INTERIM REPORT
OF THE
PUBLIC SERVICE COMMISSION OF MARYLAND
TO THE
MARYLAND GENERAL ASSEMBLY

MARYLAND
PUBLIC SERVICE COMMISSION

PART II: STRANDED COSTS, CTC PAYMENTS AND NUCLEAR DECOMMISSIONING

JANUARY 17, 2008

I. INTRODUCTION AND GENERAL CONCLUSIONS

This is the second in a series of Interim Reports by the Maryland Public Service Commission (the "PSC") to the Maryland General Assembly addressing matters identified in Senate Bill 400 ("S.B. 400"),[1] passed during the 2007 Session.[2] This report addresses the impact to ratepayers from the deregulation process defined in the Electric Customer Choice and Competition Act of 1999 ("1999 Act"), especially the terms on which the regulated utility companies divested or transferred their electricity-generating assets to unregulated entities. We focus in particular on Baltimore Gas & Electric Company ("BGE"), which transferred its generation facilities at book value to a non-regulated affiliate in a transaction that, for the reasons we detail below, should never have been found to be in the public interest at the time it was approved.

As in Part I, we ground our conclusions and recommendations on an extremely thorough – and, we believe unprecedented – review of the components of the 1999 Act, the processes of the PSC in implementing the law, and BGE's performance of its stranded costs settlement agreement. This analysis was performed at our direction and under our supervision by the national law firm of Kaye Scholer LLP ("Kaye Scholer"), which the PSC retained through a competitive procurement process. We have posted Kaye Scholer's full report (the "Stranded Costs Report")[3] on the PSC's website, and we invite the General Assembly and the public to review it.[4]

Based on Kaye Scholer's review and analysis of the underlying facts, the Commission has reached the following overall conclusions:

1. <u>The liabilities assumed by ratepayers under the BGE settlement were expressed in terms that, although accurate, understated their true magnitude</u>.[5]

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[1] Ch. 549, Acts 2007.

[2] Part I offered the PSC's analysis of the state of the electricity markets at the end of 2007 and recommendations for "re-regulation" in light of the inadequate supply of electricity in the state and region that serves to increase wholesale (and therefore retail) electric rates, and threatens the reliable supply of electricity in the next 3 to 4 years.

[3] The full title of the Stranded Costs Report is "Analysis of Retail Restructuring in Maryland: Electricity Rates, Stranded Costs From Generation Asset Divestiture, and Decommissioning Funding." BGE was provided a redacted copy of the Stranded Costs Report on Friday, January 11 and permitted until Monday, January 14 to identify any confidentiality concerns and to raise obvious errors of fact. BGE agreed that nothing contained in the redacted Stranded Costs Report raised current confidentiality issues, and thus the Report is being released in full. In addition, BGE identified a small number of issues that Kaye Scholer has addressed in the final version of the Report.

[4] The PSC's website address is www.psc.state.md.us. The Report is available in the "Document Room" section of the website, in the Commission Reports section.

[5] We do not mean to suggest that the PSC intentionally understated ratepayers' obligations – only that the terms of the settlement presented to the PSC by the parties understated ratepayers' obligations and that the documents we have reviewed contain no references or translations to the actual impacts that Kaye Scholer and we have identified here.

This is particularly true with regard to two critically important figures: (a) BGE's "stranded costs," which are characterized as 528 million pre-tax dollars rather than the $975 million ratepayers actually paid, and (b) the cost of decommissioning Calvert Cliffs Units 1 and 2, which is continually expressed as $520 million in 1993 dollars, rather than $778 million (the liability at the time of the 1999 settlement), or $5 billion (the projected actual cost of decommissioning the plants when their licenses expire). We found no evidence that these figures were before the 1999 Commission as it considered whether to approve the settlement.

2. <u>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</u>.

This is particularly true with regard to the nuclear decommissioning liability, which remains with ratepayers even though BGE's affiliate took title to the nuclear plants themselves. Not only do ratepayers hold this obligation, but it was seriously underfunded at the time of the settlement and remains so today – leaving an enormous future funding burden on ratepayers' shoulders that will, in the absence of action by the General Assembly, resume in 2016.

3. <u>Had the full extent of costs and benefits been known and properly weighed, we do not believe that the settlement would have been found to be in the public interest</u>.

BGE's affiliates – the entities comprising the Constellation Energy Group – received *all* of BGE's generation assets, got paid nearly a billion dollars in "stranded cost" payments, and left the biggest outstanding liability from the transaction on the backs of ratepayers. Moreover, our analysis of BGE's and Constellation's treatment of the "stranded costs" payments suggests that BGE bought its power from a Constellation affiliate for higher-than-market prices and used the stranded costs payments to offset losses, not to defray "stranded costs." As such, there are serious questions about whether the premises underlying the settlement were correct, *i.e.*, whether there were stranded costs in the first place, and thus whether ratepayers even received the disproportionately small benefit that was bargained for them.

In simplest terms, the settlement allowed BGE to give its power plants to an affiliate at book value, collect nearly a billion dollars in "stranded costs" payments from ratepayers, and avoid liability for funding the cost of decommissioning its nuclear plants – all in exchange for a rate decrease that, we believe, ratepayers themselves funded. And it left Constellation Energy in the best of all possible worlds: Constellation emerged with the assets and the right to make money selling power in the deregulated market, a stream of money from ratepayers for six years, and the right to have ratepayers fund the single biggest source of potential exposure in the deal. As a result, we believe that the settlement was seriously imbalanced at the time and that BGE and Constellation's performance of the settlement only bolsters that view.

After identifying these problems, we answer the obvious next question: what can and should the PSC and the General Assembly do now to address these issues? *First*, the PSC will initiate two new proceedings – one to investigate BGE's accounting and treatment for the "stranded cost" payments, and a second to investigate Constellation's handling and accounting for the funds ratepayers have contributed for nuclear decommissioning. *Second*, we ask that the General Assembly enact legislation granting the PSC the clear authority to regulate nuclear decommissioning funds and to consider legislation that reallocates the liability for nuclear decommissioning or authorizes the PSC to consider the issue. We also ask the General Assembly to consider legislation granting the PSC authority to order appropriate relief for ratepayers if the PSC finds that BGE and Constellation violated the terms of the settlement or used settlement funds for purposes other than those intended.

