ANALYSIS OF RESOURCE AND POLICY OPTIONS FOR MARYLAND'S ENERGY FUTURE

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FOR THE MARYLAND PUBLIC SERVICE COMMISSION

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Table of Acronyms

ACP	Alternative Compliance Payment
AE	Allegheny Energy
AECO	Atlantic City Electric Company
AEP	American Electric Power
AFI	Allowance for Indeterminants
AMC	Allegheny Mountain Corridor
APS	Allegheny Power System
AUI	Advanced Utility Infrastructure
Bbl	Barrel
BGE	Baltimore Gas & Electric
BlueWater	BlueWater Wind
BRA	Base Residual Auction
BSA	Bill Stabilization Adjustment
C&I	Commercial and Industrial
CAIR	Clean Air Interstate Rule
CAMR	Clean Air Mercury Rule
CapEx	Capital Expenditure
CAPP	Central Appalachian Basin
CC	Combined Cycle
CETL	Capacity Emergency Transfer Limit
CETO	Capacity Emergency Transfer Objective
CMEC	Capacity Markets Evolution Committee
CO_2	Carbon Dioxide
ComEd	Commonwealth Edison
Commission	Maryland Public Service Commission
CONE	Cost of New Entry
CPCN	Certificate of Public Convenience and Necessity
CPI-U	Consumer Price Index for all Urban Consumers
CT	Combustion Turbine
DAM	Day-Ahead Market
DCF	Discounted Cash Flow
DCLM	Direct Control Load Management
DOE	Department of Energy
DPL	Delmarva Power & Light
DPUC	Department of Public Utility Control
DR	Demand Response
DRC	Delaware River Corridor
DSM	Demand Side Management
DTI-SP	Dominion Transmission Inc. South Point
Duquesne	Duquesne Light Company
E&AS	Energy and Ancillary Services
E&P	Exploration and Production
EBITDA	Earnings Before Income Taxes, Depreciation and Amortization
EE&C	Energy Efficiency and Conservation
EFORd	Equivalent Demand Forced Outage Rate
EIA	Energy Information Administration
EMAAC	Eastern Mid-Atlantic Area Council
EMD	EmPOWER Maryland
EPA	Environmental Protection Agency
EPC	Engineering Procurement Construction

EVA	Economic Value Added
FERC	Federal Energy Regulatory Commission
FGD	Flue Gas Desulfurization
FMV	Fair Market Value
G&A	General and Administrative
GDP	Gross Domestic Product
GO	General Obligation
GSC	Generation Service Cost
GT	Gas Turbine
GW	Gigawatt
GWh	Gigawatt Hour
HAA	Healthy Air Act
HRSG	Heat Recovery Steam Generator
HVAC	Heating, Ventilating and Air Conditioning
ICAP	Installed Capacity
ID	Interruptible Demand
IEO2008	2008 International Energy Outlook
ILR	Interruptible Load for Reliability
IMM	Independent Market Monitor
IOU	Investor Owned Utility
IRM	Installed Reserve Margin
IRR	Internal Rate of Return
IRS	Internal Revenue Service
ISA	Interconnection Service Agreement
ISO	Independent System Operator
ISO-NE	Independent System Operator – New England
ITC	Investment Tax Credit
JCPL	Jersey Central Power & Light
kW	Kilowatt
kWh	Kilowatt Hour
LAI	Levitan & Associates, Inc.
LDA	Locational Deliverability Area
LI	Lerner Index
LIPA	Long Island Power Authority
LMP	Locational Marginal Price
LNG	Liquefied Natural Gas
LSE	Load Serving Entity
MAAC	Mid-Atlantic Area Council
MAANC	Mid-Atlantic Area National Corridor
MAC	Mid-Atlantic Corridor
MACRS	Modified Accelerated Cost Recovery System
MAPP	Mid-Atlantic Power Pathway
MdTA	Maryland Transportation Authority
MidAmerican	MidAmerican Energy Holdings Company
MISO	Midwest Independent System Operator
MMBbl	Million Barrels
MMBtu	Million British Thermal Units
MMU	Market Monitoring Unit
MRC	Markets and Reliability Committee
MTM	Mark-to-Market
MW	Megawatt
MWh	Megawatt Hour
NAPP	Northern Appalachian Basin
NIETC	National Interest Electric Transmission Corridor

NOAA	National Oceanic and Atmospheric Administration
NO_x	Nitrogen Oxides
NYISO	New York Independent System Operator
NYPA	New York Power Authority
NYPSC	New York Public Service Commission
O&M	Operation and Maintenance
OATT	Open Access Transmission Tariff
OGPR	Oil Gas Price Ratio
OPC	Office of People's Counsel
OPEC	Organization of Petroleum Exporting Countries
PA PUC	Pennsylvania Public Utility Commission
PATH	Potomac Appalachian Transmission Highline
PCMI	Price Cost Markup Ratio
Pepco	Potomac Electric Power Company
PHI	Pepco Holdings, Inc.
PJM	PJM Interconnection
PPA	Power Purchase Agreement
PPL	Pennsylvania Power & Light
PRB	Powder River Basin
PSC WV	Public Service Commission of West Virginia
PSEG	Public Service Electric & Gas
PURPA	Public Utility Regulatory Policies Act
PV	Present Value
REC	Renewable Energy Credit
RFP	Request for Proposals
RGGI	Regional Greenhouse Gas Initiative
ROE	Return on Equity
ROR	Rate of Return
RPM	Reliability Pricing Model
RPS	Renewable Portfolio Standard
RTEP	Regional Transmission Expansion Plan
RTM	Real-Time Market
RTO	Regional Transmission Organization
SCC VA	State Corporation Commission of Virginia
SCR	Selective Catalytic Reduction
SO_2	Sulfur Dioxide
SOM	State of the Market
SOS	Standard Offer Service
ST	Steam Turbine
SWMAAC	Southwest Mid-Atlantic Area Council
T&D	Transmission and Distribution
Tcf	Trillion Cubic Feet
Tetco M3	Texas Eastern Transmission Company Zone M3
TO	Transmission Owner
TrAIL	Trans-Allegheny Interstate Line
TrAILCo	Trans-Allegheny Interstate Line Company
TZ6NNY	Transco Zone 6 Non-New York
U_3O_8	Uranium
UCAP	Unforced Capacity
UI	United Illuminating

VRR	Variable Resource Requirement
WTI	West Texas Intermediate

INTRODUCTION

In accordance with Chapter 549, Maryland Laws of 2007, the Maryland Public Service Commission (Commission) was required to evaluate the status of restructuring in Maryland and to assess options for re-regulation. Under the direction of the Commission, a study of Maryland's long-range energy options was undertaken by Levitan & Associates, Inc. (LAI) under subcontract to Kaye Scholer, LLC.[1] The report of the results of the first phase of the study, *Analysis of Options for Maryland's Energy Future* (Interim Report), was published on November 30, 2007.[2] In the Interim Report, LAI and Kaye Scholer compared the net benefit to ratepayers of a range of resource options over a 20-year planning horizon. The resource options examined in the Interim Report included new gas-fired combined-cycle (CC) plants, the addition of a supercritical pulverized coal plant, a new nuclear reactor unit at Calvert Cliffs, fulfillment of Governor O'Malley's EmPOWER Maryland (EMD) "15 by 15" conservation and load management initiative, addition of a major new "backbone" transmission project, and expansion of the in-state wind turbine fleet, both onshore and offshore. In addition, LAI examined the relative economic merit associated with long-term power purchase agreements (PPAs) between Maryland's investor-owned utilities (IOUs) and third-party generation companies in order to sustain a substantial surplus in generation reserves over the 20-year planning horizon. Maryland's potential investment in a generation surplus over the planning horizon was referred to as the *1200 MW Overbuild Case*.

The relative economic benefits associated with each resource option were compared to the wholesale costs under the *Reference Case*, that is, the least-cost addition of a gas turbine (GT) peaking plant and/or CC plant in Maryland and the PJM Interconnection (PJM) just-in-time to meet target reserve margin requirements established by PJM. Also embedded in the *Reference Case* was about 25% of the mix of demand-side management (DSM) programs associated with the EMD initiative. With respect to ratepayer benefits, the most promising resource options identified in the Interim Report included the new backbone transmission projects into and around Maryland, the addition of a third nuclear power plant at Calvert Cliffs, and DSM under the EMD initiative. The economic benefits associated with the *1200 MW Overbuild Case* were also favorable. Much less favorable or unfavorable were the new pulverized coal option, the optimized mix of gas-fired generation capacity additions, and the wind case. The economics of new wind in Maryland were impaired due to the high capital cost of adding 300 MW of offshore wind. In the Interim Report, we identified a number of non-economic factors that bear on the feasibility of different technology options, for example, siting and permitting constraints, uncertainty about wholesale market design, and financing risk.

To support policy decisions regarding the merit of short- and long-term initiatives for Maryland's energy resource future, further evaluation of the most attractive resource options was needed. In this Final Report, LAI and Kaye Scholer continue the evaluation of the most promising resource options to meet Maryland's long-term energy needs. Emphasis has been placed on different ways to re-regulate the wholesale power market in Maryland.

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[1] Semcas Consulting Associates also participated in the evaluation of DSM options.

[2] The Interim Report may be found at: http://www.psc.state.md.us/psc/Reports/home.htm.

Over the last year there have been fundamental market changes that alter the distribution of risks and rewards among market participants. Skyrocketing oil and gas prices have been followed by unprecedented declines in absolute dollars. In addition to fundamental market developments in PJM, the anticipated acquisition of Constellation Energy by MidAmerican Energy Holdings Company (MidAmerican) and the recent credit implosion have changed the market outlook. The worldwide credit dislocation that followed the sub-prime mortgage meltdown affects the cost and availability of capital for resource investments, regardless of technology type, but we have assumed a return to normal capital market conditions. In finalizing this report, we have incorporated many changes to key assumptions and model parameters that affect the relative merit of competing resource options. We note that the Final Report does not include an assessment of the competitive impact associated with MidAmerican's planned acquisition of Baltimore Gas & Electric Co. (BGE) or the generation plants owned and operated by Constellation in Maryland, as that transaction is currently before the Commission for review.[3] Similarly, despite the large potential commercial and environmental promise associated with Constellation's proposed addition of a third nuclear power plant at Calvert Cliffs, we have not performed an update of this resource option herein.

LAI formulated the majority of the model assumptions incorporated in this study in June, July, and August, 2008. In updating key factor inputs, LAI has focused on the options that are within the authority of the General Assembly and/or the Commission to effectuate through legislative mandate, regulatory action, and/or new energy policy. Alternative resource options and re-regulation scenarios featured in the Final Report have been prioritized by the Commission in response to questions and interests raised by the Senate Finance Committee and the General Assembly in early 2008.

The primary areas of concern addressed herein include quantification of the following:

- The (dis)benefits ascribable to aggressive DSM penetration in Maryland under the EMD initiative;
- The (dis)benefits ascribable to new onshore wind generation in Maryland or offshore wind generation off the coast of Delaware or Maryland;
- The (dis)benefits related to implementing Maryland's solar initiative when considered from the ratepayers' perspective as well as an investor's;
- Utility versus third-party ownership and operation of new gas-fired generation; and
- The impact of a return to traditional rate base regulation for the Maryland portion of the Potomac Electric Power Company (Pepco) service territory associated with the postulated condemnation of generation assets in Maryland that are presently owned and operated by Mirant.[4]

[3] *In the Matter of the Acquisition of Constellation Energy Group, Inc., the Parent Company of Baltimore Gas and Electric Company, but MidAmerican Energy Holdings Company and Constellation Energy Holdings, LLC and of Baltimore Gas and Electric Company by BGE Holdings, LLC*, Case No. 9160.

[4] This report does not address postulated condemnation of the generation assets in Maryland that are presently owned by affiliates of Constellation, as the planned acquisition of BGE and the generation plants owned by

Each of the resource options and policy alternatives identified in the bullets above was examined by evaluating eight study cases. Section 1 defines the study cases and presents an overview of the analysis framework. Section 2 presents the modeling methodology and the approach for assessing the economic and environmental benefits for each of the study cases. Section 3 discusses the external circumstances affecting the economic outcome of each case, and describes the sensitivity scenarios evaluated. Sections 4 through 8 present the results of the eight study cases, grouped by similar technology or policy objective, and Section 9 contains a summary of conclusions.

Constellation is currently before the Commission for review. *Id*. Nor does this report address the impact of a return to traditional rate base regulation elsewhere in Maryland.

EXECUTIVE SUMMARY

The array of resource and regulatory policy options before the Commission has been formulated as eight study cases. Four cases are centered on renewable technologies and DSM that constitute alternative resource technologies to conventional gas-fired generation, as follows:

- In the ***15x15 DSM Case*** we evaluate the potential benefits if the conservation and energy efficiency initiatives under EMD, as well as the objectives of the demand response (DR) programs, are achieved in full by 2015.

- In the ***Onshore Wind Case*** we evaluate the benefits of 200 MW of new onshore wind turbines under 20-year PPAs with the IOUs.

- In the ***Offshore Wind Case*** we evaluate the benefits of a 500-MW offshore wind project based on the commercial terms incorporated in the BlueWater Wind (BlueWater) PPA with Delmarva Power & Light (DPL). In the *Offshore Wind Case* we assume that Maryland IOUs would enter into long-term PPAs for 300 MW of installed capacity.

- In the ***Solar Case*** we evaluate the cost to ratepayers to comply in full with the solar initiative under Maryland's Renewable Portfolio Standard (RPS). As part of this study case, we also examine the economics of developing a 1-MW photovoltaic plant from a commercial customer's perspective.

Three cases are centered on different contracting and ownership alternatives to the merchant model established by PJM for purposes of supporting the development of new conventional generation in Maryland, as follows:

- In the ***Contract CC Case*** we postulate the addition of 1,080 MW – two 540-MW, state-of-the art CC projects located in Southwest Mid-Atlantic Area Council (SWMAAC). Development would be by third parties, *i.e.*, merchant generators. The in-service date is 2012. To ensure timely commercial operation, we assume that the merchant generators enter into 20-year PPAs with four IOUs in Maryland. At the end of the PPA terms, we assume that the IOUs exercise their right to extend the contracts for 10 years.

- In the ***Utility CC Case*** we evaluate the same 1,080-MW additions in 2012, but instead of PPAs to support project financing, we assume IOU ownership and operational responsibility. In formulating the *Utility CC Case*, we have assumed that the Commission authorizes the recovery of all prudently incurred costs.

- In the ***Overbuild Case*** we evaluate the addition of 1,080 MW under long-term PPAs with the IOUs in accord with the *Contract CC Case*. In order to sustain the overhang in Maryland, thereby reducing energy and capacity prices in SWMAAC, in particular, we assume Maryland's IOUs will enter into additional long-term contracts over the study horizon to maintain a surplus in SWMAAC, thereby supplanting new merchant generation otherwise built elsewhere in Maryland or PJM.

Finally, we envision the impact of a return to traditional cost of service regulation. This case is centered on a major legislative initiative that would create a vertically integrated utility or a new power Authority through the postulated condemnation or consensual sale of the generation assets in the Maryland portion of the Pepco service territory that are currently owned by Mirant, as follows:

- In the ***Rate Base Regulation Case*** we compute the fair market value (FMV) of Mirant's coal-, oil- and gas-fired generation assets, about 4,780 MW. Under traditional cost of service regulation, we have quantified the resultant ratepayer benefits when the generation assets are owned and operated either by Pepco or by a newly formed state power Authority.

The yardstick for evaluating each resource and policy option is the *Reference Case*. The *Reference Case* constitutes the "business as usual" condition representing Maryland's resource mix, transmission infrastructure, environmental policy, and profile of load growth in the absence of new energy initiatives undertaken by the General Assembly, the Commission, or PJM. In formulating the *Reference Case*, we have incorporated about one-quarter of the DR and conservation / load management program benefits defined by the EMD initiative. In the *Reference Case* and each study case (other than the *Solar Case*) the total cost of wholesale power to serve Maryland load over a 30-year planning horizon has been calculated. The difference in the cost to serve Maryland's load between the *Reference Case* and each alternative case represents the aggregated net benefit or cost associated with the postulated resource or policy option. The net benefit or cost is expressed on a present value (PV) basis over the study horizon. The differential in cost relative to the *Reference Case* is referred to as Economic Value Added (EVA): the greater the EVA, the higher the net economic benefit in relation to the *Reference Case*. A negative EVA represents an increase in costs under the resource or policy option examined in this study. EVA represents a "Mark-to-Market" (MTM) accounting of the change in cost to serve total load in Maryland under the estimated wholesale power prices.

While the *Reference Case* represents a minimal set of assumed policies and actions against which specific policies and action are measured, the *Base Scenario* represents the external variable assumptions under which all policies and actions (cases) are evaluated. The *Conventional Wisdom* fuel price forecast included in the *Base Scenario* was prepared in the summer of 2008, a time when oil prices briefly exceeded $145 per barrel and the global credit implosion had not yet occurred. Throughout this report the *Base Scenario* fuel price forecast and the *Conventional Wisdom* outlook are used synonymously. Also included in the *Base Scenario* is the assumption that the Trans-Allegheny Interstate Line (TrAIL) transmission project will be in-service in 2014, about three years after TrAIL's sponsors and PJM have indicated planned commercial operation. This is a very conservative assumption that was made well before the recent decision of the Pennsylvania Public Utility Commission (PA PUC) on November 13, 2008, approving the portion of TrAIL that is located in Pennsylvania. To account for uncertainty about fuel prices and the timing of TrAIL, we have formulated four alternative scenarios. These alternative scenarios have been used to evaluate the sensitivity of key study results. Most important is the low fuel price case, referred to as the *Federal Outlook Scenario*. High fuel prices are referred to as the *Peak Oil Scenario*. We have contemplated no new backbone transmission in PJM over the study horizon, *i.e.*, the *No TrAIL Scenario*. We have also contemplated two new backbone transmission projects, *i.e.*, the *TrAIL+PATH Scenario*. In the

TrAIL+PATH Scenario, we conservatively assume that TrAIL is commercialized in 2014 and the Potomac Appalachian Transmission Highline (PATH) is commercialized one year later.

Primary Findings

Across the eight resource and regulatory policy options evaluated in this study, LAI's primary observations and findings are as follows:

- ❒ Wholesale power prices in Maryland will remain sensitive to variations in world oil and North American natural gas prices for the foreseeable future. Although Maryland's existing generation resource base is reasonably well diversified under current economic and environmental conditions, the existing market rules and transmission limitations governing how wholesale energy prices are set in Maryland mean that premium fossil fuel costs will likely remain the primary determinant of wholesale and retail electricity prices during on-peak hours and increasingly during the off-peak period over the study horizon.[5]

- ❒ Natural gas prices historically have been correlated strongly with oil prices. We expect this price linkage to remain moderate to strong over the planning horizon as premium fossil fuel prices whipsaw in response to global market dynamics. The long-term outlook for natural gas prices across the Atlantic seaboard reflects a developing gap in the U.S. between strong demand and indigenous continental supplies. While the anticipated supply deficit can be satisfied through increased reliance on liquefied natural gas (LNG) at import facilities like Dominion's Cove Point terminal, the U.S. will need to compete with Europe and Asia for LNG supplies that originate in the Middle East, the former Soviet Union, Africa, and Trinidad. Destination-flexible cargoes are typically priced in relation to benchmark oil prices in Europe, Asia and, to a lesser extent, the U.S. For this reason and others, we expect natural gas prices at market centers in PJM to remain extremely volatile over the planning horizon. Wholesale power prices in Maryland are also likely to remain linked to the cost of natural gas and therefore be volatile as well, regardless of the amount of renewable energy, DSM, and/or high voltage transmission added to Maryland's resource base.

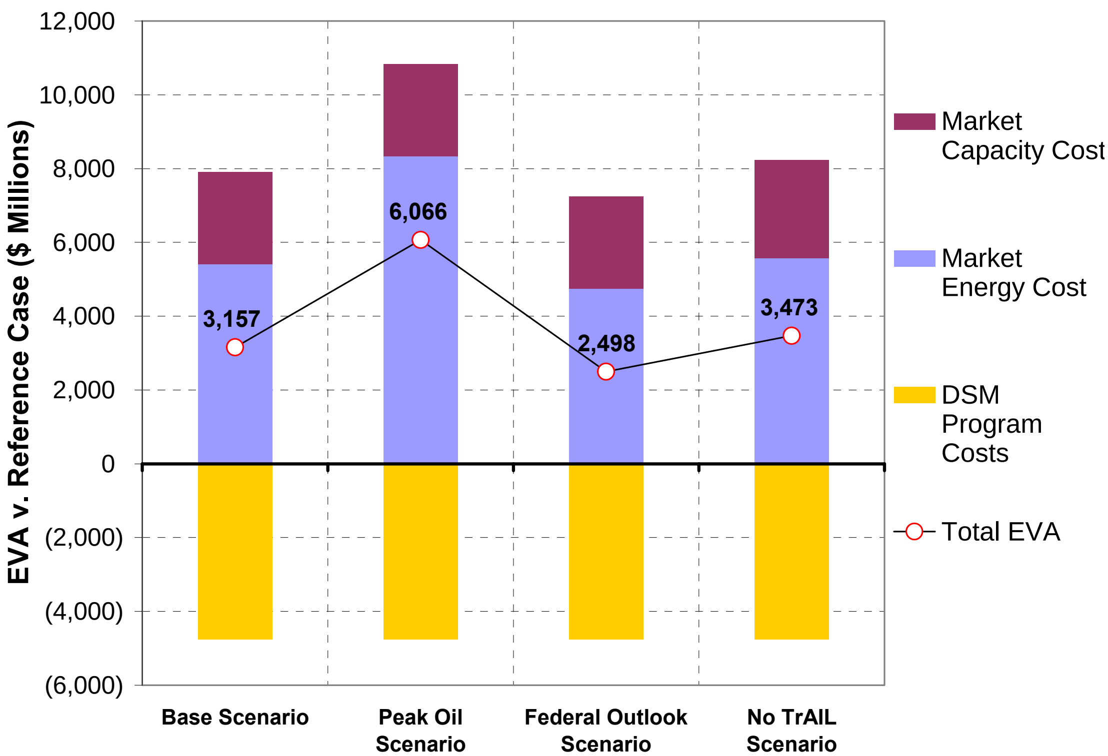
- ❒ New transmission will alleviate transmission constraints in SWMAAC, but does not appear to be a panacea. The PJM-approved TrAIL project can produce significant economic and reliability benefits in Maryland. In the Interim Report we quantified an EVA of $2.2 billion, corresponding to a benefit-to-cost ratio over 21:1 – by far, the highest among all resource and policy options examined last year. Based on PJM's guidance, the expected change in the Capacity Emergency Transfer Limit (CETL) in SWMAAC ascribable to the start-up of TrAIL is 230 MW. If TrAIL is delayed to 2014, a very conservative assumption in light of the PA PUC's recent ruling, and if actual DSM penetration does not materialize on a fast track, Maryland may face a significant capacity deficit for two to three years beginning in 2012.

[5] This is due to the fact that a large percentage of marginal units in PJM (those that set the locational marginal price or "LMP" for energy) are fueled by natural gas and natural gas costs have been correlated strongly with oil prices.

- ❒ Maryland has several promising resource options that can help satisfy the state's resource requirements. Most promising is DSM. As the target saturation rate for DSM steadily increases through 2015, the anticipated economic and environmental benefits increase. Consistent with our prior findings in the Interim Report, we caution that the DSM case reflects aggressive program implementation and broad voluntary ratepayer participation through 2015, both at unprecedented levels. Although we have assumed conservative program implementation costs to account for the uncertainty associated with advanced utility infrastructure, smart grid technology, smart switches, remotely controlled thermostats, and advanced meters, the achievable net savings should still be considered uncertain.

  As shown in Figure 1, program implementation costs associated with DSM are very high, about $4.76 billion over the planning horizon (see yellow bar below the x-axis). The value of avoided market-based energy and capacity costs are far greater. In the *Base Scenario*, project EVA is $3.157 billion. Under the *Peak Oil Scenario*, the EVA nearly doubles to $6.1 billion. Under the *Federal Outlook Scenario*, the EVA remains strongly positive, about $2.5 billion. When we contemplate the indefinite delay of TrAIL, project EVA increases from $3.157 billion to $3.473 billion, an increase of 10% reflecting the avoidance of more expensive energy in SWMAAC absent the addition of backbone transmission.

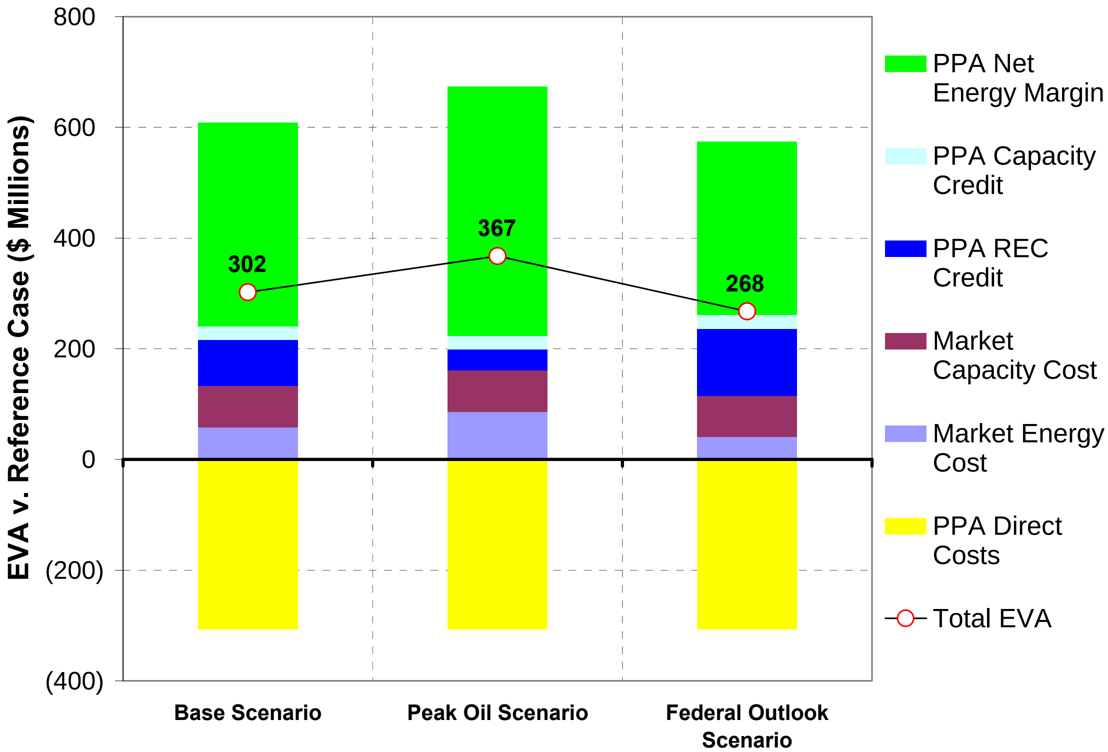
Figure 1. EVA – *15x15 DSM Case*



- ❒ The development of onshore wind also represents a promising resource option, yielding significant economic and environmental benefits each year over the planning horizon. The addition of 200 MW of onshore wind equates to PJM-designated unforced capacity (UCAP) of 33 MW. Because the capacity benefits associated with onshore wind in Maryland are small, onshore wind entry will not encourage a significant deferral or cancellation of conventional generation resources to satisfy reliability requirements. The market value of energy produced is the largest driver of savings ascribable to wind. Value is also derived from the sale of renewable energy credits (RECs) as each state's RPS targets grow annually and the demand for RECs increases across PJM. On the other hand, portfolio benefits vis-à-vis the reduction in energy and capacity prices elsewhere in Maryland are insignificant.

As shown in Figure 2, the net energy margin and market capacity value from the onshore wind projects offset the direct contract costs, and the avoided purchase of Tier 1 RECs, along with a depression of energy prices and capacity prices, provides additional ratepayer benefits. We note that the value of the RECs trends in the opposite direction to the value of energy.

Figure 2. EVA – *Onshore Wind Case*



We have also examined the economics of offshore wind. The addition of 500 MW of installed capacity off the coast of Delaware equates to UCAP of about 128 MW. Using BlueWater as a proxy for the economic benefits associated with offshore wind, we conclude that the high cost of building and operating offshore wind places this technology in an unfavorable economic light, particularly in relation to onshore wind projects in Maryland or elsewhere in PJM. Maryland's IOUs' share of the total direct project costs amounts to $1.3 billion, about 60% of the total project costs. Under the *Base Scenario* fuel price outlook, project benefits amount to $1.04 billion, 85% of which are energy-related. As shown in Figure 3, there are other small, comparatively insignificant market benefits associated with the consequent diminution of energy and capacity prices. The project EVA is negative $198 million. Under the *Peak Oil Scenario*, energy benefits are substantially increased, boosting project EVA marginally into the black, *i.e.*, $26 million. Under the *Federal Outlook Scenario*, project EVA is deep in the red, *i.e.*, negative $253 million.

Figure 3. EVA – *Offshore Wind Case*

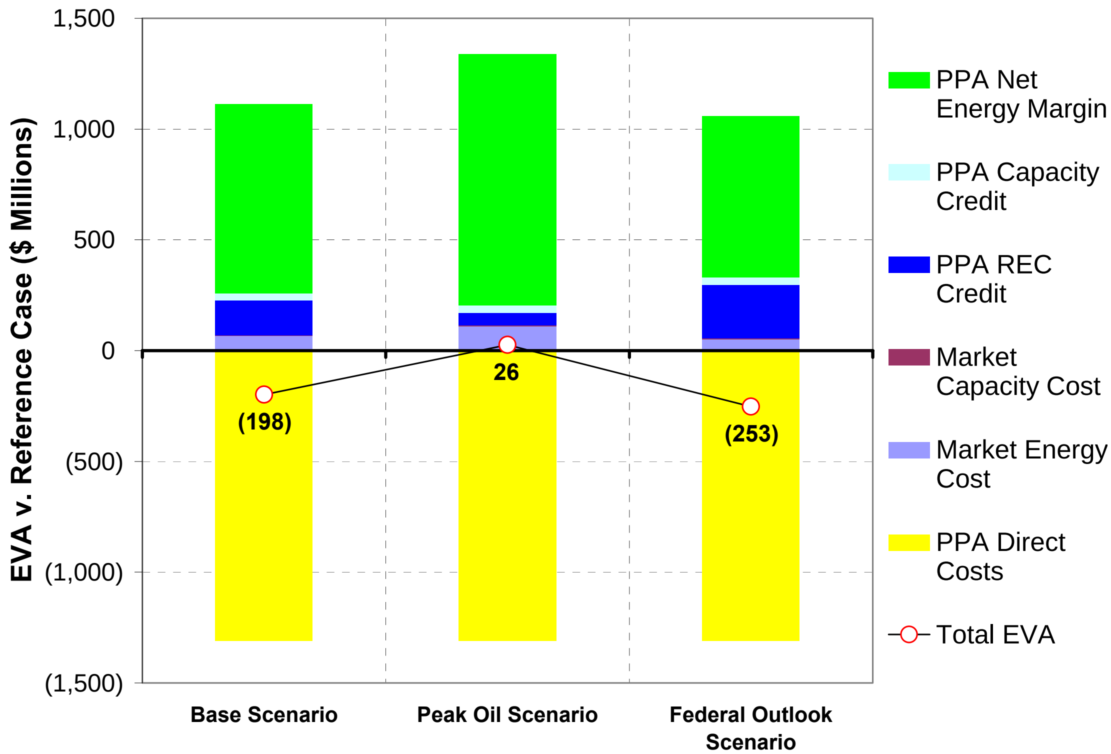
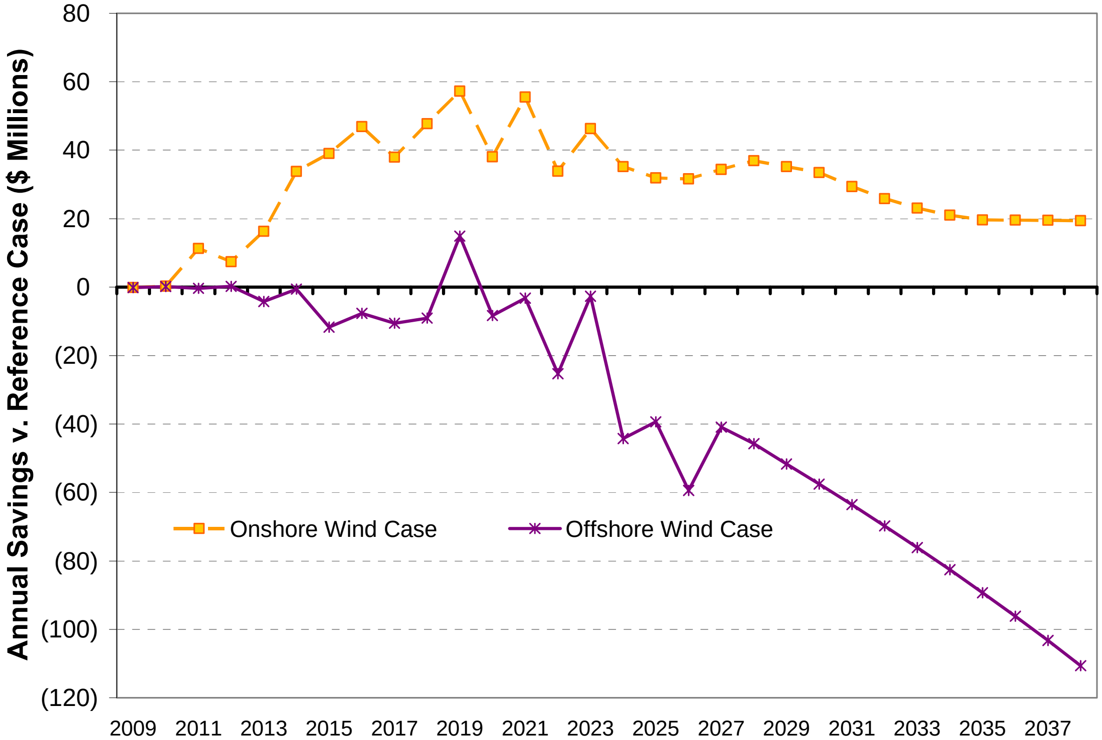


Figure 4 shows the annual net benefits for the *Onshore Wind Case* and the *Offshore Wind Case* under the *Base Scenario*. We note that the net benefits for onshore wind are positive in all years, but taper off as the postulated 20-year contracts end and the facilities remain in the merchant market. In contrast, the offshore project is a single addition in 2014 and imposes costs (negative benefits) in almost every year of the 25-year project. The magnitude of the negative benefit increases in the later years due to the compounding effect of the fixed escalation in the BlueWater pricing provision.

Figure 4. Annual Savings – Wind Cases (*Base Scenario*)



Despite the comparatively lackluster economics relative to onshore wind, offshore wind may still be worthwhile to the extent onshore wind development is stymied by local opposition. Also, production related intermittency problems associated with offshore sites may require less expensive solutions in order to integrate offshore wind generation into the resource base.

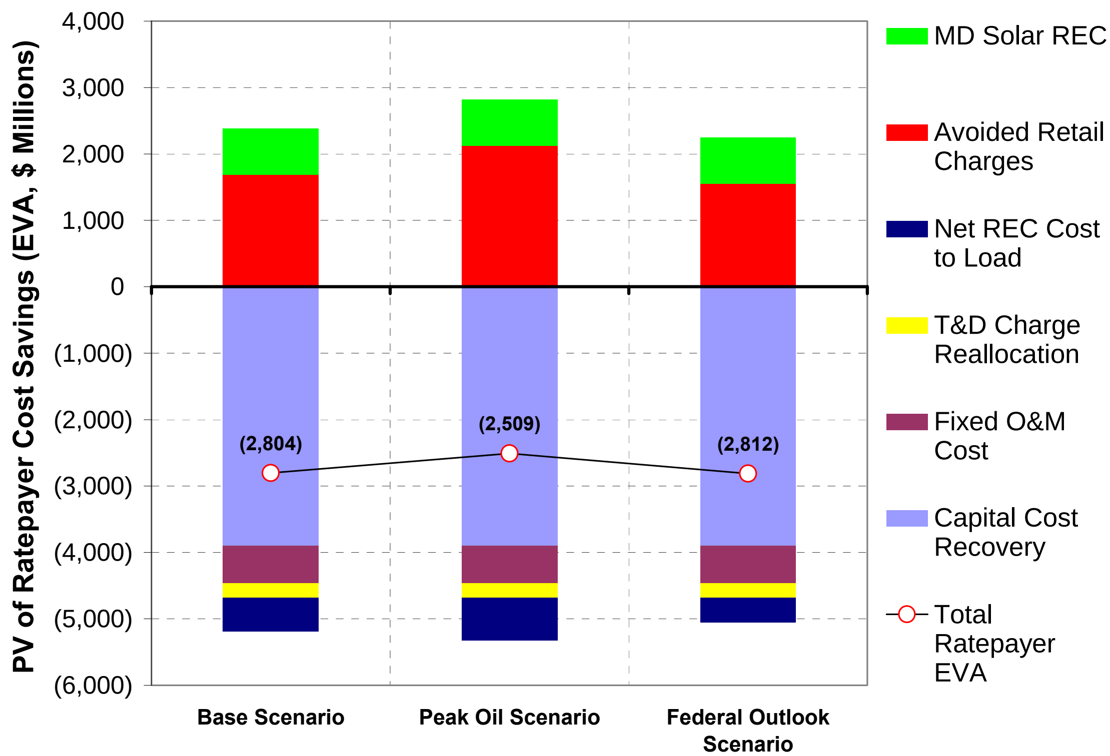
- The case for solar is mixed. Substantial technology progress has been made in the last two years, thereby reducing significantly the all-in cost of the new thin film photovoltaic cells using cadmium-tellurium technology rather than crystalline models. While there continues to be a broad range in the capital cost of photovoltaic installations, LAI has incorporated a substantial reduction in the projected all-in cost relative to that used in the Interim Report, about a one-third reduction. We also contemplate continued technology progress, thereby reducing the cost of installing rooftop photovoltaics. We have assumed the continuation of the 30% Federal Investment Tax Credit (ITC) through 2017 and Tier 1 Solar REC values initially at $450/MWh for behind-the-meter photovoltaic projects. Favorable tax incentives, Tier 1 solar REC benefits in Maryland, and avoided energy and retail transmission and distribution (T&D) charges result in a favorable economic determination from the perspective of a customer who makes an early investment in photovoltaics.

  An investor today appears able to realize a marginally acceptable return on a 1-MW rooftop installation, approximately a 10% internal rate of return (IRR) assuming the use of 30% debt leverage. Absent the ITC or the high initial Tier 1 Maryland Solar REC value in the next few years, an investor’s IRR would be inadequate. In reporting solar economics from the investor's perspective, social costs, that is, subsidies from other Maryland consumers, have not been factored into this analysis.

When we examine the solar RPS initiative in the broader context of all of Maryland's ratepayers, the economic results are not encouraging. By 2022, roughly 1,100 MW of solar capacity will need to be installed to meet the in-state solar RPS requirement. In examining the financial performance of Maryland's solar RPS initiative, we have assumed that the 30% ITC tax incentive is not extended beyond 2017. A 10% ITC is assumed to be in place over the duration of the study period. Continued technology progress is also assumed, a 2.5% real reduction in installed cost year over year throughout the study period. We treat the Maryland Tier 1 Solar REC as a transfer among the ratepayers as a whole, so the net REC value to ratepayers is the normal Tier 1 REC price. Figure 5 shows the EVA effects of the *Solar Case*. Bars above the x-axis represent benefits, including the avoided retail charges and the Maryland Solar REC. Below the x-axis are capital recovery charges, fixed operation and maintenance (O&M) costs, the reallocation of a portion of the avoided retail charges that must still be recouped from other ratepayers, and the cost to the ratepayers of the Maryland Solar RECs. We have also accounted for the value of displaced non-specific Tier 1 RECs.

Under these assumptions, the Solar EVA is a negative $2.8 billion in the *Base Scenario*, and remains highly negative regardless of the alternative fuel price outlook used to quantify energy prices in Maryland.

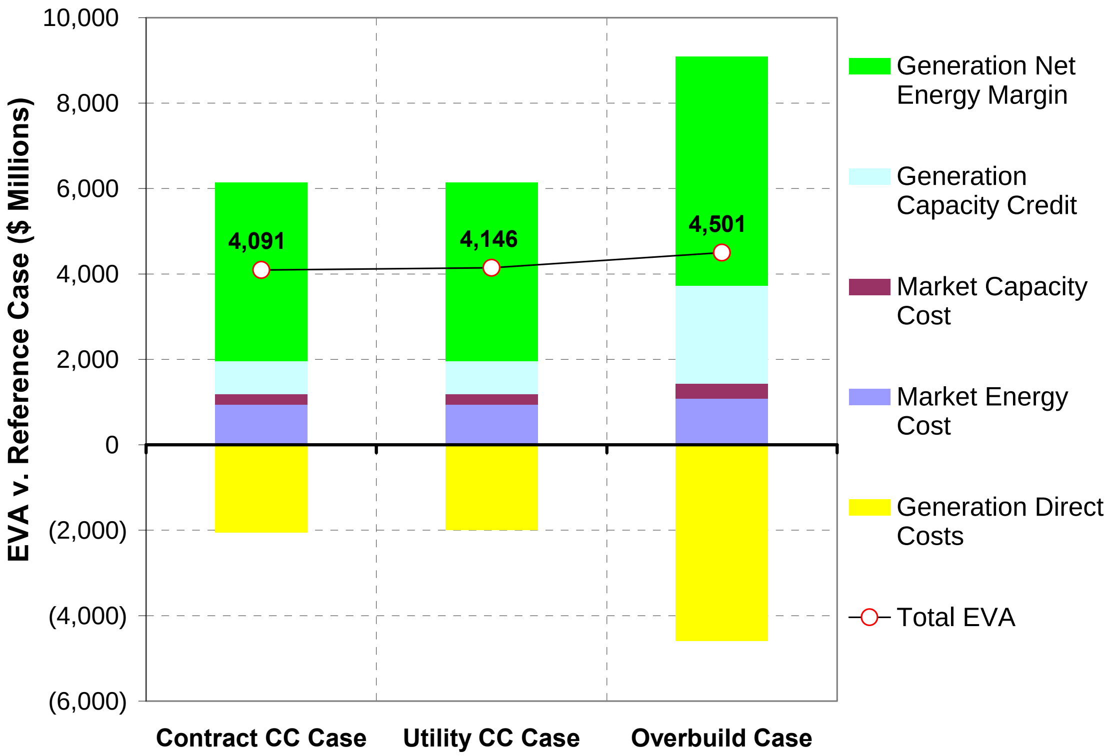
Figure 5. EVA – *Solar Case*



- Also promising is the addition of new, efficient CC plants – either IOU-owned and -operated units or under long-term PPAs. So long as an IOU has the Commission's approval to recover costs under a PPA, a long-term contract with one or more IOUs would be viewed favorably by the rating agencies. In LAI's experience, under the PPA structure the merchant generator can make a reasonably assured return on investment, while retaining the potential to enjoy additional financial return if plant performance exceeds the guarantee level. On the downside, the developer is exposed to project cost overruns that cannot be recouped under fixed capacity and non-fuel variable pricing incorporated in the PPA. For this reason, the PPA pricing typically includes an allowance for costs that cannot be determined well before they are incurred, as well as a contingency factor. Under IOU ownership and traditional cost of service regulation, we have assumed that the Commission would authorize a return on investment for all prudently incurred costs, which may include recovery for any cost overruns.

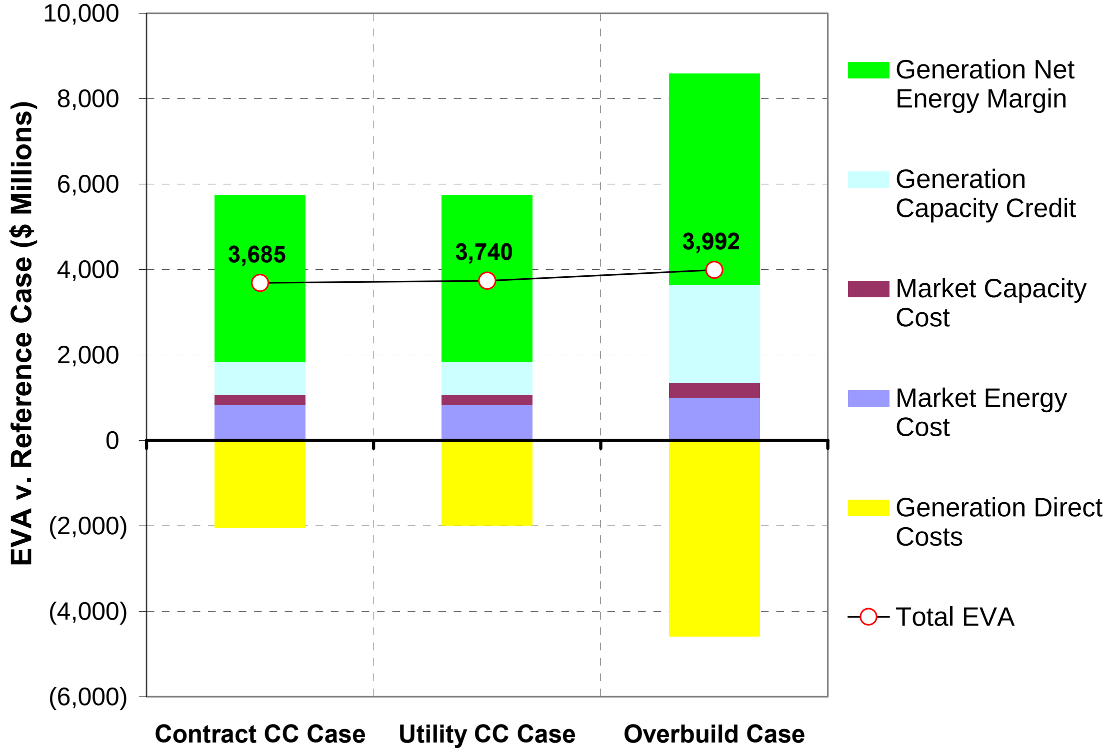
  Under our *Base Scenario*, the EVA under the PPA versus IOU ownership is $4.09 billion and $4.15 billion, respectively, as shown in Figure 6. Hence, in gauging the rival economic merit of third-party versus IOU ownership of new CC plants, LAI reports a small and insignificant ratepayer benefit favoring IOU ownership.

Figure 6. EVA – Conventional Generation Cases (*Base Scenario*)



Project EVAs have been sensitized under the low fuel price scenario – a more realistic long-term outlook than the *Conventional Wisdom Scenario*. As shown in Figure 7, the results under the *Federal Outlook Scenario* are consistent with the relative EVAs reported in the *Base Scenario*.

Figure 7. EVA – Conventional Generation Cases (*Federal Outlook Scenario*)



Like the addition of 1,080 MW of CC plants, the *Overbuild Case* is strongly positive, but it is *not* accretive from a ratepayer perspective. As shown in Figure 6, the EVA of the *Overbuild Case* is $4.5 billion, or $355 million higher than IOU ownership of 1,080 MW of new CC plants. Of critical importance, the realization of incremental benefits under the *Overbuild Case* would result in incremental direct generation costs assignable to the IOU equal to $2.54 billion over the study period. The incremental benefits are too small and also too risky relative to the IOU own or lease case for 1,080 MW. Therefore the *Overbuild Case* does not represent a worthwhile outcome as the lion's share of the economic benefits can be realized at much less cost and risk when the resource additions are limited to 1,080 MW under either IOU ownership or PPAs.

A Commission policy designed to sustain a capacity overhang would likely represent a significant financial encumbrance on the IOUs' respective balance sheets since virtually all new conventional resource additions would require IOU sponsorship in one form or another, thereby deferring or canceling the addition of conventional generation elsewhere in PJM. Relative to other policy options available to the Commission to ensure grid reliability objectives and promote economic benefits, the *Overbuild Case* does not confer enough incremental value to warrant the additional economic drag on the IOUs' borrowing capacity.

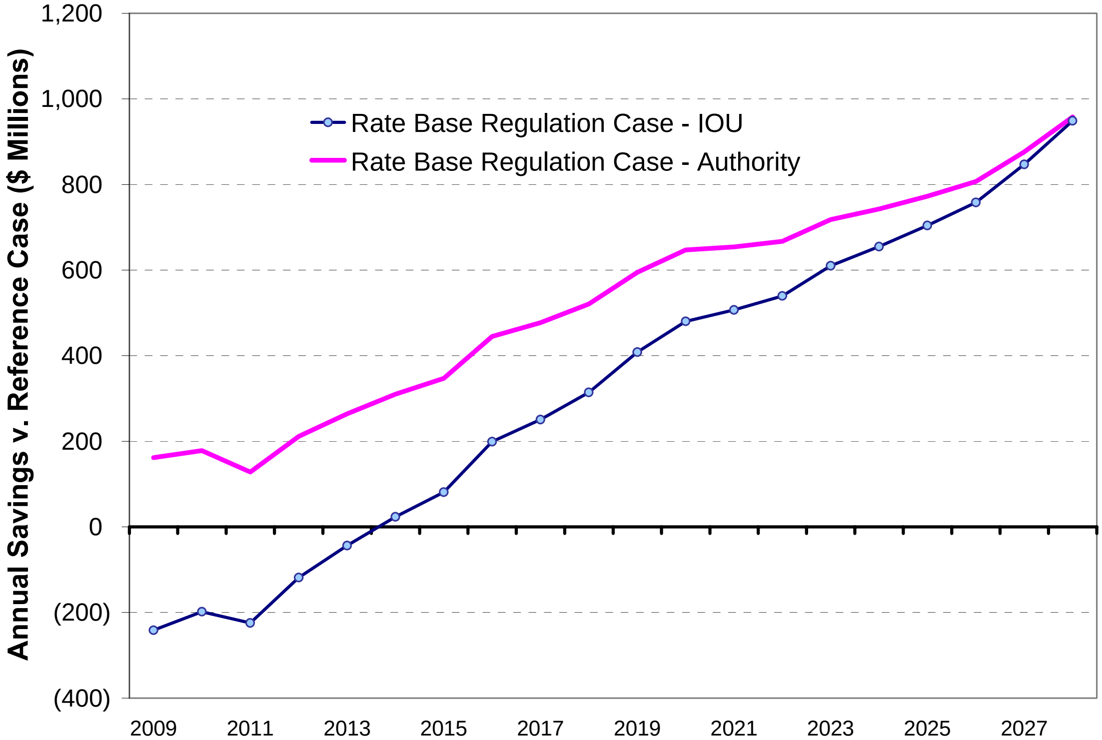
❒ A return to rate base regulation for generation located within the Maryland portion of the Pepco service territory was considered in the *Rate Base Regulation Case*. Readers are cautioned that the only analysis undertaken in this report is the impact of the cost of purchasing the assets under fair market valuation principles relative to ratepayer benefits. LAI has not been asked to address in detail the myriad complexities, substantial risks and potential additional costs that surround such a transaction. Therefore, identification of risk factors has been performed strictly on a qualitative basis.

Under FMV, the cost to acquire the generation assets located within the Maryland portion of the Pepco service territory is estimated to range from $6.1 to $7.9 billion. This valuation reflects reliance on the fuel price forecast presented under the *Conventional Wisdom Scenario* and also reflects the anticipated material upward adjustment in capacity values. The value of the generation assets in the service territories of BGE, DPL and Allegheny Power (APS) are not included in the aforementioned range. Assuming Pepco's cost of capital, the acquisition of the Mirant generation assets in the Maryland portion of the Pepco service territory appears to provide substantial benefits to Pepco's ratepayers. If Maryland were to create a state power Authority to finance the acquisition of the Mirant fleet, the benefits will increase materially assuming an Authority's ability to issue revenue bonds. We assume such an Authority's debt issuance would be backed by guaranteed cost recovery from ratepayers for 100% of the purchase price, but would not encumber the full faith and credit of the State of Maryland. It is important to note that the estimated Authority issuance of roughly $6 billion to acquire Mirant's generation assets is more than five times that of the Maryland Transportation Authority (MdTA) as of December 31, 2007.[6] In reviewing the financial results, the magnitude of the benefits ascribable to load is attributable to the much lower cost of capital assumed for an IOU or an Authority relative to what ratepayers would otherwise pay competitive suppliers responsible for the aggregation of energy, capacity and ancillary services. Benefits to ratepayers elsewhere in Maryland not located in the Pepco service territory are insignificant.

In Figure 8, we report the pattern of savings under IOU ownership versus Authority ownership.

[6] The MdTA's total indebtedness as of December 31, 2007, was $1.07 billion. The size of a bond issuance required to purchase all generation assets in Maryland – not only Mirant's – would likely be at least an order of magnitude increase over the MdTA's current indebtedness.

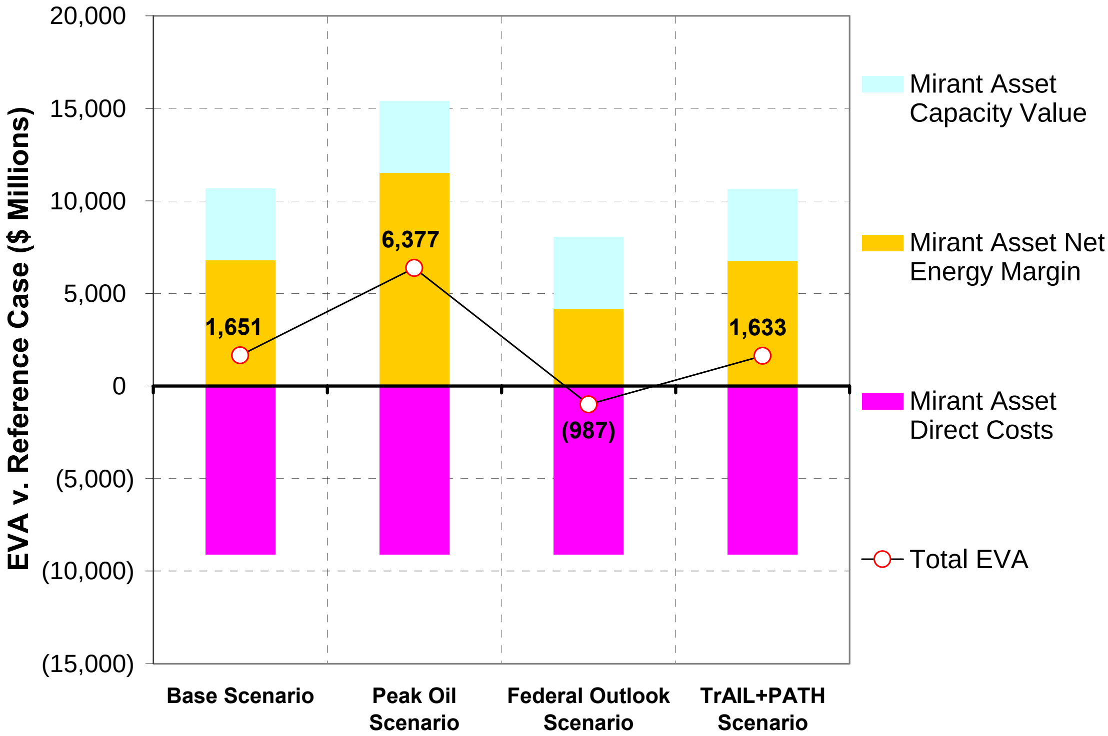
Figure 8. Annual Savings – *Rate Base Regulation Case* (*Base Scenario*)



Assuming "overnight" implementation of this initiative, that is, effective January 1, 2009, under IOU financing assumptions, there would be significant increased ratepayer costs for about four years. This is due to the interest expense on the outstanding debt issued to finance the acquisition of the Mirant fleet as well as the traditional pattern of higher fixed costs in the early years under cost of service regulation. The lower cost of capital associated with Authority ownership provides ratepayer benefits every year over the study horizon.

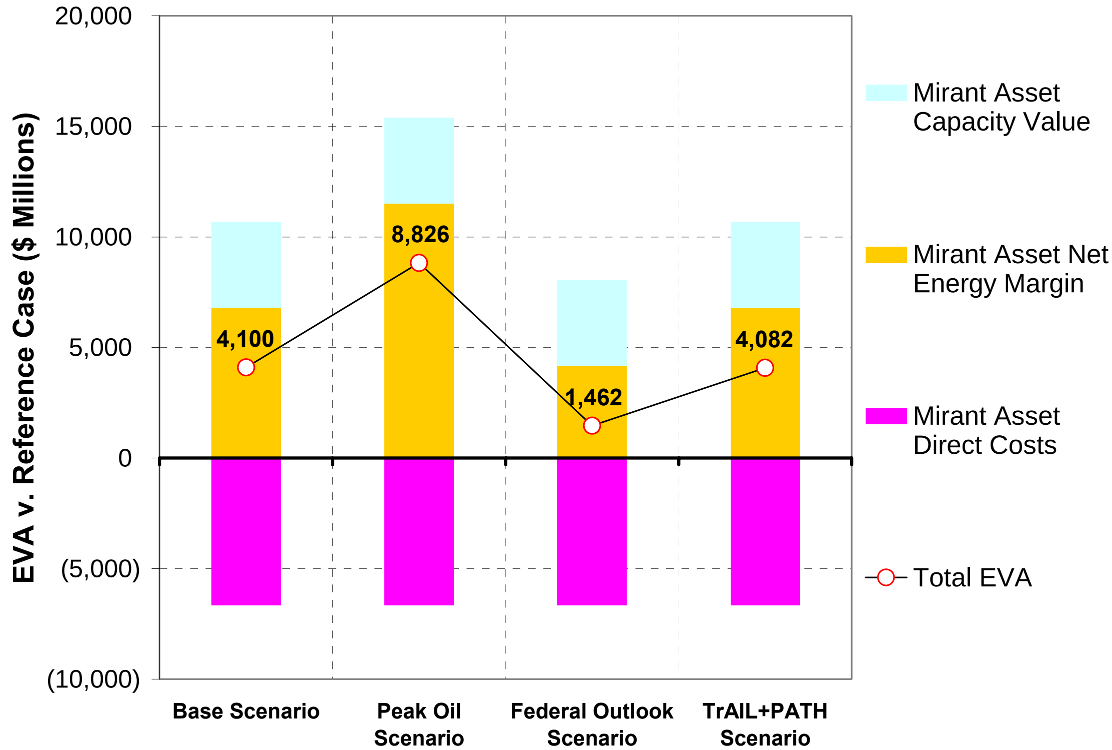
As shown in Figure 9, under IOU ownership the project EVA is expected to be $1.65 billion. This reflects a starting rate base of $6.3 billion. Assuming determination of FMV under the *Conventional Wisdom Scenario* fuel price forecast, different market price outcomes associated with *Peak Oil* and the *Federal Outlook Scenarios* yield a large earnings surprise for ratepayers or a significant economic loss. Under these alternative scenarios project EVA increases to $6.38 billion or decreases to negative $0.99 billion, respectively. The *TrAIL + PATH Scenario* results in about the same economic outcome as the *Base Scenario*.

Figure 9. EVA – *Rate Base Regulation Case* (IOU Ownership)



Assuming the issuance of taxable debt over 20 years for 100% of the purchase price of the Mirant fleet, Authority ownership yields much greater economic benefits than IOU ownership across all market scenarios. Under the *Base Scenario* project EVA increases from $1.65 billion to $4.1 billion, a 250% increase. Due to the low cost of capital, ratepayer benefits are consistently positive across alternative scenarios.

Figure 10. EVA – *Rate Base Regulation Case* (Authority Ownership)



As previously mentioned, there are a number of risks and complexities surrounding this transaction that have not been monetized under the *Rate Base Regulation Case*, for example:

- First, we have not quantified any potential societal costs associated with re-regulation in Maryland. Transference of control back to Pepco or to an Authority has the potential to undermine the competitive wholesale power market in Maryland, thereby causing a "domino effect" in PJM. IOU or Authority ownership of the Mirant fleet would likely weaken wholesale price signals that are designed by PJM to induce merchant generator entry – both conventional and renewable. As a result, a return to rate base regulation would likely require Pepco or the Authority to support additional generation entry for a significant period of time, even though merchant entry might be sustained elsewhere in PJM.

- Second, the return to rate base regulation would be likely to impact the Commission's administration of Standard Offer Service (SOS) in Pepco's service territory. Presently, competitive suppliers manage a variety of business, market, financial and regulatory risks for their respective load obligation(s). If Pepco or an Authority were to self-supply there could be exposure to all or a portion of the business risks currently borne by competitive suppliers. In addition, a return to rate base regulation will likely require an end to the customer choice program, effectively requiring all customers to return to IOU service, including industrials. Whether the wholesale market in Maryland could efficiently co-exist with a return to rate base regulation has not been adequately assessed.

- Third, the financial results under the array of scenarios examined herein largely confirm the economic benefits related to a return to rate base regulation. Under IOU ownership, lower than anticipated fuel prices relative to those used to compute FMV have the potential to cause about $1 billion in economic losses. The lower cost of capital under Authority ownership insulates ratepayers from any economic loss, however. While asset ownership can be an effective hedge against uncertain and volatile fuel prices, ratepayers would nonetheless be exposed to both earnings surprises (upsides) and disappointments from year to year relative to the *pro forma* assumptions used to derive FMV. Although the prospect is low, the creation of a second "wave" of stranded cost liabilities is always a potential risk.

- Fourth, the Mirant fleet in Maryland is comprised of 2,568 MW of coal plants, some of which are over forty years old. Mirant has budgeted major capital improvements to ensure timely compliance with the Healthy Air Act as well as more stringent controls on sulfur dioxide (SO_2), nitrogen oxides (NO_x), and mercury, should they be promulgated by the Environmental Protection Agency (EPA). Any purchase price ascribable to those assets should reflect the state's potential exposure to economic and technical obsolescence or diminished energy margins attributable to stricter than anticipated controls on greenhouse gas emissions. The timetable and form of the federal legislation to regulate carbon dioxide (CO_2) emissions is not yet known.

- Fifth, significant risks may arise during a multi-year transition period in response to the practical constraints associated with obtaining the requisite manpower to operate these facilities. For a two-to-five year period it might be necessary to outsource the manpower and operational responsibilities to a qualified third party, thereby incurring additional costs. Of concern would be an Authority's ultimate ability to manage the transition and to retain qualified in-house staff. In addition, the costs associated with attracting and retaining the caliber of personnel required to staff the Authority may be substantial.

- Sixth, the FMV of the assets is driven largely by assumptions made with respect to energy and capacity prices within PJM. Given the significant and unprecedented volatility within the commodities market at the present time, FMV and the resultant EVA analysis on any given day may differ significantly from the results presented in this report.

- Seventh, there may be significant advisory costs associated with a potential condemnation or negotiation to purchase the assets. Condemnation, in particular, may result in a protracted and expensive legal battle. These costs will ultimately be borne by ratepayers, but have not been included in the financial analysis conducted in this study.

- Finally, we have not attempted to calibrate Maryland's appetite for a large bond issuance. To the extent revenue bonds are issued by a newly formed Authority in order to stabilize and reduce energy costs for ratepayers in Maryland, there could be adverse bond pricing impacts associated with increased financing costs on other state general obligation (GO) or revenue bond issuances. How long these increased financing costs persist following a multi-billion dollar bond issuance is not presently understood.

Environmental Benefits

Each of the resource options examined in this study – efficient gas-fired CC turbines, expanded DSM, and wind turbines – reduces emissions of greenhouse gases and pollutants that contribute to the formation of acid rain, fine particle pollution (haze), and exceedances of federal air quality standards in Maryland and downwind states. The net environmental benefit of these measures was quantified by calculating the total emissions of CO_2, SO_2, and NO_x for each study case versus the *Reference Case*. The average annual net reductions for each resource option, once the measures are fully implemented, are illustrated in Figure 11, Figure 12, and Figure 13.

Under the Regional Greenhouse Gas Initiative (RGGI), Maryland has committed to capping at a baseline level its annual emissions of CO_2 from power plants each year from 2009 through 2014, then reducing total emissions by 2.5% each year for the next four years. As illustrated in Figure 11, each resource option in the study cases represents a significant contribution toward achieving the annual step-down goal. Full implementation of the EMD program, expressed as the *15x15 DSM Case*, would allow Maryland to achieve its annual reduction target for 2015, 2016, and most of 2017. That is, the average annual reduction from the EMD program, about 2.7 million tons of CO_2, is about 2.9 times the RGGI reduction target of 937,600 tons in each of those years. Development of wind projects and state-of-the-art CC plants will also create greenhouse gas reductions and contribute to the annual RGGI goals.[7]

Each measure reduces regional net emissions by displacing local generation within Maryland and by reducing imports. For the *15x15 DSM Case* and both the *Onshore* and *Offshore Wind Cases*, CO_2 emissions are reduced both within and outside of Maryland by virtue of the new non-emitting resources constructed or implemented. For the *Contract CC* and *Utility CC Cases*, net CO_2 emissions within SWMAAC increase, but across the region there is a net decrease, as state-of-the-art CC units displace imports from less efficient and more carbon-intensive generation. These resource options also reduce regional net SO_2 and NO_x through displacement of dirtier, less efficient generation in Maryland and reduction of imports from outside Maryland. Regardless of where the reductions originate, however, the societal benefits associated with reducing power plant emissions and the economic benefits arising from RGGI auction revenues and the project EVA are preserved.

[7] The CO_2 reductions for the *Offshore Wind Case* reflect the impact of the entire 500 MW project, even though Maryland would only contract for 300 MW.

Figure 11. Average Annual Net CO_2 Emission Reduction

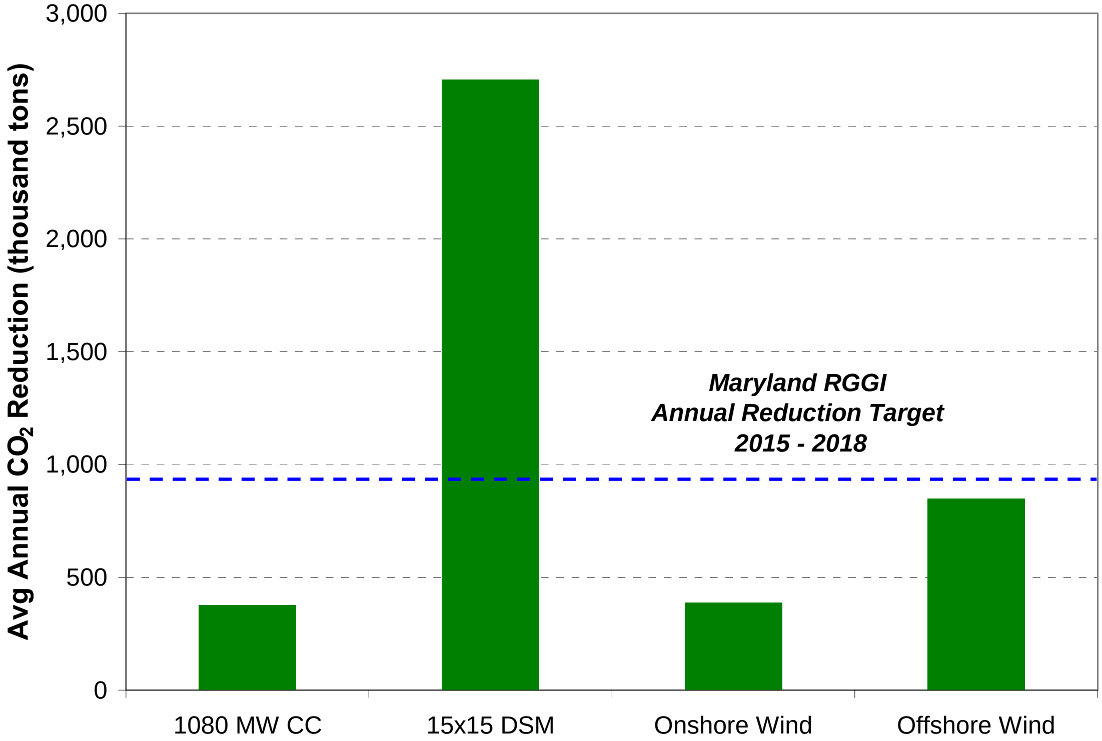


Figure 12. Average Annual Net SO_2 Emission Reduction

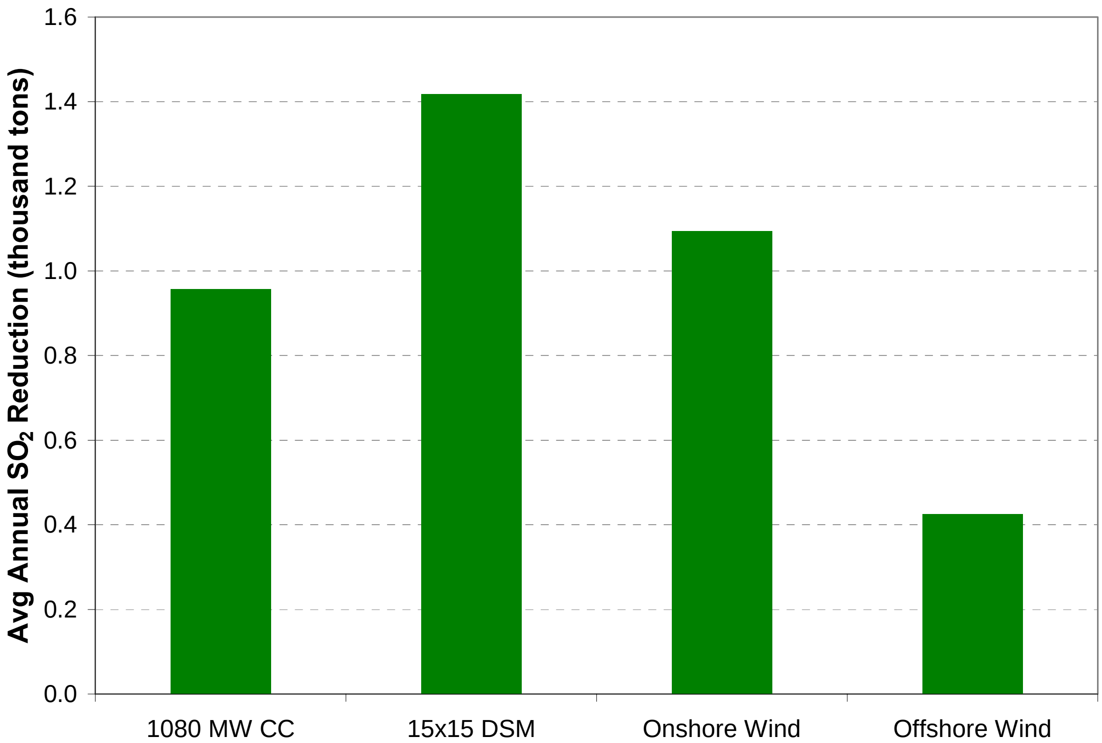
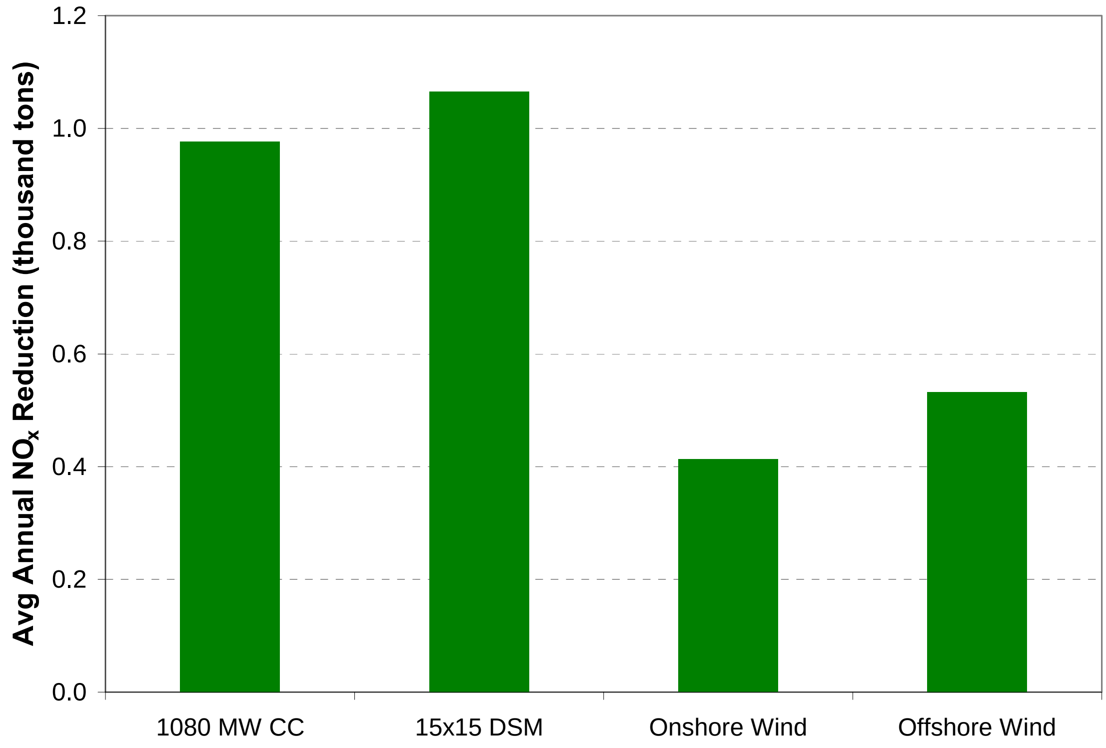


Figure 13. Average Annual Net NO_x Emission Reduction



1. STUDY FRAMEWORK

1.1. Definition of Cases

1.1.1. Study Cases

Eight study cases have been formulated to assess the net benefits to Maryland ratepayers based on technology, regulatory and policy options under consideration by the Commission. The economic costs and benefits of these cases over a long-term planning horizon, 2009 through 2038, are the basis for this evaluation.

1. The ***Contract CC Case*** postulates a 20-year PPA with a 10-year renewal option unilaterally exercisable by the IOU. Two 540-MW (nameplate)[8] gas-fired CC plants to be located in SWMAAC are assumed in the resource mix. The 540-MW (nameplate) design reflects a state-of-the-art “two on one” frame design, that is, two GTs, two heat recovery steam generators (HRSGs), and one steam turbine (ST). Both 540-MW units are assumed to have in-service dates in 2012. The PPA is assumed to be iron-clad, that is, without a regulatory-out provision or other unusual commercial requirements that place the seller substantially at risk for market, financial, or federal / state regulatory changes. The benefits and costs of the new CC capacity are assigned to the SOS-eligible loads of the four IOUs on a load-weighted basis. The results of this case study are presented in Section 4.3.1.

2. The ***Utility CC Case*** postulates the same 1,080 MW of incremental capacity in SWMAAC as the *Contract CC Case*, but assumes that the units are owned by the IOUs. Annuitization of cost reflects the IOUs’ allowed rate of return (ROR), including an upward adjustment to ROR to account for the inherent risk associated with ownership of generation relative to T&D assets. All market revenues are apportioned to the IOUs’ SOS-eligible customers. The results of this case study are presented in Section 4.3.2.

3. The ***Overbuild Case*** assumes 1,080 MW of gas-fired CCs in excess of the SWMAAC requirement are added to the resource mix in SWMAAC under long-term PPAs with the IOUs. About 1,080 MW of excess capacity is sustained until 2018, thereby requiring the IOUs to add new generation under long-term contract that might otherwise be built as merchant generators elsewhere in SWMAAC or PJM. The PJM reserve margin drops back to 15.5% by 2018. The results of this case study are presented in Section 4.4.

4. The ***15x15 DSM Case*** assumes that Governor O’Malley’s EMD conservation initiative is realized in full by 2015. DR programs specifically designed to shave peak demand and approved by the Commission early in 2007 are relied on as well. Cost-effective DSM measures, program costs and penetration rates are based on the respective DSM plans submitted by the IOUs to the Commission in September 2008. The results of these case

[8] Nameplate capacity refers to the manufacturer-rated capacity of a unit. PJM discounts the nameplate capacity of a unit based upon its unforced outage rate to determine the amount of capacity for which a unit will get “credit” in PJM.

studies are presented in Section 5.3. Overall, the programs sponsored by Maryland's four IOUs are designed to reduce peak demand by 3,044 MW, which is more than the peak demand reduction target of 2,517 MW set by EMD. However, the IOUs' programs are expected to achieve energy savings of 4,692 MWh, which is only about two-thirds of the EMD target of 7,014 MWh. The *15x15 DSM Case* assumes that the EMD energy savings target of 7,014 MWH is 100% met. Accordingly, the level of penetration of the EMD energy efficiency and conservation (EE&C) measures is increased, while the DR programs are not. Grossing up energy efficiency measures results in associated increased peak demand reductions. Even though the DR programs were not effectively grossed up, the overall peak demand reduction modeled by LAI exceeded the EMD target by 33%.

5. The ***Onshore Wind Case*** assesses the merit of 200 MW (nameplate) of new onshore wind plants constructed in western Maryland. From 2011 to 2015, 40-MW projects are added each year in the APS zone. This equates to 59 MW of UCAP for reliability purposes. All plants are assumed to be under a 20-year PPA with the IOUs. The contract terms mirror those defined in the Synergics PPAs with DPL for its Delaware load. The benefits and costs are allocated to the four IOUs based on load share. The results of this case study are presented in Section 6.3.

6. The ***Offshore Wind Case*** assumes that a 500-MW (nameplate) wind project is constructed offshore and in service in 2014. The economic and operational benefits attributable to offshore wind reflect the provisions defined by BlueWater in its long-term PPA with DPL. Although 500 MW is added to the resource mix in Eastern MAAC (EMAAC), we assume only 300 MW would be purchased under long-term PPAs with the Maryland IOUs. The 500-MW addition equates to 128 MW of UCAP for reliability purposes. The results of this case study are presented in Section 6.4.

7. The ***Solar Case*** is an economic analysis of the benefits or disbenefits related to Maryland's mandatory solar RPS requirement. The *Reference Case* and all study cases postulate full compliance with the Maryland solar RPS through installation of 1-MW photovoltaic cells at commercial and industrial (C&I) sites. The analysis is based on the *Reference Case* solar buildout, and considers the economics of photovoltaic installations from the perspective of retail customers as well as the photovoltaic owner / investor. The quantity assumed equates in 2015 to 45 MW of UCAP for reliability purposes.

8. The ***Rate Base Regulation Case*** postulates a return to traditional cost of service regulation in Pepco's service territory. Under the *Rate Base Regulation Case*, we assume that the existing Mirant generation fleet in Maryland is acquired through condemnation or consensual negotiation, thereby requiring payment to Mirant under FMV principles. Two different ownership conditions have been evaluated: *first*, assuming Pepco ownership and operation, thereby reflecting the use of taxable debt and equity at prices that are in general accord with the utility's weighted average cost of capital; and, *second*, assuming the formation of a not-for-profit state power Authority, thereby reflecting the use of taxable debt for all or the majority of the Authority's capital requirements. Costs and benefits have been evaluated assuming cost of service regulation in Pepco's service territory over a 20-year horizon. The results of this case study are presented in Section 8.

1.1.2. Reference Case

In order to identify the economic benefits and costs over the planning period, each resource option was gauged against the *Reference Case*, a baseline estimate of Maryland's future wholesale energy costs. The *Reference Case* represents a long-term competitive equilibrium where there are no unserved energy requirements over the study horizon. The inherent uncertainty surrounding the prospect of a new nuclear power plant at Calvert Cliffs and the associated timing precludes its inclusion in the *Reference Case*.[9] As the benchmark for quantifying the net benefits ascribable to the alternative resource and policy options, the *Reference Case* constitutes a conventional resource future in which electricity supply and demand in Maryland remain approximately in competitive equilibrium over the 30-year study period. The *Reference Case* forecast also incorporates expected values and conditions for external variables that are largely or exclusively outside either the Commission's or the Legislature's control. Such external variables include federal environmental standards, development and Nuclear Regulatory Commission licensing of a new nuclear unit at Calvert Cliffs, development of new conventional or renewable resources in and outside Maryland, load growth in neighboring control areas and in PJM, and sundry financial parameters.

The *Reference Case* incorporates the following assumptions:

- Applicable reliability criteria in PJM and other control areas were adhered to over the study period. There is no unserved load or shortage hours requiring voltage reductions, rotating blackouts, or system-wide outage contingencies. Production simulations incorporate a capacity buildout schedule composed of an optimum combination of gas-fired peakers or CCs added just-in-time to maintain grid reliability objectives.
- Across PJM the amount of DSM incorporated in the load forecast is based on PJM's outlook. In Maryland, however, the amount of DSM included in the *Reference Case* each year of the planning horizon is set at 25% of the total program additions through 2015 under the EMD initiative and DR programs. The composition of DSM programs, saturation rates, and program costs were defined based on the IOUs' DR filings already approved by the Commission as well as the EMD filings presently before the Commission.
- The inclusion of TrAIL beginning in Q2 2014. An alternative scenario reflects the indefinite deferral of TrAIL.
- The inclusion of a federal cap-and-trade program governing the cost of CO_2 emissions from fossil power plants commencing in 2014. Between 2009 and 2013, we assume that the CO_2 emissions are regulated only in the RGGI states in the study region.

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[9] As discussed in the Interim Report, in the event a third nuclear power plant is added at Calvert Cliffs there would likely be a material reduction in energy and capacity prices in Maryland for many years following the start-up of the third unit. The apportionment of economic benefits between Constellation and Maryland's ratepayers has not been determined.

- We have added renewable generation units across PJM based on each state's RPS requirements, available wind resources, and transmission infrastructure. Since wind projects comprise 98% of the proposed renewable energy projects in the PJM interconnection queue, new renewables are limited to wind resources only. In Maryland, we have added 100 MW of onshore wind projects, *i.e.*, Synergics Eastern Wind Energy and Synergics Roth Rock Wind. The remainder of Maryland's RPS requirement is assumed to be satisfied from out-of-state purchases of renewable energy, RECs, or the Alternative Compliance Payment (ACP).
- Maryland's solar RPS requirements are assumed to be fulfilled over the study period through installation of photovoltaic cells on customer sites. The treatment of solar energy resources and the economics of photovoltaic investments have been refined since the Interim Report.[10]

1.1.3. Base Scenario and Alternative Scenarios

In accord with the engineering economic approach used in the Interim Report, LAI has employed the same suite of production cost simulation and financial models to capture wholesale market dynamics over the study period. Study results are expressed on a deterministic basis. However, the economics of competing resource options and re-regulation initiatives have been sensitized to address uncertainty in world oil and natural gas markets. Although natural gas, not oil, is a major fuel source for electricity production in PJM and Maryland, there is a moderate-to-strong correlation between benchmark oil prices and natural gas prices. We have therefore formulated three scenarios in order to test the impact of uncertain natural gas and oil prices on each of the resource and re-regulation options evaluated in the Final Report. The three fuel price forecasts include: a most likely or "*Conventional Wisdom*" *Scenario* (also termed the *Base Scenario*), a high price scenario (*Peak Oil*), and a low price scenario (*Federal Outlook*). As discussed in Section 3.1, each of the three fuel price forecasts represents an internally consistent set of assumptions and outlook regarding global demand for oil and LNG, world-wide oil production and reserves, and domestic natural gas production over the study period. Internally consistent adjustments to coal prices have been accounted for in each of the three scenarios.

