ANALYSIS OF RETAIL RESTRUCTURING IN MARYLAND: ELECTRICITY RATES, STRANDED COSTS FROM GENERATION ASSET DIVESTITURE, AND DECOMMISSIONING FUNDING

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IN RESPONSE TO TASK #1
REQUEST FOR PROPOSALS PSC #01-01-08

FOR THE MARYLAND PUBLIC SERVICE COMMISSION

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1999 Act	Electric Customer Choice and Competition Act of 1999
A&G	Administrative and General
ADIT	Accumulated Deferred Income Taxes
ADITC	Accumulated Deferred Income Tax Credits
AFUDC	Allowance for Funds Used During Construction
ALJ	Administrative Law Judge, Hearing Examiner
APS	Allegheny Power System
BGE	Baltimore Gas and Electric Company
CAPM	Capital Asset Pricing Model
CCI	Calvert Cliffs, Inc.
CCNPP, Calvert Cliffs	Calvert Cliffs Nuclear Power Plant, Inc.
Commission, PSC	Maryland Public Service Commission
Constellation	Constellation Energy Group, Inc.
CPSGI	Constellation Power Source Generation, Inc.
CPSI	Constellation Power Source, Inc.
CTC	Competitive Transition Charge
CWIP	Construction Work in Progress
DCF	Discounted Cash Flow
Delmarva	Delmarva Power & Light Company
DNR	Department of Natural Resources
DOE	U.S. Department of Energy
DS	BGE's Default Service
DSM	Demand Side Management
ESF	External Sinking Fund
FERC	Federal Energy Regulatory Commission
GAAP	Generally Accepted Accounting Principles
GRT/PSC	Gross Receipts Tax/PSC Fees
IRP	Integrated Resource Planning
ISF	Internal Sinking Fund
ISFSI	Independent Spent Fuel Storage Installation
kWh	Kilowatt Hours

kW-year	Kilowatt Year
MAPSA	Mid-Atlantic Power Supply Association
MEA	Maryland Energy Administration
mmBtu	Million British Thermal Units
MRA	Maryland Retailers Association
MW-day	Megawatt Day
MWH	Megawatt Hour
NRC	U.S. Nuclear Regulatory Commission
NYMEX	New York Mercantile Exchange
O&M	Operations and Maintenance
OPC	Office of the People's Council
OPEB	Other Post Retirement Benefits
PA PUC	Pennsylvania Public Utility Commission
PEPCO	Potomac Electric Power Company
PFS	BGE's Price Freeze Service (SOS)
PJM	PJM Interconnection, L.L.C.
Potomac Edison	Potomac Edison Company/Allegheny Power
PPA	Power Purchase Agreement
PRB	Post Retirement Benefits
PUC	Maryland Code, Public Utility Companies
PURPA	Public Utility Regulatory Policies Act of 1978, as amended
ROE	Return on Equity
RTO	Regional Transmission Organization
Safe Harbor	Safe Harbor Water Power Corporation
Senate Bill 1	An Act Concerning Public Service Commission – Electric Industry Restructuring
SEC	U.S. Securities and Exchange Commission
SOS	Standard Offer Service
VSERP	Voluntary Special Early Retirement Programs

I. Executive Summary

The Electric Customer Choice and Competition Act of 1999 ("1999 Act") restructured Maryland's electric industry by deregulating generation supply and pricing in the retail electricity market. The 1999 Act required traditional vertically integrated electric utilities that owned transmission, distribution, and generation resources to divest their generation assets, but permitted them to seek recovery of transition costs, *i.e.*, "stranded costs" related to divested generation assets and other costs associated with restructuring.

This Interim Report analyzes the legal and factual underpinnings for the Commission's stranded cost determinations for Maryland's four electric utilities. Only Baltimore Gas and Electric Company ("BGE") had significant stranded costs, however.[1] Thus, our analysis focused on BGE's $528 million transition cost settlement, its collection of transition costs from Maryland customers, its divestiture of generation assets to affiliated companies, and the treatment of decommissioning costs for the Calvert Cliffs Nuclear Power Plant ("CCNPP" or "Calvert Cliffs").

