

Interim Report of the Maryland Public Service Commission

PART I. Options for Reregulation

PART II. Stranded Cost Analysis

January 17, 2008

Senate Bill 400 – Reregulation Study

- The Public Service Commission shall, among other tasks:
 - *conduct hearings* and utilize any necessary *outside experts*, to study and evaluate the status of electric restructuring in the State
 - consider changes that provide residential and small businesses a *reliable electric system* at the *best possible price*, including options for reregulation
 - also consider the availability of *adequate transmission and generation facilities* to serve the electrical load demands of all customers in the State
 - consider the implications of requiring or allowing *IOUs to construct, acquire, or lease generating plants* and associated transmission lines;

Summary of PSC Actions: 2007 Interim

- ❑ Conducted 13 days of contested case proceedings
- ❑ Conducted 3 days of quasi-legislative proceedings
- ❑ Received testimony and comments from 59 witnesses and experts
- ❑ Received and reviewed more than 1,200 pages of written testimony and reports
- ❑ Retained the legal and economic consulting services of Kaye Scholer LLP (“Kaye Scholer”) and Levitan Associates, Inc. (“Levitan”) to prepare analyses of reregulation options, generation and transmission options, stranded costs and related issues.



Two Goals of Reregulation

- Maintain the **reliability** of the electric grid:
- Obtain the **best possible prices** for Maryland Ratepayers
- Threshold question: Will the “market” address the needs of Maryland’s ratepayers?

Reliability

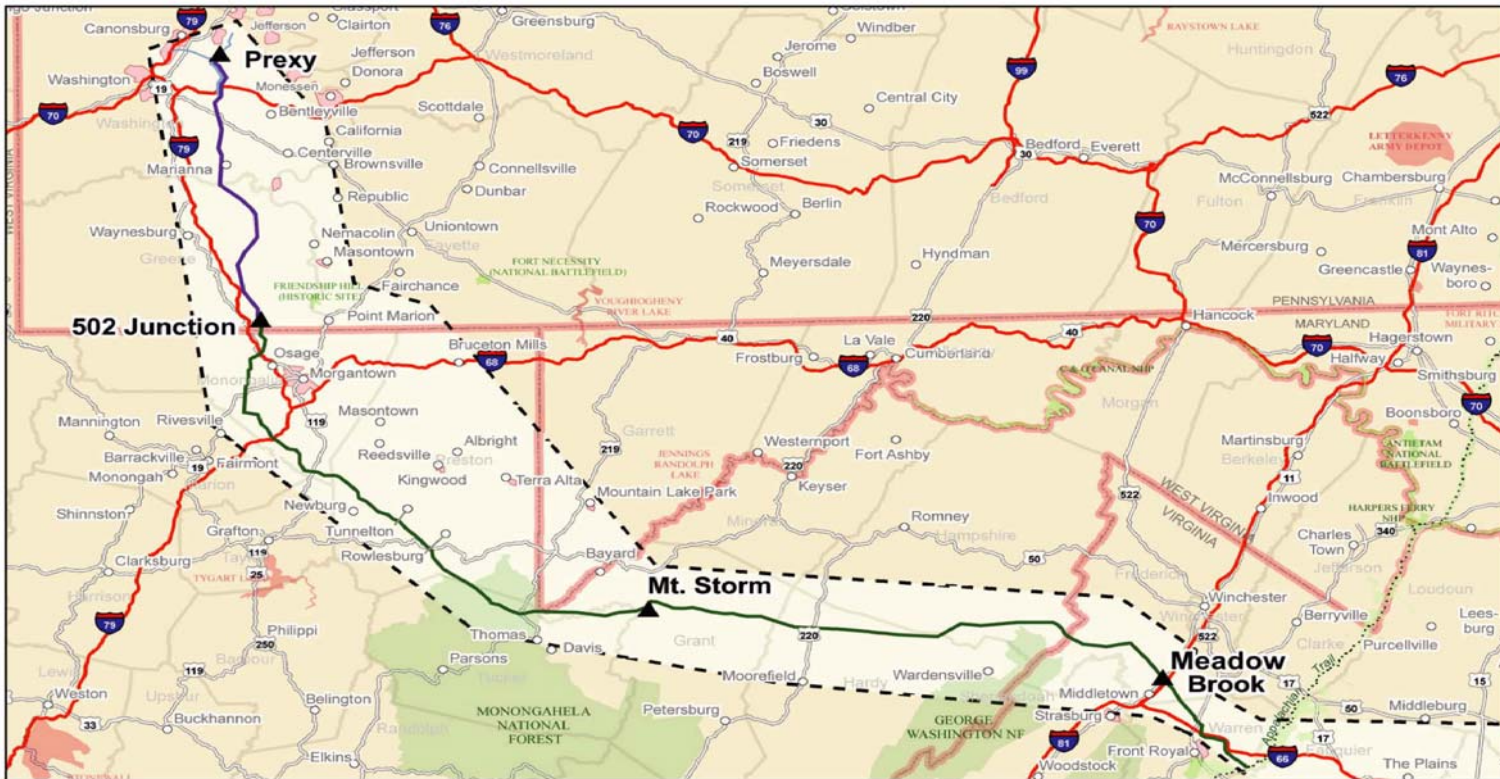
□ Reliability:

- As we discuss in these slides, Maryland faces a **serious reliability concern** in the 2011-2012 timeframe.
- The lack of new generation in the state, coupled with inadequate transmission capability and growing demand means Maryland faces the prospect of brown-outs or even rolling black-outs on hot summer days in 2011-2012.

Reliability (cont'd)

- **Two major transmission lines** have been approved by PJM to address Maryland's and the region's reliability shortfall.
- **The first line**, the Trans-Allegheny Interstate Line (“**TrAIL**”) is a 500-kV line through VA, WVA, and PA.
- **The 2nd line**, the **PATH** line, runs 300 miles from West Virginia through Washington and Frederick Counties to Kemptown Md. Substation.
- CPCN proceedings for the TrAIL line are pending before the utility commissions for each of these states.
- As expected, there is organized opposition to the lines.

Trans-Allegheny Interstate Line (TRAIL)



Legend

- Study Area
- Substation NAD83
- 500 kV Transmission Line for local need
- Proposed 500 kV Line Route
- Proposed 138 kV Line Routes
- Populated Places
- County Boundary

Federally Owned Land (Transparent Overlay)

- Department of Defense
- Forest Service
- Fish and Wildlife Service
- National Park Service

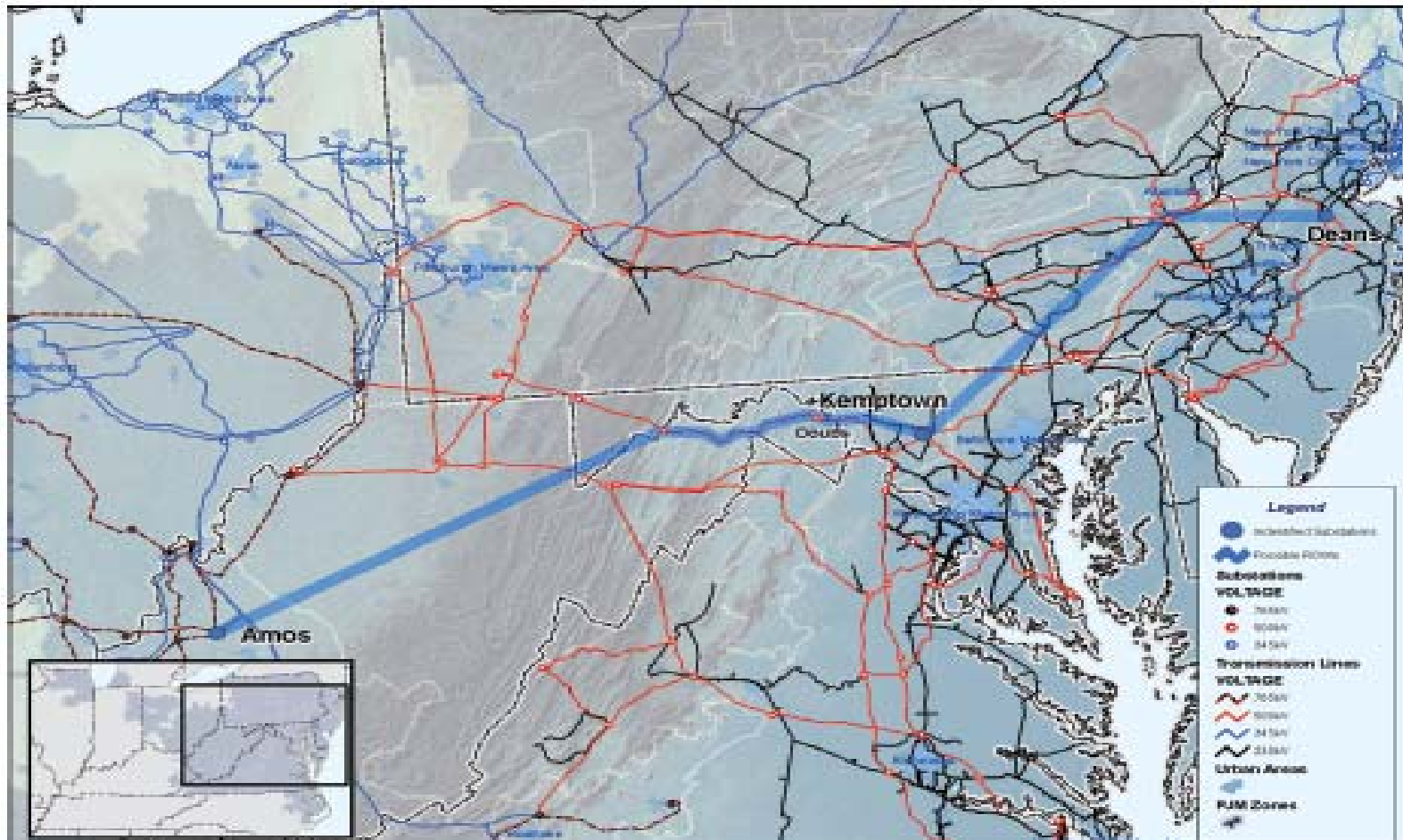
Map data source: Environmental Systems Research Institute (ESRI) High resolution ground base data



Geographic Coordinate System: Universal Transverse Mercator; Datum: NAD 1983; Zone: 17N; Projection: Transverse Mercator; Linear Unit: Meter; Ellipsoid: Geoidetic Reference System 80.