Transmission infrastructure into and within Maryland has a direct impact on wholesale electricity prices. In 2007, PJM approved four major transmission projects designed to alleviate congestion across SWMAAC and EMAAC. These projects are discussed in detail in Section 3.2 and Appendix A. In the Interim Report, one of the four backbone projects was tested as a separate transmission scenario – the 502 Junction-Loudoun line (TrAIL). PJM has indicated that TrAIL will be commercialized in Q2 2011 and should alleviate or eliminate reliability problems in Maryland in 2011 and 2012. For various reasons, Allegheny Energy (AE) and Dominion, TrAIL's developers, may not be able to complete TrAIL by 2011. In this study, we have included TrAIL in the *Base Scenario* for the *Reference Case* and all study cases; however, we have conservatively assumed that TrAIL will be commercial in 2014, three years after PJM's announced in-service date. For each of the resource options evaluated in this study, an additional

[10] Modifications to the financial treatment of photovoltaics are based on correspondence from Sun Edison to the Commission, dated January 10, 2008.

sensitivity scenario has been conducted to test the impact of an indefinite delay in TrAIL's in-service date. For the *Rate Base Regulation Case*, we also postulate a scenario in which both TrAIL and PATH are completed (the *TrAIL+PATH Scenario*).

A summary of cases evaluated in the Final Report is presented in Table 1. The *Base Scenario*, by definition, assumes a TrAIL in-service date of 2014 and the *Conventional Wisdom Scenario* outlook on fuel. The alternative study cases are each evaluated under the *Base Scenario* and one or more sensitivity scenarios.[11]

[11] LAI uses the term "case" synonymously with the array of distinguishable energy futures associated with technology and policy options. The term "scenario" refers to sets of assumptions for variables beyond the control of the Commission or the Legislature.

Table 1. Summary of Scenarios and Cases

	Case Assumptions[12]				Scenarios				
						Alt. Fuel Scenarios		Alt. Transmission Scenarios	
Case	**Generation under PPA with MD IOUs**	**IOU-owned generation in MD**	**Other Generation Buildout in MD**	**DSM (% EMD)**	**Base[13]**	**Peak Oil**	**Federal Outlook**	**No TrAIL**	**TrAIL + PATH**
Reference Case	None	None	Merchant as needed for reliability	25%	√	√	√	√	
Contract CC Case	1,080 MW CC	None	Merchant as needed for reliability	25%	√	√	√	√	
Utility CC Case	N/A	1,080 MW CC	Merchant as needed for reliability	25%	√	√	√	√	
Overbuild Case	1,080 MW CC + new entry for reliability	None	Under PPA	25%	√	√	√	√	
15x15 DSM Case	None	None	Merchant as needed for reliability	100%	√	√	√	√	
Onshore Wind Case	+200 MW western MD	None	Merchant as needed for reliability	25%	√	√	√	√	
Offshore Wind Case	+300 MW offshore DE	None	Merchant as needed for reliability	25%	√	√	√	√	
Solar Case	None	None	Merchant as needed for reliability	25%	√				
Rate Base Regulation Case	None	Mirant plants in MD[14]	Merchant as needed for reliability	25%	√	√	√		√

[12] For all study cases, generation buildout in rest of PJM is as required to satisfy grid reliability objectives, as described in Section 2.1.

[13] The *Base Scenario* assumes TrAIL is in service in 2014.

[14] This case also considers an alternative in which the Mirant portfolio is acquired by a state power Authority.

1.2. Model Structure

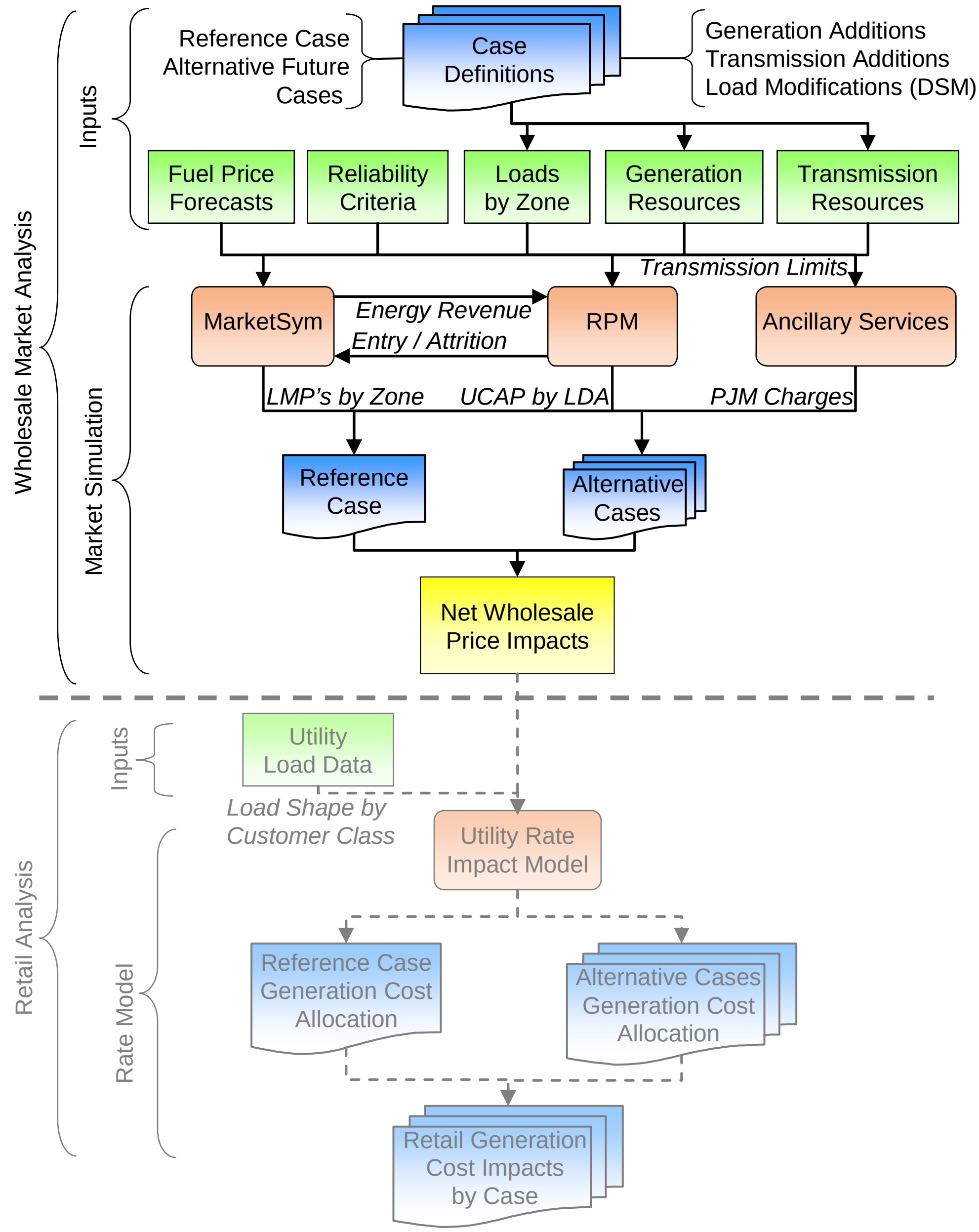
The analysis of potential energy resource and ownership options in Maryland is based on an integrated suite of economic and production simulation models. A schematic of the modeling framework is illustrated in Figure 14. The modeling framework simulates wholesale energy, capacity, and ancillary services markets in PJM over the long term and tests the impact of postulated technology, policy, and regulatory initiatives on the total wholesale and retail cost to serve Maryland load. Consistent with current market rules in PJM, energy and capacity prices are differentiated by location. The study horizon established in the Interim Report has been extended ten years in order to provide the Commission with commercial information of relevance in calibrating the benefits of utility versus third-party-owned generation. Hence, the study horizon for this Final Report is 2009 through 2038.[15]

The modeling framework – MarketSym, a capacity price model of PJM's Reliability Pricing Model (RPM), and a financial model for ancillary services – is essentially unchanged in structure from that used in the Interim Report. Certain factor inputs to the models have been updated with respect to the values used in 2007. Updated factor inputs encompass fuel prices and emission allowance costs, load data, production cost data by plant, transmission supply from west to east, and an array of other adjustments pertaining to market behavior and PJM reliability criteria. Over a 20-year period, LAI has forecasted location-based wholesale energy and capacity prices. For the additional ten years in the planning horizon, LAI has extrapolated end-period values.

In the financial analysis, the total cost to serve load encompasses *all* electricity load in Maryland covered by the four IOUs. We have not incorporated any adjustments for municipal or cooperative utility loads. The analysis includes the retail loads of customers who "shop," *i.e.*, retail customers who have migrated to competitive suppliers but receive distribution service from one of four IOUs. To the extent that a state-backed energy initiative lowers or stabilizes market electricity prices, all Maryland customers would benefit, including municipal and cooperative loads. In order to keep this analysis from becoming unwieldy, direct program costs are assumed to be non-bypassable. They are therefore allocated fully to BGE, DPL, APS, and Pepco. The net impacts on wholesale generation costs have been allocated to each of the Maryland IOUs to assess the total impact on cost to serve retail load.

[15] The electric market simulation model spans a 20-year forecast period. The financial model extends the study through 30 years to account for contract extensions, economic life of plant equipment, and terminal value effects.

Figure 14. Study Framework



2. ELECTRICITY MARKET MODEL STRUCTURE

Generators in PJM realize operating revenues from the sale of energy, capacity and ancillary services. Figure 14 illustrates the schematic inter-relationship between the quantitative tools used to simulate the wholesale electric system in Maryland and surrounding regions. There are three principal model components used to derive operating revenues:

- MarketSym, a chronological production simulation model used to forecast hourly locational energy prices over a 20-year forecast period;
- A capacity price model that simulates PJM's RPM to forecast capacity values;[16] and
- A financial model that integrates MarketSym and RPM results, as well as adjustments to account for the provision of ancillary services, in order to compute the cost to serve load.

These models are the primary building block components used to forecast locational prices and the wholesale cost to serve Maryland load under the *Reference Case* and each study case.

2.1. Energy Market

The long-term forecast of wholesale energy prices in PJM was performed using the MarketSym chronological dispatch simulation model. MarketSym is licensed by Ventyx, an Atlanta-based energy software and data firm. The model accounts for entry and attrition of generation assets over time, performance and production cost data for each power plant in the regions simulated, seasonal variability of delivered fuel costs, transmission congestion, seasonal load variability, environmental compliance requirements and allowance costs, and relevant market dynamics affecting LMPs. MarketSym has been customized to incorporate the principal internal transmission interfaces that result in hourly LMP locational differentials. Model solutions also incorporate PJM's three-part bid structure and account for commitment to provide spinning reserves.[17] Consistent with the study guidelines defined in the Interim Report and reapplied in the present context, we do not allow for unserved load over the planning horizon.

2.1.1. <u>MarketSym Topology</u>

MarketSym produces the operating cash flows and net margins derived from energy sales and ancillary services. For this application, the production simulation model covers PJM (excluding Illinois), the New York Independent System Operator (NYISO), ISO New England (ISO-NE), the Carolinas and those parts of Pennsylvania, Ohio, and Indiana that are part of the Midwest-ISO (MISO), rather than PJM.[18] Thus, we have accounted for the bulk power interchange across

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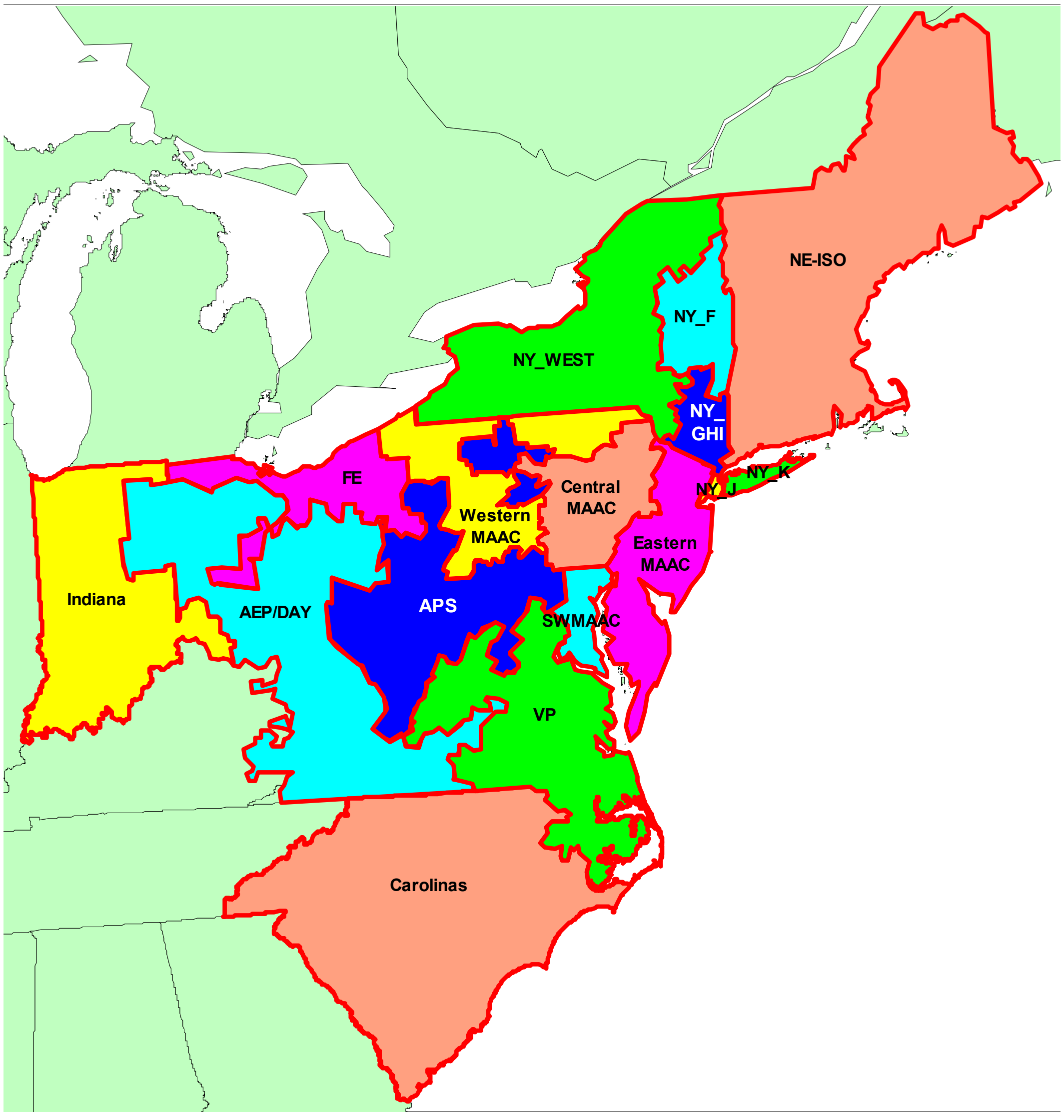
[16] The capacity price model does not include any of the structural modifications of RPM currently under consideration at PJM.

[17] Three-part bids include generator start-up, minimum load, and incremental energy costs.

[18] Commonwealth Edison (ComEd), an Exelon company, serves Chicago. ComEd is part of PJM, but has not been included in MarketSym. ComEd is in the far western part of PJM and is not contiguous to Maryland. Its omission does not constitute a significant measurement bias.

the major transmission lines that link PJM with interconnected market regions. The modeled area has been divided into sub-areas, as shown in Figure 15.

Figure 15. MarketSym Topology of Relevance



For the purpose of understanding LMP differentials within Maryland and adjacent areas, model topology differentiates certain key zones. We have also combined other zones whose historical prices have remained in close conformance, as follows:

- EMAAC includes PECO Energy, DPL, Atlantic City Electric Company (AECO), Jersey Central Power & Light (JCPL), Public Service Electric & Gas (PSEG), and Rockland Electric.
- SWMAAC includes BGE and Pepco.
- Central MAAC includes Metropolitan Edison and Pennsylvania Power & Light (PPL).

- Western MAAC (Pennsylvania Electric) and Virginia Power were modeled separately.
- PJM-West was modeled as two zones: APS and American Electric Power (AEP) plus Dayton Power; ComEd has not been included. Duquesne Light Company (Duquesne) was included in MISO.

The zones included in EMAAC show average price spreads over the past two years (July 1, 2006, through June 30, 2008) that vary by ±$3/MWh. Figure 16 shows average price spreads between the LMP average of the PJM Eastern Hub and the IOUs in EMAAC by hour of day for the 24-month period of July 1, 2006, through June 30, 2008. Of the five EMAAC zones shown, DPL shows the least divergence from PJM Eastern Hub, and therefore EMAAC as a whole is a reasonable marker for modeling DPL.

Figure 16. Historical Price Spreads for EMAAC Zones

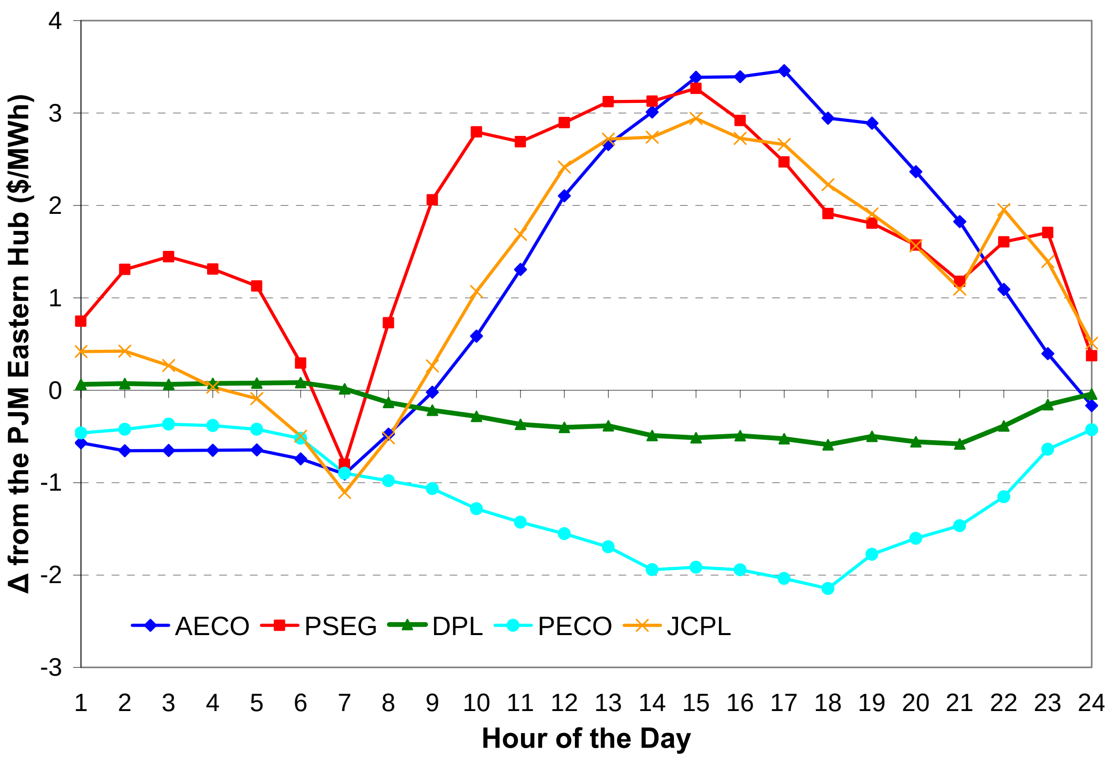
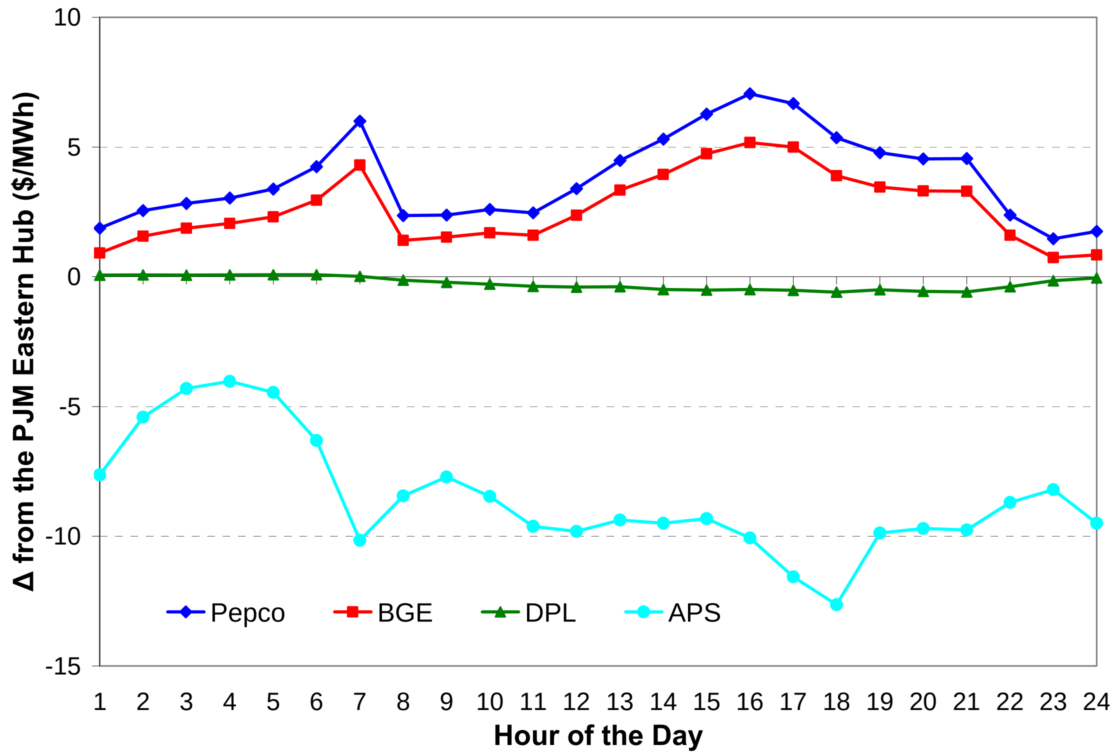


Figure 17 shows average price spreads between the LMP average of the PJM Eastern Hub and the four IOUs in Maryland for the same 24-month period. LMPs in BGE and Pepco were highly correlated and relatively independent of the LMPs in DPL and APS. Hence, BGE and Pepco have been treated as a single SWMAAC zone. APS has been treated separately from SWMAAC and DPL.

Figure 17. Historical Price Spreads for the Maryland IOUs



2.1.2. <u>Transmission Interface Values</u>

Transfer limits within and between markets have been updated to reflect the latest available information published by PJM and the neighboring ISOs, as indicated in Table 2. Figure 18 shows the principal western, central and eastern PJM 500-kV interfaces. Regarding the addition of new transmission supply in Maryland, we have relied on PJM with respect to the change in the CETL ascribable to TrAIL. In the *Base Scenario* of both the *Reference Case* and the seven study cases, increased CETL in SWMAAC starting in 2014 is a constant. The increase in CETL in SWMAAC is 230 MW, except in the *No TrAIL Scenario* where CETL equals PJM's operating assumptions used in the fourth capacity auction covering Delivery Year 2010/11. More discussion regarding transmission transfer capability with and without TrAIL may be found in Section 3.2.

Figure 18. PJM Western, Central and Eastern 500-kV Interfaces

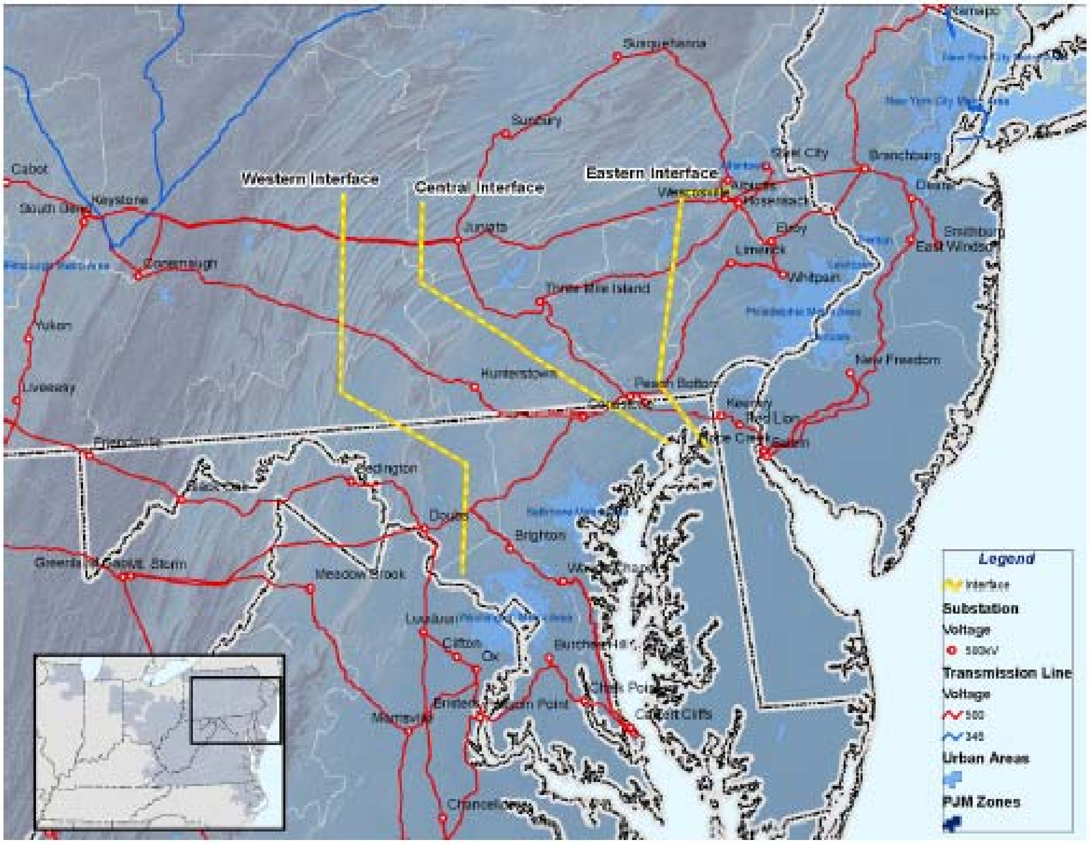


Table 2. Sources of ISO Transmission Limits

PJM	Updated Reliability Requirements for 2008/09 and 2009/10 Planning Period Parameters[19] & Historical PJM Net Tie Schedule[20]
NYISO	New York Control Area Installed Capacity Requirements May 2007 through April 2008
ISO-NE	Regional System Plan 2006
Other Areas	Ventyx MarketSym Database

2.1.3. Load Forecast

Load data in the MarketSym database are derived from the PJM and other ISO publications listed in Table 3. The principal source of the load forecast is PJM's 2008 Load Forecast Report, issued in May 2008. The 2008 Load Forecast was prepared in Q1 and Q2 2008. Economic conditions in the end of 2007 and first five months of 2008 differ significantly from the current economic outlook. To the extent the U.S. experiences a deep recession or worse from the

[19] See http://www.pjm.com/markets/rpm/downloads/planning-period-parameters.xls; and http://www.pjm.com/services/system-performance/operations-analysis.htm.

[20] See http://www.pjm.com/markets/jsp/nts.jsp.

present credit implosion, the load growth assumptions reflected in the 2008 forecast may significantly overstate electricity demand in the next three to five years, thereby resulting in clearing prices less than the Net Cost of New Entry (CONE) due to excess supply.

Table 3. Sources of ISO Load Data

PJM	2008 Load Forecast Report
NYISO	2008 Load and Capacity Data Report
ISO-NE	Forecast Data 2008[21]
Other Areas	Ventyx MarketSym Database

PJM's load forecast for all of PJM anticipates a peak demand of 138 GW for 2008 (excluding ComEd the coincident peak is 115 GW). For the four load zones covering Maryland, non-coincident peak demand is forecast to be 27.3 GW in 2008. The anticipated annual average peak load growth rates for Maryland by zone for the 2008 to 2018 period, reported by PJM in the 2008 Load Forecast Report are shown in Table 4.

Table 4. Annual Average Peak Load Growth Rates (2008-2018)

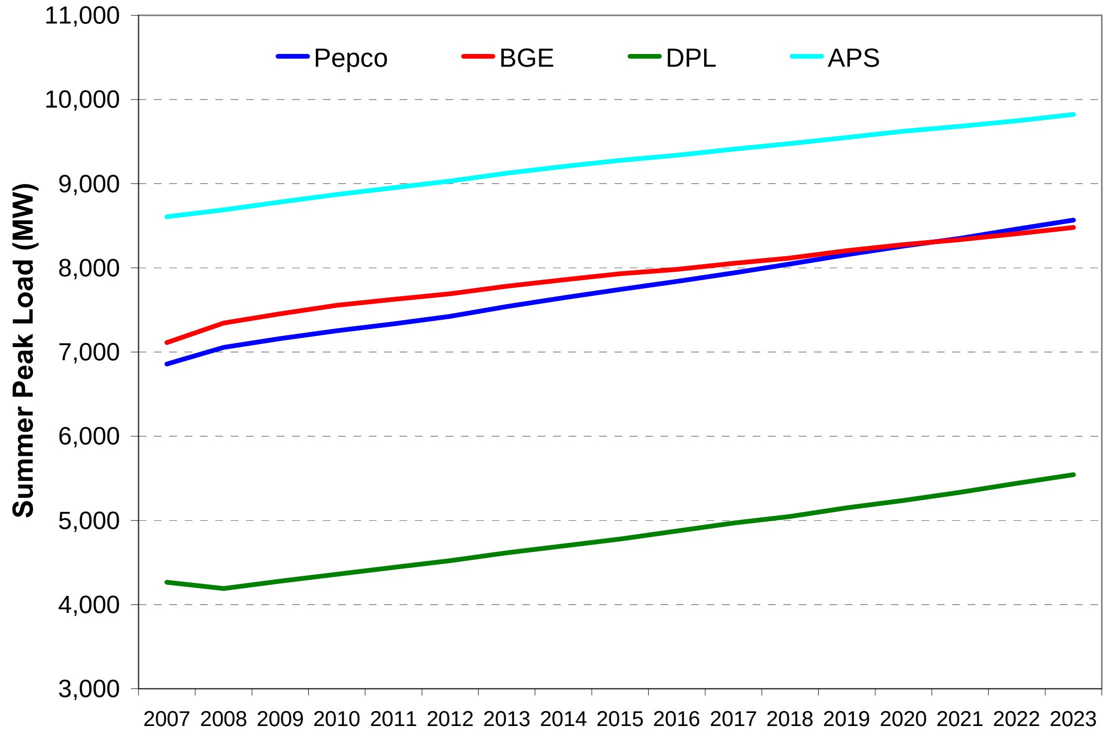
Zone	Growth Rate
BGE (Central Maryland)	1.0%
DPL (includes Eastern Shore)	1.9%
Pepco (Central & Southern Maryland	1.3%
APS (includes Western Maryland	0.9%

These loads are PJM zonal loads and therefore three of these zones include parts of other states. BGE is the only zone that is 100% within Maryland. DPL includes parts of Virginia and Delaware. Pepco includes Washington, D.C. APS includes portions of Pennsylvania, West Virginia, and Virginia. Unless otherwise specified, the load information and the cost to serve load are based on the PJM zonal loads, and not only the load of the IOU customers residing within Maryland.

The summer peak load growth over the 15-year PJM forecast period is shown in Figure 19 for the four PJM zones of relevance in Maryland. PJM provides only a 15-year forecast. Therefore, for the purpose of MarketSym, the PJM forecast has been extrapolated for an additional five years.

[21] See http://www.iso-ne.com/trans/celt/fsct_detail/2008/isone_2008_forecast_data.xls.

Figure 19. Summer Peak Load Growth Forecast for the Maryland PJM Zones[22]



PJM's load forecast includes peak load reductions due to Direct Control Load Management (DCLM) and Interruptible Demand (ID). PJM's *2007 Load, Capacity, and Transmission Report* indicates a constant level of peak load reductions for the period 2007 through 2015. In extrapolating PJM's load forecast to 2028, the model assumes that DCLM and ID remain constant through 2028. PJM's total peak load reduction of 1,673 MW corresponds to 1.2% of the PJM summer peak load (before DCLM and ID) of 139,342 MW in 2008. DR is treated as "virtual generation" in the production simulation model.

Quantities that are based on retail sales under the Commission's jurisdiction *only* utilize state-specific data sources. As discussed in Section 5, Maryland's EMD target is based *generally* on the IOUs' filings before the Commission in Case 9111. The RPS target by state is based on the state electricity profiles compiled by the U.S. Energy Information Administration (EIA). The respective ISOs' peak load growth forecasts are applied over the study horizon.

2.1.4. Resource Adequacy in PJM

Based on the *2006 Reserve Requirement Study*, PJM's installed reserve margin (IRM) for 2007/08, 2008/09 and 2009/10 was set at 15%.[23] PJM's *2007 Reserve Requirement Study*

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[22] Based on *PJM Load Forecast Report January 2008, revised May 2008* (Table B-1)

[23] *2006 PJM Reserve Requirement Study – PJM Capacity Obligation Parameters for the 2007/08 Planning Period*. See summary of results sent to PJM Planning Committee, April 19, 2006.

recommended an increase of the IRM to 15.5% for the 2010/11 and 2011/12 planning periods.[24] The 15.5% IRM has been treated as a constant over the planning horizon.[25]

Across the study area, new generation projects that are currently under construction, have executed long-term contracts, and/or have cleared in an applicable capacity market auctions have been added to the resource base in MarketSym.[26] Nearly all new entry is wind, gas-fired simple-cycle and CC projects, with the exception of 700 MW of new coal-fired generation in APS.

DSM resources, representing one-quarter of the EMD target, have also been added to the resources in each year in the *Reference Case*. To capture the impact on capacity requirements and the operation of conventional resources across PJM, LAI has represented the array of DSM resources in our production simulation model as "virtual generators." See Section 5.4.

For the purpose of maintaining system reliability across PJM, additional new generic resources have been included across PJM to maintain an IRM equal to 15.5%. Generic simple-cycle and CC units were added to maintain an optimized blend across the study horizon. A portion of the new generation added in PJM for the *Reference Case* is assumed to be wind turbines to satisfy the states' respective RPS requirements. The capacity addition schedule and the distribution of these wind capacity resources are discussed in detail in Section 6.2. Figure 20 shows the annual peak capacity for each modeled zone in PJM incorporated in the *Reference Case* in accord with the PJM 2008 load report. Figure 21 illustrates the capacity buildout in accord with the IRM across PJM zones APS, EMAAC and SWMAAC by technology type in the *Reference Case.*

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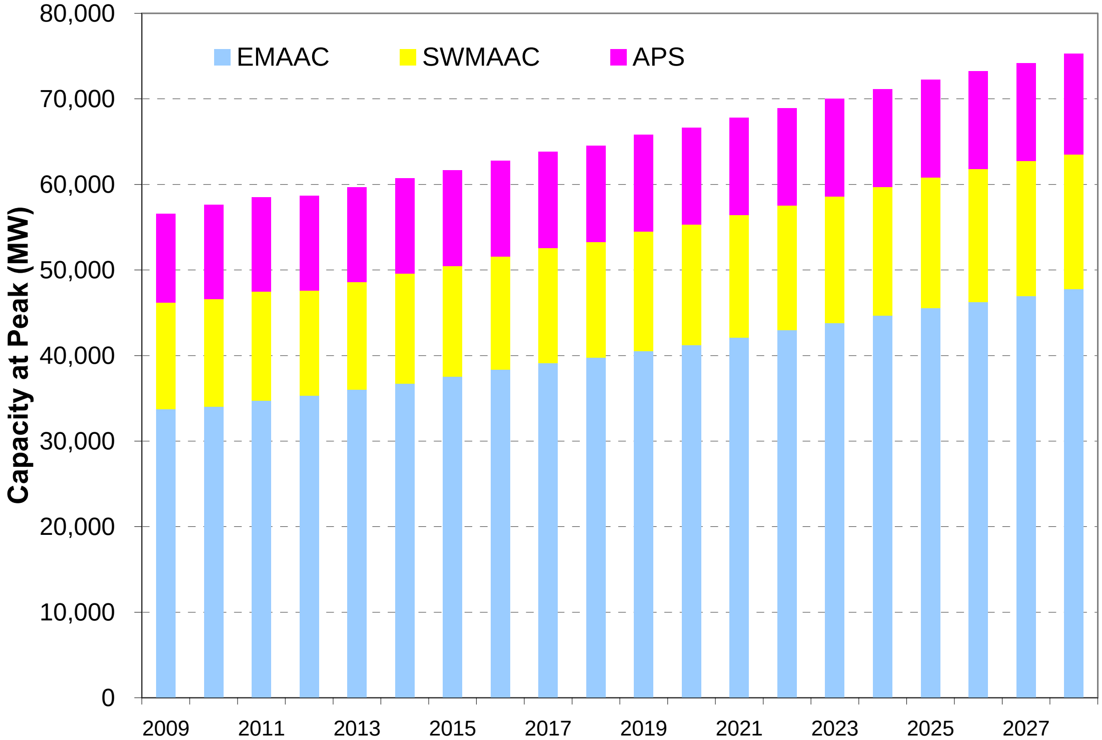
[24] *2007 PJM Reserve Requirement Study – PJM Capacity Obligation Parameters for the 10-year Planning Horizon from June 1, 2007 through May 31, 2017* (August 15, 2007)

[25] The *2008 Reserve Requirement Study* recommended an increase in the IRM to 16.2%, but the increase has not yet been approved by the PJM Board.

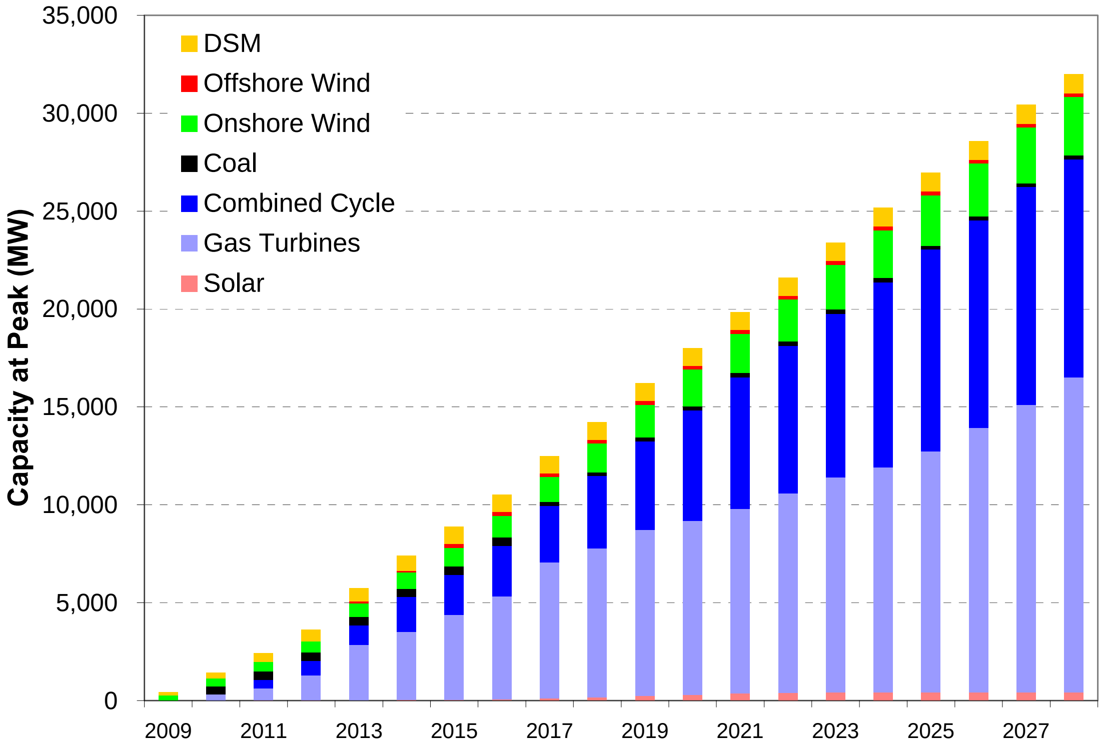
[26] Additions include the 100-MW AES Armenia Mountain in PA, 60-MW Synergics's Eastern Wind and 40-MW Roth Rock Wind in MD, and the 700-MW Longview coal project in WV. New projects in New York and Connecticut include 905 MW and 1,300 MW, respectively.

Figure 20. ***Reference Case*** **Peak Capacity by Zone**[27]



[27] Peak capacity is similar to UCAP, not installed capacity (ICAP). It is the maximum hourly capacity for each generator in the month of July.

Figure 21. *Reference Case* Capacity Additions in PJM[28]



PJM has indicated that TrAIL will be commercialized in 2011. Significant delay of TrAIL may cause reliability constraints in Maryland, particularly in SWMAAC. If TrAIL is not developed on schedule, Maryland and the surrounding states face a potential capacity deficit in the short term until either TrAIL becomes operational or other resource options are developed, including DSM. In formulating the *Reference Case* we have conservatively assumed TrAIL's in-service date is 2014. We have also assumed substantial DSM entry, *i.e.*, one-quarter of the EMD target. Since the potential capacity deficit may be remedied once the transfer capacity into SWMAAC is increased, there may not be adequate economic incentives for new conventional generation to be added to Maryland's resource mix to meet a short-term need. To manage the uncertainty surrounding TrAIL's in-service date and the penetration rate of DSM in Maryland, the Commission is in the process of investigating a Gap RFP to alleviate potential short-term reliability problems in Maryland from 2011 to 2016. Again, for the purposes of this study, no unserved energy is contemplated over the study horizon. Therefore we have postulated the timely addition of conventional gas-fired generation resources to ensure bulk power security regardless of the uncertainty surrounding TrAIL and/or DSM.

Readers are therefore cautioned not to interpret the capacity balance in the *Reference Case* as evidence of resource adequacy through 2014.[29]

[28] For renewable generation, such as wind and solar, capacity at peak is neither ICAP nor UCAP. In this figure, PJM includes SWMAAC, EMAAC, Central MAAC, Western MAAC, APS, AEP and VP.

[29] The impact of the financial crisis on load growth has not been assessed in this report.

More discussion of the potential range in capacity constraints in relation to TrAIL and other PJM planning criteria is provided in Section 3.2.6.

2.1.5. Attrition Analysis

As of November 2008, the PJM generator deactivation list includes the generators listed in Table 5 below. For the purpose of the MarketSym model, these units were assumed to be retired as of the requested deactivation date. It is important to note that anticipated capacity constraints in Maryland could result in the rescission or postponement of generators on the PJM deactivation list.

Table 5. PJM Deactivation List

Plant Name	Unit Size (MW)	Service Territory	Requested Deactivation Date
Indian River 2	89	DPL	5/2010
Indian River 1	90	DPL	5/2011
Buzzard Point East Banks 1,2,4-8	112	Pepco	5/2012
Buzzard Point West Banks 1-8	128	Pepco	5/2012
Benning 15	275	Pepco	5/2012
Benning 16	275	Pepco	5/2012

2.1.6. Bidder Behavior

LAI's forecast of energy prices reflects PJM's market design under workably competitive wholesale market conditions. Hence, LMPs reflect cost-based scheduling of generation in both the Day-Ahead Market (DAM) and the Real-Time Market (RTM). In MarketSym, generators are assumed to bid "rationally," that is, at or slightly above marginal cost. Bid adders, the amount by which a generator increases its bid above its marginal cost, are not included in the *Reference Case*, but are accounted for in specific study cases where relevant.[30] While forecast results are accurate in most hours, volatility results that often occur during peak demand periods raise market prices above the marginal cost of the most expensive unit scheduled to meet the last increment of demand. In actual practice, both infra-marginal and marginal units that set the LMP may include a significant bid adder over the marginal cost of producing electricity. The inclusion of bid adders is consistent with the Federal Energy Regulatory Commission (FERC)-approved wholesale market design in PJM. During congestion events – intervals of extreme heat and humidity – bid adders may be large. Including bid adders increases LMPs relative to the marginal cost of producing electricity, but, subject to limits, is in accord with market power safeguards administered by PJM's Independent Market Monitor (IMM). If the IMM finds

[30] Study objectives and production milestones preclude inclusion of bid adders in the *Reference Case*. The omission of bid adders does not constitute a significant measurement bias. See Appendix B for a description of the derivation of bid adders used in the *Rate Base Regulation Case*.

evidence of the ability of one or more generators to exercise market power, the IMM can mitigate prices, thereby reducing payments to generators.

Quantification of the benefits associated with traditional cost of service regulation requires recognition of the economic impact of bid adders. Under the *Rate Base Regulation Case*, LAI assumes that prospective scheduling of all generation from the Mirant assets transferred either to Pepco or the Authority would be in accord with the marginal cost of production. Resultant LMPs in SWMAAC, EMAAC, and, perhaps, the Regional Transmission Organization (RTO) will be lower as a result of the suppression of bid adders by these assets. In addition, there may be some mitigation of markups by other generators as a result of purely cost-based bidding by the Mirant assets. In the *Rate Base Regulation Case*, we quantify the change in the direct cost and MTM portfolio benefit in Maryland that can be explained by the suppression of bid adders.

The methodology employed for modeling bid adders is described in Appendix B.

2.2. Capacity Market

2.2.1. Background

In June 2007, PJM implemented the RPM in order to provide generators throughout the market area with a more predictable source of revenue from capacity sales. RPM is designed to solve the complex problem of the "missing money," thus providing capacity payments to retain needed generation, as well as to motivate suppliers to enter the market. The missing money problem arises from the financial gap experienced by some generators with respect to the recoupment in full of all relevant costs through the sale of capacity, energy, and ancillary services. According to PJM's 2007 State of the Market (SOM) Report, the average net revenue from the sale of energy and ancillary services for a GT was $32,248/MW-yr for the period 1999-2007. The SOM estimated that the 20-year levelized cost to build a new GT was $75,158/MW-yr. RPM is designed to address the revenue shortfall in order to promote merchant generators' financial viability.

Prior to implementation of RPM, PJM had employed a PJM-wide spot market for capacity. RPM differentiates capacity prices by Locational Deliverability Area (LDA) to provide price signals for the retention of existing resources and development of new capacity where most needed. RPM is a forward market mechanism; except for the first four transitional Base Residual Auctions (BRAs), capacity revenues are determined three years in advance of the Delivery Year, which runs from June 1st through May 31st.[31]

Prior to every BRA, PJM determines whether there is a need for new capacity within any LDA. To do so, PJM assesses the relationship between demand, existing local capacity, and transmission constraints for each LDA based on a Capacity Emergency Transfer Objective (CETO) / CETL analysis. CETO defines the transmission import requirement into an LDA to

[31] For example, the 2008/09 BRA was held in July 2007, about one year in advance. The first auction to provide the full three years between the auction and the Delivery Year was the 2011/12 BRA held in May 2008. Henceforth, BRAs will be held every May for the Delivery Year three years into the future.

meet reliability criteria. CETL is determined using power flow analyses to define the actual import capability.[32] If CETL is calculated to be less than 5% greater than CETO for that Delivery Year, the LDA is considered potentially constrained, and a separate capacity price is set for that LDA.[33] As discussed in Section II.C.3.(a)(i) of the Interim Report, the LDAs are nested. If it is determined that a particular LDA is not constrained, generators in that LDA receive the capacity clearing price for the encompassing LDA or the RTO price for PJM as a whole, whichever is higher.

RPM utilizes a sloped demand curve, which is called the Variable Resource Requirement (VRR) curve. In each auction, a VRR curve is established for every LDA that is constrained. CONE, the levelized capital and fixed operating costs of a GT, is one of the key parameters in setting the VRR curve. Gross CONE can be differentiated by location in PJM to account for geographic differences in labor rates, construction, and interconnection costs. Net CONE is Gross CONE minus the profit margin derived from the sale of energy and ancillary services (E&AS), which also differs on a locational basis. The height of the VRR curve is set using Net CONE.

The VRR curve is designed to set a capacity clearing price at Net CONE when the market clears at PJM's IRM of 15.5% plus 1%, slightly in excess of the amount needed to maintain long-term reliability. Accordingly, the higher the Net CONE, the greater the elevation of the demand curve along the y-axis, and *vice versa.* For the first five BRAs, Net CONE in the RTO ranged narrowly between $161/MW-day to $164/MW-day.[34] The first four of five auctions were conducted less than three years in advance of the Delivery Year.

The VRR used in the 2011/12 BRA, in which there were no constrained LDAs, and an illustrative supply curve are shown in Figure 22. The procurement target, set at a 16.5% reserve margin, adjusted for the Fixed Resource Requirement and Interruptible Load for Reliability (ILR), is indicated on the demand curve. The intersection of the supply and demand curves sets the clearing price.

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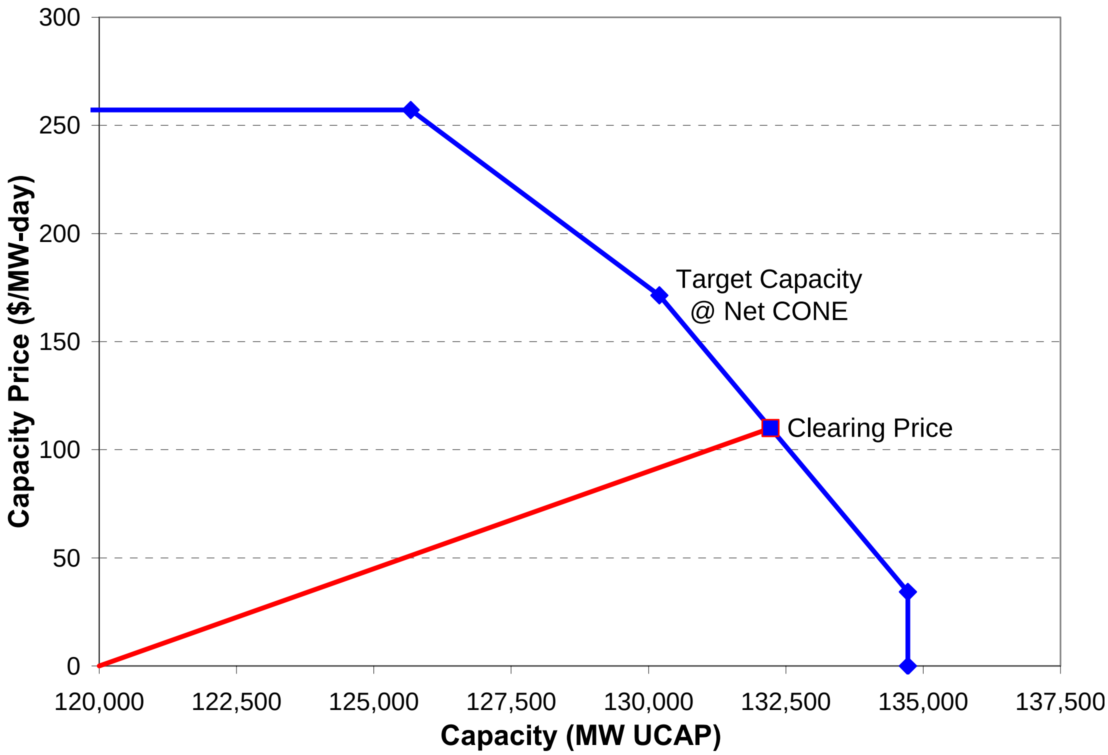
[32] CETL is effectively the maximum amount of capacity an LDA can import under certain conditions while CETO is the required amount of imported capacity to maintain reliability.

[33] Generators in a constrained LDA will receive the LDA clearing price unless that price is lower than the RTO clearing price. If that is the case, generators in the constrained LDA receive the RTO price. This was the case in the 2010/11 BRA for SWMAAC.

[34] CONE is adjusted to a UCAP value in setting the height of the demand curve. The UCAP CONE used to establish the VRR for the 2011/12 BRA was $171.40/MW-day, based on the RTO-wide Equivalent Demand Forced Outage Rate (EFORd) of 6.2%.

Figure 22. 2011/12 RTO VRR Curve and Indicative Supply Curve



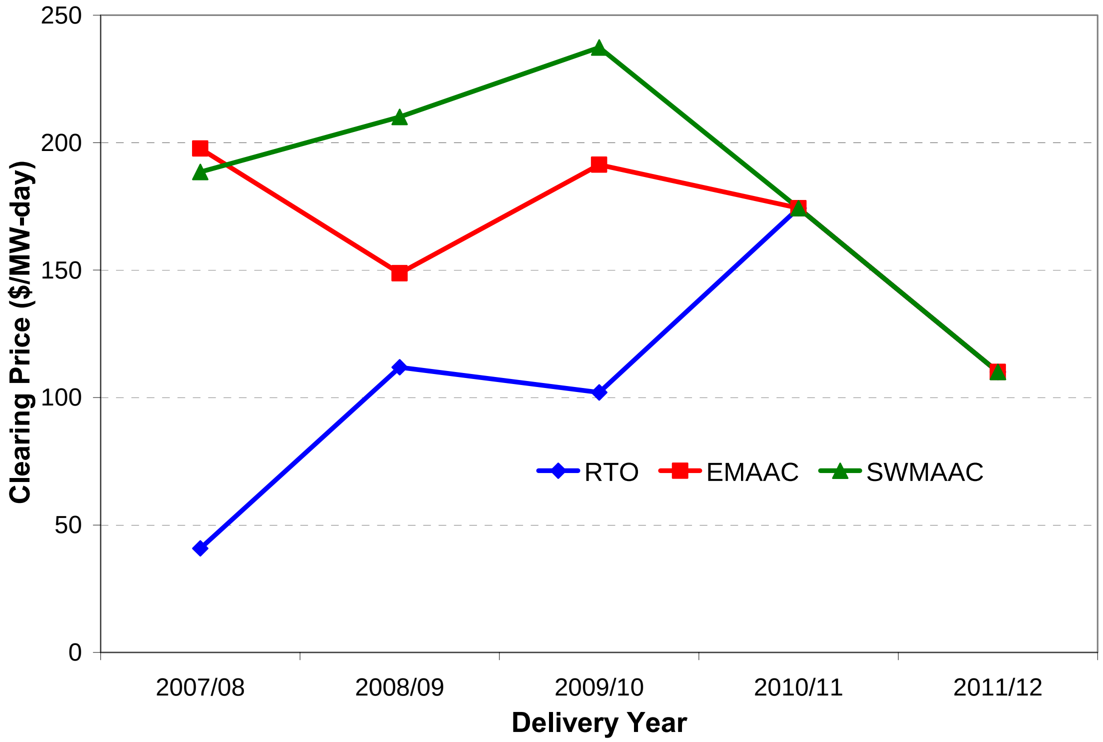
The VRR demand curve slopes downward from left to right. Therefore, if the intersection of the supply and demand curves occurs to the left of the target quantity, the capacity market is "short" and the clearing price will be set above Net CONE, in theory inducing new generation. If, on the other hand, the market is "long," as indicated by an intersection to the right of the procurement target, the clearing price will be below Net CONE, as was the case in the 2011/12 auction. The resulting low capacity price sends a signal that no new supply is needed.

Further detail on the mechanics of RPM can be found in Attachment DD of PJM's Open Access Transmission Tariff (OATT).

To date, PJM has administered five BRAs, only one of which had a three-year term between the auction date and the Delivery Year. The first four auctions covering Delivery Years 2007/08 through 2010/11 were in effect transition auctions and therefore the price signals RPM is designed to send market participants may have been muted. For example, in the 2007/08 BRA both SWMAAC and EMAAC cleared above Net CONE, which should induce new entry. But that auction was held in April 2007, less than two months before the beginning of the Delivery Year. As such, the high clearing prices paid to generators in SWMAAC and EMAAC constitute a windfall for incumbent generators, but do not support new entry.

Resource clearing prices paid to generators in EMACC, SWMAAC, and RTO set by those auctions are shown in Figure 23.

Figure 23. RPM BRA Resource Clearing Prices



In the first three BRAs, there was price separation between two LDAs, SWMAAC and EMAAC, and the RTO.[35] The high prices that cleared indicate that those LDAs had insufficient capacity to meet their respective procurement targets, which reflect transmission constraints that limit the capacity that could be imported into those LDAs. In the 2010/11 BRA, SWMAAC remained transmission-constrained, but there was no price separation because the E&AS offset reduced Net CONE and therefore the height of the demand curve. SWMAAC resources therefore received the higher RTO clearing price of $174.29/MW-day. Although there were transmission constraints into EMAAC in the 2010/11 BRA, sufficient resources cleared that the constraint was not binding and no price separation occurred.

For the 2011/12 BRA, TrAIL was included in PJM's power flow analysis and determination of CETL. This increased CETL in SWMAAC and EMAAC, and is one reason why both regions were unconstrained. As a result, all PJM capacity within PJM will receive identical UCAP prices of $110.00/MW-day for Delivery Year 2011/12.

2.2.2. RPM Update

PJM market rules require regular reviews of the RPM mechanism and its inputs. Throughout 2008, PJM and its stakeholders have been considering changes to both the structure of the RPM mechanism and the key factor inputs used to establish the VRR. The review is being undertaken

[35] MAAC+APS (which includes EMAAC and SWMAAC) cleared as a separate LDA in the 2009/10 BRA. DPL-South cleared as a separate LDA in the 2010/11 BRA. These two prices are not shown in Figure 23.

by PJM's Markets and Reliability Committee (MRC) and the Capacity Markets Evolution Committee (CMEC). PJM hopes to incorporate the changes into the next BRA, which will be for the 2012/13 Delivery Year.

There are many proposed structural changes to the RPM. Before the MRC and CMEC are proposed changes to the way in which E&AS revenues are accounted for, use of multiple technologies to establish CONE, the threshold for determining whether an LDA binds pursuant to the CETO/CETL analysis,[36] incremental auction mechanics, the mechanics of periodic CONE reviews,[37] allowances for partial year participation in the RPM, options for locking in RPM revenues for multiple years for new generators, among other things. Perhaps the key revision being considered is an upward revision to CONE.

Under the current mechanism, CONE is determined via an administrative process. PJM hires outside consultants who estimate the cost to build gas-fired peaking units in locations throughout PJM. This sets the value of Gross CONE. Net CONE is calculated based on an E&AS offset that utilizes historical revenues for E&AS.

Late last year, PJM hired Pasteris Energy and Power Project Management, to conduct this analysis. Both consultants developed estimates for three locations in PJM, and both determined that CONE was substantially higher than the estimate currently in use. Their estimates were presented to the MRC on August 6, 2008.

Since that meeting, the stakeholder process has become increasingly contentious, particularly with respect to the definition of CONE. Stakeholders representing capacity buyers (*i.e.*, load) and stakeholders representing capacity sellers (*i.e.*, generators) have disagreed on a variety of issues, with buyers resisting upward adjustments to CONE and sellers favoring large upward revisions. PJM, working with the IMM, has attempted to mediate the dispute to foster consensus. As of November 10, 2008, the date of the most recent CMEC meeting prior to the publication of this report, market participants agreed they were at an impasse. A consensus solution has not been found.

Since the stakeholder process began, a variety of proposals have been put forth by buyers, sellers, and PJM/IMM regarding CONE. They range from a proposal to keep CONE at the level in use in the 2011/12 auction to increasing it to nearly $400/MW-day. LAI has based the capacity price forecast on a proposal discussed at the November 10th CMEC meeting. Although the CMEC process was unsuccessful, we believe that the proposed CONE values shown in Table 6 represent a plausible projection of what CONE has the potential to be for the 2012/13 BRA and thereafter.

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[36] A proposal before CMEC called for increasing the margin by which CETL has to exceed CETO from 5% to 15%. This change could potentially affect clearing prices in SWMAAC. This study assumes the current 5% margin.

[37] PJM's OATT allows for the automation of CONE. Presently, CONE is reset every three years. An automation of the process would allow for CONE updates by auction results, rather than by discrete adjustments by PJM's consultant. In 4Q 2008, there have been a number of proposed CONE changes before CMEC. The CONE proposal of November 10th has been incorporated in this study.

Table 6. Proposed CONE Values – 11/10/08 CMEC Meeting

	Region 1	**Region 2**	**Region 3**
Gross CONE ($/MW-yr)	$142,443	$131,806	$132,847
E&AS Offset ($/MW-yr)	$49,709	$50,483	$9,710
Net CONE ($/MW-day)	$254.06	$222.80	$337.36

Because these proposed values have not achieved consensus among market participants – much less been approved by the PJM Board, approved by FERC and then incorporated in PJM's OATT – they are merely estimates and the CONE values ultimately agreed upon by PJM stakeholders may vary significantly from these proposals. However, there does appear to be broad acceptance of the notion that the current cost of constructing a new GT has increased. LAI believes it is likely, but by no means certain, that the value of CONE will be significantly increased. In light of the recent collapse in global commodity prices, including metals, the extent to which CONE is increased relative to recommended adjustments by PJM is uncertain. Moreover, the proposed values indicated in Table 6 represent a midpoint value that falls between the current CONE input and the other very high proposed values that have been proposed by certain stakeholders.

For our forecast, Net CONE is increased each year by inflation, beginning with the 2012/13 auction. In reality, there will be some year-by-year variability on the E&AS offset, but we estimate that such changes will have a minor impact on Net CONE.

Another dynamic that is critical to our forecast of capacity prices is the manner in which Net CONE for the RTO will be established. Stakeholders have debated the use of the Region 3 Net CONE for the RTO as a whole versus the use of the least cost Net CONE in any of the three regions.[38] LAI has exercised judgment in using the Region 2 Net CONE.

2.2.3. <u>PJM Capacity Price Forecast</u>

We have forecasted capacity clearing prices using our proprietary model that replicates the functionality of the BRA. The model was described in Section II.D.2 of the Interim Report. Since publication of the Interim Report in 2007, the model has been updated to reflect changes in CONE, market entry and attrition, and expected transmission upgrades.

For each year over the study horizon, we calculated CETO and CETL for SWMAAC and EMAAC to determine if they bind, thus causing price separation. CETO values for each LDA for the 2011/12 Delivery Year are known. To calculate the year-to-year change in CETO, we calculated the net increase in demand, *i.e.*, new demand minus new supply additions each year

[38] Region 1 is EMAAC, Region 2 is the rest of MAAC plus APS, and Region 3 includes AEP, ComEd, Dayton, and Dominion. For purposes of establishing VRR curves for our forecast, Region 2 is used for SWMAAC while Region 3 represents the RTO.

over the study period, plus an adder of 25% based on an analysis of historic changes to CETO.[39] We found that there are transmission constraints for SWMAAC that cause price separation in the early years of the forecast, as indicated below.

CETL values for the 2011/12 Delivery Year are also known, but these values assume that TrAIL will be in place for that Delivery Year. Since we conservatively assume that TrAIL will not come online until 2014 in the *Base Scenario*, and, of course, never in the *No TrAIL Scenario*, CETL was decreased by 230 MW in SWMAAC and 290 MW in EMAAC for the years in which we assume TrAIL will be delayed.[40] Those values are based on discussions between the Commission and PJM regarding TrAIL's projected impact on the CETL for each LDA. We have relied on PJM's response and planning guidance in formulating the change in CETL in SWMAAC and EMAAC.

2.2.3.1.Reference Case

Based on PJM's most current demand forecast and the resource additions discussed in Section 2.1, the UCAP price forecast and our projection of Net CONE are shown in Figure 24. Clearing prices for the first five auctions as well as the Net CONE input used to set the VRR curve in those auctions is also shown.

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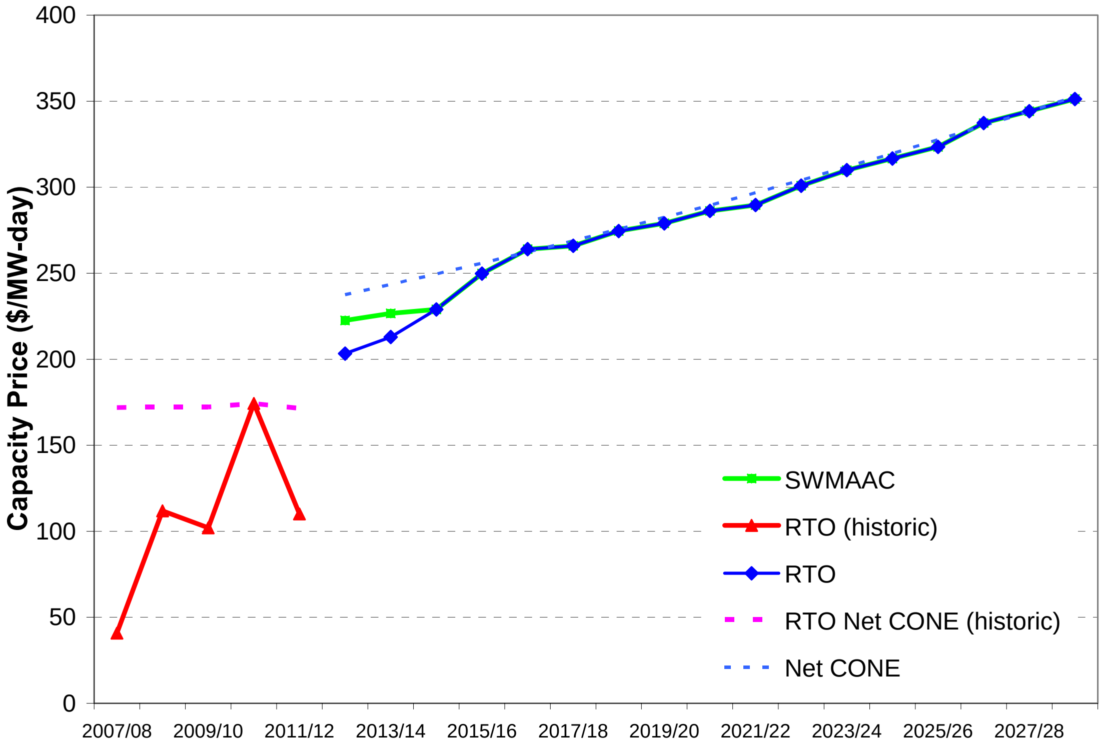
[39] Because PJM's reliability criteria are based on loss-of-load expectation for the RTO as a whole, the reliability threshold is higher for any individual LDA. Based on SWMAAC and EMAAC CETO values from the BRA planning period parameters, the RPM resource model files and the 2007 load report, we found that the ratio of resources + CETO divided by load ranged from 1.22 to 1.27. We used an average of 1.25 or 125%.

[40] The result is CETL values for SWMAAC and EMAAC that are equal to those used to administer the 2010/11 BRA.

Figure 24. Long-Term UCAP Prices – *Reference Case*



For 2012/13 and 2013/14, SWMAAC binds and clears at a price above the RTO clearing price. This is attributable to the delay in TrAIL, with which CETL would be higher, as well as the retirement of the Buzzard and Benning plants in 2012, which reduces the amount of capacity available locally.

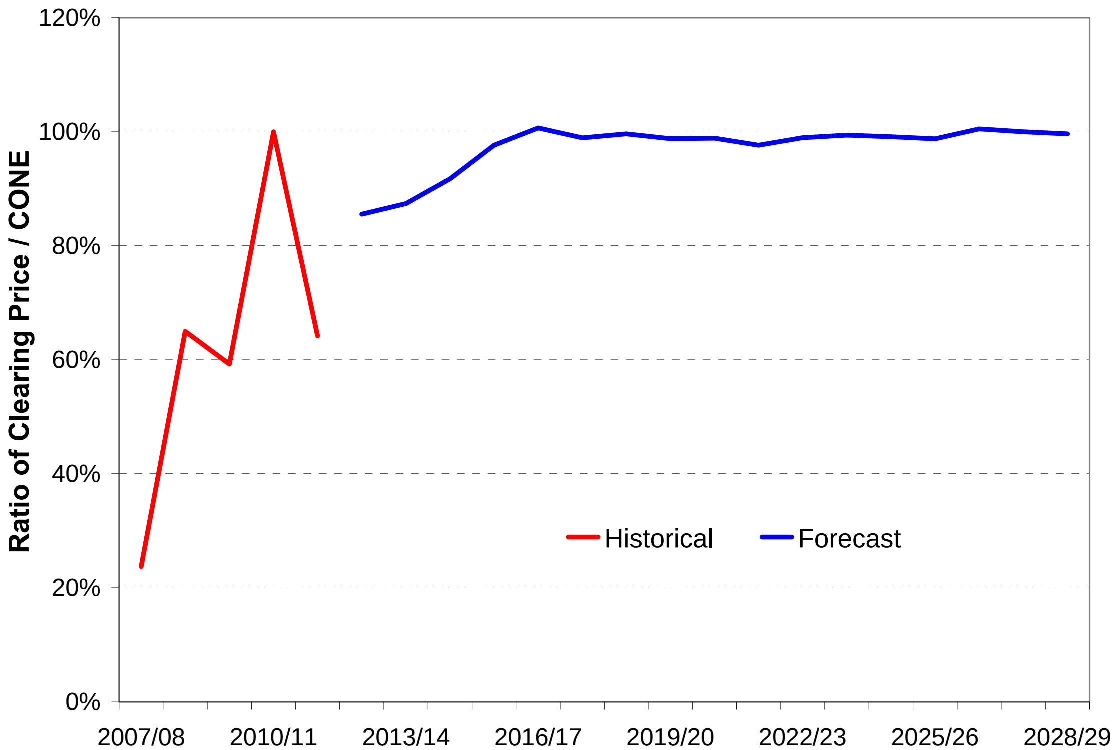
A price series is not indicated for EMAAC in the *Reference Case* plot or any of the alternative case plots. There are years when there are transmission constraints into EMAAC during the study period, but in those years there is sufficient capacity to cause EMAAC to clear at a price at or below the RTO price. As such, there is no price separation.

In the forecast for the RTO, prices clear below Net CONE for the first few years of the auction. This is explained by the excess of capacity currently in the market. For the most recent auction, 2011/12, approximately 2,000 MW of excess capacity cleared the market. Notably, an additional 5,500 MW of capacity and DR failed to clear. This extra supply keeps prices well below Net CONE until approximately 2015/16, by which time the aggregate load growth will have depleted the excess supply.[41] Since the schedule of resource additions calls for the addition of new capacity and DSM resources to meet incremental demand thereafter, the RTO clearing price oscillates around Net CONE for the remainder of the forecast.

[41] To the extent load growth in PJM decreases in response to the global credit crisis, it may take more time to deplete the excess supply reflected in the *Reference Case*.

The short-term oversupply that results in clearing prices below Net CONE is consistent with the results of the first five auctions held. In four of those auctions, there was excess capacity in the market, causing prices to clear below Net CONE for the RTO. Since the capacity market began with the 2007/08 BRA, and only one of five auctions has been held three years prior to the Delivery Year, there are no hard market trends upon which to rely. Expressed as a percentage of Net CONE, in Figure 25 we show the relationship between Net CONE and the RTO clearing price for the first five auctions as well as LAI's forecast over the study horizon.

Figure 25. Clearing Price / CONE Ratio – Historical and Forecast



Once demand catches up to supply around the middle of the next decade, our forecast reflects UCAP clearing prices converging with Net CONE and then oscillating along that plateau over the study period, adjusted for inflation.[42] The forecast assumes the continued availability of capacity from resources owned by Duquesne. In 2008, FERC approved Duquesne's request to withdraw from PJM,[43] which will likely take place in 2009.[44] At the time of the approval Duquesne's generators had already bid into the RPM through 2010/11. Duquesne's generators cleared each auction and are therefore committed to meeting their obligation. In the 2011/12 BRA, the Duquesne assets were not required to bid into RPM, but were still allowed to

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[42] The small oscillations around Net CONE following convergence is explained by the classic "lumpiness" problem associated with the addition of new generation capacity. Since assets are added at discrete points in large blocks, incremental supply does not exactly match demand growth in any given year.

[43] Duquesne's withdrawal removes Duquesne's load from the RPM.

[44] See Case No. ER08-194.

participate in the auction as external resources; they cleared the market, putting downward pressure on clearing prices.[45]

Absent a capacity market administered by MISO, it is reasonable to expect that the Duquesne generation resources will continue to participate in RPM as external resources. At this time, a capacity market in MISO has not been implemented, nor is there any indication that one will soon be implemented. Load-serving entities (LSEs) in MISO still have bilateral contract obligations, however. Furthermore, the generation resources in the Duquesne LDA hold the rights to transmission sufficient to export all of the Duquesne capacity into PJM, which rights appear to be perpetually renewable at no cost.

As noted above, PJM included the transfer limit associated with TrAIL in its determination of CETL for the 2011/12 auction. Since we conservatively assume that TrAIL will be commercialized in 2014, those auction results have been adjusted herein. Table 7 shows the relationship of CETO and CETL without TrAIL for the 2011/12 auction. CETO is unchanged, but the CETL values have been recalculated to account for the delay of TrAIL.

Table 7. 2011/12 CETO/CETL without TrAIL

	SWMAAC	**EMAAC**
2011/12 CETL including TrAIL (MW)	6,897	8,804
TrAIL Contribution to CETL (MW)	230	290
2011/12 CETL without TrAIL (MW)	6,667	8,514
2011/12 CETO (MW)	6,270	8,070
CETL/CETO (no TrAIL)	106.3%	105.5%

Even without TrAIL, CETL for both SWMAAC and EMAAC is more than 5% greater than CETO. As such, even if TrAIL is delayed, SWMAAC and EMAAC will not bind for 2011/12 and a new clearing price will not be established via an incremental auction in which either EMAAC or SWMAAC would be a constrained zone. Changes in CETL do not impact the RTO clearing price.

2.2.3.2.Study Cases

The capacity model was applied to each of the study cases, resulting in separate price forecasts which are a function of the schedule of resource additions and the load forecast.

The capacity clearing prices for both the *Contract CC Case* and the *Utility CC Case* are the same, because the postulated new CC will bid the same amount of capacity into the RPM regardless of who owns it, and all other supply and demand inputs remain fixed. The capacity price forecast for the *Contract CC Case* and the *Utility CC Case* is indicated in Figure 26.

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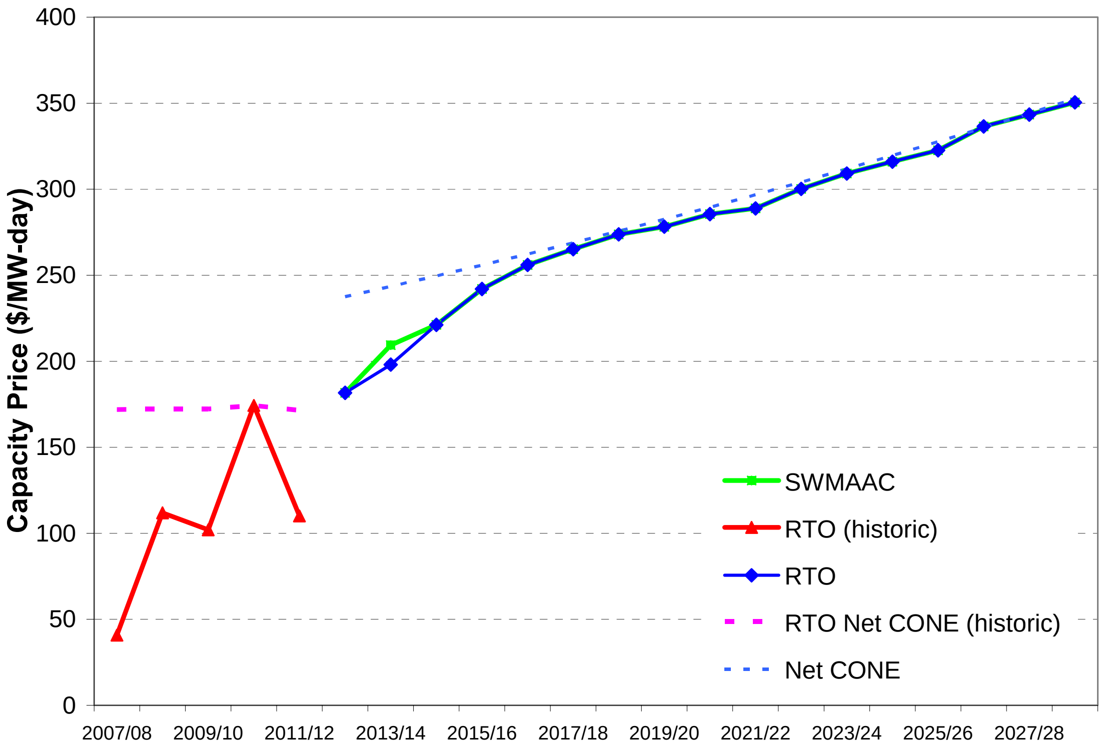
[45] Generators in the Duquesne LDA can participate in the BRA as external resources, thereby lengthening the supply and reducing UCAP prices. A June 2008 report by the Brattle Group, an advisor to PJM, estimated that RTO would have cleared at approximately $150/MW-day in the 2011/12 auction had the Duquesne assets not participated.

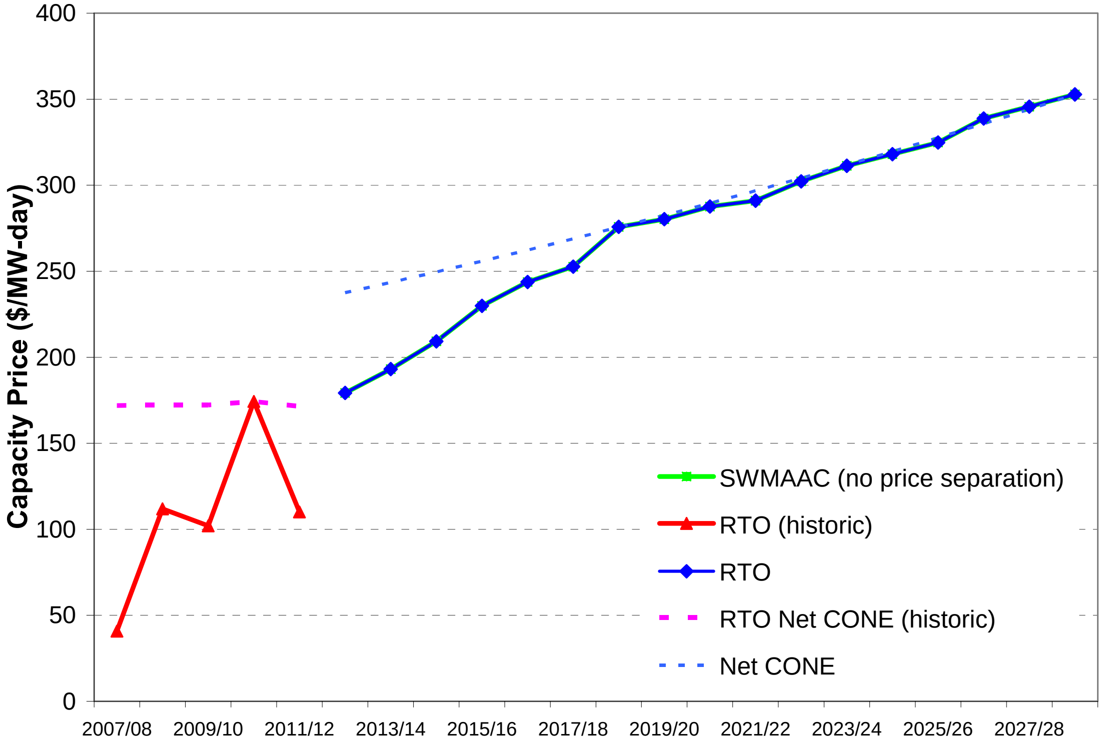
Figure 26. Long-Term UCAP Prices – *Contract CC / Utility CC Cases*



In this case, a 1080-MW (nameplate) CC unit is added in 2012 that results in a short-term supply excess. SWMAAC binds only in the 2013/14 auction, and the price separation in that Delivery Year is small. The RTO clearing price is lower than in the *Reference Case* in the early years of the forecast, and convergence to Net CONE is delayed a year. Once the supply excess is offset by aggregate demand growth, clearing prices converge with Net CONE. The later portion of the *Contract / Utility CC Cases* forecast is similar to the *Reference Case*.

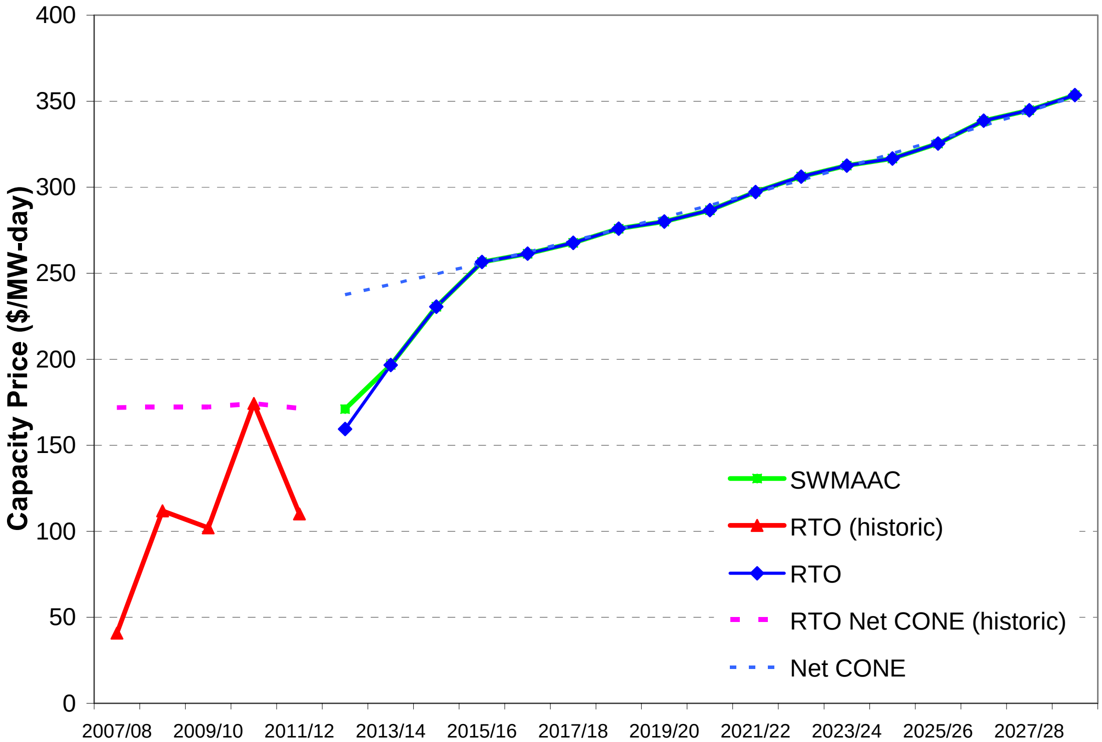
Capacity prices are depressed even further in the early years of the forecast in the *Overbuild Case*. In this case, the CC units are added in SWMAAC, but they do not offset planned additions in SWMAAC, causing a larger oversupply that persists longer. In this case, the SWMAAC price does not separate from the RTO price at any point in the forecast, and convergence of the RTO clearing price to Net CONE is delayed.

