PJM can serve as a fixed price hedge against high natural gas prices for a portion of Delmarva's portfolio. Long-term contracts with renewables in the region may also help hedge RPS obligations and cost impacts associated with future CO2 regulations.

One way to hedge energy price risk (other than congestion), carbon dioxide allowance cost risk, and RPS price risk associated with RSCI SOS is to purchase bundled energy and RECs from onshore regional wind projects. While review of the generation queues seeking interconnection in PJM indicates that there are no active onshore wind projects in Delaware,[47] there are numerous onshore wind projects in Pennsylvania, western Maryland, West Virginia and other areas within PJM, including 43 active wind projects involving over 3,000 MW in Pennsylvania alone with a project size range of 2 MW to 220 MW.[48] A telephone survey of wind project developers and wholesale marketers that have been active in purchasing wind power under long-term contracts was conducted.

[46] The same dynamic may have been at play regarding our scenario request involving retirement of generating units.
[47] See http://www2.pjm.com/planning/downloads/20070301-section-05-delmarva.pdf at 4.
[48] http://www2.pjm.com/planning/downloads/20070301-section-05-pennsylvania.pdf at 8. The total MW of onshore wind projects with active interconnection requests in PJM generation as a whole exceeds 12,000 MW. http://www2.pjm.com/planning/downloads/20070301-section-03a.pdf at 10.

The following anecdotal information was gleaned regarding availability and pricing for bundled energy, capacity and RECs for long-term contracts:

- Current prices for Pennsylvania wind projects were quoted in the range of mid \$60's/MWh to high \$70's/MWh flat, with key variables being project size and capacity factor. Sizes of most projects varied from 30 MW to approximately 100 MW with capacity factors from the high 20's to mid 30's. The basis (locational value of the energy) relative to PJM Western Hub is estimated to be in the range of negative \$1-4/MWh historically.

- Wind projects in western Maryland and West Virginia. Prices were quoted in the low 60's to low 70's (\$/MWh). The basis between the APS[49] zone was estimated to be in the negative \$1-\$1.50/MWh range relative to PJM Western Hub based on three years of historical prices, but may be significantly higher for wind projects at various locations.

The basis between PJM Western Hub and the Delmarva Zone over the past three years has averaged \$4.44/MWh (all hours).

We conducted a spreadsheet analysis using similar assumptions used in the ICF model base case run, with the IC assumptions on gas transportation and coal prices and REC prices and imputed debt assumptions that we used in the bid evaluation. We assumed a range of projects, with Project A being a 60 MW project having a price of \$65.50/MWh flat and a combined basis to the Delmarva zone of negative \$7.50/MWh., with a 35% capacity factor. For Project B we assumed a 30 MW project with a price of \$78.00/MWh flat, a 30% capacity factor and a combined basis to the Delmarva zone of negative \$8/MWh. Project A, a capacity resource, would receive capacity credit for 20% of its nameplate capacity. Project B, an energy only resource, would receive no capacity credit. Under these assumptions, for Project A, assuming a value of \$12/REC flat, which approximates the current forward price for RECs for long-term contracts, the purchases would be somewhat lower than the market, while for Project B, it would be somewhat higher. In either case, the economic result would appear to be superior to any of the bids. In particular, it should not be surprising that onshore regional wind is less expensive and easier to develop than offshore wind.

Calls were also made to large wholesale energy marketers in the region regarding their interest in making a long-term power supply sale at fixed or firm pricing. Of those we talked to, the response was mixed. One supplier that had substantial existing coal-fired generation was interested in a sale of 10 years or longer, although it would likely include price adders for CO2 allowance costs. The supplier did not want to provide indicative pricing. Other suppliers expressed an interest in a sale of 10 years, but provided little additional information. Another supplier expressed a lack of any interest in a long-term sale. Several marketers, which were also owners of substantial MW of generation in the region, indicated that they expected prices to increase in future years and that they were not willing to sell forward at prices that did not reflect such perceived price appreciation.