We have taken great pains not to render hindsight judgments on the settlement. Instead, we have based our findings and conclusions on information that was or should have been known or disclosed to the PSC at the time of the settlement, or on facts or events which were reasonably foreseeable. Mere changes in circumstances from 1999 that may now render the settlement less desirable today than it appeared in 1999 should not, in our view, serve as the basis for re-opening the rights and liabilities of the parties. Accordingly, we have limited our analysis to the "agreements, orders, and other prior actions of the Public Service Commission under the Electric Customer Choice and Competition Act of 1999," as S.B. 400 directed.

II. SUMMARY OF THE 1999 ACT

The Electric Customer Choice and Competition Act of 1999 (the "1999 Act") sought to restructure or "de-regulate" the Maryland electricity market. The General Assembly identified five principles it sought to achieve:

1. Create customer choice of electricity supply and supply services;

2. Create a competitive retail electricity supply and supply services market;

3. Deregulate the generation, supply and pricing of electricity;

4. Provide economic benefits for all customer classes; and

5. Ensure compliance with state and federal environmental standards.[6]

As we discussed in Interim Report Part I, the 1999 Act removed the market for generating electricity largely from state oversight, leaving the wholesale market that supplies Maryland's needs subject largely to federal regulation. We detailed in that report many of the adverse consequences of that decision, including dysfunctions in the federally regulated wholesale electricity market, high electricity costs, and the impending and serious shortfalls in electricity supply that threaten the reliability of Maryland's power supply in the 2011-2012 timeframe.

Unlike Part I, which examined the consequences of de-regulation, this Part focuses on events surrounding one of the first steps in deregulation – the actual separation of the generating assets from the previously regulated public utilities. Overseeing this process was one of the initial and significant tasks of the 1999 PSC in implementing the 1999 Act.

Although the PSC had initiated proceedings to deregulate the market in 1998 and restructuring proposals had already been submitted to the PSC, the 1999 Act contained a number of key provisions relevant to this first step of restructuring. Those provisions:

- Required, by July 1, 2000, the "functional, operational, structural, or legal separation" of each utility's regulated and unregulated (*i.e.*, generating) assets;

- Authorized the Commission to assess and approve each utility's restructuring plan and to oversee the transition process;

- Authorized utilities to recover two types of "prudently incurred" and "verifiable" net "transition" costs associated with the separation of the generating assets from the regulated utility: (1) stranded costs of generation assets that the utility would have traditionally recovered through rate-of-return regulation, and (2) costs associated with the restructuring process;

- Authorized the transfer of generating assets among affiliates as part of the separation of regulated and unregulated assets – such as the transfer from BGE to its affiliate, Constellation Energy;

- Generally removed from the Commission the traditional authority to regulate the utilities' generation, sale, or supply of electricity;

- Implemented price protections for customers in the form of rate caps and reductions; and

[6] Maryland Code Ann., Public Utility Companies Art. § 7-504.

- Implemented, over time, the ability of customers to choose alternative suppliers of electricity other than their utility – *i.e.*, customer choice.

The 1999 Act directed the PSC to determine whether the entities taking the generation assets would take them with "stranded costs," also defined as "transition costs." Stranded costs are the value of potential losses an electric utility incurs as a result of transferring assets from a rate-regulated structure to one in which the assets operate in an unregulated competitive market.[7] In a regulated environment, utilities are granted an agreed-upon rate of return on their assets pursuant to regulatory proceedings. As a general matter, regulated utilities are entitled to recover their costs, including investments in its generating plants, through the collection of rates from the public that are approved by the regulator. When generating assets are transferred to an unregulated environment, the competitive market provides revenues to the plants in the form of wholesale electricity sales. Any expenses, including investments in assets, associated with the assets must be met through such sales.

The basic test for measuring stranded costs compares the amount of a utility's generation assets in a regulated regime against their value in a competitive market. The comparison is made by taking the difference between the asset's "regulated" value or the "book value" and its fair market value. The determination of an asset's fair market value is central to the determination of the stranded costs associated with generating assets**.**

III. SUMMARY OF BGE SETTLEMENT

BGE initially filed a restructuring plan in 1998, prior to the passage of the 1999 Act. The Stranded Costs Report outlines in detail the filings as submitted and modified and the positions of the parties as expressed in the written submissions. As that Report concludes in detail, and as we discuss briefly below, there were widely divergent views on the stranded costs or benefits of the BGE assets.

Following the passage of the 1999 Act, the PSC issued an order requesting the filing of a settlement on the BGE application by June 15, 1999. The Commission approved a broad settlement of BGE's restructuring proposal on November 10, 1999. But the PSC held *no* adjudicatory hearings on the extensive pre-filed stranded costs testimony. The only hearings were held *after* the settlement was reached and for the purpose of considering (and ultimately blessing) the settlement.

Three components of the settlement proved especially relevant, particularly as we went on to examine BGE's performance of the settlement after its approval:

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[7] There could also have been stranded *benefits* associated with these generation assets if, for any number of reasons, the asset's book value exceeded its market value. As detailed in the Stranded Costs Report, the Office of People's Counsel's witnesses submitted testimony that BGE's generation assets would strand benefits with an affiliate if transferred at book value, although the ultimate settlement fixed a stranded cost figure instead. *See* Stranded Costs Report at 37-40.

A. Stranded Cost Determination

BGE's settlement provided that the company could recover $528 million – an after-tax present value figure – in transition costs from customers, which would be collected through a line-item on customers' bills. As discussed below, the parties to the PSC proceedings held widely divergent opinions on whether there were stranded costs associated with BGE's generating assets, and the amount of those costs (or benefits). The ultimate number of $528 million was not, according to the one set of hearings the 1999 Commission held on the matter, based on any particular set of assumptions – it was simply a compromise figure as part of the broader settlement.