Figure 27. Long-Term UCAP Prices – *Overbuild Case*



In the *15x15 DSM Case*, demand-side resources are rapidly brought online in the early years of the forecast. Because of the location, SWMAAC binds only in 2012/13 – in that year the price separation between SWMAAC and the RTO is small. The RTO price is reduced as well, compared to the *Reference Case*. By 2015/16, the additional supply has been offset by load growth, and the UCAP price converges to Net CONE. Following convergence, the *15x15 DSM Case* forecast is similar to the *Reference Case* forecast, as indicated in Figure 28.

Figure 28. Long-Term UCAP Prices – *15x15 DSM Case*



The *Onshore Wind* and *Offshore Wind Cases* add similar amounts of wind capacity to the market; the incremental capacity addition in the *Offshore Wind Case* offsets the addition of conventional resources elsewhere while the incremental addition in the *Onshore Wind Case* is too small to require a similar offset.[46] In both cases, the amount of capacity in the market is similar to that postulated by the *Reference Case* addition schedule, resulting in capacity price forecasts for both wind cases that are about the same as the *Reference Case*. Because there is slightly more capacity in the *Onshore Wind Case*, clearing prices are insignificantly lower than those in the *Offshore Wind Case*. The excess is less than 100 MW. The price difference is therefore insignificant.

In both cases, the wind additions are outside SWMAAC. SWMAAC therefore has identical clearing prices in the early years of the forecast, the period when the SWMAAC price diverges from the RTO price.

Those forecasts are shown below in Figure 29 and Figure 30.

[46] Supply bids into RPM on a UCAP, rather than ICAP, basis. Therefore, wind and other intermittent resource compete directly with conventional generation (and demand-side) resources after adjustment for EFORd.

Figure 29. Long-Term UCAP Prices – *Onshore Wind Case*

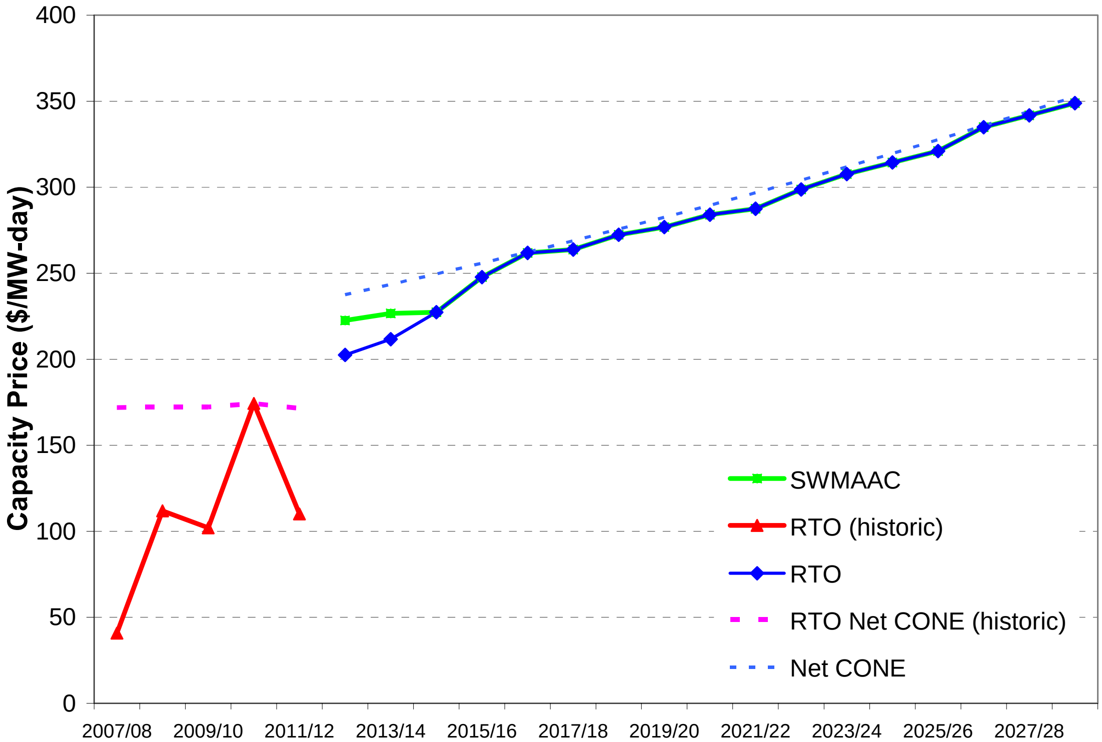
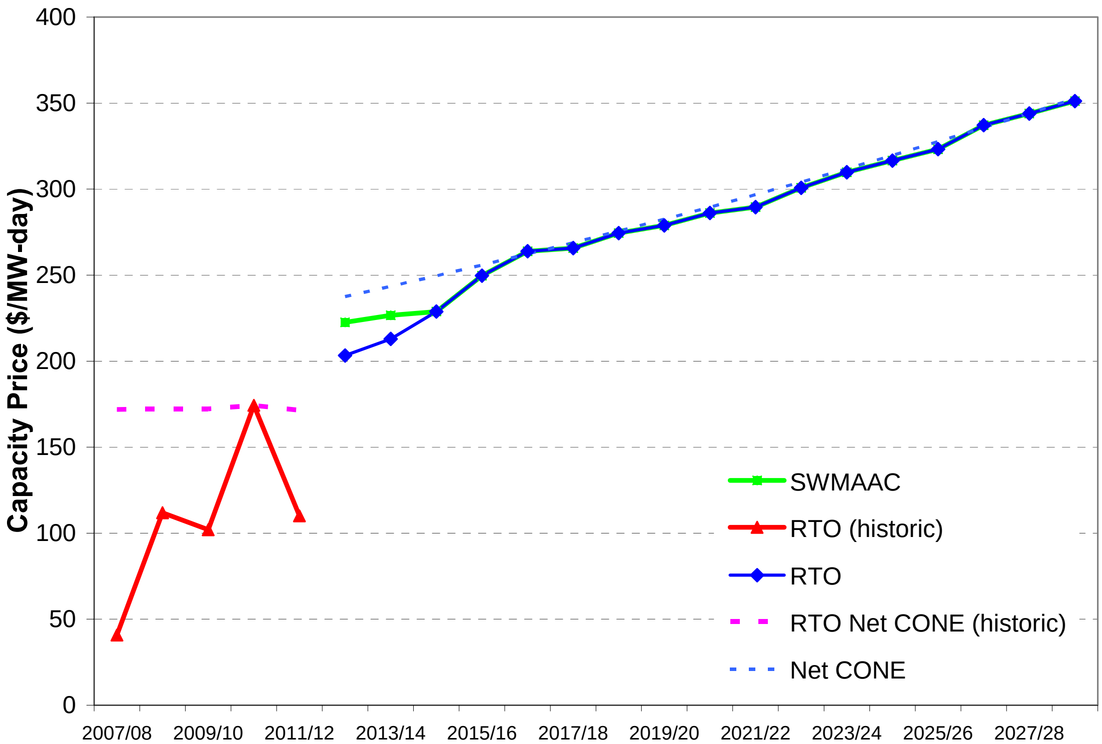
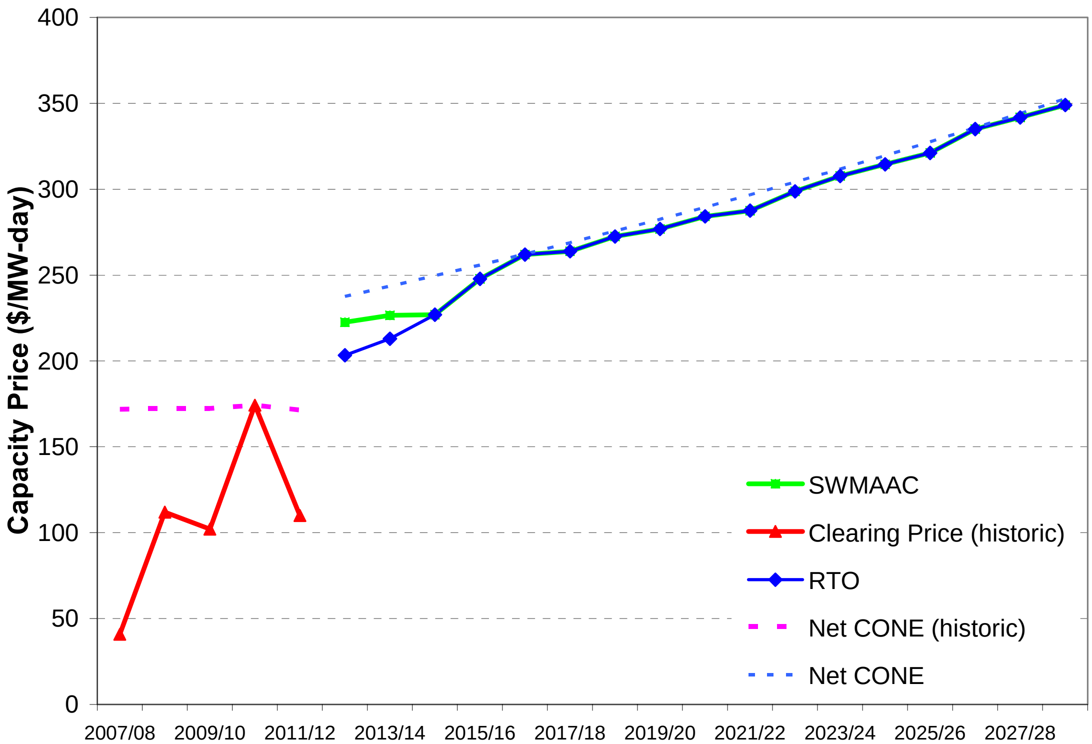


Figure 30. Long-Term UCAP Prices – *Offshore Wind Case*



LAI also ran each of the cases under the assumption that TrAIL would not be commercialized during the study horizon. Energy prices are only slightly affected. Prior to the 2014/15 auction, prices are unaffected since all cases assume that TrAIL is delayed. Without TrAIL, we assume that SWMAAC and EMAAC would need to add extra generation to meet reliability needs. In SWMAAC, a GT with total capacity around 240 MW is postulated. As such, capacity clearing prices in the scenarios without TrAIL are similar to those that include TrAIL in 2014. The *Reference Case* capacity price forecast without TrAIL is shown in Figure 31, below.

Figure 31. Long-Term UCAP Prices – *Reference Case, No TrAIL Scenario*



As with the *Reference Case*, the capacity price forecasts for the scenarios with and without TrAIL for each case are about the same. Therefore no graphic illustration of the price results need be presented here.

2.3. Ancillary Services

Ancillary services refer to sundry payments to generators or demand resources administered by PJM that are required to maintain bulk power security. FERC defined six ancillary services in Order No. 888: (1) scheduling, system control and dispatch, (2) reactive supply and voltage control from generation services, (3) regulation and frequency response services, (4) energy imbalance service, (5) synchronized operating reserves, and (6) supplemental operating reserves. PJM currently provides regulation, energy imbalance, synchronized reserve services, and supplemental operating reserves through market-based mechanisms. PJM provides energy imbalance service through the RTM and the remaining ancillary services on a cost of service basis. Ancillary services do not include energy or capacity payments, or payments arising under financial transmission rights, auction revenue rights, or transmission service, both network and point-to-point.

Historically, charges to load for ancillary services have been about 5% of the cost of energy. Payments to generators for regulation and operating reserves vary widely depending on the operating characteristics of the particular generator. In this study, we have relied on historical data in PJM's SOM Reports, as well as other commercial information available to LAI, in order to develop appropriate adders to apply to generation type and load.

2.4. Wholesale Financial Model

2.4.1. <u>Wholesale Generation Service Cost</u>

We have prepared a financial model that integrates energy price results from MarketSym and the UCAP price forecast from our RPM model. An objective function for each case has been derived representing the forecasted PV cost to supply power to each Maryland IOU over the study horizon. The total PV cost differential between the *Reference Case* and each alternative case represents EVA. EVA can be positive or negative, depending on whether the alternative case is more or less costly than the total cost to serve load under the *Reference Case*. Hence, EVA can be interpreted as the potential savings or increased cost relative to the *Reference Case* associated with a specific course of action or set of events. In each year, we have calculated the MTM cost of each IOU's forecasted load by multiplying the hourly load for each customer class by the appropriate hourly LMP. The products are aggregated by IOU, customer class, and year. We have calculated the cost of capacity to serve load, multiplying the contribution to peak load for each customer class by IOU by the capacity price each year. We have differentiated capacity prices by LDA when applicable.

A number of alternative cases are centered on long-term PPAs or IOU ownership. When either the PPA structure or IOU ownership is tested, we have incorporated net energy revenue from MarketSym for each generating unit by year. Net energy revenue is defined as energy revenue at the relevant LMP and ancillary service revenue for each hour, less total variable O&M costs by unit. Total variable O&M costs reflect the sum of total fuel costs, including start-up costs, as well as non-fuel variable O&M costs. Total variable O&M cost is quantified for each hour during the course of the year and then aggregated. We also estimated capacity revenues and fixed operating costs for each unit. Unit capital costs have been annuitized using the relevant capital recovery factor for purposes of calculating net benefits or costs. The determination of net benefits allocable to each IOU is based on a *pro rata* allocation to load.

We have performed a similar calculation for each IOU's DSM programs. To simulate the impact of DSM programs, groups of EE&C measures have been treated as virtual generators in order to capture the discernible effect different conservation and load management programs have on the profile of reduced energy load as well as avoided capacity requirements. We allocated the sum of hourly energy savings in each service territory to residential and C&I customers based on the program definitions. We assigned program and participant costs in the same manner. For each case we calculated a total annual cost of load for each IOU, including the market energy and capacity cost and applicable generation contract costs and benefits, plus PJM transmission charges and the costs or benefits of the DSM program. DSM programs and costs are described in Section 5.3.

2.4.2. IOU Costs

The 2006 retail SOS-eligible loads of the four IOUs are used as the basis for assigning costs and benefits to the IOUs and to their respective customer classes. Historical hourly load files were used to generate a typical weekly profile for month by IOU and rate class. The profiles were adjusted by year over the study period. For each simulation case, load has been marked-to-market by applying the simulated hourly price to the hourly load and then integrating the price-quantity effect over the year. Costs and benefits directly attributable to ratepayer-backed projects – either PPA or utility-owned capacity – are allocated based on energy share to the rate classes of the associated IOU. We note that DSM costs have been allocated to the appropriate rate classes for each group of measures considered.

Figure 32 and Figure 33 show the relative fractions of total energy load and peak load contribution, respectively. The annual energy allocation is referenced to the 2006 loads. The corresponding 2006 energy and peak loads are summarized in Table 8.

Figure 32. Annual Energy Allocation

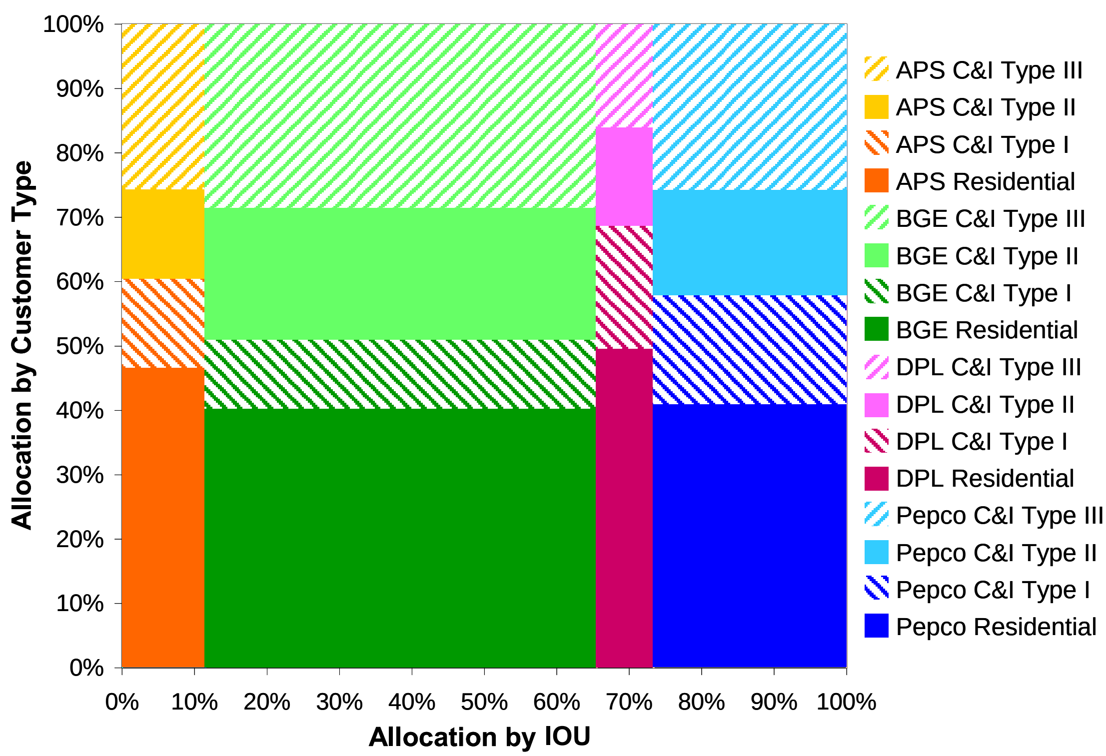


Figure 33. Peak Load Contribution Allocation

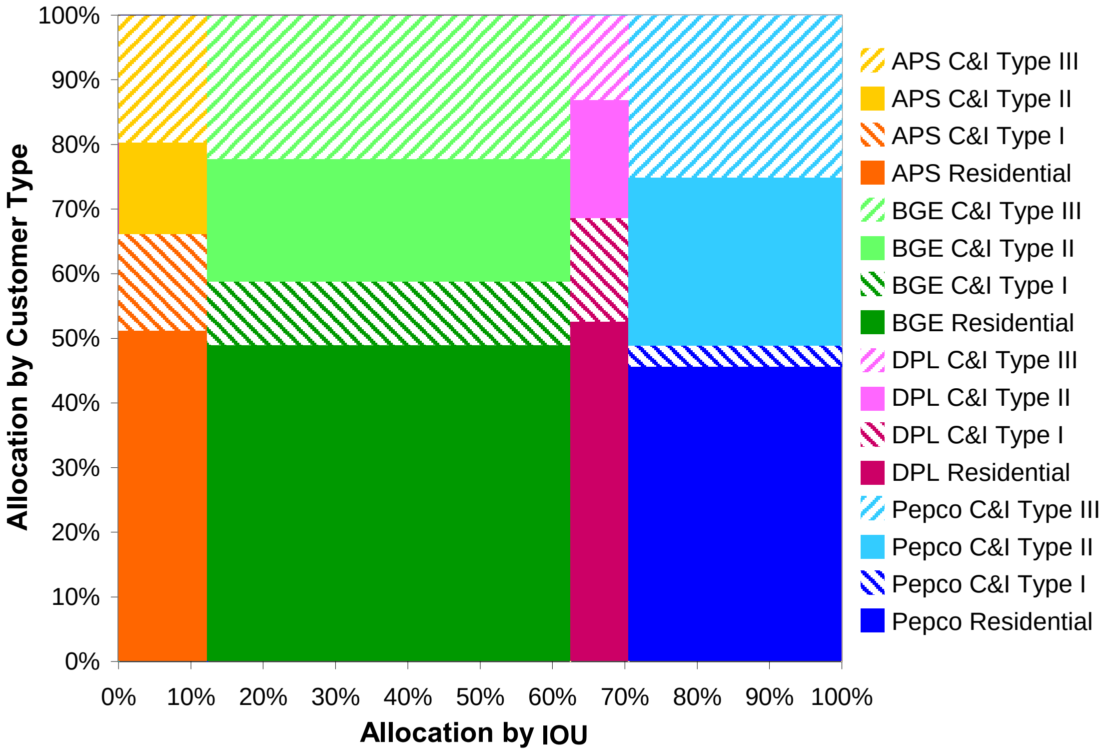


Table 8. 2006 Loads by IOU and SOS Type

	APS	BGE	DPL	Pepco	Total
Base year energy (GWh)					
Residential	3,159	12,817	2,292	6,424	24,692
Type I	946	3,404	887	643	5,881
Type II	952	6,565	711	4,600	12,828
Type III (Hourly)	1,746	9,119	746	4,057	15,668
Total	6,803	31,906	4,636	15,724	59,069
Peak load contribution (MW)					
Residential	741.4	2,897.4	498.8	1,584.2	5,722
Type I	216.7	581.5	185.1	113.9	1,097
Type II	208.4	1,135.0	140.8	908.5	2,393
Type III (Hourly)	285.5	1,320.3	125.1	875.3	2,606
Total	1,452.0	5,934.2	949.8	3,481.9	11,818

2.5. Financial Assumptions

2.5.1. <u>Financial Variables</u>

We have structured the financial analysis with the following variables that are independent of plant ownership structure. The key inflation assumption is an underlying long-term Consumer

Price Index for all Urban Consumers (CPI-U) inflation rate of 2.5%. This value is consistent with that used in the Interim Report. We have relied primarily on the most recent quarterly Survey of Professional Forecasters conducted by the Federal Reserve Bank of Philadelphia.[47] In that survey, about fifty forecasters estimated an average CPI-U inflation rate of 2.5% over the next ten years. For purposes of deriving EVA, we have assumed a discount rate of 8.0%, consistent with the discount rate used in the Interim Report. Insofar as the resource options and ownership regimes examined in this study are long-term initiatives, we have not adjusted the cost of capital or discount rate applicable to ratepayer benefits in light of the recent credit implosion.

PV calculations are referenced to 2008 unless otherwise noted. The earliest commercial operating date to construct a new GT or CC plant is assumed to be 2012. The depreciation tax lives for those and renewable energy plants are provided below, along with our assumed combined federal and state income tax rates.[48]

Table 9. Financial Variables

General inflation		2.5%
Ratepayer discount rate		8.0%
Economic life of plant		30 yrs
Tax life (MACRS)	– GT	10 yrs
	– CC	15 yrs
	– Wind	5 yrs
	– Solar	5 yrs
Federal income tax rate		35%
State income tax rate		8.25%
Effective income tax rate		40.36%

2.5.2. Current Financial Environment

In establishing financial structures and costs of capital for purposes of the Final Report, LAI recognizes the unprecedented deterioration in credit fundamentals and liquidity, thus complicating the effort to quantify the comparative merit of different ownership regimes in relation to merchant based price signals under the RPM. Many banks and other financial services firms have seen their market capitalizations erode overnight. In some instances, major commercial intermediaries and energy firms have been forced to merge or be acquired at fire-sale prices. In the last three months there has been a proliferation of bankruptcies, with more contemplated in the year ahead. The U.S. government took over Fannie Mae, Freddie Mac, and AIG. Lehman Bothers entered bankruptcy (later to be bought by Barclays), JP Morgan bought Bear Stearns and acquired Washington Mutual's assets, Bank of America bought Merrill Lynch, and first Citigroup, then Wells Fargo, purchased the banking operations of Wachovia Bank. By

[47] This quarterly survey was published on August 12, 2008. See http://www.philadelphiafed.org/research-and-data/real-time-center/survey-of-professional-forecasters/.

[48] We note that our effective income tax rate is consistent with BGE's effective tax rate of 40.7% in 2007, 37.5% in 2006, and 38.8% in 2005.

the end of November, the Government announced plans to bail out Citigroup. Goldman Sachs received a $5 billion investment from Berkshire Hathaway, while Goldman and Morgan Stanley filed with the Federal Reserve to become bank holding companies. Most recently, nine of the nation's largest banks and financial institutions have been forced to accept U.S. government equity investments to rebuild capital balances. Central banks in Europe and Asia have also provided capital infusions into their respective commercial banks. Virtually no corner of the global, interconnected banking system has been untouched.

Under the *Rate Base Regulation Case*, we have examined the financial benefits associated with the creation of a state-run power Authority similar to the New York Power Authority (NYPA) or Long Island Power Authority (LIPA). A newly formed power Authority in Maryland might own and operate assets in Maryland presently owned by Mirant. Given the state of the global credit markets in November 2008, we must seriously question whether the capital markets would have the requisite appetite to support the issuance of long-term debt to enable an Authority to own and operate generation assets of the magnitude addressed in the *Rate Base Regulation Case*. Again, in performing this analysis we have postulated the return to normal credit conditions in the capital markets. Under the *Rate Base Regulation Case* we make the simplifying assumption that market liquidity is restored and that either the assets are transferred virtually overnight to Pepco or the Authority on January 1, 2009.

As normalcy in the credit markets is ultimately restored, Maryland might be able to issue debt obligations in one form or another to capitalize an Authority. It is important to note, however, that the size of the debt issuance associated with acquisition of the Mirant fleet in Maryland under FMV would likely be several times greater than the current outstanding indebtedness of the MdTA. While the demise of Bear Stearns followed by Lehman's bankruptcy has eliminated both firms as a market-making entities and counterparties in the municipal bond market, LAI believes that the municipal bond market will adjust to these changes. Issuance of debt instruments to enable the creation of an Authority will necessitate a return to more typical conditions in the capital markets. Overnight lending, margin funding, and other short-term rates have soared as of late October 2008. Firms with lower-quality credit ratings have also been hard hit. The long-term financial markets have been less affected, but the broader effects of the global economic slowdown and the banks' diminished lending base are felt throughout the power industry, in particular, the pricing of credit, parent guarantees, and risk management products of relevance in supplier pricing of SOS. Consequently, the costs of debt and equity for all borrowers have increased, especially for lower-quality investments.

Given the 30-year study horizon in this report, we have made the simplifying assumption that the capital markets will trend toward normalcy in the next two years, reflecting a more typical and stable long-term financial environment characteristic of the capital markets prior to the sub-prime meltdown.

2.5.3. Financial Structure and Costs

We consider four plant ownership arrangements, each with its own debt-equity structure, risk profiles, costs of capital, and other financial parameters. The four financial structures are:

- Merchant generator without long-term PPA or market hedge,

- Independent merchant generator that has a long-term PPA with Maryland IOUs,
- IOU that re-enters the generation business, and
- A Maryland Power Authority, established by the Legislature.

Table 10 summarizes our assumptions for the four financial structures.

Table 10. Financing Assumptions

	Merchant	Merchant with Long-Term PPA	IOU	Authority
Debt-to-Equity	50/50	75/25	50/50	100%
Debt Interest Rate	7.5%	7.2%	7.0%	6.1%
Debt Term	20 yrs	20 yrs	30 yrs	30 yrs
Equity Hurdle Rate	12.5%	14.6%	10.5%	n/a

<u>Merchant Generator Financing</u> – The first financial structure is merchant generator financing, in which merchant generator owners do not have long-term PPAs or market hedges, but instead sell energy, capacity, and ancillary services into the respective PJM markets or enter into short-term (less than one year) hedges. PJM, NYISO, and ISO-NE adopted virtually identical financial assumptions for such merchant generator owners when they were establishing market capacity mechanisms two to three years ago.[49] In each ISO, it was assumed that the market capacity mechanisms would be relatively stable because capacity additions would be "rational" in quantity, type, and timing. Without PPAs or similar hedges against market price movements, it was generally assumed that project financing was not realistic – high debt-to-equity ratios would not be possible. The first three columns of Table 11 summarize the original merchant generator financing assumptions that were used in those capacity pricing mechanisms. [50]

Table 11. ISO Merchant Generator Financing Assumptions

	Original Values			Proposed
	NYISO	PJM	ISO-NE	PJM
Inflation Rate	2.5%	2.5%	2.5%	2.5%
Debt-to-Equity	50/50	50/50	50/50	50/50
Debt Interest Rate	7.0%	7.0%	7.0%	7.0%
Debt Term	20 yrs	20 yrs	20 yrs	20 yrs
Equity Hurdle Rate	12.0%	12.0%	12.0%	12.0%

As discussed earlier, PJM is currently considering re-setting Gross CONE. The *2008 Update of Cost of New Entry – Combustion Turbine Power Plant*, prepared by Power Project Management for PJM and published on July 15, 2008, includes an updated set of merchant generator financing

[49] ISO-NE financing assumptions were used in the original Locational Installed Capacity model, which was superceded by the Forward Capacity Market.

[50] Equity rates are usually provided on an after-tax basis. Debt rates are on a pre-tax basis.

assumptions.[51] The report proposed a debt interest rate of 7.0% "consistent with the financial structure of a creditworthy integrated electric utility company or [independent power producer]…mortgage style loan." We consider this proposed interest rate of 7.0% too low. As of mid-October 2008, the average corporate 20-year yield was about 6.3% for AA debt and 6.9% for A debt, considerably higher than recent yields. Yields for lower-rated debt were not provided for a specific 20-year term, but borrowers below investment grade are paying very high rates in the current debt market.[52] LAI does not expect these high debt rates to persist. Again, we postulate that debt markets will return to normalcy at some point in time. However, we do not believe that a merchant generator can be viewed as having a similar risk profile as an IOU that would permit such a low debt interest rate. Therefore, for the purpose of this analysis, we assume a debt rate of 7.5%, appropriate for generation companies at or close to investment grade taking on merchant project risks.[53]

The proposed PJM equity rate for re-setting Gross CONE was 12.0%. We assume a higher return-on-equity (ROE) of 12.5% given the volatility and uncertainty in the capacity market mechanisms that are the primary source for the return of and on equity capital. There have been a number of significant changes over the past months in PJM and other northeast capacity markets. For example, FERC has implemented capacity market power mitigation measures in New York City that have reduced capacity values by more than 50%. The Connecticut Department of Public Utility Control (DPUC) has authorized IOUs under its jurisdiction to enter into long-term contracts under traditional cost of service regulation for new peaking generation plants. PJM has proposed increasing Gross CONE starting in the 2012/13 BRA. These regulatory developments represent new potential risks and rewards under the sundry capacity market mechanisms implemented by PJM and other ISOs.

<u>Merchant Generator With Long-Term PPA</u> – The second financial structure is a merchant generator, contracted to provide unit capacity, dispatchable energy, and associated ancillary products to an IOU under a 20-year PPA with an optional 10-year extension term that would be unilaterally exercisable by the IOU. In this case, the PPA will be considered iron-clad, without any reg-out provision or price re-opener to account for changes in market prices, technology progress, or state or federal regulation. The merchant generator would be responsible for plant construction and performance while the IOU would assume all market risks, including fuel price risk, either through a tolling agreement or a PPA with orderly pass-through of all prudently incurred fuel costs. Under this scenario, developers retain development and performance risks, but would be willing to accept a lower ROE than in a merchant financing structure in exchange for the virtual elimination of market risks.

As states have considered encouraging new generation investment by allowing IOUs to enter into long-term PPAs, some state commissions have charted a course in the direction of

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[51] We note that the report for PJM lists a debt interest rate of 8.25% on page 3 and a different rate of 7.0% on page 14. We have confirmed with Power Project Management that the correct debt interest rate is 7.0%.

[52] Source: ValuBond October 16, 2008.

[53] Many independent generation companies are recovering from financial difficulties and have credit ratings in the B or BB range. We consider them to be special case companies that are more focused on managing their portfolios than on developing new projects.

conventional cost of service regulation. In 2008 the Connecticut DPUC set a benchmark ROE for third party generation under long-term PPA with United Illuminating (UI) and Connecticut Light & Power Co., the state's two IOUs.[54] The DPUC required utilities under its jurisdiction to enter into long-term contracts for new generation. One of the winning bidders is an affiliate of UI, the IOU serving southwest Connecticut.[55] The PPAs incorporate pricing provisions that treat the cost of equity and debt under conventional cost-of-service ratemaking. The bidders offered ROEs ranging from 9.75% to 10.75% based on debt / equity ratios that varied between 60/40 and 50/50 at the project level for rate-making purposes. The average ROE was 10.4% at a 56/44 debt / equity ratio. We recognize that these merchant generators with iron-clad PPAs would likely be able to leverage their project equity with an additional layer of debt at the parent company level, so that an equivalent ROE at an effective 75/25 debt / equity ratio would be 14.6%.[56]

The cost of debt for a merchant generator with a long-term PPA would be lower than for a merchant generator owner at a particular debt / equity ratio due to the fixed revenue certainty associated with a long-term PPA. We also recognize that the increased leverage of 75% debt for a merchant generator with a long-term PPA would entail a higher interest rate than at the 50% debt level assumed for the merchant generator owner. Therefore we have assumed a 7.2% cost of debt, based on (i) the BBB investment grade credit ratings of the counterparty Maryland IOUs, (ii) assumed explicit Commission approval that assures the IOUs of cost recovery, and (iii) a small margin for plant operating and other risks that cannot otherwise be mitigated.

Investor-Owned Utility – The third financial structure is an IOU, in which APS, BGE, DPL and/or Pepco would own and operate a power plant. Costs would be recovered (after any energy, capacity, and ancillary service revenues from the respective PJM markets) from ratepayers through traditional rate-base treatment of the plant over a 30-year economic life.

Table 12. Maryland IOU Financial Factors

	BGE	**Pepco**	**Potomac Edison**	**DPL**
Allowed ROE	11.0%	10.0%	n/a	10.0%
Credit Rating	BBB/Baa2	BBB/Baa2	BBB-/Baa3	BBB/Baa2

The Maryland IOUs currently have allowed ROEs as shown in Table 12. In Order No. 81518, issued July 19, 2007, in Case No. 9093, the Commission established a 10.0% ROE for DPL. The Commission considered testimony from witnesses for DPL, the Office of People's Counsel (OPC), and Staff, who relied on various techniques in proposing ROE values. The witnesses relied on the Capital Asset Pricing Model, Discounted Cash Flow (DCF), and Risk Premium techniques to calculate ROEs. According to the Commission, none of the witnesses addressed the issue of whether IOUs with generation assets are entitled to higher ROEs compared to IOUs that are T&D companies. In this case, the Commission concluded that DPL's ROE should be

[54] Docket No. 07-08-24.

[55] GenConn is a 50:50 joint venture comprised of NRG and UI. GenConn has entered into long-term PPAs covering the sale of capacity and energy from new quick-start generation to be added at the Devon and Middletown stations.

[56] We stress that this ROE, when adjusted to an equivalent debt / equity ratio, would be lower than for a merchant generator owner.

10.5%, and reduced it to 10.0% with approval of DPL's proposed Bill Stabilization Adjustment (BSA) that reduces risks, disengages DPL's revenue from the sale of electricity, and smoothes out billing variations explained by fluctuations in degree days. In a parallel Order No. 81517 issued on the same day in Case No. 9092, the Commission established a 10.0% ROE for Pepco as well, also citing the BSA mechanism that will reduces risk and improves cost recovery.

The last rate decision for BGE was Order No. 80460, issued on December 21, 2005, in Case No. 9036. In that Order the Commission noted "…the Company's good performance as an intangible" and decided on an ROE of 11.0% "…at the upper end of the range of acceptable returns." We note that this rate decision did not consider the impact of BSA and its impact of a 0.5% ROE decrease in later Orders. The last rate decision for Potomac Edison was Order No. 70371, issued on February 24, 1993, in Case No. 8469. The Commission approved an 11.9% ROE, but we have ignored that value for the purpose of this assignment because it occurred too long ago.

The Commission's authorized ROEs, except for that of Pepco, reflect the business risks related to T&D operations. They do not include a risk premium associated with ownership of generation. There has been considerable discussion about the risks of owning and operating generation assets versus T&D assets, and whether those additional risks warrant a higher ROE. On one hand, more things can go wrong with the construction and operation of power plants – construction delays, performance shortfalls, exposure to volatile fuel costs and penalties levied by pipeline companies or local distribution companies, equipment problems, and catastrophic failures, among other things. On the other hand, IOUs that can demonstrate prudent actions are typically granted full recovery in case of a negative event. Also, construction and operational risks can usually be actively managed. Construction risks can be mitigated through fixed-price turnkey construction contracts with incentive provisions for schedule and performance. Operating risks can be mitigated through fuel adjustment mechanisms, long-term service agreements, boiler (equipment) insurance, and business interruption insurance.

In summary, we believe that the most recent Orders approving a 10.0% ROE for DPL and Pepco are the best indicators for the IOU ownership structure. The ROE for BGE would be 10.5% after consideration of the BSA mechanism. In our view, Potomac Edison's ROE was approved too long ago to be relevant in the present context. Therefore we assume an incremental ROE of 10.5% for generating assets that may be incorporated in a Maryland IOU's rate base, which reflects a 10.0% base ROE and the inclusion of a 50-basis-point premium for potential generation risks compared to the IOU wires business. Relative to T&D operations, LAI and Kaye Scholer believe that the responsibility of generation ownership and operations may be riskier than the wires business, thereby warranting the inclusion of a small, but significant risk premium in the establishment of authorized ROE.

The Maryland IOUs have issuer and senior unsecured long-term debt credit ratings that average BBB, the lowest investment-grade category. Current long-term rates for BBB-rated corporate borrowers are about 9.7%, very high by historical standards.[57] Over the past year, BBB

[57] Source: Lehman Brothers U.S. Corporate Bond Index.

corporate rates have been as low as 5.85% and as high as 9.81%. Despite the present credit crisis, we anticipate an eventual return to equilibrium in the capital markets. We have assumed that long-term rates for BBB borrowers will be significantly reduced relative to the cost of capital in November 2008. Assuming a return to normalcy, we have assumed that the long-term debt cost rate for BBB IOU borrowers will be 7.0%.

State Power Authority – The fourth financial structure is the creation of an Authority. We assume that a newly formed Authority would have the ability to issue long-term revenue bonds. We also assume that issuance of revenue bonds would not require a pledge or any collateral from the State of Maryland or otherwise tie up the State's bondable capacity. The postulated issuance of long-term revenue bonds would certainly be exempt from state income taxation, but would not be exempt from federal income taxes. The benefits of Authority ownership of generation assets particularly relate to capital structure and cost of capital. An Authority would also limit Maryland's IOUs to the wires business rather than recreate the vertically integrated utility model. Like other power authorities, a newly formed Authority in Maryland could also pursue socially-worthwhile projects, including new renewables and certain DSM projects that might not otherwise be developed.

Interest payments from Authority revenue bonds would probably be taxable for federal income tax purposes unless the bond proceeds (i) were used to provide a clear public benefit or (ii) met strict Internal Revenue Service (IRS) definitions for qualified private purposes. The public benefit test would be satisfied if, for example, the energy, capacity, and ancillary service products from Authority-owned generation assets were only or predominantly sold to municipal utilities, state agencies, or other public entities. The public benefit test would not be satisfied if the Authority sold power to the IOUs for resale. This is because the IOUs are for-profit entities. Alternatively, interest on Authority revenue bonds would avoid federal income taxation if the bond proceeds were used to meet qualified private purposes established for specific activities that included local furnishing of electricity or gas.[58] LAI understands that the IRS has greatly restricted the application of this "local furnishing" provision over the past few years, so that avenue is almost certainly not available to a new Authority. Thus LAI has assumed that the interest from debt issued by an Authority would only be exempt from state and local income taxes.

Under the *Rate Base Regulation Case*, we assume the Authority would be able to fully fund the purchase of the generation assets located in the Maryland portion of the Pepco service territory through the issuance of debt. Rating agencies would evaluate the ability of such an Authority to meet ongoing operating expenses, necessary capital expenditures (CapEx), and debt principal and interest payments under normal and abnormal circumstances. Assuming a return to "normalcy" in the credit markets and debt issuance in the next two years, it is likely that the rating agencies would determine the ability of the Authority to meet its debt service obligations under a set of plausible "downside" assumptions about the economy and electricity demand,

[58] IRS, Subtitle A, Chapter 1, Subchapter B, Part IV, Subpart A: Private Activity Bonds. While there are other qualified private purposes that can be applied to generating assets, such as solid waste disposal and environmental enhancements of hydroelectric facilities, we do not believe that they would apply in any significant amount in the current context.

among other things. Rating agencies would thus look for a transparent and timely process to set the rates at which power is sold to the IOUs, and an equity-type cushion as part of the Authority's capital structure. We assume that the rates at which the Authority sells power to the IOUs would be set by an independent board of trustees with input from the IOUs. While the Commission has the authority to set retail rates, we also assume that the rates at which the Authority sells power to the IOUs would not be subject to Commission approval.[59] The Authority's equity cushion could be funded as part of the initial debt issuance and then be maintained by setting rates slightly above actual expenses.[60] The current credit rating of GO bonds issued by the State of Maryland is AAA/Aaa. The maximum term of those GO bonds is 15 years. However, the Authority would not have taxing powers, nor do we expect that its debt would have the full faith and credit of the State. In fact, the Authority would have its own revenues (power sales to the IOUs and certain PJM product revenues), and we see no reason that the State would co-mingle the Authority's power revenues with its own tax revenues. Therefore, a more appropriate benchmark is the MdTA, the largest state government issuer of revenue bonds.

The MdTA, an independent agency within the Department of Transportation, is responsible for managing and operating the State's toll facilities. As of June 30, 2007, the MdTA had outstanding debt of $1.06 billion, principally comprised of revenue bonds. According to the June 30, 2007, Independent Auditor's Report, the MdTA had a credit rating of AA-/Aa3, and the longest maturity bond was 30 years, *i.e.*, a 2034 maturity for the Series 2004 Revenue Bond issuance.[61] Therefore we assume that an Authority would also have a credit rating in the AA/Aa range, and be able to issue revenue bonds with maturities as long as 30 years.[62] We also assume that the average maturity for Authority bonds would be about the eighteenth year, the mid-point maturity for the MdTA Series 2004 Revenue Bonds.

The MdTA's Series 2007 Revenue Bonds were the MdTA's most recent issuance, dated as of June 30, 2007. The serial bonds had maturities ranging from March 2008 to March 2019 and coupon rates between 3.75% and 5.0%; most of the long-term maturities had coupons at 5.0%. We do not know how the bonds were priced, and thus what yield was offered to investors. It is difficult to obtain current prices and yields without being an issuer or active trader. Hence, we did not obtain these data for the MdTA Series 2007 Revenue Bonds.

We were able to obtain the current yield for one of the MdTA's Series 2004 Revenue Bonds with a 4.60% coupon maturing on July 1, 2020. As of October 22, 2008, that bond was priced at 94.537 to yield 5.23%. During the first half of 2008, this bond was priced in the 101.790-104.680 range, indicating a lower yield of approximately 4.25%, a drop of 1.0%. However,

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[59] The wholesale and retail rates set by NYPA and LIPA are not subject to New York Public Service Commission (NYPSC) approval. Likewise, the rates set by the Tennessee Valley Authority, Salt River Project and the Bonneville Power Administration are not subject to state commission jurisdiction.

[60] Definition of the financial structure is beyond the scope of this assignment. LAI has made the simplifying assumption that the Authority would issue bonds equal to the FMV of the Mirant assets in Maryland.

[61] The June 2008 Independent Auditor's Report was not completed as of mid-October 2008.

[62] The term of the debt instrument would not exceed the economic life of the generation assets acquired by the Authority under condemnation.

interest payments on these MdTA bonds are not subject to federal income taxes, and therefore are priced lower than bonds issued by a Maryland Authority. Thus the MdTA bond yields are not an ideal basis to estimate the cost of Authority bonds.

A second reference point for the cost of Authority debt is the yield for AA-rated municipal bonds. Like the MdTA bonds, municipal bond interest payments are generally not subject to federal income taxation, and may not be subject to state or local income taxation. Our data source, ValuBond, provides municipal yields for different credit ratings and maturity dates, but does not extend beyond 20-year maturities. We have averaged these data in Table 13 to minimize day-to-day financial market fluctuations. We note that the current yield of 5.23% for the MdTA Series 2004 Revenue Bond maturing in 2020 (twelve years from now) is consistent with the average municipal bond yields in this table. The interpolated yield for our assumed 18-year average maturity is about 5.85%.

Table 13. Municipal Bond Yields
(Not subject to federal income tax)

	5 Year	**10 Year**	**20 Year**
Oct 14	3.53 %	4.48 %	6.06 %
Oct 15	3.66 %	4.51 %	6.15 %
Oct 16	3.82 %	4.88 %	6.21 %
Oct 20	3.84 %	4.72 %	6.13 %
Oct 21	3.52 %	4.90 %	6.07 %
Average	3.67 %	4.70 %	6.12 %

A third point of reference is the current yield for revenue bonds issued by NYPA. NYPA is a corporate municipal subdivision of the State of New York that generates, transmits, and sells electricity, primarily at the wholesale level. NYPA's most recent debt issuance was Series 2007 Revenue Bonds in the amount of $602.4 million, issued on October 11, 2007. A portion of these bonds, Series 2007 B, were subject to federal income tax, and thus provide the best basis for estimating the cost of Authority debt. According to the Prospectus, the Series B bonds were priced to yield an additional 1.65% compared to the federally tax-exempt bonds for equal maturities of 2014-2017 at the time they were issued. In the current market environment that spread between NYPA taxable and tax-exempt bonds is about 0.5%. Therefore we believe that a reasonable spread is about 1.25%, between the two NYPA spread values.

In summary, we estimate the average cost of long-term Authority debt at 6.1% as follows:

- First, the current average municipal bond yield of 5.85% for an 18-year maturity is a good starting point, and is consistent with the current yield for MdTA Series 2004 Revenue Bonds.

- Second, we believe that current yields will soften by about 1.0%, consistent with MdTA Series 2004 Revenue Bonds pricing earlier in 2008.

- Third, we anticipate that Maryland Authority bonds would have to be priced 1.25% higher to compensate for federal income taxes.[63]

We note that our estimated revenue bond costs ignore the practical question of the market's appetite for a large bond issuance from a new state entity. We note that the MdTA's total indebtedness was $1.07 billion as of December 31, 2007, a relatively small amount compared to the estimated Authority issuance of $6 to $7 billion to acquire the Mirant assets at FMV.[64] A revenue bond issuance of this size also exceeds the State's total of $5.36 billion of GO bonds outstanding as of December 31, 2007, which thus would raises questions of how a new issuance of this magnitude would affect Maryland's enviable credit rating. The likely market for Authority revenue bonds is Maryland residents due to the exemption from state and local income taxes. Maryland's sterling credit history and diverse economy may facilitate broad-based institutional bond sales as well.

In this report, we have not attempted to calibrate the state's appetite for a large bond issuance in the present context. Similarly, we did not quantify any adverse bond pricing impacts associated with increased financing costs on other state GO or revenue bond issuances following a large offering from a newly formed Authority.

2.5.4. Plant Operating Expenses

In either the merchant generator ownership or IOU ownership case, the IOU would be ultimately responsible for procuring fuel supply, transportation, and delivery. While either the generator or the IOU might undertake to provide O&M services on its own account, they equally might outsource those services to an established plant operator. Hence, we assume that there is no significant difference in operating costs or risks during the first 20 years. Production simulations for both the PPA and utility-ownership cases are based on identical heat rates, fuel costs, emission allowance costs, and variable O&M expenses over the study period, including the extension to a 30-year plant economic life. Furthermore, fixed O&M expenses passed through to ratepayers are assumed to be the same for both the PPA and utility-ownership cases. Under conditions where a 10-year extension option is exercised, fixed O&M expenses are the same as for the ownership case as well. Assumptions regarding levels of fixed and variable O&M expenses and fuel efficiency for different generation technologies are described in later sections of this report.

2.5.5. Annual Capital Charges

Differences between merchant generator and IOU ownership have been limited to those associated with the timing and magnitude of capital recovery over the first 20 years of economic life. During the remaining 10 years of economic life, we estimate ratepayer costs with and

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[63] NYPA taxable bonds with a 20-year maturity are currently yielding about 5.95%. These bonds generally have FSIA or other municipal bond insurance, and thus benefit from a higher AAA rating. This yield is consistent with our 6.1% estimate for Authority revenue bonds that would have the same AA-/Aa3 rating as the MdTA, and thus have a slightly higher cost.

[64] See Section 8 for the derivation of FMV for the Mirant assets.

without a PPA extension and compare them to the ongoing costs of IOU ownership. Under certain scenarios the extension option may be exercised, others not. If the extension option is not exercised, the plant is assumed to remain operational for another 10 years under merchant conditions, *i.e.*, capacity sales under the RPM and energy margins based on DAM prices. If the IOU exercises the option, the fixed payments under the PPA consist of a residual capital recovery charge based on a percentage of original capitalization, plus the same fixed O&M expenses as would be incurred under IOU ownership.[65] Annual revenue requirements have been adjusted to account for terminal value. Under merchant generator ownership, the same asset terminal value has been considered in setting annual capacity payments under the 20-year term and under the 10-year term option. Under both ownership forms, an allowance for upgrade / refurbishment at year 21 of 10% of the original CC capital cost has been assumed. Under merchant generator ownership, this cost has not been included in the determination of fixed PPA payments for the first 20 years, but has been included in the back ten years when the value of the option is considered. The same cost appears as an increase in rate base under the IOU ownership format.

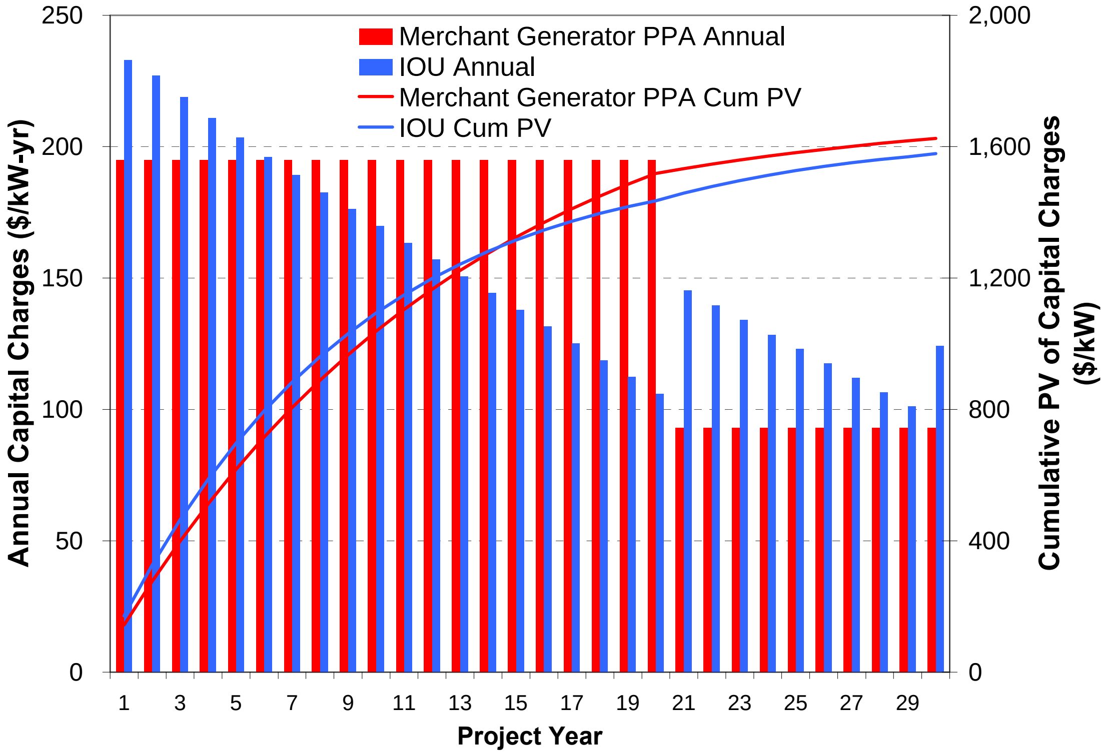
The capital costs associated with IOU ownership versus merchant generator ownership may significantly differ. Although LAI believes that the capital cost associated with merchant generator ownership will be higher – at least at the outset – the ultimate impact on retail customers associated with two different ownership regimes may be about the same. This is because the merchant generator would be expected to structure, and, possibly, execute a "bankable" Engineering-Procurement-Construction (EPC) contract prior to executing the long-term PPA. To account for uncertainty about the actual all-in construction costs as opposed to what is expected, the merchant generator would be likely to include a significant margin to account for allowance for indeterminants (AFI). In LAI's experience, the AFI can be 5% to 15% of the total "hard" cost of building the new generation plant, sometimes higher based on site specific cost factors and technology considerations. In addition, the merchant generator may include another contingency factor to account for sundry risks.

Failure to incorporate AFI and a general contingency factor would likely cause financing costs to be significantly higher. While IOU ownership would also likely require an executed EPC contract, it would be reasonable for the utility to exclude or more lightly include AFI and/or a general contingency factor. This is because the IOU would reasonably expect to pass through to ratepayers all reasonably incurred costs under the Commission's review. Uncertainties at the time the EPC contract is executed associated with timing, gas and electric interconnection costs, labor productivity rates, among other things, would not necessitate a higher project capitalization so long as the IOU has confidence in the Commission's ultimate willingness and objectivity to allow for the return of capital and the return on capital associated with prudently incurred costs.

Based on the assumptions above, fixed merchant generator PPA payments, exclusive of fixed O&M, and IOU capital recovery revenue requirements for a CC plant with a base capital cost of $1,000/kW are shown in Figure 34. The curves in Figure 34 represent the cumulative PV calculated at the ratepayer discount rate.

[65] The fixed charges have been compared against the simulated net energy margin which accrues to the IOU ratepayers under a PPA extension, but to the owner without extension.

Figure 34. Annual Capital-Related Charges



3. EXTERNAL CONDITIONS AND VARIABLES

3.1. Fuel Price Outlook

LAI's production simulation effort requires an updated forecast of various fuels delivered to power plants in PJM and surrounding market areas. The forecast period is 2009 through 2029. LAI's updated fuel price forecast encompasses oil, natural gas, coal, and nuclear fuel. The interaction of global, national and regional fuel market dynamics determines the prices and availability of generation fuels. Thus, key drivers for electricity prices in Maryland and PJM are defined by conditions in markets throughout the world.

In the third quarter of 2008, global fuel markets have shown unprecedented volatility in crude oil and natural gas prices. To a lesser extent, spot coal and uranium prices have softened. The monthly spot price for West Texas Intermediate (WTI), the primary crude oil marker price in the U.S., doubled, from $67/Bbl in June 2007 to $145/Bbl in July 2008, and then dropped below $61/Bbl in early November. The monthly spot price for natural gas at the Henry Hub, the primary North American gas pricing point, followed a similar pattern, rising from $7.35/MMBtu in June 2007 to $12.68/MMBtu in June 2008, and subsequently declining to less than $7.00/MMBtu in November 2008. Similar volatility patterns occurred in the spot market prices for coal and uranium, which peaked in 2008 and 2007, respectively. While prices dropped dramatically throughout September and October, the daily spot markets have been highly volatile, subject to wide price swings over the course of daily trading.

Oil and gas prices have never been more volatile in absolute terms. Prompt month spot prices have whipsawed throughout 2008. Until recently, robust growth in oil demand in India, China, and many of the oil producing countries, oil production disruptions in Nigeria, geopolitical uncertainty in Iran and Iraq, declining oil production in Mexico and Venezuela, and the weak dollar to Euro parity ratio created a market environment that supported extremely high oil prices.[66] The daily spot WTI price peaked around $145/Bbl on July 3rd and then again on July 14th. The rapid price increase set in motion market trends that led to the radical decline in oil prices in September and October. In response to high prices, oil demand in the U.S. and Europe declined, first slowly and then precipitously. The weakening of the global economy attributable to the sub-prime mortgage implosion accelerated the reduction in energy demand throughout the world, including the previously overheated "BRIC" economies, *i.e.*, Brazil, Russia, India and China. In Q3 2008 the dollar has appreciated relative to the Euro and other major currencies, thereby placing downward pressure on benchmark oil prices and other core commodities.

From a long-term historical perspective, oil prices have exhibited a roller coaster path of peaks and valleys on a generally upward trend. Notwithstanding this long-term trend, oil and natural gas prices have pulled back radically from the all-time highs observed in the summer of 2008, resulting in spot and long-term forward prices well below the outlook presented under the *Conventional Wisdom Scenario*. The key to any forecast of fuel prices is to put together scenarios that provide price paths likely to encompass the plausible peaks and valleys in future

[66] Traditionally, global oil transactions are priced in U.S. dollars, if the dollar weakens against other currencies, oil prices denominated in dollars rise.

fuel prices. In LAI's view, it is highly likely that oil prices will continue to demonstrate high volatility over the planning horizon.

Three fuel price forecasts have been formulated as follows:[67]

- The ***Conventional Wisdom Scenario***, which reflects supply and demand trends typical of the last ten years, in particular, tight energy supplies and continued robust demand in India and China;

- The ***Federal Outlook Scenario***, which reflects assumptions consistent with EIA's 2008 International Energy Outlook (IEO2008);[68] and
- The ***Peak Oil Scenario***, which reflects the price impact of flat Organization of Petroleum Exporting Countries (OPEC) production and a 2006 peak in global proved oil reserves.

For the purposes of this forecast, the *Peak Oil Scenario* provides a conceivable, but unlikely upper end trajectory of fuel prices over the forecast horizon. The *Federal Outlook Scenario* provides a plausible and highly likely lower price trajectory of fuel prices over the forecast horizon. The *Conventional Wisdom Scenario* provides a price path in between high and low, based on market intelligence before LAI in the summer of 2008. Figure 35 shows the crude oil price paths for each scenario.

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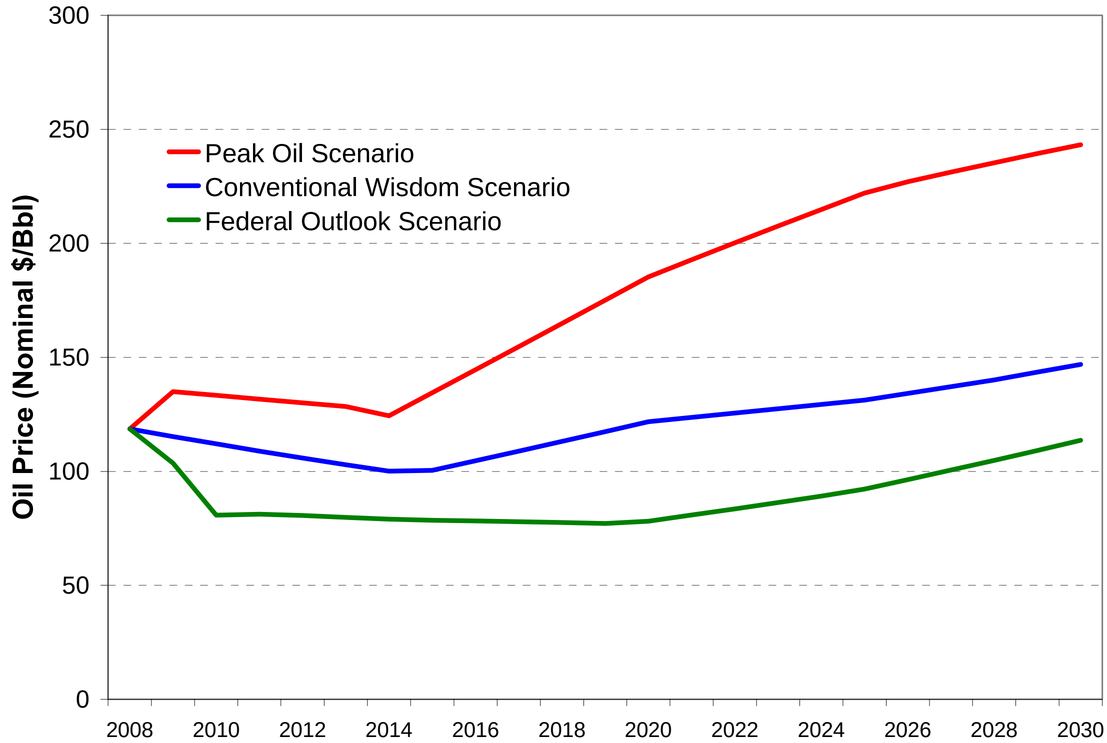
[67] Unless otherwise noted, all fuel prices are expressed in nominal dollars and reflect annual core inflation equal to 2.5%.
[68] U.S. Energy Information Administration, International Energy Outlook 2008, June 2008.

Figure 35. WTI Prices By Scenario



The three price scenarios are driven by fundamentally different assumptions regarding the growth in global oil demand, OPEC production, and global proved oil reserves. The divergence across the long-term fuel price paths provides the "bandwidth" needed for decision support regarding Maryland's resource options.

The alternative fuel price trajectories over the planning horizon are internally consistent and cover the plausible upper range of the bandwidth in future fuel prices in response to uncertain global market dynamics affecting oil and LNG trade, environmental regulations, and energy resource availability. While each of the fuel forecast cases is illustrated as a smooth, long-term trend, in reality, actual fuel prices are certainly volatile around the annual price trends.

Natural gas and coal prices will respond to different extents as the oil price trends vary in each scenario. While natural gas prices are more closely correlated to oil prices, coal prices will be driven more by productivity and environmental considerations than by oil prices. Nuclear fuel prices do not vary in the *Peak Oil* and *Federal Outlook Scenarios*.

3.1.1. *Conventional Wisdom Scenario*

Formulated in July 2008 – when oil prices hit the all-time high – this scenario is based on supply, demand, and price trends that reflect global market participants coping with current market conditions, including the dislocation effects of high oil prices and high volatility.[69] Based on New York Mercantile Exchange futures and other macroeconomic data available to LAI in the summer of 2008, we have assumed that global economic growth recovers from a relatively brief recession and that the credit crunch does not cause permanent dislocation in global oil and North American gas markets. In this scenario, we have captured the recent impact of easing worldwide prices in the medium term, but we forecast steadily rising prices over the long term. This scenario utilizes assumptions regarding energy market fundamentals that can be reasonably anticipated without significant paradigm shifts or major geopolitical surprises. These assumptions include:

- Slowing in global oil demand over the forecast horizon;
- Continued growth in OPEC production throughout the forecast;
- Slow growth in global proved oil reserves until 2025;
- Growing domestic gas production and high gas prices in Europe and Asia, which will reduce the amount of LNG likely to be imported into the U.S. during the first half of the forecast period in relation to the previous forecast; and,
- A nationwide CO_2 cap-and-trade program by 2014, which will reduce coal demand and coal prices over the long term.

In the *Conventional Wisdom Scenario*, we contemplate continued geopolitical tensions in the Middle East, Nigeria, and Venezuela at about the same level as the last few years with periodic flare-ups causing short-term volatility. OPEC and non-OPEC producers will see steady investments in global exploration and production (E&P), particularly for natural gas. Global investments sufficient to support the gradual development of alternative fuels such as ethanol, oil sands, gas-to-liquids, and coal-to-liquids are also contemplated. Long-term global economic growth over the forecast period is expected to be more consistent with economic growth since 1980 as compared with the rapid expansion that occurred from 2003 to 2007.[70]

3.1.1.1.Oil

Crude oil prices in the *Conventional Wisdom Scenario* are shown in Figure 36.

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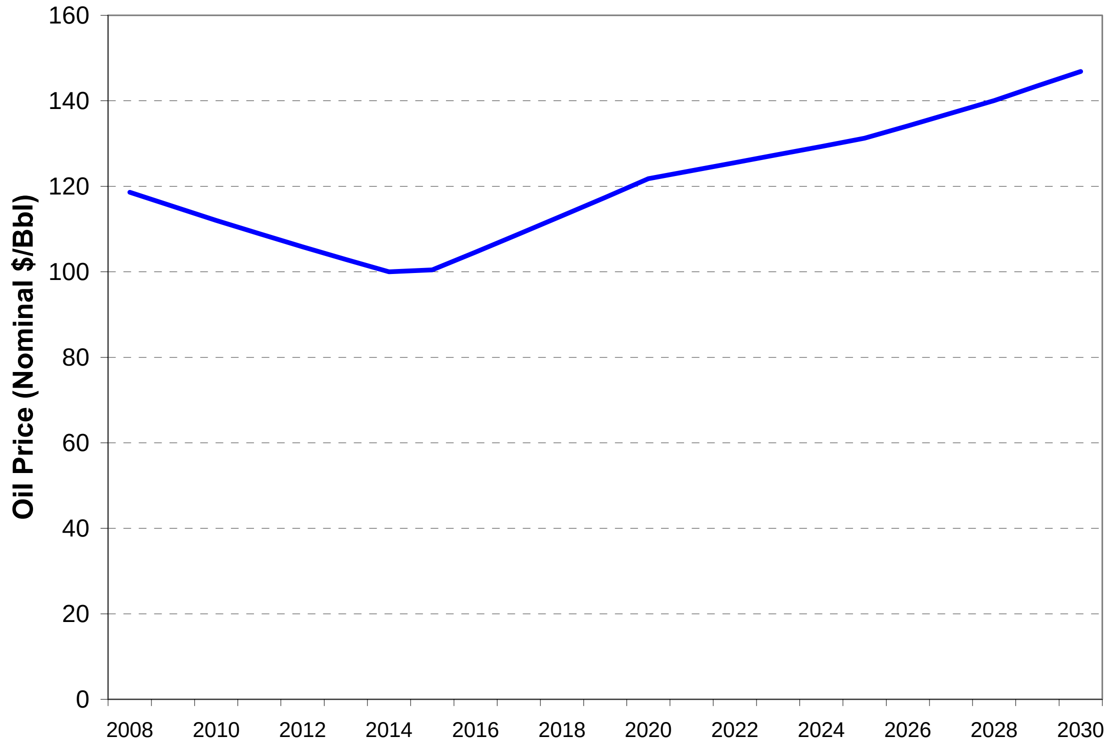
[69] Formulation of the *Conventional Wisdom Scenario* preceded the large correction in world oil prices, including forward prices, as well as the global credit crisis.

[70] According to the World Bank, global Gross Domestic Product (GDP) grew at an annual rate of 10.1% from 2003 through 2007 while the long-term global GDP growth rate averaged 6.1% per year from 1908 through 2007.

Figure 36. *Conventional Wisdom Scenario* WTI Forecast



Under this scenario world oil consumption will continue to grow, but at a gradually slowing rate, averaging 0.9% over the forecast period. This assumption is consistent with flat-to-declining U.S. oil consumption over the forecast period, primarily due to demand destruction attributable to high oil prices, as well as the expectation of progress in improving energy production and utilization technology, in particular, improved vehicle efficiency and plug-in hybrids. Based on current estimates of OPEC crude oil production capacity and likely E&P developments, OPEC production grows throughout the forecast period reaching 41 MMBbl/d by 2029. This view of OPEC production capabilities is *less* optimistic than the public pronouncements of several OPEC producers as well as a number of majors,[71] but not nearly as pessimistic as Peak Oil proponents.[72]

Under the *Conventional Wisdom Scenario*, we have assumed that global proved oil reserves will grow slowly, averaging 0.2% annually, before peaking in 2025. Gradually slowing growth in proved reserves reflects the depletion of many of the world's giant and supergiant oil fields, for example, Cantarell in Mexico and Prudhoe Bay in Alaska. Consistent with current E&P reality, under this scenario new discoveries are assumed to be generally smaller and more expensive to develop than the currently producing giant oil fields.

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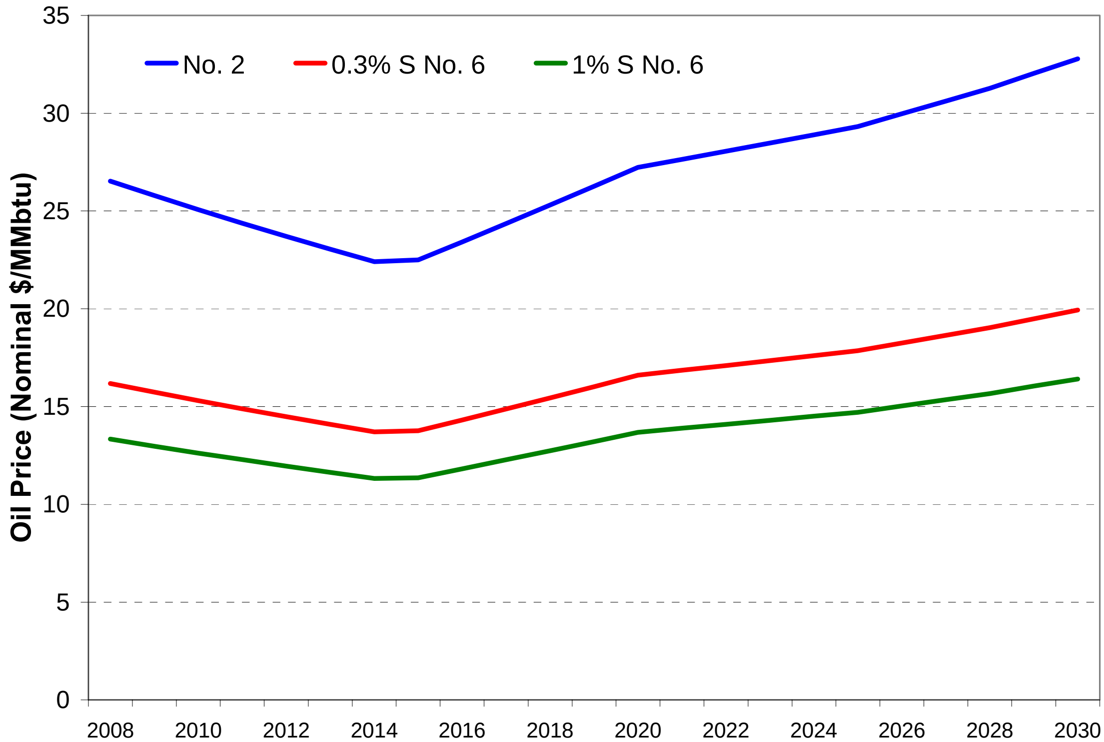
[71] ExxonMobil. *The Outlook for Energy. A 2030 View*.

[72] The Peak Oil philosophy is based on the then landmark work in the 1950's by geologist M. King Hubbert. He predicted the approximate timing in peak oil production in the U.S. Peak oil proponents espouse the decline in global oil production.

In the *Conventional Wisdom Scenario*, crude oil prices decline from an annual average price in 2008 of $118.60/Bbl to $100/Bbl by 2014. Slowing production and slowing global reserves growth subsequently result in increasing prices, which reach $144/Bbl in 2029. The strong historical correlations between WTI prices and the prices for distillate and residual fuel oil are expected to continue over the forecast period. Figure 37 provides the forecasts of prices for No. 2 fuel oil and 0.3% and 1.0% sulfur residual fuel oil at New York Harbor. The prices for fuel oil delivered to generators in eastern PJM will track the New York Harbor price indices.

Figure 37. Fuel Oil Price Forecasts



3.1.1.2.Natural Gas

U.S. natural gas production has increased by about 8% from last year’s forecast, primarily as the result of the growth in a number of shale plays, such as the Barnett Shale in northern Texas, along with coalbed methane and tight sands gas in the Rocky Mountain supply basins. Active development of gas producing shales around the country, including the Marcellus shale in Northern Appalachia, bodes well for continued onshore gas production growth over the next decade as well as for deliverability across PJM. Shale production, along with robust production from the Rocky Mountains and anticipated growth in production form the deepwater Gulf of Mexico, is expected to more than offset the decline in gas production from conventional onshore and shallow-water Gulf of Mexico fields. Our forecast contemplates a slow decline in pipeline imports from Western Canada, and flat to declining production in Atlantic Canada offset by

LNG imports through the Canaport LNG project in New Brunswick.[73] In the *Conventional Wisdom Scenario*, we assume the expansion of Dominion's Cove Point import terminal in the Chesapeake Bay to 14.6 Bcf of total storage capability and a near doubling of daily regas capacity to 1.8 Bcf by 2010.[74] Over the very long term, Alaskan gas is assumed to flow to the Lower 48 in 2021.

In spite of increasing production, natural gas prices have generally tracked oil prices over the last year or two. While oil prices are expected to have a continued influence on gas prices, particularly in the European and Asian markets, North American gas prices are forecast to be less responsive to world oil prices and therefore more responsive to continental supply developments. In the *Conventional Wisdom Scenario*, the oil-to-gas-price ratio (OGPR) averages 11.5, ranging from a high of 12.2 early in the forecast period to 10.6 by 2029. The long-term OGPR in the U.S., measured from 1990 to 2007, has averaged around 9.0. However, since 2006 the ratio has been higher than the historical average as oil prices increased more steeply than natural gas prices.

U.S. LNG deliveries include supplies covered under long-term contracts, which do not have the flexibility to change destinations in response to market conditions, and short-term contracts with flexible delivery provisions. While long-term contract cargoes to the U.S. continued at near previous levels throughout the year, spot cargoes that are destination-flexible were diverted to premium markets in Europe and Asia away from the Atlantic seaboard and Gulf Coast through the first half of 2008. The diversions, in response to prices in these markets that were significantly higher than U.S. prices, resulted in LNG imports to the U.S. decreasing by 60% in the year-to-date through August 2008 relative to the same period in 2007. LNG remains a relatively small component of total U.S. gas supply, less than 4%. Domestic production comprises about 80% of the U.S. gas supply. The remainder emanates from Canada via pipelines to the Pacific Northwest and California, the North Central states, New York, and New England. In the *Conventional Wisdom Scenario*, we assume that LNG will capture increased market share over the forecast period in response to the growth in world liquefaction capability and a gradual decline in imports from western Canada. LNG will achieve a market share of up to 15% of total U.S. supplies after 2015. The start-up of Alaskan gas deliveries to the lower 48 states will cause a temporary decline in the relative importance of LNG imports in 2021.

Figure 38 shows the annual natural gas price forecasts for Henry Hub and three regional pricing points relevant for MAAC: Dominion Transmission's South Point (DTI-SP), Texas Eastern Transmission's Zone M3 (Tetco M3) and Transco's Zone 6 Non-New York (TZ6NNY) under the *Conventional Wisdom Scenario*.

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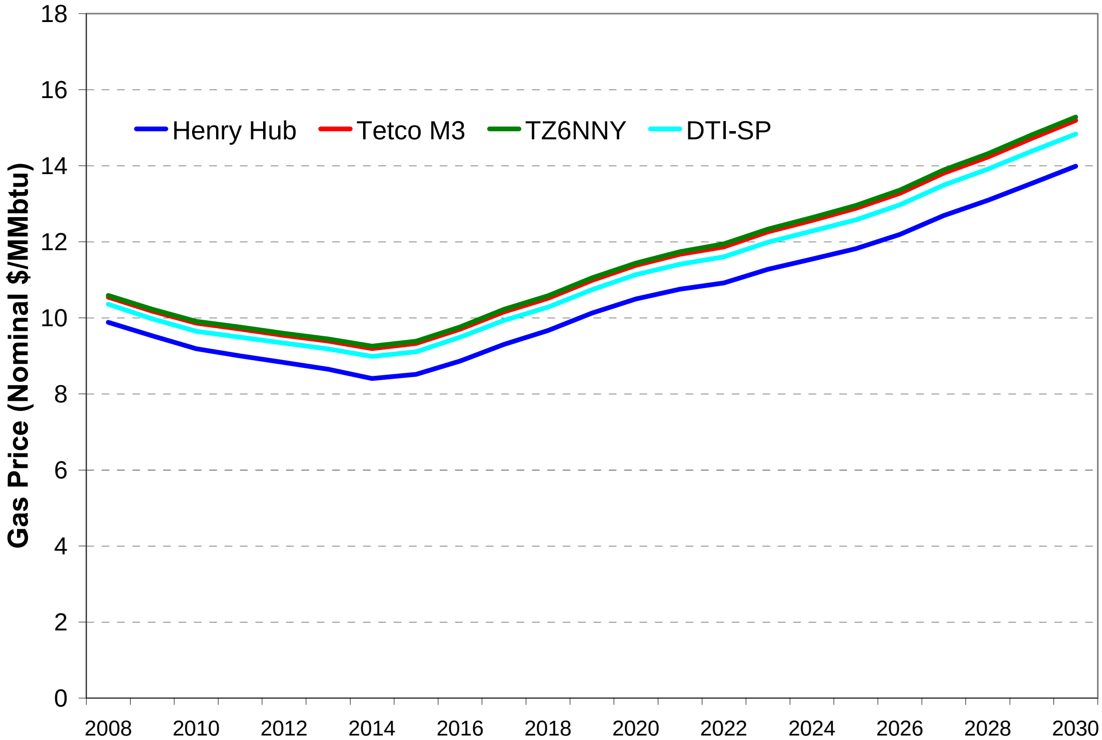
[73] Repsol's Canaport project is scheduled to be operational in 2009, but will likely take many years to achieve its target regas operating regime around 0.7 Bcf/d.

[74] LAI recognizes the potential for additional delays relating to the need for Washington Gas Light to remedy unsafe leakage in the local system.

Figure 38. ***Conventional Wisdom Scenario*** **Natural Gas Price Forecasts Henry Hub and Key Regional Pricing Points**



In nominal terms, gas prices at the Henry Hub will decrease from an annual average of about $9.88/MMBtu in 2009 to an average of $8.41/MMBtu in 2014 and then increase to around $13.50/MMBtu by 2029.

3.1.1.3.Coal

The forecast of average basin prices for coal sourced from the Central Appalachian Basin (CAPP), Northern Appalachian Basin (NAPP), and Powder River Basin (PRB) were updated to reflect the recent run-up in spot coal prices on the international markets. The effect of the increase in spot prices on basin prices is dampened significantly because 80% of the coal supplied to domestic utilities from these basins is sold under long-term contracts. The contract prices are less volatile than spot prices and the major coal-burning utilities can exercise considerable market power in dealings with the coal producers to limit price increases. Over the last year, spot CAPP and NAPP prices have increased dramatically in response to international market conditions. However, U.S. coal exports are expected to peak at between 85 million and 100 million tons by 2009. A large portion of these exports are metallurgical coal used in steel making. Thus, exports reflect a relatively small share of the domestic steam coal market of about 1 billion tons and will not have significant long-term impact on basin coal prices.

U.S. coal imports amounted to less than 40 million tons in 2007 and are expected to remain generally flat throughout most of the forecast period. Imported coal will continue to be burned at plants with access to waterborne deliveries and will be priced competitively with coal delivered from the CAPP and NAPP basins. Thus, going forward, basin coal prices are expected to reflect domestic resource conditions, mining costs and the impact of greenhouse gas regulations, rather than international market developments. In addition, PRB prices have remained relatively stable. PRB coal is generally not sold in international markets due to its lower heat content, but PRB coal does compete with both CAPP and NAPP coal in the domestic power generation market. The forecasts also account for the imposition of federal controls on CO_2, which we expect the next Congress and new president to enact. Regardless of whether the federal program is based on a carbon tax on fossil fuels or a cap-and-trade program, the regulations will add to the cost of coal-fired generation. Over the long run these added costs will dampen coal demand, also dampening coal prices.

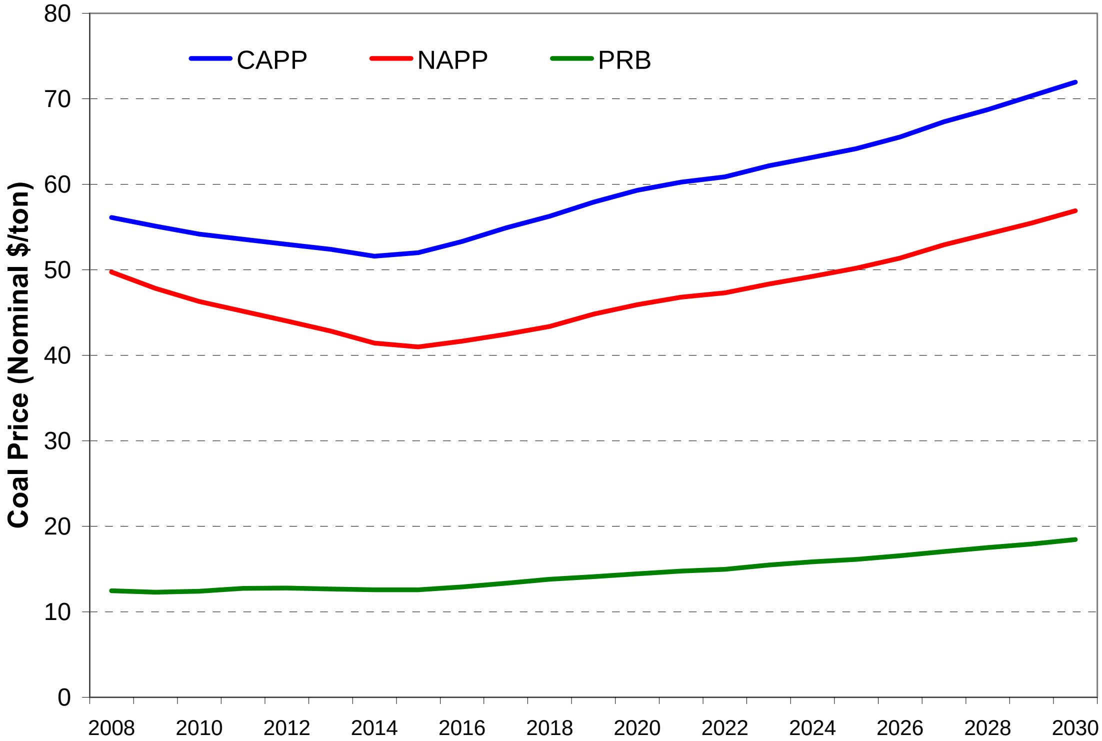
The forecasts of basin coal prices are driven primarily by mining productivity in each basin, basin production, natural gas prices, and, for CAPP and NAPP prices, the level of U.S. coal exports. Under the *Conventional Wisdom Scenario*, CAPP coal production and mining productivity will decline over the forecast period due to depletion issues. NAPP mining productivity will increase due to continued penetration of longwall mining in the basin. PRB coal production will increase by over 30% from 2008 through 2029. While PRB coal has a lower heat content than CAPP and NAPP coals, the superior economics of producing PRB coal by surface mining from thick coal seams under relatively thin overburden will allow PRB coal to offset higher transportation costs and increase its penetration into the PJM market. Increased productivity in NAPP, along with increased availability of PRB supplies, will combine with CO_2 regulations to moderate coal price increases over the forecast horizon.

Transportation costs for delivery of coal from these basins to PJM will add on average: $10/ton ($0.38/MMBtu) to the NAPP basin price, $15/ton ($0.60/MMBtu) to the CAPP basin price, and $35/ton ($1.99/MMBtu) to the PRB basin price. The average delivered price of coal in PJM for the *Conventional Wisdom Scenario* will range from $2.87/MMBtu in 2008 to $3.26/MMBtu by 2029.[75]

Figure 39 provides a comparison of the basin coal price forecasts under the *Conventional Wisdom Scenario*.

[75] This price takes into account the estimated mix of market shares in PJM for coal supplies from each basin, as well as basin prices and transportation costs.