[49] This includes all APS service areas, including those in Pennsylvania.

Based on this limited sample, regional onshore wind generation appears to be (a) a cost-effective way to hedge Delmarva's SOS customers' energy price risk (other than that caused by congestion) as well as the risk associated with RPS compliance and future carbon regulation and (b) a more cost effective hedge for regional energy price risk than any of the in-state generation bids pursuant to the RFP. Delmarva could make purchases on a modular basis, entering into one, two, or even three contracts with a size range of 30 MW to 100 MW per contract. This could hedge a significant amount of energy price risk, but in a sufficiently limited manner that it would not create significant incentives for customer migration if energy prices (or REC market prices) declined substantially. Moreover, as discussed in the following section, there are regulatory mechanisms that could be utilized to eliminate this as an issue altogether. Moreover, this approach would be consistent with the hybrid IRP/customer choice model fostered by ERUCSA in which Delmarva would develop a portfolio of measures to stabilize prices for a portion of its load on a long-term basis while continuing to procure full requirements service for SOS customers.[50]

In order to move forward with a power procurement, Delmarva could either develop an all-source RFP or one limited to renewables. A more focused renewables-only procurement would probably be less expensive to conduct while it would likely capture the best available opportunities. PECO Energy recently announced that it was planning to procure RECs on a five-year basis to "take advantage of current market prices" and bank the RECs to comply with Pennsylvania's Alternative Energy Portfolio Standards.[51] Currently, the federal production tax credit (worth $19/MWh to wind generation owners on an inflation-adjusted basis for 10 years) expires on December 31, 2008. While projects with an on-line date in 2009 and thereafter are at risk for not qualifying for the production tax credit, which would mean higher costs to buyers, the tax credit has been extended five times over the past seven years and there is a high likelihood that it will be extended again. Nevertheless, an effort to accelerate such a procurement effort could mitigate this risk.[52] A critical issue is how Delmarva would manage one or more long-term unit contingent contracts while at the same time continuing to procure standard offer service requirements service. We believe this can be done in a cost-effective manner. The specifics are addressed in the following section of this report.

In conclusion, it appears that there are more cost-effective ways to manage long-term energy price risk driven by potential upward shifts in natural gas prices as well as the risks associated with carbon dioxide emissions than any of the bids in the RFP process and there are potential vehicles to capture this risk protection. Moreover, due to the smaller size and modularity of onshore wind, the risks associated with downward market price movements are smaller than with the bid projects, especially for NRG's and Bluewater's bids. We recognize that there are risks associated with capturing those

[50] While another approach would be to increase the term of the current three-year SOS requirements contracts to provide longer-term price stability, the effect would be to increase the price premium associated with these contracts since the suppliers would be assuming migration risk over a longer period of time.

[51] http://www.exeloncorp.com/news/pressrelease/peco/NR+031907.htm.

[52] While PECO's activity in the market could provide competition for Delmarva, it also might provide the basis for complementary purchases, where Delmarva acquires primarily energy in the early years and both RECs and energy in the later years of a long-term purchase contract. Such a strategy would be consistent with the ramp up in purchase obligations under Delaware's Renewable Energy Portfolio Standards Act.

opportunities, such as the ability to execute contracts with generation developers before market conditions or the tax laws change, but we believe they should be manageable.

VI. Issues Associated With Long-Term Power Purchases or Self-Build Generation

If the State Agencies are to direct Delmarva to enter into long-term power purchase agreements ("PPAs") with one of the bidders pursuant to the RFP or to encourage or direct Delmarva to procure power and/or RECs under long-term contracts from generators pursuant to the IRP process, issues as to how long-term power purchase agreements would be managed in conjunction with utilizing full requirements laddered three-year contracts to provide standard offer service (assuming that this practice would continue) should be addressed. Related to the foregoing are issues impacting the value of the power under the long-term contracts to Delmarva's customers. In addition, the regulatory treatment and associated implications should be considered.