B. Decommissioning Funding

Although the settlement allowed BGE to transfer its nuclear power plants to an affiliate, it also provided that *ratepayers* would remain liable for the cost of decommissioning the Calvert Cliffs units and fixed customers' annual contributions to Calvert Cliffs' Nuclear Decommissioning Trust Fund at approximately $18.662 million until June 30, 2006, and on an overall basis fixed total fund contributions at $520 million – *measured in 1993 dollars*. According to the settlement, ratepayers would retain responsibility to fund the $520 million, adjusted by the Nuclear Regulatory Commission's ("NRC's") published adjustment factor, until BGE (and now Constellation) actually decommissions the plants. At the time, the licenses expired in 2014 and 2016, but have since been extended until 2034 and 2036, and the decommissioning itself could occur much later.

Under the settlement, BGE continues to collect the costs of decommissioning from ratepayers, and transfer these collections, along with existing funds already collected, to Constellation, which maintains the decommissioning funds. As we discuss below, however, it appears that that the facts surrounding this portion of the settlement were not adequately disclosed or considered in relation to the other portions of the settlement, and it appears that the Commission did not appreciate the scope of the remaining liability or the extent to which the Fund was underfunded at the time of the settlement.

C. The Price Reduction and Freeze

Under the settlement, residential customers received a total of $53.8 million annually in rate reduction benefits through June 30, 2004, and most residential customers received $50.2 million annually for two additional years. This translated into a 6.5% rate reduction allocated between generation and distribution rates. Thus, Residential customers received rates that were capped for six years (through June 30, 2006), two years beyond the four-year statutory minimum. Nonresidential customer classes received capped rated for two to four years.

The 1999 Act permitted the PSC to take into account "net transition costs or benefits" in determining the amount and duration of any price freeze or reduction, suggesting that a global settlement of the type approved by the 1999 Commission, in which the various components of the settlement were interdependent, was expressly contemplated by the General Assembly. In fact, the terms of the 1999 settlement, as presented and approved by the 1999 Commission were non-severable.

IV. FINDINGS, CONCLUSIONS, AND RECOMMENDATIONS

The transactions memorialized in the BGE settlement and its aftermath are complex, and it is no accident that the Stranded Costs Report requires 100 single-spaced pages to review and analyze them. But once unpacked, and viewed solely in terms of the information that was or should have been known at the time, we cannot escape the conclusion that the settlement appears to have been seriously imbalanced in favor of BGE and Constellation and against Maryland ratepayers:

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	**$1.15B**	

We discuss each of the three critical settlement provisions in turn, offering our findings and recommendations for further action as to each.

A. DECOMMISSIONING LIABILITY

Discussion

As noted above, the BGE settlement left the financial obligation to fund the decommissioning of the two nuclear generating units at the Calvert Cliffs site with ratepayers, even though the asset to which the liability related would be transferred to Constellation. Kaye Scholer summarizes the obligations as follows:

> The settlement freezes the *total contribution* to the cost of nuclear decommissioning to be paid by customers at $520 million **in 1993 dollars**. Thus, BGE – or, more accurately, its unregulated affiliate – is "responsible for any actual decommissioning costs in excess of the $520 million in 1993 dollars" and "retain[s] any cost savings if actual

> decommissioning costs are less than the $520 million in 1993 dollars, escalated per the NRC formula." …. If the trust funds accumulate "at the time of decommissioning" an amount "in excess of the $520 million (1993 dollars), escalated per the NRC formula," BGE must refund the balance to customers. ..… Likewise, the settlement entitles BGE to "recover any deficiency" between the balance in the nuclear decommissioning trust fund and the $520 million (1993 dollars), escalated per the NRC formula.[8]

A review of the record from 1999, including the Order approving the settlement and the single set of hearings held by the 1999 Commission on the Settlement, show that decommissioning costs for Calvert Cliffs assumed by ratepayers were consistently expressed as $520 in 1993 dollars. The manner in which the liability was addressed in the settlement before the PSC, however, served to distort and mask the true scope of the liability that ratepayers retained under the Settlement.

As the Stranded Costs Report explains, the decommissioning liability in current dollars at the time of the settlement in 1999 was $778.5 million, the result of applying the NRC inflation factor to the $520 million from 1993 to 1999 as the settlement required.[9] The Commission's Order approving the settlement does not recognize this fact. Rather, the Commission order refers to the decommissioning liability as being "capped," and references this "cap" as beneficial to ratepayers. We find no evidence that the Commission fully considered the impact of the NRC inflation factor on the ultimate liability to which ratepayers would be exposed. The testimony in support of the settlement contained no modeling or projections, assuming variations in the NRC inflation rate that would have informed the 1999 Commission on this point.

More importantly, however, the Stranded Costs Report raised another alarming fact – that the ratepayer liability was, and is, vastly underfunded. In 1999, while ratepayer liability had risen to $778.5 million in 1999, actual funds available for decommission that had been collected from ratepayers through that date were only $287.5 million, a deficiency of $491 million.[10] The Order approving the Settlement simply does not address, or even acknowledge, the unfunded liability of almost one-half billion dollars embedded in this portion of the Settlement, and we discovered no disclosure of the true figures to the Commission in the record at the time. In balancing the costs and benefits of the various components of the Settlement, the Order is silent regarding this crucial point.