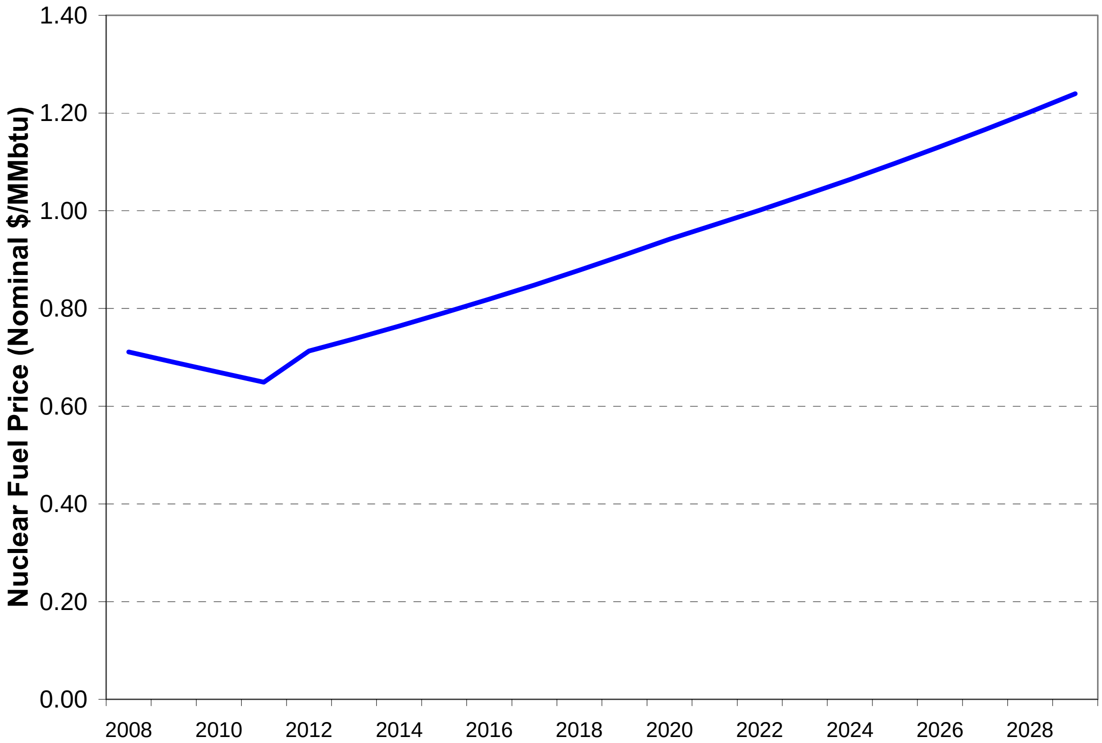
Figure 39. ***Conventional Wisdom Scenario*** **Coal Supply Basin Price Forecasts**



3.1.1.4.Nuclear Fuel

The forecast of nuclear fuel prices was adjusted to reflect recent developments in the uranium (U_3O_8) market. Nuclear fuel costs include the costs of uranium, as well as the costs for fuel conversion, enrichment, and fabrication. After peaking near $135/pound last year, U_3O_8 prices fell to around $45/pound by October 2008. Increased mine production, in response to the run up in prices, is primarily responsible for the decline in U_3O_8 prices. We project that prices will continue to be relatively flat at levels much lower than 2007 prices through 2012. Our forecast assumes that U_3O_8 prices will then increase from 2012 when increased global demand catches up with production. U_3O_8 prices are then expected to increase over the rest of the forecast period. U_3O_8 prices contribute on average about half of the cost of nuclear fuel over the forecast period. Our updated forecast of nuclear fuel prices is indicated in Figure 40.

Figure 40. Nuclear Fuel Price Forecast



3.1.2. Federal Outlook Scenario

Initially designed to represent a lower trajectory of commodity prices over the study horizon, the *Federal Outlook Scenario* represents a reasonable long-term forecast of energy prices, particularly in light of the recent dramatic pull back in global commodity prices in September and October, 2008. This forecast scenario reflects an extension of the market conditions that have been experienced since 1980 with periodic peaks and valleys on a long-term upward trend. The oil price run-up of 2007 and 2008 represents one of the peaks, albeit the highest by historical standards, in the trend going forward that is based on adequate oil supplies and increasing supplies of natural gas, coal and uranium. This forecast scenario takes an optimistic view (for end-users) of the average annual increase in prices over the long term, although daily and monthly prices are likely to be extremely volatile around this trend, periodically reaching well above or below the trend line. Global economic growth is expected to grow at a rate consistent with the growth rates experienced since 1980. However, this economic growth will be slower than the 4.6% annual rate of growth in the global economy seen from 2003 to 2007. After a brief downturn in 2008 and 2009, the growth in the global economy will also return to its long-term trend.

The *Federal Outlook Scenario* is based on the primary forecast inputs that the U.S. EIA developed for the IEO2008 Reference Case. EIA released this information in June 2008. The IEO2008 Reference Case assumes that current global laws and energy policies remain unchanged over the forecast horizon. It assumes that there are no significant barriers to increasing oil, natural gas and coal production over the long term. Fossil fuel resources will be sufficient to meet production, although new conventional oil production will be more expensive to develop than current producing fields. Under the *Federal Outlook Scenario*, no new CO_2 emissions regulations are imposed. Therefore, the use of coal increases by more than 60% worldwide over the IEO2008 forecast horizon.

Included in these assumptions are relatively strong production from new conventional oil sources in Azerbaijan, Brazil (offshore) and Kazakhstan as well as from unconventional sources such as Canadian oil sands, coal-to-liquids, gas-to-liquids, biomass, and oil shale. The use of natural gas increases by 52% over the IEO2008 forecast period. The *Federal Outlook Scenario* assumes that OPEC will increase production to 47 MMBbl/d in order to maintain cash flow and market share. The IEO2008 forecast assumes that global energy consumption will continue at rates comparable to current long-term rates and that the recent price spike will effect a significant supply response, not only for oil production but for the global production of natural gas and coal as well.

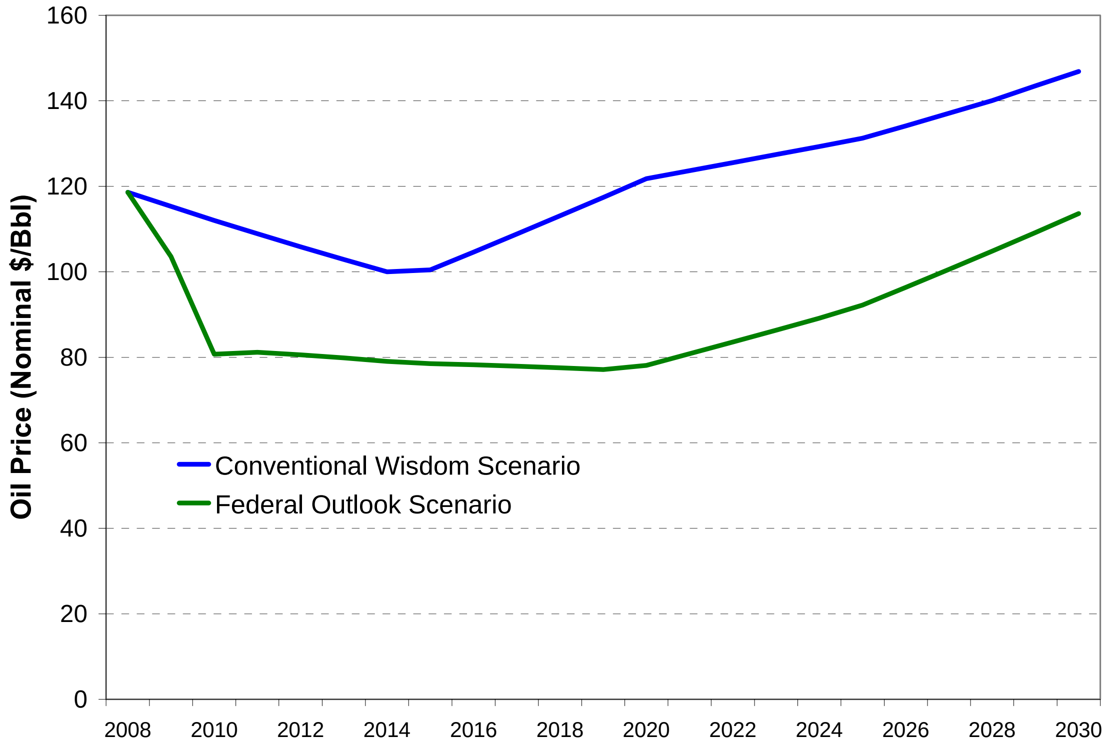
In our review of IEO2008, LAI believes that the assumptions underlying the long-term forecast represent a likely price scenario, particularly in the wake of the global financial crisis that has caused demand destruction while tempering expectations about the sustainability of triple-digit oil prices. When viewed in the context of historical trends in global consumption and OPEC production, the average annual increases in consumption of around 1.2% and in OPEC production of 1.2% for IEO2008 do not seem unreasonable.[76] LAI included these assumptions along with an assumed increase in global proved reserves of about 1.4% per year from 2008 to 2029 in our models, which resulted in a forecast of oil prices that tracked the IEO2008 Reference Case forecast very closely.[77]

In this scenario, the oil forecast results in the price of WTI decreasing to $77/Bbl by 2019 and subsequently increasing to $109/Bbl by 2029. Figure 41 shows the forecast of WTI in the *Federal Outlook Scenario*. The *Conventional Wisdom Scenario* WTI forecast is included as a reference.

[76] From 1980 through 2007 world oil consumption grew at an average annual rate of 1.2% while OPEC production grew at an average annual rate of 1%.

[77] The growth in OPEC production over the 10 years from 1997 to 2007 averaged 1.5%.

Figure 41. *Federal Outlook Scenario* – WTI Forecast



Prices for distillate and residual products are expected to follow similar paths as that of the WTI price.

Under the *Federal Outlook Scenario*, natural gas prices remain stable, with growing demand offset by large increases in global gas production and trade. Global gas consumption is expected to increase at an average annual rate of 1.7% over the forecast horizon. Major production increases are expected to be sourced from the non-Organization for Economic Coordination and Development countries in the Middle East, Africa, Asia and South America, based in part on large investments in liquefaction facilities. Production from these regions will increase by more than 2.3% annually from 65 Tcf in 2005, reaching 116 Tcf by 2030 or almost 75% of global natural gas demand. In North America, the IEO2008 forecast assumes that unconventional gas production will continue to grow over the forecast period at rates consistent with the development of new shale formations throughout North America.

The *Federal Outlook Scenario* also includes a 65% increase in global coal production, primarily from mines in the U.S., China, India and Australia. Taken together these countries will account for 85% of the increase in coal production. The bulk of the coal production and consumption increases will occur before 2020. By the end of the forecast period, coal will fuel 46% of global electricity generation. Under this scenario coal will fuel more than half of U.S. electricity generation and will support a growing coal-to-liquids industry. Most of the coal production increases expected will be sourced from PRB, NAPP and the Illinois basin.

3.1.3. Peak Oil Scenario

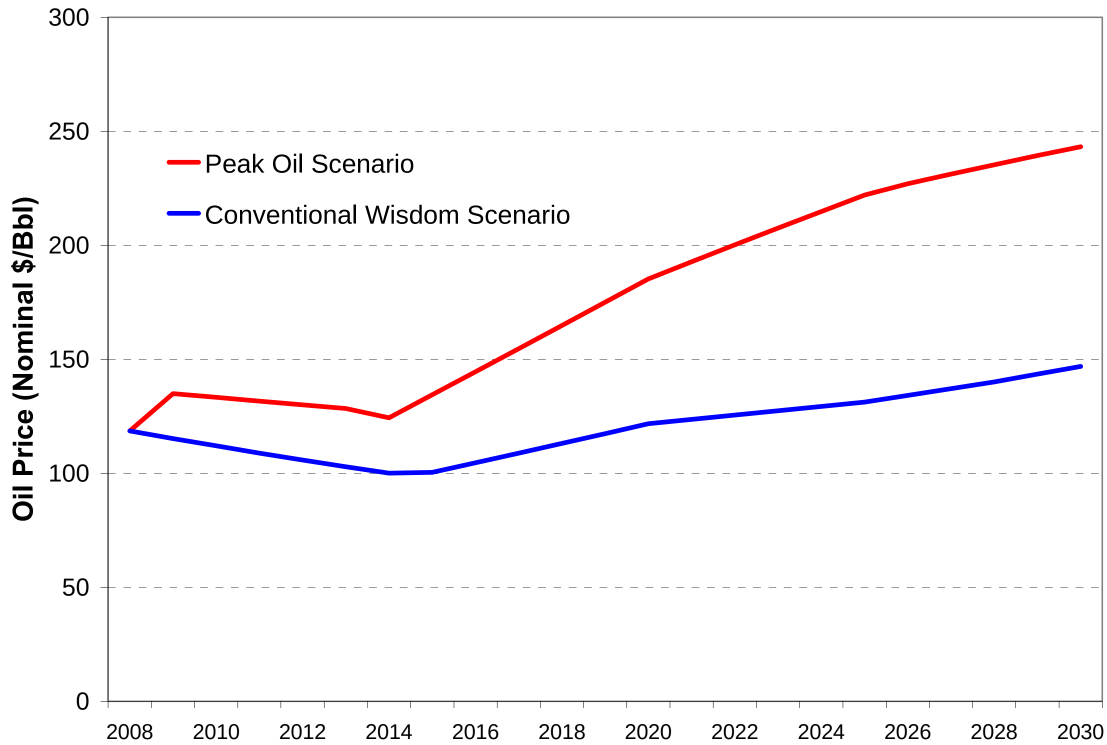
The *Peak Oil Scenario* is characterized by continued high global demand growth during the early years of the forecast period along with the peaking of both OPEC production and proved reserves. OPEC production is assumed to increase slowly from 35.5 MMBbl/d in 2008, reaching a peak around 37 MMBbl/d in 2010. Subsequent sustained decline to 32 MMBbl/d by 2029 is reflected in the forecast. Employing the philosophy of the Peak Oil enthusiasts, we assumed that proved global oil reserves peaked in 2006.[78] Proved reserves are assumed to decline at an average annual rate of less than 1% through 2015, then at about 2% per year through the remainder of the forecast period.

Under the *Peak Oil Scenario*, oil prices increase to $135/Bbl in 2009, decrease slightly through 2014 and then increase from $124/Bbl in 2014 to $239/Bbl by 2029. Global oil consumption grows much more rapidly during the first half of the forecast period than under the *Conventional Wisdom Scenario*, but then slows and eventually declines after 2020 under the weight of high prices. The continued increase in prices after 2020 is driven by resource depletion and reduced production by both OPEC and non-OPEC producers. In addition to demand destruction brought about by high prices, under this scenario the U.S. supply mix will include more high cost sources such as coal-to-liquids and oil shale during the latter part of the forecast period.

Figure 42 shows the forecast of WTI in the *Peak Oil Scenario*, with the *Conventional Wisdom Scenario* WTI forecast shown as a reference.

[78] Data from the BP Statistical Review of World Energy shows a decline in global proved oil reserves from 1,239.5 billion Bbl in 2006 to 1,237.9 billion Bbl in 2007. In 2007 the world consumed more than 85 MMBbl/d or about 31 billion Bbl. Current proved reserves are equivalent to 40 years of consumption at current rates.

Figure 42. ***Peak Oil Scenario*** **– WTI Forecast**

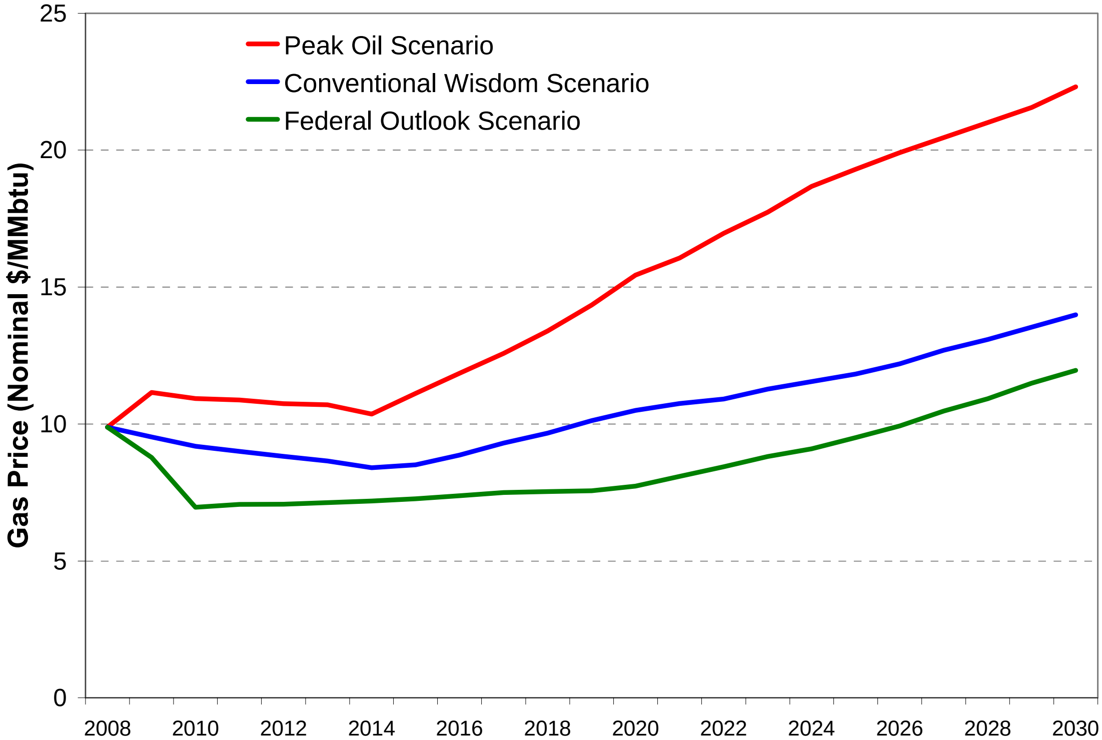


As in the other scenarios, prices for distillate and residual products are expected to follow similar paths as that of the WTI price.

Under this scenario, natural gas prices will be pulled upward to a certain extent by the higher oil price trend, which will primarily be the result of higher global LNG prices and greater imports of LNG into North America to meet growing gas demand. Coal prices will also increase under this forecast scenario, reflecting higher domestic demand, greater exports and higher production from all of the basins.

Figure 43 provides a comparison of the gas price forecasts for the *Federal Outlook, Conventional Wisdom* and *Peak Oil Scenarios*.

Figure 43. Natural Gas Price Forecasts



3.2. Transmission Infrastructure

3.2.1. New Backbone Transmission Development in PJM

PJM annually conducts Regional Transmission Expansion Planning (RTEP) studies to identify transmission system upgrades and enhancements that are needed to preserve the reliability of the electricity grid. This is done by assessing reliability criteria violations up to 15 years in the future. PJM's RTEP studies have revealed that load growth and the location of new generation facilities will impose increasingly heavy levels of west-to-east power flows across the transmission system that covers PJM and links the market area to neighboring control areas. To accommodate these increasing levels of west-to-east power flows and the ensuing reliability criteria violations through 2021, PJM has recognized the need to increase the west-to-east transfer capability. In 2007 a number of transmission "backbone" projects were approved by PJM's Board in order to strengthen the reliability and efficiency of the transmission system.[79]

In May 2005, PJM unveiled the Project Mountaineer concept. As proposed, Project Mountaineer would consist of two or more new backbone 500-kV and/or 765-kV transmission projects to enhance the west-to-east transfer capability of the PJM transmission system. On October 10, 2006, PJM submitted a request to the Secretary of Energy in response to the Department of Energy's (DOE's) Congestion Study, to designate three National Interest Electric Transmission Corridors (NIETCs or National Corridors) within PJM: the Allegheny Mountain Corridor

[79] Backbone reliability upgrades typically refer to interstate 500-kV or 765-kV transmission projects.

(AMC),[80] the Delaware River Corridor (DRC),[81] and the Mid-Atlantic Corridor (MAC).[82] In response, DOE designated the Mid-Atlantic Area National Corridor (MAANC) and the Southwest Area National Corridor as NIETCs.[83] It is important to note that the PJM region of the MAANC, as designated by DOE, encompasses practically all the counties that PJM had identified in its three proposed NIETCs.[84] Given the environmental and political controversy surrounding the permitting of various backbone projects, designation as NIETCs portends successful development of the high-voltage transmission projects despite pockets of local resistance and/or state refusal to grant the requisite permitting approvals.

To date, PJM has evaluated several alternatives for backbone transmission development and, working with the Transmission Owners (TOs), has identified four new backbone transmission projects which are addressed below.

3.2.2. Impact of Transmission Buildout on Maryland

Transmission infrastructure within Maryland and into Maryland materially affects energy and capacity prices for the IOUs. We have reviewed the planned backbone transmission projects and also some minor local transmission upgrades planned in the BGE, Pepco, DPL and APS service areas. Our review suggests that the minor local transmission upgrades are not expected to increase transfer limits and importing capabilities into Maryland. In contrast, the backbone transmission projects, if completed, are likely to materially improve transfer capabilities into the import-constrained regions, thereby reducing prices in BGE, PEPCO, and DPL. Four high-voltage backbone transmission projects have received PJM Board approval:

- 502 Junction-Loudoun (TrAIL),
- Amos-Kemptown (PATH),
- Susquehanna-Roseland, and

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[80] The AMC is a high-voltage pathway in PA, WV, VA, and MD to support enhanced transmission capability to Baltimore, Washington, D.C. and northern VA. The AMC would provide the load centers with access to generation west of the Allegheny Mountains, WV, and the Ohio and Kanawha River valleys.

[81] The DRC is a high-voltage, bulk power transmission pathway within OH, WV, PA, and NJ to support service to eastern portions of the Mid-Atlantic area, principally Newark and northern NJ The DRC would provide EMAAC with improved access to generation resources west of the Allegheny Mountains.

[82] The MAC is a high-voltage, bulk power transmission pathway within VA, MD, DL, PA, N.J. and Washington, D.C. The MAC extends northeastward from the Washington, D.C. / Baltimore / Northern VA area across the Chesapeake Bay and the Delaware River to support service to southeast PA, NJ, and the Delmarva Peninsula. This corridor would provide load centers with enhanced access to generation in the west and the AMC.

[83] The initial designation appeared in the Federal Register, October 5, 2007. On March 6, 2008, DOE denied requests for rehearing of the designated NIETCs. On March 11, 2008, DOE issued a notice of denial. NIETCs are defined under the Energy Policy Act of 2005 as areas experiencing electric transmission capacity constraints or congestion that adversely affect consumers. NIETC designation grants FERC jurisdiction over the permitting of transmission facilities located therein.

[84] PJM filed comments on the draft NIETC designations supporting DOE's proposed boundaries within PJM's market area. Within the PJM footprint, PJM said that the draft National Corridor encompasses the existing, constrained west-to-east transmission lines. PJM noted that the National Corridor is sufficiently broad to encompass a range of potential solutions for enhanced west-to-east flows.

- Possum Point-Salem (Mid-Atlantic Power Pathway, or "MAPP").

The Susquehanna-Roseland and MAPP projects were not included in the *Base Scenario* or any of the alternative scenarios. More detail about these two projects can be found in Appendix A.

On May 19, 2008, the Commission met with PJM regarding the status of TrAIL. PJM senior management indicated that TrAIL will be ready for commercial operation in Q2 2011. There are a number of reasons, however, why TrAIL's developers may not complete the project by Q2 2011, as described in Section 3.2.3.

To hedge against the uncertainty surrounding the completion of TrAIL and other backbone transmission projects, on August 13, 2008, the Commission initiated a proceeding under Case 9149 to evaluate the methods to alleviate potential short-term reliability problems in Maryland and the surrounding region. The Commission noted that PJM's analysis of the Maryland capacity situation had identified potential reliability shortfalls that could occur in 2011 or 2012. The Commission requested input on the possible size, timing and location of the capacity shortfall state-wide, and in SWMAAC and EMAAC, in particular.[85]

3.2.3. TrAIL

3.2.3.1. Project Need

In studies for the 2006 RTEP, PJM observed that overload of the Mt. Storm-Doubs 500-kV circuit in 2011 for four different 500-kV outages violates North American Electric Reliability Council reliability standards, PJM load and generator deliverability planning criteria and Dominion planning criteria. PJM also observed that the overload of the Pruntytown-Mt. Storm 500-kV circuit in 2014 for three different 500-kV outages violates PJM generator deliverability planning criteria. Growing west-to-east power transfers to serve eastern load centers were identified as a major driver of the generator deliverability-based overloads which were observed on these circuits. PJM identified, and the PJM Board approved, the addition of the TrAIL 500-kV circuit as the recommended system upgrade to relieve the observed overloads. The construction of the line will resolve reliability criteria violations by increasing west-to-east transfer capability, provide critical support for the entire eastern PJM area, and maintain reliability in Northern Virginia and the Baltimore / Washington, D.C. area.

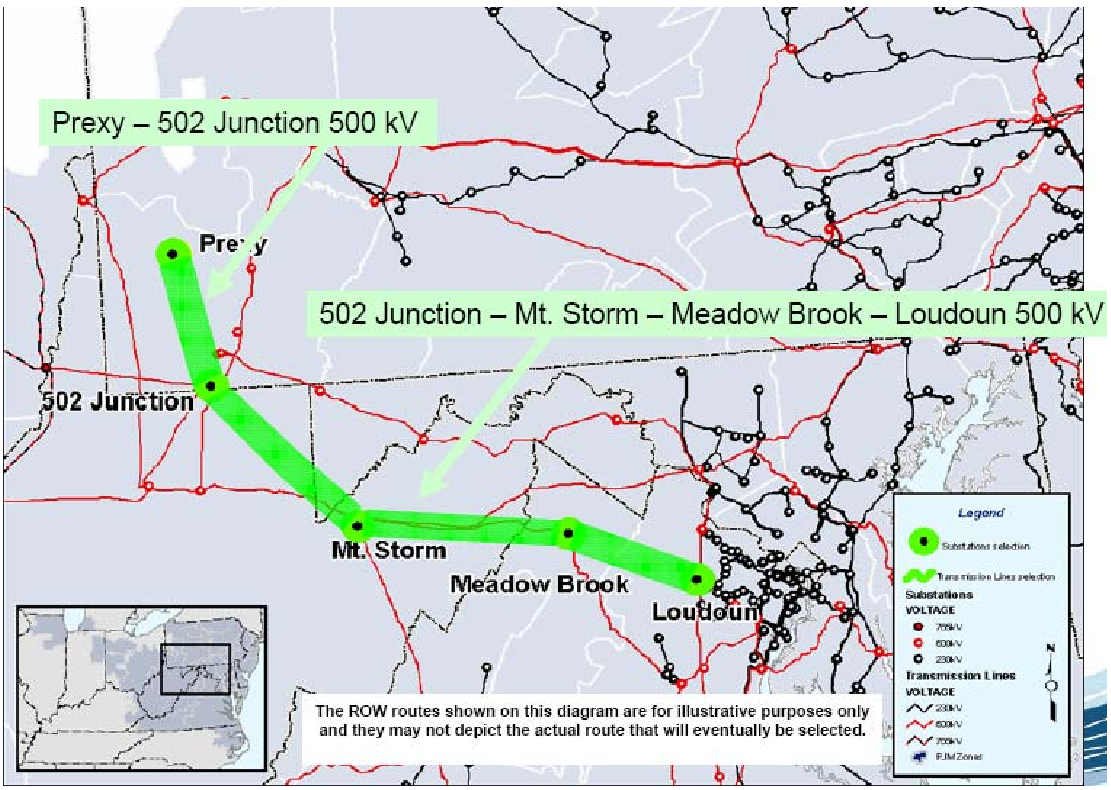
3.2.3.2. Project Description

TrAIL will extend 37 miles in southwestern Pennsylvania, 114 miles through West Virginia, and 93 miles through northern Virginia (see Figure 44). The line will be built by Trans-Allegheny Interstate Line Company (TrAILCo), an indirect subsidiary of AE and Dominion Virginia Power. TrAILCo will build about 36 miles of the project in Virginia, which will be built by Dominion. The 500-kV line will connect the new 500/138-kV Prexy Substation (located in Washington County) and the 500-kV 502 Junction Substation (located in Greene County) in Pennsylvania, *i.e.*, the Prexy Segment. From the 502 Junction, TrAIL will be routed for about

[85] Comments were filed on September 12, 2008, and reply comments were filed on September 19, 2008.

1.2 miles to the state line with West Virginia – Pennsylvania 502 Junction Segment. The 500-kV line will continue into West Virginia to the existing Mt. Storm Substation. From the Mt. Storm Substation, the line will continue eastward in West Virginia and then across the state line into Virginia to Meadow Brook. The line will continue east to a point near the western boundary of the National Park Service's Appalachian National Scenic Trail Property in Virginia, where ownership of the line will change to Dominion through the Appalachian National Scenic Trail property, then to TrAILCo and Dominion Virginia Power jointly for 30 miles. TrAIL includes three new 138-kV transmission lines from the Prexy Substation to West Penn Power. TrAIL's cost is estimated to be $850 million. In this study, no quantitative analysis has been performed to reflect a TrAIL in-service date before 2014

Figure 44. TrAIL



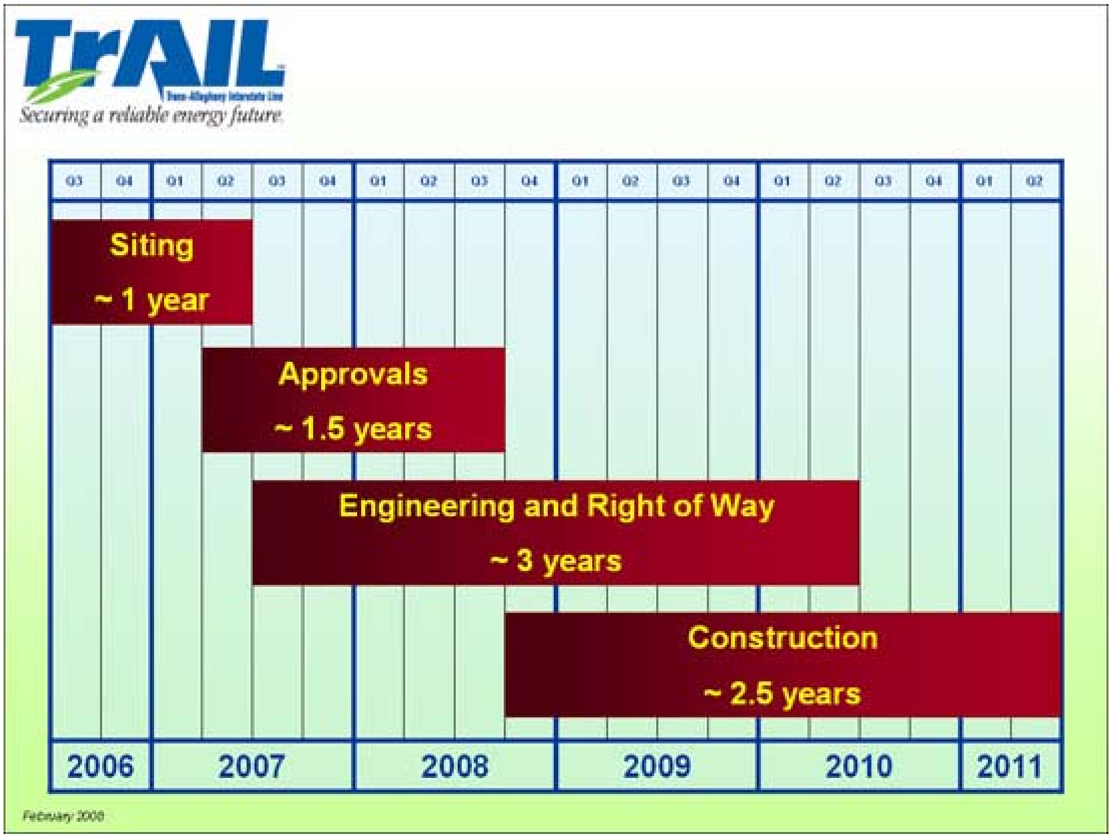
3.2.3.3.Project Status

TrAIL was approved by the PJM Board in 2006 and included in the 2006 RTEP. The project is in the engineering and planning phase of development.

The project developers have applied for Certificates of Public Convenience and Necessity (CPCNs) for authorizing the construction and operation of the line in Pennsylvania, West Virginia, and Virginia. The applications were submitted in March and April, 2007. Construction of the line can only commence after receiving the approvals of PA PUC, the Public Service Commission of West Virginia (PSC WV) and the State Corporation Commission of Virginia (SCC VA). Both the PSC WV and the SCC VA have granted the CPCNs. On November 13, 2008, the PA PUC approved the Pennsylvania 502 Junction Segment. Additional details regarding the PA PUC approval and associated proceedings can be found in Appendix A.

We note that, even with the PA PUC approval, the Q2 2011 in-service date as proposed may not be achievable. To meet a Q2 2011 in-service date, the current TrAIL project schedule, as shown in Figure 45, calls for completion of all approvals by Q3 2008 with construction commencing in Q4 2008. As previously discussed, we have conservatively assumed a 2014 in-service date in our *Base Scenario.*

Figure 45. Proposed TrAIL Schedule[86]



3.2.4. PATH

PJM evaluated a number of transmission proposals to resolve long-term reliability criteria violations. Dozens of transmission options were considered, as well as combinations. In 2007, the PJM Board approved three new backbone transmission projects. One of these is the Amos-Bedington-Kemptown line, also known as PATH.

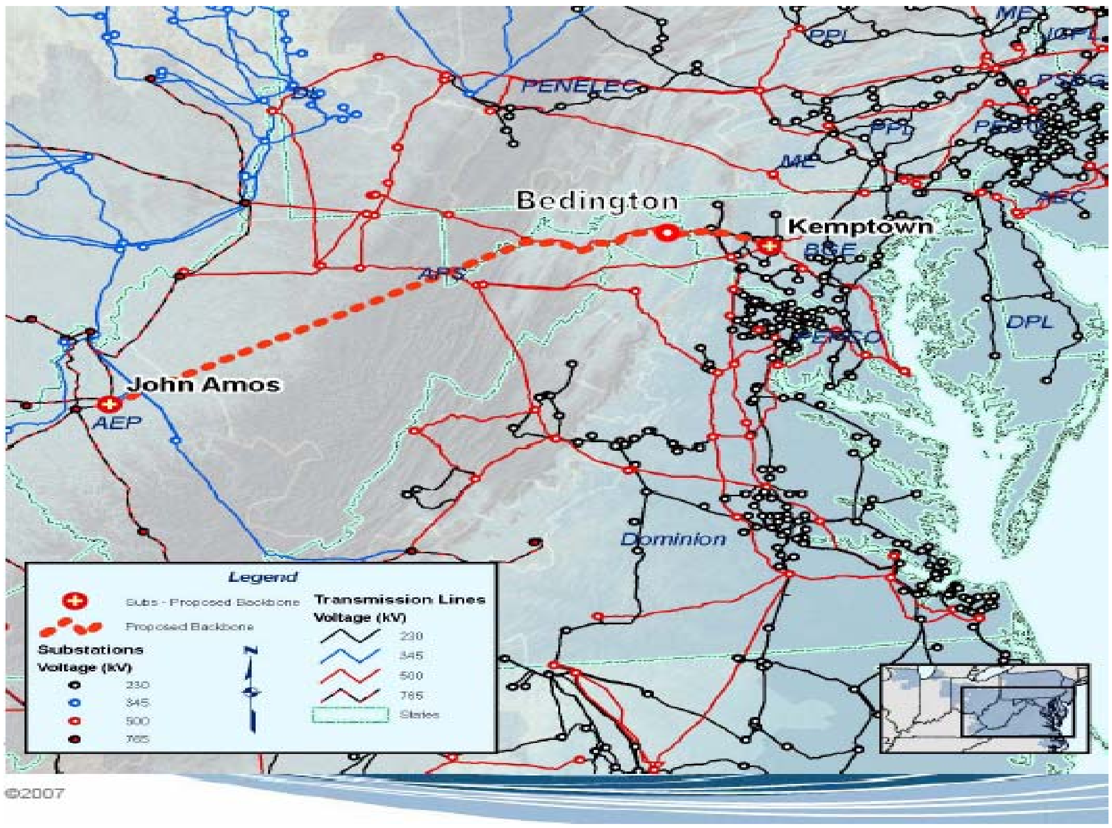
PATH, as currently proposed, will extend from the John Amos 765-kV substation in southwestern Virginia to the Bedington station in West Virginia.[87] This portion, 244 miles long,

[86] Source: TrAILCo: http://www.aptrailinfo.com/index.php.

is designed at 765 kV. From Bedington, a twin circuit, 46-mile, 500-kV line will be extended to a new station at Kemptown, Maryland. The Kemptown station will be located along the existing Doubs-Brighton-Conastone 500-kV right-of-way. PATH is being developed by AE and AEP. The 765-kV portion will be owned by PATH West Virginia and the 500-kV portion will be owned by PATH Allegheny. The change in CETL into Kemptown will reduce the flow on the existing PJM 500-kV west-to-east transmission paths and provide significant benefits to SWMAAC. PATH is expected to reduce overloads on existing lines in Maryland, Pennsylvania, Virginia and West Virginia. The line is expected to be in service in Q3 2013.[88] The estimated cost is about $1.8 billion, about two-thirds borne by AE.[89]

The project remains in the engineering and regulatory approval phase.

Figure 46. PATH



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[87] At the November 5, 2008, Transmission Expansion Advisory Committee meeting, PJM notified stakeholders that due to siting considerations around the Bedington substation, the configuration of the project has been changed. The line will no longer go through Bedington. The line will start at the Amos 765-kV bus and go to a new midpoint station in the TrAIL line. The exact location of the new midpoint will be determined pending additional siting work. There will be two 765/500-kV transformers at the new midpoint station. The line will continue from the 765-kV bus at the new midpoint and go to Kemptown.

[88] Press release, "PATH Announces Change to Transmission Line In-Service Date," October, 31, 2008.

[89] Based on the existing configuration of the line.

3.2.5. Estimated Transfer Limits

The transfer limits that define energy flows between the MarketSym topology zones depend on a number of variables, including load levels, load distribution, generation availability, generation source and sink combinations, transmission facility outage assumptions, transmission facility ratings, and phase angle regulator settings. Varying any of these factors produces a range of values for any transfer limit. The transfer limits are normally determined using a load flow model. LAI did not conduct any transmission power flow or security-constrained dispatch modeling of TrAIL to determine the transfer limits of relevance in SWMAAC and EMAAC. Instead, we relied on PJM. Informal guidance from PJM was obtained.[90]

For purposes of defining the change in CETL attributable to TrAIL, PJM recommended that the Commission compare the CETL values in the 2010/11 BRA Planning Parameters (pre-TrAIL) to the CETL values in the 2011/2012 BRA (post-TrAIL). For SWMAAC, the difference was at least 230 MW. For EMAAC the difference was at least 290 MW.[91]

During the course of this study, the Commission sought technical information from PJM for purposes of defining the anticipated change in CETL for relevant zones in Maryland.[92] We interpreted PJM's response as confirmation that 6,897 MW is the actual 2011/12 CETL for SWMAAC and 8,514 MW is the actual 2010/11 CETL for EMAAC. However, these differences in CETL by zone may constitute the lower limit. Much higher CETL benefits are considered possible, but have not been incorporated in any transmission analysis conducted in the Final Report. The main reason there is not more benefit to SWMAAC is that the area has historically been limited by the 500/230-kV transformation and, to a lesser extent, the 230-kV circuits. Since PJM recommended to the Commission that we use 230 MW for SWMAAC and 290 MW for EMAAC, we proceeded accordingly.

For purposes of this report, we assumed that the impact of PATH on CETL in SWMAAC and EMAAC is the same as TrAIL.[93]

3.2.6. Resource Gap

To hedge against the uncertainty surrounding the completion of TrAIL or other major transmission projects, the Commission has considered methods by which to alleviate potential

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[90] A formal information request was submitted to PJM by the Commission. Specific information about changes in transfer capability associated with TrAIL line and the impact on LDAs was requested. Technical information from PJM was not available for purposes of preparing the Final Report.

[91] The 2010/11 CETL value for SWMAAC is 6,667 MW and the 2011/12 CETL value is reported as >6,897 MW. The difference between the two values is 230 MW. PJM recommended that this difference is the appropriate proxy for the CETL change in SWMAAC attributable to TrAIL. The 2010/11 CETL value for EMAAC is >8,514 MW and the 2011/12 CETL value for EMAAC is 8,804 MW, a difference of 290 MW. LAI notes that it is not clear whether the >6,897 MW and the >8,514 MW values for SWMAAC and EMAAC are the actual values.

[92] In the information request, the Commission expressed concern that 6,897 MW represents the 10% cut-off point for the CETO/CETL test. Of particular interest were the actual CETL values for each LDA.

[93] In PJM's response to the Commission's questions in Case CN 9117, November 9, 2007, PJM noted that both TrAIL and PATH would not have a significant effect on the capacity balance in SWMAAC.

short-term reliability problems in Maryland and the surrounding region.[94] Prior to the addition of TrAIL, reserve margins can be ensured by adding some combination of new gas-fired generation, unit uprates to existing capacity, and/or DR. The size of the capacity deficiency prior to the start-up of TrAIL is sensitive to the supply and demand assumptions used to gauge resource adequacy in SWMAAC and EMAAC. A broad range of the size of the potential capacity deficits can be supported depending on the assumptions used in the analysis. On May 21, 2008, Mr. Michael Kormos, Senior Vice President of PJM, met with the Commission to review multiple scenarios. The presentation consisted of status reports on the results of the 2011/12 PJM BRA and the Gap without TrAIL in 2011.[95]

Five Gap scenarios presented by PJM are summarized below. PJM's reported gap estimates are stated regionally and are not specific to SWMAAC or Maryland. The Maryland portion estimated by PJM is based upon the proportion of Maryland load relative to the affected region. PJM's assessment pertains to transmission constraints affecting the delivery of energy to MAAC, not SWMAAC or EMAAC. The critical facility limiting the ability to deliver into MAAC is the Mt. Storm to Doubs 500-kV transmission line. In our analysis, we have differentiated SWMAAC from EMAAC and the RTO. In deriving the gap in relation to MAAC, PJM estimated the load within Maryland to be about 23% of the load in MAAC.

Scenario 1

This is a 2012 case conducted by PJM in October 2007 assuming TrAIL (2011) and PATH (2012) would not be in-service. Load growth and DR assumptions were based on the January 2007 PJM load forecast. Generation assumptions were based on existing generation plus the new generation that had entered into Interconnection Service Agreements (ISAs) as of January 2007. Of the key generators assumed, Catoctin, Benning (units 15 & 16) and Buzzard were not modeled. Under this set of assumptions, PJM reported a capacity gap in Maryland of 1,500 MW.

Scenario 2

In this scenario, which is an update to Scenario 1, PJM performed the gap analysis using an updated 2012 PJM RTEP case. Load growth and DR assumptions were based on the January 2008 PJM load forecast. Generation assumptions were based on existing generation plus new generation that had entered into ISAs by February 29, 2008. Consistent with Scenario 1, PJM did not include the Benning and Buzzard units. PJM did include Catoctin, however.[96] In addition, PJM did not include Indian River (units 1 &

[94] *In the Matter of the Investigation of the Process and Criteria for us in Development of Request for Proposal by the Maryland Investor-owned Utilities for New Generation to Alleviate Potential Short-Term Reliability Problems in the State of Maryland,* Case No. 9149.

[95] From a resource perspective, the gap is PJM's estimate of the generation needed in 2011 and 2012 to reduce loading on the most limiting transmission facility down to 100% if TrAIL and PATH are not in-service. Reliability criteria violations were identified during the RTEP analysis. From an LSE's perspective, the gap is PJM's estimate of the area load at-risk. The determination of at-risk generation is affected by generation availability, load growth, and DR.

[96] We assume that PJM was expecting the Catoctin plant to clear in the 2011/12 BRA.

2)[97] and Bergen 2.[98] The inclusion of Parlin, B.L. England (units 1, 2 &3) and Sewaren (units 1-4) in EMAAC were assumed as each of these units had withdrawn their respective deactivation requests. Under this set of assumptions PJM reported a capacity gap in Maryland ranging from 460 to 1,200 MW.

Scenario 3

This is a 2011 case without TrAIL and with only that generation (both existing and new) and DR that cleared in the 2011/12 BRA. Load growth assumptions were based on the January 2008 PJM load forecast. The key generation assumptions are the same as those in Scenario 2, except Catoctin was excluded. Benning, Buzzard Point and Bergen 2 were included in the resource mix. Under this set of assumptions PJM reported a capacity gap in Maryland ranging from 600 to 690 MW.

Scenario 4

This is also a 2011 case without TrAIL, but with all generation (new and existing) that was then expected by PJM to bid in the 2011/12 BRA. In this scenario, the DR included in the 2011/12 BRA and the load growth assumptions were based on the January 2008 PJM load forecast. The key generation assumptions are the same as for Scenario 3. In this scenario, there is no gap in Maryland in 2011. However, PJM reported the line loading under the limiting reliability criteria test at 99% of the facility rating. Hence, under these conditions there would be virtually no remaining line loading capability and no reliability margin. Simply put, while system reliability criteria would be within limits, the system would effectively be operating on the edge of normal design criteria. This scenario was created by PJM prior to the 2011/12 BRA and is no longer relevant.

Scenario 5

This is also a 2011 case without TrAIL, but with all existing generation and both new generation and DR that cleared the 2011/12 BRA. In addition, PJM assumes the inclusion of all other existing generation that did not clear the 2011/12 BRA. Load growth assumptions were based on the January 2008 PJM load forecast. The key generation assumptions are the same as for Scenarios 3 and 4. Consistent with Scenario 4, there is no gap in Maryland. However, PJM reported the line loading under the limiting reliability criteria test at 100% of the facility rating. Like Scenario 4, there is virtually no remaining line loading capability and no reliability margin under this scenario. The system operates on the edge.

On June 20, 2008, the Commission requested that PJM analyze two additional scenarios, using Scenario 5 as the basis.

[97] Officially requested deactivation on September 28, 2007.

[98] Bergen 2 withdrew its deactivation notice effective May 6, 2008.

Scenario 6A

This scenario incorporates updates to BGE's forecast: compound annual peak load growth of 1.1%, 566 MW of DR in 2011, and an unrestricted peak load for 2011 of 7,729 MW. The Benning and Buzzard plants are not included in this scenario. Relative to Scenario 5, BGE's DR decreased by 89 MW in 2011, load forecast increased by 103 MW, and generation supply decreased. PJM reports the gap as a range of 350 to 460 MW with remedial action required by PJM.

Scenario 6B

This is a 2012 case without the Benning and Buzzard units and also assuming that TrAIL and PATH are not in service. The BGE peak load forecast is increased to 7,854 MW with 635 MW of BGE for 2012. Catoctin is excluded. While there was an increase in BGE's DR by 375 MW, the BGE load forecast also increased by 161 MW, resulting in an overall negative net supply and an even higher gap range relative to Scenario 6A. In this scenario PJM reports the gap as a range from 460 to 1,200 MW. We note that Scenario 6B produces the same gap range as Scenario 2.

As is evident in Scenarios 2 through 6B, derivation of the gap is assumptions-driven and can range from zero to 1,200 MW.[99] The modeled gap is a function of key variables which can not be pinned down with any certainty at this juncture: the quantity of generation and DR resources that will participate and clear in the BRA each year, generation deactivations and retirements, and the forecast of load, with and without the then projected amount of DR. Moreover, PJM and the TOs each have different outlooks for these variables. From a public policy standpoint, the Commission may consider defining the gap under expected conditions or, alternatively, under a *plausible worse case* set of resource planning parameters.

Based on our review of the PJM analysis on the potential gap in Maryland and also the ongoing proceedings in Case 9149, it is clear that the gap issue, as it relates to potential delays in the backbone transmission projects, is a regional challenge. The magnitude of the gap is driven by the assumptions employed by resource planners in deriving the capacity balance. Based on the factor inputs presented herein, LAI has determined the gap for SWMAAC using a load and resource balance methodology.

Based on our review of PJM's analysis and filed comments, LAI has estimated the gap in SWMAAC to be 0 MW in 2011 and 230 MW in 2012 and 2013.[100] To the extent the actual penetration rate of DSM is different from the assumptions reflected in the *Reference Case*, the capacity deficit may be significantly different.

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[99] Independent determination of the potential capacity deficit when a delay in TrAIL's in-service date is considered is outside the scope of this analysis.

[100] The *Reference Case* reflects the retirement of Pepco's Benning and Buzzard Point units, a loss of about 868 MW. The anticipation of a capacity deficit in SWMAAC might warrant a delay in the retirement of one or both plants.

3.2.7. Modeling Scenarios

3.2.7.1.Base Scenario

Under the *Base Scenario*, TrAIL has been included in the transmission topology of the region in 2014. This scenario is applied to the *Reference Case* and all study cases.

3.2.7.2.No TrAIL Scenario

Neither TrAIL nor any of the 2007 RTEP backbone transmission projects have been included in the *No TrAIL Scenario*, which is applied to the *Reference Case* and all study scenarios except for the *Rate Base Regulation* and *Solar Cases*.

3.2.7.3.TrAIL+PATH Scenario

Both TrAIL and PATH have been included in the *TrAIL+PATH Scenario,* which is applied only to the *Reference Case* and the *Rate Base Regulation Case*.

3.3. Environmental Regulations

The electric market simulation models incorporate current and anticipated state and federal environmental compliance requirements over the study horizon. The fixed and variable operating costs arising from environmental compliance programs are addressed in this section.

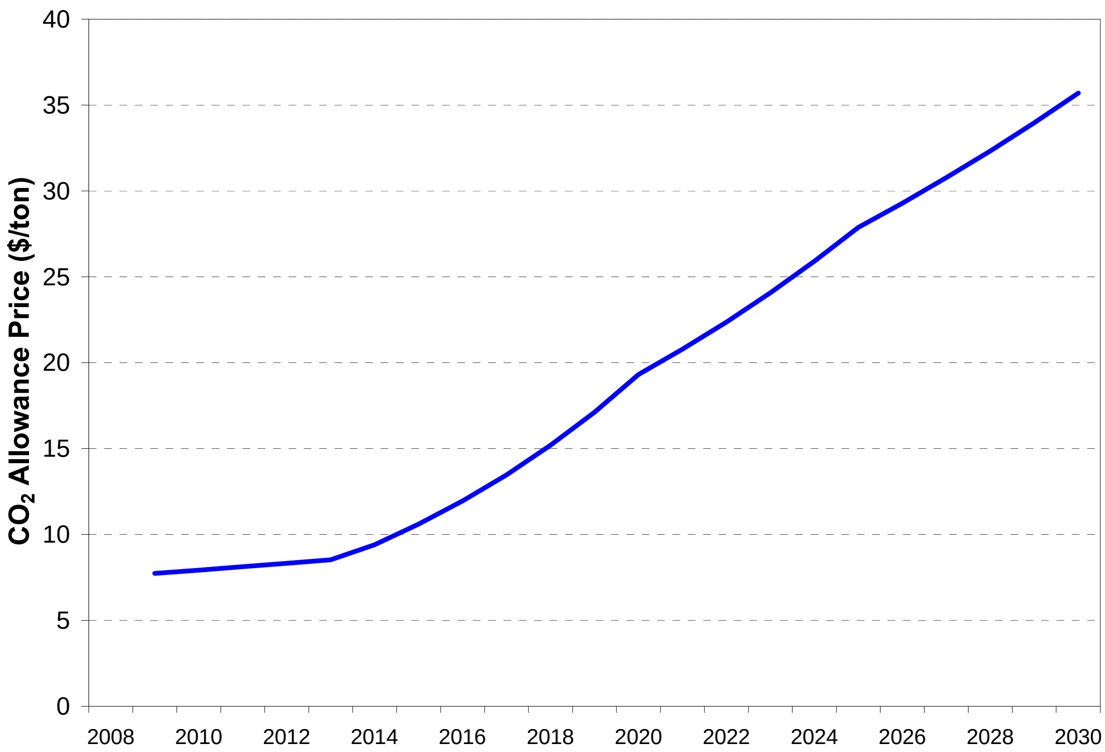
3.3.1. Greenhouse Gas Regulation

Beginning on January 1, 2009, CO_2 emissions from fossil fuel-fired power plants 25 MW and larger within ten northeast states and Washington, D.C., will be subject to an annual cap under RGGI. Similar to successful cap-and-trade programs for SO_2 and NO_x, facilities subject to the rule must acquire and retire one CO_2 allowance for each ton emitted. The objective of RGGI is to levelize total CO_2 emissions from these plants through 2014, and then achieve reductions of 2.5% per year through 2018. Within PJM, only Maryland, New Jersey, Delaware, and Washington, DC, are part of the RGGI footprint. Elsewhere across the U.S., similar state and regional initiatives to control greenhouse gases have been launched. On the federal level, a number of bipartisan greenhouse gas bills have been introduced in Congress over the past few years. Given the momentum on the state and federal levels, and the expected climate change policies of the new administration, we anticipate that Congress will enact federal greenhouse gas controls within the next few years. For forecasting purposes, we assume that federal CO_2 controls will be implemented as cap-and-trade program across all states in 2014, similar to, but supplanting, RGGI.

Whether treated as an actual cost or an opportunity cost, the requirement to retire CO_2 allowances adds to the variable operating cost of fossil fuel-fired units. Under RGGI or a federal program, we expect the incremental operating cost for plants that burn carbon-intensive fuels, such as coal and oil, will increase relative to gas. The programs afford a cost-advantage to non-carbon-emitting generation, such as nuclear and renewables, relative to fossil fuel units.

The first auction for 2009-vintage RGGI allowances was conducted on September 25, 2008. The clearing price was $3.07/ton. However, only six states participated in this auction, and the total number of allowances offered was only about 7% of the total 2009 RGGI allocation for all states. Another auction is scheduled for December 17, 2008, and then quarterly auctions will follow in 2009 and thereafter. Prior to the first auction, there had been a thin market in RGGI allowance futures, and prices reported for these trades suggested that the starting price in 2009 would be in the neighborhood of the RGGI Stage 1 trigger price of $7/ton (2005$).[101] We believe that the low clearing price in the first auction is a reflection of the immaturity of the market and the recent low demand outlook across the power sector, which has put downward pressure on allowance prices. LAI's long range CO_2 allowance price forecast is presented in Figure 47. While there is considerable uncertainty in the forecast, we have assumed that as the market expands the Model Rule Stage 1 trigger price will set the price through 2013. Thereafter, a federal program is expected to reduce leakage (imports) from outside of RGGI states and increase the demand for allowances. In anticipation of a federal program, we assume that allowance prices will increase in real terms (above inflation) by 7.5% from 2013 to 2014 with the onset of the federal cap-and-trade program. From 2014 to 2020 we forecast an annual real rate of increase of 10%. Through 2025 we forecast an annual real rate of increase of 5%, and through 2030 an annual real rate of increase of 2.5%.

Figure 47. CO_2 Price Allowance Forecast



[101] According to Platts MWh Daily (July 25, 2008), the highest price for a reported deal done has been $8.50/short ton. Brokers and traders report that the bid / ask range for the allowances has been $7.75-$8.20.

3.3.2. NO_x and SO_2

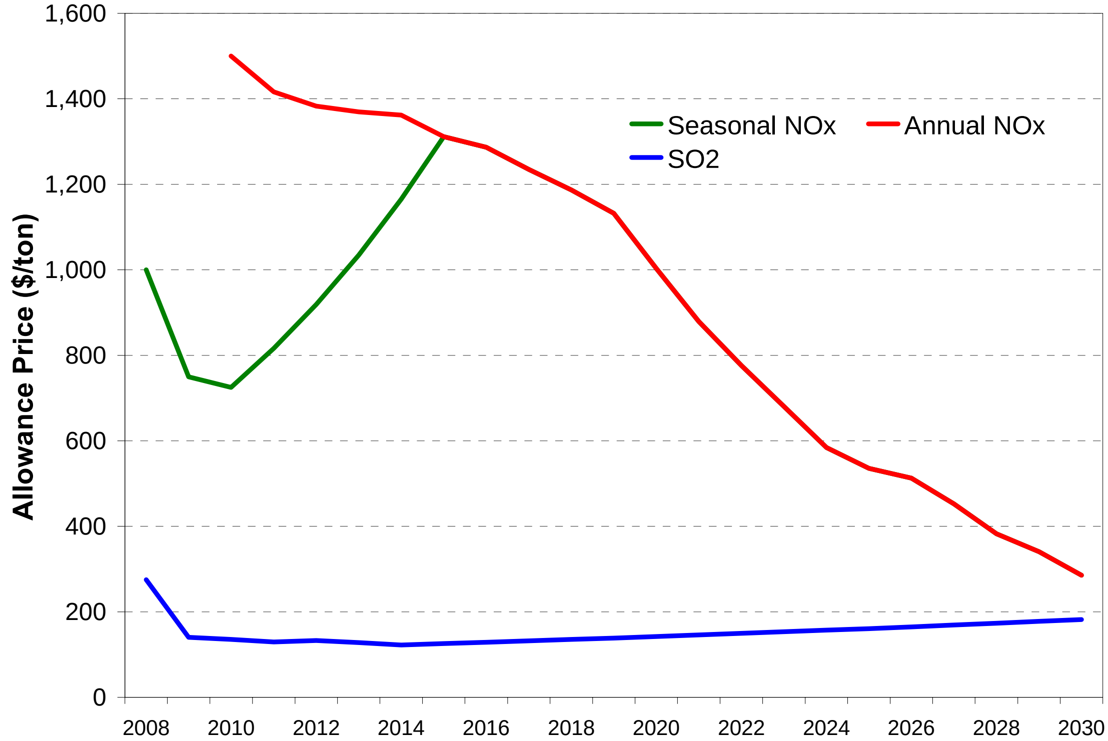
On July 11, 2008, the D.C. Circuit Court vacated the EPA's Clean Air Interstate Rule (CAIR) which would have expanded existing controls on NO_x and SO_2 emissions through cap-and-trade mechanisms. Following the Court's decision, the price of SO_2 and NO_x allowances fell sharply. For the purpose of our NO_x and SO_2 allowance price forecasts, we have assumed that the EPA will remedy the Court's objections to CAIR and eliminate the tightening of the ratio of allowances to tons of emitted SO_2. Thus, LAI's forecast continues to value SO_2 allowances equal to one ton of SO_2 over the entire forecast period, and reflects the current excess supply of SO_2 allowances ascribable to greater use of low sulfur coal and greater than expected scrubber retrofits.

The updated NO_x forecast assumes that NO_x allowance prices will not be affected to a significant extent beyond 2008 by the CAIR ruling. Initially the costs of running selective catalytic reduction (SCR) systems on an annual basis will result in higher compliance costs and higher annual allowance prices relative to seasonal prices. As the industry adjusts to annual controls, the price of seasonal and annual NO_x allowances will converge, around 2015. Long term, the price of allowances will be driven by reduced emissions and the declining marginal costs of NO_x removal technology. Figure 48 presents LAI's updated forecasts of SO_2 and NO_x emission allowance prices.

The Maryland Healthy Air Act (HAA) was promulgated with the objective of bringing Maryland into attainment with the National Ambient Air Quality Standards for ozone and fine particulate matter by the federal deadline of 2010. Phase I of the HAA requires statewide NO_x reductions of nearly 70% by 2009, and SO_2 reductions of 80% by 2010, relative to a 2002 baseline. Under Phase II, further reductions in NO_x and SO_2 are required by 2012 and 2013, respectively. Most of the coal-fired plants in Maryland which did not have SCR and wet flue gas desulfurization (FGD) have been required to undertake significant CapEx to retrofit this equipment or comparable emission controls. With respect to the Mirant fleet, these projects are well underway or nearly complete. As discussed in Section 8, capital costs associated with Mirant's HAA compliance through 2010 are included in financial model for the *Rate Base Regulation Case*.[102]

[102] Fixed costs for Mirant or other units do not enter into the MarketSym dispatch modeling.

Figure 48. NO_x and SO_2 Price Allowance Forecasts



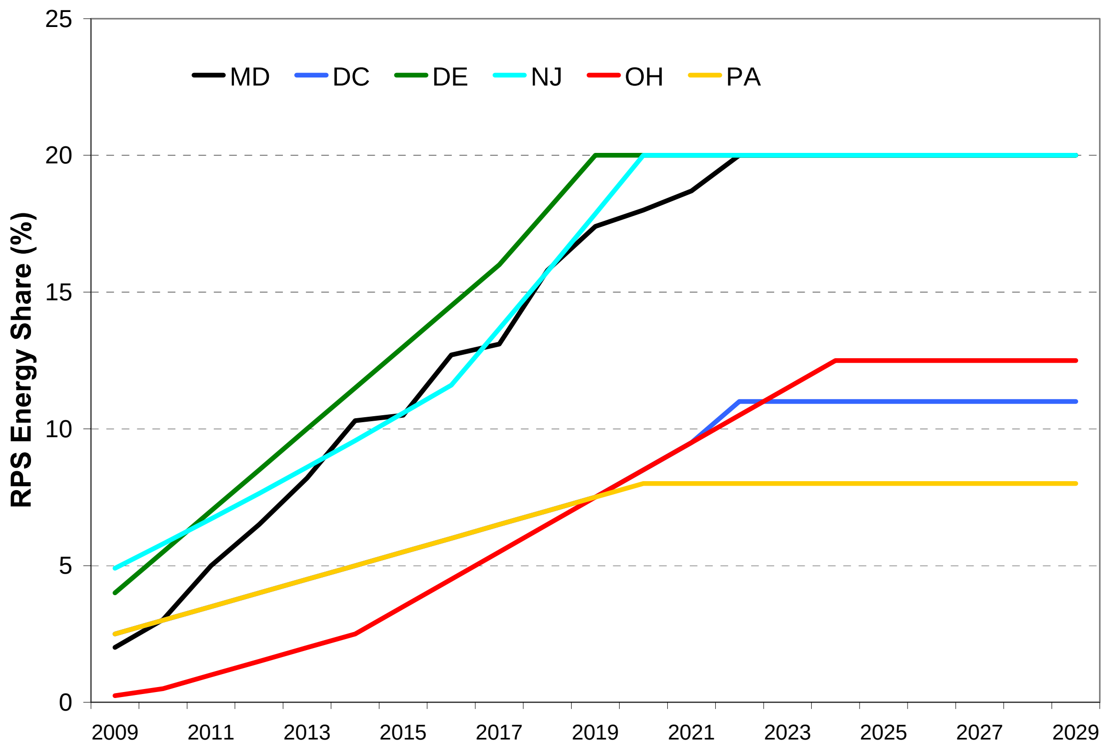
3.3.3. <u>Mercury</u>

Federal mercury regulations under the Clean Air Mercury Rule (CAMR) were vacated by the D.C. Court of Appeals on February 8, 2008, effectively leaving in limbo the status of federal controls on mercury from power plants. However, several states across the study region – MD, NJ, MA, CT, NH, and DE – have implemented regulations that are comparable to or more stringent than those required under CAMR. In Maryland, Phase I of the HAA will reduce statewide emissions from coal-fired plants by 80% by 2010, relative to a 2002 baseline. Further reductions are required by 2013. We assume that the required mercury reductions from the state's fleet of coal-fired plants will be achieved as co-benefits from the installation of SCR and FGD to meet the NO_x and SO_2 limits under the HAA.

3.3.4. <u>Renewable Portfolio Standard</u>

Across the study region, the various states' RPSs, coupled with the RGGI program and state tax policies, are intended to promote the construction of new renewable generation. RPS rules require states to provide an increasing percentage of their generation each year from qualified renewable resources, as indicated in Figure 49. In 2008, Maryland's Tier 1 RPS required LSEs to provide 2.005% of their sales from Tier 1 renewables, including at least 0.005% from solar, and 2.5% from Tier 2.[103] Under HB 375, effective in 2011, the Tier 1 renewable requirements will be substantially increased, to reach a target of 20%, including a 2% solar carve-out, by 2022. Tier 2 targets remain constant through 2018, and then expire.

Figure 49. Tier 1 Renewable Portfolio Standards of PJM States in the Study Region[104]



Compliance with the RPS is demonstrated by accumulating RECs, with each REC representing the environmental attributes from one MWh of qualified renewable energy. Maryland RECs may be derived from qualified renewable resources within Maryland, elsewhere in PJM, or from states adjacent to PJM. Effective in 2011, resources from the PJM-adjacent states will no longer be eligible. LSEs that do not obtain sufficient non-solar Tier 1 RECs are subject to an ACP penalty, established by statute at $20/MWh and increasing to $40/MWh in 2011. The Tier 2 ACP is $15/MWh. The solar ACP begins at $450/MWh and declines over time, as indicated in Figure 50. For comparison, the solar ACP for NJ is also shown in this figure.

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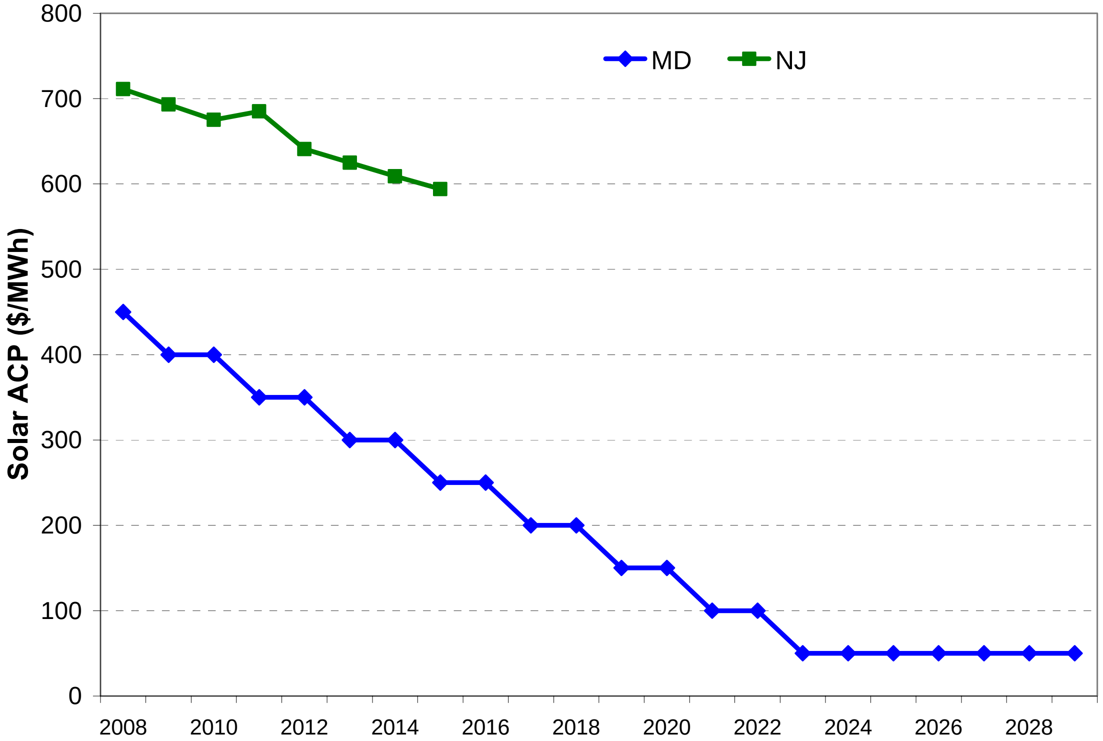
[103] Tier 1 includes solar, wind, qualifying biomass, landfill gas, geothermal, ocean energy, fuel cells, small hydroelectric, and poultry litter. Tier 2 includes hydroelectric larger than 30 MW (excluding pumped storage) and waste-to-energy.

[104] Tier 1 (or Class 1) includes any minimum solar requirement.

Figure 50. Solar Alternative Compliance Payments



The ACP is an effective cap on state REC prices. Table 14 summarizes the non-solar ACP penalties for relevant states within the study area.

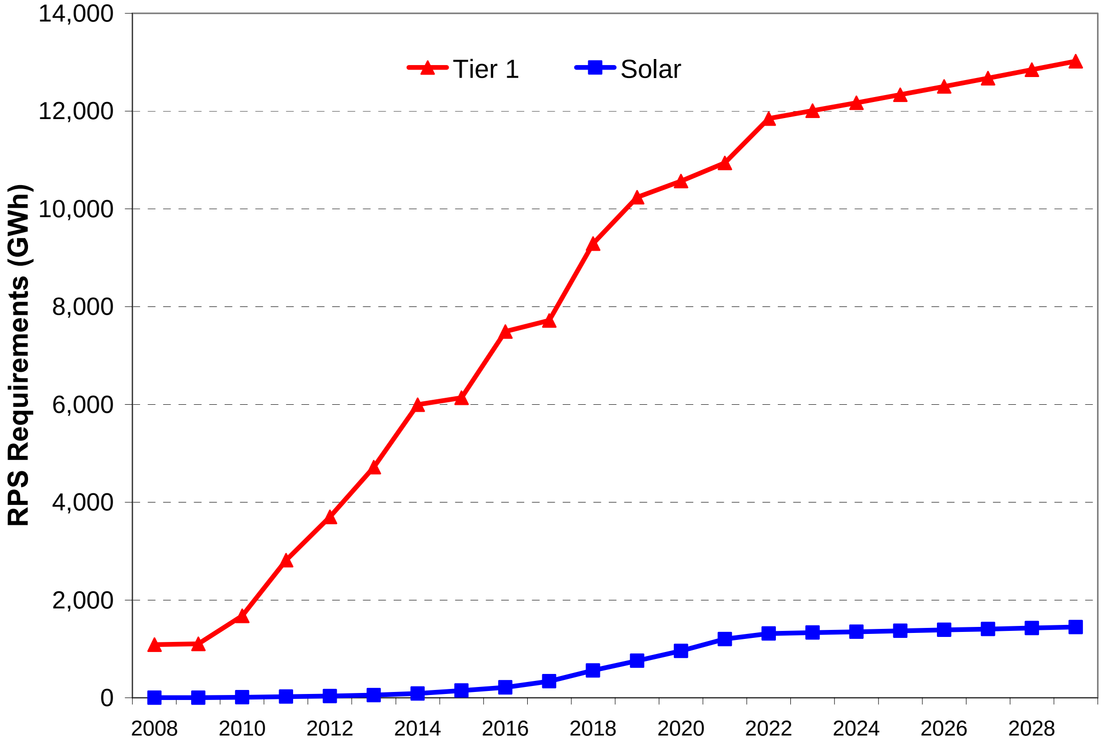
Table 14. Alternative Compliance Payments for Study Region States[105]

State	Alternative Compliance Payment Rules
DE	$25/MWh, increases in subsequent years for suppliers who elect to pay: $50/MWh in year 2, $80/MWh in year 3
DC	Tier 1 and 2: $50.00/MWh in 2003, $51.41/MWh in 2004 increasing with the CPI
MD	Tier 1: $20/MWh through 2010, $40/MWh effective 2011 Tier 2: $15/MWh
NJ	Class 1 and II: $50/MWh – unchanged since 2004
OH	$45/MWh in 2009, escalation thereafter at the CPI
PA	Tier 1 and Tier 2: $45/MWh
CT	$55/MWh
RI	$57.12/MWh in 2007, $58.58/MWh in 2008
MA	$50.00/MWh in 2003 escalating with CPI to $58.58/MWh in 2008
NH	$57.12/MWh in 2007 for Class I, $150/MWh for Class II and $28/MWh for Class III, adjusted yearly to CPI
ME	$57.12/MWh in 2007 escalating annually for inflation
VT	None

Figure 51 shows Maryland's Tier 1 and solar RPS in terms of total renewable energy, based on the Maryland load forecast used in this analysis. If the renewable energy requirement in 2028 is converted to MW of onshore wind or photovoltaics, the RPS requirements for Tier 1 are equivalent to 6,000 MW of installed wind capacity or 1,200 MW of photovoltaics.

[105] Database of State Incentives for Renewables and Efficiency, available at: http://www.dsireusa.org/index.cfm?EE=0&RE=1. Note that the New York RPS relies on a central procurement process to encourage development of renewable resources. RECs are not traded in New York and there is no applicable ACP. The NYPSC intends to review this policy in 2009, and may convert to an RPS similar to surrounding states.

Figure 51. Maryland RPS Requirements



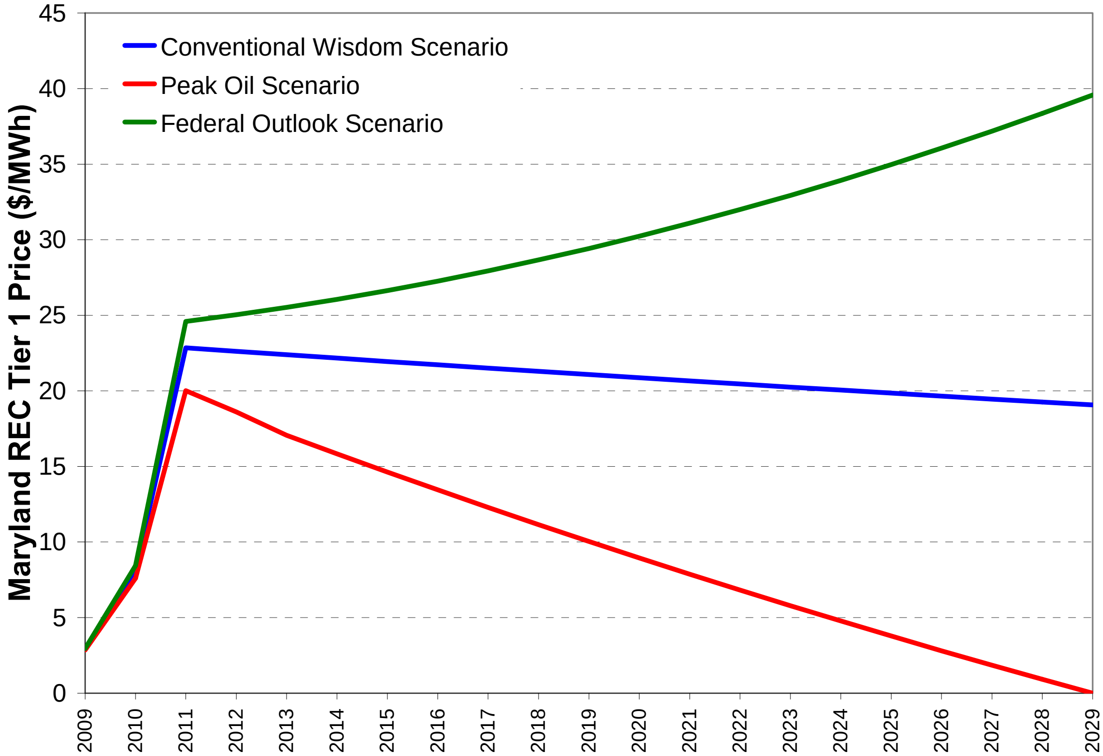
Sufficient supplies of Maryland-compliant RECs throughout PJM to date have kept Tier 1 REC prices around $1 and Tier 2 REC prices below $1. As the RPS requirements in Maryland and elsewhere in PJM increase, we expect the REC supply-demand balance to tighten, putting upward pressure on REC prices. The market price for RECs is determined by several factors, including the REC supply and demand in each of the PJM states, the cost of constructing and operating new renewable resources, the LMPs, the effective ACP cap for each state, and the availability of production tax credits.[106] We have developed a forecast for Maryland Tier 1 REC prices based on the supply and demand factors for the tradable REC commodity. Relative to the *Reference Case*, energy prices differ for each study case and scenario; hence, REC forecasts have been differentiated by study case and scenario where appropriate.

The REC price forecast for the *Reference Case* under each of the three fuel price scenarios is shown in Figure 52. In each scenario, the REC price increases steeply until 2011 as the surplus shrinks due to rapidly growing RPS requirements. Beyond 2011, the REC price represents an equilibrium condition as Maryland competes with other states across PJM for the supply of available RECs. By far, the largest driver of the REC forecast is the fuel forecast. LMPs are highest under the *Peak Oil Scenario* as the marginal generating units dispatch on premium fossil fuels. With higher revenues from energy sales, and operating costs largely unaffected by the price of fossil fuel, the residual revenue requirements for a renewable energy project are reduced, thereby putting downward pressure on REC prices. The converse is true under the *Federal*

[106] The production tax credit available for wind resources was recently extended for one year under the bailout package, but we assume it will not be extended further.

Outlook Scenario. The *No TrAIL Scenario* and the study cases based on a different mix of capacity resources result in a much smaller impact on the REC forecast. A detailed description of the REC forecast model and the price forecast for each of the alternative study cases are presented in Appendix C.

Figure 52. *Reference Case* REC Price Forecasts



Unlike non-solar Tier 1 or Tier 2 resources, we anticipate a continued shortfall in solar energy resources in Maryland. Whether Maryland's total solar energy resources expand from 1 MW to above 1,000 MW in 10 years is uncertain. The economics of photovoltaic installations are discussed in detail in Section 7. Consistent with our prior treatment, we value solar RECs based on the Maryland solar ACP throughout the study period (Figure 50).

4. CONVENTIONAL GENERATION

4.1. Introduction

To keep pace with load growth and retirement of uneconomic plants, grid reliability objectives have traditionally been met by the addition of new generation using established technologies. These include hydroelectric, fossil fueled boiler / steam plants, nuclear power, GTs and CC plants. Until the early 1980s, nearly all generation added to the resource mix throughout PJM was utility-owned and -operated, thereby subject to traditional cost of service regulation. In 1978 Congress passed the Public Utility Regulatory Policies Act (PURPA). PURPA required utilities to purchase third-party generation at prices indexed to the avoided cost of utility-owned generation. Most generation added in PJM in the 1980s and 1990s was under long-term PPAs, the majority of which was comprised of either waste-coal projects or gas-fired generation. Public utility commissions throughout PJM and neighboring states have permitted utilities to pass through to retail customers contract costs related to long-term purchases from qualifying facilities. Over the years, FERC has consistently upheld the enforceability of such long-term contract obligations.

In the mid- to late-1990s utilities in many parts of the U.S. elected to divest their generation assets in order to foster the goals of wholesale competition and retail choice. Utilities in Maryland either divested or transferred generation assets to unregulated companies. With the advent of de-regulation, new additions were expected to be built by unregulated generation companies responding to market signals regarding the amount and type of generation required to maintain system reliability. As discussed in Section 2.2.1, the problem of the missing money has caused PJM, as well as neighboring ISOs, to implement capacity pricing mechanisms to facilitate new investment.[107] New conventional resources have been added in PJM and neighboring ISOs under the new capacity price mechanism. However, most of the new generation that depends on natural gas, as well as new wind projects, has been supported by long-term PPAs with other market participants. Specific resource additions in Maryland have been limited to the 100 MW of wind projects known to be under contract. Other generic resource additions in Maryland over the forecast period in the *Reference Case* assume merchant-based cash flows under the RPM and the wholesale energy market.

Over the next 3 to 5 years – the period of time when Maryland may face a capacity deficit – supply options available to meet Maryland's resource requirements are limited to natural gas-fired generation and wind. New gas-fired generation can be simple-cycle GTs or CC plants. Gas-fired generation can generally burn either natural gas or distillate fuel oil as a backup. With appropriate emission control technologies such as dry low-NO_x burners, SCR, and carbon monoxide oxidation catalysts, gas-fired generation offers low emission levels of most pollutants. A natural gas-fired turbine emits roughly half the CO_2 of a coal-fired plant and about two-thirds the CO_2 of a residual oil-fired plant on a per-MMBtu fuel input basis. As discussed in the Interim Report, relative to coal-fired steam plants, gas-fired generation has low capital costs, requires less land, and can be built quickly. For these reasons, in this Final Report we have

[107] MISO has not implemented a capacity pricing mechanism.

assumed that the benefits of ratepayer-supported capacity obligations can be measured in terms of gas-fired generation added to the resource mix in Maryland.

In Table 15 we summarize the operating and performance characteristics of gas-fired generation.

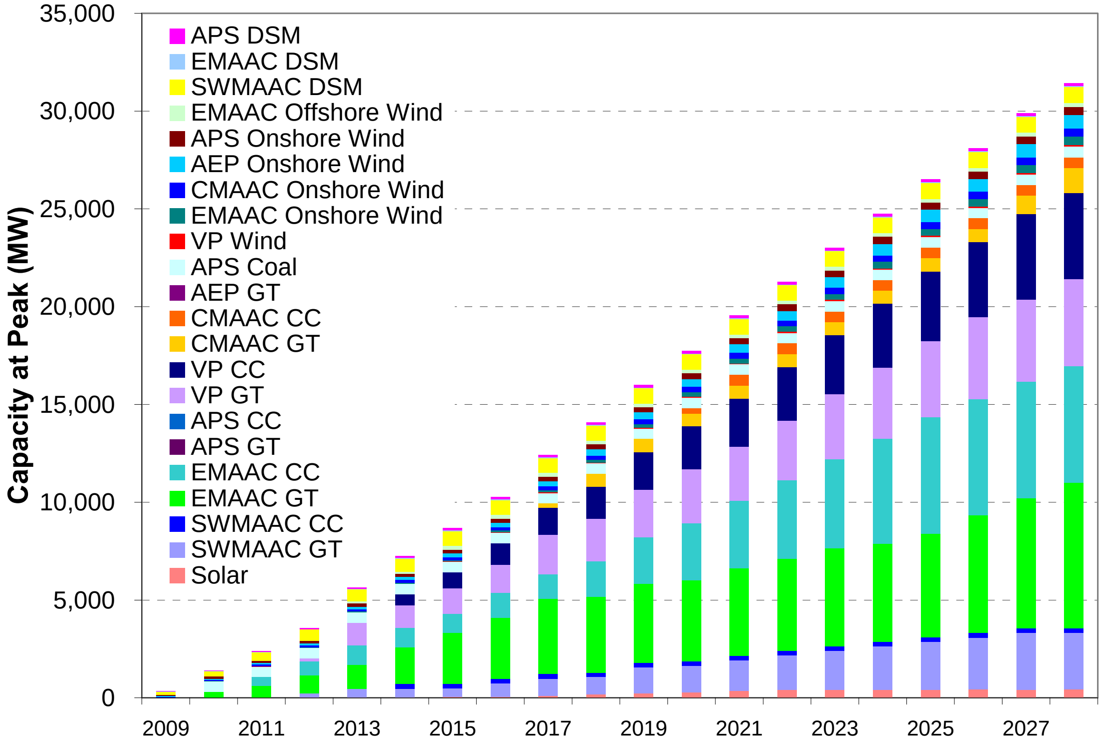
Table 15. Operating Characteristics of Simple-Cycle and CC Plants

	Simple Cycle	**Combined Cycle**
Configuration	2 x 7FA	2 x 7FA + STG
Output (net)	330 MW	505 MW
Availability	95%	92.5%
Construction Period	2-3 years	3 years
Capital Cost (net $/kW)	$ 700	$ 1,200
Fixed O&M ($/kW-yr)	$ 22.50	$ 25.00
Variable O&M ($/MWh)	$ 3.30	$ 3.00
Net Heat Rate (Btu/kWh; full load)	10,700	7,300

4.2. Merchant Entry (*Reference Case*)

As described in Section 2.1.4, new generic resource additions in the *Reference Case* over the long-term planning horizon include simple-cycle and CC GTs, renewable energy projects to meet RPS requirements, and DSM based on 25% of the EMD target each year. Simple-cycle and CC GTs are installed in an optimal mix just-in-time to meet reliability requirements. The higher capital intensity associated with CC plants can be offset by much greater profit margins from energy sales and, to a lesser extent, ancillary service sales. A detailed breakout of the annual capacity additions by technology type and zone is illustrated in Figure 53.