There are several different ways that the energy and capacity under long-term contracts could be managed in the context of SOS. The first approach is simply to sell the capacity and energy under the long-term contract back into the spot market resulting in a gain or loss to be recovered by ratepayers. A second approach would be to require one or more bidders to supply their portion of SOS load on top of the capacity and energy provided by the seller under the long-term contract. A third approach would be to sell the energy and capacity to wholesale suppliers for 3-year terms at the same time that SOS requirements service is procured. A fourth approach, similar to the third, would be to allow wholesale suppliers the option of linking a SOS requirements sale bid with a long-term unit contingent PPA purchase.

From a hedging perspective, a superior approach would be to sell back power under the long-term unit contracts at the same time that requirements purchases would be made. Based on the experience of the Maine Public Utilities Commission, the optimal approach would appear to be to allow bidders to link a requirements sale bid to a unit contract purchase bid.[53] This has resulted in the best combination of purchase and sales prices. The benefit of this approach is that if market prices are high at the time bids are solicited, the SOS requirements prices will be high, but they will be offset, in part, by high prices

[53] Central Maine Power Company ("CMP") has a number of long-term PPA's, most of which are unit contingent contracts. Maine, like Delaware, has a competitive retail market with standard offer service being procured on a full requirements basis RFPs to sell CMP's PPA entitlements have been conducted simultaneously with RFPs to procure standard offer service. Several times, for three-year periods, the winning bidder for SOS service has bid to purchase CMP's PPA entitlements as part of a package (so-called "contingent bidding"). The Maine Public Utilities Commission has found this approach to have benefits for ratepayers:

Through its experience in conducting the standard offer bid processes, the Commission has found that contingent bidding can be a means to maximize the value of utility power entitlements to the benefit of the utility's ratepayers. This is because the business risk for a bidder can be reduced when load obligations and the resources to serve that load are simultaneously obtained. Reduced risk translates to lower costs and a higher value for the entitlements.

See http://www.maine.gov/mpuc/industries/electricity/electric%20restructuring/appendixe.htm.

for the sale of power under the unit contract. This will provide a "more perfect" hedge than if power from the unit contracts are simply sold back into the spot market. The downside is that there will be a bid-ask spread cost associated with selling power under the unit contracts for a three-year term. While these benefits and costs are difficult to value, we believe they will offset each other, although the net effect should be somewhat positive.

Renewable wind projects will have the largest hedge benefit for energy, the largest single cost factor, because of their fixed price and lack of carbon exposure. On the other hand, they will likely experience a larger bid-ask spread than other contracts due to their intermittency. The Conectiv bid, which has firm energy albeit at variable pricing, should also have significant hedge value followed by NRG. The alternative of selling the capacity and energy into the market on a spot basis will reduce the hedge value due to procurement timing issues (market prices move between SOS procurements) but also reduce or eliminate bid-ask spreads.

From a regulatory standpoint, a cost recovery mechanism similar to a fuel clause adjustment would appear to be the best way to recover the net costs under a long-term power purchase agreement. The costs under the PPA would be netted out against the revenue of selling the capacity, energy, and/or RECs back to the market or to an energy marketer, with the net cost or net benefit assigned to the appropriate customer group. This would appear to be the class of RSCI customers, or at least those RSCI customers on SOS. Based on existing law, RSCI customers that migrate from SOS would appear to have the ability to avoid any net PPA charge. While the Commission would have the authority to reassign any net PPA charge to at least all RSCI customers, even those that have migrated if it imposed a cost burden on the remaining SOS customers,[54] this remedy is not ideal. A better approach would be to assign the net costs to all customers in the class for whom the power is procured regardless of whether they subsequently migrated to competitive service. However, it would appear that a change in the underlying legislation may be required to implement this mechanism.