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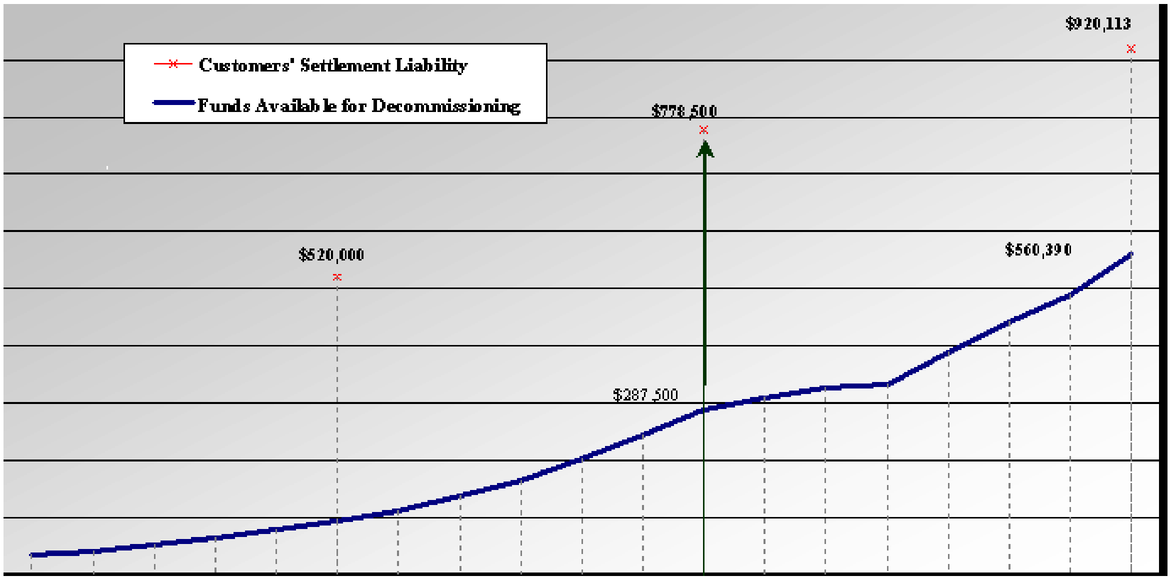
[8] Stranded Costs Report at 84 (italics in original, underlining and bold added, citations omitted).
[9] *Id*. at 86.
[10] *Id*. at 86-87

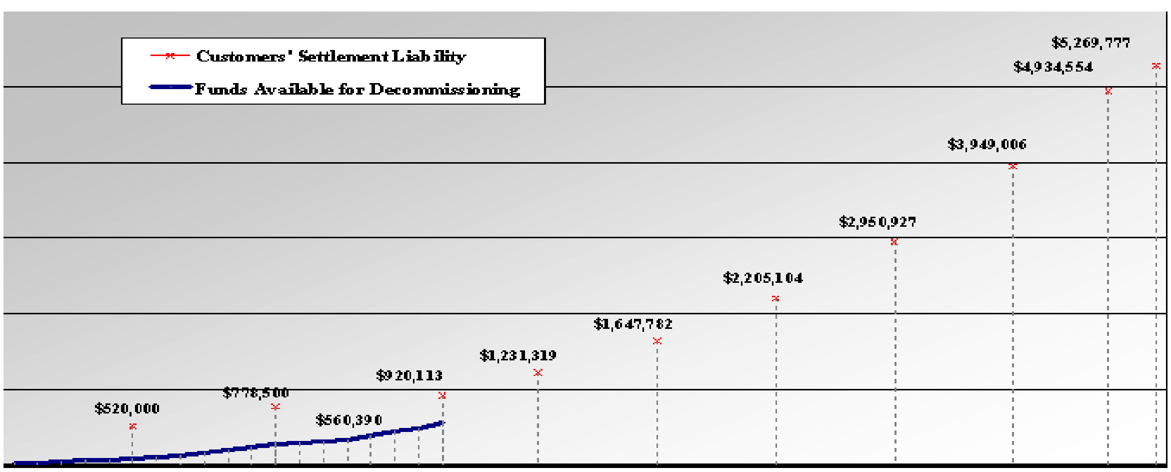
The following chart from the Stranded Costs Report illustrates through 2006 the escalating liability as well as the scope of the unfunded portion of the liability:[11]

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



Based on the application of the NRC inflation factor and other escalators approved in the settlement, by 2006, the co-called "capped" liability had risen to $920 million in 2006 dollars. And data obtained from BGE shows that when the plants are finally decommissioned in 2034 and 2036, ratepayer liability could exceed $5 billion:[12]

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



[11] *See id*. at 89.

[12] *See id*. at 91. And decommissioning costs could continue to increase after these license expiration dates if decommissioning is deferred, if the license expiration dates are again extended, or if a third nuclear power plant is constructed at the Calvert Cliffs site.

The liability is underfunded for several reasons. *First,* as illustrated in the above chart, collections were short in 1993 and the shortfall persisted through 1999. Ratepayer contributions were not sufficient to make up the shortfall during that period. *Second*, the 1999 settlement limited the overall liability at $520 million in 1993 dollars, but also capped ratepayer contributions on a yearly basis to $18.6 million for the 1999-2006 period. This annual cap perpetuated the shortfall through 2006. As the Stranded Costs report determined, in 2006 when the capped contribution level expired, BGE filed data showing that ratepayer contributions would need to increase to about $25 million annually in order to address the chronic level of underfunding. But at the suggestion of BGE, and for reasons that the record does not reveal, the PSC declined in 2006 to increase the amount of ratepayer contributions, opting to maintaining the payments at the $18 million level.

The shortfall is exacerbated by Senate Bill 1 because of the manner in which the General Assembly suspended the obligation of ratepayers to fund the decommissioning liability. In the bill, the General Assembly required BGE to credit residential ratepayers an amount equal to the $18.6 million normally collected from all ratepayers to fund the decommissioning reserves. BGE continues to fund the decommissioning reserves for the 10-year period. However, the General Assembly also prohibited the PSC from raising the amount of the contributions beyond the $18.6 level, and also did not alter the ultimate liability of ratepayers. The net effect of these provisions is to insulate BGE from directives to fund the reserves fully, and since the current level is inadequate, after 2016, when ratepayers would resume payment to BGE, annual contributions would need to almost double from their former level, to over $33 million.[13]

One final area of concern relates to the structure of the decommissioning reserves themselves. In the 1980's, BGE established an internal reserve fund for decommissioning collections. Later, in response to an NRC directive, an external trust fund was established, and the NRC disallowed the use of an internal reserve fund. However, BGE continued to make nominal contributions to the internal fund as well as external funds. In its restructuring filings in 1999, BGE represented that it would transfer the decommissioning trust fund and internal reserve to Calvert Cliffs and that "will provide the assurance of decommissioning funding required by the Nuclear Regulatory Commission."[14]

At the time of the asset transfer in 2000, BGE reported that it transferred to Calvert Cliffs all of its collected and accrued decommissioning funds – $303.6 million (as of July 1, 2000). This transfer consisted of two types of reserves. The first were funds reported separately on its Balance Sheet as external qualified or nonqualified decommissioning funds. This amount was $230.3 million. The second set of funds consisted of $73.4 million designated for decommissioning but maintained in BGE's "internal reserve." According to Kaye Scholer, the $73.4 million of internal reserve funds are not maintained

[13] *Id*. at 87.
[14] *Id*. at 83-84.

in a segregated account like the external funds, and therefore are not reported separately on BGE's balance sheet.[15]

As Kaye Scholer concludes, the settlement provides no protections for the internal reserve that BGE transferred to Calvert Cliffs in 2000, which have now been valued at more than $135 million. This internal reserve is not a separate account like the external reserves and therefore these ratepayer dollars could be used for other purposes. In fact, as Kaye Scholer determined, Constellation does not report the internal reserve as funds available for decommissioning in financial reports subject to federal securities law and regulation.