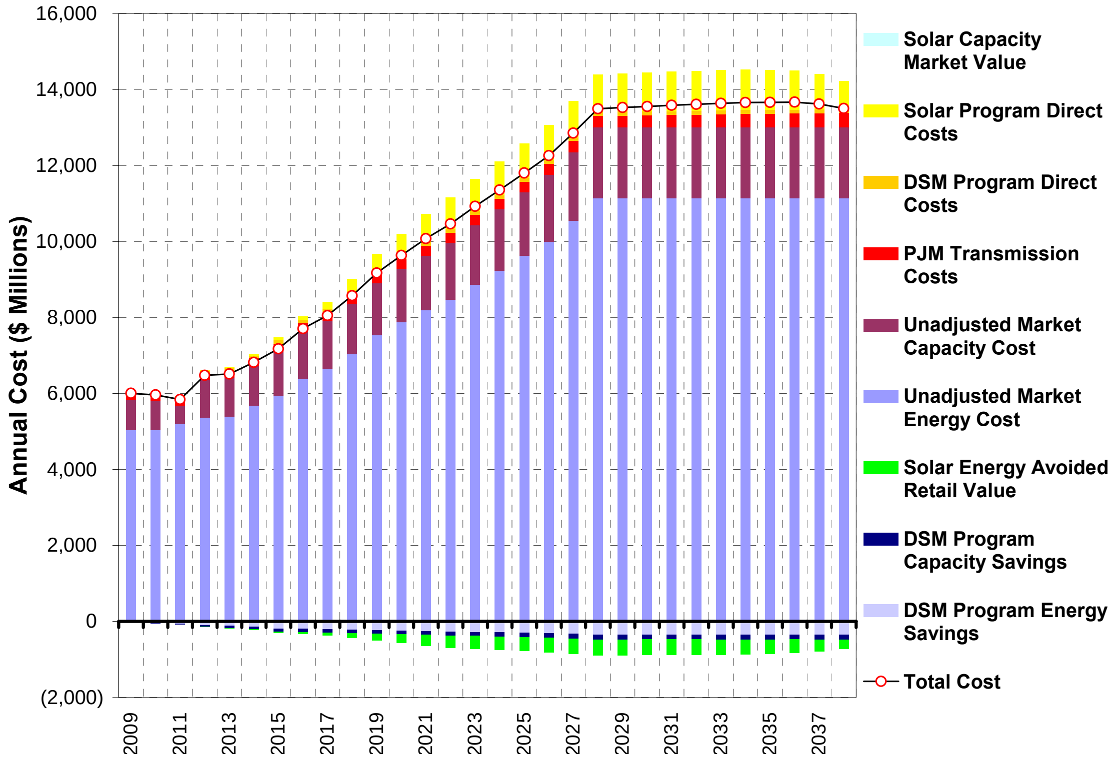
Figure 53. Capacity Additions – *Reference Case, Base Scenario*



The working hypothesis about merchant additions does not preclude contracts between the supplier and creditworthy counterparties. The generic unit additions may be expected to enter into short-, intermediate- or long-term contracts with creditworthy market participants other than IOUs. Off-take contracts facilitate project financing under reasonable pricing terms. Hence, we have made the assumption that the sale of capacity, energy, and ancillary services in the relevant PJM market will be sufficient to attract capital and earn a reasonable rate of return. Under the merchant model, IOU load is not assigned any direct cost responsibility for the fixed or variable costs associated with maintaining unit availability or producing energy. The cost of producing energy at market prices is reflected in the generation service component of SOS or through the cost of competitive retail supply. These generation costs reflect the forward electricity prices offered by wholesale suppliers, which are closely linked to the price of natural gas delivered to Maryland during heavy load hours. During light load hours and weekends, forward electricity prices are only moderately correlated with natural gas prices. When merchant entry is assumed, the risk and reward associated with new generation is left wholly with the merchant generator regardless of fluctuations in the value of capacity and energy.

The total annual costs to load for the *Reference Case* under the *Base Scenario* are shown in Figure 54. All study cases are reported in terms of differences relative to the *Reference Case*. Clearly, market energy cost is the largest component evaluated, followed by market capacity cost.

Figure 54. Annual Costs for *Reference Case* (*Base Scenario*)



4.3. Ratepayer-Backed New Generation

New generation supported by assured cost recovery from IOU ratepayers can provide benefits in two ways: first, by providing a hedge against volatile market prices – energy and, to a lesser extent, capacity – and, second, by temporarily creating a "long" market, thereby reducing energy and capacity prices. The reduction in energy and capacity prices benefits all load, not just the IOUs' ratepayers. Assured cost recovery can be effectuated either through a PPA between the IOU and a merchant generator, or through direct utility ownership. Under either arrangement, ratepayers incur fully the costs of renting or owning a new generation resource. Both the leasehold structure and utility ownership result in ratepayers receiving the market value of the capacity, energy, and ancillary services. Under the PPA case, we refer to the difference between the market value of the products and the cost of either renting or owning the resource as *contract benefits***.** Under the utility ownership case, we refer to the difference as *direct benefits*.[108] Under both the PPA and IOU ownership cases, payments to the IOU or merchant generator are much more predictable relative to a merchant operating regime, but are not necessarily lower over the life of the plant. Market revenues offset the market costs of procuring substantially the same services from the wholesale market – hence, the arrangement hedges a portion of the market costs to serve the ratepayer load in a fixed for variable swap.

To the extent that a large block of ratepayer-backed capacity creates a temporary surplus of supply, it would have the effect of reducing market prices. Since load is ultimately served by

[108] The contract benefits and direct benefits may be positive or negative in any year.

purchases from the market, either directly or through wholesale contracts of relatively short term, the lower market prices would result in lower costs to all ratepayers, regardless of whether they subscribe to standard or competitive retail supply.[109] In gauging the relative merit of ratepayer-backed capacity arrangements, we have quantified the expected MTM impact of the change in total portfolio costs. Benefits that arise through creation of a transient or extended long market are referred to as *portfolio benefits*. Whereas contract and direct benefits inure only to the IOU's ratepayers, portfolio benefits will accrue to all load that experiences the market impact of excess supply.

Two cases have been defined that are distinguished by ownership criteria rather than technology type or size. Both cases reflect the addition of two 540-MW (nameplate) CCs to the resource mix in SWMAAC in 2012. Each 540-MW station is a two on one design with two GTs, two HRSGs, and one ST. In the *Contract CC Case*, the IOUs "rent" the facility from an unregulated merchant generator. In the *Utility CC Case*, the IOUs develop, own, and operate the facility. The addition of 1,080 MW of CC plant nameplate capacity would be expected to defer the addition of other merchant suppliers in the *Reference Case*.[110] Assuming the addition of TrAIL in 2014, the capacity surplus in SWMAAC is depleted in 2017. Figure 55 shows the differential new capacity by type and location, relative to the *Reference Case*. The dark blue bar in 2012 has a height of 960 MW, which is the summer rating of the 1,080-MW nominal CC facility. The light blue bar below the x-axis in 2012 represents an avoided GT of about 230 MW. Additional GTs are avoided in 2013 and 2017. The drop in the height of the dark blue bar in 2014 represents the avoidance of a 250-MW CC unit scheduled in the *Reference Case* for that year.

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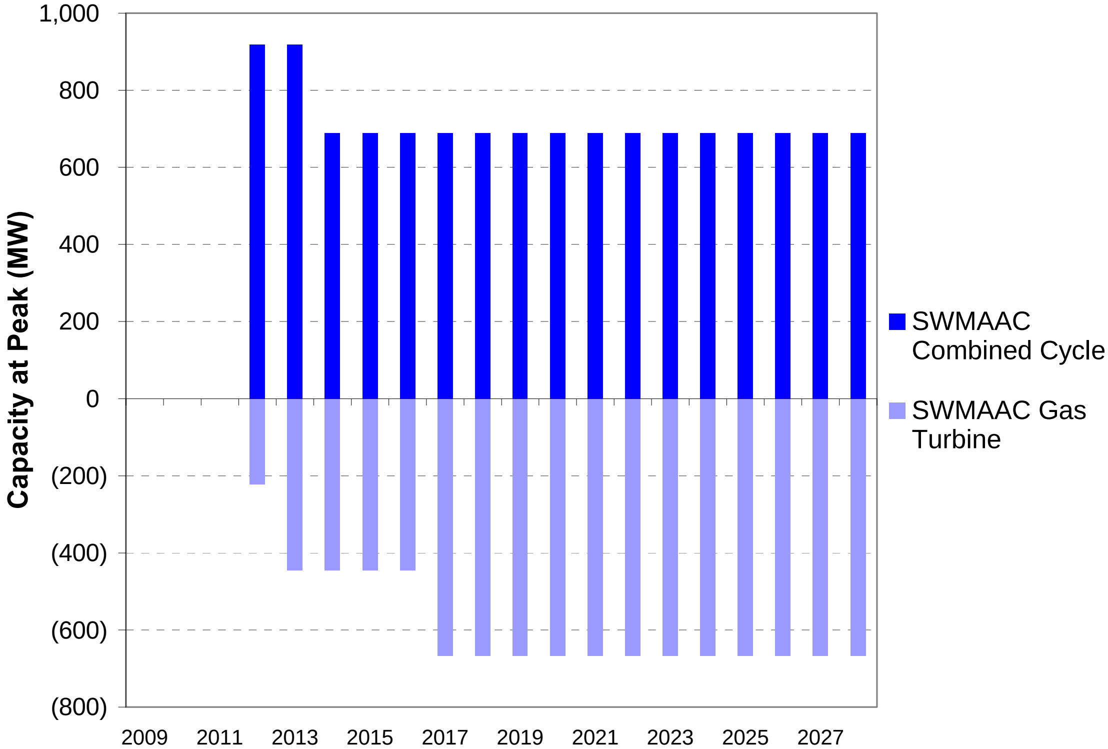
[109] The lower prices also mean lower revenue to all generators. The prospect of lower revenues may discourage new entry by merchant generators, creating future shortages or requiring future market structure adjustments to meet reliability requirements.

[110] About 250 MW of the displaced capacity is CC, the remainder would be simple-cycle GTs.

Figure 55. Incremental Capacity Additions – *Contract CC* and *Utility CC Cases*



4.3.1. Long-Term Contracts for New Generation (*Contract CC Case*)

Developers throughout the mid-Atlantic and the greater Northeast have expressed interest in long-term contracts in order to obtain financing on reasonable cost terms. Maryland's IOUs have investment grade credit ratings and can therefore provide generation companies with an assured revenue source. So long as an IOU has the Commission's approval to recover costs under a PPA, a long-term contract with one or more IOUs would be viewed favorably by the rating agencies. In LAI's experience, under the PPA structure the developer can make a reasonably assured return on investment, while retaining the potential to enjoy additional financial return if plant performance exceeds the guarantee level. On the downside, the developer is exposed to project cost overruns that cannot be recouped under fixed capacity and non-fuel variable pricing incorporated in the PPA. For this reason, the PPA pricing typically includes an AFI as well as a contingency factor.[111] In competitive solicitations for long-term PPAs, developers typically compete aggressively for a contract award, but failure to include an AFI and/or general contingency can impair or preclude the ability to raise capital.

The *Contract CC Case* quantifies the benefits of a PPA that grants to buyer – in this case, the utility on behalf of ratepayers – the entitlement to the market value of 1,080 MW of new CC

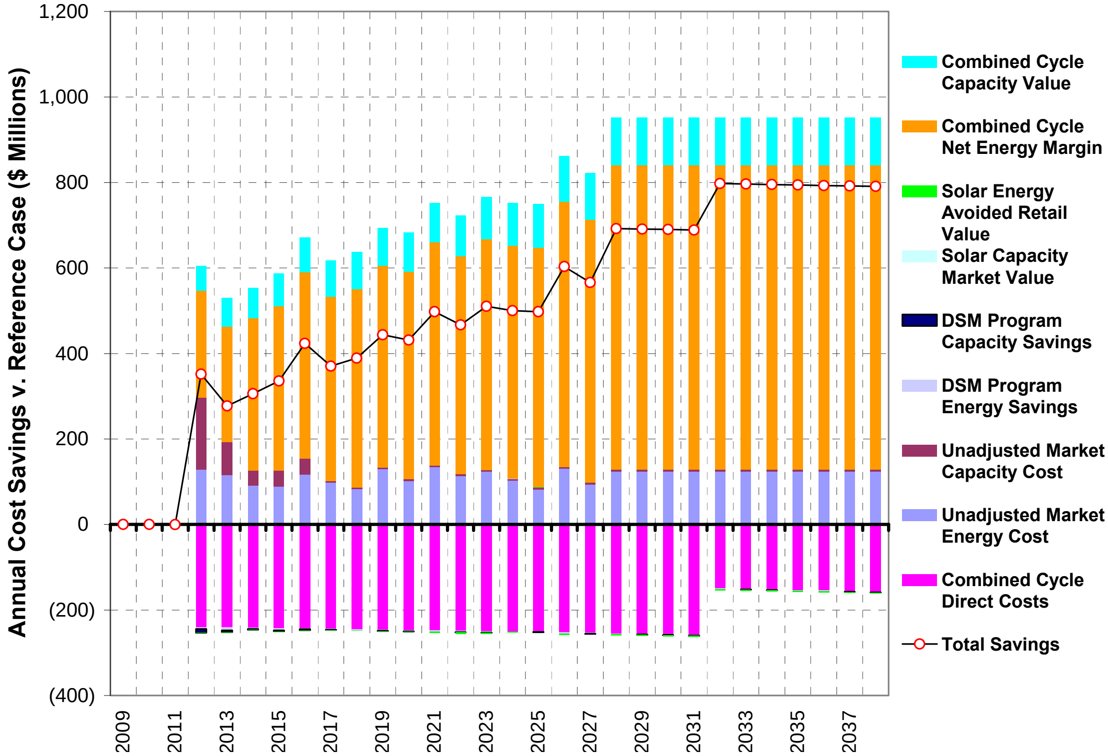
[111] AFI and contingency is intended to cover cost overruns that the developer is not protected against under its EPC contract. PPAs do not typically commit the seller to a guaranteed performance level that is not matched by underlying warranties from the manufacturer.

capacity in SWMAAC. In exchange, the merchant generator receives fixed and variable contract payments. The financial analysis is structured based upon the following assumptions:

- Through fixed PPA payments, the merchant generator owner will seek a full recovery of original capital costs during the initial 20-year PPA term, less an assumed sale of the site (and equipment "as-is") at the end of that term. The merchant generator will set revenue requirements to recover actual capital costs, less expected resale value of the site-related asset. The annual capital charges are described in more detail in Section 2.5.5.
- The merchant generator would also expect a return on the investment. The capital structure is consistent with financing terms for a merchant generator with a long-term contract summarized in Table 10.
- To continue to provide service for another 10 years under the renewal option, additional CapEx will be required. We have estimated that the incremental CapEx will be 10% of the initial plant cost in nominal terms.
- Variable contract payments will allow the merchant generator to recover fuel and non-fuel operating costs consistent with the operating parameters in Table 15. Fuel costs are based upon the delivered price of natural gas to SWMAAC and a heat rate function established in the PPA.
- The IOU, on behalf of the ratepayer, is credited with the market value of the products from the two CC plants: energy, capacity, and ancillary services.

Base Scenario annual cost savings, relative to the *Reference Case*, are shown in Figure 56. Note that the majority of the benefits are ascribable to the net energy margin of the facility – the difference between market energy revenue and fuel and other variable costs. The market value of the capacity itself is significant, but much smaller than the direct costs. Portfolio benefits in the form of lower costs to load for market energy and capacity are relatively small. The market capacity cost effect is negligible after 2016, when the surplus created by the project is worked off.

Figure 56. Annual Savings – *Contract CC Case*



4.3.2. Utility Ownership of New Generation (*Utility CC Case*)

Another way for ratepayers to support new generation is through direct ownership by the utility. Maryland IOUs do not presently own generation. Under the *Utility CC Case*, we postulate that the IOUs, with authorization granted by the Legislature and the Commission, re-establish the corporate infrastructure to own and operate generation plants in Maryland. The benefits of utility ownership have been limited to 1,080 MW of new CC capacity in SWMAAC.

Under utility ownership, the IOUs are authorized to recover from ratepayers all prudently incurred capital and O&M costs, including fuel expense. Capacity, energy and ancillary services are sold into the wholesale market rather than directly to SOS customers. Therefore, the revenue requirements of the new plants, net of market revenues from the sale of capacity, energy, and ancillary services, are charged or credited to ratepayers as a non-bypassable charge. The financial assumptions associated with IOU ownership of new generation are presented in Section 2.5.3.

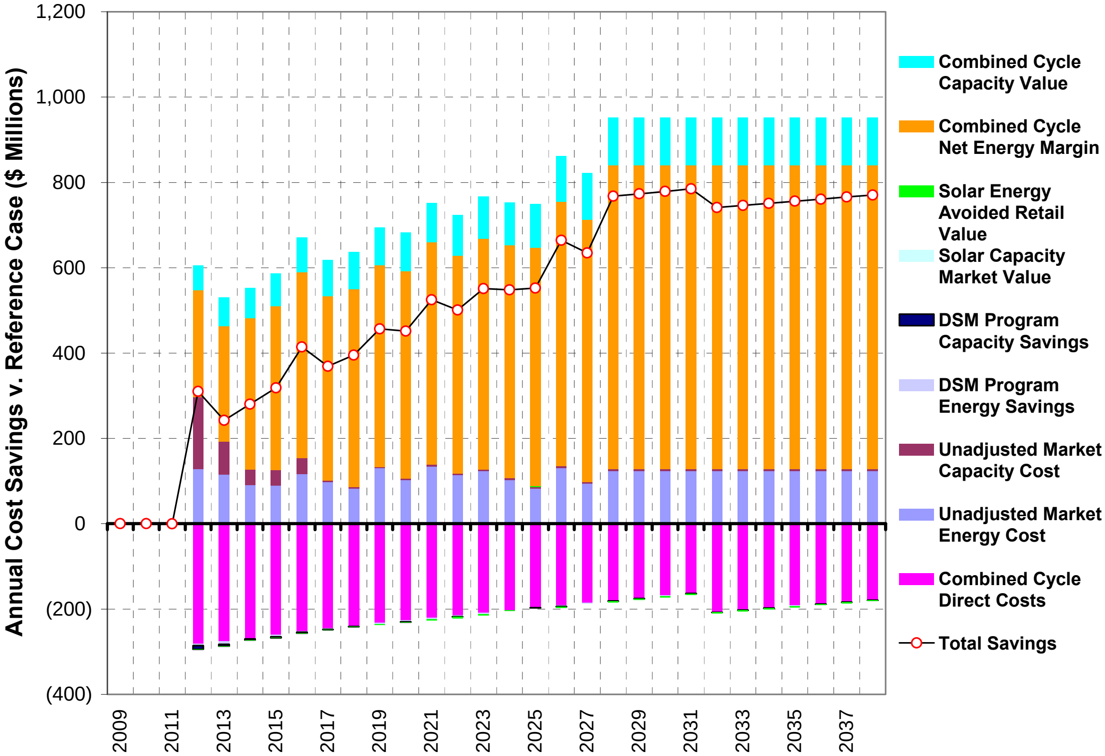
Under this structure the IOUs will remain subject to traditional cost of service regulation. Whereas cost of service regulation is presently limited to the T&D function, the Commission would need to assess what generation-related costs should be passed through to ratepayers, as well as the appropriate rate of return to compensate the IOUs for the increased risk of owning and operating generation, if any. To the extent the IOUs' actual cost to build new generation reflects reasonable incurrence of sundry cost components associated with environmental pollution control equipment, gas or electric interconnection costs, community improvements, among other things, it would be reasonable for the Commission to allow such costs to be allocated to ratepayers. For this reason, it would not be necessary for the IOU to capitalize as large an AFI or general contingency factor to account for capital cost uncertainty. Instead, actual costs will be justified from rate case to rate case.

The financial analysis of the *Utility CC Case* is structured similar to the *Contract CC Case*, with the following distinctions:

- The IOU will recover its capital costs through annual charges for depreciation, interest, and ROE, as described in Section 2.5.3. These charges are largest in the early years as the outstanding rate base is largest. They decline in proportion to cumulative depreciation.
- The IOU will incur the same future capital costs to assure performance through a 30-year overall life. These result in a small increase in capital recovery charges in year 2032, relative to 2031. Charges in all years assume that the sale of the site and remaining assets at the end of the contract life will be at the same price as assumed for the *Contract CC Case*.
- All fixed and variable O&M expenses and fuel expenses will be passed through directly to the ratepayers, offset by the market value of the capacity, energy, and ancillary service products of the facility.

Base Scenario annual savings of the *Utility CC Case*, relative to the *Reference Case* are shown in Figure 57. Note the difference in pattern for the pink bars representing “CC direct costs”, relative to those for the *Contract CC Case* in Figure 56. The line representing total annual savings is similar for the two cases.

Figure 57. Annual Savings – *Utility CC Case*

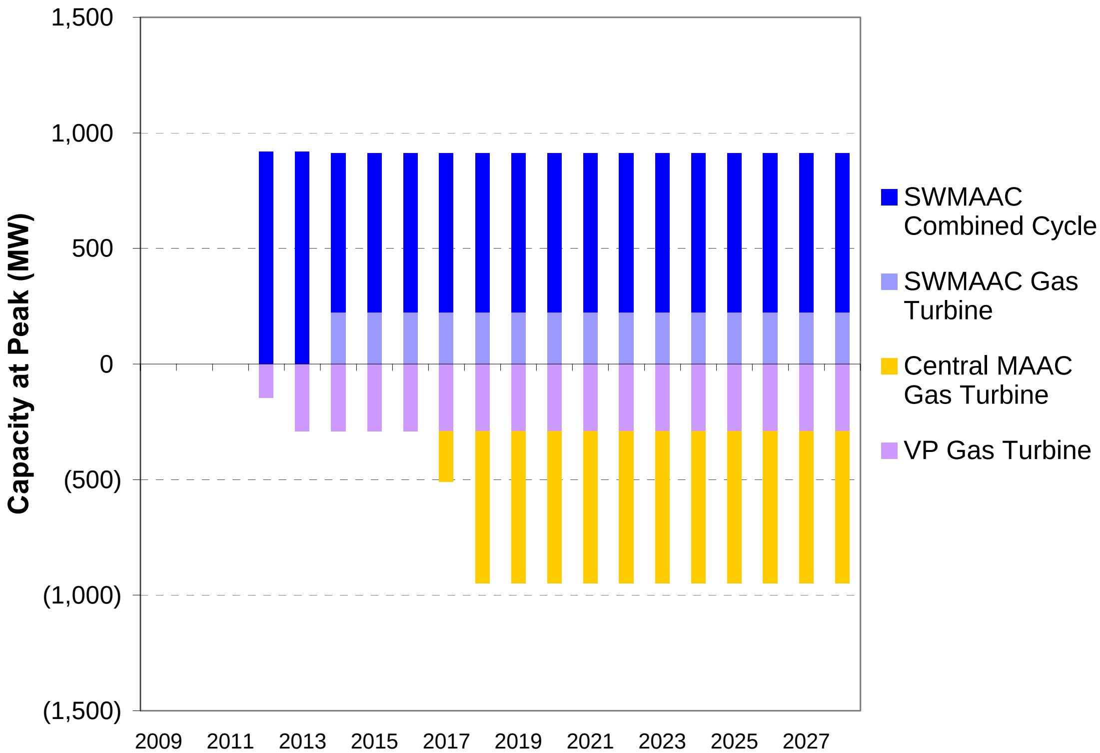


4.4. Ratepayer-Backed Surplus (*Overbuild Case*)

Ratepayer-backed capacity reasonably assures the timely addition of new capacity, thereby meeting PJM reliability requirements. Reliance on market signals to support merchant entry is much less likely to support this objective. Ratepayer-backed capacity can result in a short-lived or long-lived capacity surplus, yielding portfolio benefits to load. To maintain long-lived capacity surplus to support portfolio benefits, Maryland's IOUs would likely need to continue purchasing new capacity under long-term agreement, or otherwise build it. In the *Overbuild Case*, we assume that the 1,080-MW CC plants plus future resource additions in SWMAAC are ratepayer-backed PPAs.[112] The capacity surplus created in SWMAAC would lead to deferral of capacity additions elsewhere in PJM, all other things being the same. In Figure 58 the capacity overhang is sustained until 2018 by deferrals of additions in other PJM zones.

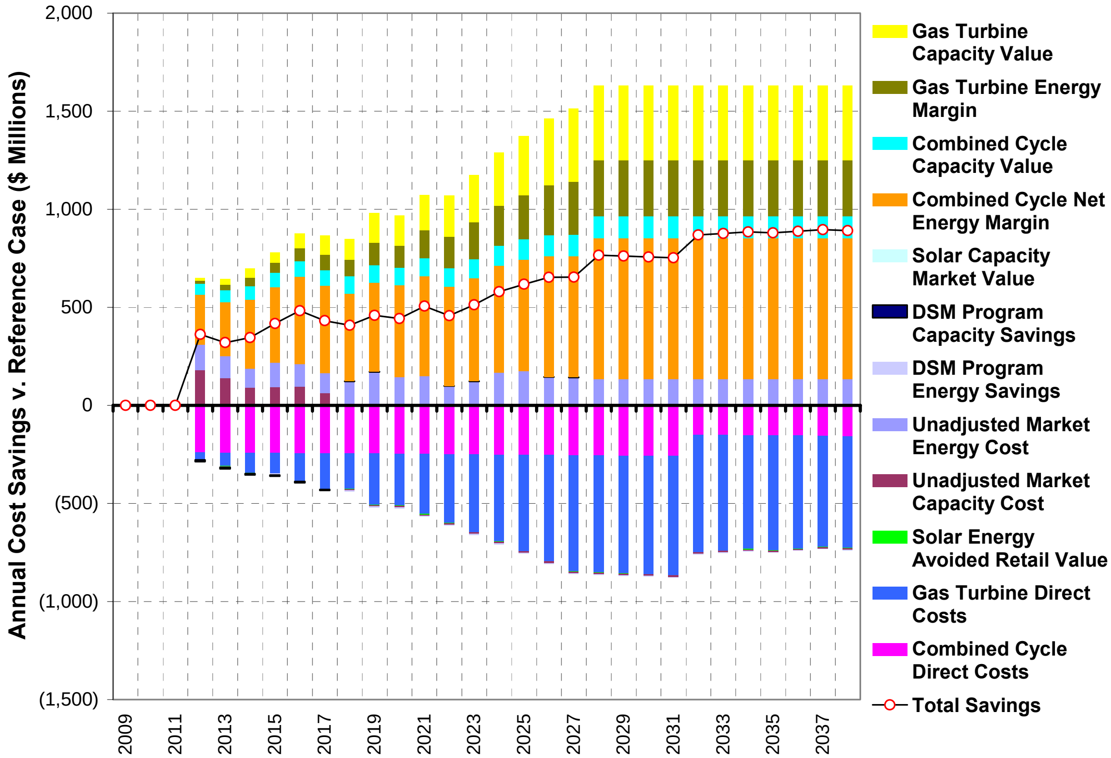
[112] In the *Reference Case*, a 230-MW CC is added in 2014. In the *Overbuild Case*, we assume that this unit would be replaced by a 223-MW simple-cycle unit, also ratepayer supported.

Figure 58. Incremental Capacity Additions – *Overbuild Case*



Base Scenario annual cost savings for the *Overbuild Case*, relative to the *Reference Case*, are shown in Figure 59. The additional bars in this figure represent the direct costs, market capacity value, and market energy value of the simple-cycle GTs that are assigned to ratepayers under this case. These costs and benefits become significant in the later years, but they tend to cancel each other out. The capacity price effect for load is more significant for the *Overbuild Case* than for the *Contract CC* and *Utility CC Cases*, but it is still reduced to insignificance by 2018 due to displacement of GTs in neighboring PJM zones.

Figure 59. Annual Savings – *Overbuild Case*



4.5. Financial Comparison of Cases

4.5.1. Base Scenario

Financial results for the *Contract CC Case*, the *Utility CC Case*, and the *Overbuild Case* under the *Base Scenario* assumptions for fuel prices and transmission infrastructure, are shown in Figure 60 and Figure 61. The *Overbuild Case* offers a somewhat higher PV of savings (EVA) than the other two cases, and all offer significant value relative to the *Reference Case*. In terms of direct costs, the *Contract CC Case* is more costly than the *Utility CC Case* by about $55 million, and the *Overbuild Case* has more than double the direct costs. The *Overbuild Case* provides significantly more capacity value, but little additional net energy margin. The portfolio benefits of the *Overbuild Case*, relative to the other cases, are negligible. It should be noted that the ratio of gross benefits to "generation direct costs" is about 2.99:1 for the *Contract CC Case*, 3.07:1 for the *Utility CC Case*, and only 1.98:1 for the *Overbuild Case*, indicating that the additional direct cost commitment to maintain a surplus in SWMAAC does not provide the same return as the commitment for the 1,080-MW station.

Figure 60. Annual Savings – Conventional Generation Cases (*Base Scenario*)

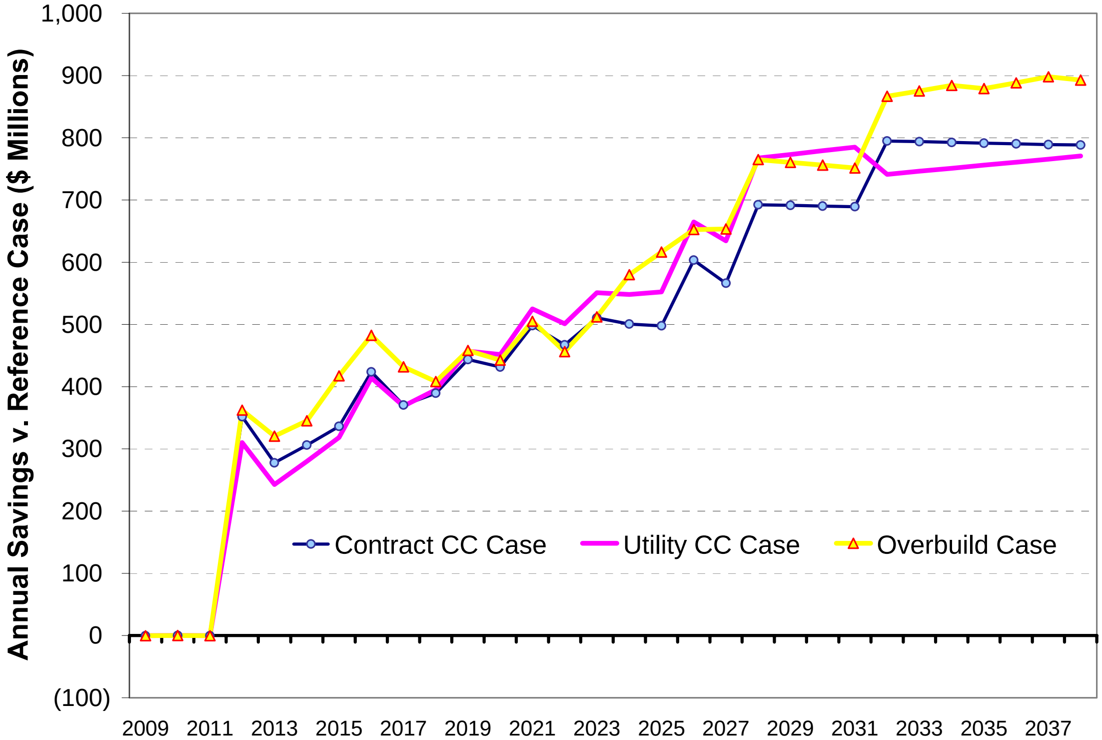
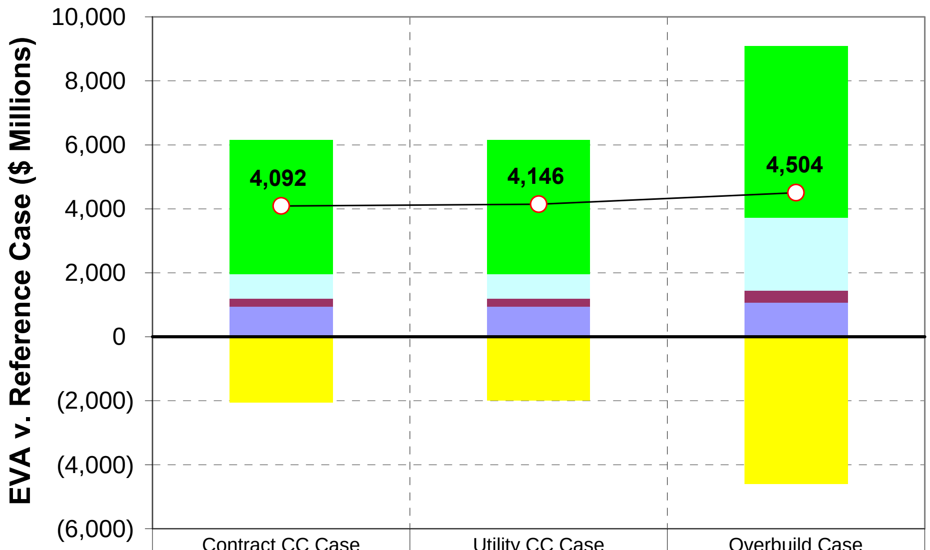


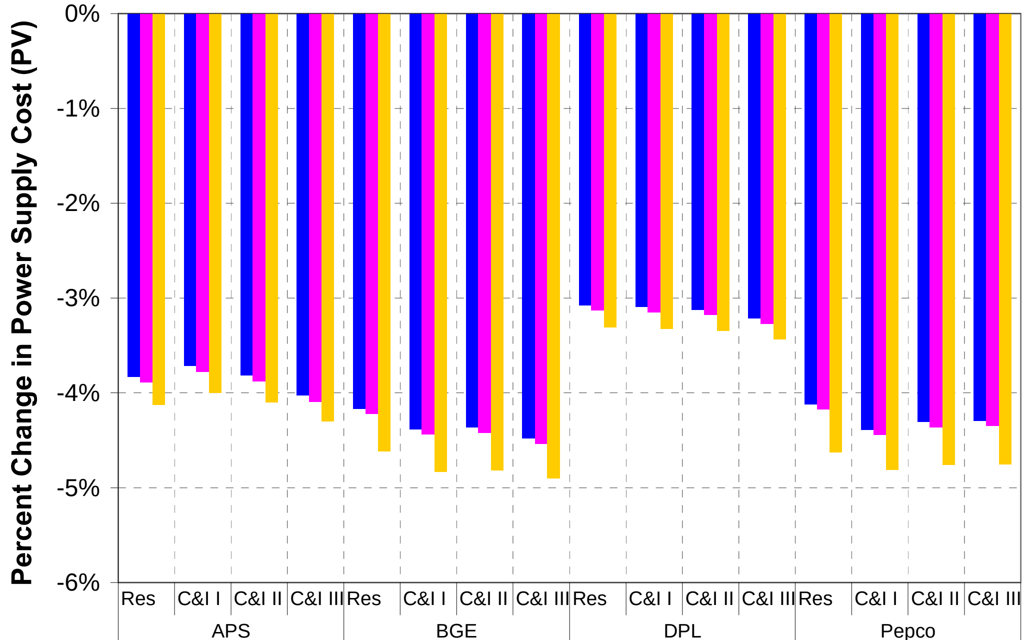
Figure 61. EVA – Conventional Generation Cases (*Base Scenario*)



	Contract CC Case	Utility CC Case	Overbuild Case
Generation Net Energy Margin	4,191	4,191	5,364
Generation Capacity Credit	769	769	2,292
Market Capacity Cost	246	246	362
Market Energy Cost	941	941	1,075
Generation Direct Costs	(2,054)	(2,000)	(4,588)
Total EVA	4,092	4,146	4,504

Ratepayer cost effects are shown by IOU and class as a percentage of the *Reference Case* power supply charge in Figure 62.

Figure 62. Ratepayer Impact – Conventional Generation Cases (*Base Scenario*)

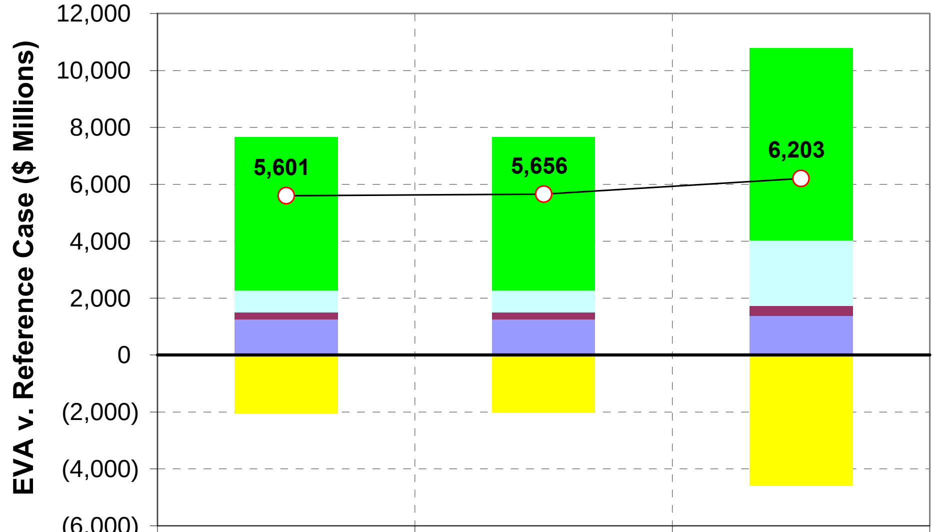


	APS Res	APS C&I I	APS C&I II	APS C&I III	BGE Res	BGE C&I I	BGE C&I II	BGE C&I III	DPL Res	DPL C&I I	DPL C&I II	DPL C&I III	Pepco Res	Pepco C&I I	Pepco C&I II	Pepco C&I III
Contract CC Case	-3.8%	-3.7%	-3.8%	-4.0%	-4.2%	-4.4%	-4.4%	-4.5%	-3.1%	-3.1%	-3.1%	-3.2%	-4.1%	-4.4%	-4.3%	-4.3%
Utility CC Case	-3.9%	-3.8%	-3.9%	-4.1%	-4.2%	-4.4%	-4.4%	-4.5%	-3.1%	-3.1%	-3.2%	-3.3%	-4.2%	-4.4%	-4.4%	-4.3%
Overbuild Case	-4.1%	-4.0%	-4.1%	-4.3%	-4.6%	-4.8%	-4.8%	-4.9%	-3.3%	-3.3%	-3.3%	-3.4%	-4.6%	-4.8%	-4.8%	-4.8%

4.5.2. <u>Alternative Fuel Price Scenarios</u>

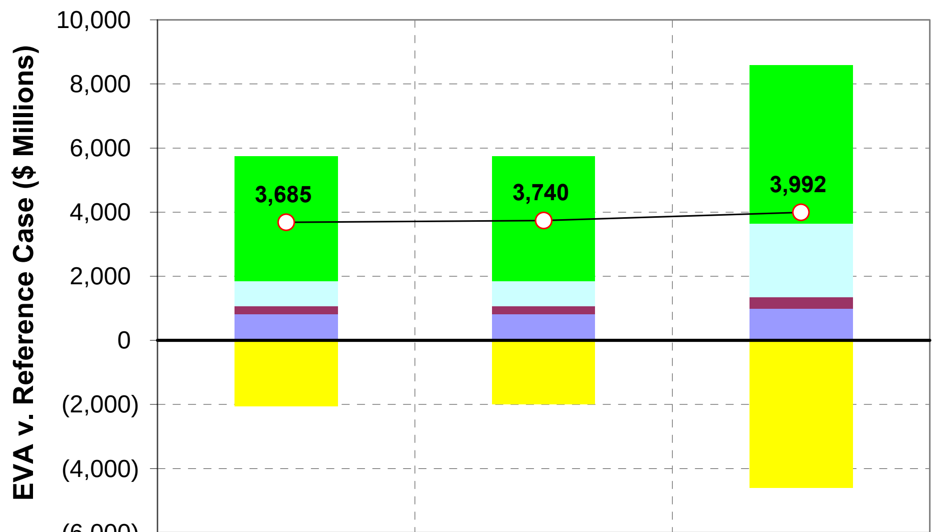
PV results for the conventional generation cases under the alternative fuel price scenarios are shown in Figure 63 and Figure 64 EVAs for all three cases are higher under the *Peak Oil Scenario* and lower under the *Federal Outlook Scenario*, relative to the *Base Scenario*. The fuel scenarios have no effect on the difference between the contract and IOU ownership arrangements. The *Overbuild Case* becomes relatively more attractive under the unlikely *Peak Oil Scenario*, and less attractive under the more reasonable set of fuel prices embodied in the *Federal Outlook Scenario*.

Figure 63. EVA – Conventional Generation Cases (*Peak Oil Scenario*)



	Contract CC Case	Utility CC Case	Overbuild Case
Generation Net Energy Margin	5,391	5,391	6,767
Generation Capacity Credit	769	769	2,292
Market Capacity Cost	246	246	362
Market Energy Cost	1,251	1,251	1,373
Generation Direct Costs	(2,055)	(2,000)	(4,592)
Total EVA	5,601	5,656	6,203

Figure 64. EVA – Conventional Generation Cases (*Federal Outlook Scenario*)

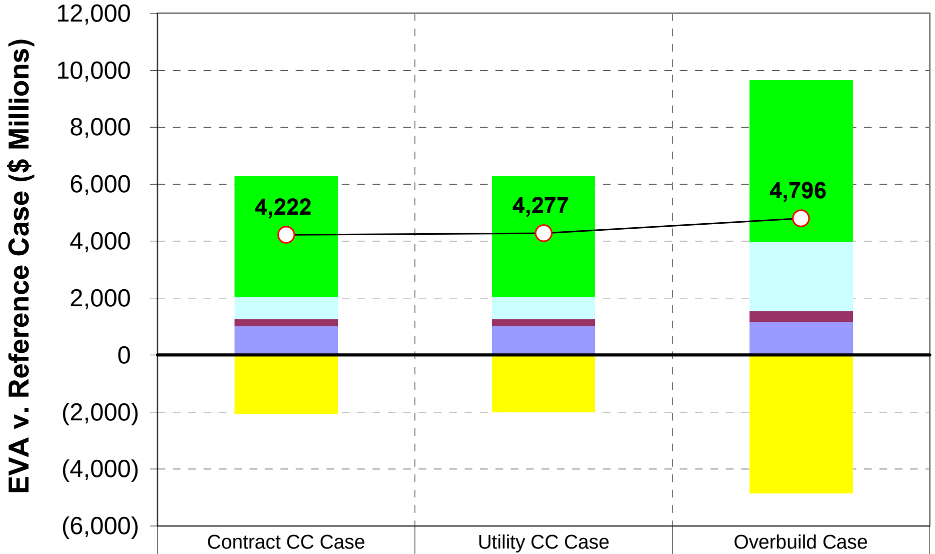


	Contract CC Case	Utility CC Case	Overbuild Case
Generation Net Energy Margin	3,900	3,900	4,938
Generation Capacity Credit	769	769	2,292
Market Capacity Cost	246	246	362
Market Energy Cost	826	826	992
Generation Direct Costs	(2,055)	(2,000)	(4,592)
Total EVA	3,685	3,740	3,992

4.5.3. No TrAIL Scenario

EVA results for the conventional generation cases under the *No TrAIL Scenario* are shown in Figure 65. The absence of TrAIL has little impact on the relative standing of the conventional generation scenarios.

Figure 65. EVA – Conventional Generation Cases (*No TrAIL Scenario*)

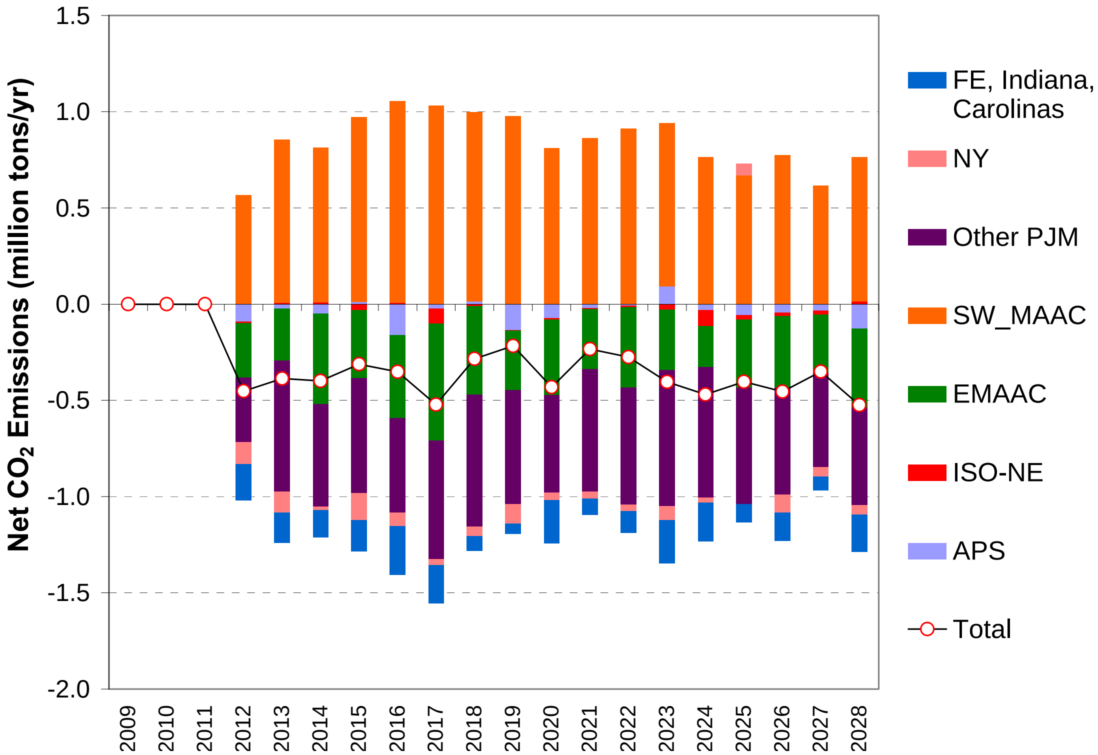


	Contract CC Case	Utility CC Case	Overbuild Case
Generation Net Energy Margin	4,251	4,251	5,678
Generation Capacity Credit	764	764	2,439
Market Capacity Cost	245	245	362
Market Energy Cost	1,017	1,017	1,170
Generation Direct Costs	(2,055)	(2,000)	(4,852)
Total EVA	4,222	4,277	4,796

4.6. Net Environmental Benefits

Among a host of other variables, the chronological dispatch simulation model tracks hourly fuel consumption and emissions of CO_2, SO_2, and NO_x on a plant by plant basis. The net air quality benefits of 1,080 MW of CC units have been quantified by calculating the differences in aggregated annual emissions of CO_2, SO_2 and NO_x between the *Utility CC* and *Contract CC Cases* and the *Reference Case* for the *Base Scenario*. Figure 66 illustrates the annual net CO_2 emissions by zone across the study area. Within SWMAAC, annual CO_2 emissions increase relative to the *Reference Case*. With the exception of small quantities from NY and APS in a few years, all other zones experience a net decrease in annual CO_2 emissions. Summing across the study region, total CO_2 emissions are reduced by roughly 217,000 to 523,000 tons per year when the new CC plants are in service, relative to the *Reference Case*.

Figure 66. Change in CO_2 Emissions – *Contract CC / Utility CC Cases*



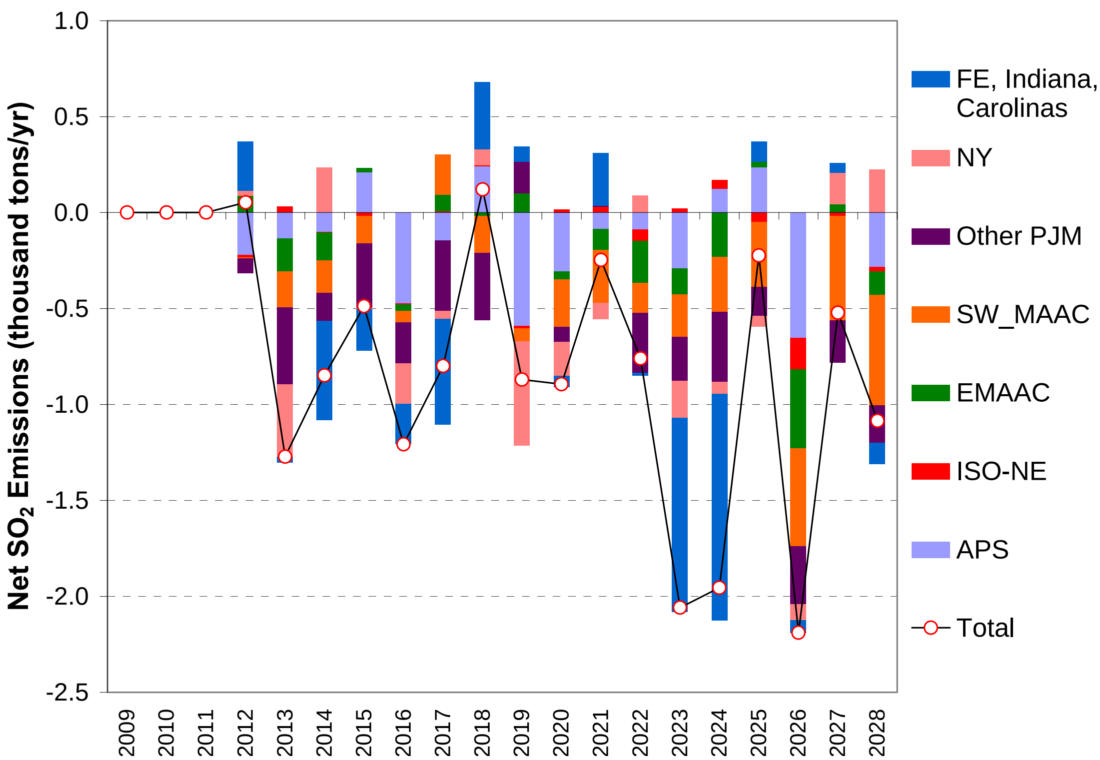
CO_2 emissions are a relative gauge of energy output from the fossil fuel-fired generation portfolio. The net increase in CO_2 from SWMAAC, but decrease from nearly all other zones indicates that the addition of 1,080 MW of CCs in SWMAAC will materially reduce imports. The avoided imports likely include output from coal units as well as older vintage oil-fired generation elsewhere in PJM, MISO, and the Carolinas, which include units that are more carbon-intensive, less efficient and equipped with less efficient pollution controls.

Under RGGI, Maryland's annual CO_2 budget each year from 2009 through 2014 is 37,504,000 tons. From 2015 through 2018, Maryland and each of the RGGI states has committed to reducing their total CO_2 emissions each year by 2.5% of the 2009-2014 baseline. Maryland's annual reduction target for 2015 through 2018 is 937,600 tons. All else equal, the net CO_2 reduction from the installation of 1,080 MW of new CC units represents roughly one-third to one-half of Maryland's 2015 RGGI reduction target.

The CO_2 emission reductions are largely created *outside* of Maryland by virtue of new generation constructed *within* Maryland. Stakeholders in Maryland would, however, be indifferent to where the reductions are created, for several reasons. *First*, greenhouse gases are a global problem, not a local air quality issue. *Second*, the quantity of RGGI allowances allocated annually to each state was established under the RGGI memorandum of understanding, and is not a function of actual emissions or emission reductions achieved. Therefore Maryland's share of revenues from each RGGI auction will be unaffected. *Third*, as long as the alternative results in a positive EVA relative to the *Reference Case*, the total cost to serve load for Maryland's IOUs is reduced and ratepayers will see an economic benefit from the measure.

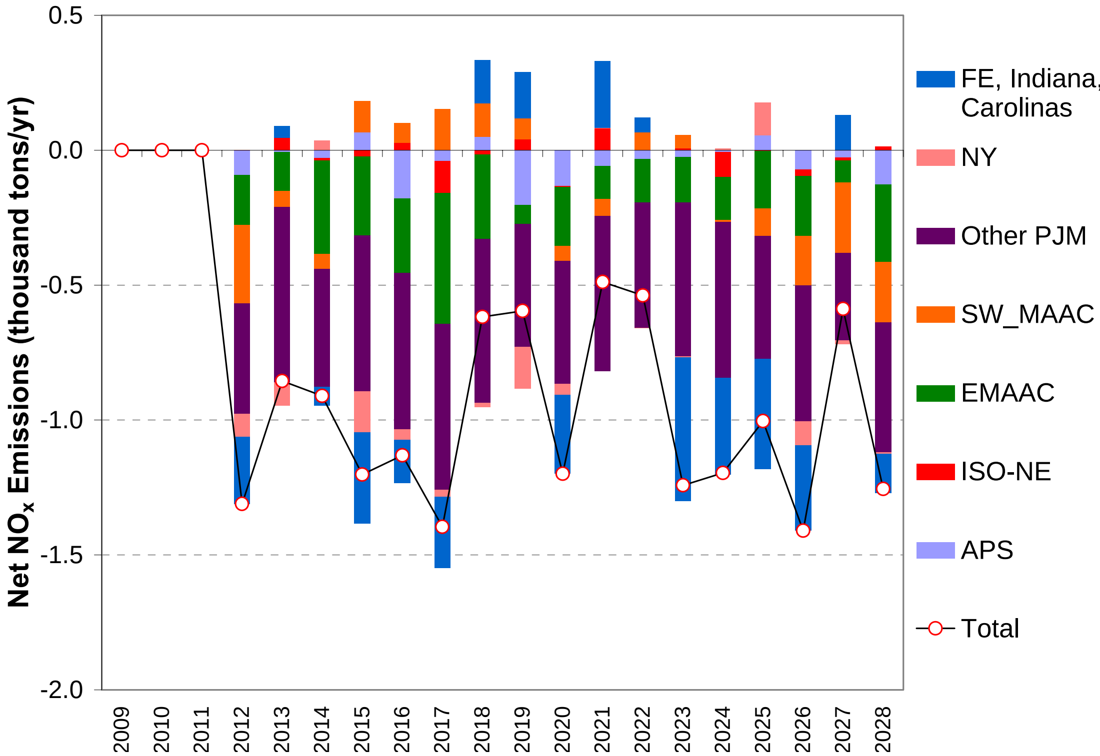
Figure 67 and Figure 68 indicate the change in emissions of SO_2 and NO_x, respectively, by zone across the study area, relative to the *Reference Case*. The loadings of SO_2 generally decrease not only in SWMAAC, EMAAC, and APS, but in most other zones in most years. Thus, part of the emission reductions results from displacing energy from dirtier in-state plants, and part is ascribable to reductions of out-of-state imports. Across the study area, the total net change in SO_2 emissions ranges from a slight increase of 121 tons per year to a net reduction of 2,190 tons per year, relative to the *Reference Case*. Similar results are seen for NO_x. Across the study area, the total net reduction in annual NO_x emissions ranges from 488 to 1,396 tons per year relative to the *Reference Case*. For comparison, the R. Paul Smith Power Station, a 110-MW coal plant in AES's Maryland fleet, reported 2005 emissions of SO_2 and NO_x as 3,359 tons and 921 tons, respectively.[113]

Figure 67. Change in SO_2 Emissions – *Contract CC / Utility CC Cases*



[113] From EPA eGRID data.

Figure 68. Change in NO_x Emissions – *Contract CC / Utility CC Cases*



In addition to the net air quality benefits, these CC projects may provide benefits or disbenefits with respect to net water consumption, impacts on traffic, land use, and impacts on cultural and other natural resources. These impacts are dependent on siting and detailed design of the CCs, and have not been quantified. Impacts to natural and cultural resources may be material but localized if the new CC projects are constructed on greenfields or near environmentally sensitive areas.

5. DEMAND-SIDE OPTIONS

5.1. Introduction

Energy policy throughout the U.S. is centered on using less energy and being more efficient in the production and consumption of electricity. Maryland is on the forefront of this emerging trend. Recently, the Commission has evaluated an array of DSM programs available to Maryland's IOUs in order to moderate the growth in the demand for electricity and the related upward pressure on prices. In addition to conserving limited societal resources, DSM programs offer the added benefit of reducing the emissions of greenhouse gases and pollutants that affect air quality in Maryland and its downwind neighbors.

In July 2007, Governor O'Malley introduced the EMD initiative. The goal is a *per capita* reduction in electric consumption in Maryland by 15% by 2015, in order to "save taxpayers money, reduce stress on Maryland's energy markets, and improve the environment." Competitive markets are designed to send price signals that induce conservation during periods of scarcity, but those price signals are sometimes ineffective for a variety of reasons. Industry experts recognize that many potential societal benefits associated with DSM will not be realized without aggressive policy support. Potential DSM benefits include:

- Lowering the demand for electricity both on-peak and off-peak, thereby reducing electricity prices;
- Location benefits in load pockets where it is often expensive and challenging to permit new generation or transmission;
- Deferring or conceivably avoiding costly investments in generation and/or T&D;
- Quick turnaround relative to the permitting and construction of new generation or transmission; and,
- Environmental benefits through the reduction of greenhouse gases and other power plant air emissions, reductions in the use of water and other consumables, and preservation of open space and cultural resources.

Greater investment in DSM programs would help PJM manage grid reliability problems in SWMAAC. Increased DSM penetration has the potential to reduce uplift in SWMAAC, *i.e.*, the operation of power plants out of merit order. From Maryland's perspective, EE&C programs could reduce consumers' exposure to high energy prices as well as possible disruptions in energy supply. Related economic benefits associated with construction, employment and economic multiplier effects may also be meaningful since conservation programs spur local spending for materials, supplies, labor, and professional services. The benefits realized by local businesses will have a broader multiplier impact on the local economy.

In this Final Report, many significant changes have been incorporated in the definition of DSM, program penetration rates, and project costs relative to our treatment in the Interim Report. The adjustments incorporated herein are based largely on information made available by the IOUs over the last year.[114] New data included revised and expanded energy efficiency programs as well as more information about the avoidance of capacity costs corresponding to various efficiency measures. The EMD programs are described in more detail in Section 5.2. Relying on information provided by the IOUs, LAI has formulated a representative mix of DSM programs, penetration rates, and program costs in general accord with updated information provided by the IOUs. Many professional judgments have nevertheless been exercised in order to define the blend of DSM programs, penetration rates and implementation costs that achieve the EMD EE&C objective by 2015.

5.2. EmPOWER Maryland: The "15 x 15" Initiative

The EMD initiative sets a target reduction for both energy and peak demand reductions for each IOU in Maryland. The DSM targets are based generally on each IOU's relative load in Maryland.

The *15x15 DSM Case* developed for purposes of this analysis covers the load served by Maryland's four IOUs. Non-jurisdictional municipal and cooperative utility loads have been excluded, a comparatively small portion of total state-wide electricity demand.[115] On April 24, 2008, Governor O'Malley signed into law the EmPOWER Energy Efficiency Act of 2008. The Act codified the energy and peak demand reduction goals consistent with the EMD initiative, and also established the interim reduction goals for 2011 (not less than 5%) and 2013 (not less than 10%). The Act specifically states that EE&C and demand reduction programs developed to achieve the EMD goals must be cost-effective. Maryland's IOUs were required to submit plans in accord with the Act by September 1, 2008, and every three years thereafter. On August 6, 2008, the Commission specified the contents of the required September 1, 2008 filings for the IOUs. The Act requires that the Commission take action on each plan by December 31, 2008. The revised DSM programs subsequently submitted by the IOUs were docketed separately.[116]

5.3. IOU DSM Plans

LAI has evaluated the IOUs' filings before the Commission. Based on the most recent information, substantial changes to the DSM data used in the Interim Report have been made. The IOUs have acknowledged that their respective DSM plans fall short of the reduced energy use objective in 2015. In this study, we have formulated penetration rates for various measures

[114] LAI relied on filings by APS, BGE, Pepco and DPL to develop the *15x15 DSM Case*. APS submitted its filings on August 28, 2008; Pepco submitted on September 1, 2008; and BGE and DPL filed on September 2, 2008.

[115] DSM programs deemed feasible for the IOUs could yield similar economic benefits if deployed by cooperative and municipal utilities. Lacking scale, general and administrative (G&A) costs may be higher for public power companies.

[116] The IOUs were ordered by the Commission to provide their plans under Case No. 9111. Subsequent filings were docketed with individual case numbers, *i.e.*, Cases 9153, 9154, 9155, and 9156 for APS, BGE, Pepco, and DPL, respectively.

in order to satisfy the EMD conservation objective. LAI relied on filings submitted by the IOUs on or about September 1, 2008.[117] A brief summary of each filing is provided below.

5.3.1. BGE

BGE's filing includes EE&C programs targeted to both residential and non-residential customers. [118] The C&I plans include direct incentives as well technical assistance for the installation of efficiency products including lighting and control, heating, ventilating and air conditioning (HVAC) equipment, refrigeration, *etc*. Programs for retrofitting existing buildings are also included.

There are also EE&C programs specifically for residential customers. They include programs that provide incentives to install Energy Star appliances, upgrade HVAC and hot water equipment and separate programs to target new and existing homes. There is also a program designed for low income residential customers.

As well as the EE&C programs, BGE also indicates in its filing that it intends to implement substantial residential and non-residential DR programs. The DR data provided in the September 2nd filing is limited. This is primarily because BGE's DR programs, namely the PeakRewards and ILR programs, have already received Commission approval. Since these were sufficient for BGE to meet its EMD peak demand reduction target, no additional programs have been proposed.[119] In its September 2008 filing, BGE included the projection for peak demand and energy savings that the DR program would achieve, but cost projections were not included. Estimates for the costs of BGE's DR program were based on cost data provided by Pepco and DPL, as discussed in detail below.

On September 29, 2008, BGE filed a supplemental filing that provided more detailed costs data and described two new residential efficiency programs, one designed for multi-family residences and a customer education / awareness program. This information is not incorporated in this study. LAI used BGE's information presented in its filing of September 2nd, including adjustments to achieve the EMD goal.

5.3.2. Pepco

Pepco's EE&C programs for C&I customers includes "prescriptive" programs, that is, generalized incentives for consumers to purchase and install energy efficient technologies such as compact fluorescent lights or light-emitting diode lighting, HVAC-specific programs, and custom programs that provide incentives to customers based on their unique, site-specific needs. Residential EE&C programs include incentives for Energy Star products and efficient lighting

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[117] Subsequent filings were made, for example, BGE's filing on September 29th. Production constraints precluded LAI's reliance on subsequent information placed before the Commission.

[118] BGE's initial filing lacked significant reductions associated with large commercial and industrial customers. In the Interim Report, LAI relied on utility data outside Maryland for C&I programs.

[119] See http://www.bgesmartenergy.com/peakrewards.

and appliances, an HVAC efficiency incentive program, and a separate program for low income consumers.

Pepco also provides information on its DR program. Pepco has designed a residential direct load control program, which the Commission has already approved, as well as an air-conditioner direct load program for non-residential customers. Pepco also describes its design for an internet portal for large non-residential customers that will facilitate participation in PJM's demand response markets.

5.3.3. DPL

DPL and Pepco are both owned by Pepco Holdings, Inc. (PHI). Hence, DPL's proposed programs share many similarities with Pepco's. For non-residential customers, prescriptive EE&C as well as custom programs are described, and there is a separate HVAC program. The residential and DR programs also employ similar measures. For both non-residential and residential customers, the costs and penetration rates differ materially. As such, the DPL program was evaluated separately rather than treated as a scaled down version of the Pepco program.

5.3.4. APS

Like the other IOUs, APS provided separate EE&C programs for non-residential and residential customers. For non-residential customers, APS has designed both prescriptive and custom programs. For residential customers, APS has designed incentives for the purchase and installation of Energy Star products as well as an HVAC and hot water program. APS also operates the Watt Watcher residential programs, but has not reported the energy savings since it does not track them.

APS has not included information about its upcoming program. The filing indicates that it will implement an Advanced Utility Infrastructure (AUI) pilot program, but no projected costs or savings are available. Therefore we have not incorporated potential benefits and costs associated with this program in the projected penetration rate of sundry DSM programs in the APS market area. APS had previously proposed a DR program, but it was not approved by the Commission.

5.4. Derivation of Model Inputs

5.4.1. Program Penetration Rates

Each IOU projected peak demand reductions and energy savings for each year from 2009 to 2015. The projected 2015 peak demand reduction and energy savings for each IOU are indicated in Table 16 along with their targets for each metric under the EMD initiative.

Table 16. EMD Targets and Filed Plans by IOU[120]

	BGE	DPL	Pepco	APS	Total
2015 Peak Reduction Target (MW)	1,411	234	685	186	2,515
2015 Projected Demand Reduction (MW)	1,941	243	801	59	3,044
% Compliance	138%	102%	115%	32%	121%
2015 Energy Savings Target (GWh)	4,297	503	1,875	339	7,014
2015 Projected Energy Savings (GWh)	2,719	370	1,409	194	4,692
% Compliance	63%	68%	69%	57%	67%

Each IOU fell short in meeting the energy savings goal. APS fell short of meeting the peak demand reduction goal as well.[121] Importantly, APS's filing, unlike those of the other IOUs, had a higher level of compliance with the target energy savings than with the target peak demand reduction savings. In order to model full compliance for each of the four IOUs, LAI incorporated various adjustments in order to gross up the mix of programs. For APS, the gross-up causes APS to exceed its energy savings target. For the other IOUs, energy savings were the limiting factor. Hence, the adjustments caused greater than target demand reductions. For example, BGE exceeded its demand reduction target by 38%, but achieved only 63% of its energy reduction target. Therefore, the BGE program was grossed up by slightly more than 50%, so that the energy target would be reached. Doing so meant that BGE demand reduction exceeded its target by more than 38% even without grossing up the DR programs proposed by BGE. Since the DR programs provide minimal energy savings, the effect of increasing their level of penetration on the energy savings would be minimal as well. Therefore, we made no adjustments to the DR levels of penetration.

Because BGE, DPL, and Pepco were already in compliance with their respective demand reduction targets before the gross-up, LAI did not model the DR programs represented in the DPL and Pepco filings – the statewide targets were achieved without these programs, due in large part to BGE's DR program. The gross-up measures were uniformly phased in from 2009 to 2015. Following 2015, we have assumed that new DSM resources would be added in each IOU's service territory at the same pace as load growth, approximately 1.5% per year. This simplifying assumption holds constant long-term compliance with the EMD goal. Of course, the large majority of new DSM resources added during the study period are added to the resource mix by 2015. For the *Reference Case* and all other project cases (other than the *15x15 DSM Case*) we have assumed that 25% of the EMD target is met.

5.4.2. Load and Energy Saving Profiles

To determine the load profiles for the IOUs' EE&C programs, LAI aggregated the programs into categories, *e.g.*, lighting, HVAC, *etc*. The load profile corresponding to each program category was developed on an hourly basis with seasonal adjustments. For each category, we defined the

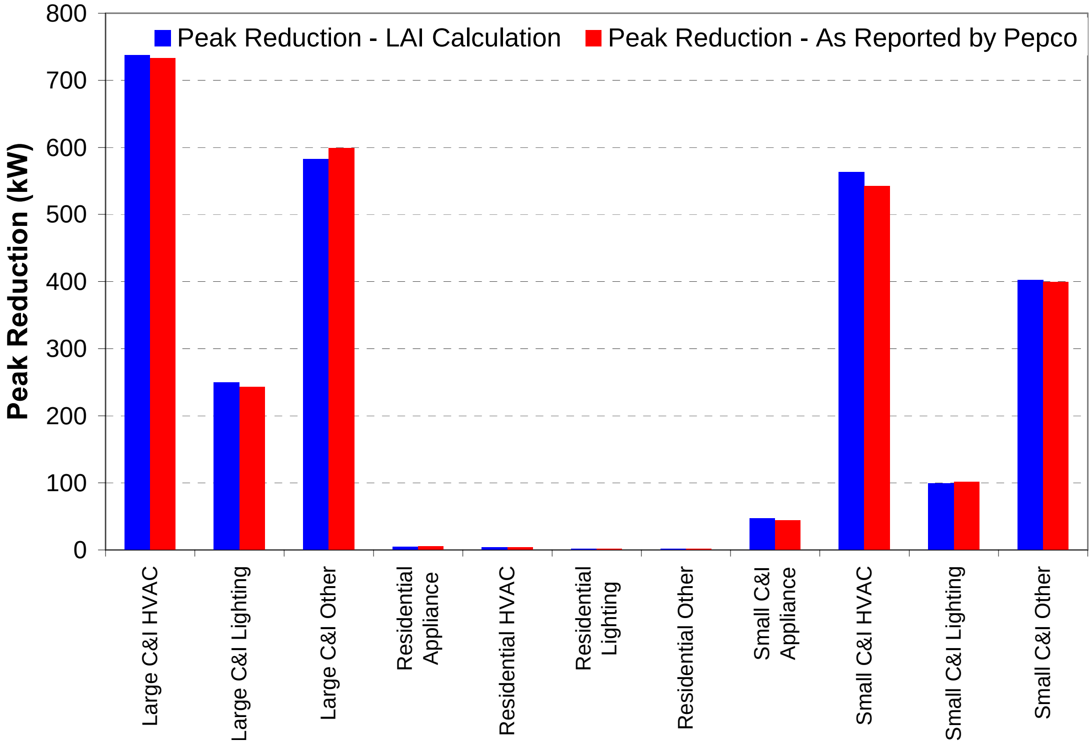
[120] See Table ES-2 of each IOU's filing.

[121] This is explained in part by the exclusion of APS's AUI pilot program. LAI relied only on the programs described in the early September 2008 filings.

peak hours by season, which determined each category's contribution to the reduction in coincident demand. The load profiles reflect the assumption that each measure would be effective during peak load hours, *i.e.*, weekday afternoons. The change in energy use during all other on-peak hours varies by program measure and season.

The load profiles were reconciled with the total demand reduction reported in the proposed measures for each of four IOUs. Figure 69 compares the summer demand reduction reported by Pepco to the calculated peak reduction. Similar validation was conducted for BGE, APS and DPL.

Figure 69. Coincident Peak Demand Reduction By Measure – Pepco



5.4.3. <u>Modeling Results</u>

In total, the grossed up programs modeled in the *15x15 DSM Case* exceed the peak demand reduction target by approximately 33% in 2015, while approximately meeting their energy savings targets. Total savings for the four IOUs versus the total target is shown in Table 17.

Table 17. *15x15 DSM Case* Simulation Results vs. EMD Targets

	EMD Target	Modeled	% Target Achievement
Demand Reduction (MW)	2,515	3,354	133%
Energy Savings (GWh)	7,014	6,987	100%

Measured on a percentage basis, energy savings have been increased by more than the peak demand reduction. This is due in part to our decision to suppress the DR programs proposed by both Pepco and DPL. Had we not done so, the State as a whole would have exceeded its peak reduction target by an even greater margin.

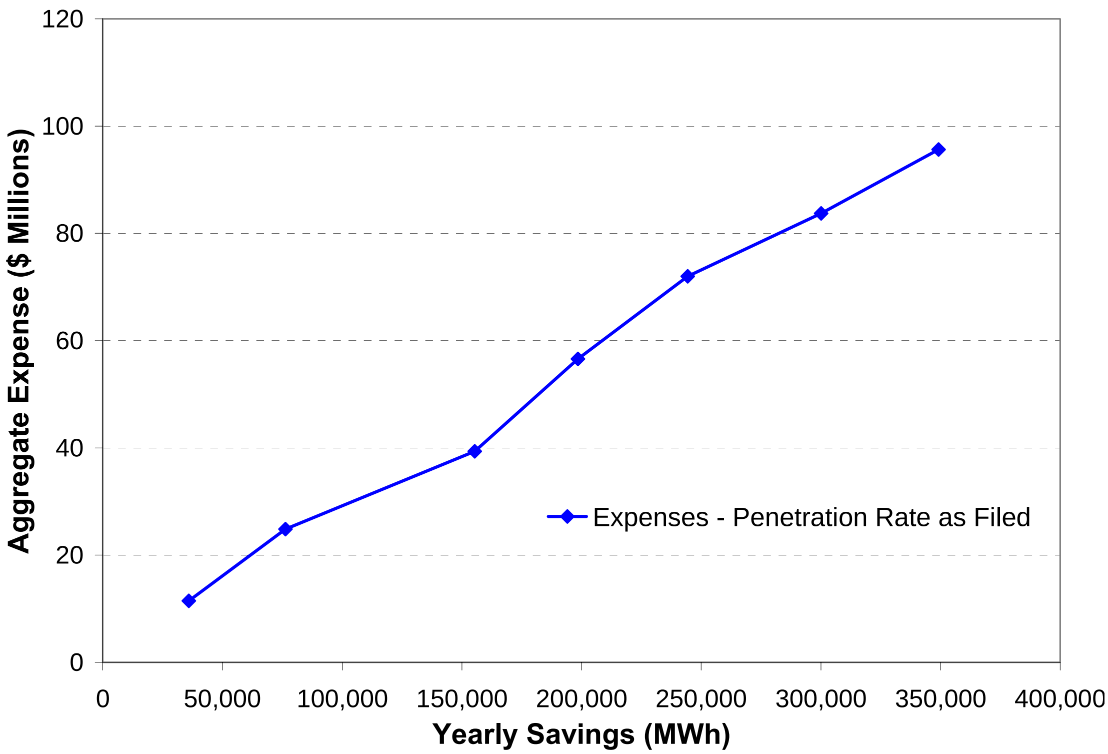
In calculating the projected savings for each IOU, all programs were increased proportionally rather than only expanding the lowest cost program options. This way we minimized the risk of postulating unrealistic penetration rates, that is, creating measures with penetration rates greater than 100%.

5.4.4. Costs

In order to estimate the costs of the grossed up efficiency measures for the *15x15 DSM Case*, LAI utilized a linear regression methodology based on the relationship between cost and energy savings, rather than peak demand savings. Each of the IOU filings included projected annual program costs. Analysis of these cost data indicated that there was a very high correlation between annual energy savings and aggregate program expenses, *i.e.*, program expenses to date, corrected for startup costs, if applicable.

Figure 70 shows the projected annual energy savings and projected aggregate expenses for the DPL program as filed. As the plot indicates, the relationship between the two is nearly perfectly linear:

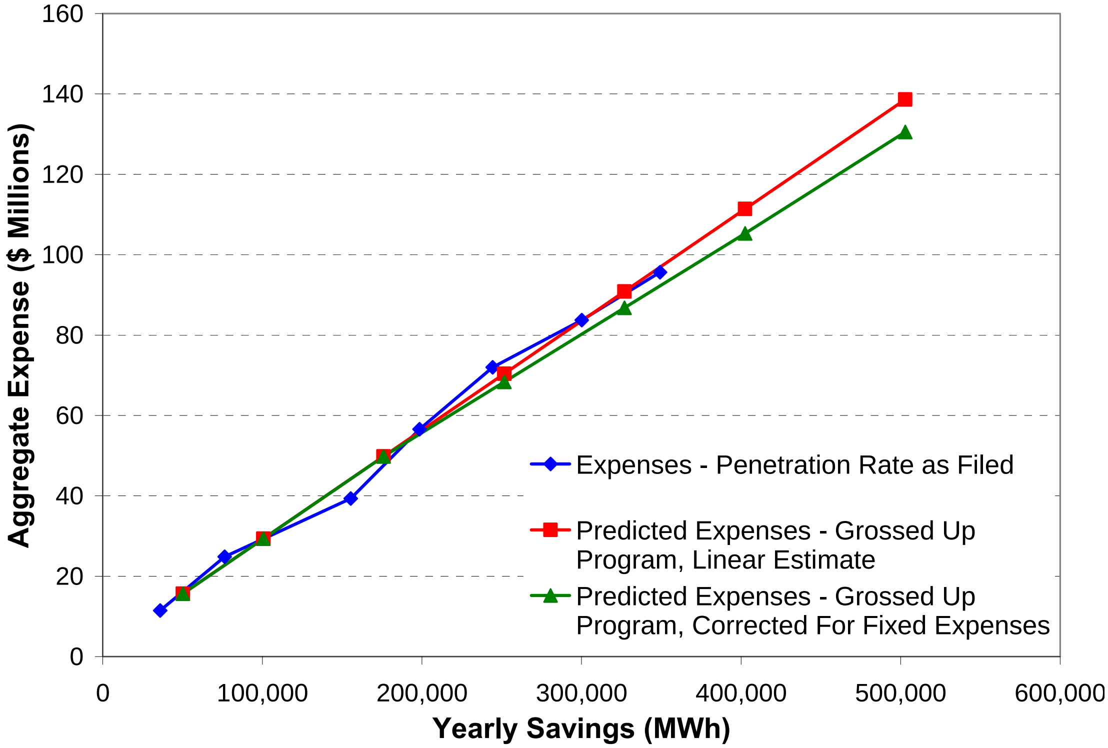
Figure 70. Projected Annual Energy Savings vs. Aggregate Expense – DPL (as filed)



The correlation between aggregate expense and annual MWh savings in this case is greater than 0.99. Each point on the plot represents the filed MWh savings and the aggregate expense for a given year. For example, the first point on the chart represents DPL's energy savings in 2009 of approximately 35,000 MWh at a cost of approximately $15 million.

In Figure 71, we show the forecast of expenses for DPL's grossed up program, based on the regression equation that forecasts expenses from imputed energy savings. The energy savings and aggregate expenses shown in Figure 71 are indicated for reference.

Figure 71. Projected Annual Energy Savings vs. Aggregate Expense – DPL (grossed up)



The red line in the plot represents the forecast of expenses based on the regression equation, corrected for upfront, fixed expenses that will be incurred once, but not incurred again. Such expenses include administrative and marketing related costs. Based on DPL's filing, LAI estimates that DPL will incur about $2 million through 2011. Hence, as indicated by the green line, we have reduced the program expense after 2011.

Costs for DR programs were calculated separately. Since DR results in very little energy savings, the relationship between energy savings and aggregate expense is not valid for predicting the expense of DR. LAI relied on data from Pepco's and DPL's filings to project DR costs since BGE did not provide DR expense data and APS did not include DR in its filing at all.[122]

Based on the Pepco and DPL filings, we found that the incremental cost to add new DR was fairly constant over the period 2009-2014. For each year in that period, the IOUs provided annual expenses for DR. From these data, the annual cost to add new DR can be calculated, as indicated in Table 18.

Table 18. Calculation of DR Costs

	2009	2010	2011	2012	2013	2014
Pepco						
Annual DR Expense ($000)[123]	15,003	29,976	34,512	32,503	12,093	12,075
DR Peak Reduction (MW)	36	93	189	254	278	302
Incremental DR Addition (MW)	36	57	96	65	24	24
$/Incremental DR ($/MW)	416,741	525,898	359,497	500,039	503,858	503,108
DPL						
Annual DR Expense ($,000)	4,806	6,988	8,133	10,794	8,401	4,162
DR Peak Reduction (MW)	13	28	53	81	102	113
Incremental DR Addition (MW)	13	15	25	29	21	11
$/Incremental DR ($/MW)	375,451	475,374	324,016	378,731	394,394	396,378

We found that the average cost of installing new DR is approximately $429/kW, about 40% of the installed cost of a GT reported by PJM's consultant.[124] This cost, adjusted for inflation, was applied to new DR additions in the financial model.

Through 2015, we estimate that the four IOUs will spend roughly $2.1 billion to achieve the EMD target. $1.4 billion of this total will be spent on energy efficiency measures and $0.7 billion will be spend on DR.[125] The total estimated consolidated program implementation cost for all four IOUs is much higher than the total identified by the IOUs, in order to account for the much higher penetration rates needed to satisfy the objective and the inclusion of DR costs for BGE.

To be sure, actual IOU costs to achieve DSM may be materially higher or lower than the estimation of program implementation costs developed by LAI in the Final Report.

[122] BGE presented the detailed cost data for its DR programs in its earlier filings with the Commission. Our review of the relevant information suggests that the BGE's DR costs might be consistent with the DR costs identified by Pepco and DPL.

[123] See Table ES-4 of each IOU's filing.

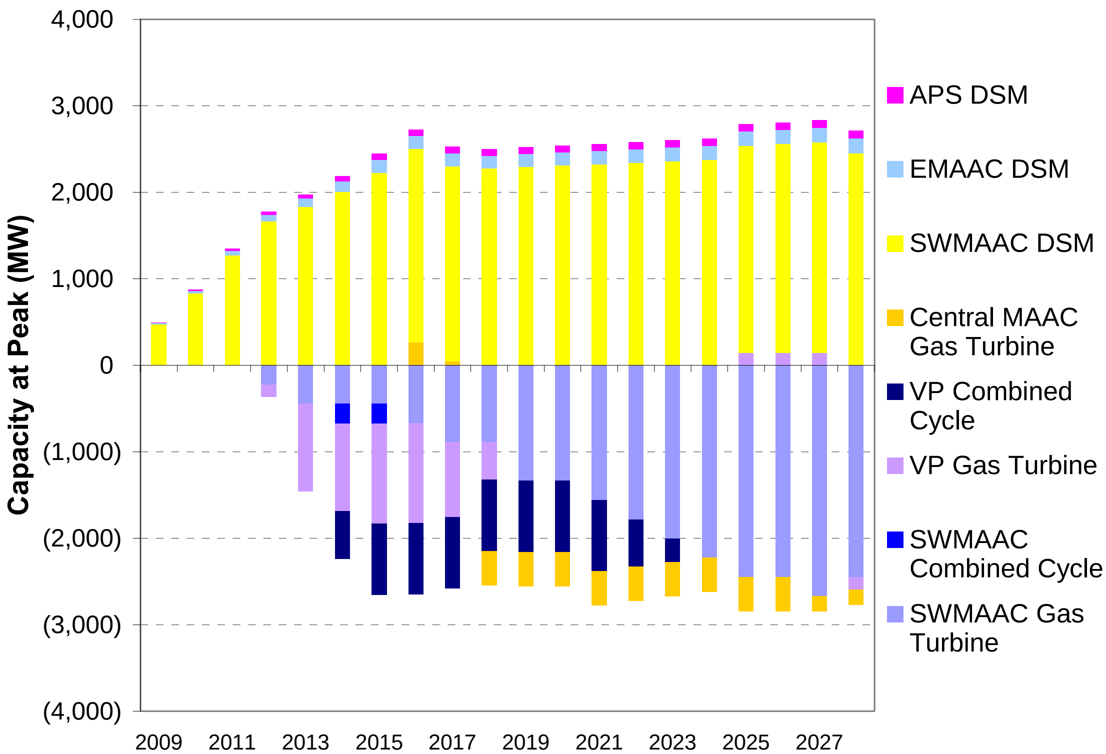
[124] See Power Project Management, LLC, *2012-2013 CONE Update with PJM Member Base Assumptions*, August 25, 2008, Table 3, Frame 7FA plant in SWMAAC 2.

[125] These amounts have not been discounted. The PV of the investment is lower.

5.4.5. <u>Capacity</u>

The difference between the capacity buildout for the full implementation of EMD versus 25% attainment assumed in the *Reference Case*, is shown in Figure 72. Implementation of the aggressive conservation benefits will be expected to result in the deferral of conventional capacity in Virginia and, to a lesser extent, Central MAAC. However, the majority of the capacity resources that can be avoided would be GTs in SWMAAC. This is because the capacity benefits attributable to DSM are concentrated in SWMAAC where the Pepco and BGE loads are centered.

Figure 72. Incremental Capacity Additions – *15x15 DSM Case*



5.5. Financial Analysis of Expanded DSM

5.5.1. <u>Base Scenario</u>

The annual savings from the DSM measures embedded in the *Reference Case* are summarized in Figure 73. EVA for the same measures is shown in Figure 74. The gross benefit to direct cost ratio for this level of DSM measures is 3.52:1.