0 10 20 30 Miles

Potomac Appalachian Transmission Highline (PATH)



Maryland's Transmission Shortfall

- According to PJM if the TrAIL line is not service by 2012, the region's electricity load could exceed the transfer capability of the existing transmission system by 2000 MW.
- If the PATH line is not in service by 2012, the net load would exceed the import capability by 3,000 MW.
- And if neither line is in place on time, the regional shortfall could be as much as 6500 MW.
- **Maryland's allocation of this shortfall is approximately 1500MW - equivalent to more than two 600MW power plants.**

Maryland's Transmission Shortfall (cont'd)

- PJM has characterized the Mid -Atlantic shortfall as “**critical**” in testimony before the PSC.

- PEPCO & Delmarva Power and Light testified that the completion of both the TrAIL and PATH lines is:
 - “...critical to maintaining the long term reliability and reducing persistent congestion in the Mid-Atlantic Region”

- According to PJM, the “load shedding” i.e. voltage reductions and brown-outs that would result from this transmission shortfall would occur on “**any hot day**” in the area – not just 1 or 2 days a year.

Maryland's Transmission Shortfall

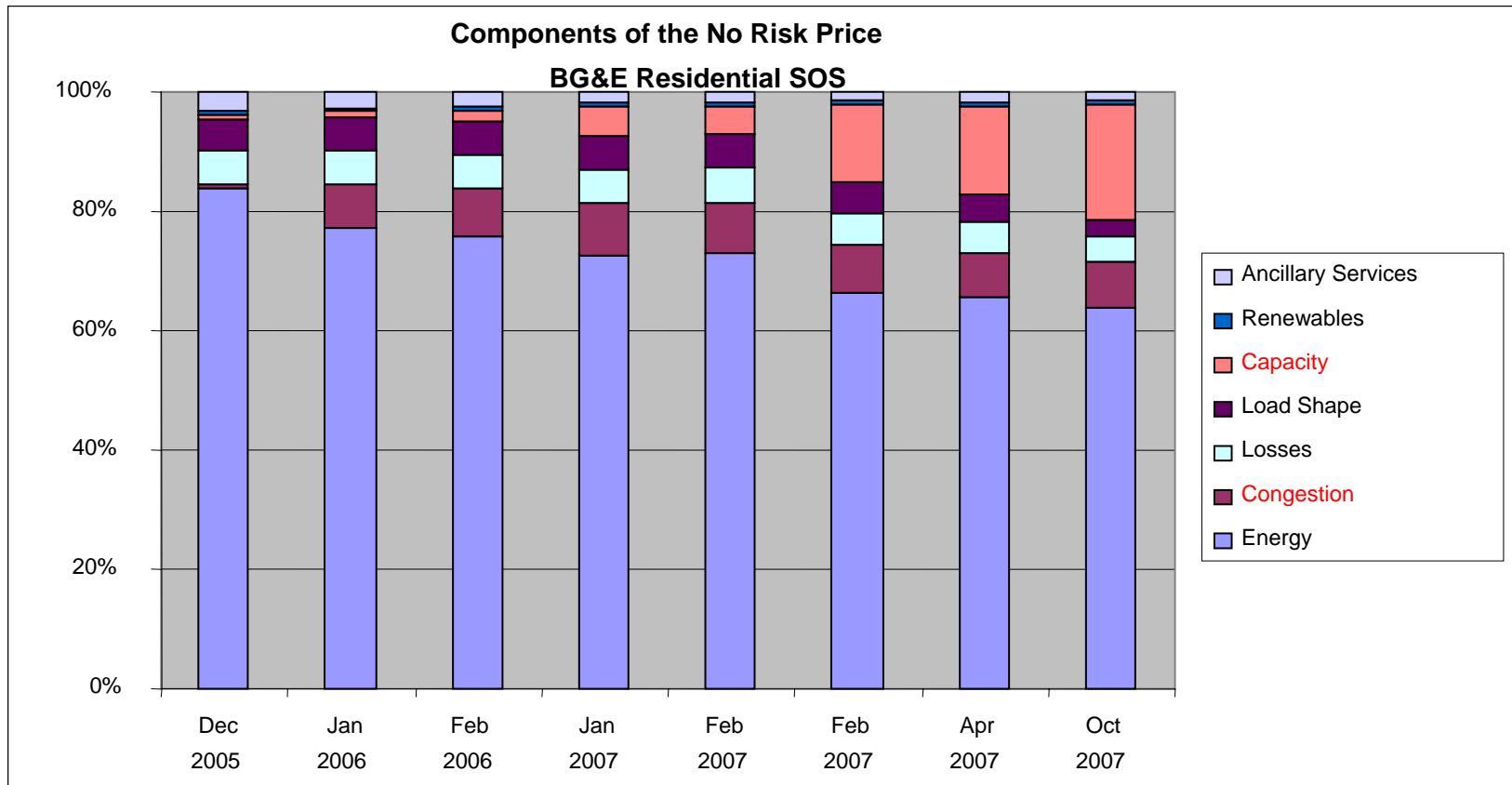
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- ❑ PSC staff: "...the **probability** that either or both of the TrAIL or PATH lines will be completed on schedule **is low**"
- ❑ It has been over a decade since a project of the size of these lines has been attempted – the last major line took over 15 years to complete.
- ❑ Maryland is part of the recently designated federal National Interest Electric Transmission Corridor, meaning the federal government could act to site and approve the lines in the absence of state action.
- ❑ However, states affected by the NIETC designation have expressed opposition to this designation.

Electricity Prices

- Market conditions have caused high prices in Maryland:
 - As we discuss in the following slides, being a net importer of energy, coupled with inadequate transmission, means Maryland pays high electricity prices.
 - Wholesale market rules adopted by FERC and PJM exacerbate Maryland's high prices.
 - Maryland has among the highest congestion and capacity charges in all of PJM.

Impact of Congestion and Capacity on SOS Prices



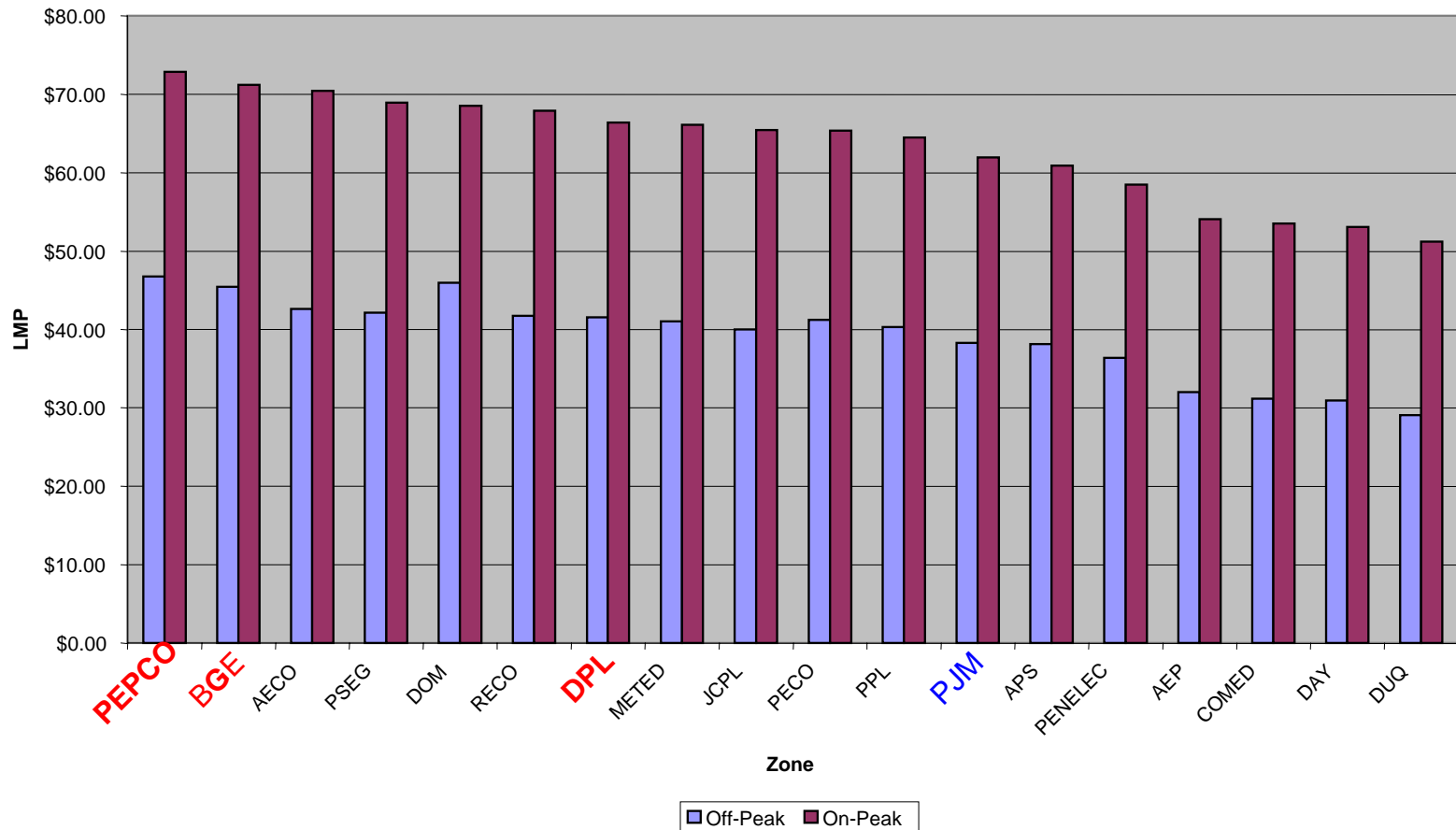
NOTE: Dates are SOS supply auction dates; Price allocations are based on auction results on the dates indicated for the future delivery of SOS supply. Ex: October 2007 auctions were for summer 2008 delivery.