Although the 1999 Order reports that proponents of the decommissioning provision supported these transfer provisions as a "protection of customers against potentially substantial nuclear decommissioning costs," nothing in the Settlement Agreement or the Commission's Order required any of the funds collected from ratepayers to be placed in a Trust Fund or specified what earnings those funds should earn. Kaye Scholer concludes, and we agree, that there is inadequate regulatory oversight of the decommissioning funds. In our view, the 1999 Order fails to provide safeguards for the use and preservation of the contributions by ratepayers which are being transferred and held by an unregulated entity – Constellation.

<u>Findings</u>

1. **While the BGE nuclear assets at Calvert Cliffs were 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.**

2. **Although the amount of that liability was described as being "capped" by the Commission at $520 million in 1993 dollars, there was a lack of transparency regarding the actual magnitude of the liability, and the issue received little attention and analysis by the 1999 Commission. This ratepayer liability was actually $778 million at the time of the settlement in 1999, and moreover, was underfunded by $491 million. We found no evidence that these figures were before the 1999 Commission as it considered whether to approve the settlement. Given the actual magnitude of this liability in relation to the benefits received by ratepayers in the settlement, it does not appear that the Settlement was in the public interest.**

3. **The ratepayer liability for decommissioning had grown to $920 million in 2006, and could rise to as much as $5 billion when the plants are decommissioned in 2036.**

[15] *Id*. at 84.

4. **The current level of underfunding is likely to increase under current circumstances because contributions to the decommissioning funds are insufficient. Put another way, Senate Bill 1's tradeoffs exacerbate the level of underfunding.**

5. **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. The reserves are not adequately regulated.**

<u>Recommendations</u>

1. **The Commission will initiate proceedings to determine or examine:**

   a. **Whether the funds as currently administered provide adequate safeguards and protections to ensure they are available to pay future decommissioning costs, including whether the external decommissioning trusts are irrevocable trusts and "contributions to the trusts and earnings thereon are reserved for decommissioning the site in the future and for on-going costs of administering the trust" as asserted by BGE, and whether BGE or Constellation is appropriately maximizing earnings on those funds;**

   b. **The rationale for depositing decommissioning funds in an internal reserve rather than external reserve, including whether there may be a tax-related rationale for placing collected funds in internal reserves;**

   c. **The accounting treatment of the internal reserve, as well as the corporate purposes for which those funds may have been utilized, which will include examination of decommissioning assurance reports filed with the NRC and other communications between NRC and Constellation related to the decommissioning funds, and copies of tax filings for the external trust; and**

   d. **The current status and extent of the underfunded liability and 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.**

2. **The Governor or the General Assembly should consider the introduction of Legislation that would:**

   a. **Provide clear oversight authority of the PSC over the decommissioning funds and their disposition, including the authority to require the funds be held in a form determined by the Commission that best protects the interests of ratepayers, and to require (1) updates on the**

external funds' performance, (2) prior notification at any time Constellation or any affiliate may take steps that might adversely affect customers' contributions to the decommissioning reserves, and (3) audits of the internal reserve funds, including sufficient information to determine the value of those funds to Constellation;

b. **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;**

c. **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; and**

d. **In the alternative, reallocate all or a portion of the ratepayers' future liability for funding the decommissioning of Calvert Cliffs to the owners of Calvert Cliffs based on the public interest and the failure of the 1999 Settlement to disclose fully and fairly the magnitude of the ratepayer liability as part of the broader stranded cost settlement.**

B. USE OF STRANDED COST SETTLEMENT PROCEEDS BY BGE AND ITS AFFILIATES

Discussion

The Kaye Scholer analysis highlights a second major area of concern regarding the 1999 Settlement, the disposition of the funds received by BGE from ratepayers that represented the payment of the stranded costs. Kaye Scholer summarized the provisions relating to the collection of funds as follows:

> BGE's settlement authorized the company to collect transition costs of $528 million (after-tax), which was expressed on a present-value basis as of January 1, 2000. In other words, BGE was entitled to collect total revenues equivalent to the present value of $528 million (in January 1, 2000 dollars) after it paid income taxes (assumed to be 35%) and a gross receipts tax (about two percent) on collections. ***In total, BGE reports that it actually collected about $975 million from ratepayers during the six-year rate freeze period.***[16]

As an initial matter, we note with considerable concern that as with the decommissioning costs, the stranded cost figures in the settlement are expressed in a way that masks the true extent of the liability assumed by the ratepayers. In this case, the 1999 Order refers only to the obligation as $528 million "after-tax," without acknowledging or

[16] *Id*. at 57 (emphasis added, footnotes and citations omitted).

recognizing that taxes and inflation yield an actual liability for ratepayers of almost one billion dollars. It is not clear that in balancing the costs and benefits to ratepayers, the 1999 PSC considered the payments being made by ratepayers rather than the ultimate after-tax funds received by BGE. And had the liability been defined in real-dollar terms, we doubt that the settlement would have been found to be in the public interest, particularly when coupled with the unfunded nuclear decommissioning liability.