Delmarva did not seriously consider self-build generation in its IRP.[55] The issues associated with rate base treatment for self-build projects are similar, although more complex, we believe, than the issues addressed above for long-term PPAs. If self-build generation is to be considered seriously, even as part of a contingency plan, the associated ratemaking issues would need to be addressed, including which class of customers should be charged.

Finally, it has been our experience that Delmarva perceives risk management as a "one way" risk for its shareholders—a concern that it be required to enter into a long-term contract whose costs would exceed market prices, ultimately creating the potential for less than full cost recovery. Proper implementation of its responsibilities under ERUCSA requires a far more balanced view of risk assessment and risk management, with a focus on risks from the perspective of the Company's customers. The Commission may wish to institutionalize some degree of financial incentive/disincentive by making the

[54] 26 Del C. § 1010(c).
[55] See IRP Compliance Filing at 26-27.

Company's performance in the IRP process a factor in determining its rate of return or through some other mechanism.

VII. Conclusions and Recommendations

In this report, we have provided our preliminary assessment of Delmava's IRP, with a focus on assisting the State Agencies in assessing the risks and benefits of a decision to go forward with or not to go forward with one of the bids in the RFP process in the context of important assumptions, recommendations and alternatives considered or required to be considered in Delmarva's IRP. After further inquiry, consideration ofadditional scenarios and assessing the risks discussed in this report, we do not recommend any change in the our ranking of bids pursuant to the RFP at this time.

However, we believe that as a conceptual matter it is sensible for Delmarva to hedge a portion of the long-term market price risk for RSCI SOS customers. We are also of the view that it is better as a conceptual matter to obtain competing proposals for long-term contracts from a larger universe of potential bidders and regional supplies than to limit consideration to three bidders with proposed new power plants in Delaware with the associated need to have greater reliance on forecasts of market prices, regardless of how reasonable the forecasts may be. Absent such a "market test," we are not comfortable in making a recommendation that the State Agencies direct Delmarva to negotiate a power purchase agreement with any of the bidders. In this context, we draw the following conclusions and make the following recommendations:

1. A decision on the bids pursuant to the RFP should await the analysis conducted at the request of the Commission staff that addresses the impact on reliability and system economics if Indian River units 1 and 2 are retired; if substantial issues are presented from this analysis, it should then be determined whether selecting one of the bids pursuant to the RFP is a cost-effective means of addressing the associated risks.

2. Delmarva should be responsible for assessing the need for additional generating capacity on the Delmarva peninsula from a reliability and economic standpoint (based on "bottom up" evaluation and monitoring) and for conducting a risk assessment as part of its IRP obligations. Consistent with the foregoing, the Company should be directed to prepare (and update as needed) a contingency plan to obtain required generation either through a power purchase agreement or through self-build generation as part of its IRP obligation in order to hedge locational capacity and congestion risk. This might entail installation of a combustion turbine or natural gas-fired combined cycle plant to mitigate increases in locational capacity prices and/or congestion at a favorable site, subject to Commission approval.

3. Delmarva's IRP is deficient in that the Company has failed to seriously evaluate long-term power purchase contract opportunities with regional power generators. The purchase of energy and Renewable Energy Credits from developers of regional onshore wind generation projects appears to provide the potential for

cost-effective hedging of systemic energy and RPS compliance risks by Delmarva for its SOS RCSI customers.

4. Based on a risk analysis and assessment of additional scenarios as well as available market information, we do not recommend a change in our ranking of bids or recommend that Delmarva be directed to sign a contract with any of the bidders at this time in the absence of a market test.