The First Cost-Driver: Congestion

- **Simply put**, congestion is the inability to import lower cost electricity because transmission lines are at their limit.
- When lines are “congested” or “constrained,” they cannot carry enough low cost electricity to meet demand, and PJM must dispatch higher cost, local generation located in the constrained zone.
- In Maryland’s case, that means there is a limit to how much lower cost electricity existing transmission lines can bring in from west to east.
- Under PJM and FERC market rules, when these local, “marginal” generating units are dispatched, they set the price **for all units** operating in the zone, even lower cost units

Impact of Congestion on Maryland Prices – by Utility

Average 2006 PJM Zonal LMPs



Transmission Congestion and Locational Marginal Pricing (cont'd)

- One PSC consultant estimates that for 2008, congestion will add over **\$160M** in costs to residential SOS rates.
- The PJM market monitor estimates that gross congestion costs for all of Maryland (not netted with any offsets) in 2006 were **\$1.2 Billion**. Actual costs could be as much as **\$500M**
- The PSC is continuing to examine the costs with the assistance of Levitan and Associates

The Second Cost-Driver : Capacity (a/k/a Reliability Pricing Model-RPM)

- The Reliability Pricing Model is an additional cost in wholesale rates intended to address PJM's concerns that insufficient generation (i.e. capacity) was being built in some areas.
- By creating additional payments to generators, RPM is supposed to create a financial incentive for the development of new generation.
- RPM is administered through "auctions" for regions within PJM.
- When capacity is in short supply in a particular region, this results in higher clearing prices in the auctions – basic supply and demand.
- Auctions to establish future prices of capacity through 2008-2009 have been held.

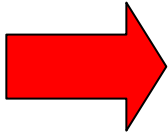
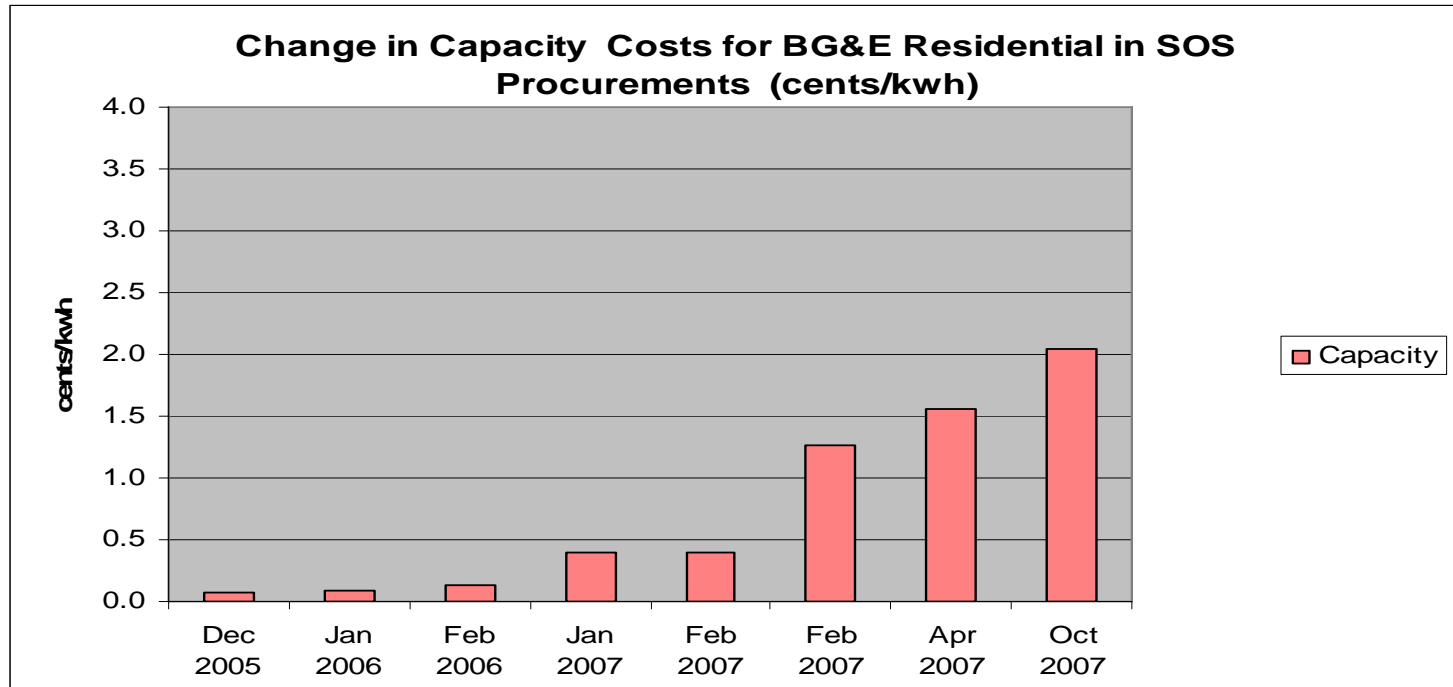
Capacity Prices In Maryland are the Highest in PJM

YEAR	PJM REGION	CAPACITY PRICE
2006 (No RPM)	PJM	\$5.73 per MW-Day
2007/2008 (RPM)	PJM	\$40.80 per MW-Day
	SWMAAC (BGE & PEPCO)	\$188.54 per MW-Day
	EMAAC (Delmarva)	\$197.67 per MW-Day
2008/2009 (RPM)	PJM	\$111.92 per MW-Day
	SWMAAC (BGE & PEPCO)	\$210.11 per MW-Day
	EMAAC (Delmarva)	\$148.80 per MW-Day
2009/2010 (RPM)	PJM	\$102.04 per MW-Day
	SWMAAC (BGE & PEPCO)	\$237.33 per MW Day
	EMAAC (Delmarva)	\$191.32 per MW-Day



Note: Net price for capacity paid by loads is lower than clearing price due to offsets

Impact of RPM on SOS rates



One PSC consultant has estimated that RPM added over \$500 M in costs to residential SOS service in 2008, based on current auction results.

Is RPM solving Maryland's Price and Reliability Problems?

- According to PSC staff, so far the RPM auctions are not adequately addressing Maryland's shortfall -
 - The net change for [PEPCO & BGE] capacity for the three years was an increase of less than 1%.

- According to People's Counsel Expert Jonathan Wallach:
 - "...in all three RPM auctions, the amount of capacity procured for the [PEPCO & BGE] region has fallen short of the minimum reliability requirements for the region. **Moreover, that shortfall has grown with each successive auction**"

Expert conclusions on RPM's impact on Maryland:

□ Kaye Scholer:

- “Rather than the declining capacity prices that had been predicted and that had been experienced in other part of PJM, **Maryland’s capacity prices have increased with no assurances that those prices will do anything to stimulate new generation or demand response**”

□ Levitan:

- “ The result of these RPM auctions indicate that the **customers in Maryland will be paying higher capacity costs until** (i) at least **one major transmission line** is completed (ii) **significant in-state generation** capacity is constructed or (iii) **enough demand response** is developed to reduce demand significantly”



Conclusion: To date, the market has not served Maryland's needs

- After 7 years of de-regulation, Maryland faces a capacity shortfall of 1500 MW, and the region is short 6500 MW....
- After 7 years of de-regulation, parts of Maryland have the highest capacity prices and congestion costs of the PJM region, increasing SOS rates

Options for Reregulation – Kaye Scholer Report

- Reregulation: Tradeoffs Among Direct Costs, Risks, and Benefits
 - Investment Risk
 - Market Risk
 - Regulatory Risk
- Current Framework
 - Status quo means continued high RPM and LMPs
 - Status quo favors current generators
 - Investment uncertainty due to T-lines
 - Wholesale market has flaws and inefficiencies

Options for Reregulation – Kaye Scholar Report

- States Examined:
 - Connecticut
 - Delaware
 - New Jersey
 - Illinois
 - Michigan
 - New Hampshire

Options for Reregulation – Kaye Scholer Report

- **Option 1: Re-capture previously regulated generation fleet by requiring Utilities to re-purchase Maryland generating fleet, or through condemnation power and fair value payment**
 - Costs: \$18-24 Billion
 - Benefits: Return to rate-regulated regime, mitigates some wholesale market costs

Options for Reregulation – Kaye Scholer Report

- **Option 2: Direct Utilities to enter into Long-Term Contracts (new generation)**
 - Costs: Ratepayers share in O&M costs for generation; contract would most likely include energy price adjuster/inflator, or else high risk premium to supplier; contract may be out-of-the money if energy prices fall; could discourage new merchant generation
 - Benefits: Encourages/establishes new domestic generation in constrained areas of state, lowering capacity & congestion costs; helps address reliability concerns; full risks of construction and operations not borne by ratepayers

Options for Reregulation – Kaye Scholer Report

□ **Option 3. State Power Authority**

- Costs: If Power Authority initiates power projects, risks rest with all ratepayers or even taxpayers; may be less efficient than for-profit merchant developer
- Benefits: Costs can be allocated across all utilities; requires smaller ROR; enhances state control over new generation

□ **Option 4 . Integrated Resource Planning**

- Costs: Additional PSC staff plus outside consulting fees
- Benefits: Coordinated planning of generation, transmission and demand response ensures cost-effective energy resource allocations

Options for Reregulation – Kaye Scholer Report

- **Option 5. Aggressive Efforts to shape PJM Wholesale Markets**
 - Costs: Largely outside legal fees + PSC staff dedicated to this function
 - Benefits: Shape PJM and FERC policies on wholesale pricing through interventions in FERC proceedings, litigation, etc. (i.e. RPM, offer capping rules, etc.)