We also are troubled by the way in which the stranded cost payments were used by BGE and Constellation. At our request, Kaye Scholer examined the post-settlement collection of these stranded cost payments, which are referred to as customer transition charge collections or "CTC" payments. Kaye Scholer's analysis began by identifying a post-settlement transaction between BGE and Calvert Cliffs, which in our view altered the use of the stranded cost payments compared to the purpose contemplated in the 1999 Act. The facts of the post-settlement agreement are as follows:

> On June 14, 2000, BGE and Calvert Cliffs executed a Competitive Transition Charge Collection Agent Agreement ("CTCCA Agreement"), giving Calvert Cliffs 90% of CTC collections. (CTC Collection Agent Agreement). BGE retained the remaining share of collections, presumably to cover BGE's out-of-pocket costs related to restructuring. This agreement made BGE an agent for its affiliate [Calvert Cliffs] to collect CTCs from its electric customers and remit 90% of the proceeds to Calvert Cliffs net of (1) a "Negative SOS Offset," *i.e.*, losses that BGE incurred from contracts with SOS suppliers during the price freeze period and (2) "the amount of any tax (including but not limited to federal and state income taxes or public service company franchise taxes) that may be imposed on BGE with respect to the 90% of the CTC revenue, net of any tax benefit provided by the SOS Offset.[17]

In short, this agreement authorized BGE to divert CTC collections from ratepayers to fund any losses it incurred in supplying electricity to customers during the rate freeze period rather than to pay stranded costs associated with the Calvert Cliffs plants.

BGE entered into a second inter-affiliate agreement at the same time as the CTC collection agreement, this time with Constellation Power Source, Inc. ("CPSI"), in order to supply the electricity it needed to serve Standard Offer Service customers through June 2003.[18] This inter-affiliate agreement was not prohibited in the Settlement because the language left entirely to BGE's discretion the manner in which it would procure electricity to supply service through July 2003. The settlement requires that after 2003, BGE obtain

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[17] *Id*. at 60-61.
[18] *Id*. at 61.

its electricity supply through a competitive bid process, but before then it was free to buy from whomever it wanted – and, it seems, at whatever rate.

A third inter-affiliate agreement, this time between Calvert Cliffs and Constellation Power Source, was a three-year power purchase agreement for marketing and wholesale sales of Calvert Cliffs' net output.[19] Constellation's nuclear application to the NRC for transfer and amendment of Calvert Cliffs' licenses references this contract.

The net effect of the three agreements indicates to us that BGE used the stranded cost payments from the Settlement to fund the rate decrease, *not* to defray stranded costs – which begs the question of whether BGE's assets had stranded costs in the first place. *First*, BGE agreed to buy from its affiliate, Constellation Power Source, the electricity it needed to supply price-frozen rates from 2000-2003. *Second*, if BGE lost money on these inter-affiliate purchases – *i.e.*, if Constellation Power Source charged its affiliate, BGE, more than what BGE would collect from its customers – BGE could apply the stranded costs proceeds it collects from ratepayers to fund those losses, and pass on to Calvert Cliffs what is left, leaving Calvert Cliffs with less than the Settlement contemplated. *Third*, Constellation Power Source will be the marketing and sales arm of Calvert Cliffs, suggesting that Calvert Cliffs could in fact supply the power BGE agreed to buy from Constellation Power Source.

As Kaye Scholer summarizes in its report, BGE ended up diverting the majority of funds to Constellation Power Source rather than Calvert Cliffs due to major losses it incurred in buying power from its affiliate:

> BGE collected about $975.25 million of CTC revenues from ratepayers during the 2000–2006 period. These collections reflect the settlement's $528 million after-tax transition costs expressed on a present value basis as of January 1, 2000. … BGE incurred about $520 million in SOS losses before July 2003, under its contract with its affiliate. In contrast, BGE incurred only about $7 million in losses during the three year period, July 2003 through July 2006, when it was required to obtain SOS supply through a "competitive bidding process." … [Calvert Cliffs] received no CTC payments through 2003 but received four payments totaling $329.85 million from 2004 through 2006.[20]

The following chart summarizes the use of the stranded cost funds:

[19] *Id*. at 61-62.
[20] *Id*. at 62.

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**

We agree that nothing in the settlement agreement, the 1999 Order by the Commission approving the settlement, nor the brief public hearings held by the Commission on the subject raised the possibility that ratepayer contributions designed ostensibly to compensate Calvert Cliffs for stranded costs would instead be utilized by BGE to fund the rate freeze. Kaye Scholer summarized the concern with this agreement:

> Under the logic of the Settlement Agreement, BGE transferred that facility to [Calvert Cliffs] at book value when those assets were actually worth less, and the stranded costs collected from ratepayers were intended to make up that deficit. Instead of the portion of CTC collections attributable to stranded costs going to [Calvert Cliffs], however, more than half – $527 million – went to compensate BGE for its "losses" incurred from SOS contract payments to its affiliate that exceeded SOS rates. ***Thus, the CTC collections actually subsidized the first three years of the price-freeze period by eliminating any BGE losses. There is no evidence that the Commission or the other settling parties knew or expected that ratepayers' stranded costs payments would be used for this purpose***.[21]

In our view, the greatest benefit of the settlement to ratepayers, the benefit that would offset the hundreds of millions of dollars paid in stranded costs, was the extended rate caps, or price freeze. It appears from these agreements, however, that Constellation did not need compensation for stranded costs, and that ratepayers funded their own rate freeze when BGE used over $500 million in CTC collections to offset the cost of purchasing power from its own affiliate.

This is not the only concern Kaye Scholer identified. The Stranded Costs Report notes that there is evidence to suggest that the losses sustained by BGE in sales from its affiliate were based on a non-economic transaction that served to inflate what BGE paid for electricity during the 2000-2003 period, before it procured the electricity in a competitive process:

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[21] *Id*. at 63 (emphasis added).

> Constellation's report to the NRC on the Calvert Cliffs' license transfer indicated that its rates charged to [Constellation Power Source's] remained essentially steady throughout the price-freeze period. In contrast, [Constellation Power Source's] rates charged to BGE for SOS supply were significantly higher before July 2003 than they were afterward, when the settlement required BGE to seek competitive suppliers for standard offer service… data suggest that the pre-2003, non-competitive contract between BGE and CPSI included a markup above the market price. Thus, because BGE used almost all of its CTC collections before July 2003 to pay for what appear to have been above-market SOS prices before July 2003, those revenues may have actually subsidized CPSI's energy trading and marketing operations.[22]

BGE's testimony in last year's rate case only bolsters this view. In Commission Case No. 1999, in support of its request to increase rates, BGE submitted testimony describing significant increases in fuel prices between 1999 and 2005.[23] But as the Stranded Costs Report demonstrates, BGE paid $45 MWh for power in 2001, when the settlement gave BGE discretion to determine how to obtain power, but only $43 MWh in 2005, after BGE was required to (and did) acquire power through the PSC's competitive bidding process.[24] This suggests to us that the 2001 prices were inflated, and thus that the losses BGE incurred during this time period resulted from an above-market power purchase contract with its affiliate rather than the rate reduction itself.