Figure 73. Annual Savings – *Reference Case* DSM (*Base Scenario*)

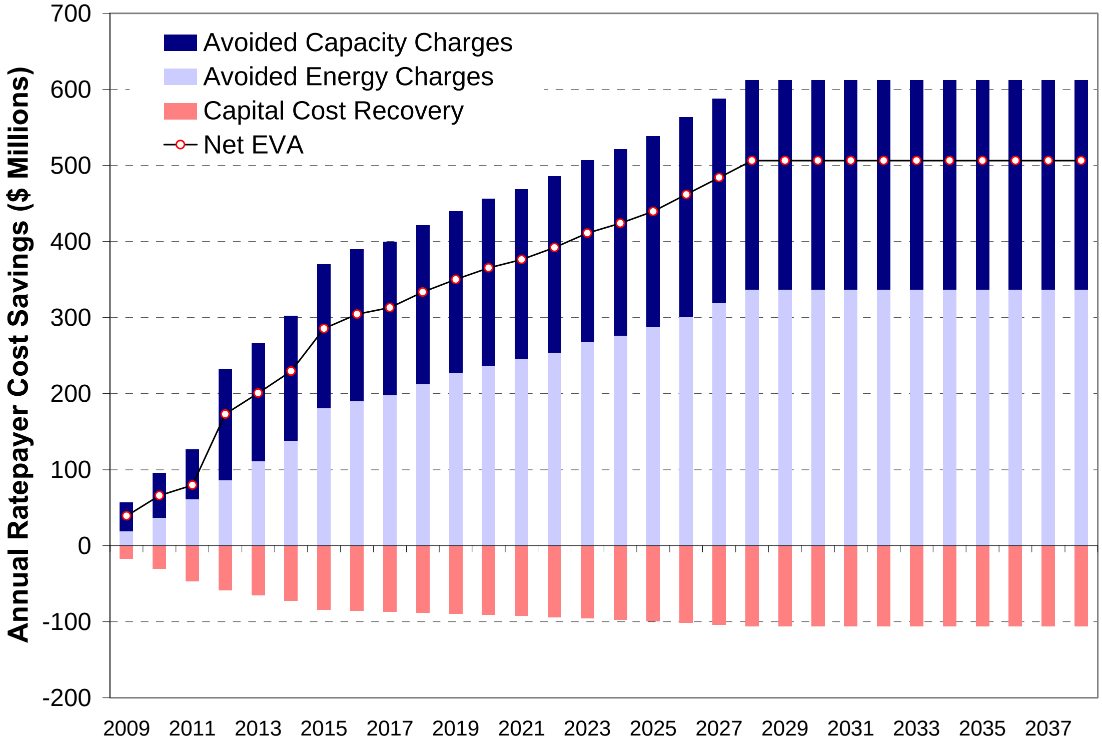
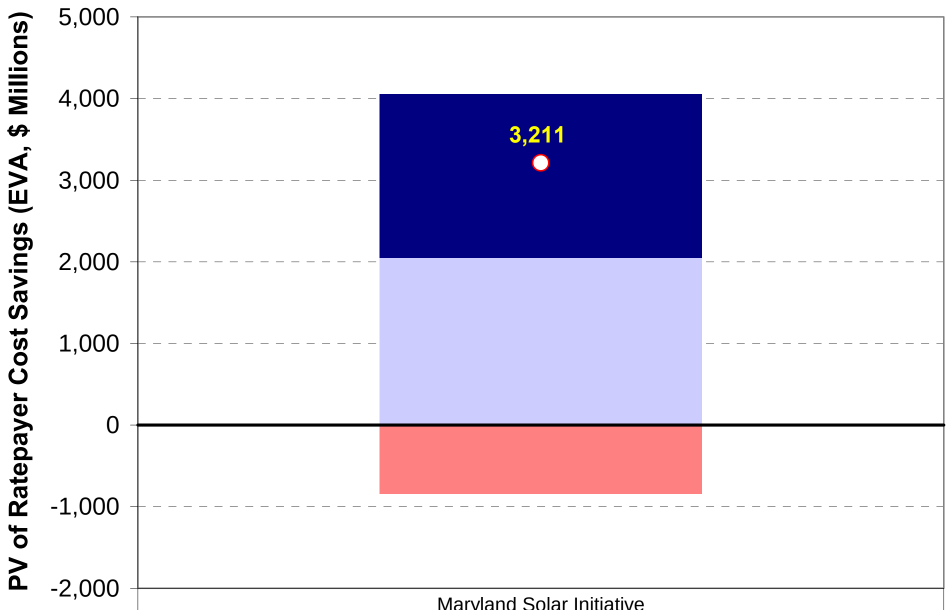


Figure 74. EVA – *Reference Case* DSM (*Base Scenario*)



	Maryland Solar Initiative
Avoided Capacity Charges	2,008
Avoided Energy Charges	2,046
Capital Cost Recovery	(843)
Net EVA	3,211

Annual savings for the *15x15 DSM Case*, relative to the *Reference Case*, are shown for the *Base Scenario* in Figure 75. EVA for the incremental measures is summarized in Figure 76. The benefit-to-cost ratio for the incremental measures is 1.66:1. Highly positive, this benefit-to-cost ratio compares unfavorably to the benefit of the DSM bargain for the first 25% of the total program initiative that has been included in the *Reference Case* (3.52:1.) or the benefit-to-cost ratios for the *Contract CC Case* (2.99:1.) or *Utility CC Case* (3.07:1.), respectively. They are not mutually exclusive, however.

Figure 75. Annual Savings – *15x15 DSM Case* (*Base Scenario*)

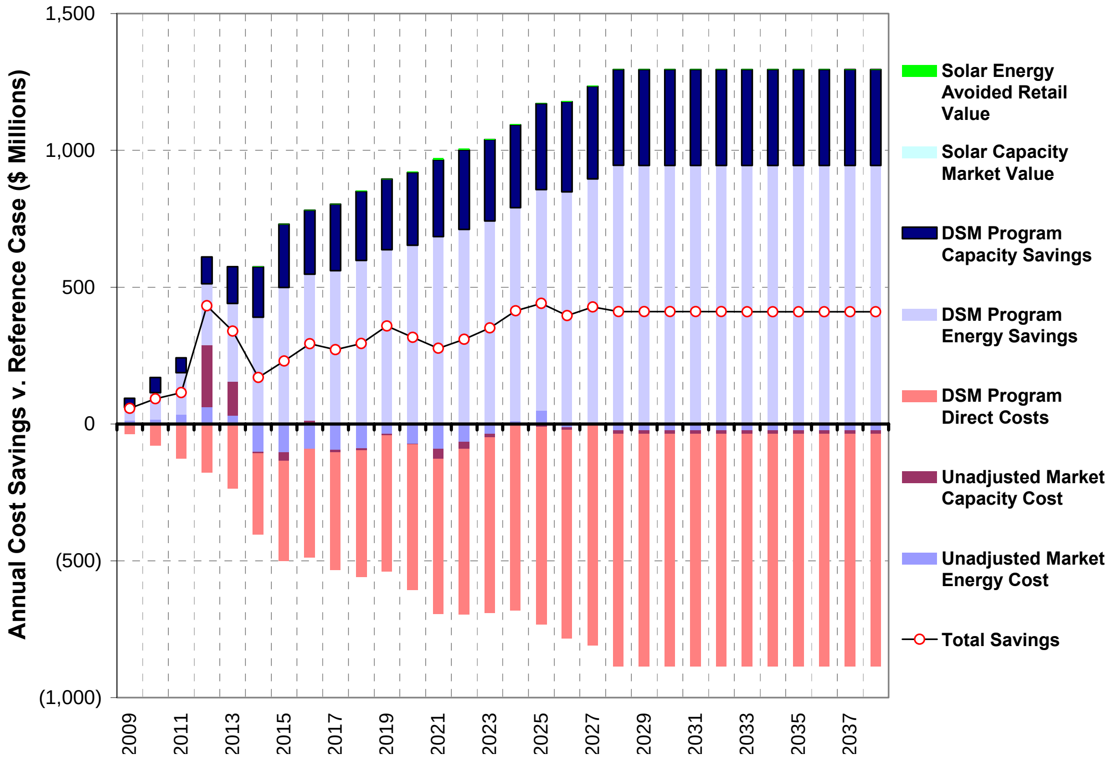
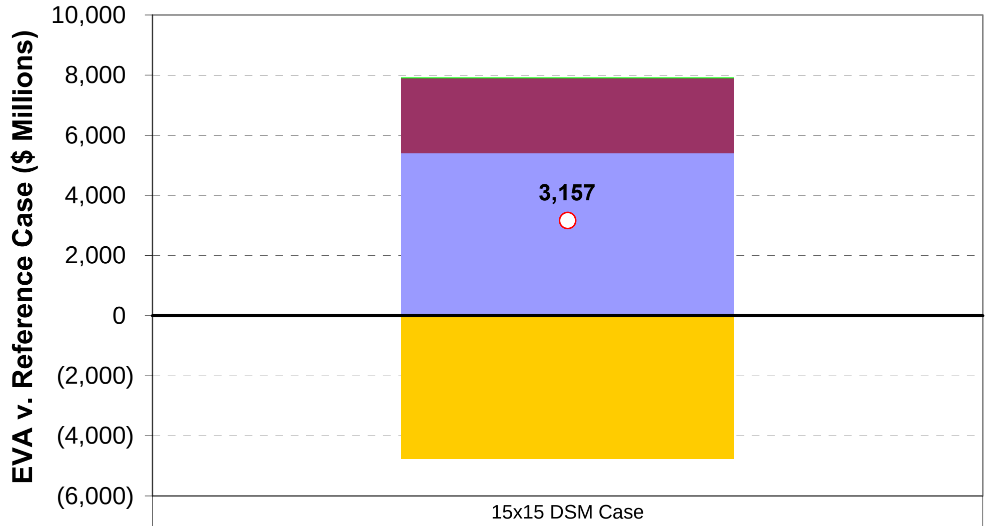


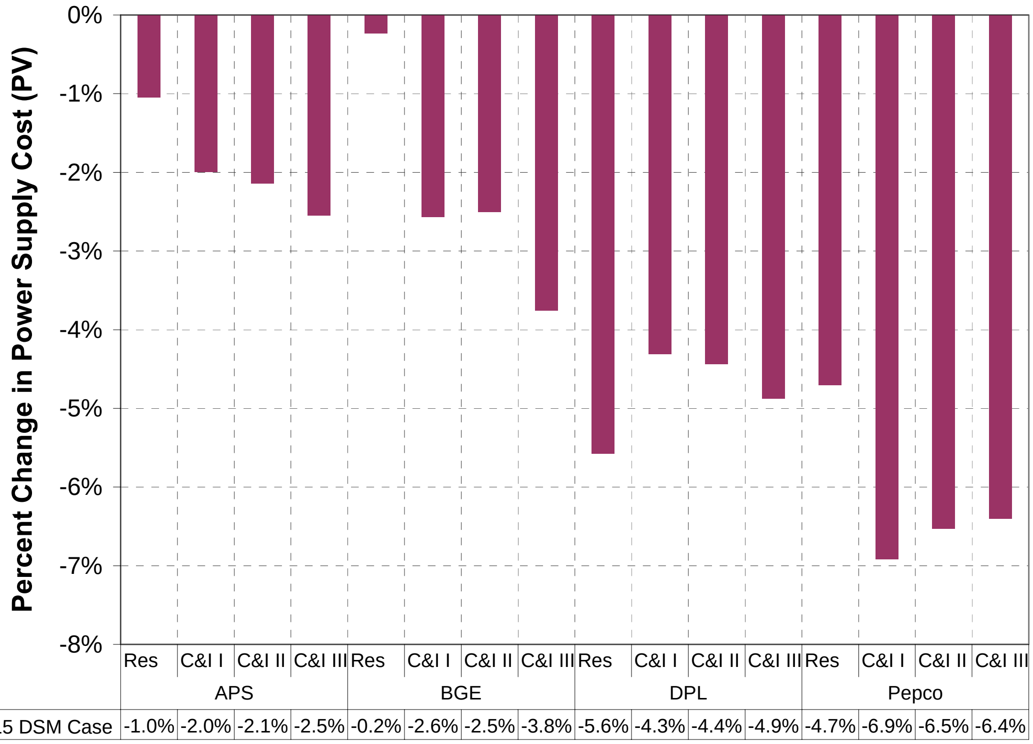
Figure 76. EVA – *15x15 DSM Case* (*Base Scenario*)



	15x15 DSM Case
PPA Net Energy Margin	14
PPA Capacity Credit	0
PPA Direct Costs	0
Market Capacity Cost	2,500
Market Energy Cost	5,403
DSM Program Costs	(4,760)
Total EVA	3,157

Ratepayer effects of the *15x15 DSM Case*, relative to the *Reference Case*, are summarized in terms of reduced total power supply charge by IOU and class (for the class in aggregate) in Figure 77.

Figure 77. Ratepayer Impact – *15x15 DSM Case* (*Base Scenario*)



	APS Res	APS C&I I	APS C&I II	APS C&I III	BGE Res	BGE C&I I	BGE C&I II	BGE C&I III	DPL Res	DPL C&I I	DPL C&I II	DPL C&I III	Pepco Res	Pepco C&I I	Pepco C&I II	Pepco C&I III
15x15 DSM Case	-1.0%	-2.0%	-2.1%	-2.5%	-0.2%	-2.6%	-2.5%	-3.8%	-5.6%	-4.3%	-4.4%	-4.9%	-4.7%	-6.9%	-6.5%	-6.4%

5.5.2. Alternative Scenarios

Annual savings for the *15x15 DSM Case* under alternative fuel and transmission scenarios are shown in Figure 78. EVA effects are shown in Figure 79.

Figure 78. Annual Savings – *15x15 DSM Case* (Alternative Scenarios)

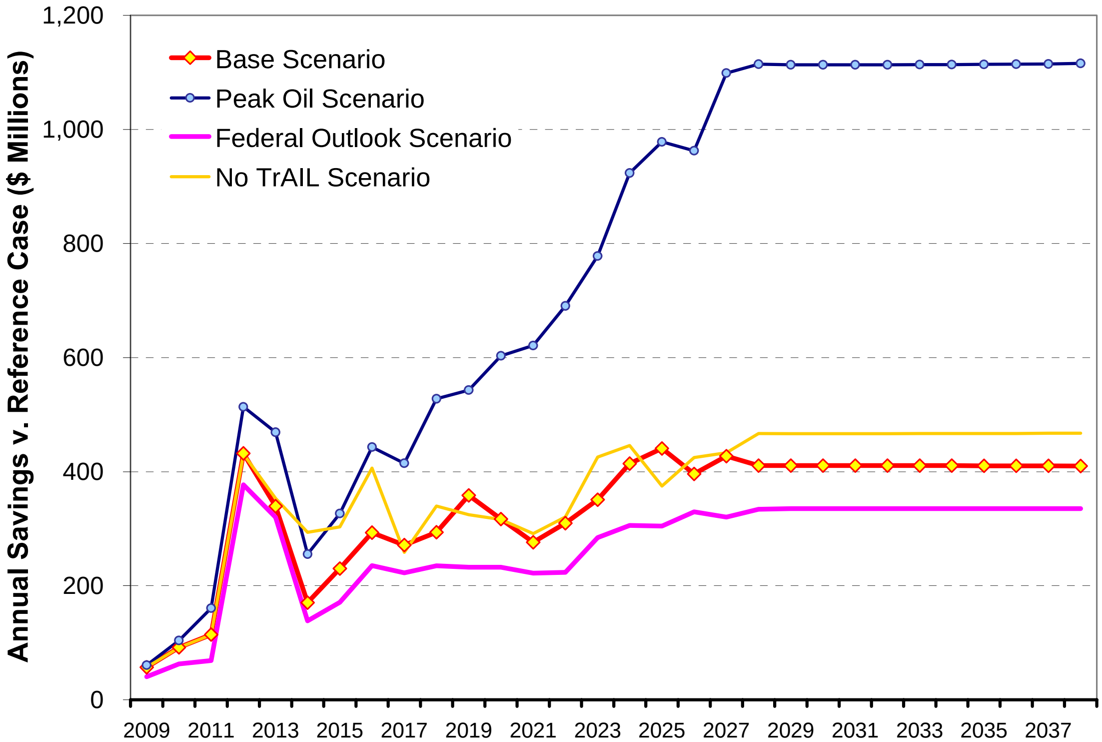
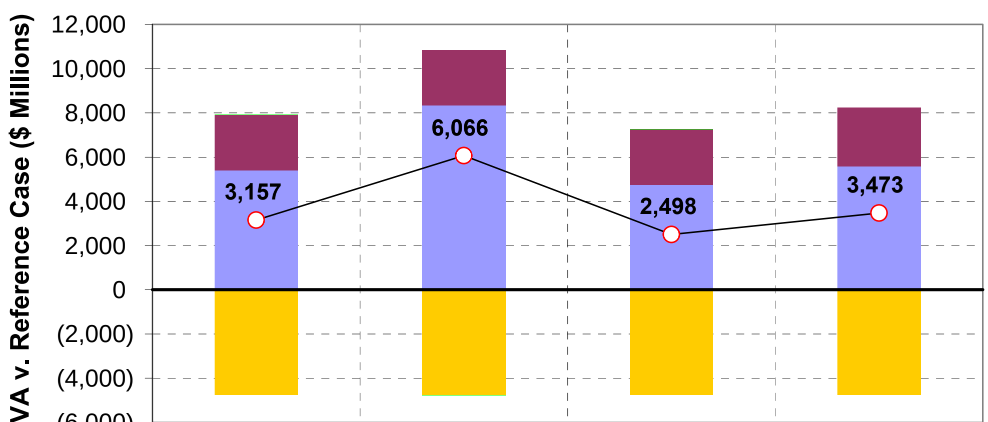


Figure 79. EVA – *15x15 DSM Case* (Alternative Scenarios)



	Base Scenario	Peak Oil Scenario	Federal Outlook Scenario	No TrAIL Scenario
PPA Net Energy Margin	14	(11)	6	2
PPA Capacity Credit	0	0	0	0
PPA REC Credit	0	0	0	0
PPA Direct Costs	0	0	0	0
PJM Transmission Cost	0	0	0	0
Market Capacity Cost	2,500	2,500	2,500	2,656
Market Energy Cost	5,403	8,337	4,752	5,575
DSM Program Costs	(4,760)	(4,760)	(4,760)	(4,760)
Total EVA	3,157	6,066	2,498	3,473

5.6. Net Environmental Benefits

Net air quality benefits were quantified by calculating the differences in CO_2, SO_2 and NO_x emissions between the *15x15 DSM Case* and the *Reference Case* under the *Base Scenario*. Results are presented in Figure 80, Figure 81, and Figure 82. Once the EMD program is fully implemented in 2015, net reductions in CO_2 across the study area range from about 2.2 million to 3.3 million tons per year. Over the same time period, the change in SO_2 varies from an annual net gain of about 450 tons, to a net reduction of about 3,100 tons per year. Annual NO_x reductions range from about 60 to 2,300 tons per year. Net reductions are ascribable to load reductions within SWMAAC, EMAAC, and APS, and also to overall reductions in imports from the rest of PJM and elsewhere.

Between 2015 and the end of the forecast horizon, the annual average CO_2 reduction is 2.7 million tons. Compared to the state's RGGI CO_2 reduction goals for the years 2015 through 2018, full attainment of the EMD program would allow Maryland to achieve its annual reduction target in 2015, 2016, and most of 2017. That is, the average annual reduction from the EMD program is about 2.9 times the RGGI reduction target of 937,600 tons in each of these years.

Figure 80. Change in CO_2 Emissions – *15x15 DSM Case*

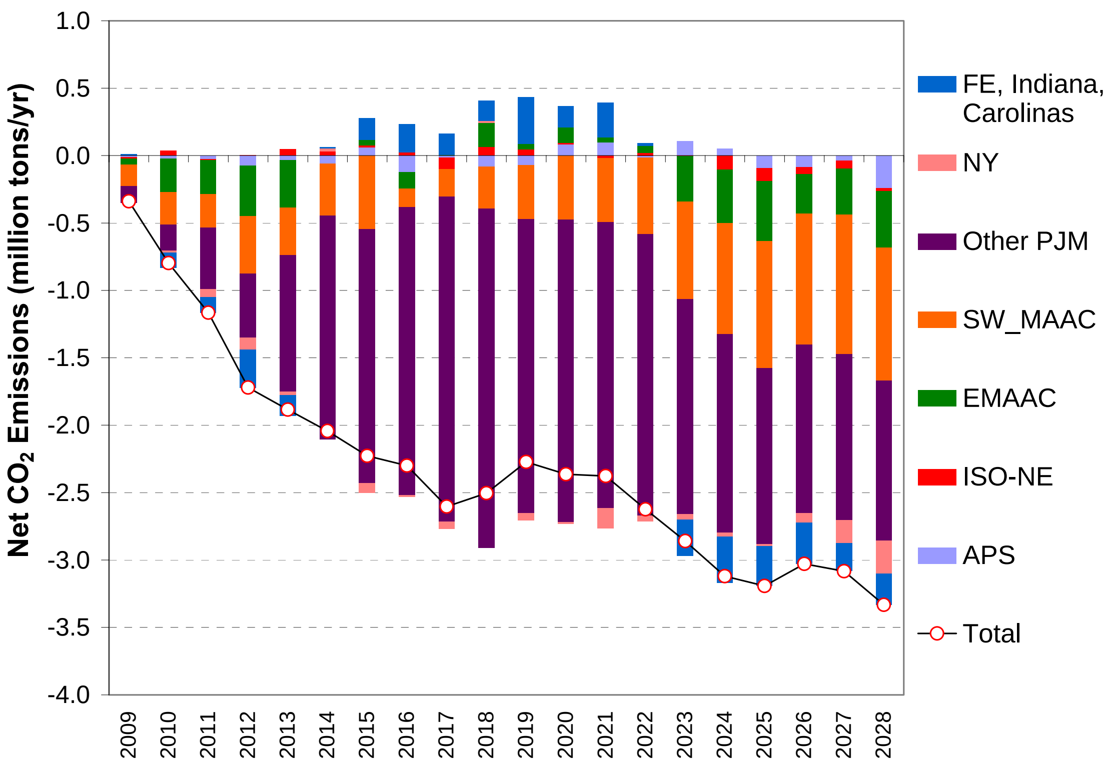


Figure 81. Change in SO_2 Emissions – *15x15 DSM Case*

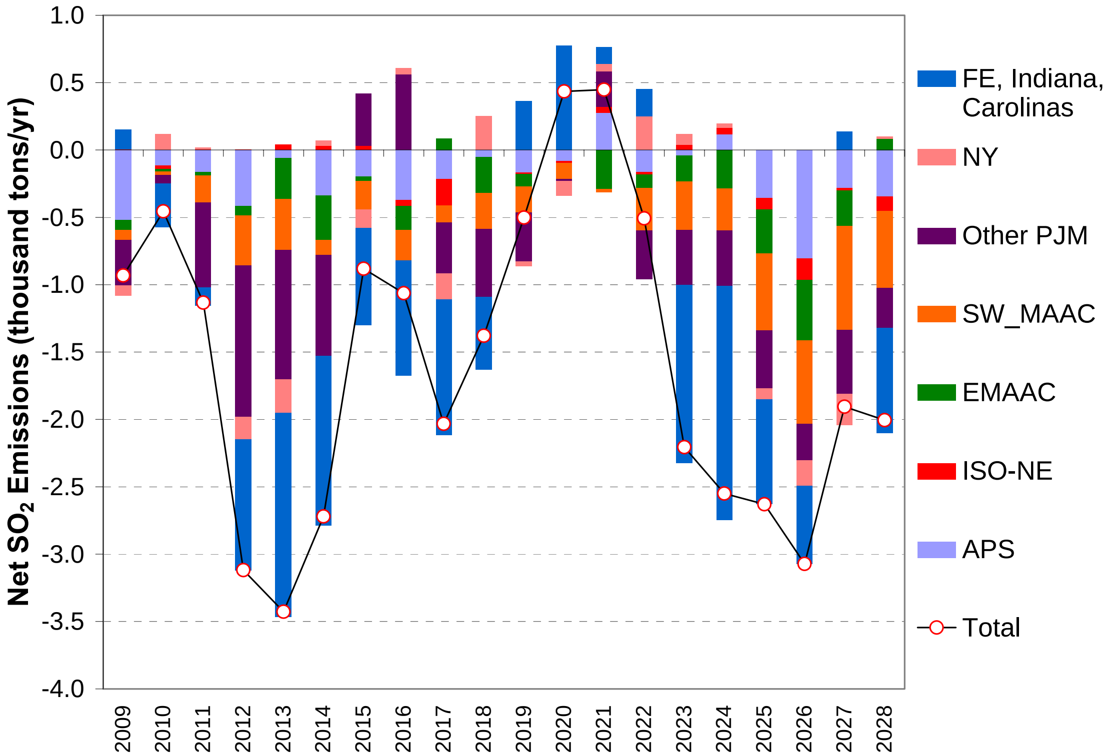
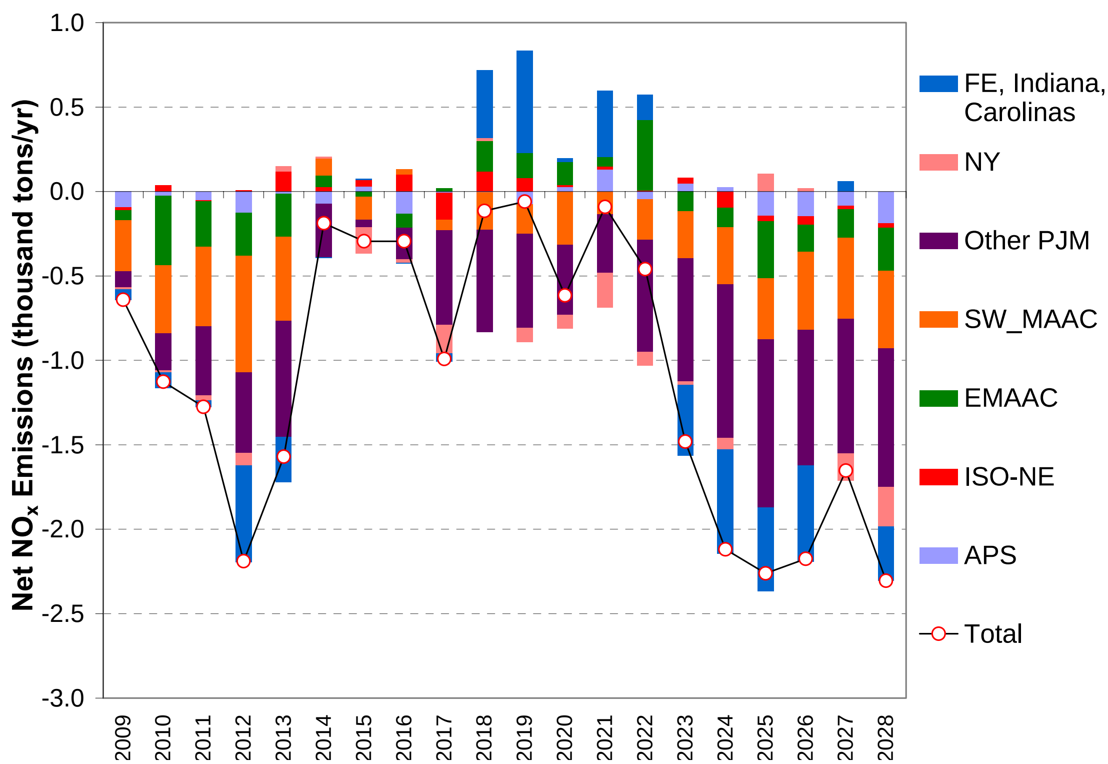


Figure 82. Change in NO_x Emissions – *15x15 DSM Case*



In addition to the net emission reductions, DSM measures also avoid or delay the need to construct new power plants. Land use impacts, traffic, water use and consumption, and impacts to natural and cultural resources would be avoided. Quantifying these benefits is outside the scope of this study.

6. RENEWABLE GENERATION: ONSHORE AND OFFSHORE WIND

6.1. Introduction

Aggressive RPS targets in Maryland and elsewhere in PJM have created a large wind interconnection queue within PJM. To date, however, only those projects which have secured off-take contracts for energy and/or RECs appear likely to obtain financing. Currently, the ICAP of all renewable resources in Maryland is approximately 200 MW.[126] Despite the relative scarcity of in-state renewable generation, Maryland's IOUs have been able to achieve their respective RPS goals by acquiring RECs from other renewable resources elsewhere in PJM. Thus, the price of Maryland Tier 1 RECs has remained in the $1/MWh range. As discussed in Section 3.3.4, as the demand for RECs in PJM and surrounding states increases, Maryland's IOUs will increasingly compete with other IOUs for RECs, thereby placing upward pressure on REC clearing prices.

Other states, notably Massachusetts, Connecticut, Illinois, and Delaware, have solicited proposals for renewable resources, and have authorized their IOUs to enter into long-term PPAs for the renewable energy and/or separately for RECs. Delaware has approved contracts between DPL and four wind projects to serve Delaware load. Three of these contracts are for onshore capacity located in Pennsylvania and Maryland, with fixed pricing for energy and RECs for the entire term.[127] The fourth is for a 200-MW portion of the proposed BlueWater project off the Delaware coast.[128] This contract will not become effective unless BlueWater is able to sell additional capacity under long-term contract. BlueWater is expected to be operational by December 1, 2014, perhaps earlier.

Both the *Onshore Wind* and *Offshore Wind Cases* examine whether it is in the interest of Maryland's ratepayers for the IOUs to enter into long-term contracts to support wind entry in Maryland. Both the economic and environmental net benefits have been quantified in these study cases. Capital and operating costs for wind projects assumed in the financial models used to evaluate the PPAs are summarized in Table 19. For comparison, capital and operating costs for solar photovoltaic are also included in Table 19. The capital and operating costs for wind projects are generally consistent with DPL's payment terms for both their onshore and offshore PPAs.

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[126] PJM 2007 411 Report – Municipal Solid Waste: 109 MW, Hydro (less than 30 MW): 18 MW.

[127] The onshore PPA that DPL signed with Armenia Mountain Wind LLC in June 2008 for 100.5 MW has a fixed energy payment rate of $68/MWh and a fixed REC payment rate of $24/REC for the entire 15-year term.

[128] In the BlueWater PPA, the Base Capacity Payment Rate is $70.23/kW-yr, the Base Energy Rate is $98.93/MWh and the Base Renewable Energy Credits Rate is $15.32/REC. All the BlueWater rates, including these, are subject to a fixed 2.5% annual inflation adjustment rate for each year after 2007. Schedule 2 of the BlueWater PPA gives an initial expected energy production schedule for the facility with an average annual capacity factor of 32%.

Table 19. Characteristics of Renewable Generation (2008$)[129]

	Onshore Wind[130]	Offshore Wind[131]	Solar Photovoltaic[132]
Configuration and Size (gross)	30 x 1.5 MW = 45 MW	86 x 3.5 MW = 300 MW	1 MW
Capital Cost (net $/kW)	$1,800-2,200	$2,500-5,000[133]	$5,500
Fixed O&M, ($/kW-yr)	$12	$36	$55
Variable O&M ($/MWh)	$7.5	$23	$0

6.2. Wind Resources in the *Reference Case*

In the *Reference Case*, wind entry has been distributed and scheduled across the region to meet the various states' increasing RPS requirements. Wind penetration rates across the study area depend on a number of factors. In our dispatch simulation and REC forecast models, wind resources were added by zone across the study area based on each state's RPS requirement, indigenous wind resources, number of projects currently in the PJM interconnection queue, proximity to transmission, and any locational requirement set forth in various RPS rules.[134] The potential wind capacity of each zone was estimated based on American Wind Energy Association state profiles.[135] Although the total RPS requirement across the modeled portion (excludes Illinois) of the PJM footprint would equate to about 32,000 MW of installed wind capacity by 2028, we added about 14,000 MW of wind generation. We assume that the remainder of the requirement is sourced from outside PJM or through payment of the ACP. The REC price forecast in Appendix C is based on this buildout of wind resources. The postulated wind buildout in the modeled PJM states corresponds to about 43% of the RPS requirement for

[129] Costs in LAI's 2008 Factor Inputs Memo to the Commission were based on ISO-NE, "New England Electricity Scenario Analysis," August 2, 2007 but have been updated with the latest available capital cost data from various sources including DOE's report "20% Wind Energy by 2030" (May 2008).

[130] Black & Veatch, "20% Wind Energy Penetration in the U.S.," October 2007. Updated to 2008. Onshore capital costs are forecast to decrease 10% by 2030. Onshore variable O&M costs are expected to decline while onshore fixed O&M costs are expected to be flat in real terms.

[131] We assume offshore wind is in shallow water, *i.e.*, less than 30 meters.

[132] Capital costs for solar photovoltaic do not include federal and state rebates which can reduce the cost by up to $3,000/kW.

[133] U.S. DOE Energy Efficiency and Renewable Energy, "20% Wind Energy by 2030," May 2008, p. 49.

Black & Veatch, "20% Wind Energy Penetration in the U.S.," October 2007, p. 5-12. Capital costs are expected to decline 12.5% by 2030.

[134] Ohio, for example, requires that one-half of the RECs be sourced in-state.

[135] See http://www.awea.org/projects/.

this region, and approximately 8% of the total ICAP in the modeled portion of the PJM footprint by 2028.[136]

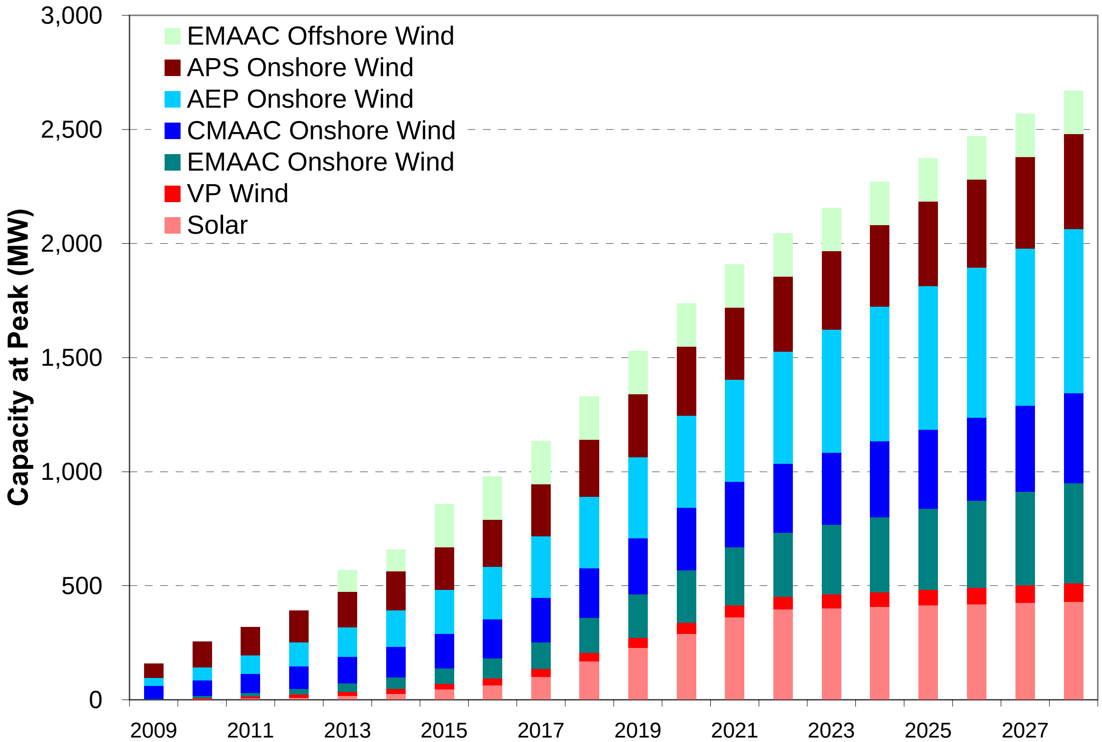
As noted in Section 2.1.4, all wind projects under construction in Maryland or under contract with Maryland IOUs have been included in the resource mix. AES's 100-MW Armenia Mountain project in Pennsylvania, which is under contract to DPL, is included in the *Reference Case*. Two Maryland projects have executed agreements with DPL: Synergics' 60-MW Eastern Wind Energy and 40-MW Roth Rock Wind Energy. These projects have been included in Maryland's generation mix in the *Reference Case*. No other onshore wind capacity has been added to the resource mix in Maryland. Even though BlueWater has a 200-MW contract with DPL, since this project is contingent on additional sales, it is not included in the *Reference Case*.[137] Offshore wind capacity has been added in EMAAC to reflect New Jersey offshore projects in PJM's interconnection queue. Limited onshore projects were also added to EMAAC in New Jersey over the long term. Consequently, there is a shortfall of in-state renewable resources to meet Maryland's RPS. The shortfall is satisfied through the purchase of out-of-state RECs. The REC price forecast model indicates that the Maryland price does not reach the ACP under any scenario or study case.

The timing of additions of both wind and solar resources in the *Reference Case* is shown in Figure 83. Note that this figure shows a measure of capacity at peak, which is similar to the UCAP credit.

[136] Illinois is not part of the modeled topology but could accommodate a significant proportion of PJM's wind resources, about 9,000 MW.

[137] Wind speeds along the Maryland coast and in the Chesapeake Bay appear sufficient to support wind production.

Figure 83. Solar and Wind Capacity Additions in *Reference Case*



The UCAP recognized by PJM for a wind facility is based on summer peak output, June through August, from 2 p.m. to 6 p.m. As indicated in Table 20, predicted capacity factors vary across PJM zones, depending on the available wind resources in the area. Wind resources generate "as the wind blows," that is, they are non-dispatchable. Wind production was calculated for each zone from available wind data, and the energy output curves were incorporated in MarketSym.[138,139]

[138] Primary sources for wind data were the state anemometer programs, the National Oceanic and Atmospheric Administration's (NOAA's) National Data Buoy Center, EPA's CASTNET site data and other publicly available data.

[139] Hourly wind speed data for specific sites in each zone were scaled to a hub height of 80 m onshore and 100 m offshore. Class 3 wind speed (6.4 to 7.0 m/s) is considered to be the minimum speed required for the installation of a commercial wind farm. If the only wind speed data available has an average wind speed less than 6.5 m/s and state wind speed maps indicated that there were Class 3 sites in that zone, we applied a multiplier to the annual average wind speed to increase it to 6.5 meter/second. The scaled wind speeds were converted to generation based on power curves from GE for onshore (1.5-MW) and offshore (3.6-MW) turbines. Hourly generation was converted to capacity factors by dividing by the nameplate capacity of the facility. Finally, capacity factors for each zone were summarized by hour by day and by month.

Table 20. Wind UCAP Factor by PJM Zone[140]

MarketSym Zone	UCAP Factor (%)
West-MAAC	36.4
Cent-MAAC	36.0
East-MAAC Onshore	22.2
East-MAAC Offshore	25.5
APS	16.7
VP	11.6
AEP/DAY	26.2
Onshore Maryland (APS)	29.7
Offshore MD (EMAAC)	25.5

As indicated in Figure 83, the *Reference Case* includes approximately 2,900 MW of onshore wind capacity at peak in PJM in 2028 which corresponds to approximately 12,000 MW of wind ICAP, equating to UCAP of about 3,500 MW.

6.3. Long-Term Contracts for New Onshore Resources

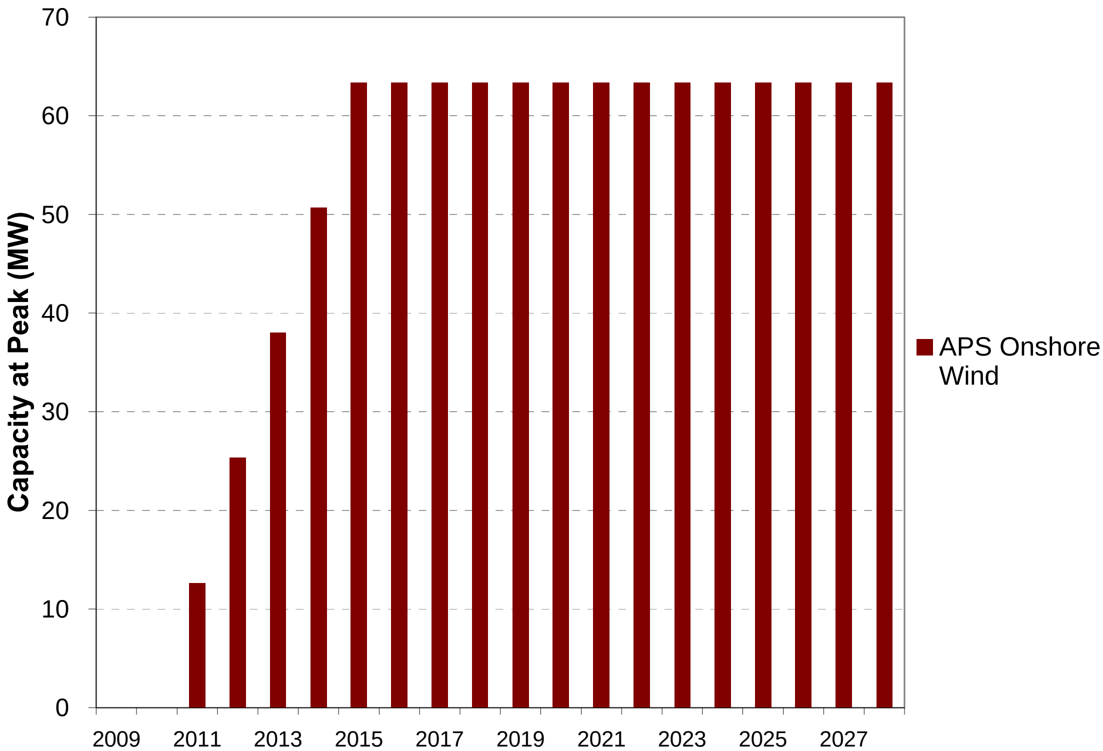
In the *Onshore Wind Case* we assess the merit of onshore wind under a 20-year PPA with total ICAP of 200 MW.[141] The new wind capacity is assumed to be located in western Maryland. In the Interim Report, we added 40 MW of onshore wind in the APS zone every year from 2009 to 2013, totaling 200 MW. In this Final Report, we add 40 MW of onshore wind each year from 2011 to 2015. The benefits and costs are apportioned to the four IOUs based on load share. Costs and contract terms are similar to those of recent wind contracts for projects in western Maryland and Pennsylvania. The contract prices for energy and RECs are expressed in constant $/MWh. In the financial model, we assumed a PPA payment rate of $73.51/MWh (for energy, capacity and RECs) in 2008 dollars subject to a fixed 2.5% annual inflation rate for each year. The IOUs are entitled to all capacity, energy, and RECs from the projects. Because the UCAP of the annual 40 MW of onshore wind capacity is only 12 MW, the addition of this onshore wind capacity does not offset any other capacity additions in PJM.

[140] EPA CASTNET Sites: PSU 106, Penn State, PA, 2007 (West-MAAC)
ARE 128, Arendtsville, PA, 2007 (Cent-MAAC)
NOAA National Data Buoy Center: Station ACMN4, Atlantic City, NJ (East-MAAC Onshore)
Station 44009, Southeast of Cape May, NJ (East-MAAC Offshore, Offshore MD)
Station SWPV2, Sewells Point, VA, 2005 (VP)
Virginia Anemometer Program: Floyd, VA, 2003 (APS)
Maryland Anemometer Program: Manchester, MD, 2007-2008 (Onshore Maryland)
Green Energy Ohio: Wapakoneta and Bryan, OH, May 2005-June 2007 (AEP/DAY)

[141] We estimate that 500 MW of onshore wind would be necessary to meet 50% of Maryland's RPS requirement in 2015.

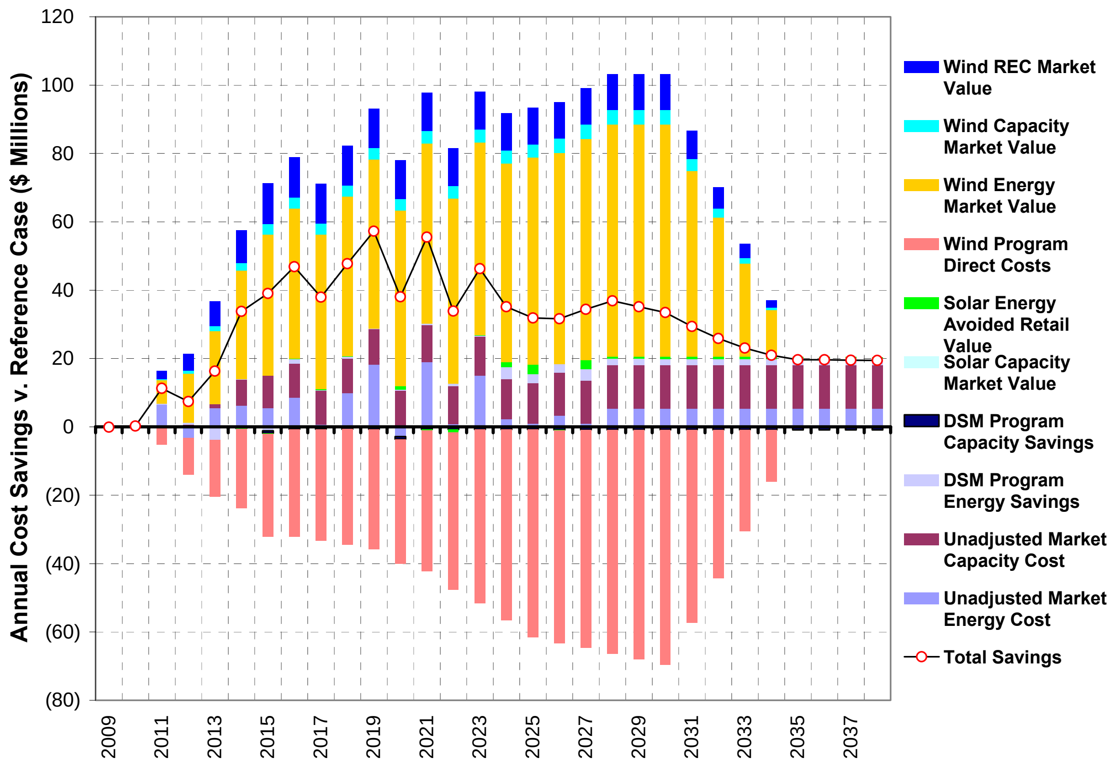
Modeled capacity additions for the *Onshore Wind Case* are shown in Figure 84. Due to the small effective "capacity at peak" of the 200 MW of wind ICAP, no other generation is displaced in the APS zone or other PJM zones. The modeled effect is to create a small capacity surplus relative to the *Reference Case*.

Figure 84. Incremental Capacity Additions – *Onshore Wind Case*



Base Scenario annual cost savings for the *Onshore Wind Case*, relative to the *Reference Case*, are shown in Figure 85. The savings are positive in all years. While the PPA benefits to the ratepayer end after 20 years for each 40-MW installation, the capacity remains in the generation mix, providing small portfolio benefits after 2034. While the market value of the energy produced is the largest driver of savings, the REC market value is significant as well. Portfolio effects are relatively small, but still contribute significant value in most years.

Figure 85. Annual Savings – *Onshore Wind Case*



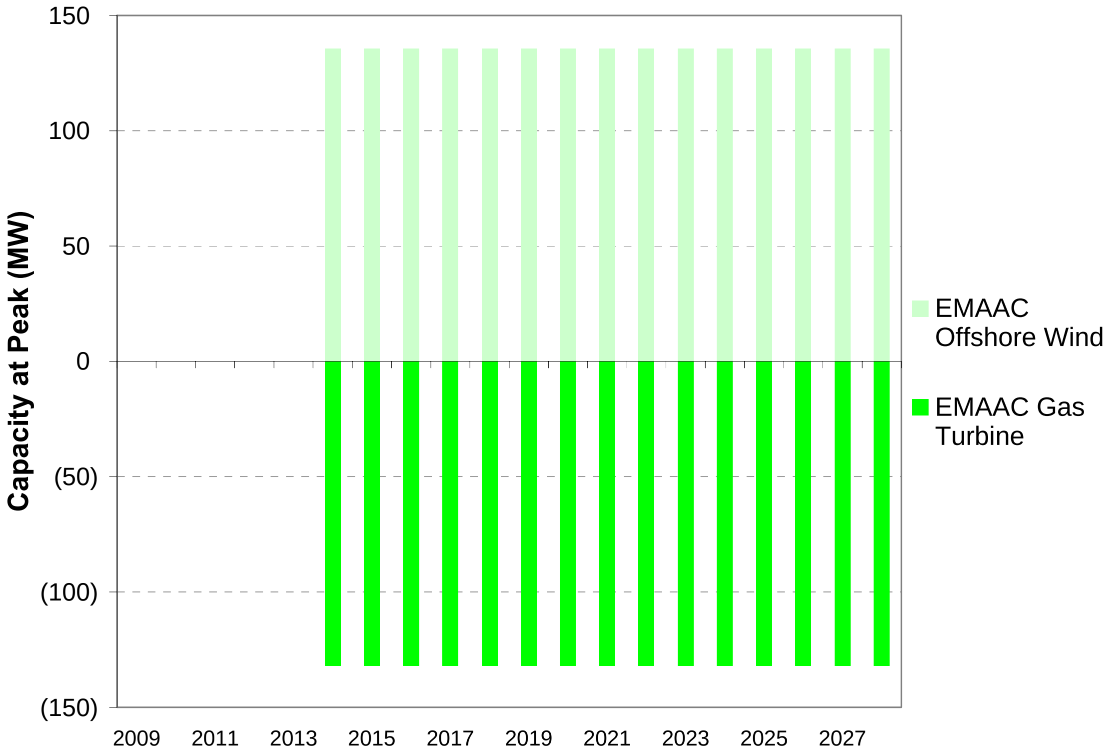
6.4. Long-Term Contracts for New Offshore Resources

The *Offshore Wind Case* postulates that the Maryland IOUs contract for 300 MW of ICAP from BlueWater.[142] This additional capacity sale would enable that project to proceed, thus adding 500 MW of wind ICAP to the regional mix in 2014. To place wind production for the *Offshore Wind Case* in a more favorable and realistic light, we have based the expected energy production profile for the offshore wind project on NOAA data rather than the materially lower schedule provided by BlueWater.[143] Favorable legislative treatment of RECs in Delaware applicable to BlueWater has not been assumed in Maryland, however. We have assumed that the Maryland IOUs would see the same pricing as DPL for its Delaware load. In the financial model, we assumed a PPA payment rate of $135.37/MWh (for energy, capacity and RECs) in 2008 dollars subject to a fixed 2.5% annual inflation rate for each year. As shown in Figure 86, the addition of a 500-MW (nameplate) offshore wind resource in EMAAC has the effect of eliminating the need for a 140-MW GT addition in EMAAC in 2014.

[142] 300 MW of offshore wind would be necessary to meet 50% of Maryland's RPS requirement in 2015.

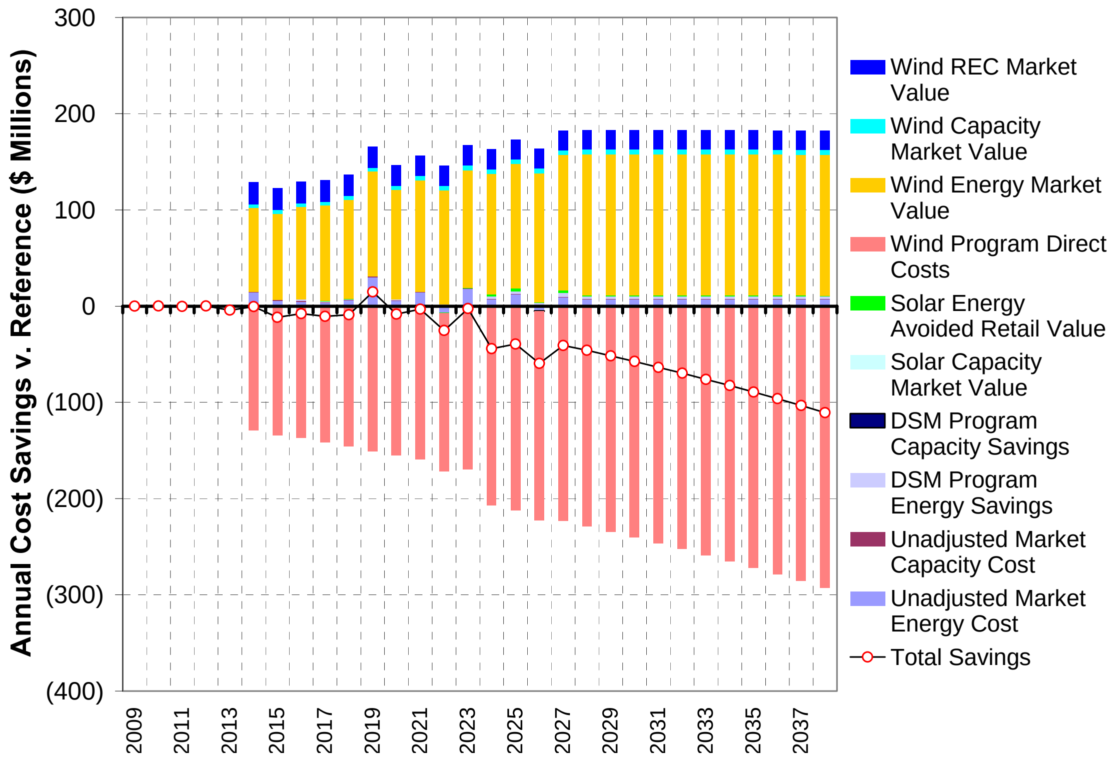
[143] The capacity factors in Schedule 2-1 of the PPA between DPL and BlueWater had an annual average of 32%. The capacity factors for a commercial offshore facility are typically over 40%.

Figure 86. Incremental Capacity Additions – *Offshore Wind Case*



Base Scenario annual savings for the *Offshore Wind Case*, relative to the *Reference Case*, are shown in Figure 87. Note that the net savings are negative in most years, driven primarily by the high direct costs associated with the BlueWater PPA terms. This is expected since offshore wind capital and operating costs are roughly twice as high as onshore costs. Despite the lackluster economics relative to onshore wind, offshore wind may still be worthwhile insofar as production-related intermittency problems are less problematic relative to onshore wind or to the extent onshore wind development is stymied by local opposition.

Figure 87. Annual Savings – *Offshore Wind Case*



6.5. Financial Comparison of Cases

6.5.1. <u>Base Scenario</u>

The annual savings for each of the wind cases under the *Base Scenario* are shown in Figure 88. EVA effects are compared in Figure 89. The *Onshore Wind Case* clearly provides a more favorable balance of direct costs and associated benefits than does the *Offshore Wind Case*, despite the relatively higher energy production and UCAP value per installed kW of the offshore wind project. The benefit-to-cost ratio for the *Onshore Wind Case* is 1.99:1, while the ratio for the *Offshore Wind Case* is 0.85:1. As shown in Figure 88 the *Offshore Wind Case* is deep in the red – the benefit-to-cost ratio below 1.0 underscores the expected economic loss borne by retail customers.

Figure 88. Annual Savings – Wind Energy Cases (*Base Scenario*)

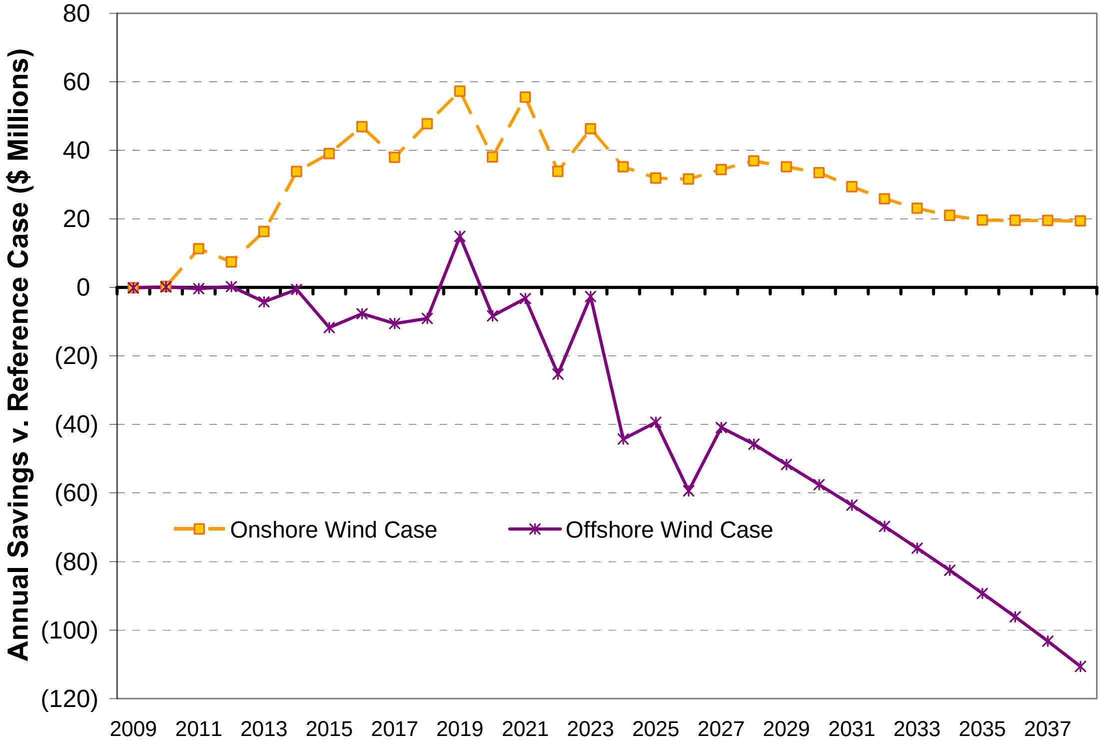
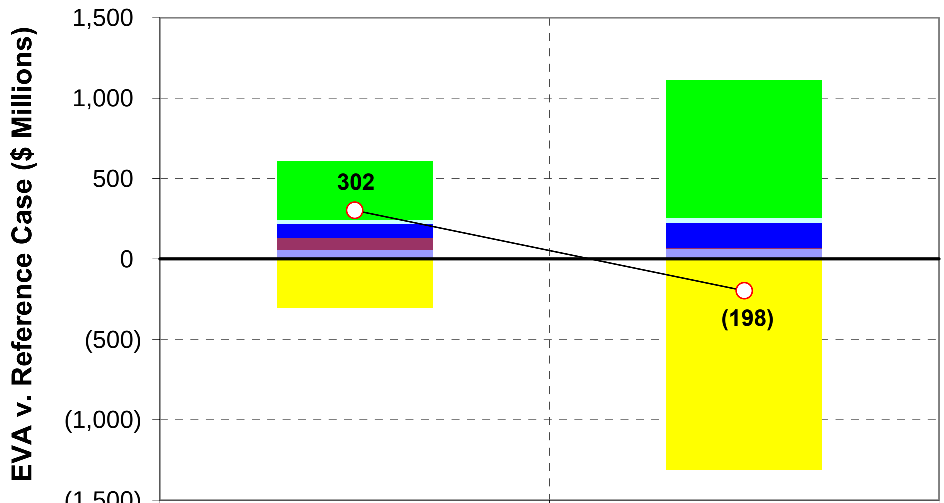


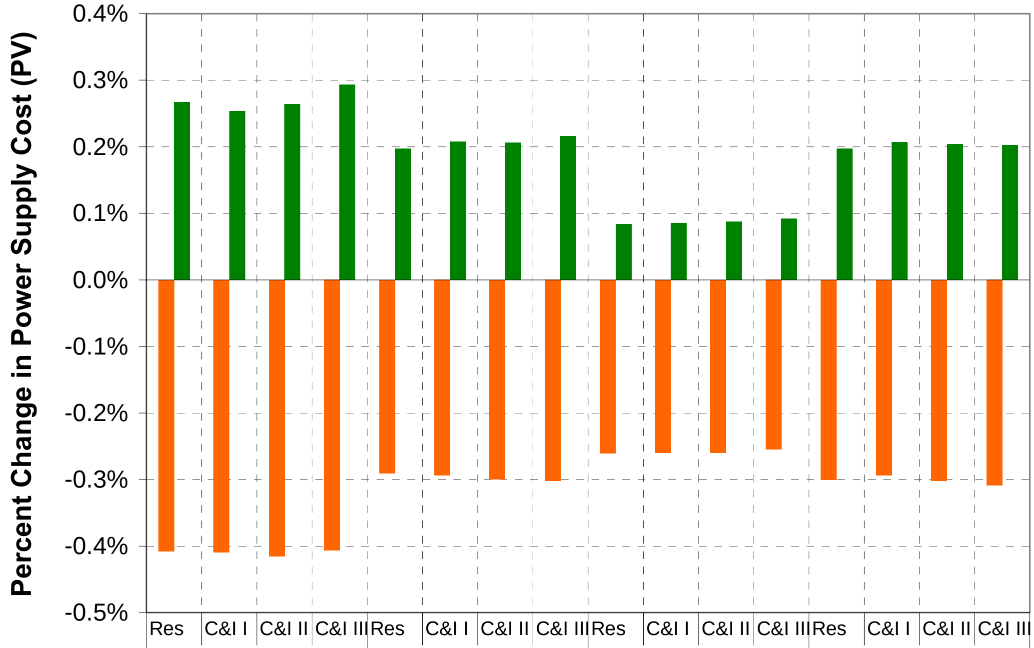
Figure 89. EVA – Wind Energy Cases (*Base Scenario*)



	Onshore Wind Case	Offshore Wind Case
Wind PPA Net Energy Margin	369	854
Wind PPA Capacity Credit	25	32
Wind PPA REC Credit	83	156
Market Capacity Cost	75	4
Market Energy Cost	58	66
Wind PPA Direct Costs	(307)	(1,311)
Total EVA	302	(198)

Ratepayer cost effects for the wind energy cases under the *Base Scenario* are shown in Figure 90 in terms of percentage change in power supply cost by IOU and class. Since the proposed projects are relatively small, the impact on rates is only a few tenths of a percent, with favorable impacts from the *Onshore Wind Case* and unfavorable impacts from the *Offshore Wind Case*.

Figure 90. Ratepayer Impact – Wind Energy Cases (*Base Scenario*)

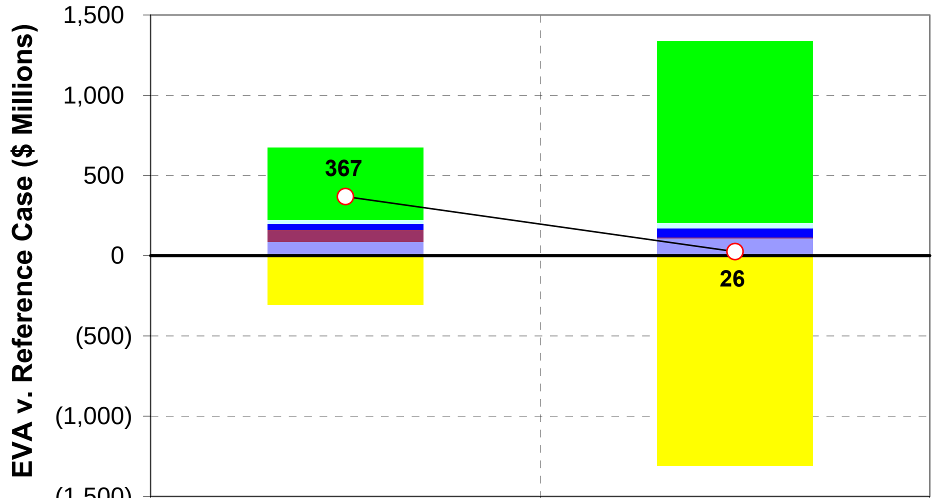


	APS				BGE				DPL				Pepco			
	Res	C&I I	C&I II	C&I III	Res	C&I I	C&I II	C&I III	Res	C&I I	C&I II	C&I III	Res	C&I I	C&I II	C&I III
Onshore Wind Case	-0.4%	-0.4%	-0.4%	-0.4%	-0.3%	-0.3%	-0.3%	-0.3%	-0.3%	-0.3%	-0.3%	-0.3%	-0.3%	-0.3%	-0.3%	-0.3%
Offshore Wind Case	0.3%	0.3%	0.3%	0.3%	0.2%	0.2%	0.2%	0.2%	0.1%	0.1%	0.1%	0.1%	0.2%	0.2%	0.2%	0.2%

6.5.2. Alternative Fuel Price Scenarios

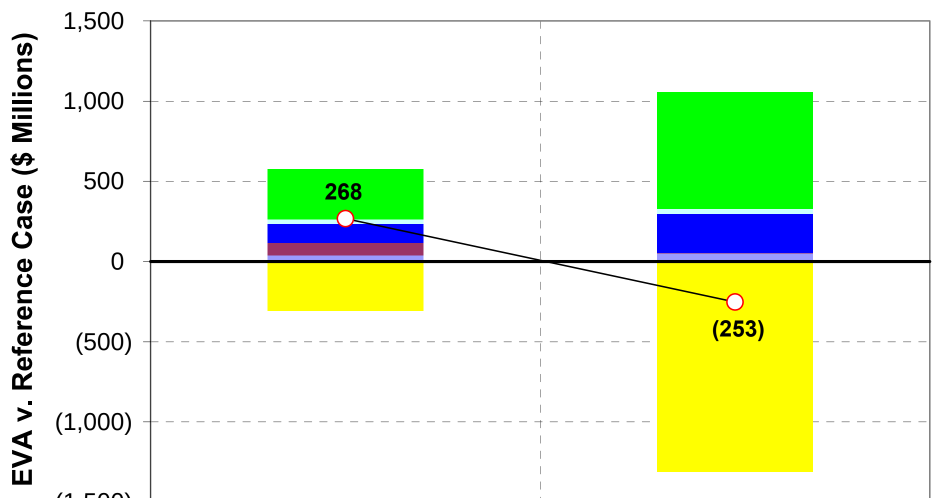
EVA results for the wind energy cases under the *Peak Oil* and *Federal Outlook Scenarios* are shown in Figure 91 and Figure 92, respectively. EVAs for both cases are enhanced under the *Peak Oil Scenario*, to the extent that the *Offshore Wind Case* shows a slightly positive EVA. Under the *Federal Outlook Scenario*, EVAs for both cases are reduced, but the *Onshore Wind Case* EVA remains positive.

Figure 91. EVA – Wind Energy Cases (*Peak Oil Scenario*)



	Onshore Wind Case	Offshore Wind Case
Wind PPA Net Energy Margin	451	1,133
Wind PPA Capacity Credit	25	32
Wind PPA REC Credit	38	58
Market Capacity Cost	75	4
Market Energy Cost	86	109
Wind PPA Direct Costs	(307)	(1,311)
Total EVA	367	26

Figure 92. EVA – Wind Energy Cases (*Federal Outlook Scenario*)

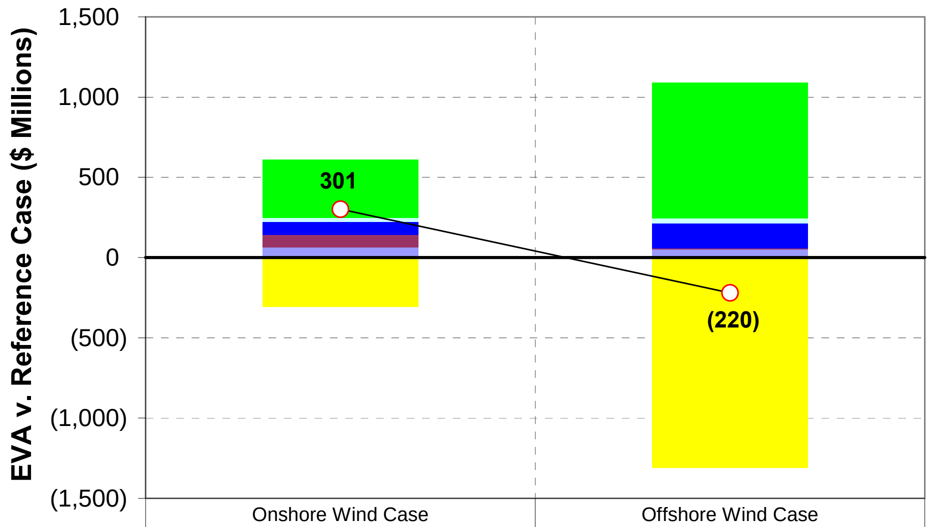


	Onshore Wind Case	Offshore Wind Case
Wind PPA Net Energy Margin	314	729
Wind PPA Capacity Credit	25	32
Wind PPA REC Credit	121	242
Market Capacity Cost	75	4
Market Energy Cost	40	50
Wind PPA Direct Costs	(307)	(1,311)
Total EVA	268	(253)

6.5.3. *No TrAIL Scenario*

EVA results for the wind energy cases under the *No TrAIL Scenario* are shown in Figure 93. Results are very similar to those under the *Base Scenario*.

Figure 93. EVA – Wind Energy Cases (*No TrAIL Scenario*)



	Onshore Wind Case	Offshore Wind Case
Wind PPA Net Energy Margin	361	847
Wind PPA Capacity Credit	24	32
Wind PPA REC Credit	83	156
Market Capacity Cost	75	4
Market Energy Cost	65	51
Wind PPA Direct Costs	(307)	(1,311)
Total EVA	301	(220)

6.6. Net Environmental Benefits

By displacing generation from fossil fuel-fired stations, the development of wind turbines reduces the net emissions of CO_2, SO_2, and NO_x from power generation across the study area. The net air quality benefits have been quantified by extracting plant emission data from the dispatch simulation model for the *Base Scenario*. Other environmental issues associated with siting wind turbines, such as impacts to bats and avian migration, are outside the scope of this study.

Figure 94 and Figure 95 show net CO_2 emissions for the *Onshore* and *Offshore Wind Cases*, respectively. Once the full 200 MW is in service, the *Onshore Wind Case* results in annual CO_2 reductions ranging from approximately 267,000 to 487,000 tons per year. The *Offshore Wind Case* results in annual CO_2 reductions ranging from 747,000 to 975,000 tons per year. The higher CO_2 reductions associated with the *Offshore Wind Case* arise from the fact that the 500 MW of ICAP were added offshore, whereas only 200 MW were added onshore.[144] Furthermore,

[144] The CO_2 reductions from the entire 500-MW offshore project are included here, although Maryland would only contract for 300 MW of ICAP.

offshore wind turbines have generally higher and less variable capacity factors than onshore wind turbines and therefore displace a larger quantity of conventional fossil-fired generation. Compared to Maryland's RGGI reduction target of 937,600 tons for 2015 (and each year thereafter, through 2018), the 500 MW of offshore wind resources would nearly accomplish the reduction target for a single year. The 200 MW of onshore wind resources would accomplish roughly one-quarter to one-half of the RGGI reduction target for a single year.

Figure 94. Change in CO_2 Emissions – *Onshore Wind Case*

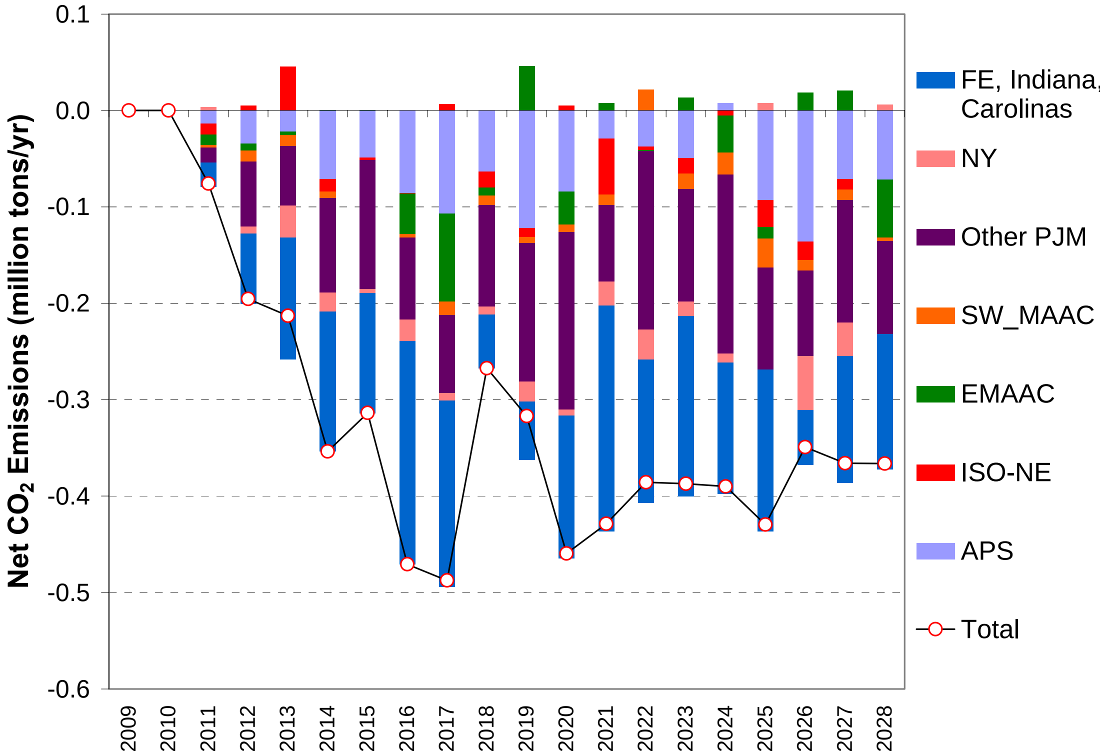
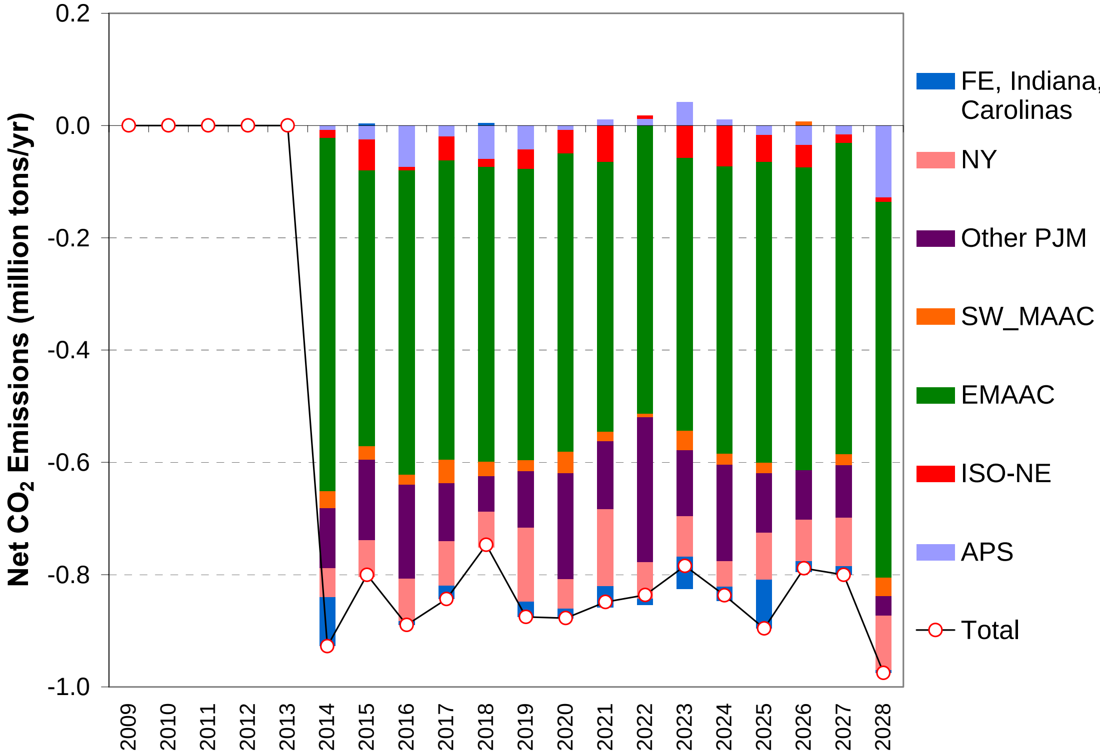


Figure 95. Change in CO_2 Emissions – *Offshore Wind Case*



In the *Offshore Wind Case*, most of the CO_2 reductions are created locally in EMAAC, where the wind turbines would be installed. In the *Onshore Wind Case*, the turbines would be installed in APS, but the CO_2 emission reductions are created not only locally, but elsewhere within and outside of PJM. On average EMAAC is an importing zone. This indicates that, in general, the marginal cost of local generation is higher than the marginal import cost. Therefore, inframarginal wind energy will displace local generation more often than imports. Conversely, APS is an exporting zone, so inframarginal wind energy will be exported more often than it will displace local generation.

Figure 96 and Figure 97 illustrate the net change in SO_2 emissions by zone across the study area. For the *Onshore Wind Case*, SO_2 reductions range from approximately 380 to 2,000 tons per year, once all wind turbines are in service. For the *Offshore Wind Case*, SO_2 impacts range from an increase of about 360 tons per year to a reduction of about 1,340 tons per year.

Figure 96. Change in SO_2 Emissions – *Onshore Wind Case*

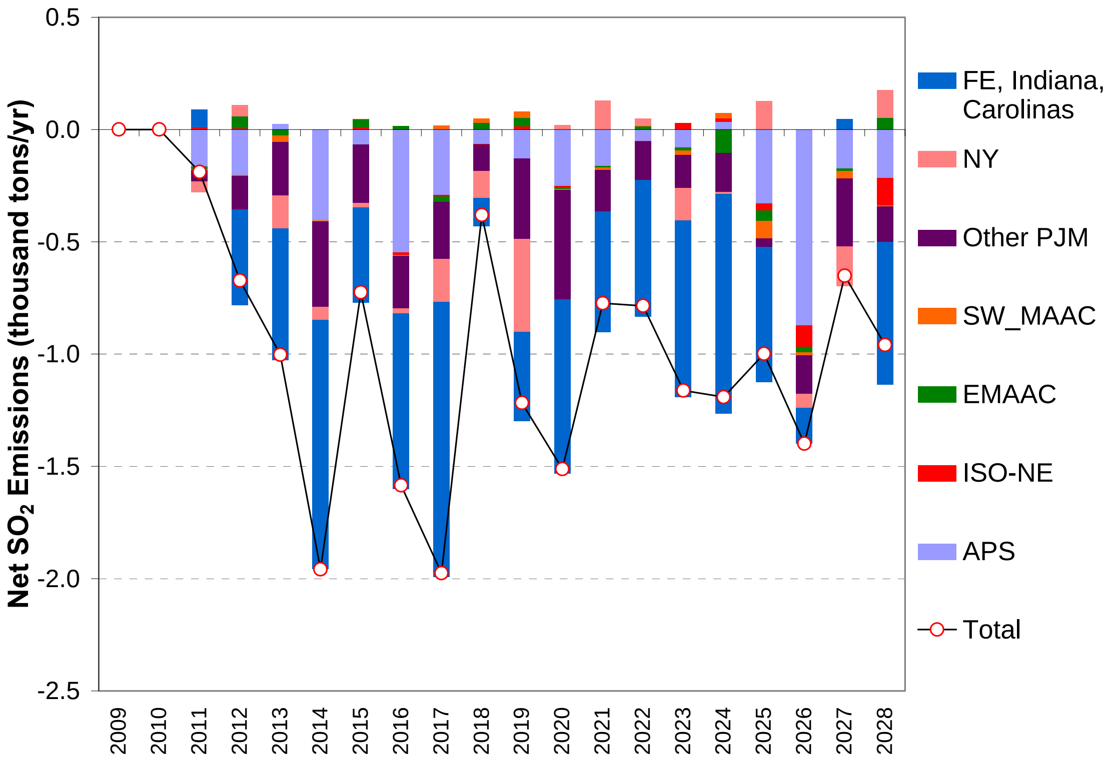


Figure 97. Change in SO_2 Emissions – *Offshore Wind Case*

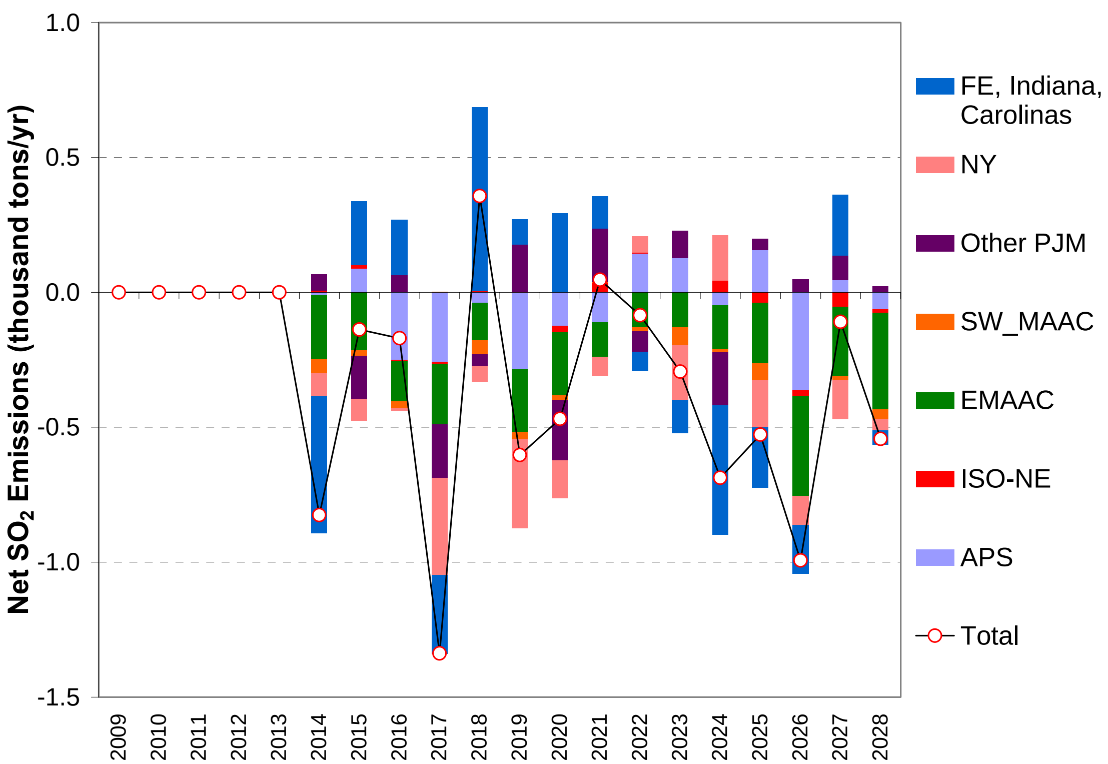


Figure 98 and Figure 99 illustrate the net impact on NO_x emissions for the *Onshore* and *Offshore Wind Cases*, respectively. Total net NO_x reductions for the *Onshore Wind Case* range from about 20 to 670 tons per year, once all the wind turbines are in service. Total net NO_x reductions for the *Offshore Wind Case* range from about 250 to 770 tons per year.