Levitan Analysis - Utility Long-Term Contracts

- Uses an integrated suite of economic, mathematical, and production simulation models.
- Tests the impact of postulated technology, policy, and regulatory initiatives designed to ensure that electricity demand and supply in Maryland remain approximately in equilibrium over the 20-year study period.
- This approach simulates wholesale energy markets in PJM over the long term when different resources are added by technology type in Maryland.
- Consistent with current market rules in PJM, we have differentiated energy and capacity prices by location over the study horizon.
- Develops an EVA, or present value calculation of the Economic Value Added of the various options
- Estimated the long-term retail rate impact by class of service for each of the technology options examined in this study.

Levitan Report – Reference Case

- Represents Maryland’s existing generation resource mix, transmission infrastructure, and a limited level of demand side management (“DSM”)
- Incorporated about one-fourth of the objective associated with Governor O’Malley’s “15 by 15” Initiative – a 15% reduction in per capita energy demand by 2015. (Using “low-case” targets as per PSC)
- Reference Case limits resource additions to peaking plants through 2027 – no new other resources.
- Assumes that each Maryland utility will continue to comply with Maryland’s renewable portfolio standard (“RPS”), but will meet only the mandatory solar component through photovoltaic additions within Maryland.

Levitan Report – Supply Alternatives

- **Optimum Mix** – Substitutes more efficient but more costly combined cycle generation plants for peaking plant additions if market conditions warrant. Assumes a long-term contract with Maryland’s utilities.
- **Coal** – Adds a 648 MW supercritical pulverized coal plant with state-of-the-art pollution controls in lieu of an equivalent amount of peaking plants. Assumes the new coal plant would achieve commercial operation in 2015 under long-term utility agreements authorized by the PSC.
- **Nuclear** – Adds a new 1,600 MW reactor unit at the Calvert Cliffs facility. Assumes the new plant would be on-line in 2017 under long-term agreements with Maryland’s utilities.

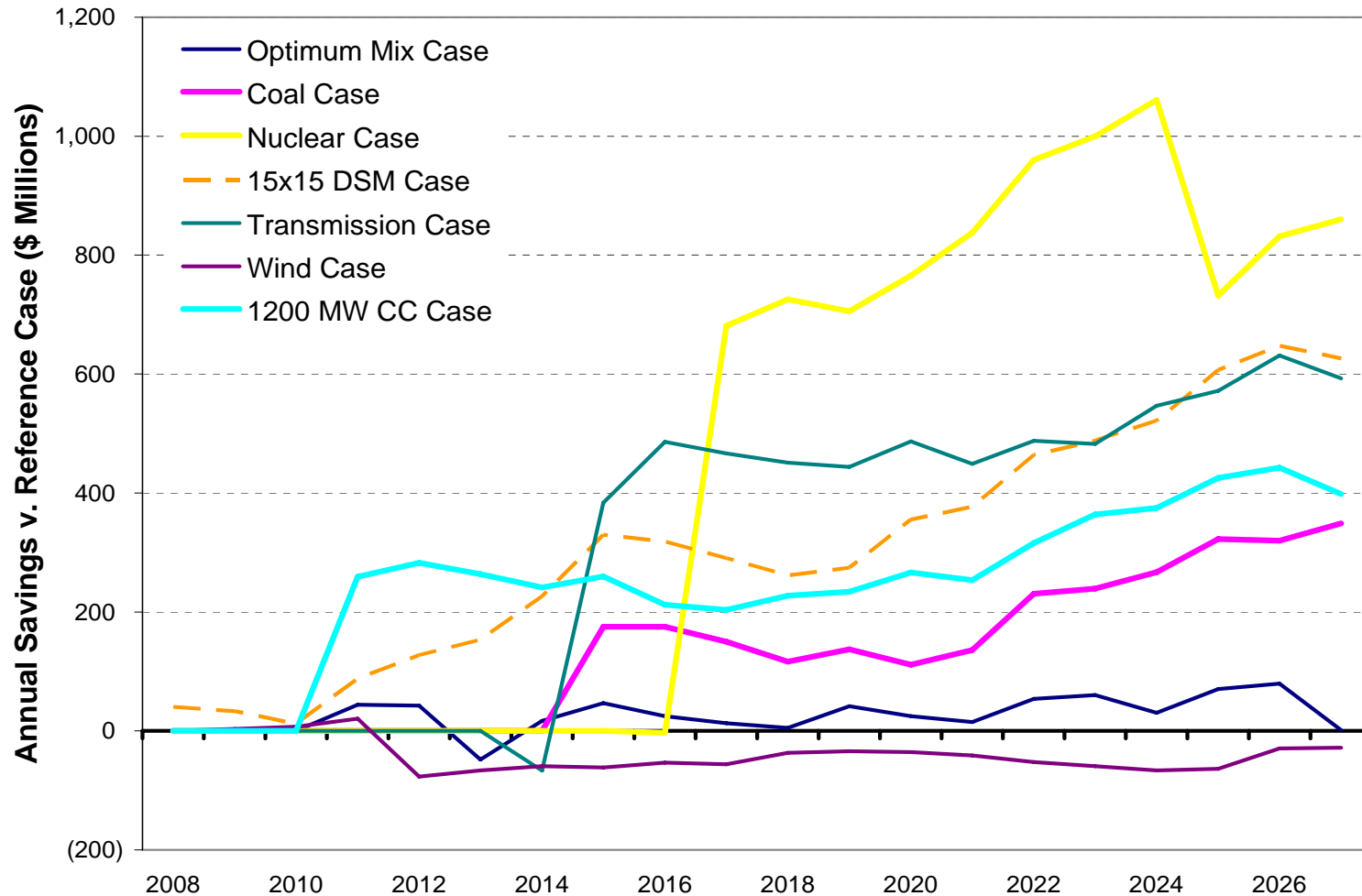
Levitan Report – Supply Alternatives

- **15 x 15 DSM** – Adds ambitious conservation and load management initiatives with full achievement of the “15 by 15” Initiative.(Using “low case” targets). This reduces Maryland’s dependence on peaking plants to ensure adequate supply, but primarily achieves more efficient use of energy around-the-clock.
- **Transmission** – Models one new backbone transmission project that will begin serving Maryland in 2015. This addition would lessen Maryland’s dependence on new peakers from 2015 throughout the remainder of the study horizon. Under transmission ratemaking principles approved by the FERC the cost of new transmission would be apportioned among ratepayers in Maryland and ratepayers elsewhere in PJM.

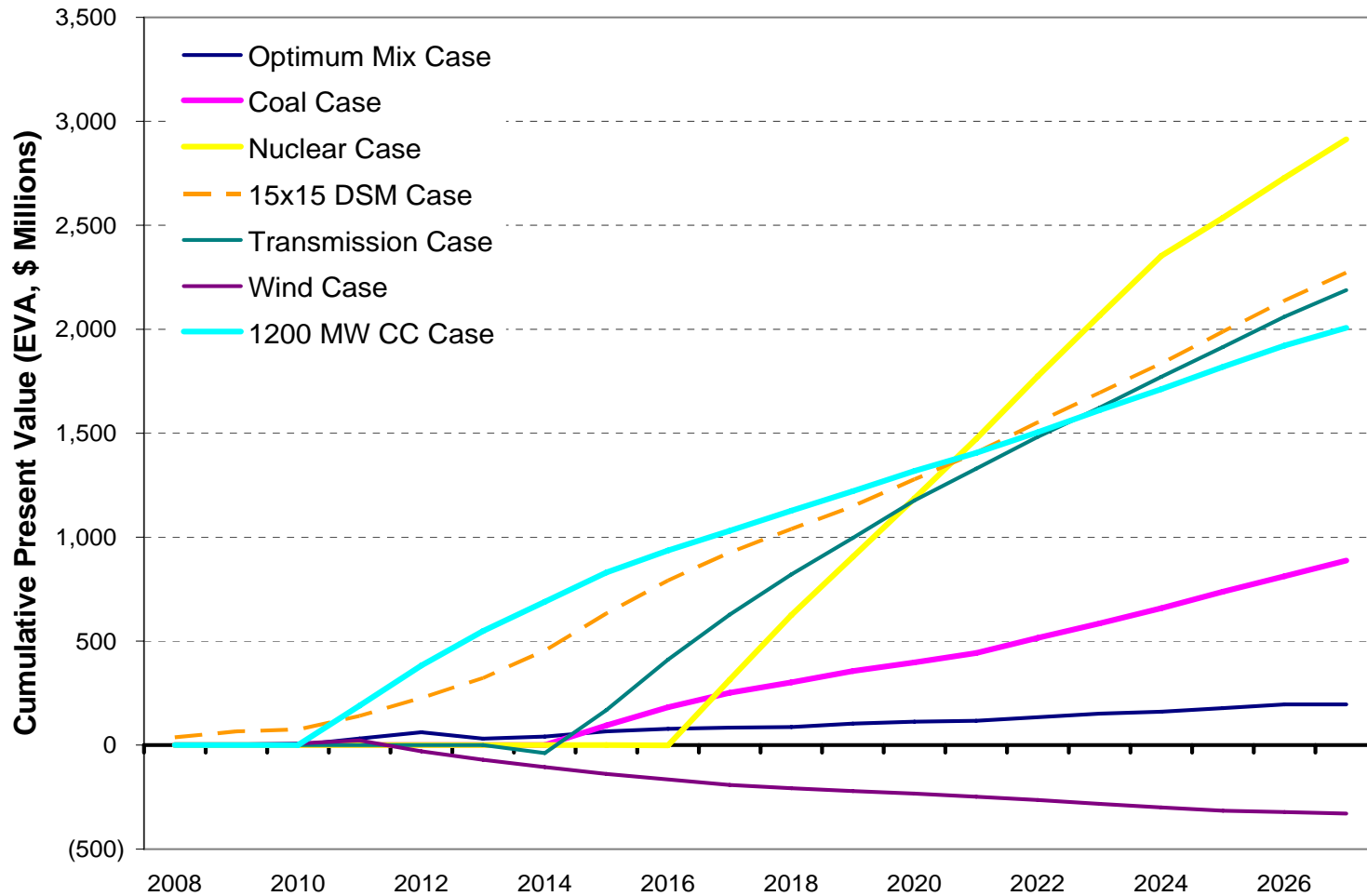
Levitan Report – Supply Alternatives

- **Wind** – Adds 500 MW of new wind turbines, both onshore and offshore by 2012. Because wind is intermittent, only about one-fifth of the total nominal installed capacity can be treated as dependable capacity. Therefore, wind only slightly reduce the need for peakers to maintain reliability. We assume that the addition of new wind generation would require long-term agreements authorized by the PSC between wind developers and Maryland’s utilities
- **Overbuild** – Adds a generation reserve surplus of 1,200 MW beginning in 2011. Assumes that the reserve surplus will consist of new combined cycle plants in Maryland and will be sustained through the study horizon. Both the 1,200 MW of combined cycle plants as well as gas turbine peaking plants added later to the resource mix would require long-term contracts with the utilities