In light of the possibility that one of BGE's affiliates sold electricity to BGE at above-market prices, Kaye Scholer recommends further proceedings to determine whether the action of the parties to these agreements "complied with the spirit and letter of the 1999 Act and the settlement agreement." We agree with this recommendation, but believe that the General Assembly should take additional steps as well.

<u>Findings</u>

1. **Although the 1999 Settlement Agreement, and 1999 Order approving the Agreement repeatedly and consistently refer to the stranded cost obligation of ratepayers as $528 million, neither the Agreement nor the Order discloses that the actual obligation on ratepayers was $975 million, the amount needed to provide after-tax, inflation-adjusted receipts to BGE of $528 million;**

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[22] *Id*. at 64.
[23] *See* Direct Testimony of Jonathan A. Lesser, Ph.D, Case No. 9099 (filed March 30, 2007), at 15-19.
[24] *See* Stranded Costs Report at 64, Table 13.

2. As we concluded with regard to the decommissioning liability, the less-than-transparent manner in which this huge liability was expressed masked its magnitude, and in relation to the benefits to ratepayers, supports our belief that the settlement would not have been found to be in the public interest had the terms been properly disclosed;

3. BGE and two of its affiliates entered into post-settlement agreements that permitted BGE to divert stranded costs collections from ratepayers to fund BGE's costs in purchasing electricity from its affiliate under the price caps. We saw no evidence that this was understood and approved by the settling parties, and this diversion does not appear consistent with the intent of the 1999 Act; and

4. 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 and possibly inflating the sales recorded by the affiliate.

Recommendations

1. The Commission will initiate proceedings to determine:

(a) The circumstances surrounding the execution of the various inter-affiliate agreements, including the economic or other rationale for the agreements;

(b) Whether Constellation Power Source supplied BGE with electricity at above market rates, which serve to inflate the losses of BGE; and

(c) Whether the agreements complied with the terms of the Settlement Agreement and the terms or intent of the 1999 Act and other law or regulations.

2. The General Assembly should consider the introduction of legislation that would:

(a) Clarify the Commission's authority to issue subpoenas to and examine the books and records and personnel of any affiliate of an public utility in the state;

(b) Clarify that the PSC may order refunds to ratepayers if it concludes BGE violated the terms and conditions of the 1999 Settlement or the terms and conditions of the 1999 Act; and

(c) 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 stranded costs.

C. DETERMINATION OF THE $528 MILLION IN STRANDED COSTS

Discussion

The methods used to measure stranded costs were administrative determinations (*i.e.*, discounted cash flow or "DCF" calculations), asset sales (or comparisons to sales), and capital market valuations. The "administrative" valuations conducted by the parties were hugely divergent and relied on subjective and speculative predictions about future fuel costs and wholesale prices. They were based on models that required future prediction on such unknowables as fuel prices and wholesale electric rates that would drive revenues for the unregulated generating assets. Small changes in assumptions which fed the valuation models produced huge swings in stranded cost predictions. As Kaye Scholer summarized:

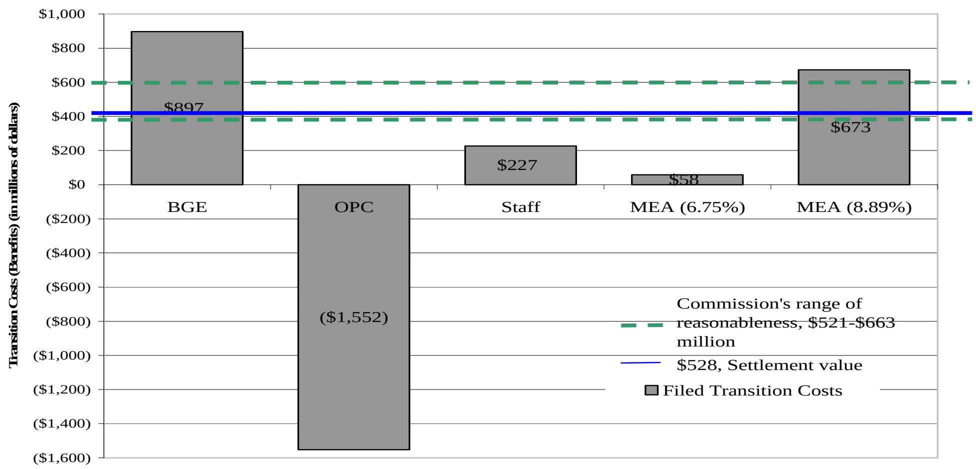
> BGE's sensitivity analyses confirmed that changes to input assumptions significantly affected the assets' revenue streams, as well as the assets' market valuation and, ultimately, stranded costs. ….. a $1/MWh increase in the forecasted average wholesale market price would increase BGE's generation assets' market value by $200 million. ….. Another sensitivity analysis showed that by changing fuel price trajectories from three percent (in nominal terms and, thus, remaining flat in real terms) to two percent (declining in real terms), the average wholesale market price fell by $.50/MWh by 2004 and by $1/MWh by 2007…….A third sensitivity analysis showed that changing hourly net imports from west and south PJM, and hourly net exports to north PJM (*see* Ex. RHB-4 (8794/2)), caused a total 500 MW change of net imports (exports) that would reduce (increase) price each year by $1/MWh….[25]

Other assumptions materially altered the stranded cost estimates. The choices of discount rate and timing are other examples. MEA's analysis also showed that a two percent change in the assumed cost of capital (from 8.89% to 6.75%) nearly eliminated stranded costs. Staff's analysis showed that a one-year delay of Calvert Cliffs' capital improvements also reduced stranded costs.

[25] *See* Stranded Costs Report at 33-34.