Figure 98. Change in NO_x Emissions – *Onshore Wind Case*

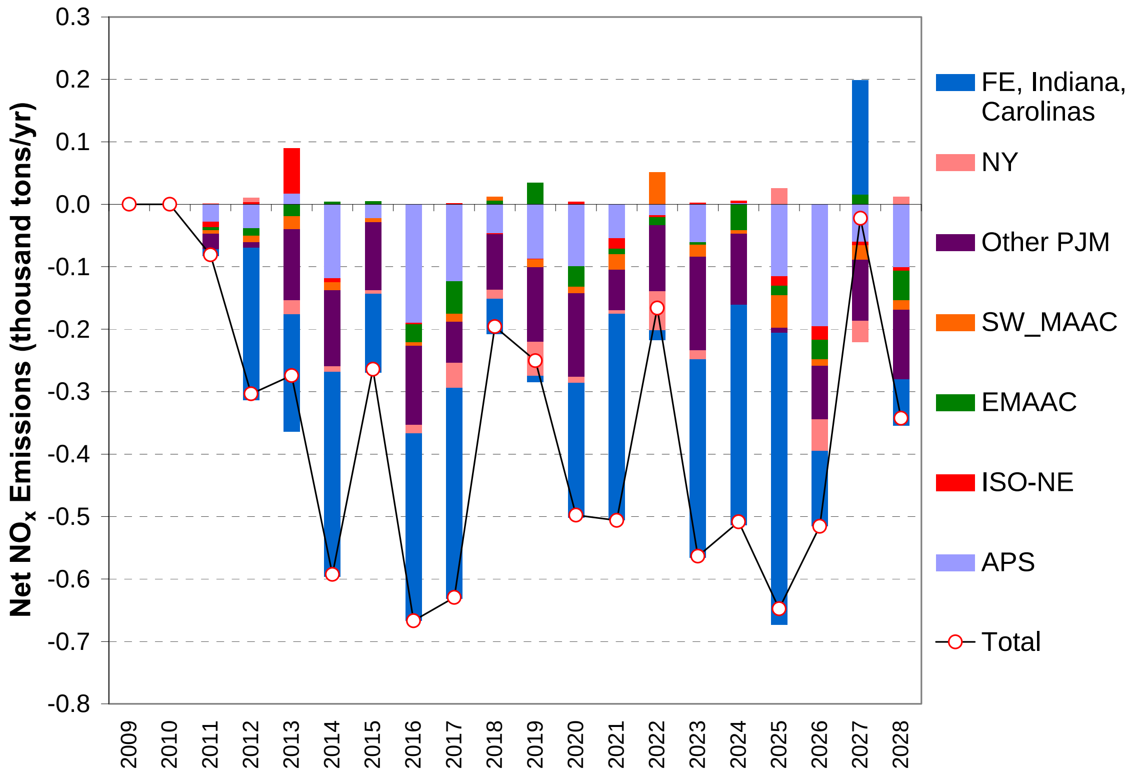
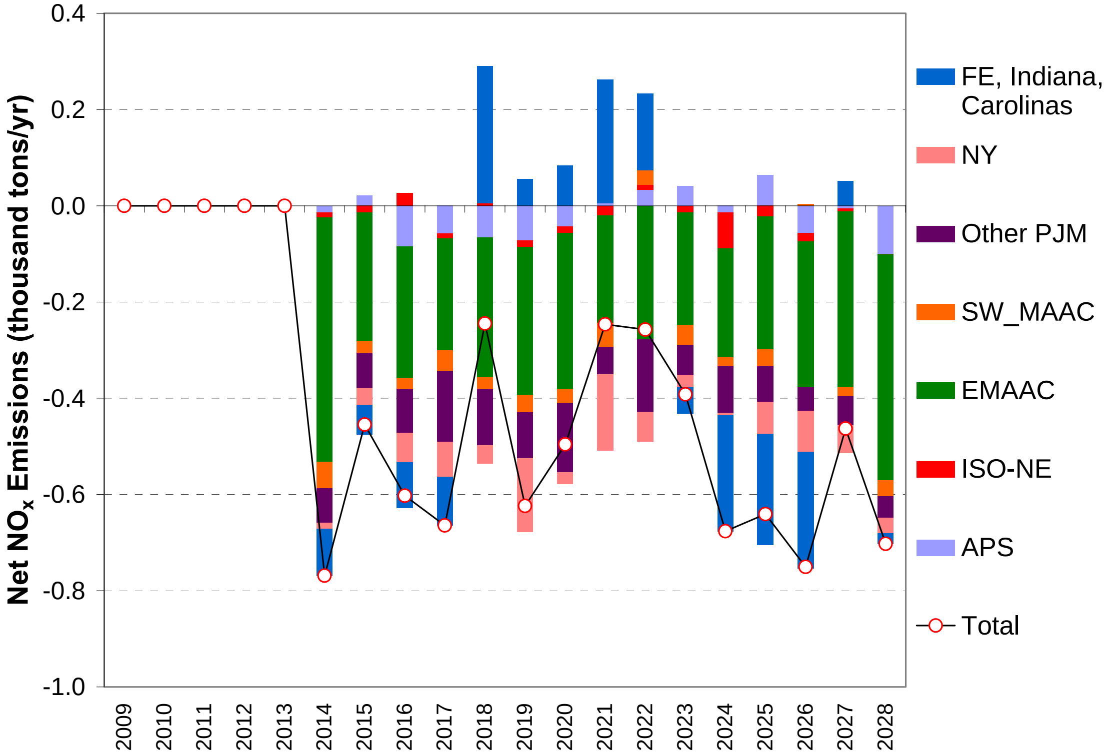


Figure 99. Change in NO_x Emissions – *Offshore Wind Case*



7. RENEWABLE GENERATION: SOLAR POWER

7.1. Solar Power Installation in Maryland

The *Reference Case* assumes full compliance with the Maryland solar RPS initiative, as described in Section 3.3.4. In this study, we postulate that the IOUs will meet Maryland's solar requirement by installing a sufficient number of 1-MW crystalline silicon photovoltaic installations on large customer sites in the state. Such C&I photovoltaic installations have a lower unit installed cost than residential installations due to economies of scale.[145] To meet the annual solar RPS target shown in Figure 51, solar photovoltaic installations were scheduled over the study period as shown in Figure 83. By 2022, roughly 1,100 MW of solar capacity will have to be installed to meet the in-state solar RPS requirement.

We have used the PVWatts performance model, originally developed by Sandia National Laboratories, to calculate monthly energy production for crystalline photovoltaic systems. We used average historical weather data for Baltimore for all the solar calculations. We modified the fixed array tilt in the PVWatts model to 15 degrees as adjusted by Sun Edison. The UCAP value for a solar facility is based on summer peak output, June through August, during the 2 p.m. to 6 p.m. time period. For Baltimore, the PVWatts model predicts a summer peak capacity factor of 27.9%. This means that a 1-MW facility will have a summer UCAP value of 279 kW in PJM.

Reported photovoltaic capital costs for a C&I installation range from $4,000/kW to $11,000/kW. ISO-NE's Scenario Analysis reported a range of $4,000/kW to 6,000/kW for a 1-MW facility.[146] Figure 100 indicates that the retail price index, which tracks the capital cost of a photovoltaic installation, of a solar photovoltaic module has leveled off at about $4,800/kW. EIA assumes an overnight capital cost for photovoltaic technology of $4,825/kW to $5,084/kW in 2010.[147,148]

The new thin-film photovoltaic cells using Cadmium-Tellurium technology are less expensive than crystalline modules and are reported to produce more energy per unit of ICAP. Southern California Edison plans to install 250 MW of commercial rooftop thin-film photovoltaic technology at an estimated cost of $3,500/kW (2008$).[149] The capital cost of a recently completed 6-MW thin-film photovoltaic installation in Germany was in the $4,700/kW range.[150] A recent levelized cost of energy comparison study found the thin-film technology capital costs to be in the $2,750/kW to $4,000/kW range, while the crystalline photovoltaic technology was in the $5,000/kW to $6,000/kW range.[151] Based on the wide range of cost data and uncertainties regarding the inclusion of all costs, we assumed photovoltaic capital costs to be fixed at

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[145] While there certainly will be a combination of C&I and residential photovoltaic installations in Maryland over the next 20 years, estimating the penetration of solar installations in the residential market was beyond the scope of this study.

[146] ISO-NE, "New England Electricity Scenario Analysis," August 2, 2007.

[147] Google's 1.6-MW facility is estimated to cost $8,125/kW. See http://www.spectrum.ieee.org/print/5568.

[148] Report #DOE/EIA-0554 (2008).

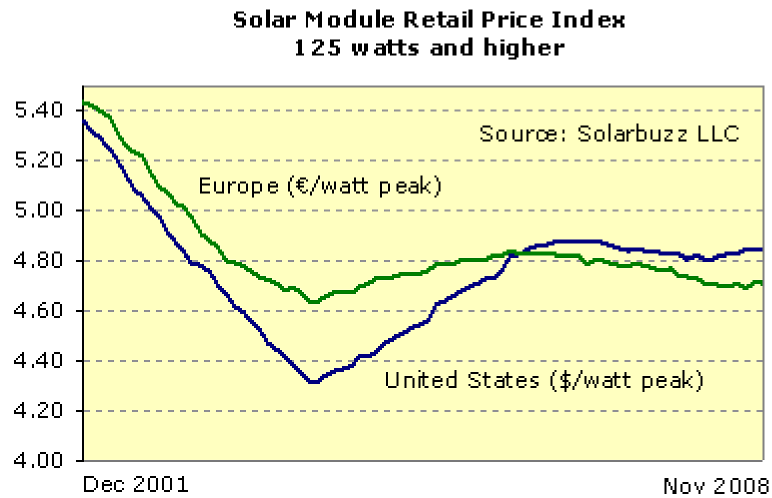
[149] Public Utilities Fortnightly, July 2008.

[150] See http://www.renewableenergyworld.com/rea/news/print?id=48027.

[151] Lazard, "Levelized Cost of Energy Analysis – Version 2.0", (June 2008).

$5,500/kW in every year of the analysis, implying a 2.5% annual decline in cost over the study period.

Figure 100. Solar Module Retail Price Index – U.S. and Europe[152]



Operating cost estimates for C&I photovoltaic installations are minimal. Although some sources report zero O&M costs, the more conservative sources list O&M costs in the $10/kW-yr to $50/kW-yr range. We assumed O&M costs of $55/kW-yr for stationary photovoltaic installations, roughly 1% of the capital costs. The major reason for including higher O&M estimated costs is to account for the need to replace inverters on a periodic basis over the life of the solar facility. Based on industry data, low longevity of inverters and their relatively high costs remain a concern for solar technology developers.[153] While the photovoltaic modules and other system components have a life of 25 years or longer, the average life of the typical inverter is 10 years or less. Therefore, the inverter may be expected to be replaced, on average, three or more times over the entire life of the solar facility. The cost of the inverter amounts to about 10% of the initial system costs, or more. If the initial total cost of the 1-MW solar facility is $5.5 million, the cost of its inverter is estimated to be $550,000. Assuming one inverter lasts 10 years, the O&M costs attributable to the replacements of the inverters would equal to $55/kW-yr.

In the Interim Report, we considered the solar facilities as wholesale generators. In this report we view them as being installed "behind the meter" and displacing retail electricity purchases. We have used the BGE SOS Type II rate structure as a cost basis, and escalated 2008 T&D and delivery charges at 1.25%, one-half the inflation rate, to account for service improvements over time. We estimated the energy supply charge by assuming that it represents the load-weighted equivalent of the wholesale hourly energy charge, grossed up for losses, ancillary services, and uplift. We estimated the fixed retail charge using the RPM capacity price unitized based on the on-peak-hour load factor and a reserve requirement of 115%, plus the allocated cost of Tier 1

[152] For modules 125 Watts and higher. See http://www.solarbuzz.com/.

[153] See http://www.nrel.gov/analysis/seminar/pdfs/2006/ea_seminar_jan_12.pdf.

and Maryland-specific solar RECs. We group all of theses charges under "Avoided Retail Charges" for presentation purposes.

7.2. Stand-Alone Facility Analysis

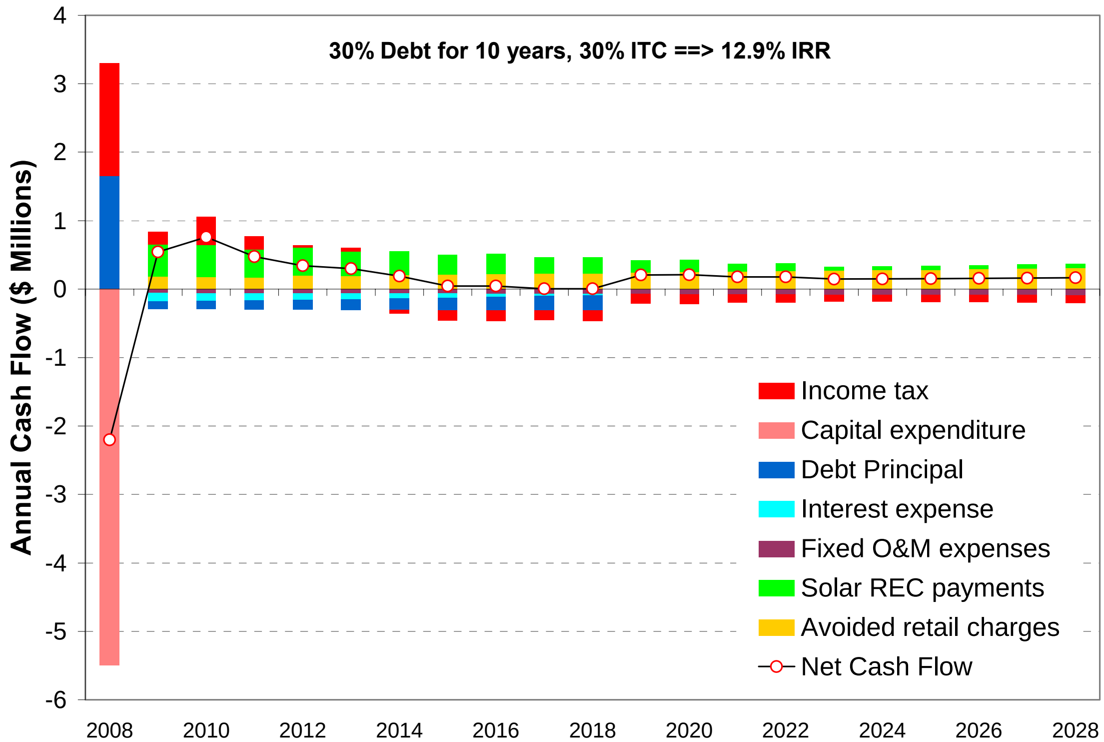
We have analyzed the financial feasibility of a 1-MW rooftop solar photovoltaic facility in SWMAAC to test the assertion that such facilities are economically viable, given current subsidies and tax benefits. Such photovoltaic facilities have been installed by C&I customers in states with high solar REC prices or other state incentives, such as California and New Jersey. We assume capital costs of $5,500/kW for the facility and fixed O&M costs of $55/kW. Annual cash flows for such a facility, assuming *Base Scenario*, *Reference Case* energy and capacity prices, are shown in Figure 101. With 30% debt financing over 10 years, the return on equity is 10%.[154] There are three key subsidies and tax benefits that drive this result.

- The 30% ITC reduces the effective equity outlay to about $2 million assuming the ITC can be fully utilized in the year earned. The assumption that the 30% ITC will be in place through 2017 is critical to the commercial viability of a stand-alone behind-the-meter facility.
- The $450/MWh Maryland solar REC payment substantially boosts cash flow in the early years.
- The 5-Year Modified Accelerated Cost Recovery System (MACRS) depreciation provides a tax shield for other taxable income, enhancing the return on equity, again assuming that these tax benefits can be fully utilized in the years earned.

Overall, it appears that a rooftop solar facility as postulated is financially feasible, given the current tax benefits and the high early year solar REC payment. If the ITC is not renewed after 2017, and solar REC prices drop as proposed, installations in later years may not be viable unless significant reductions in capital costs are achieved greater than the sustained real decline of 2.5% per year postulated in this study.

[154] 30% debt is the maximum amount of debt that ensures positive cash flows in all years.

Figure 101. Stand-Alone Rooftop Solar Cash Flows

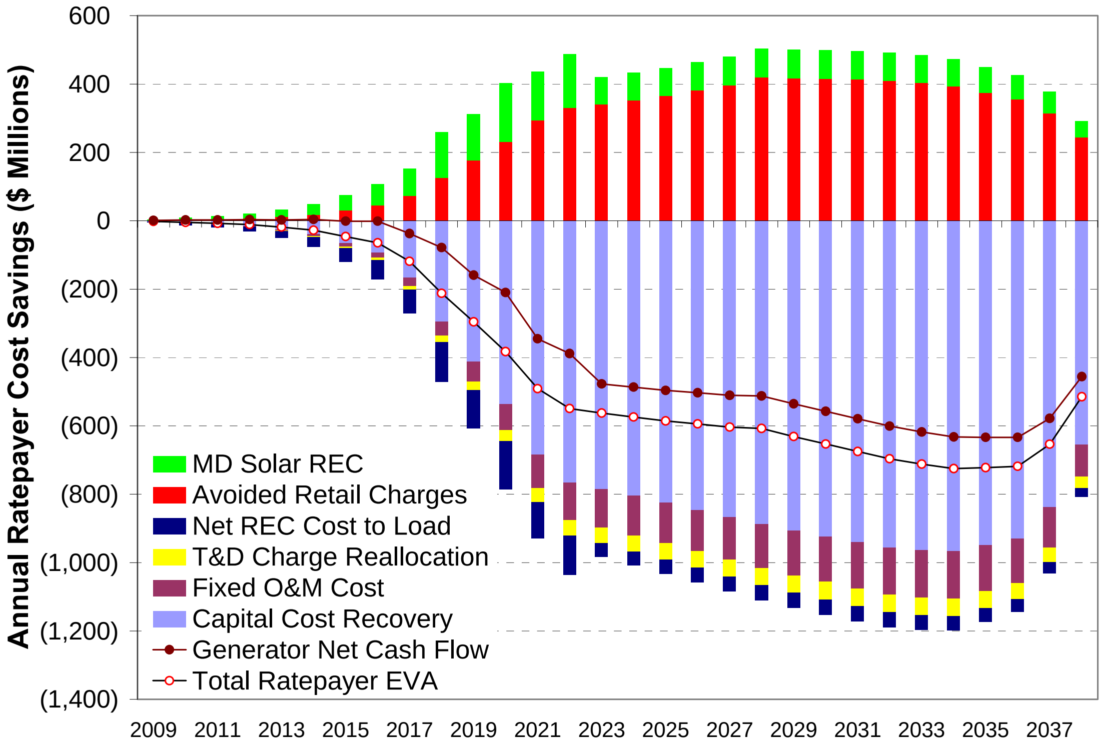


7.3. Financial Analysis of Reference Case Resources

7.3.1. Base Scenario

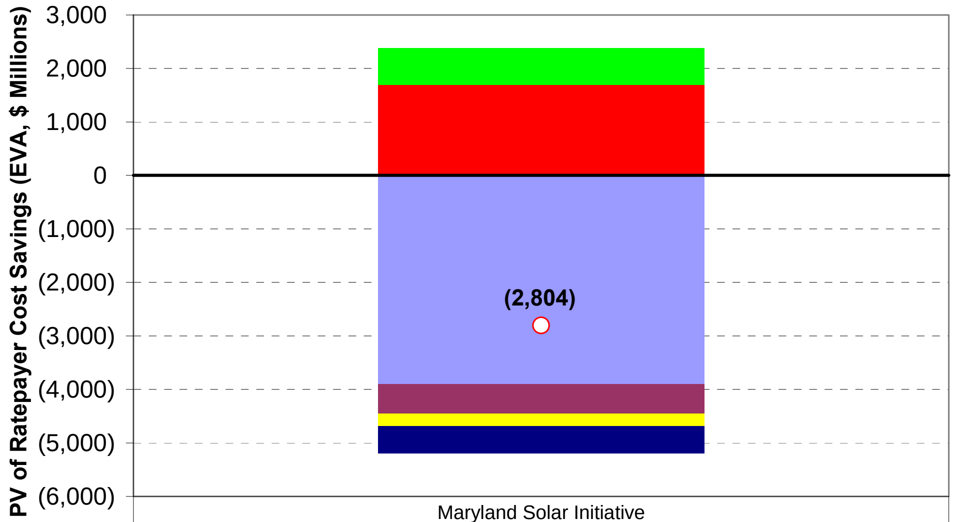
The direct costs and benefits of the *Reference Case* photovoltaic solar resources were calculated with ratepayer-backed PPAs for 20 years on each vintage of installation to reduce investor risk. The PPAs use the same general structure as those considered for the *Contract CC Case*, with ratepayers providing a fixed regular payment in exchange for the energy, capacity, and RECs from the facilities. Annual ratepayer savings under the *Base Scenario* are shown in Figure 102. For purposes of calculating ratepayer savings, it is necessary to add back as costs the Maryland solar RECs paid to the facilities, less the equivalent Tier 1 value of those RECs. It is also necessary to add back as a cost the T&D charges avoided at the retail level by the facilities. This is because the avoided T&D charges behind the meter are tantamount to historic investment in used and useful plant, and therefore likely to be recouped in full by the IUO. The net savings for the aggregated solar program are negative in all years. The "generator net cash flow" does not include the REC and T&D add-backs, and is positive for a few years, but is eventually overwhelmed by capital recovery charges as the Maryland solar REC price drops and, particularly, after 2017, when the federal ITC drops from 30% to 10%.

Figure 102. Annual Savings – *Reference Case* Solar Capacity (*Base Scenario*)



The same components are shown in PV form in Figure 103. Note that EVA is negative at ($2,804 million). The total would remain negative, even without the contribution of the Net REC Cost to Load, and T&D Charge Reallocation add-backs.

Figure 103. EVA – *Reference Case* Solar Capacity (*Base Scenario*)

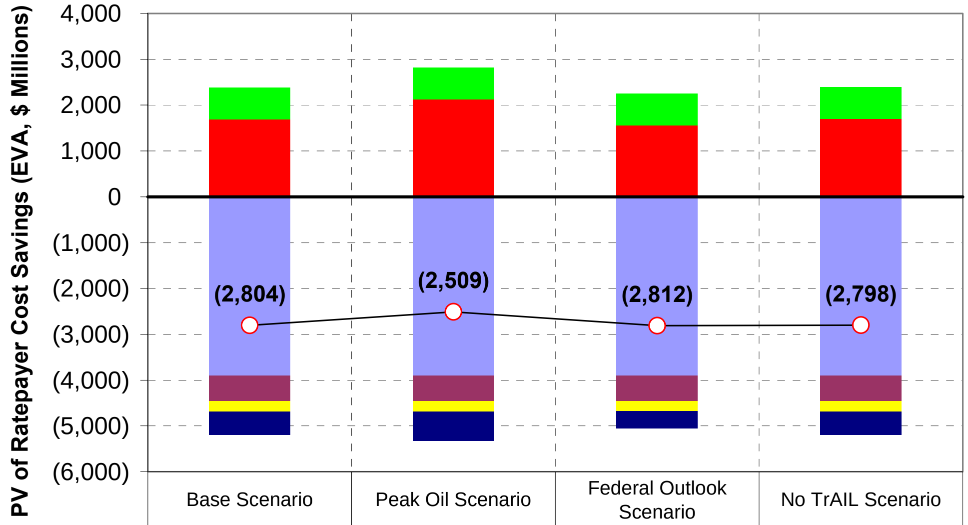


	Maryland Solar Initiative
MD Solar REC	695
Avoided Retail Charges	1,691
Net REC Cost to Load	(505)
T&D Charge Reallocation	(225)
Fixed O&M Cost	(561)
Capital Cost Recovery	(3,899)
Total Ratepayer EVA	(2,804)

7.3.2. Alternative Scenarios

The effects of different fuel price forecasts and transmission infrastructure on the merits of the *Solar Case* are relatively small, as indicated in Figure 104.

Figure 104. EVA – *Solar Case* (Alternative Scenarios)



	Base Scenario	Peak Oil Scenario	Federal Outlook Scenario	No TrAIL Scenario
MD Solar REC	695	695	695	695
Avoided Retail Charges	1,691	2,122	1,553	1,696
Net REC Cost to Load	(505)	(642)	(375)	(505)
T&D Charge Reallocation	(225)	(225)	(225)	(225)
Fixed O&M Cost	(561)	(561)	(561)	(561)
Capital Cost Recovery	(3,899)	(3,899)	(3,899)	(3,899)
Total Ratepayer EVA	(2,804)	(2,509)	(2,812)	(2,798)

8. RATE BASE REGULATION

8.1. Overview

The *Rate Base Regulation Case* represents a return to cost of service regulation in contrast to the more limited return to regulation that is characterized by one or more long-term contracts between merchant generators and Maryland's IOUs to meet incremental resource requirements. There are many complex and interrelated policy, legal, regulatory and economic constraints associated with the paradigm referred to in this study as the *Rate Base Regulation Case*. None of those constraints are analyzed in this report. Readers are therefore reminded that the analysis contained herein contains only a comparison of the costs of the assets under fair market valuation principles versus the benefits those assets are likely to generate over the study period. Many of the aforementioned constraints may be time consuming and potentially costly, and therefore may affect the EVA analysis presented herein.

At present, Maryland's IOUs have a rate base that includes only T&D. Generation has not been included in an IOU's rate base for nearly a decade. Although Maryland's IOUs do not presently have in-house generation management and operational expertise, all four IOUs have management links to unregulated affiliates that have the requisite manpower and operational expertise to manage and operate generation assets. When the generation assets were divested or transferred in 1999-2000, management and operating infrastructure were assigned to the successor companies. Under certain circumstances such management and operational know-how could be transferred back to an IOU or to a newly formed state power Authority.

A return to rate base regulation of the generation function could be achieved a number of ways. In order to quantify the potential benefits and costs associated with the return to rate base regulation, we have considered the acquisition of the generation plants located in the Maryland portion of the Pepco service territory that Pepco sold to Mirant in 1999. Financial analysis has been conducted to assess the benefits to retail customers assuming the Mirant assets are acquired under either condemnation or consensual negotiation. One way or another, we have assumed that the value of the generation assets would be established under FMV principles. Study results are presented under Pepco ownership assumptions as well as under Authority ownership.

Quantification of potential retail benefits and costs under the *Rate Base Regulation Case* first requires derivation of the FMV of the generation assets located in the Maryland portion of the Pepco service territory. By definition, FMV means no forced sale. The FMV of those assets therefore reflects what a willing buyer would pay Mirant under the conventional valuation measures applied by investors in appraising the long-term value of a generation portfolio.[155] Importantly, we have therefore made the assumption that there will be a return to normal capital market conditions to enable the transaction. Consistent with LAI's calculation methodology in the Interim Report, two valuation methods have been employed: *first*, using an investment banking approach where a multiple is applied to Earnings Before Interest, Taxes, Depreciation, and Amortization (EBITDA); and, *second*, using a net income capitalization approach. The net

[155] We have ignored the market conditions that existed at the time MidAmerican proposed to acquire Constellation's assets, including BGE, Calvert Cliffs, and other generation assets.

income capitalization approach is a DCF method that necessitates explicit assumptions about the cost of capital. The results under the two methods are summarized in Table 21.

Table 21. Valuation Results

Method	Value ($ Billions)	Value ($/kW)
8 x EBITDA	$6.6	$1,391
DCF	$6.3	$1,318

8.2. Legislative / Regulatory Requirements

In condemnation proceedings, states generally have to demonstrate that acquiring property is for the "public good," that is, a public purpose is well served. A state that pursues condemnation must ensure due process in order to protect the economic interests of the party owning the condemned property.[156] If Maryland were successful in obtaining a legal judgment approving the condemnation of the generation assets in Pepco's service territory, then Mirant would be entitled to fair compensation in exchange for the taking of their generation assets.

In lieu of condemnation, Pepco might be able to acquire the Mirant assets through a voluntary, consensual negotiation with Mirant. Again, FMV principles would apply. A consensual negotiation has a number of advantages. A costly and protracted condemnation process could be avoided. Second, a voluntary process would allow other interested parties to participate. Those parties may facilitate a timely transaction. Third, parties are often able to negotiate an acceptable transaction price through arms-length negotiations rather than through a costly and contentious adversarial proceeding.

If the assets were to be held by a state power Authority following transfer of ownership, such an agency would have to be created and empowered by the state. Only a few states have such power authorities, including New York, California and Illinois.[157] Other states have proposed the creation of state power authorities.[158] NYPA was established by state legislation in 1931 to secure public control of New York's upstate hydropower resources. NYPA first developed the 900-MW St. Lawrence Power Project and then, years later, the 2400-MW Niagara Power Project. LIPA was established in 1998 to assume the financial obligations of the Long Island Lighting Co., a utility in financial distress due to the failed Shoreham nuclear power plant. In the midst of the California energy crisis in 2001, the California Power Authority was established to

[156] LAI has not researched condemnation law and precedents in Maryland.

[157] In September 2008 following the successful 2008/09 procurement solicitation by the Ameren Illinois Utilities and ComEd, the Illinois Power Agency submitted its first 5-year procurement plan covering 2009-2014. The Plan outlines the procurement strategy that the Agency will implement to purchase electricity supply for eligible retail customers.

[158] An authority has been proposed in Rhode Island to facilitate the development and financing of renewable energy projects. In Connecticut, an authority was proposed to build power plants and buy wholesale power supplies for the state's utilities. As of November 2008, neither of these authorities has been formed.

issue up to $5 billion in revenue bonds to build power plants, repair aging generators, buy land, make loans, seize property by eminent domain, and restructure the state's dysfunctional natural gas market.

8.3. Asset Valuation Principles

FMV reflects the price a willing buyer would pay a willing seller with both parties acting prudently and without compulsion. Valuation under FMV assumes generally normal financial conditions, a seller that is not distressed, and multiple creditworthy purchasers. A condemnation process through the state judicial system would determine an "award" to be paid by the buyer to the seller. The basis for determining the amount of the award must be clearly explained, including all sources of value. Under most state condemnation processes, any award paid to Mirant must be "just" with consideration beyond current market value, including planned and potential improvements, as well as direct and consequential losses from the condemnation.

Both the condemnation and voluntary approaches have virtually identical goals – establishing a just and reasonable amount that constitutes the FMV of the assets, including adjustments for potential future earnings. Under traditional valuation principles, FMV can be computed a number of ways, but three approaches are common industry standards:[159] Comparable Sales, Replacement Cost, and Net Income Capitalization. For properties that have going concern value such as the Mirant fleet, the Net Income Approach is most common. Other approaches may be used to support the reasonableness of the Net Income Approach.

- The Comparable Sales Approach – also referred to as the Market Data Evaluation Approach – relies on sales analysis of comparable properties. Comparability does not connote many sales, and it does not necessarily imply identical properties. In this case, other than MidAmerican's intended acquisition of Constellation at a "fire sale price," few generation assets close to Pepco's service territory have been sold. Each asset is unique in terms of technology, age, condition, operating strategy, revenue contracts / hedges, operating cost, and other variables. Other generation sales in PJM could serve as a useful FMV indicator, but adjustments for location, cost, and technology considerations require extensive accounting. In sum, the Comparable Sales Approach may be of limited use for purposes of approximating the value of the Mirant fleet.
- The Reproduction Cost Approach involves estimating the cost of reproducing the subject properties as long as the property would be replaced in kind, with allowances for diminished condition and operating performance. A refinement of this approach, Replacement Cost New Less Depreciation, relies on the current cost to construct a property of equivalent function built to current standards and under current conditions, less depreciated value. While these approaches are reasonable for a property that is new, it is difficult to apply these methods for purposes of approximating the value of the Mirant fleet in Maryland.

[159] While these three approaches are common appraisal techniques, in LAI's commercial experience the use of a multiple around EBITDA is commonly applied by global investors in the valuation and acquisition of power plants.

- The Net Income Approach is the method most commonly used in modern finance to value generation assets as long as future revenues and operating expenses can be accurately estimated. The resulting forecast of EBITDA can be capitalized using a multiplier that reflects the capital structure and costs for typical generation asset buyers. Alternatively, the resulting forecast cash flow (after depreciation, income taxes, and debt payments) can be discounted to arrive at an equivalent net PV. Both the EBITDA multiplier and DCF discount rate must reflect the benefits, costs, and risks of the assets, current market conditions, and other key determinants of value.

8.4. Description of the Mirant Assets in Maryland

A list of Mirant's generation assets in Maryland is provided in Table 22. Other Mirant assets located elsewhere in PJM are not considered in this valuation.[160]

Table 22. Mirant Assets in the Pepco Service Territory in Maryland

Plant	Nameplate Capacity (MW)	Fuel	Technology
Morgantown	1,412	Coal, Oil	CT, ST
Dickerson	837	Coal, Oil, Gas/Oil	CT, ST
Chalk Point	2,338	Coal, Oil, Gas/Oil	CT, ST
SMECO	84	Gas	CT
Total	4,671		

Other generation assets are located in the Maryland portion of Pepco's LDA, for example, the Panda Brandywine CC facility and the Montgomery County Resource Recovery Facility. Although Panda Brandywine is scheduled by Mirant in PJM's DAM pursuant to the PPA that was assigned to Mirant from Pepco at the time the assets were divested, it is not owned by Mirant, and the Montgomery County Resource Recovery Facility is neither owned nor operated by Mirant. Therefore neither of these facilities is included in the valuation.

8.5. Forecast of Revenues and Expenses

Mirant purchased the assets from Pepco in 1999, a sale that included transference of its long-term PPAs. In preparing the forecast of revenues and expenses, LAI has reviewed the proprietary database licensed by Ventyx, FERC Form 1s and 10-K filings by Mirant and Pepco, among other data sources.

We forecasted power plant revenues for each year of the study period based on the sale of energy, ancillary services, and capacity.[161] We also forecasted expenses for variable O&M (fuel, consumables, maintenance accrual, emissions allowances, *etc.*) as well as fixed O&M for production (labor, insurance, *etc.*), and non-production expenses (G&A, insurance, property

[160] Potomac River (514 MW) is in Pepco's service territory, but is in Virginia.

[161] The transaction transferring ownership is assumed to take place on January 1, 2009.

taxes, *etc.*) for each plant type in the Mirant fleet. CapEx for environmental upgrades was accounted for as well.

Revenue estimates gained from the sale energy and ancillary services were developed using data from our MarketSym simulation runs, which provides dispatch and capacity factor data on a plant-by-plant basis, as well as the value of E&AS sold each year based on each plant's operating characteristics. Table 23 shows key technical data by plant, including EFORd assumptions used to compute each unit's capacity in UCAP terms.

Table 23. Estimated Full Load Heat Rates and Year In-Service

	Full Load Heat Rate (Btu/kWh)	Year In Service	Location	EFORd
Chalk Point 1	9,680	1964	Prince George's County	4.6
Chalk Point 2	9,135	1965	Prince George's County	11.9
Chalk Point 3	10,200	1975	Prince George's County	1.5
Chalk Point 4	10,300	1981	Prince George's County	3.1
Chalk Point CT 1	12,200	1967	Prince George's County	6.2
Chalk Point CT 2	13,300	1974	Prince George's County	12.0
Chalk Point CT 3	12,200	1991	Prince George's County	1.8
Chalk Point CT 4	12,200	1991	Prince George's County	4.3
Chalk Point CT 5	11,200	1991	Prince George's County	7.6
Chalk Point CT 6	11,200	1991	Prince George's County	7.8
SMECO SCT 1	11,888	1990	Prince George's County	2.8
Dickerson 1	9,500	1959	Upper Montgomery County	2.1
Dickerson 2	9,300	1960	Upper Montgomery County	2.6
Dickerson 3	9,300	1962	Upper Montgomery County	2.0
Dickerson D CT1	13,100	1967	Upper Montgomery County	1.7
Dickerson H1 CT	10,900	1992	Upper Montgomery County	27.4
Dickerson H2 CT	10,900	1993	Upper Montgomery County	6.0
Morgantown 1	8,900	1970	Charles County	3.3
Morgantown 2	9,200	1971	Charles County	3.7
Morgantown CT 1	14,500	1970	Charles County	3.3
Morgantown CT 2	14,500	1971	Charles County	0.0
Morgantown CT 3	12,500	1973	Charles County	5.5
Morgantown CT 4	12,500	1973	Charles County	0.1
Morgantown CT 5	12,500	1973	Charles County	0.0
Morgantown CT 6	12,500	1973	Charles County	0.0

Capacity revenues are based on the results of our UCAP price forecast under PJM's BRA. Detailed discussion about the building block assumptions employed in the capacity price forecast is presented in Section 2.2.3.

Our forecasts of fuel and emissions expenses are also shown Sections 3.1 and 3.3, respectively. LAI has developed annual costs for fuel and emission allowances for each plant based on its dispatch regime and operating characteristics, delivered fuel costs, and emission allowance price forecast. Mirant's production expenses were estimated based on available FERC Form 1 filings, which were verified using Pepco's 10-K data.[162] Production expenses were aggregated for the assets based on two categories, coal-fired STs and combustion turbines (CTs). Many of the facilities are dual-fuel capable.[163] Production expenses using the Form 1 data are summarized in Table 24. [164]

Table 24. Pepco Production Expense from 2000 Form 1 (assets transferred to Mirant only)

	Fixed Production Expenses ($/kW-yr)	Variable Production Expenses ($/MWh)
ST ($2000)	$10.88	$11.77
Inflation Factor	1.25	1.25
ST ($2009)	$13.59	$14.71
CT ($2000)[165]	$1.56	$11.35
Inflation Factor	1.25	1.25
CT ($2009)	$1.95	$14.18

These variable production expenses data include an adder for capital expenses that would likely be accounted for on a variable basis. The Form 1 data show that Pepco spent approximately $203 million in "Gross Additions to Utility Plant" in 2000. In 2000 the Pepco fleet produced about 18.8 GWh. The adder to variable costs to account for these expenses is $10.73/MWh, which is included in the totals shown above.

The Form 1 data provide production operating expenses only. We have grossed up the operating expenses to account for non-operating costs, *e.g.*, insurance, overhead, and other soft costs. In order to account for significant expenses not associated with operating the plants, LAI reviewed the G&A expense for the Pepco fleet in 1999 and 2000 that was available in the annual Form 1 filings at FERC. More recent data from Mirant are not available. The Pepco Form 1s provided the total G&A expense for the Pepco fleet, as well as operating expenses for the various Pepco business segments: generation, T&D, sales, and customer service. To apportion the G&A expense among business segments, LAI calculated the generation segment's total production costs less fuel and purchased power. That total was then compared to the total production expense for the other business segments. G&A expense was then apportioned on a *pro rata*

[162] The most recent Form 1s were filed by Pepco, which was then the plant owner.

[163] The Morgantown ST is still capable of burning oil as well as coal in our MarketSym forecast, if it is economic to do so.

[164] The Form 1 data are expressed in 2000 dollars. A factor of 1.25 has been applied to account for inflation at 2.5% per year through 2009.

[165] Although the Morganton CT runs on No. 2 oil while the other CTs are gas-fired, operating cost data for Morgantown is limited. As such, we have assumed its operating costs are the same as the gas-fired CTs.

basis. A gross-up factor of 1.38 was then determined based on the average 1999 and 2000 values, as shown in Table 25.

Table 25. Derivation of A&G Gross-Up Factor

	2000	1999
Total Power Production Expense	$1,100,382,013	$1,016,442,172
Less Fuel and Purchased Power	988,549,759	915,576,770
Total	111,832,254	100,874,402
Transmission Production Expense	21,191,510	18,488,635
Distribution Production Expense	63,710,745	65,938,590
Customer Accounts Production Expense	45,918,626	42,259,241
Customer Service Production Expense	3,594,843	4,379,296
Total Sales Expenses	3,028,567	3,947,276
Total	137,444,291	135,013,038
Total G&A Expense	85,681,481	96,685,735
% Attributable to Power Generation	45%	43%
% Attributable to other	55%	57%
Power Production G&A	38,439,048	41,346,482
Total Non-Fuel Production Expenses	111,832,254	100,874,402
Total Gross-up Factor	1.34	1.41

The gross-up factor was then applied to both the variable and fixed operating expenses to calculate O&M by plant type. Those calculations are shown in Table 26 below.

Table 26. Derivation of Grossed Up O&M Expenses

		Production	Factor	Total O&M
ST	Fixed ($/kW-yr)	$13.59	1.38	18.71
	Variable ($/MWh)	$14.71		20.25
GT	Fixed ($/kW-yr)	$1.95	1.38	2.69
	Variable ($/MWh)	$14.18		19.52

The expenses shown are in 2009 dollars. Inflation is a constant 2.5% per year over the study horizon. The incremental CapEx related to required environmental upgrades are also accounted for the in the valuation. The Maryland HAA requires retrofits of several coal-fired plants owned by Mirant. Mirant's capital outlays required to comply with the HAA are shown in Table 27.

Table 27. CapEx Associated with Maryland's HAA Compliance[166]

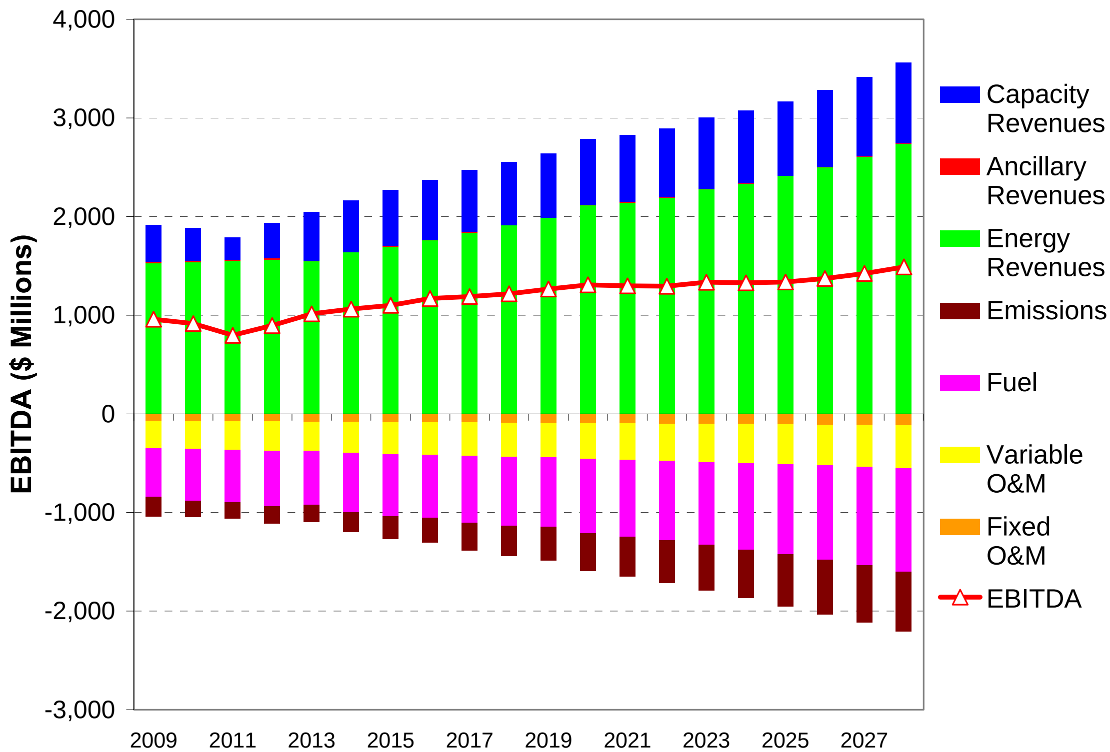
	2008	2009	2010
Compliance CapEx ($ millions)	689	286	125

In deriving the FMV of the Mirant fleet in Maryland, LAI has considered environmental CapEx that is prospective only. Environmental expenditures that have occurred to date have been accounted for in the analysis. The forecast of consolidated EBITDA accounts for the remaining environmental CapEx scheduled in the next two years. The PV of the remaining environmental related expenditures is $374.2 million. In the DCF valuation, the expenditures have been depreciated over 20 years.

8.6. EBITDA Valuation

EBITDA is a measure of profitability that is stated before interest, taxes, depreciation and amortization. It is a widely used commercial benchmark of asset values. For the Mirant fleet in Maryland, average EBITDA over the first five years of the forecast horizon is $876.3 million.[167] A projection of yearly EBITDA for the Mirant assets is shown in Figure 105.

Figure 105. EBITDA for the Pepco Service Territory Assets by Year



[166] Source: Mirant's 2007 10-K

[167] Using the average over five years reduces the probability that an unusual result in any one year will bias the valuation.

Based on BRA auction results to date, EBITDA declines in the first few years of the forecast – 2011/12 is the low point due to the comparatively low auction results for Delivery Year 2011/12 for SWMAAC. This pattern generally persists for each asset class. As shown in Figure 23 in Section 2.2, UCAP prices for Delivery Years 2007/09 through 2010/11 are materially higher than 2011/12.

In Table 28 we report the valuation results using multiples of 7x to 9x. The PV of the environmental related CapEx is deducted from the five-year average EBITDA value.

Table 28. EBITDA Valuation Results

First Five Year Average EBITDA ($MM)	Multiple	Value of Earnings ($MM)	Less PV Environmental CapEx ($MM)	Adjusted Value of Earnings ($/MM)	Unitized Value ($/kW)
$876.3	7	$6,134	$374.2	$5,760	$1,207
$876.3	8	$7,010	$374.2	$6,636	$1,391
$876.3	9	$7,887	$374.2	$7,513	$1,574

The range of EBITDA multiples incorporated in this analysis reflects investors' financing cost and risk tolerance assumptions prior to the credit crisis. To the extent the present global credit implosion changes investors' risk tolerance, hurdle rates, and project financing debt terms, the range of applicable multiples may be significantly lower than 7x to 9x. As previously discussed, in deriving FMV we have postulated the return toward normalcy in the capital markets. Therefore the use of the three multiples effectively brackets the range of asset values likely to be observed in a competitive solicitation for quality generation assets in SWMAAC under normal conditions in the capital markets.

Figure 106 and Figure 107, below, show EBITDA by year sorted by technology type. For purposes of comparison, earnings are shown on a $/kW basis for each year.

Figure 106. Annual Cash Flows – Mirant Coal Plants

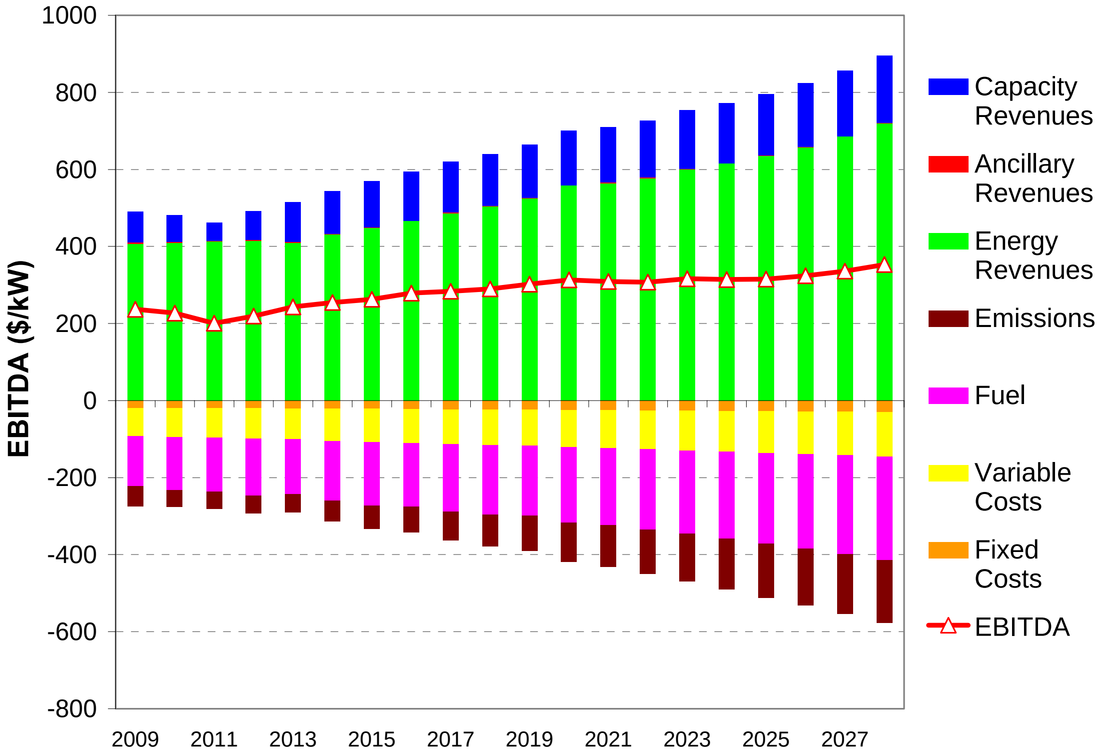
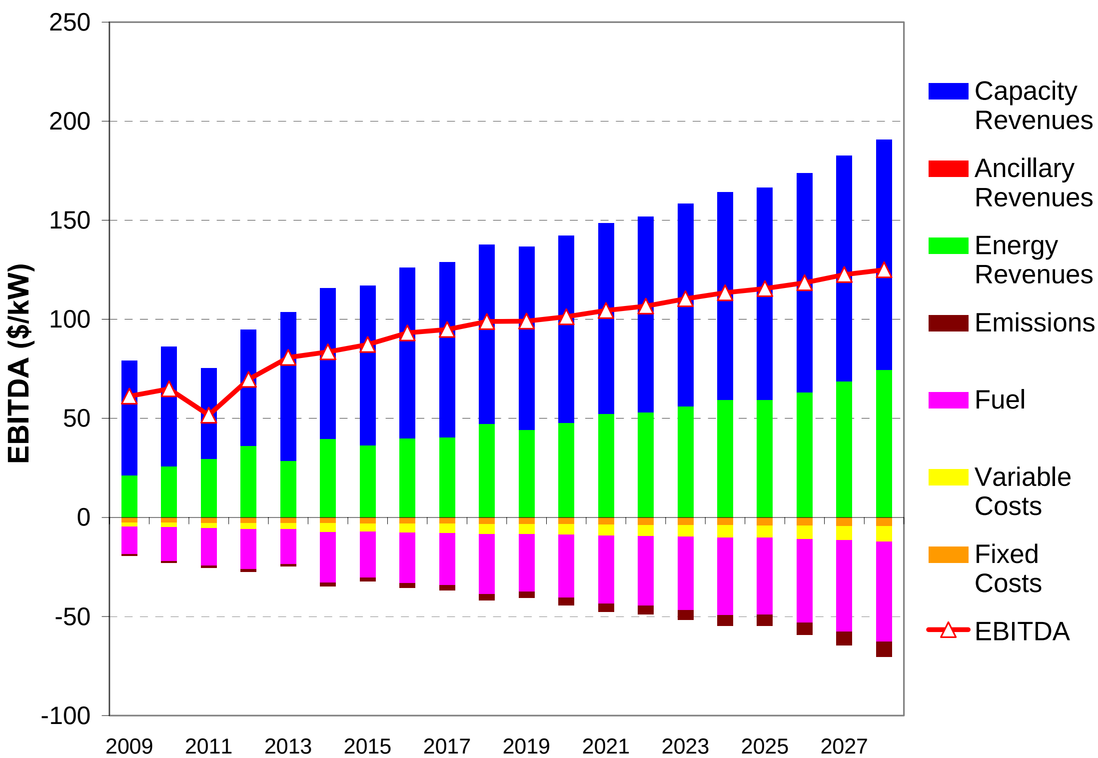
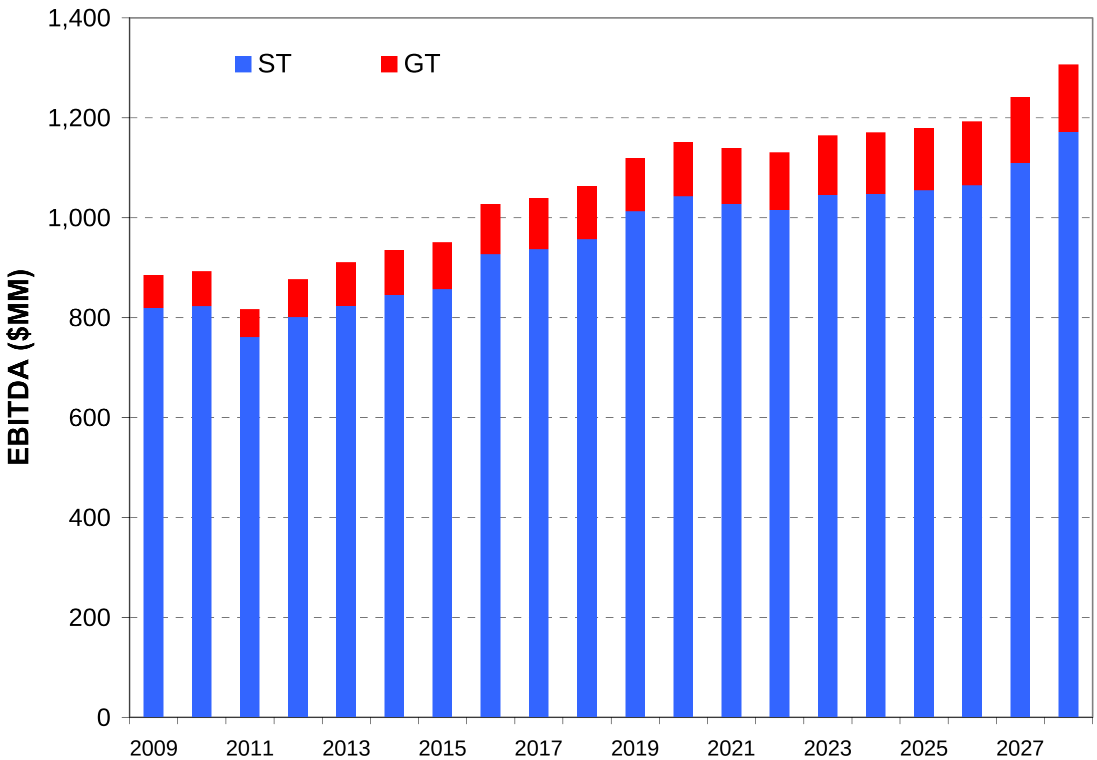


Figure 107. Annual Cash Flows – Mirant CTs (Oil and Gas)



In general, the FMV of the coal units is much higher than that of the gas / oil CTs. This is because the coal plants are reasonably efficient and therefore pocket the dark spread based on natural gas based LMPs in SWMAAC and the total marginal cost of producing coal-based energy. Whereas the ST generators derive the majority of income from energy sales, the CTs are primarily dependent on capacity sales. In Figure 108 we show the contribution to fleet-wide EBITDA by year for the STs and the CTs. On average, the CTs account for less than 10% of the yearly EBITDA of the Mirant assets.

Figure 108. Coal Based STs v. Oil / Gas CTs – Consolidated EBITDA



8.7. DCF Valuation

The other method used to estimate the value of the Maryland assets is DCF. DCF accounts for the impacts of financing costs, income taxes, and ROE. To determine FMV under DCF, we have calculated the PV assuming 50/50 debt / equity financing over a 20-year term and an after-tax ROE of 12.5%. The cash flows the investment generates are the EBITDA values shown in Figure 105, net income taxes, debt payments, and depreciation. The relevant financial inputs to the DCF valuation are shown below.

Table 29. DCF Financial Assumptions

Inflation	2.5%
Effective Tax Rate[168]	40.36%
Interest Rate	7.5%
Debt / Equity Ratio	50/50
Debt term	20 years
Depreciation Period	20 years
Depreciation Type	MACRS
ROE	12.5%

These financial assumptions are consistent with the debt costs and risk profile of a merchant generator like Mirant. Under either a condemnation or consensual negotiation scenario, Mirant must be paid the FMV of the assets. The extent to which an IOU or an Authority is uniquely positioned to realize additional ratepayer benefits is of no relevance.

The FMV under this method is about $6.3 billion or $1,245/kW. We have made the simplifying assumption that the depreciation schedule is 20 years for all plant types. We have not adjusted FMV for potential terminal value benefits.

8.8. Portfolio Benefits Under Rate Base Regulation

The portfolio benefits derived from re-regulation of the Mirant assets result from the suppression of energy bid adders in favor of daily scheduling in strict accord with marginal cost. Under the existing wholesale market design approved by FERC, Mirant, like other generators throughout PJM, may include mark-ups above the marginal cost of producing energy in the DAM or RTM. These markups are included in the energy revenues. In this analysis, we have eliminated the mark-ups, thereby lowering the cost of energy in SWMAAC when a Mirant asset sets the LMP.

More detail about how markups have been derived is presented in Appendix B.

8.9. Net Costs to Load

The starting rate base reflects the FMV of the generation assets located in the Maryland portion of the Pepco service territory plus an allowance for the short-term CapEx required for environmental compliance. Either Pepco's or an Authority's cost of capital would then determine the annual cost to load under cost of service ratemaking. If ownership and operational control is the IOU's, we assume that Pepco would be permitted to recover prudently incurred costs associated with the management and maintenance of the generation assets. For an interim period, this could include all costs reasonably incurred under a turnkey, third-party arrangement. We assume that the Commission would allow Pepco to earn a reasonable return on its investment.

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[168] The effective tax rate is the combination of the Maryland state tax rate and the federal tax rate, calculated as 8.25% + 35% * (1 – 8.25%) = 40.36%.

The financial parameters used in this analysis under either IOU or Authority ownership are summarized in Table 30. More detail about the financial assumptions and market considerations associated with these ownership structures can be found in Section 2.5.

Table 30. Recommended Financing Assumptions for Rate Base Regulation Option

	IOU	**Authority**
Debt / Equity Ratio	50/50	100%
Debt Interest Rate	7.0%	6.1%
Debt Term	30 yrs	30 yrs
Equity Hurdle Rate	10.5%	n/a

If an Authority were established for purposes of ownership and operational control of the Mirant assets, the new entity would be capitalized through the issuance of long-term revenue bonds, plus a small amount of short-term debt, perhaps a revolver facility, to fund day-to-day needs and receivables. We anticipate that interest payments for the Authority's bonds would not be exempt from federal income taxes, but would be exempt from state and any local income taxes in Maryland.

8.10. Financial Analysis

8.10.1. Base Scenario

Our analysis of cost to load combines the capital recovery charges for the Mirant assets and environmental CapEx, less the annual EBITDA values used to determine FMV, less any portfolio benefits from the elimination of bid adders. We assume that the energy, capacity and ancillary services from each generation plant would continue to be sold into the DAM or RTM. Likewise, we assume no change in the requisite product purchases to serve retail load. Annual impacts on cost to load are summarized in Figure 109 and Figure 110 for the two ownership structures. It is important to note that under IOU ownership, the net savings are significantly negative for the first five years. The negative savings – additional costs – for the first five years are explained by the front-loaded capital recovery pattern for a regulated utility. Under Authority ownership the negative savings in the first few years are avoided due to the return component of the capital recovery factor being much lower than that of the IOU.

Figure 109. Annual Cost Savings – IOU Ownership (*Base Scenario*)

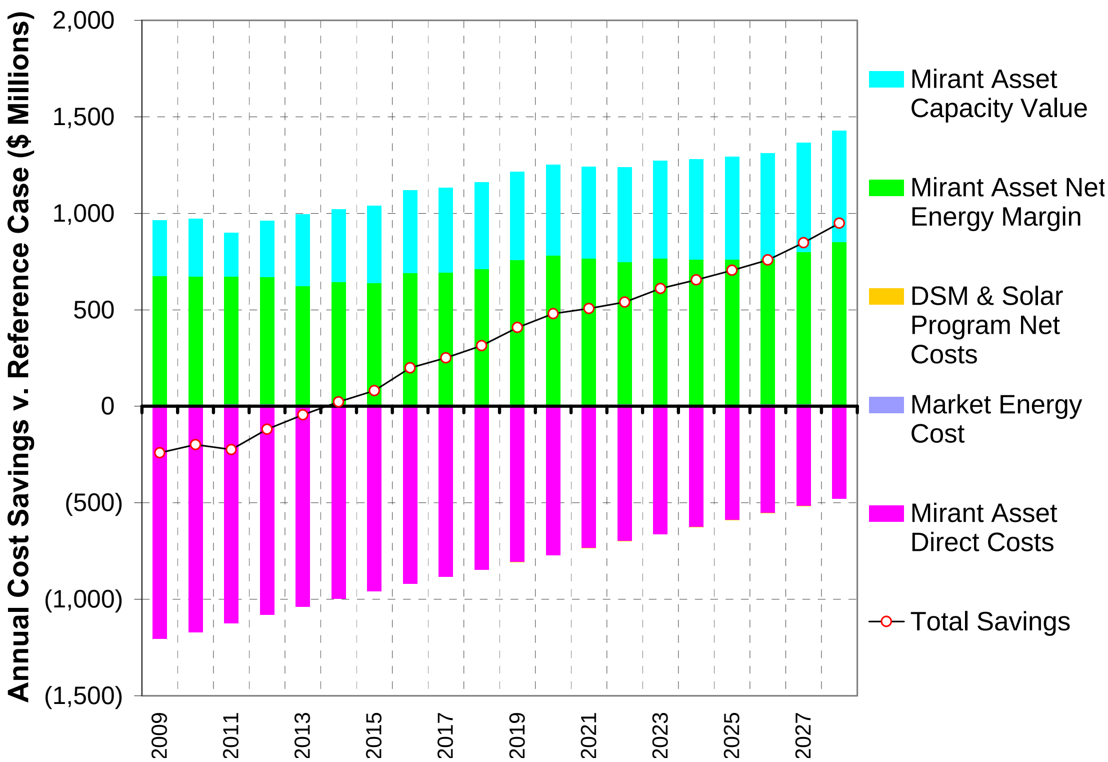
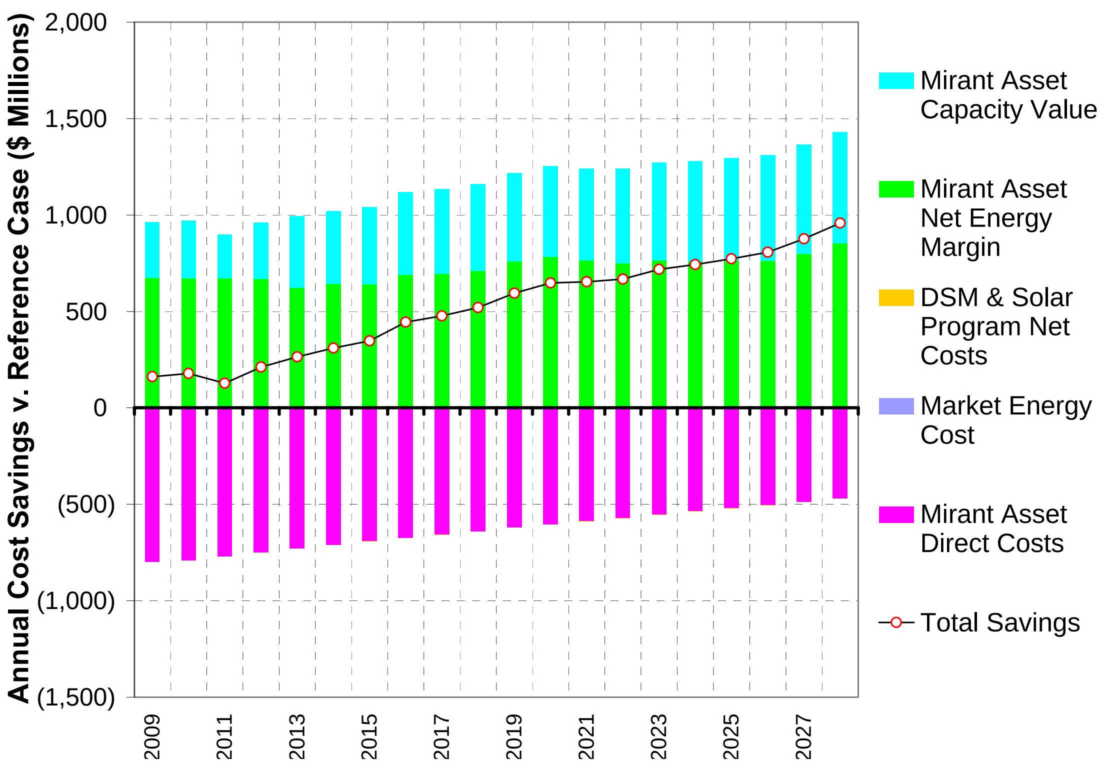
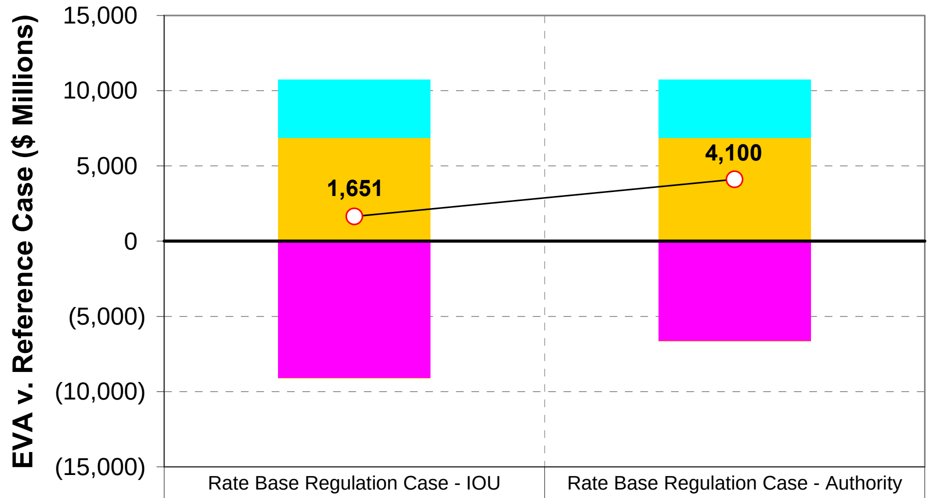


Figure 110. Annual Cost Savings – Authority Ownership (*Base Scenario*)



Financial results for the *Base Scenario* are shown in terms of EVA in Figure 111. In addition to the Pepco LDA, EVA captures other economic benefits throughout Maryland. As it turns out, the composition of EVA is overwhelmingly comprised of net energy margin, capacity value, and direct costs for the Mirant assets in the Pepco LDA. The portfolio benefits across Maryland ascribable to the suppression of bid adders are relatively insignificant.

Figure 111. EVA – *Rate Base Regulation Cases* (*Base Scenario*)



	Rate Base Regulation Case - IOU	Rate Base Regulation Case - Authority
Mirant Asset Capacity Value	3,874	3,874
Mirant Asset Net Energy Margin	6,806	6,806
Market Energy Cost	73	73
PJM Transmission Cost	0	0
Market Capacity Cost	0	0
DSM and Solar Net Cost	(3)	(3)
Mirant Asset Direct Costs	(9,099)	(6,650)
Total EVA	1,651	4,100

We have assumed that retail customers in Pepco's service territory would receive virtually all of the direct benefits (net energy margin and capacity value, less direct costs) of the acquisition. Portfolio benefits are small and would be confined to SWMAAC. Annual impacts on the generation service cost (GSC) covering SOS load in the Pepco LDA are shown in Figure 112. Representing IOU ownership, the upper curve shows GSC above 100% for five years of what the GSC would otherwise be absent condemnation or a consensual sale of the Mirant assets. Under IOU ownership the GSC decreases to about 80% by year 20. Under Authority ownership, GSC costs are far below 100% throughout the study horizon. Figure 113 shows similar results for SOS Type II C&I load costs.

Figure 112. Pepco Residential GSC Impact (*Base Scenario*)

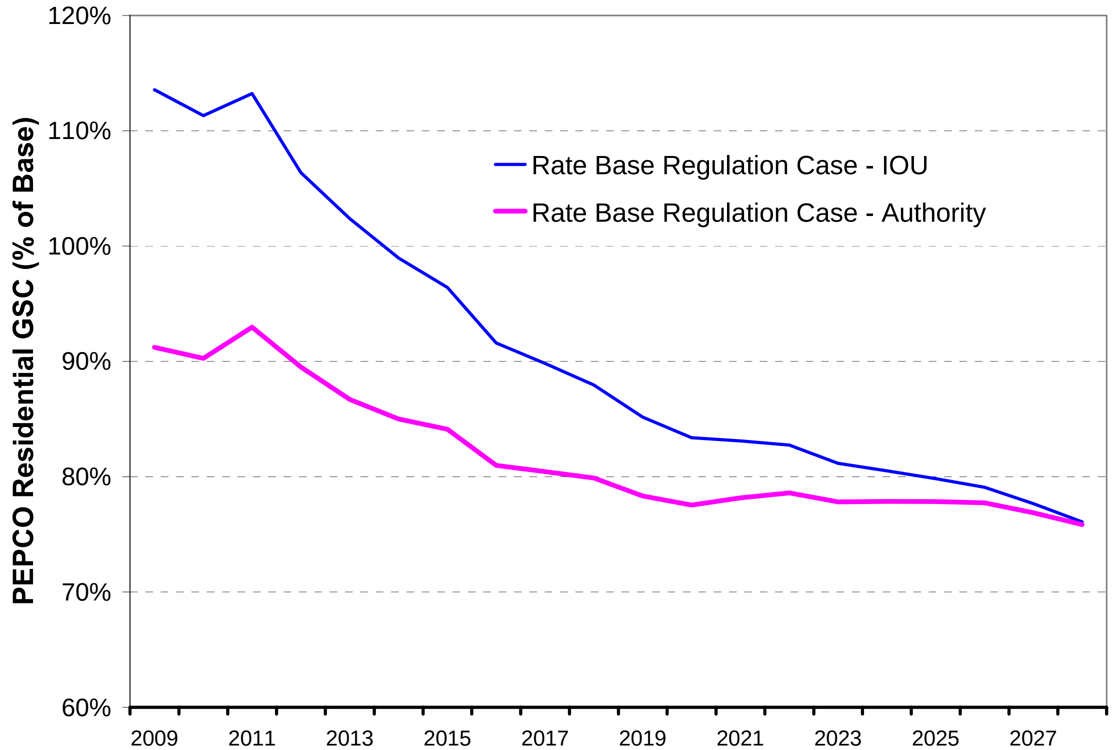
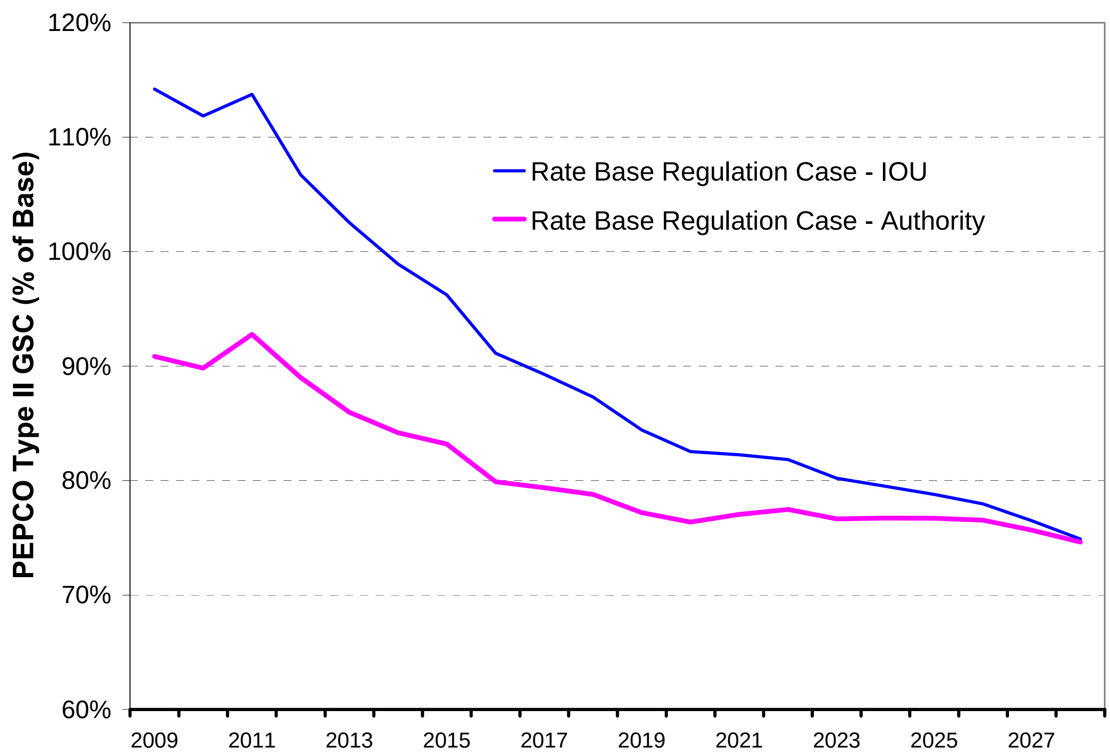


Figure 113. Pepco Type II GSC Impact (*Base Scenario*)



8.10.2. Alternative Fuel and Transmission Scenarios

We have tested the potential benefits related to the *Rate Base Regulation Case* under a range of different external conditions. Figure 114 shows the net annual savings for the IOU ownership case under the *Peak Oil*, *Federal Outlook*, and *TrAIL+PATH Scenarios*. Note that savings are negative for several years under the *Federal Outlook Scenario*, but eventually turn positive. The *TrAIL+PATH Scenario* produces results very similar to those of the *Base Scenario*, while the *Peak Oil Scenario* produces higher savings in all years. Figure 115 shows similar results for the Authority ownership option, which has only negligible negative early year savings under the *Federal Outlook Scenario*.

Figure 114. Annual Savings – IOU Ownership (Alternative Scenarios)

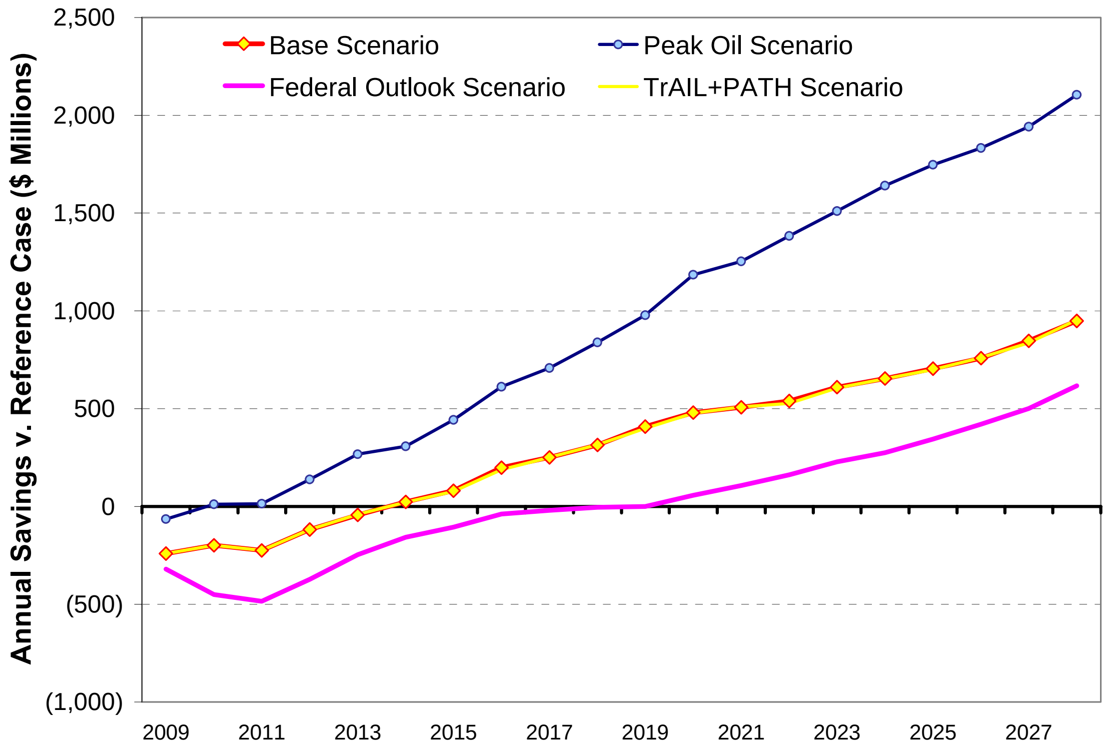
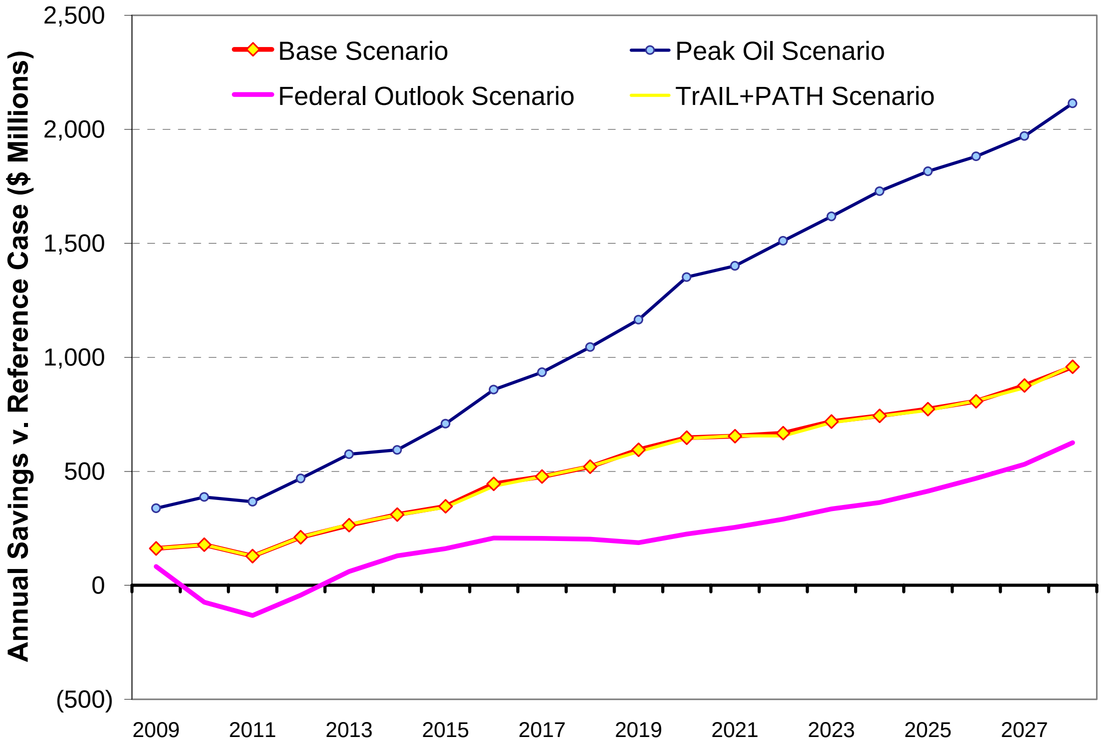
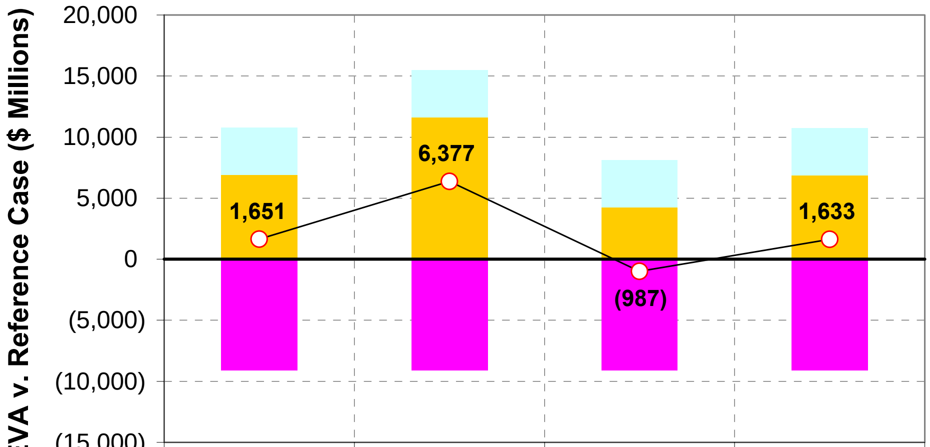


Figure 115. Annual Savings – Authority Ownership (Alternative Scenarios)



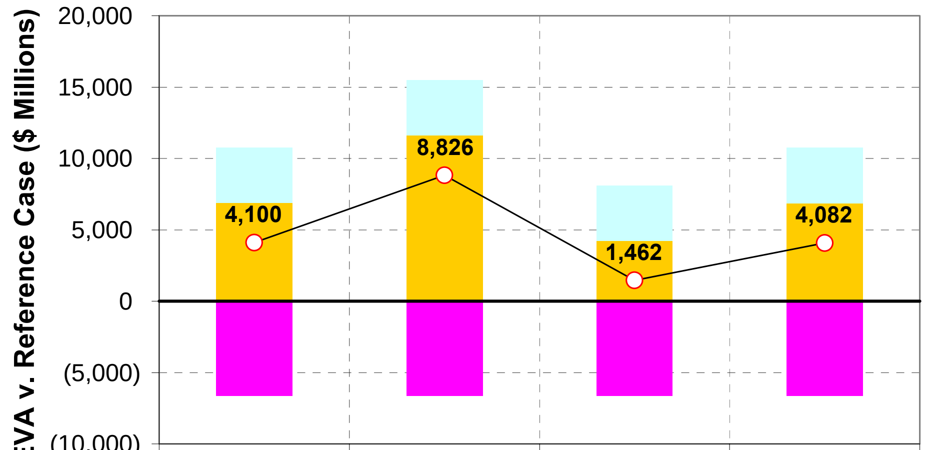
EVA results for the two ownership options are shown in Figure 116 and Figure 117. Again, under the IOU ownership scenario, EVA is negative under the *Federal Outlook Scenario*, but favorable under other scenarios. Under Authority ownership, EVA is positive under all scenarios.