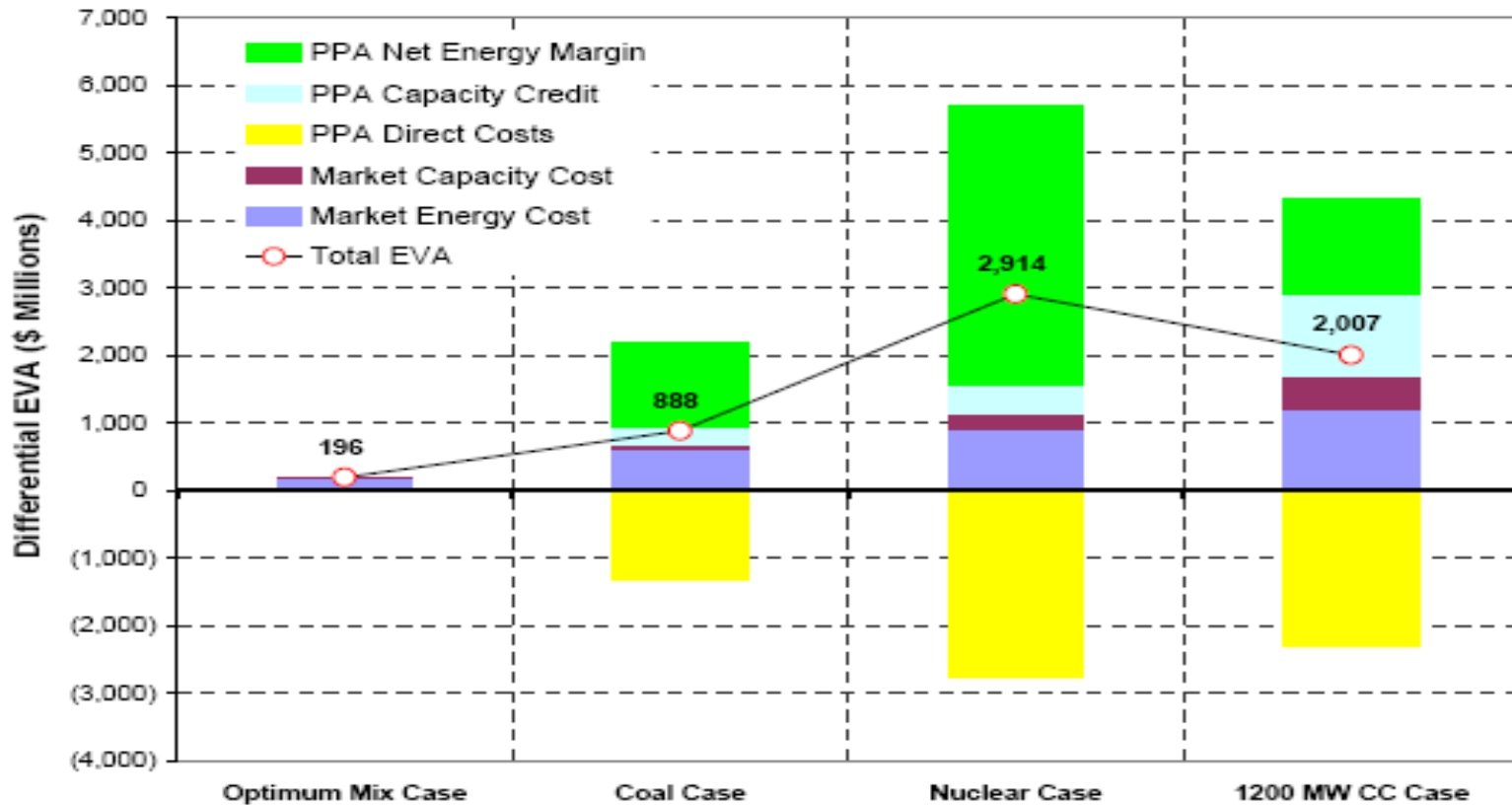
Annual Savings for Alternative Cases



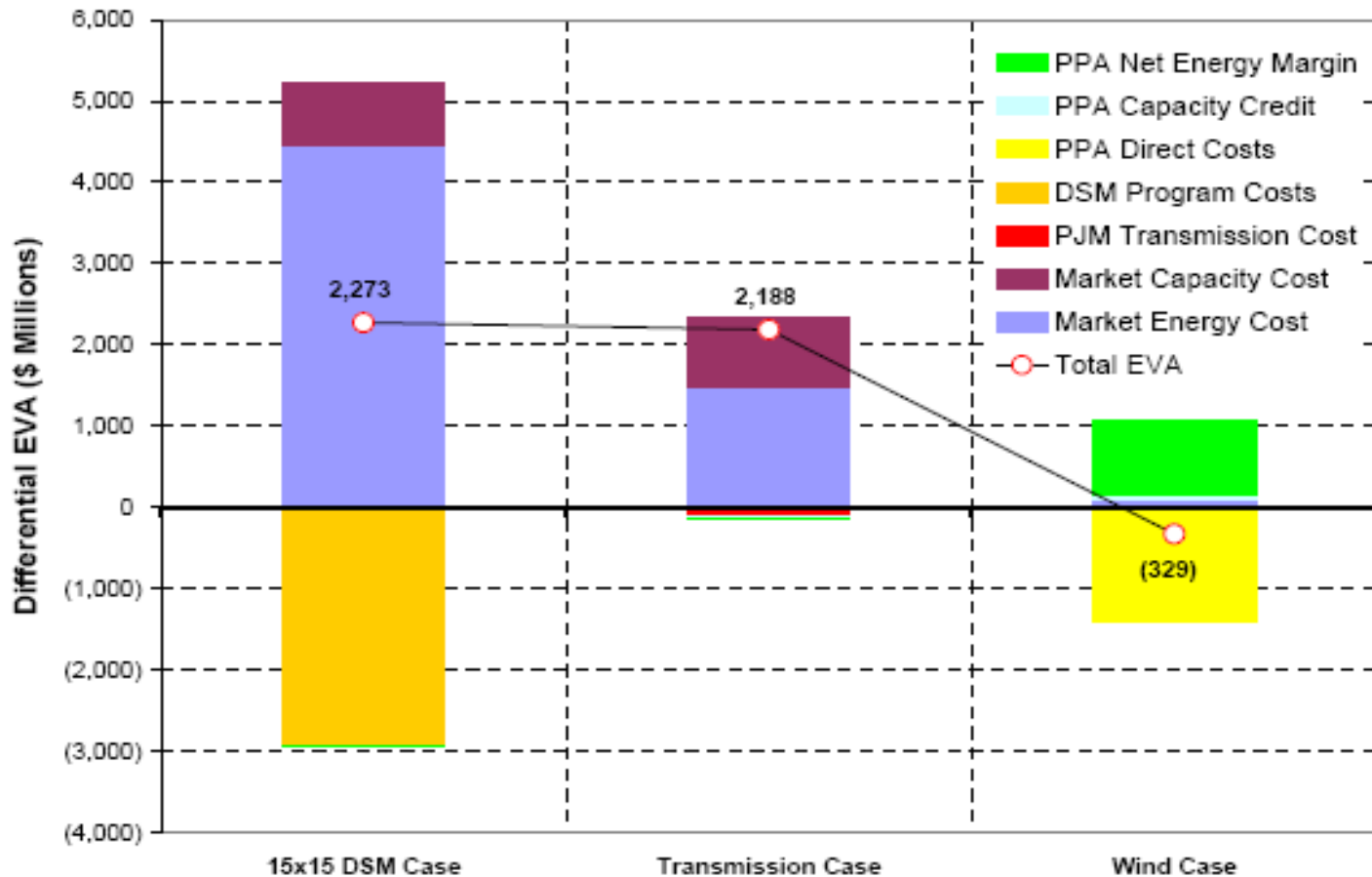
Cumulative EVA



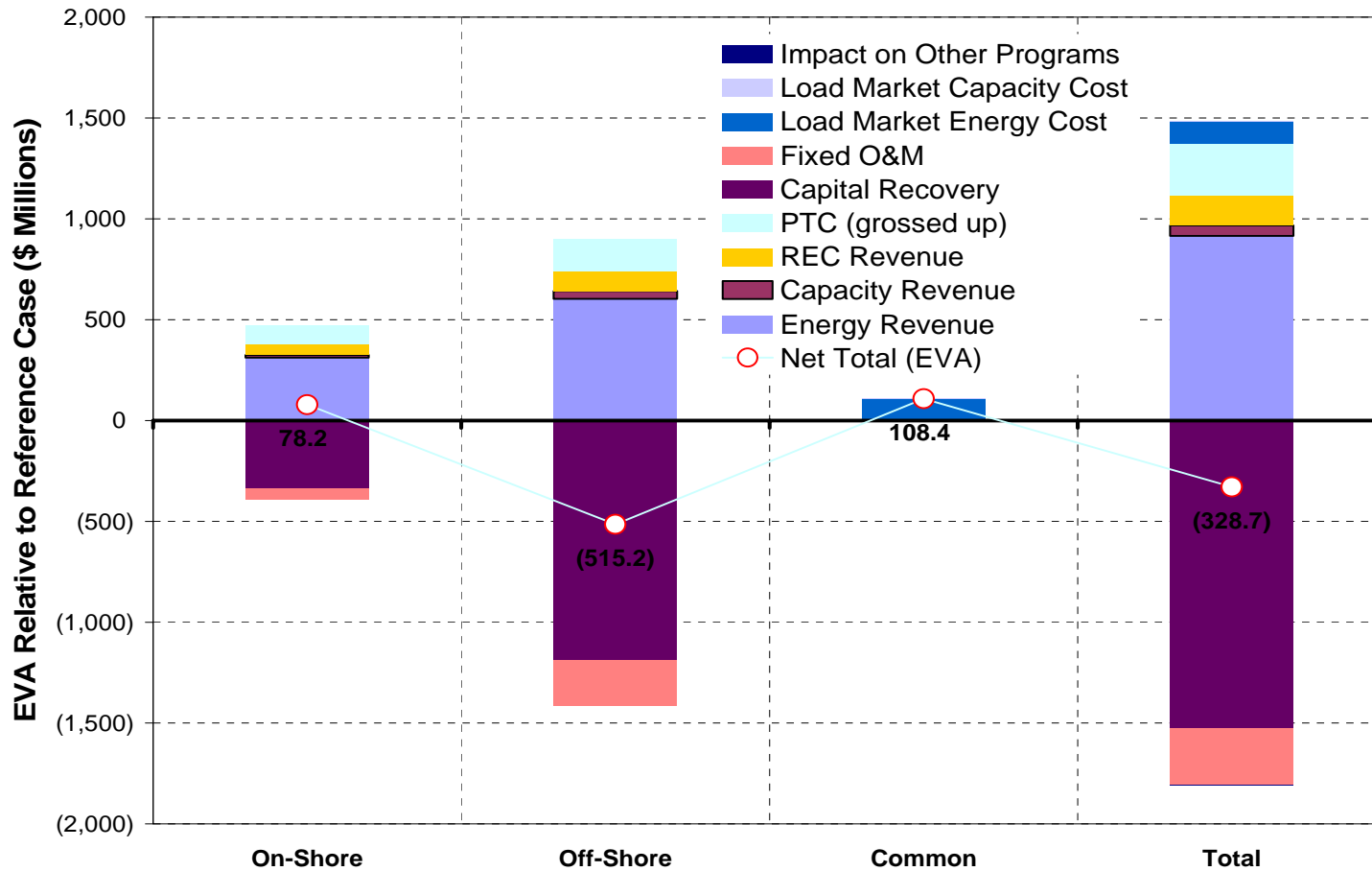
EVA by Component – Generation Case



EVA by Component – Non-Traditional Cases



Breakout of Off-Shore vs. On-Shore Wind



Conclusion and Next Steps - Reregulation

- The prospect for new, material transmission expansion such as the TrAIL or PATH lines is uncertain.
- Maryland must take action on its own to address the reliability issues we face and secure the lowest possible rates for ratepayers.
- In Case No. 9117, several parties – including the Maryland Energy Administration, the Office of the People’s Counsel, and Staff for the PSC – agreed that the State must prepare for the potential shortfall in capacity for the 2011-2012 timeframe **by directing the utilities to develop RFPs for new generation that could be issued by the summer of 2008.**
- As other state PSCs have done, we plan to move forward with this option, as permitted under current law, to address capacity shortfalls and price concerns.

Conclusion and Next Steps – Reregulation (cont'd)

- We plan to implement the long-term contracting strategy over the next 6-9 months.
- Before directing the utilities to issue RFPs for longer term contracts for generation, the PSC will monitor and evaluate the next two RPM auctions for the planning years 2010-2011 and 2011-2012 to determine the shortfall, and model the impacts of additional capacity beyond the minimum required for reliability purposes.
- The RPM auctions take place in January 2008 and May 2008.
- We will devote the intervening time to a more in-depth study of the specific components and contents of the RFP so that we could direct the utilities to issue Requests for Proposals after the May 2008 auction.
- We will seek the input of stakeholders and affected parties.

Conclusion and Next Steps – Reregulation (cont'd)

- ❑ PSC actively pursuing changes at the Federal level (FERC).
- ❑ Currently reviewing 15 x 15 proposals from utilities.
- ❑ Reviewing SOS procurement process, including a change to a managed portfolio approach.

Interim Report of the Maryland Public Service Commission

PART II – Analysis of Stranded Cost Settlements

January 17, 2008

SB 400 (2007)

- The PSC was directed to:
 - Conduct hearings, including the use of any outside experts and consultants, to reevaluate the general regulatory structure, agreements, orders, and other prior actions of the PSC under the 1999 Act, including the determination of and allowance for stranded costs;
 - Provide to residential customers of BGE funds for the mitigation of rate increases resulting from any adjustment, in favor of those customers, to allowances for stranded costs for assets that were transferred from BGE to an affiliate; and
 - Require that any funds for mitigating rates for residential customers under item (2) of this subsection must be in the form of a non-by passable credit on the customers' bill, and may not be recovered subsequently in rates or otherwise.

Key Components of the 1999 BGE Settlement

□ Stranded Cost Determination