5. We recommend that Delmarva be directed to conduct a market test (or that the State Agencies direct that one be conducted on their behalf) to explore one of the following two alternatives:

    a. A short-form version of an all-source RFP for long-term power supplies that would not be limited to new generation within Delaware. The bidders in the RFP process would be allowed to keep their bids in place or rebid. This will allow the Company to assess the economic and other benefits of regional generators or power supplies and compare these other alternatives to the bid projects; or.

    b. A renewables-only RFP for energy, capacity and RECs as a means to hedge energy and RPS compliance risk if the State Agencies determine that one of Bluewater's bids is the most attractive pursuant to the current RFP. Regional renewable generators would be entitled to participate. Bluewater would be allowed to keep its bids in place or rebid.

Appendix A

LETTER TO DELMARVA POWER

(Request for Additional Scenario Runs)

New Energy Opportunities, Inc.

Barry J Sheingold
President

March 14, 2007

Mr. Mark Finfrock
Director, Corporate Risk
Delmarva Power & Light Company
800 King Street
Wilmington, DE 19899

By Email Only: mark.finfrock@pepcoholdings.com

Dear Mark:

You have asked me to memorialize the requests of the Independent Consultant for additional model runs to be conducted by ICF on behalf of Delmarva Power and the basis for the requests.

After substantial discussion, our requests are as follows (the key inputs/assumptions are set forth under the applicable scenario):

1. High Gas/IC Scenario
    a. IC case assumptions on coal and gas transportation prices
    b. ICF high gas price scenario
    c. NJ energy efficiency reduces load growth from 1.7%/year from the IRP's Higher NJ Load Case to 1.0%/year instead of 20% by 2020
    d. No on-shore wind in Delaware
    e. ICF reference case carbon assumptions

2. Capacity/Transmission Limits Scenario
    a. IC case assumptions on coal and gas transportation prices
    b. No nuclear units in PJM Classic
    c. NJ energy efficiency reduces load growth from 1.7%/year from the IRP's Higher NJ Load Case to 1.0%/year instead of 20% by 2020
    d. No MAPP/AEP transmission lines
    e. Retirement of units: units currently that have applied to PJM for retirement and oil/gas steam units and combustion turbines under 200 MW when they have reached a life of 60 years.
    f. No on-shore wind in Delaware
    g. ICF reference case gas and carbon assumptions

3. Revised IC Reference Scenario—same as High Gas/IC Scenario but with ICF reference case gas scenario.

We are making these requests in connection with the report that we are preparing for the State Agencies that is due on April 4, 2007. The report, based on review of Delmarva's IRP, is for the purpose of providing the State Agencies "a framework within which to consider the results of the RFP evaluation." (Order No. 7131 at 3-4). The report will address the risks and benefits of a decision to go forward with or not go forward with one of the bids in the RFP process in the context of important assumptions, recommendations and alternatives considered or required to be considered in Delmarva's IRP.

4. Sensitivities in Connection with Price Stability Analysis.

In addition, we request that certain additional scenarios be run as sensitivities to the price stability analysis. As you recall, we requested previously that several modifications to the Delmarva reference case be made—primarily, reduced coal prices and increased gas transportation costs. While ICF did produce a scenario with our recommended assumptions, none of the other scenarios used in the price stability analysis incorporated our assumptions involving reduced coal prices and increased gas transportation costs.

We believe that the price stability analysis would have greater credibility if a sensitivity was run using the assumptions involving reduced coal priced and increased gas transportation costs. Specifically, we would like the following scenarios run with these assumptions:

a. Low gas
b. Low CO2
c. High CO2

While the Company's earlier limited responsiveness to our requests could be justified by the exigencies of having to meet a Legislatively-directed deadline for producing the bid evaluation reports, there is additional time to conduct some additional analysis that will help put the price stability evaluation in better perspective.

For clarification, please provide results for a market scenario and each bid for each of the foregoing requested scenarios. To simplify the task, ICF can provide results for the best of each bid (i.e. Connectiv's Alternative Bid, Bluewater Full 25-year bid, NRG 25 yr w/o CCS).

We look forward to your prompt response. Our report will indicate that we made the above-described requests and will describe your response to the requests.

Very truly yours,

Barry J. Sheingold