Figure 116. EVA – IOU Ownership (Alternative Scenarios)



	Base Scenario	Peak Oil Scenario	Federal Outlook Scenario	TrAIL+PATH Scenario
Mirant Asset Capacity Value	3,874	3,874	3,874	3,880
Mirant Asset Net Energy Margin	6,806	11,523	4,170	6,781
Market Energy Cost	73	82	69	74
PJM Transmission Cost	0	0	0	0
Market Capacity Cost	0	0	0	0
DSM and Solar Net Cost	(3)	(3)	(2)	(3)
Mirant Asset Direct Costs	(9,099)	(9,099)	(9,099)	(9,099)
Total EVA	1,651	6,377	(987)	1,633

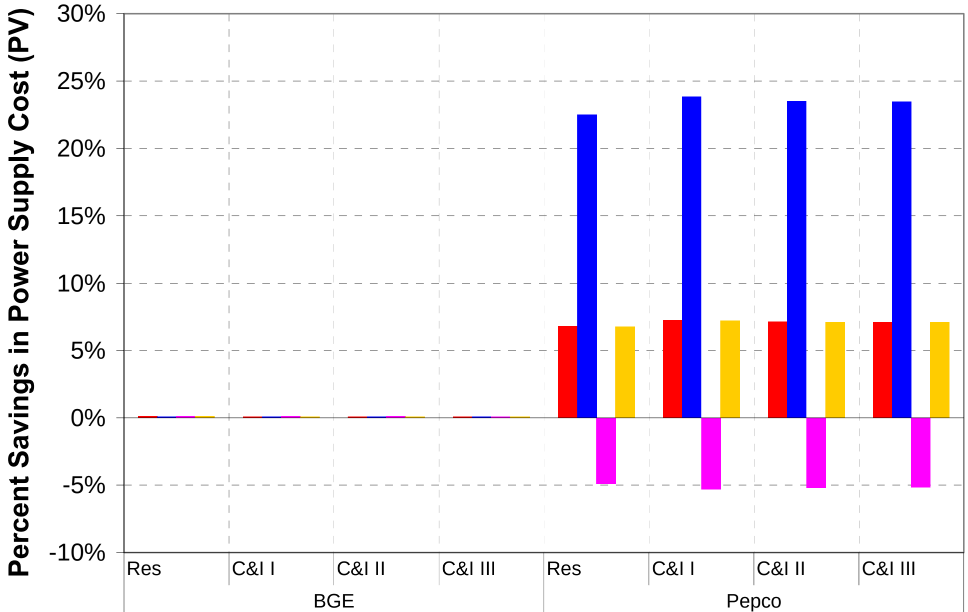
Figure 117. EVA – Authority Ownership (Alternative Scenarios)



	Base Scenario	Peak Oil Scenario	Federal Outlook Scenario	TrAIL+PATH Scenario
Mirant Asset Capacity Value	3,874	3,874	3,874	3,880
Mirant Asset Net Energy Margin	6,806	11,523	4,170	6,781
Market Energy Cost	73	82	69	74
PJM Transmission Cost	0	0	0	0
Market Capacity Cost	0	0	0	0
DSM and Solar Net Cost	(3)	(3)	(2)	(3)
Mirant Asset Direct Costs	(6,650)	(6,650)	(6,650)	(6,650)
Total EVA	4,100	8,826	1,462	4,082

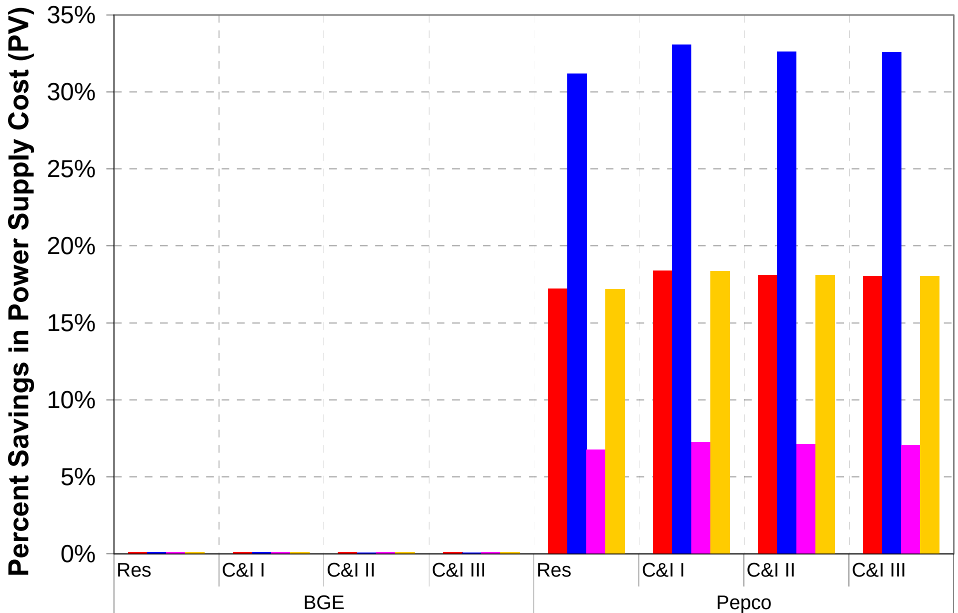
The direct costs and benefits of re-regulating the Mirant generation fleet are assigned to Pepco load. In Figure 118 and Figure 119, we report the economic benefits to BGE's and Pepco's retail customers under IOU and Authority ownership, respectively. The benefits to BGE are insignificant.

Figure 118. Savings by Rate Class – IOU Ownership



	BGE Res	BGE C&I I	BGE C&I II	BGE C&I III	Pepco Res	Pepco C&I I	Pepco C&I II	Pepco C&I III
Base Scenario	0.11%	0.10%	0.10%	0.10%	6.82%	7.27%	7.16%	7.13%
Peak Oil Scenario	0.10%	0.10%	0.09%	0.09%	22.49%	23.85%	23.51%	23.50%
Federal Outlook Scenario	0.12%	0.11%	0.11%	0.10%	-4.90%	-5.30%	-5.19%	-5.17%
TrAIL+PATH Scenario	0.11%	0.10%	0.10%	0.10%	6.77%	7.21%	7.11%	7.08%

Figure 119. Savings by Rate Class – Authority Ownership



	BGE Res	BGE C&I I	BGE C&I II	BGE C&I III	Pepco Res	Pepco C&I I	Pepco C&I II	Pepco C&I III
Base Scenario	0.11%	0.10%	0.10%	0.10%	17.22%	18.39%	18.10%	18.03%
Peak Oil Scenario	0.10%	0.10%	0.09%	0.09%	31.19%	33.09%	32.62%	32.60%
Federal Outlook Scenario	0.12%	0.11%	0.11%	0.10%	6.77%	7.24%	7.12%	7.07%
TrAIL+PATH Scenario	0.11%	0.10%	0.10%	0.10%	17.21%	18.37%	18.08%	18.03%

8.11. Risk Factors

The *Rate Base Regulation Case* constitutes a bold initiative, particularly in light of the global credit implosion. Irrespective of the high potential economic benefits associated with the *Rate Base Regulation Case*, there are many practical market, transactional, financial and regulatory risk factors that have the potential to impede or possibly undermine Maryland's consumer benefits. In reporting the economic benefits and costs associated with the potential condemnation or consensual sale of the Mirant assets, LAI has not quantified any potential societal costs associated with re-regulation in Maryland, including the myriad complexities, substantial risks and potential additional costs that surround such a transaction. Transference of control back to Pepco or to an Authority has the potential to undermine the competitive wholesale power market in Maryland, thereby causing a "domino effect" in PJM. IOU or Authority ownership of the Mirant fleet would likely weaken wholesale price signals that are designed by PJM to induce merchant generator entry – both conventional and renewable. As a result, a return to rate base regulation would likely require Pepco or the Authority to support additional generation entry for a significant period of time, even though merchant entry <u>might</u> be sustained elsewhere in PJM.

The return to rate base regulation would be likely to impact the Commission's administration of SOS to serve retail load in Pepco's service territory. Presently, competitive suppliers manage business, market, financial and regulatory risks for their respective load obligation(s). If Pepco or an Authority were to self-supply their load obligations, Pepco or an Authority may be exposed to all or a portion of the risks currently borne by competitive suppliers. In addition, a return to rate base regulation will likely require an end to the customer choice program, effectively requiring all customers to return to IOU service. Also, there is a significant question regarding whether the wholesale market in Maryland could efficiently coexist with a return to rate base regulation.

The financial results under the *Peak Oil*, *Federal Outlook*, and *TrAIL+PATH Scenarios* provide useful market intelligence regarding the degree to which retail customers would be benefited under materially different market conditions. Under IOU ownership, much lower than *Base Scenario* fuel price assumptions result in substantial disbenefits, about $1 billion on an EVA basis. The lower cost of capital under Authority ownership insulates ratepayers from any economic loss, however. As observed in 2008, actual fuel prices over the study horizon are likely to remain extremely volatile, whipsawing across pronounced valleys and troughs over the study horizon. While asset ownership can be an effective hedge against uncertain and volatile fuel prices, ratepayers would nonetheless be exposed to both earnings surprises (upsides) and disappointments from year to year relative to the *pro forma* assumptions used to derive FMV at a single point in time. However remote the prospect, the creation of a second "wave" of stranded cost liabilities is always a potential risk in light of the uncertainties surrounding the long-term regulation of greenhouse gas emissions, in particular. Aside from generation asset ownership, other risk management methods may be available to Pepco to control the price volatility of oil, natural gas and electricity prices.

The Mirant fleet in Maryland is comprised of 2,568 MW of coal plants. Mirant has budgeted major capital improvements to ensure timely compliance with the HAA as well as more stringent controls on SO_2, NO_x, and mercury, should they be promulgated by the EPA. In order to reduce greenhouse gas emissions, President Obama's administration coupled with a democratically controlled House and Senate may support new federal legislation that makes it more expensive for existing coal facilities to maintain market share. If that occurs, there is a significant risk of exposure to economic obsolescence or diminished energy margins attributable to stricter than anticipated controls on CO_2 emissions.

Significant risks may arise during a multi-year transition period in response to the practical constraints associated with obtaining the requisite manpower to operate these facilities. For several years it might be necessary to outsource the manpower and operational responsibilities to a qualified third party, thereby incurring additional costs. Of particular concern would be an Authority's ultimate ability to initially attract and then maintain the employment incentives to retain qualified in-house staff. The costs associated with attracting and retaining the caliber of personnel required to staff the Authority or IOUs may be substantial, although this concern is less pronounced in the context of IOU ownership.

The return to rate base regulation analysis assumes that the generation assets located in the Maryland portion of the Pepco service territory will be in operation for another 20 years. The CapEx associated with maintaining high unit availability is explicitly part of the valuation under FMV, however. Since certain of the units are more than 40 years old, there is increased risk that the incremental CapEx needed to maintain high plant availability has not been accurately defined. In theory, the value of Mirant's fleet in Maryland under FMV should account fully for the risk of technical obsolescence. In practice, there may be risk factors attributable to the age of the plants that might not be easy to discover during the due diligence process.

The FMV of the assets is driven largely by assumptions made with respect to energy and capacity prices in PJM. Given the significant and unprecedented volatility in the commodities market at the present time, FMV and the resultant EVA analysis may differ significantly from the estimates provided herein.

There may be significant advisory and transaction costs associated with a potential condemnation or negotiation to purchase the assets. Condemnation may result in a protracted and expensive legal battle. The costs associated with transaction support or a legal contest would likely be borne by ratepayers, but have not been included in the derivation of EVA.

We have not attempted to calibrate Maryland's appetite for a large bond issuance in the present context. To the extent revenue bonds are issued by a newly formed Authority in order to stabilize and reduce energy costs for ratepayers served by Pepco, there could be adverse bond pricing impacts associated with increased financing costs on other state general obligations or revenue bond issuances. How long these increased financing costs might persist following a multi-billion dollar bond issuance to support the creation of an Authority has not been evaluated. In the event Mirant's FMV is much lower than $6 billion, Maryland's exposure to adverse bond pricing impacts would be tempered, but not necessarily eliminated.

9. CONCLUSIONS

The main points are these:

- ❒ Wholesale and retail electricity costs in Maryland will be closely tied to the delivered cost of natural gas and, to a lesser extent, oil. As natural gas becomes increasingly a global market rather than a continental market, power prices will reflect the market forces that bear upon oil and natural gas prices. Regardless of the amount of renewable energy, DSM, and/or high voltage transmission added to the region's resource base, wholesale power prices will likely remain volatile over the long term.

- ❒ The array of DSM programs proposed by Maryland's IOUs offer large potential economic and environmental benefits to ratepayers with minimal risk of stranded costs or unintended market consequences. Full implementation of the EMD program will require aggressive program management and ratepayer participation at levels unprecedented in Maryland or neighboring states. In light of the uncertainty surrounding program costs, customer penetration rates, and both capacity and energy benefits, active Commission management and monitoring of program efficacy is needed to safeguard consumer interests. Even at much lower penetration rates than those underlying the EMD program, there is still great economic and environmental promise ascribable to the "low hanging fruit" that has been incorporated in the *Reference Case.*

- ❒ Provided that renewable generation continues to be required by RPS legislation and supported by REC prices on a state or national level, onshore wind generation can provide substantial economic and environmental benefits to Maryland and the region.

- ❒ Development of offshore wind generation creates significant net environmental benefits in terms of avoided greenhouse gases and criteria pollutants, but is <u>not</u> expected to yield economic benefits for Maryland consumers in relation to other renewable energy sources that are much less expensive to construct and operate. The amount of onshore wind potential in the existing PJM interconnection queue coupled with the absence of a deliverability standard in PJM raises complex public policy concerns about the reasonableness of regulatory and legislative mandates for offshore wind in Maryland. While much more expensive than onshore wind, offshore wind may be worthwhile to the extent onshore wind projects do not get developed due to local opposition or, to a lesser extent, in response to the higher anticipated wind integration costs associated with intermittent production from onshore facilities.

- ❒ The benefits of installing solar photovoltaic cells across Maryland are mixed. A customer who is positioned to make an early investment in a rooftop photovoltaic installation will be likely to realize a satisfactory financial return due to favorable federal tax incentives, solar REC revenues, and avoided retail charges. In contrast, achievement of Maryland's solar RPS goal is likely to place a heavy economic burden on retail customers. Unless favorable tax incentives are continued over the long term <u>and</u> the next generation of photovoltaic technology happens on a fast track at much lower installed costs than the installed cost assumptions incorporated in this study, Maryland's solar RPS goal will be likely to impose substantial economic costs on ratepayers throughout the state.

- ❒ PJM's RPM may not result in UCAP prices that provide merchant generators with a bankable revenue source. At this juncture, merchant generators cannot be counted on to assure timely investment in a new CC plant. In light of the recent credit implosion there are fewer creditworthy counterparties to enter into off-take agreements that foster project financing. To ensure new entry of CC plants, Maryland's IOUs will therefore need to anchor project development under a long-term PPA or, alternatively, own the facilities themselves. One way or another there are substantial economic, reliability and environmental benefits likely to follow the addition of new CCs in SWMAAC. The answer to the question own versus lease is a small and insignificant incremental economic benefit in favor of IOU ownership.

- ❒ A policy to sustain a capacity overhang over the long term does not confer enough incremental value relative to IOU ownership or PPA commitments limited to 1,080 MW to warrant the financial drag on the IOUs' balance sheets. The lion's share of the economic and reliability benefits can be achieved at much less cost and much less risk by restricting IOU participation to 1,080 MW.

- ❒ A return to rate base regulation for generation located within the Maryland portion of the Pepco service territory through condemnation or consensual transfer is likely to yield substantial economic benefits. We have not attempted to quantify the costs associated with the myriad complexities relating to the return to rate base regulation. The magnitude of the benefits is driven by the lower cost of capital assumed for an IOU or an Authority relative to what retail customers would otherwise expect to pay competitive suppliers for load following SOS. While asset ownership can be an effective hedge against uncertain and volatile fuel prices, ratepayers would nonetheless be exposed to both earnings surprises (upsides) and disappointments from year to year relative to the *pro forma* assumptions used to derive FMV. Implementation of this initiative would likely mark the end of the competitive wholesale market in Maryland, and would be likely to necessitate a high up-front "ante," that is, the transaction cost of acquiring the Mirant fleet under FMV, roughly $6.3 billion under the fuel price outlook formulated in the *Conventional Wisdom Scenario,* coupled with a significant increase in capacity values under PJM's RPM. While the absolute level of the benefits following a return to rate base regulation is high, there are risk factors that warrant rigorous scrutiny, as follows:

  - The ability of the IOU or Authority to operate the generation assets efficiently, including the ability to attract and sustain the requisite manpower and the cost associated therewith;

  - Potential exposure to stranded cost liabilities if coal generation is effectively banned through stricter greenhouse gas emission legislation and/or new market structures;

- Significant potential advisory costs associated with a potential condemnation or negotiation and a potentially protracted and expensive legal battle associated with a condemnation; and

- Adverse bond pricing impacts associated with increased financing costs on other state general obligations or revenue bond issuances.

APPENDIX A. PJM TRANSMISSION SYSTEM DETAILS

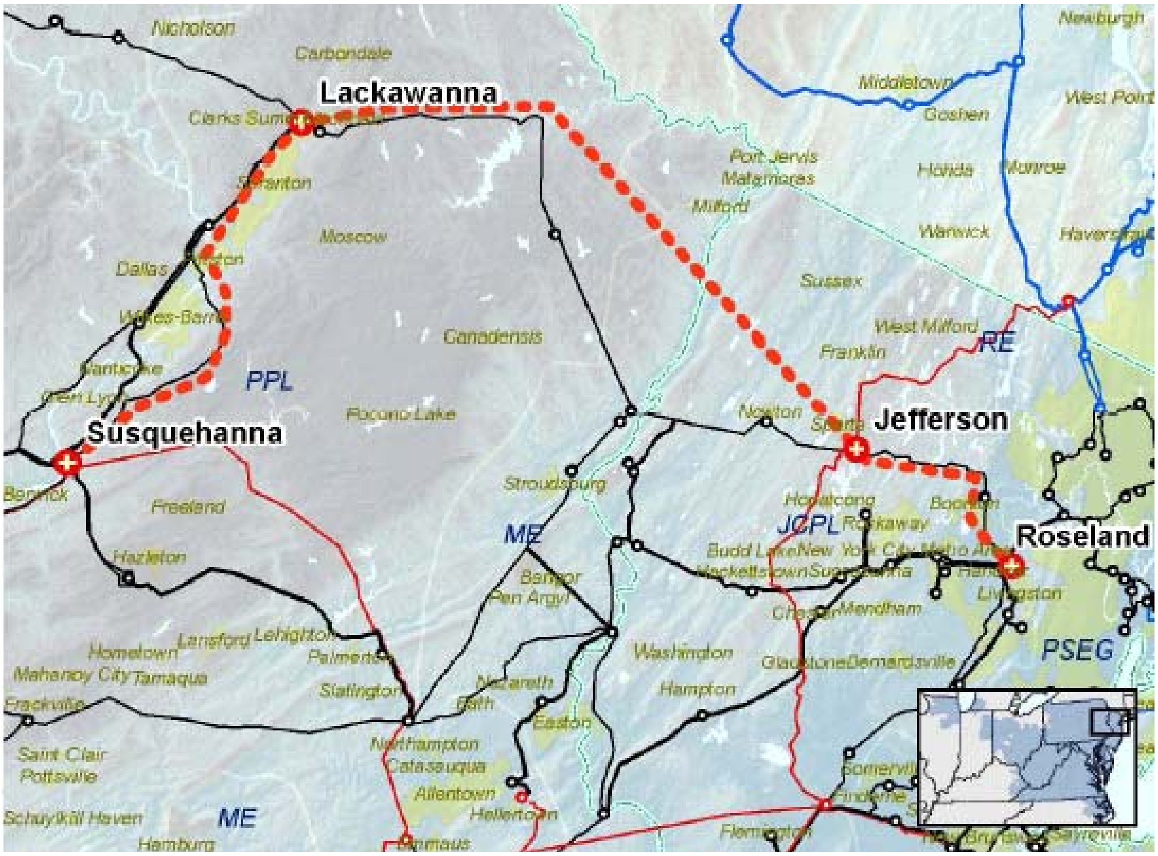
Backbone Transmission Projects

In addition to TrAIL and PATH, two additional high-voltage backbone transmission projects have received PJM Board approval: Susquehanna-Roseland and MAPP.

Susquehanna-Roseland

The Susquehanna-Lackawana-Jefferson-Roseland 500-kV transmission line would run approximately 130 miles from the Susquehanna 500-kV station in northeastern Pennsylvania to Lackawana and then eastward to a new Jefferson substation where it will tap the existing Branchburg-Ramapo 500-kV circuit and where multiple 230-kV and 115-kV circuits are also tightly networked. The circuit would then continue to Roseland on the PSEG system. In addition, 500/230-kV transformers are proposed at Lackawana and Roseland substations. A map of the planned route is shown in Figure A1.

Figure A1. Susquehanna-Roseland



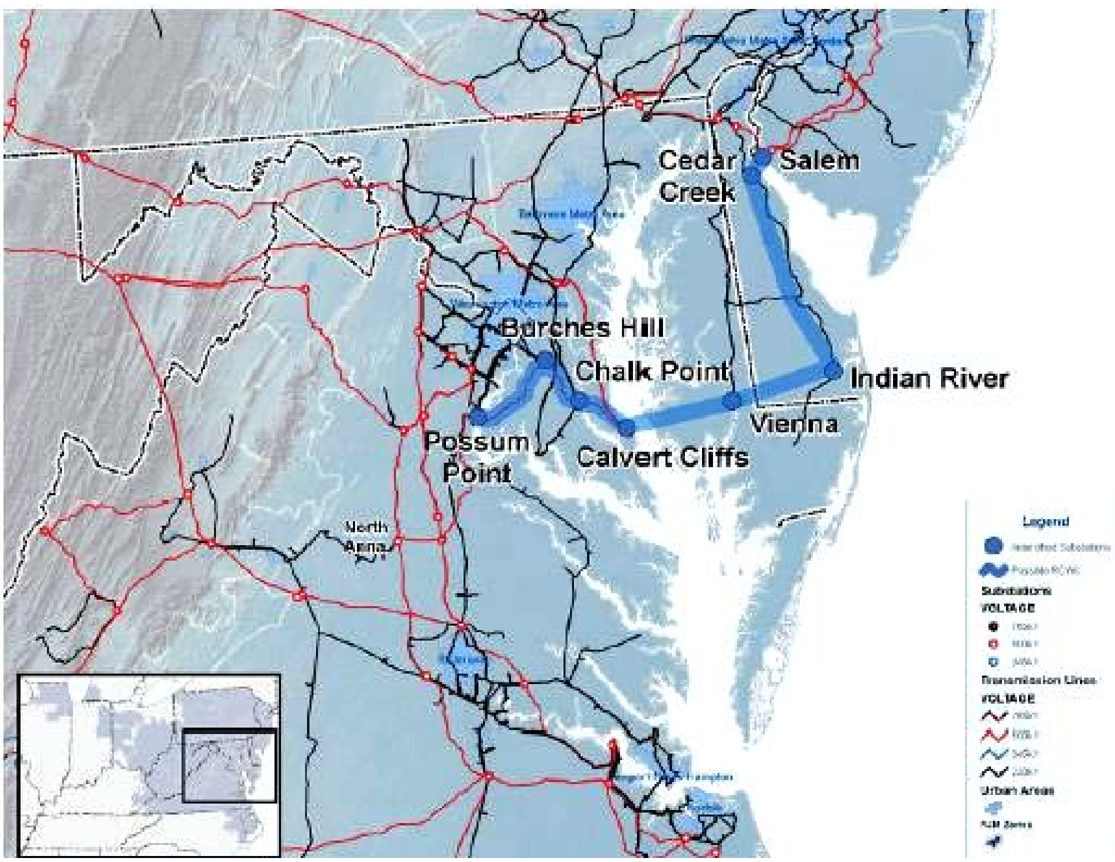
The circuit is expected to create a strong link from generation sources in northeastern and north-central Pennsylvania, including the Susquehanna Nuclear Station, across northeastern Pennsylvania into New Jersey. The line is expected to address overloads expected to occur as soon as 2013 on 23 existing transmission lines in New Jersey and Pennsylvania. The line is being jointly developed by PPL and PSEG. The line's announced in-service date is Q2 2012 and it is estimated to cost $930 million.

The project is currently in the engineering / planning phase of development. In the last quarter of 2008, the developers are expected to make applications to local municipalities and state agencies and conduct hearings as requested.

Mid-Atlantic Power Pathway

As currently proposed, MAPP is a 500-kV circuit that will run from Possum Point in Virginia to the Salem 500-kV station in New Jersey. The 220-mile long line is expected to be built primarily along existing rights-of-way and is intended to pass through Burches Hill, Chalk Point, Calvert Cliffs, Vienna, Indian River and Cedar Creek Stations, as shown in Figure A2. The line is expected to be overhead construction with the exception of the Chesapeake Bay crossing, which is planned as a submarine cable.

Figure A2. MAPP



The line is expected to relieve expected overloads on the existing transmission system and also improves the ability to deliver electricity to customers on the Delmarva Peninsula. That area has limited local generation and limited transmission, which comes only from the north. MAPP will provide a transmission path into the southern end of the peninsula. The project also addresses power supply concerns raised by the pending retirements of the Benning Road and Buzzard Point generating stations, which have a total of 800 MW of capacity. The line is being developed by PHI and is estimated to cost $1.05 billion.

PJM and PHI are continuing to explore the applicability of using high-voltage direct-current technology for the submarine portion of the circuit as there are voltage rise concerns for a 500-kV alternating current submarine cable crossing of the Chesapeake Bay.

Regulatory Proceedings for TrAIL

As described in section 3.2.3 of the report, the developers of TrAIL applied for CPCNs in March and April of 2007, which require regulatory approval from the PA PUC, the PSC WV and the SCC VA in order for the project to go forward.

Virginia

On October 7, 2008, the SCC VA agreed with its hearing examiner on the reliability need for the line, and granted the requested CPCN, authorizing construction of the line subject to the following key conditions:

- The CPCN and authorizations granted are conditioned on the respective state commission approval of both the West Virginia portion and the Pennsylvania portion of the proposed line, prior to commencing construction, the applicants must submit to the SCC VA a copy of the orders from the PSC WV and the PA PUC approving construction of the line's portions in West Virginia and Pennsylvania respectively;
- Within thirty days from the date of the Order, the applicants shall file with the SCC VA a detailed right-of-way clearing plan that follows FERC guidelines and addresses future maintenance right-of-way; and
- The approved transmission line must be constructed by July 1, 2011; however the developers are granted leave to apply for an extension for good cause shown.

West Virginia

On August 1, 2008, PSC WV granted the requested CPCN, authorizing construction of the line subject to the following key conditions:

- Prior to beginning construction of the project in West Virginia, TrAIL must obtain and file with the PSC WV the approvals for the total length of the line through all other states through which the line must pass;
- If there are any changes to the scope of the project as approved, TrAILCo shall petition the PSC WV for approval of such changes prior to beginning construction; and
- Within six months of the date of the Order, TrAILCo, or its corporate affiliates, shall install a static volt-ampere reactive compensator at the Meadow Brook substation.

Pennsylvania

On November 13, 2008, the PA PUC approved the settlement agreement between TrAILCo, West Penn (TrAILCo's affiliate) and the Greene County Board of Commissioners (collectively the Parties) and noted that consideration of the application with regard to the Prexy facilities is stayed pending the outcome of the collaborative effort set forth in the settlement agreement and the filing of a new or amended application. On the same date the PA PUC also approved the Pennsylvania 502 Junction Segment and the 502 Junction Substation. The salient points of the settlement agreement are as follows:

- The Parties acknowledged that the siting of the Prexy Facilities[169] has been controversial and contentious, as evidenced by the opposition of certain federal, state and local legislators, and the opposition of local property owners. The Parties further agreed that it is in the public interest to work together to develop new and creative alternatives to the construction and/or siting of the Prexy Facilities. The alternatives will include, but not be limited to, use of DSM, energy efficiency, enhancement and improvements to existing facilities and new transmission infrastructure. The Parties requested a stay of any adjudication of requests made with respect to the Prexy Facilities until completion of the collaborative effort to seek alternatives.
- Not later than 14 days after all of the Parties execute the Agreement, TrAILCo will relinquish its title to rights of way or easements associated with the Prexy Segment or the Prexy 138-kV facilities.
- TrAILCo will no longer seek authorization from the PA PUC to exercise eminent domain authority with respect to siting the Prexy Segment as proposed in TrAILCo's April 13, 2007, filing, but reserved the right to do so in connection with any new alternative that may result from the collaborative process that the Parties would undertake to find a new solution. TrAILCo further agreed that it will not submit an application to the FERC requesting that it approve the construction and siting of the Prexy Segment, pursuant to FERC's NIETC backstop siting authority under Federal Power Act Section 216. However, TrAILCo reserved its right to submit such a request to FERC to approve any amended or new application.
- With respect to the 502 Junction Substation and the Pennsylvania 502 Junction Segment, the Parties agreed that the PA PUC should approve all elements of, and all of the relief requested in the application, including but not limited to, authorization to locate and construct the 502 Junction Substation and the Pennsylvania 502 Junction Segment. While TrAILCo agreed not to file an NIETC designation application to FERC regarding the Prexy Segment, TrAILCo reserved the right to do so regarding the 502 Junction Substation and the Pennsylvania 502 Junction Segment in the event the PA PUC's decision is not consistent with the settlement agreement.
- TrAILCo agrees to pay a contribution of $750,000 to Greene County,. Greene County shall use such contributions for the support of educational, environmental,

[169] Prexy Facilities includes the Prexy Substation, the Prexy 138-kV lines and the Prexy Segment.

public health and community infrastructure projects located in Greene County. The contribution can not be recovered in the rates of either TrAILCo or West Penn.

- TrAILCo's obligations under the agreement are expressly contingent on the PA PUC accepting and approving by February 16, 2009, in a final order, all the terms and conditions of the agreement. In the event the PA PUC does not approve the settlement agreement, the Parties reserved their respective rights to proceed in any manner allowable under the law.

APPENDIX B. DERIVATION OF BID ADDERS USED IN THE *RATE BASE REGULATION CASE*

Markup Pricing Fundamentals

Energy prices in both the DAM and the RTM typically reflect inclusion of a significant bid adder over the marginal cost of production during heavy load hours, when generation resources are more fully utilized. In addition to the overall degree of tightness of the supply-demand balance affecting the amount of markup, an individual generator's ability to engage in markup pricing is also related to the extent of concentration of ownership and control of generation resources. The net benefit to a generator of including markups is related to the amount of capacity the supplier controls and the marginal costs and operating constraints of the units in the supplier's regional portfolio. In general, the more capacity controlled by a generator, the more rewarding it is to offer bids that are above cost on the highest cost units since all units in the supplier's portfolio will receive the same (or nearly the same) price. The higher the cost of a unit, the higher the optimal markup will be since less net revenue will be foregone if the bid is not accepted.

The theory behind bid behavior is made complicated in PJM by the mix of unregulated merchant generators and regulated vertically-integrated utilities doing business under cost-of-service regulation. The bidding incentive of a vertically integrated utility depends on the size of its load obligation relative to its generation capacity. A vertical utility with a net short position (load obligations exceed generation resources it controls) has an incentive to bid as low as possible, rather than attempting to bid above marginal cost.

In quantifying the benefits and costs associated with the condemnation of the Mirant generation fleet in Maryland, it is important to consider the change in LMPs resulting from the suppression of bid adders under traditional cost of service regulation. There are at least two methods that may be used to simulate bidder markups in the LMP forecast. The *bid-based* simulation approach models explicit bidding strategies together with modeling of production costs. The *cost-markup* approach first uses cost-based simulation to produce marginal costs, and then applies a markup function to determine prices. LAI has applied the *cost-markup* approach to the *Rate Base Regulation Case*.[170]

Markup Pricing Model and Data

Implementation of the cost-markup approach involves the following steps. First, a markup function is developed and its parameters are estimated from historical data. Second, MarketSym is run using its cost-based bidding mode of simulation in order to produce hourly marginal costs by zone. Third, the markup function is applied to transform marginal costs into LMPs that include bidding behavior deviations from marginal costs.

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[170] The different approaches may be appropriate for different purposes. The bid-based approach requires extensive data to characterize bidding behavior functions and also requires lengthy, iterative simulations of each player with pricing ability to reach an equilibrium state where no player would further alter its bids in reaction to other players' bids. The cost markup approach uses an empirical markup function that only has a few variables. While the bid-based approach attempts to model bidding behavior of individual producers, the cost markup approach more simply includes key characteristics of aggregate markup behavior.

We use the price-cost markup index (PCMI), defined as:

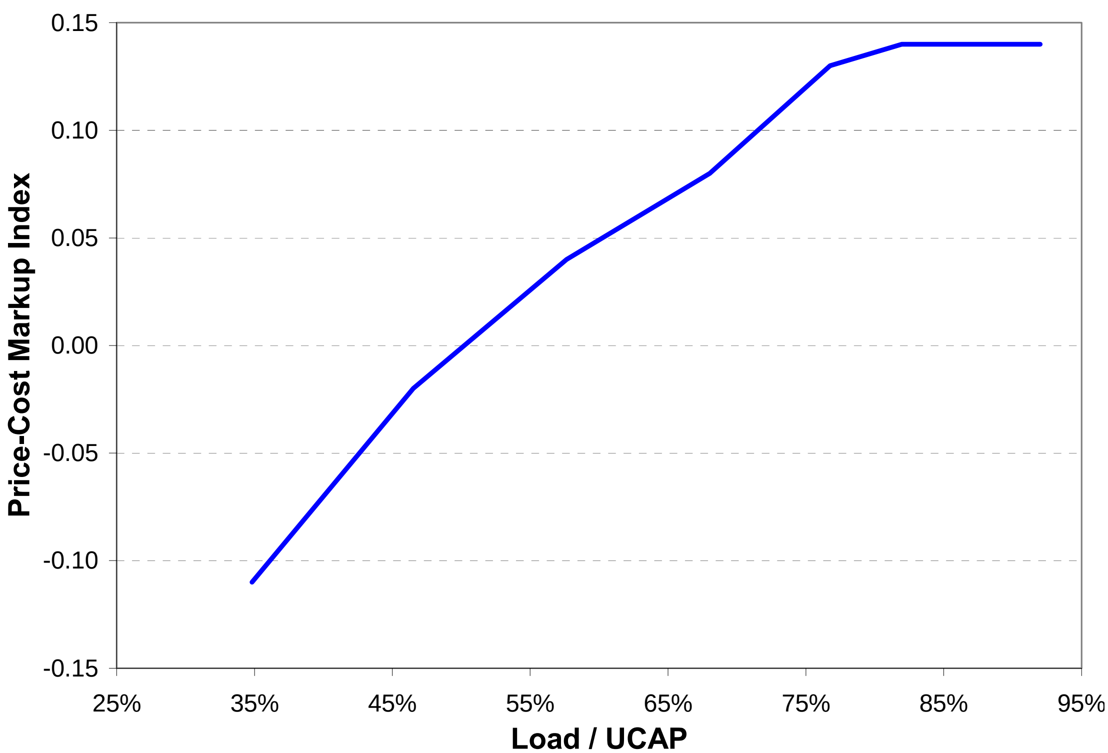
$$PCMI = (Price - Cost) / Cost$$

where *Cost* is hourly marginal cost and *Price* is hourly LMP. The hourly LMP is then calculated from MarketSym output as:

$$LMP = (1 + PCMI) * Cost.$$

In order to make the value of PCMI dynamic or conditional on supply and demand conditions, actual markup information in the annual PJM SOM reports by the Market Monitoring Unit (MMU) has been employed.[171] Using the SOM data, PCMI can be expressed as a function of the relative tightness of the load-resource situation for any given hour. Specifically, PCMI is a function of the ratio of load to total system UCAP. This function allows the PCMI to respond to diurnal, weekly and seasonal variations in the load level, and to the long-term growth in load and resource capacity. The result of this analysis of bidding behavior, based on actual markups for 2006 and 2007 calculated by the MMU, is displayed in Figure B1, which shows that the PCMI increases with the load/UCAP ratio, up to a maximum of 14% at a load / UCAP ratio of about 82%.

Figure B1. 2006-2007 Average PCMI Function of Load / UCAP for PJM



[171] An alternative approach of fitting a markup function between historical LMPs and a backcast run of MarketSym in which its data is set to historical values of load, outages, fuel and emissions prices, *etc.*, was deemed too burdensome to undertake for this study.

The flattening of the PCMI beyond a load / UCAP ratio of 82% does not mean that tighter load-resource positions do not result in larger dollar markups. In the high load / UCAP region of the chart, the supply cost function has a steep upward slope, so the same 14% markup will result in larger dollar markups as higher cost units operate on the margin. Also note that the PCMI is negative at load / UCAP values below about 50%. Since marginal costs are much lower for load / UCAP ratios below 50%, the negative dollar markups are much less than the positive dollar markups. While markups may rationally be negative during low load hours of the week, the average markup over the length of a unit's run (from startup to shutdown) is expected to be positive.

The MMU calculates the dollar markup over marginal cost as determined by its own production cost simulation model.[172] The SOM reports provide a markup index that uses different definitions for positive and negative markups in order for the index to be bounded by –1 and +1. Positive markups use the Lerner Index (LI), defined as:

$$LI = (P - C) / P$$

while negative markups use the PCMI definition. For PJM, Table B1 summarizes markup information provided by the MMU for 2006 and 2007.[173] Note that above \$75/MWh, the 2007 dollar markups are materially higher than in 2006.

[172] We assume MarketSym is similar in accuracy to the model used by the MMU. Therefore no calibration adjustment has been made to the markup function. Since the details of the MMU's marginal cost simulation model are unknown, the MMU's reported dollar markup and markup index values are used with caution. Production cost simulation models differ in the inclusion of resource constraints. If a model omits a significant constraint, such as an annual limit on the number of operating hours permitted for a CT, then it will underestimate actual marginal costs.

[173] Data prior to 2006 have not been included due to changes in the PJM footprint. Also, implementation of the BRA may account for other structural changes in bidder behavior after 2006.

Table B1. Average Price Markup by Price Category, 2006 and 2007[174,175,176]

	2006			2007		
Price Category	Hours, Cumulative %	Average MMU Markup Index	Average Dollar Markup	Hours, Cumulative %	Average MMU Markup Index	Average Dollar Markup
< $25	10.0	-0.13	($3.37)	8.4	-0.09	($2.36)
$25 to $50	61.7	-0.02	($1.38)	46.8	-0.02	($1.43)
$50 to $75	90.6	0.01	($2.37)	81.4	0.06	$0.01
$75 to $100	98.0	0.02	($0.87)	95.6	0.13	$9.50
$100 to $125	99.2	0.06	$4.95	98.9	0.17	$18.33
$125 to $150	99.4	0.04	$4.61	99.7	0.19	$25.88
> $150		0.10	$34.56		0.14	$51.01

Table B2 presents summary measures of PJM supply and demand fundamentals for 2006 and 2007, and PJM obligations, ICAP and UCAP, and market concentration measures for 2006 to 2009. The 2006 and 2007 years were similar, with UCAP increasing slightly, and average on-peak and off-peak load increasing slightly. Hence, the load / UCAP ratios for average on-peak and off-peak periods vary little between 2006 and 2007. However, peak load was significantly lower in 2007 than 2006, which runs counter to the much higher markups for high price hours in 2007, shown in Table B1. The Herfindahl-Hirshman Index and the highest market share concentration measures declined slightly in 2007, indicating less potential for markup pricing. The changes in these concentration measures also run counter to the higher markups observed in 2007.

[174] Sources: 2006 State of the Market Report, Table 2-32, for 2006 index and dollar markups; 2007 State of the Market Report, Table 2-34, for 2007 index and dollar markups; 2007 State of the Market Report, Table C-10, for cumulative hours in percent.

[175] The MMU markup index is (P-C)/P if P-C > 0 or (P-C)/C if P-C <0.

[176] Cumulative hours percentages interpolated as needed from $10 bins.

Table B2. Load, Capacity, and Market Power Indexes, 2006 to 2009[177]

	2006	2007	2008	2009
System Peak Load (MW)	144,644	139,428		
Average Load				
On-Peak (MW)	88,323	91,066		
Off-Peak (MW)	71,810	73,499		
On-Peak / Off-Peak	1.23	1.24		
Obligation (MW)	142,864	148,277	150,936	153,480
Installed Capacity, June 1 (MW)	162,571	163,721	164,444	166,916
Unforced Capacity, June 1 (MW)	152,581	154,076	155,590	157,629
Load / UCAP Ratios[178]				
Peak Load / UCAP	0.948	0.905		
Average On-Peak Load / UCAP	0.579	0.591		
Average Off-Peak Load / UCAP	0.471	0.477		
Obligation / UCAP	0.936	0.962	0.970	0.974
Average EFORd	6.4%	6.9%		
Herfindahl-Hirshman Index	930	895	879	853
Highest Market Share	16.4%	16.0%	18.5%	18.4%

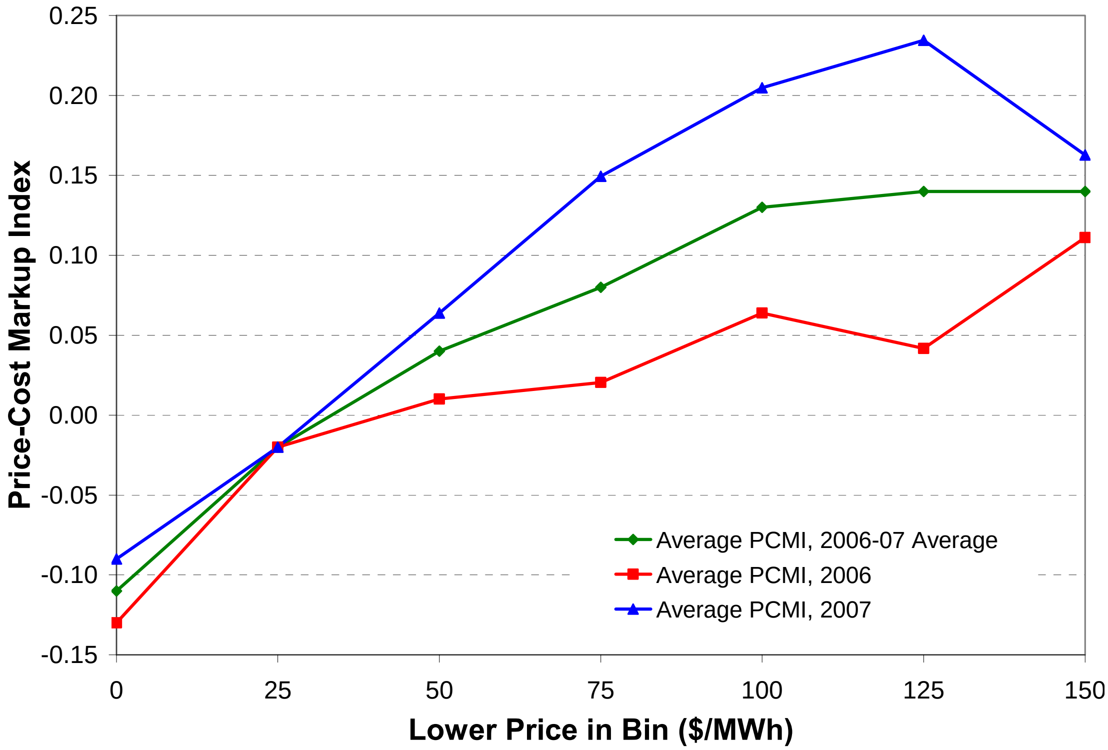
On balance, the supply-demand situation and concentration measures do not appear much different between 2006 and 2007, but the markup values are significantly different. Hence, markup index, load and price distribution, and UCAP values for 2006 and 2007 were averaged in order to obtain a more robust PCMI function of load / UCAP.[179] The result of averaging the Table B1 data on the markup index as a function of price is shown in Figure B2.

[177] Sources: 2006 SOM Report and 2007 SOM Report.

[178] Load / UCAP ratios calculated from the other measures.

[179] While a deeper analysis may undercover further structural drivers of the changes in markups from 2006 to 2007, there would still be the problem of projecting those drivers. The adopted approach only relies on the fundamentals of load and UCAP as the conditional variables that impact markup behavior.

Figure B2. PCMI Function of Price



The SOM reports do not present markup indexes as a function of load. However, since load and price duration curves are highly correlated, it is possible to use the load distribution information provided by the MMU to transform the markup function from a price to a load basis. Table B3 presents the PJM load distribution data for 2006 and 2007. By associating these load distribution data with the Table B1 price distribution data and paired markup indexes, the PCMI function of the load / UCAP ratio shown in Figure B2 was developed.

Table B3. Frequency Distribution of PJM Real-Time Hourly Load, 2006 and 2007[180]

Load Bin (GW)	Frequency (Hours), 2006	Frequency (Hours), 2007	Cumulative (%) 2006	Cumulative (%) 2007
45 to 50	2	0	0.02	0.00
50 to 55	129	79	1.50	0.90
55 to 60	504	433	7.25	5.84
60 to 65	689	637	15.11	13.12
65 to 70	967	890	26.15	23.28
70 to 75	1079	878	38.47	33.30
75 to 80	1501	1227	55.61	47.31
80 to 85	1337	1338	70.87	62.58
85 to 90	943	981	81.63	73.78
90 to 95	569	741	88.13	82.24
95 to 100	295	577	91.50	88.82
100 to 105	215	382	93.95	93.18
105 to 110	161	223	95.79	95.73
110 to 115	145	179	97.44	97.77
115 to 120	102	106	98.61	98.98
120 to 125	45	43	99.12	99.47
125 to 130	27	31	99.43	99.83
130 to 135	19	12	99.65	99.97
135 to 140	19	3	99.86	100.00
> 140	12	0	100.00	100.00

Of interest to Maryland is how markups in Maryland zones compare to the PJM average markups. Table B4 compares PJM dollar markups with those for the BGE, Pepco, DPL and APS zones. The markup component of the PJM all-hours load-weighted average LMP was $5.86/MWh or 9.5% in 2007, compared to $1.54/MWh or 2.9% in 2006.

[180] Source: 2007 State of the Market Report, Table C-1.

Table B4. DA Average LMP Markup by Time Period in PJM and Maryland Zones, 2006 and 2007 ($/MWh)[181]

Zone	All Hours		On-Peak		Off-Peak	
	2006	2007	2006	2007	2006	2007
PJM	$1.54	$5.86	$3.08	$8.59	($0.10)	$2.91
BGE	$1.95	$6.93	$3.70	$9.89	$0.11	$3.80
Pepco	$1.83	$6.83	$3.71	$9.62	($0.21)	$3.78
DPL	$2.08	$6.69	$4.18	$9.69	($0.11)	$3.51
APS	$1.36	$4.81	$2.75	$6.86	($0.08)	$2.65

Load-weighted average day-ahead LMPs, dollar markups, and PCMI values in PJM and in Maryland zones for 2006 and 2007 are presented in Table B5.

Table B5. DA Load-weighted Average LMP and Markup in PJM and Maryland Zones, 2006 and 2007[182]

Zone	2006			2007		
	LMP	Markup ($/MWh)	PCMI[183]	LMP	Markup ($/MWh)	PCMI
PJM	$51.33	$1.54	0.031	$57.88	$5.86	0.113
BGE	$61.00	$1.95	0.033	$70.22	$6.93	0.109
Pepco	$56.46	$1.83	0.033	$65.21	$6.83	0.117
DPL	$58.57	$2.08	0.037	$66.84	$6.69	0.111
APS	$49.58	$1.36	0.028	$57.34	$4.81	0.092

For the *Rate Base Regulation Case*, we assume that the Mirant units in Maryland that are acquired under condemnation would be bid in strict accord with cost-of-service principles, *i.e.*, no markups. Other generation units in Maryland and elsewhere in PJM would continue to include markups to the extent applicable. Although MarketSym can dispatch units in a bid-based simulation mode, the representation of bid adders within MarketSym does not sufficiently capture the dynamic relationship between markup and load-resource tightness or the concentration of ownership.[184] There are also practical data limitations to running MarketSym with an explicit bid adder function for all resources. Therefore, for the purpose of the *Rate Base Regulation Case*, markups have been computed in a post-processing module to determine the bid-based LMPs. The LMP energy cost savings to load attributable to the suppression of bid

[181] 2006 SOM Report, Tables 2-33 and 2-34; 2007 SOM Report, Table 2-36.

[182] 2006 SOM Report, Table 2-53; 2007 SOM Report, Tables 2-36, 2-63, and 2-64.

[183] PCMI values were calculated by LAI.

[184] In light of the research emphasis in the Final Report and the production schedule, practical limitations related to programming explicit bid adders for all resources in MarketSym was not possible for the DSM, wind, and CC cases under different ownership assumptions. For the *Rate Base Regulation Case*, where bid adders or the lack thereof have a significant impact on the merit of condemnation, markups have been computed in a post-processing module to determine the bid-based LMPs.

adders captures the reduction in energy prices in the Pepco LDA as well as any additional portfolio benefits in Maryland. We next describe how the post-processing calculation of markups was performed.

MarketSym reports the name of the specific unit that is on the margin for each zone. A simple, but incorrect, post-processing approach would be to assign *LMP = Cost* if the marginal unit is a cost of service unit, or calculate *LMP = (1 + PCMI) * Cost* if the marginal unit is a bid-based unit. The reason this method is flawed is that the merit-order of units differs between the cost-based dispatch used in MarketSym and the desired bid-based dispatch. The problem this creates may be illustrated in the following pairs of diagrams for two cases. Assume four equal capacity units. Units B1, B2, and B3 submit bids with markups and unit C is cost of service. In each case, supply intersects load at the third unit, which is the marginal unit for setting the LMP.

Figure B3 compares cost and bid-based dispatch when unit C is marginal in cost-based dispatch, but becomes infra-marginal in bid-based dispatch.

Figure B3. Case 1: Cost of Service Unit is Marginal in Cost-based Dispatch and Infra-marginal in Bid-Based Dispatch

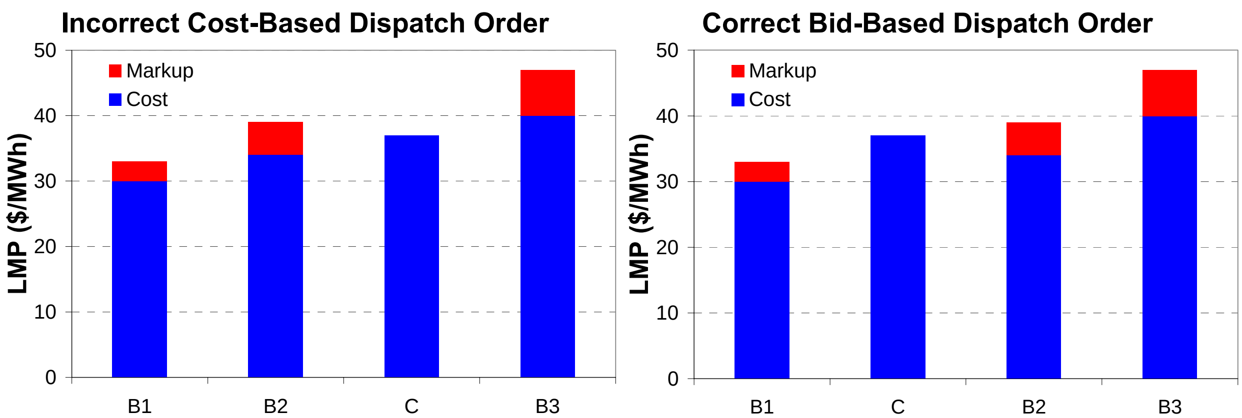
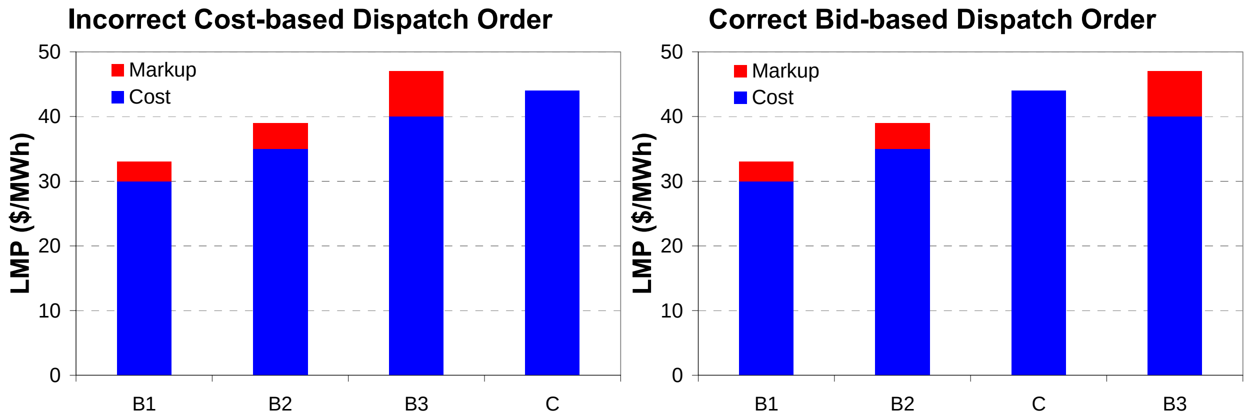


Figure B4 compares cost and bid-based dispatch when unit C is extra-marginal in cost-based dispatch, but becomes the marginal unit in bid-based dispatch.

Figure B4. Case 2: Cost of Service Unit is Extra-marginal in Cost-based Dispatch and Marginal in Bid-based Dispatch



The solution is that the LMP energy cost savings ascribable to a portfolio of cost of service units can reasonably be approximated by applying a probabilistic approach. We assume that when bid adders are applied to all other units but suppressed on the cost-of-service units, there is equal probability that a cost of service unit will either shift from being the marginal unit to become an infra-marginal unit (Case 1), or will shift from being an extra-marginal unit to become the marginal unit (Case 2). On this assumption, we retrieve key plant type characteristics (unit technology type and primary fuel) of the marginal unit in cost-based dispatch and discount the price markup by the proportion of cost of service capacity to total capacity within that plant type group. The calculation of LMPs in the *Rate Base Regulation Case* modifies the markup formula to be:

$$LMP = (1 + PCMI * BidCapacity / TotalCapacity) * Cost$$

where *BidCapacity* is the capacity of the bid-based units within the plant type group of the marginal unit, and *TotalCapacity* is all capacity (bid-based capacity plus cost of service based capacity) within the plant type group of the marginal unit. The larger the share of cost of service capacity, the more likely a cost of service unit will be the marginal unit within each plant type group, and the lower the expected markup.[185]

Markup Pricing Model Results

The impact of not including price markups on the Mirant assets turned out to be minimal. Over the 20-year study period, the average decrease in markup fell by only about 0.1%. The reasons for this small estimated decrease in price markups with Mirant units bidding at cost are discussed here.

The Maryland Mirant capacity consists of 1,231 MW of natural gas-fired combustion GT capacity and 3,698 MW of ST capacity. In 2009, the shares of Mirant capacity to total capacity

[185] A different composition of assets may result in a more significant impact as a result of the suppression of bid adders.

will be 72.5% of GT and 52.5% of ST capacity. Over the study period, new GT capacity is built in the SWMAAC zone, so by 2028 the share of Mirant GT capacity falls to 26.8%, while the share of ST capacity remains constant because we do not assume any ST capacity is built or retired in SWMACC.

For 2009, a summary decomposition of the hour-weighted PCMI values from the simulation is shown in Table B6. While the high (72.5%) proportion of Mirant GT capacity results in a large decrease in average markup by GT plants in SWMAAC, from 10.2% to 2.8%, this group of assets is on the margin only 0.1% of the time, so its contribution to the overall reduction in average annual markup is only 0.01%. While the Mirant share of ST capacity in SWMAAC is smaller (52.5%) and the average markup is not as high as for GTs, this plant category accounts for more of the reduction in overall markup, 0.08%.[186]

Table B6. Composition of Time-Weighted Markups by Marginal Unit Type and Location, and by Case, 2009

Marginal Unit Type and Location	Hours Share	Capacity Share Not MD Mirant	Markup By Unit Type		Hours-weighted Markup	
			All Units	Not MD Mirant	All Units	Not MD Mirant
GT in SWMAAC	0.10%	27.55%	10.22%	2.82%	0.01%	0.00%
ST in SWMAAC	1.64%	47.46%	9.12%	4.33%	0.15%	0.07%
Other in SWMAAC	3.52%	100.00%	8.30%	8.30%	0.29%	0.29%
In other zones	94.74%	100.00%	5.11%	5.11%	4.84%	4.84%
	100.00%				5.29%	5.21%

In later years, the reduction in markups is slightly larger. The average composition over the 2009-2028 period, shown in Table B7, indicates that the average reduction in markup is 0.11%. While the Mirant share of GT capacity is less on average over the 20-year period than in 2009, both GT and ST assets in SWMAAC are on the margin a greater portion of the time, so having some of these units bid at cost has a larger impact on reducing average markups over the 20-year period than in 2009.

[186] The PCMI values discussed here are not price or load-weighted. Higher markups occur in higher price and higher load hours, so the average load-weighted cost markup is about 2% higher.

Table B7. Composition of Time-Weighted Markups by Marginal Unit Type and Location, and by Case, 2009-2028 Average

Marginal Unit Type and Location	Hours Share	Capacity Share Not MD Mirant	Markup By Unit Type		Hours-weighted Markup	
			All Units	Not MD Mirant	All Units	Not MD Mirant
GT in SWMAAC	0.47%	53.44%	10.94%	6.70%	0.05%	0.03%
ST in SWMAAC	5.22%	47.46%	3.46%	1.64%	0.18%	0.09%
Other in SWMAAC	3.24%	100.00%	8.80%	8.80%	0.29%	0.29%
In other zones	91.07%	100.00%	5.18%	5.18%	4.72%	4.72%
	100.00%				5.23%	5.12%

Imposing cost of service bidding on a different composition of assets located in SWMAAC would not make much difference in the suppression of price markups since the primary barrier to more substantial price reduction is that the simulation model results in a unit located outside of SWMAAC being the marginal cost unit more than 91% of the time over the twenty-year study period. Even if all SWMAAC units bid at cost, the average (time-weighted) PCMI would only fall from 5.23% to 4.72%, or by about 0.5%, as can be seen from Table B7.

APPENDIX C. REC PRICE FORECAST MODEL AND RESULTS

REC Price Forecast Model

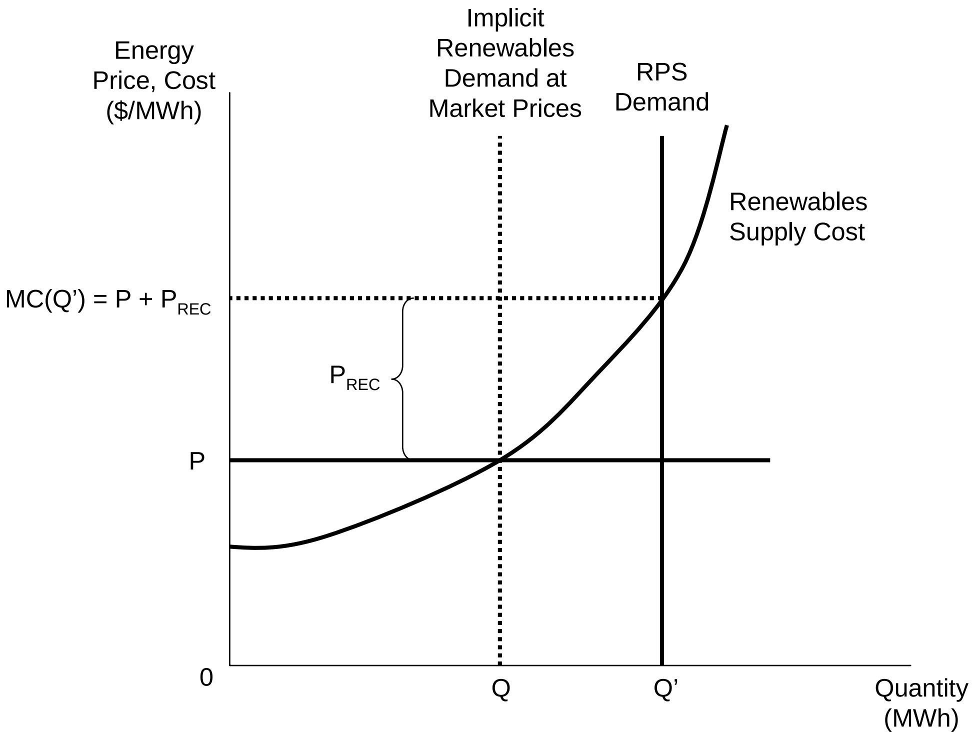
Fundamentals

The fundamental determinants of REC pricing are shown in the diagram in Figure C1, which represents a simplified static renewable energy supply-demand relationship without and with a governing RPS regulation. In either case, suppliers of renewable energy will be price takers, since most renewable technologies are non-dispatchable, have limited energy availability, and/or have low variable costs. Therefore these generators generally produce energy whenever the resource is available.

In the case without RPS regulation, a price-taker faces a horizontal demand curve for energy at market price, P, resulting in some supply of renewable generation without any subsidization. The equilibrium level of renewable generation is at Q, the point of intersection between the upward sloping renewable supply cost function and the horizontal energy demand function. For wind energy, the principal renewable resource that is close to being economic without subsidy, the position and shape of the renewables supply curve is determined primarily by the capital costs of wind turbines and transmission interconnection costs, and by wind farm generation performance (primarily a function of wind speeds). As successively less attractive sites are developed, characterized by less windy conditions and/or greater distance from transmission lines, the marginal cost for incremental capacity increases.

In the case with RPS regulation, there is a vertical demand curve at Q', the mandated RPS quantity. If the market solution at Q is less than the RPS requirement at Q', then the market REC price, P_{REC}, is equal to the difference between the marginal cost of supplying renewables at the RPS level Q', MC(Q'), and the market energy price, P. P_{REC} is the subsidy that must be provided in order to induce sufficient renewables supply to meet the RPS demand.

Figure C1. REC Price Formation with a Hard RPS Requirement

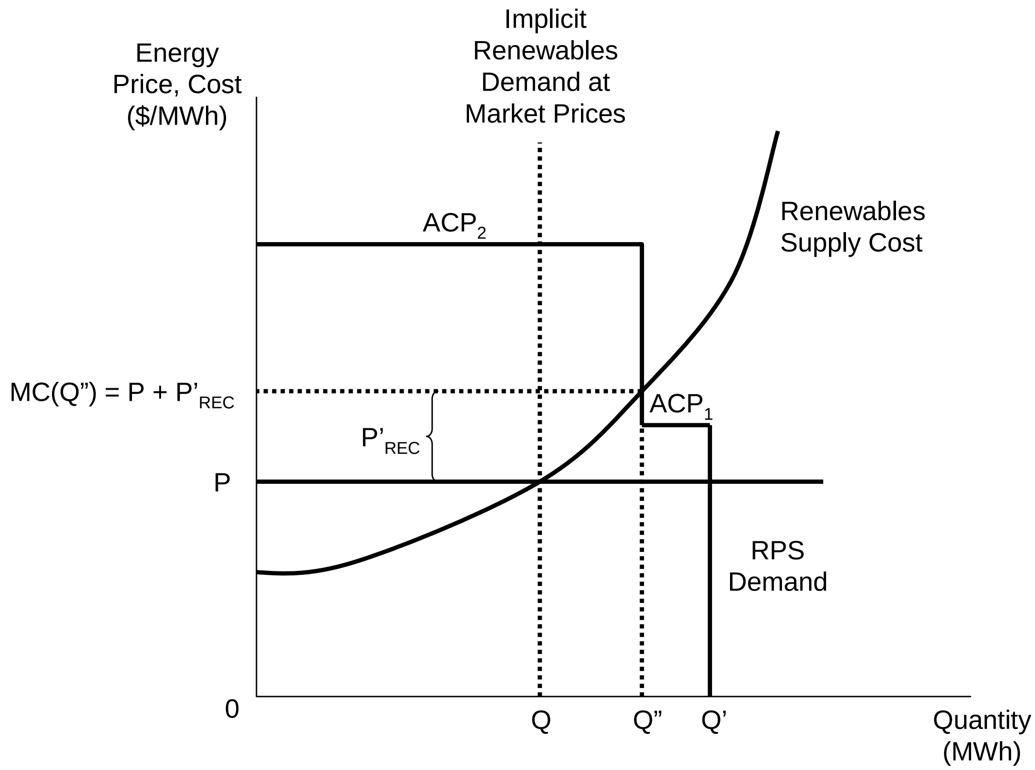


If the RPS program includes an ACP mechanism, then the ACP (in $/MWh) effectively places a cap on market prices for RECs. This results in a "soft" RPS constraint, which does not have to be fully met with renewable energy supply. Consequently, the amount of renewables supplied will be less than the nominal RPS requirement if ACP is less than MC(Q').

The analysis in Figure C1 represents the key drivers of the market. It does not account for a change in P resulting from the change in the dispatch of fossil fuel-fired generation units. It also does not account for changes in operating reserves that may be required so that conventional fossil and hydro capacity can load follow fluctuating renewable energy resource such as wind, solar, and small hydro. For this simplified analysis, we assume the net effect is zero change in the market clearing price of energy.

Figure C2 illustrates how two ACP levels (*e.g.*, for a two-state region) effectively cap the RPS demand curve, turning it into a stair-step curve. The result in this example is to reduce renewables generation from Q' to Q" and reduce the price of RECs to a lower point of intersection with the same renewables supply cost curve as in Figure C1. While this example shows the point of intersection at a vertical segment of the demand curve, it is also possible that the market price of RECs will be equal to one of the state ACP prices.

Figure C2. REC Price Formation with a Soft RPS Requirement



In addition to legislated RPS demand for RECs, there is a growing voluntary demand that pushes REC prices higher than otherwise. It is unlikely that this voluntary demand will continue at a significant level after more states implement RPS programs or the federal government introduces a national RPS program. The voluntary demand for RECs could also dissipate as greenhouse gas allowances become a significant factor in the cost of producing non-renewable electricity. For these reasons, this analysis does not include voluntary REC demand.

Differences in State RPS Policies

Other RPS policy rules that differ between states and which influence the market price of RECs include (1) banking of RECs for multiple years, (2) credit multipliers for certain preferred technologies, (3) the locations, vintages, and technologies of eligible resources, and (4) whether RECs can be unbundled from the sale of energy.

Banking: Among the six PJM states with RPS requirements, Maryland and Pennsylvania allow banking for up to two years after the renewable generation year. Allowing banking of RECs implies that market equilibrium prices will not increase by more than the market discount rate from one year to the next. For example, if the current 2008 REC price is $1.00/MWh, then the 2009 price will not be more than $1.095/MWh if the discount rate is 9.5%. The ability to inventory RECs for future use will increase the current price, by making less supply available for retirement, and decrease the price in the future year in which they are retired. In states that do not allow banking, the value of RECs for a given annual vintage can rise or plummet as the end of the compliance or reconciliation period approaches, depending on whether participants are long or short RECs for meeting the remainder of the annual requirement.

Preferred technology multipliers: Some states have provided a multiplier for RECs produced by preferred technologies. Maryland currently offers wind- and methane-powered electric energy resources a 110% credit through 2008. Washington, D.C., offers wind and solar a 110% credit through 2009. Delaware offers DPL a 150% credit for onshore wind turbines installed in-state before 2013 and a 350% credit for offshore wind turbines installed before June 2017. Delaware also offers a 300% credit for in-state customer-sited photovoltaic generation and for fuel cells using renewable fuels that are installed before 2015. The direct effect of these credits is to reduce the actual required renewable generation below the notional target. The indirect effect is that the multipliers will tend to decrease REC prices.

Eligible resources: States differ somewhat in the technologies included as eligible Tier 1 and Tier 2 renewable resources, which will have some effect in altering their supply cost curves compared to an alternative supply stack that includes or excludes certain non-common resources, *e.g.*, poultry litter in New Jersey. The PJM states with RPS rules generally allow resources from other PJM states to be eligible for meeting the given state's RPS requirement. In addition, some states also allow renewable resources from states adjacent to or interconnected with PJM states to qualify. For Maryland, resources within PJM and delivered into PJM qualify in all years, but resources from adjacent states only qualify through 2010.

Unbundled / bundled RECs: Allowing unbundled RECs will tend to lower their price because the supplier of the RECs need not also sell the energy to the buyer. Unbundled RECs also allow for intermediary brokers / traders of RECs to participate in the market. The PJM states all allow unbundled RECs.

Current Differences in REC Prices between States

Current 2008 vintage REC prices for Tier 1 RECs vary widely across the PJM states. Most of the differences are accounted for by the relative tightness of meeting state-specific RPS quotas from existing renewables generation sources. When the state RPS requirement can be met with existing generation resources, such as currently for Maryland, market REC prices may be above zero but quite low, *i.e.*, in the range of \$0.50/MWh to \$1.50/MWh. These very low values may represent their voluntary demand or their option value for holding them for possible use in a later year. In other states, such as New Jersey and Pennsylvania, REC prices are above \$10/MWh, signaling that the RPS requirement is constraining.

Over the next several years, as each state steps up its annual RPS share of load requirements, Tier I REC prices are expected to converge towards a single price at a level that indicates a binding constraint.

Relation between REC Prices and Electric Energy Prices

Electric energy prices rise and fall in tandem with fossil fuel prices and emission allowance prices, since fossil-fired generation units are usually on the margin in the supply stack. Thermal generators currently include SO_2 and NO_x cap-and-trade program allowance prices in their energy bids. Starting in 2009, electric energy prices in PJM will also increase as a result of the RGGI states requiring CO_2 allowances.[187] The replacement of the RGGI program with a more constraining federal greenhouse gas cap-and-trade program would further increase LMPs. An increase in LMPs would increase energy revenues and decrease the REC price needed to subsidize renewable generation.

The REC price forecast model uses a financial model of production costs and revenues for a Maryland onshore wind farm to estimate the break-even market price of RECs that allow the wind farm to receive a return equal to its cost of capital. This simple model does not account for the many complexities discussed above of different states having different REC market rules regarding banking, eligibility, ACP levels, and RPS schedules. The REC price forecast model was applied to the LMP results from each of the 24 MarketSym energy price forecast simulation cases to forecast Maryland REC prices.

REC Price Forecast Results

The REC price forecasts for each study case for the *Conventional Wisdom*, *Federal Outlook*, and *Peak Oil Scenarios* are shown in the following charts. The *No TrAIL Scenario* results are not shown because they are nearly indistinguishable from the *Conventional Wisdom Scenario*. Only minor differences in REC prices occur between cases, so the graphs appear almost identical. In the *Federal Outlook Scenario* for each study case, the maximum REC price forecasted remains barely below the ACP price of $40/REC by 2029 in the low fuel price scenarios. In the *Peak Oil Scenario* for all study cases, the representative wind farm does not require a subsidy by 2029, so the REC price falls to zero in that year.

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[187] The PJM states in RGGI are NJ, DE, and MD. The PJM zones overlapping with the RGGI footprint will be most directly affected by changes in CO_2 allowance prices.

Figure C3. *Reference Case* REC Price Forecasts by Fuel Price Scenario

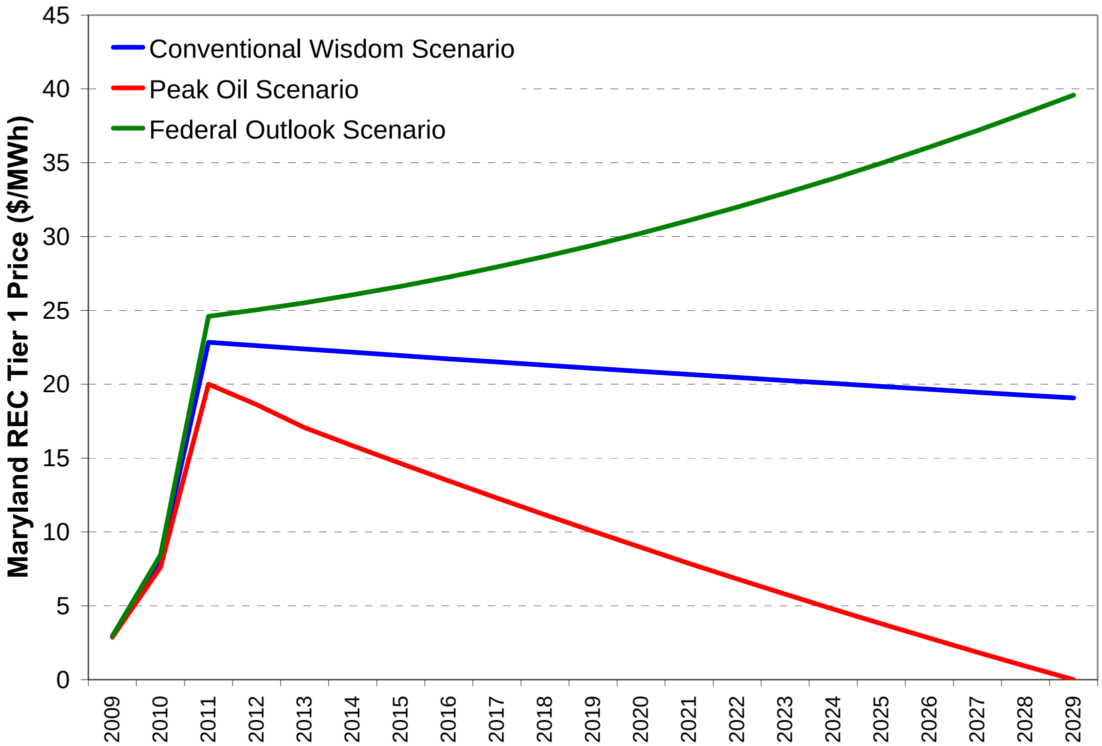

Figure C4. *Contract CC / Utility CC Cases* REC Price Forecasts by Fuel Price Scenario

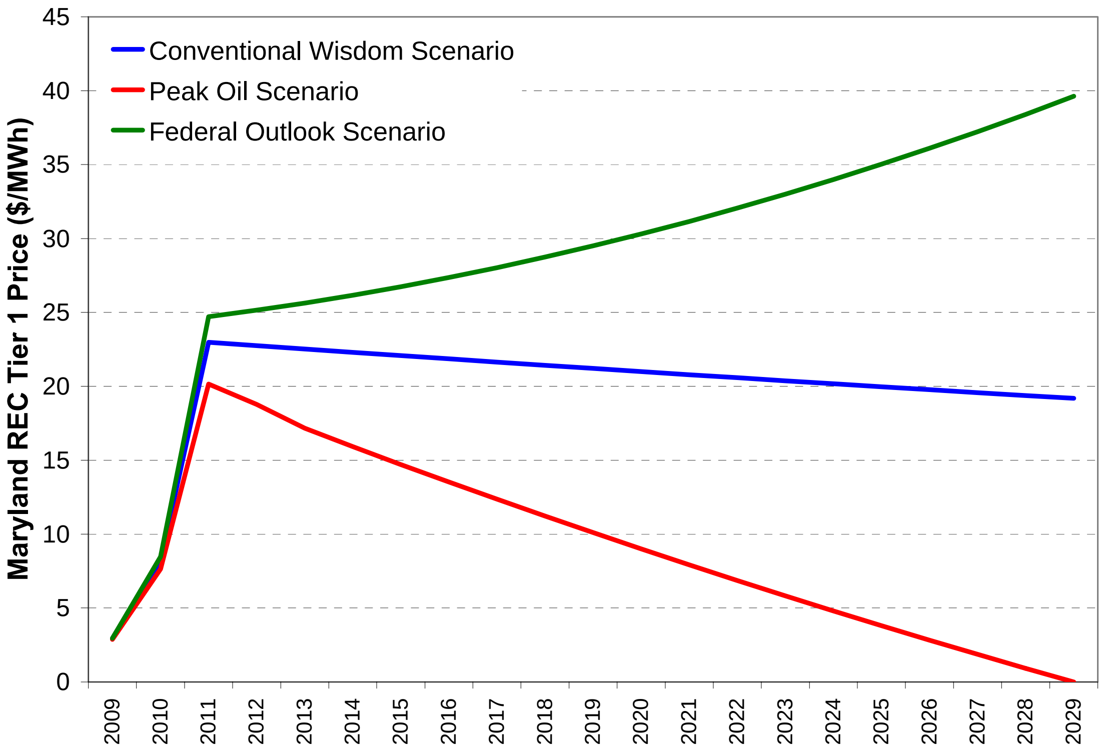

Figure C5. *Overbuild Case* REC Price Forecasts by Fuel Price Scenario

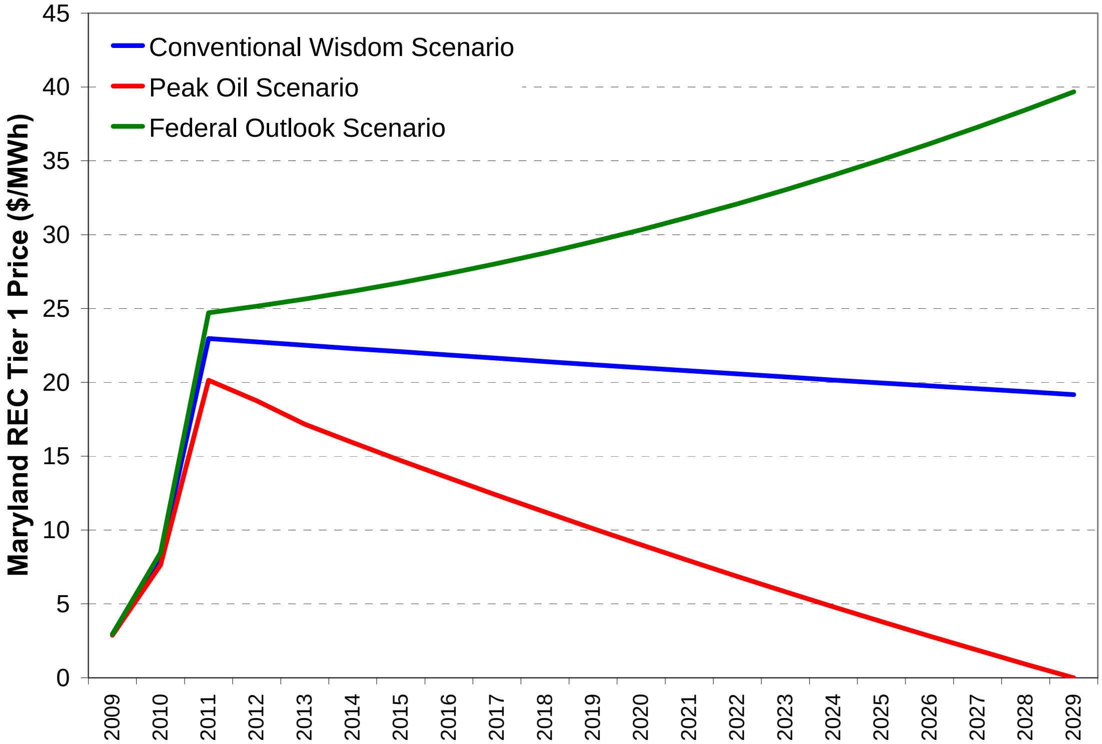

Figure C6. *15x15 DSM Case* REC Price Forecasts by Fuel Price Scenario

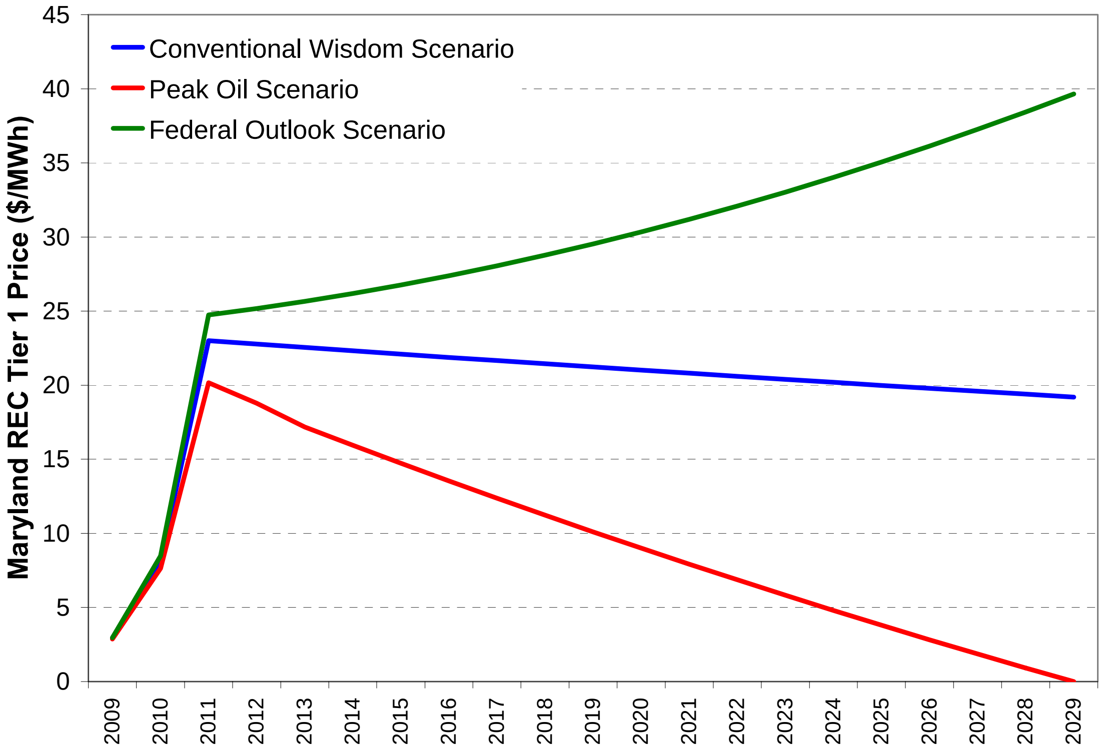

Figure C7. *Onshore Wind Case* REC Price Forecasts by Fuel Price Scenario

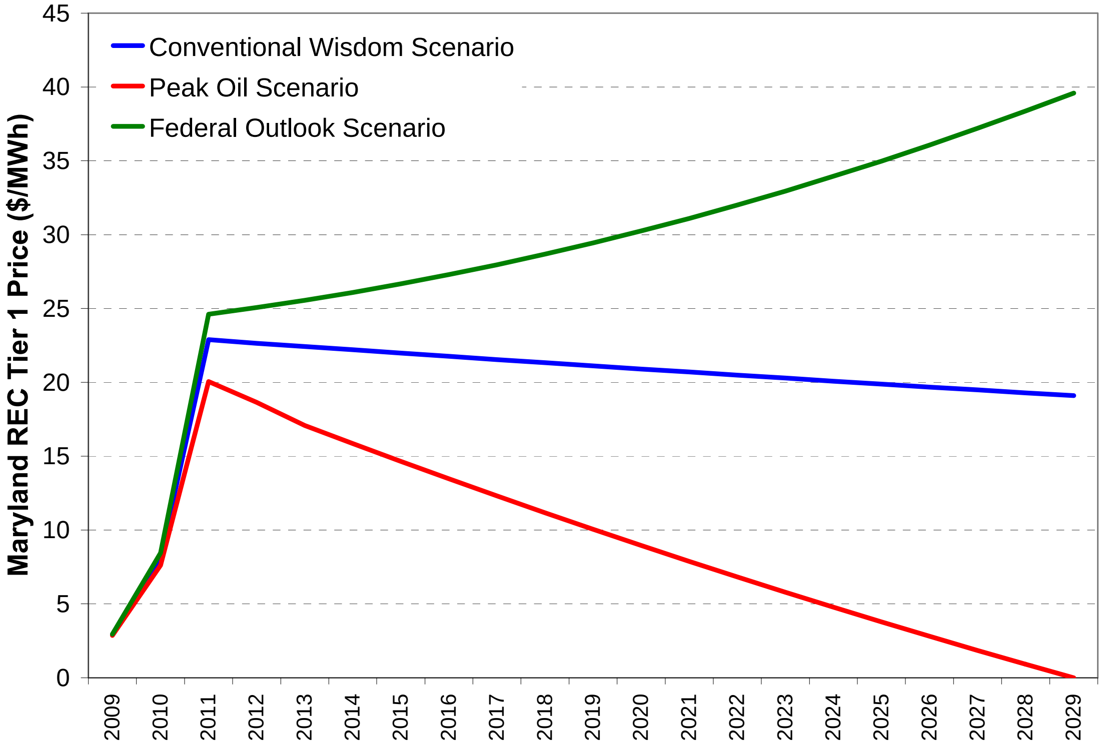

Figure C8. *Offshore Wind Case* REC Price Forecasts by Fuel Price Scenario