- BGE's settlement provided that the company could recover \$528 million (after-tax, present value) transition costs from customers, which would be collected through the line-item on customers' bills.

□ Decommissioning Costs

- The settlement also fixed customers' contributions to Calvert Cliffs' Nuclear Decommissioning Trust Fund at approximately \$18.662 million on an annual basis until June 30, 2006, and on an over-all basis fixed total contributions at \$520 million in 1993 dollars.

□ Price Reduction and Freeze

- All residential customers would receive a total of \$53.8 million annually in rate reduction benefits through June 30, 2004, and most residential customers would receive \$50.2 million annually for two additional years. This translated into a 6.5% rate reduction. Thus, Residential customers received rates that were capped for six years (through June 30, 2006), two years beyond the four-year statutory minimum.



Summary of Key Conclusions

- The liabilities assumed by ratepayers under the BGE settlement were expressed in terms that, although accurate, understated their true magnitude.
- The 1999 Order approving the settlement does not reflect the actual costs of the settlement to ratepayers, nor the huge imbalance of costs and benefits.
- Had the full extent of costs and benefits been properly weighed, we do not believe that the settlement would have been found to be in the public interest.

Summary of Key Findings

- The cost of decommissioning Calvert Cliffs was expressed in 1993 dollars, as “capped” at \$520 million. This ratepayer liability was actually an escalating liability, and was \$778 million in 1999, and could be \$5 billion by 2036. In 1999 the liability was underfunded by \$491 million, and remains underfunded.
- The ratepayer liability for stranded costs of BGE was expressed as \$528 million “after-tax.” To provide BGE with \$528 million “after-tax,” ratepayers paid \$975 million.
- We found no evidence that the true magnitude of these obligations were in the record before the Commission. They are not reflected in the 1999 Settlement, nor the Commission’s Order approving the Settlement.
- Of the \$975 million paid by ratepayers for stranded costs, \$527 million was diverted to fund BGE’s purchase of electricity from its affiliate, Constellation Power Source, to supply BGE’s price-capped SOS service.

Summary of Ratepayer Costs and Benefits as of 1999

Settlement Component	Ratepayer Cost	Ratepayer Benefit
Stranded Costs of BGE Plants	\$975 M	
Unfunded Decommissioning Liability	\$491M	
Rate Relief 1999-2006		\$315.6M
NET RATEPAYER COSTS	\$1.15 B	



Summary of PSC actions

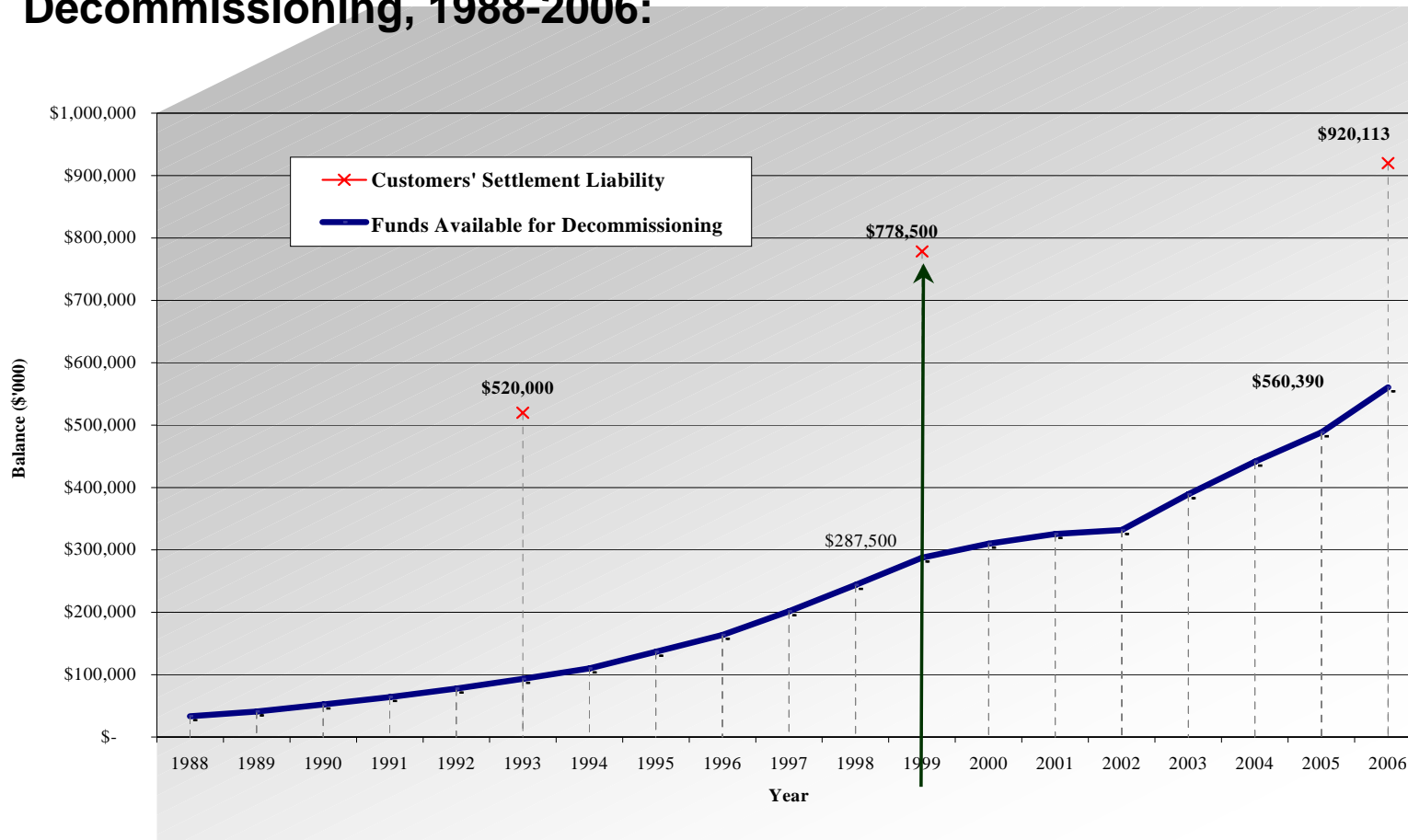
- Investigate the decommissioning reserves (status, amount of unfunded liability, accounting treatment of internal and external reserves, possible violations of 1999 Act or Settlement)
- Investigate the BGE inter-affiliate agreements in which stranded cost payments were diverted to fund rate reductions rather than stranded costs (rationale for agreements, possible violations of 1999 Act or Settlement, sale of electricity at above-market rates)