All parties acknowledged the uncertainty and risk associated with such predictions, as reflected in the following exhibit from the Stranded Costs Report:[26]

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



Nuclear assets in particular were extremely difficult to value at the time of the PSC proceedings. In papers filed with the PSC before the settlement was approved, most parties, including BGE itself, urged the Commission to delay final valuation in light of this uncertainty, and urged the Commission to adopt a transitional valuation process over a number of years

The parties' pre-settlement filings clearly showed that the administrative valuations of the generating assets, and therefore the stranded cost valuations, were largely subjective and extremely sensitive to changes in input assumptions. Once presented with a black box settlement, the Commission was not able to test these assumptions' reasonableness in adjudicatory proceedings, nor explore their sensitivity to changes in assumptions regarding future fuel or wholesale electric prices, without risking dissolution of the settlement. The parties and the Commission recognized that the future was extremely uncertain, but rather than hedging those risks by proceeding slowly into deregulation – as BGE initially proposed – the settlement reflected a bargain that traded risk for certainty and implemented deregulation immediately.

Kaye Scholer summarized the settlement in the following way:

> The evidence before the Commission, if credited, could have supported widely divergent conclusions, but the Commission should have inferred from this conflicting testimony that any fixed settlement terms were likely to be proved materially mistaken as events unfolded. In the face

[26] *Id*. at 47.

> of this contradictory evidence, the Commission could reasonably have tested the parties' various assumptions through evidentiary hearings – as the 1999 Act dictated – or required the parties to defer implementing some aspects of restructuring until the facts could be discerned more accurately. Nevertheless, based on information available at the time of the Commission's determination and the limitations inherent in the 1999 Act's divestiture provisions, the Commission – like the settling parties – apparently placed greater value on fixing the restructuring terms.[27]

We agree with these observations, especially as to the lack of robust evidentiary hearings which we believe would have served to highlight the "roll of the dice" the Commission was making in approving the settlement. Furthermore, such hearings might have served to better surface in a more transparent way the true magnitude of the liabilities ratepayers were assuming.

Given the wide divergence of stranded cost estimates, and their sensitivity to minor changes in the inputs of the valuation models, we also agree with this point by Kaye Scholer:

> While the Commission could not have predicted precise market conditions that developed after the settlement, the evidence is clear that the absence of knowledge about future market conditions created significant risk that any valuation in 1999 would prove to be wrong – perhaps dramatically wrong.[28]

Even still, it is worth noting that limitations in the 1999 Act impaired the PSC's ability to base the stranded cost determinations on the best available information:

> Prior to passage of the 1999 Act, Senator Frosh proposed an amendment that would have, among other things, substantially changed the statute's rules regarding divestiture and transition costs.[29] The amendment proposed to replace a key provision of the statute, PUC § 7-513, and would have (1) required the Commission to assess stranded costs or benefits before commencement of "retail access," (2) required a public auction for all generation assets except nuclear and PURPA contracts unless the Commission found that an auction was not in the public interest, (3) allowed the Commission to defer the transition to retail access, (4) created a rebuttable presumption that power purchase

[27] *Id*. at 55.
[28] *Id*. at 3.
[29] *See* SB0300/603616/1 (Mar. 25, 1999), *available at* http://mlis.state.md.us/1999rs/billfile/sb0300.htm.

> contracts should be auctioned with generation assets, (5) established procedures for the auction, and (6) prohibited assets from being transferred at book value to an affiliate. The amendment failed on a vote of 10 to 35.
>
> As evidenced by this amendment, the General Assembly considered – but rejected – alternatives that might have hedged known uncertainties by slowing down the deregulation process and that, in hindsight, may have ultimately provided ratepayers with greater protections. For instance, if the Frosh Amendment had been enacted, a public, competitive auction would have established unequivocally the value of divested asset and any stranded costs (or benefits) and would have prevented BGE's transfer of its generation assets to a Constellation affiliate at book value.[30]

In testimony filed with the PSC prior the final passage of the 1999 Act, the Office of People's Counsel highlighted the risks of relying on administrative valuations, a matter involving a 1998 administrative valuation by the Pennsylvania Public Service Commission that only six months later was proven to be unfounded when the assets were actually sold in a open auction. Although conducted after the passage of the 1999 Act, Pepco's sale of generating assets illustrates the opportunity for error of an administrative valuation. In its proceedings, Pepco estimated its stranded costs at $600.4 million, but when these same assets were then auctioned to non-affiliates, sale proceeds produced $457 million of stranded benefits.[31]

Kaye Scholer also noted that many interveners in the PSC proceedings that preceded the passage of the 1999 Act agreed that auctioning assets was the best way to derive their market value.[32] We agree with Kaye Scholer that, by rejecting language that would have permitted public auctions in order to value generating auctions, the General Assembly limited the PSC's ability 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 – a legislative predicate for the stranded costs "problem" that the 1999 Settlement was designed, but failed, to resolve.

We now know, of course, that the BGE assets today are estimated to be worth between $9.7 to $12.5 billion, an astonishing increase in value compared to the stranded *cost* estimate of $528 million after-tax 1999 dollars only eight years ago. While the change in market conditions alone may not serve as grounds to re-open the terms of the settlement, as we discussed in previous sections, the limitations in the process may have

[30] Stranded Costs Report at 13-14.
[31] *Id*. at 16-17, 55.
[32] *Id*. at 24.

contributed to the failures to appreciate the liabilities assumed by the ratepayers ***at that time***.

<u>Findings</u>

1. **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 asset transfers did not occur on an arms-length basis**;

2. **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 assumptions which fed the valuation models produced huge swings in stranded cost predictions;**

3. **Prior to 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;**

4. **The only adjudicatory hearings held by the Commission on the BGE restructuring proposal were held *after* the parties reached a settlement. As a result, the underpinnings of the settlement were never thoroughly tested in open proceedings. There was no meaningful independent scrutiny of the assumptions underlying the valuations that would have resulted from public cross examination of expert witnesses; and**

5. **Full adjudicatory hearing 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.**

V. CONCLUSION

This represents Part II of the Maryland Public Service Commission's Interim Report to the General Assembly pursuant to S.B. 400. The Commission will continue to examine the issues discussed in this Part and will report further to the General Assembly as requested.