1. Decommissioning Charges - Findings

- ❑ Although Calvert Cliffs was transferred to Constellation Energy under the 1999 Settlement, ratepayers were saddled with the significant, continuing, and escalating liability associated with those assets - the costs of decommissioning the nuclear plants.
- ❑ The liability was described as being “capped” by the Commission at \$520 million in 1993 dollars. The Commission believed capping the liability in 1993 dollars was advantageous to ratepayers.
- ❑ There was a lack of transparency regarding the actual magnitude of the liability. This liability was subject to inflation based an inflation factor determined by the Nuclear Regulatory Commission. This ratepayer liability was actually \$778 million at the time of the settlement in 1999.
- ❑ The liability was underfunded by \$491 million in 1999. There is no evidence the Commission considered this figure in weighing the Settlement, nor that it was presented to the Commission.
- ❑ The ratepayer liability for decommissioning had grown to \$920 million in 2006.

1. Decommissioning Charges - Findings (cont'd)

Comparison of Ratepayer Liability and Funds available for Decommissioning, 1988-2006:

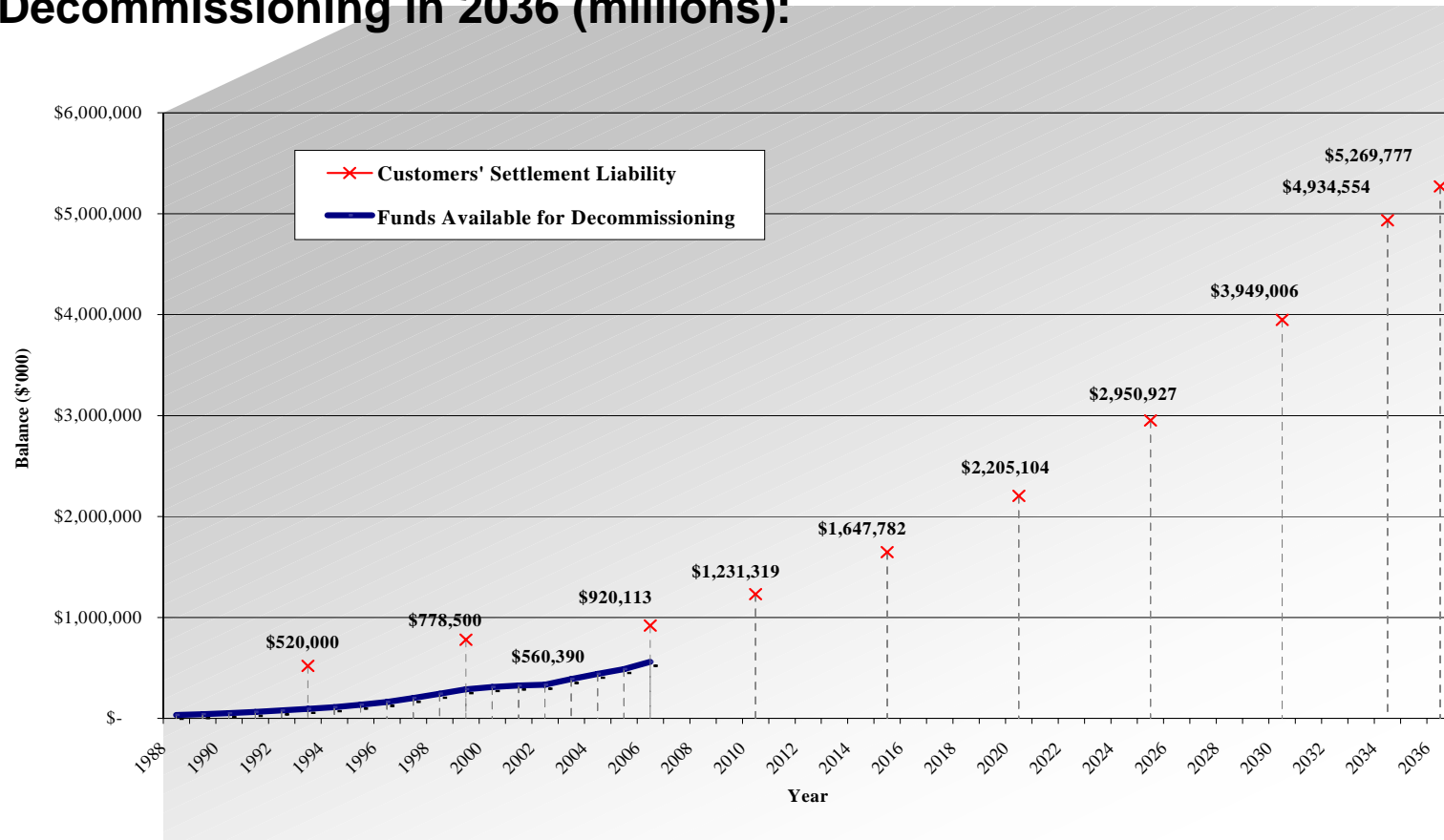


1. Decommissioning Charges – Findings (cont'd)

- It does not appear there was any sensitivity analysis presented to the Commission analyzing the potential growth in the liability, which could rise to as much as \$5 billion when the plants are decommissioned in 2036.
- The current level of underfunding is likely to increase because contributions to the decommissioning funds are insufficient.
- Under SB 1, BGE assumed the payments for decommissioning through 2016 to offset the costs of deferring the 72% increase.
- S.B. 1 exacerbates the level of underfunding by capping BGE's contribution at \$18.6 million a year until 2016. In 2016, ratepayer contributions may need to increase to \$33 million.
- Over \$135 million of decommissioning funds previously contributed by ratepayers are held in an unregulated internal reserve fund by one of BGE's unregulated affiliates, Calvert Cliffs.

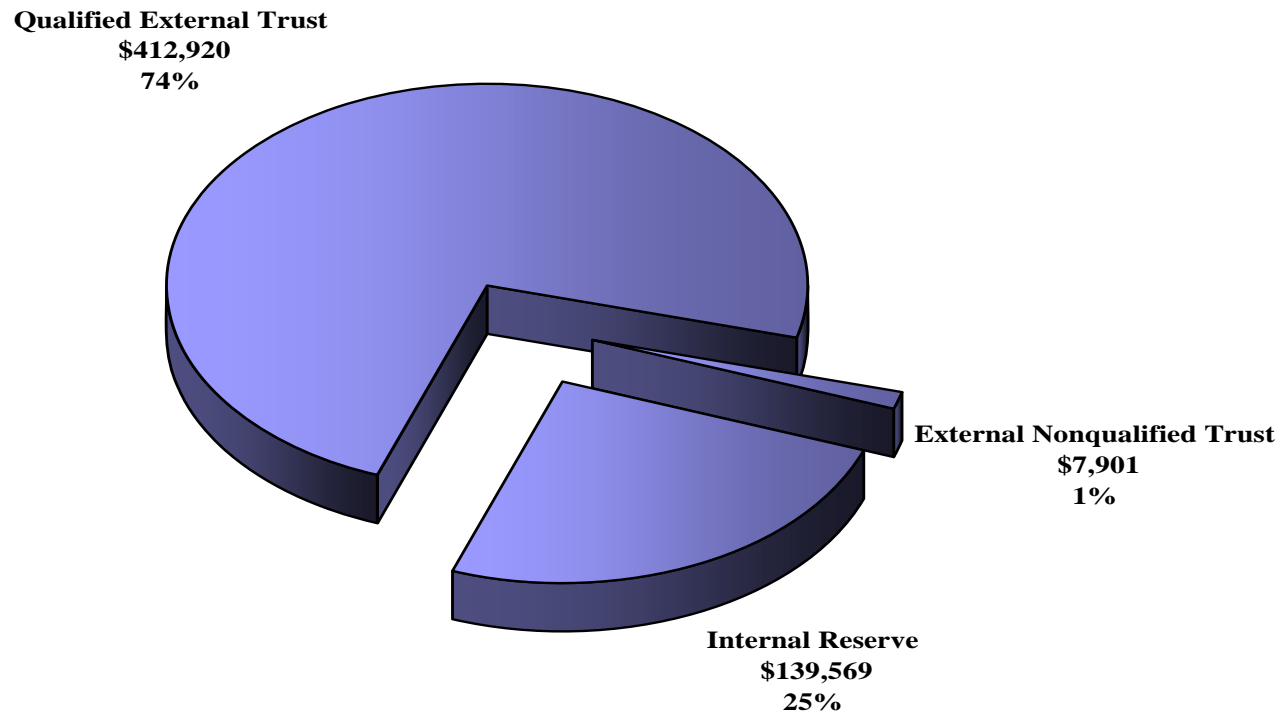
1. Decommissioning Charges – Findings (cont'd)

Illustration of Potential Ratepayer Liability at Time of Decommissioning in 2036 (millions):



1. Decommissioning Charges – Findings (cont'd)

Comparative Status of Decommissioning Funds as of 12/31/06 (thousands)



1. Decommissioning Charges - Recommendation

- **The Commission will initiate proceedings to determine or examine:**
 - Whether the decommissioning funds as administered provide adequate safeguards for ratepayers to ensure the funds are available and earning reasonable returns to pay future decommissioning costs;
 - The current status and extent of the underfunded liability, the annual contributions that would be needed to satisfy the projected liability, including the impact of the provision of Senate Bill 1 on the annual reserve contributions;
 - The rationale for attributing decommissioning funds to an internal reserve;
 - The accounting treatment of the internal reserve, as well as the corporate purposes for which those funds may have been utilized;
 - Whether there has been any violation of the Settlement Agreement, the 1999 Order, or any other law in connection with the maintenance and funding of the decommissioning liability;

1. Decommissioning Charges – Recommendations (cont'd)

- **Consider the introduction of Legislation that would:**
 - Provide clear oversight authority for the PSC over the decommissioning funds and their disposition;
 - If funds have been managed to the disadvantage of ratepayers, authorize the PSC to require BGE or the appropriate BGE affiliate to credit to ratepayers any such amounts to make ratepayers whole;
 - Permit the PSC to require that BGE or the appropriate affiliate increase its contribution to the decommissioning reserve to address the underfunded liability through 2016;
 - In the alternative, reallocate all or a portion of the ratepayers' future liability for funding the decommissioning of Calvert Cliffs based on the failure of the 1999 Settlement to fully and fairly address the magnitude of the unfunded ratepayer liability as part of the broader stranded cost settlement.

2. Stranded Costs – Findings

- The 1999 Settlement Agreement, and 1999 Order approving the agreement repeatedly and consistently refer to the stranded cost obligation of ratepayers as \$528 million “after-tax.”
- Neither the Settlement Agreement nor the 1999 Order disclose that the actual obligation on ratepayer was \$975 million, the amount needed to provide after tax receipts to BGE of \$528 million.
- As we concluded in the case of the decommissioning liability, the manner in which this huge liability was expressed was not transparent, masked its magnitude, and in relation to the benefits to ratepayers, raises questions as to whether the settlement was in the public interest. We found no evidence that the \$975 figure was presented to the 1999 Commission.
- The estimated value of the BGE generating fleet today is \$9.7 billion to \$12.5 billion.

2. Stranded Costs – Findings (cont'd)

- ❑ BGE and two of its affiliates entered into post-settlement agreements that permitted BGE to divert stranded costs collections from ratepayers.
- ❑ Under these agreements, BGE used stranded cost payments from ratepayers to fund losses BGE incurred in purchasing electricity from its affiliate, Constellation Power Source (CPS). In essence, consumers funded their own price caps rather than compensating BGE for stranded costs associated with the asset transfer. CPS bought the electricity from Calvert Cliffs.
- ❑ We saw no evidence this post-Settlement conduct was understood and approved by the settling parties, and this diversion does not appear consistent with the intent of the 1999 Act or the Settlement.
- ❑ There is a possibility that the BGE affiliate that supplied electricity to BGE during the price cap period did so at above-market rates, creating losses for BGE but possibly inflating the sales recorded by the affiliate.

2. Stranded Cost – Findings (cont'd)

CTC Collections (millions)	Reported
CTC revenues collected from ratepayers	\$975.25
CTC revenues applied to offset losses from SOS agreements with affiliate	\$527
Retained by BGE for restructuring costs and gross receipts tax	\$118.4
CTC collections remitted to CCNPP (Calvert Cliffs)	\$329.85

2. Stranded Costs - Recommendations

- **The Commission will initiate proceedings to determine:**
 - The accounting for, and transfer of, the stranded cost payments from BGE to Constellation affiliates.
 - The circumstances surrounding the execution of the various inter-affiliate agreements, including the economic or other rationale for the agreements;
 - Whether Constellation Power Source supplied BGE with electricity at above-market rates, which serve to inflate the losses of BGE;
 - Whether the agreements complied with the terms of the Settlement Agreement and the terms or intent of the 1999 Act.



2. Stranded Costs – Recommendations (cont'd)

- **Consider the introduction of legislation that would:**
 - Clarify the Commission's authority to issue subpoenas to and examine the books, records and personnel of any affiliate of a public utility in the state;
 - Clarify that the PSC may order refunds to ratepayers if it concludes BGE violated the terms and conditions of the 1999 Settlement agreement or the terms and conditions of the 1999 Act;
 - Authorize the PSC to refund to ratepayers any stranded cost collections that it determines were diverted to subsidize rate freezes implemented under the 1999 Act rather than to fund the payment of stranded costs.

3. Valuation of Stranded Costs - Findings

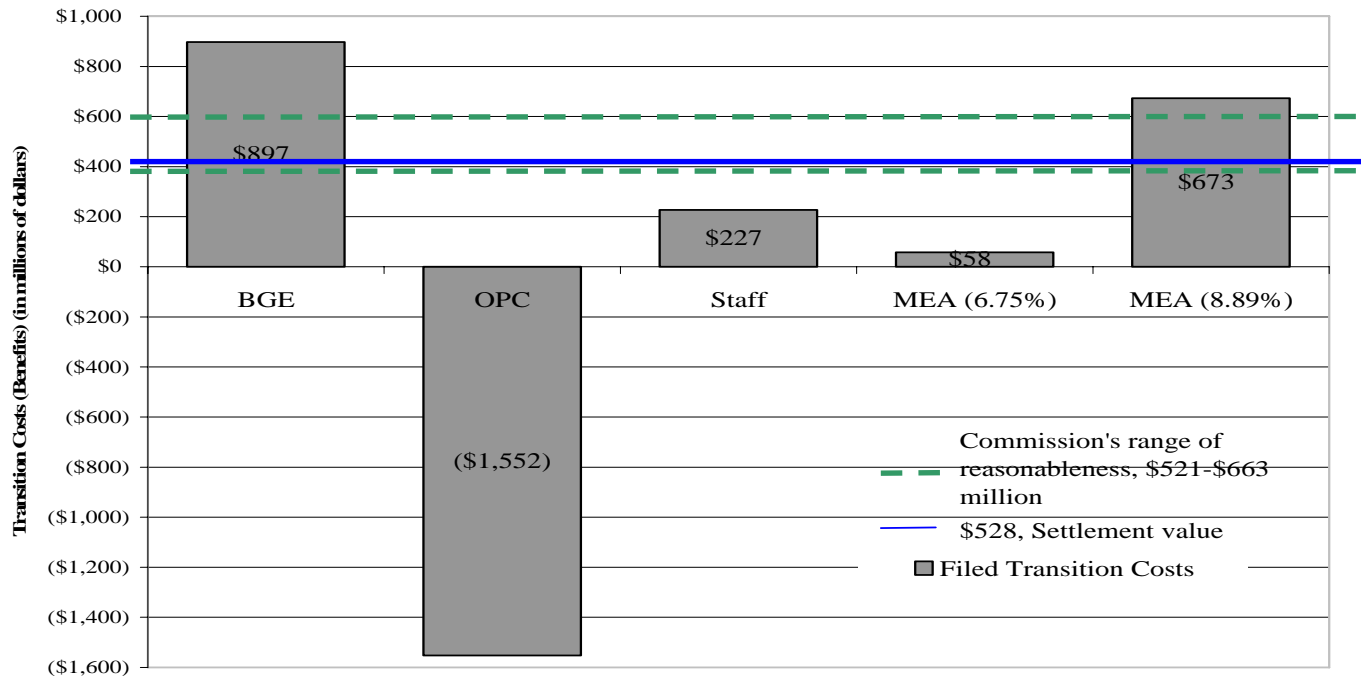
- ❑ By rejecting language that would have required public auctions in order to value generating auctions, the General Assembly limited the ability of the PSC to utilize the most reliable method of valuing assets.
- ❑ This limitation, coupled with the express right granted to utilities to transfer assets to affiliates, and a prohibition on the PSC to prevent such transfers, meant that assets transfers did not occur on an arms-length basis.
- ❑ The “administrative” valuations conducted by the parties were hugely divergent and relied on subjective and speculative predictions about future fuel costs and wholesale prices.
- ❑ Small changes in inputs for the valuation models produced huge swings in stranded cost predictions.
- ❑ A \$1 mw/h change in assumed wholesale electricity costs resulted in a \$200 million swing in stranded cost projections.

3. Valuation of Stranded Costs – Findings (cont'd)

- In proceedings before the Commission prior and during the passage of the 1999 Act, all parties recognized the speculative nature of the valuations, especially as to the BGE nuclear assets.
- Most parties, including BGE itself, urged the Commission to delay final valuation in light of this uncertainty.
- By delaying the valuation of the BGE assets, as many parties (including BGE) proposed, the 1999 Commission most likely could have avoided having ratepayers pay for any stranded costs in connection with BGE's restructuring.

3. Valuation of Stranded Costs - Findings (cont'd)

Comparison of BGE Stranded Cost Estimates by Key Parties Before the PSC:



3. Valuation of Stranded Costs – Findings (cont'd)

- The only adjudicatory hearings held by the Commission on the BGE restructuring proposal were held after the parties reached a settlement.
- Because the only hearings were held after the settlement was reached, the underpinnings of the settlement were not adequately or thoroughly tested in open proceedings.
- Full adjudicatory hearings would have allowed for meaningful independent scrutiny of the assumptions underlying the valuations that would have resulted from public cross-examination of expert witnesses. However, this would have risked dissolving the settlement.