In Section II, we analyze the 1999 Act's key provisions that controlled the Commission's transition cost determination for BGE and other utilities, including the Commission's limited authority over utilities' restructuring plans, divestiture requirements, rate protections, and the timing for implementing customer choice. Extensive administrative proceedings at the Commission preceded passage of the 1999 Act, and that record included written testimony from numerous parties including BGE, the Office of Peoples' Counsel ("OPC"), the Maryland Energy Administration ("MEA"), Commission Staff, and numerous intervenors affected by market restructuring. As we discuss in this Report, the extensive record included widely divergent testimony on issues such as asset valuation and proposals for a transition to a restructured market.

Our review of the Commission's records and the legislative history of the 1999 Act suggest that the General Assembly could have prescribed different legislative choices in the 1999 Act that would have protected customers more comprehensively. For example, some parties in Commission proceedings prior to consideration of the 1999 Act had suggested requiring an independent auction to establish the fair market value of divested assets. Evidence submitted to the Commission before the General Assembly considered the 1999 Act and subsequent events all suggest that this approach would have provided a superior and more reliable method for accurately valuing BGE's generating assets and would have better protected ratepayers. Although OPC advocated an auction in the Commission proceedings and other states had required an independent auction to determine the fair market value of divested assets, the General Assembly expressly rejected this approach for reasons that are not fully explained in the legislative record. The General Assembly could also have prohibited utilities' divestiture of generating assets to their affiliates, *e.g.*, it could have precluded BGE's transfer of its

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[1] The Commission gave BGE an advance copy of the factual portions of this Interim Report, and BGE responded on January 15, 2008. Letter from Daniel P. Gahagan, Counsel for BGE, and John D. Corse, Counsel for the Constellation Energy Group to Douglas R.M. Nazarian, General Counsel, Public Service Commission of Maryland (Jan. 15, 2008) (on file with the Commission). We have considered BGE's response in this Interim Report, but it did not materially change any reported fact or conclusion.

generating assets to its Constellation affiliates. Instead the General Assembly expressly permitted such a transfer, and did not require that inter-affiliate transactions be conducted at arm's length.

In other areas the General Assembly also placed certain "guard rails" around the Commission's processes, apparently intending to ensure that its ultimate policy objectives for restructuring were not impeded. For example, the General Assembly required that the Commission act on an application to divest within 180 days of receiving the application and supporting information and directed that the Commission "may not . . . prohibit an electric company from divesting itself voluntarily of a generation asset." MD. CODE ANN., PUB. UTIL. COS. ("PUC") §§ 7-505(b)(9), 7-508(c)(3). Taken together, these two provisions suggest a strong legislative preference that the Commission's processes should not delay or frustrate the utilities' attempts to divest their assets. That preference ultimately disadvantaged ratepayers materially. By creating undue pressure to approve a settlement that was based on assumptions about future values, the Commission may not have given sufficient weight to the wide divergence in record evidence suggesting that any compromise value would almost certainly be proved materially wrong by subsequent developments.

While the General Assembly did constrain the Commission's discretion in these areas, in other aspects of the law's implementation, the General Assembly gave the Commission significant latitude. Most notably, although the statute directed a four-year rate reduction for residential ratepayers that could range from 3% to 7.5%, the law gave the Commission authority to modify these benefits if it "approves or has in effect a settlement that the Commission determines is equally protective of ratepayers." *Id.* § 7-505(d)(5). This section of the 1999 Act expressly authorized the Commission to consider – and, we believe, to balance the benefits of – a rate reduction along with other costs or benefits ratepayers would expect to receive under restructuring, including their responsibility for stranded costs. Finally, and, we believe, importantly, the General Assembly directed the Commission to conduct public hearings in connection with the determination of any stranded costs or benefits under a restructuring proposal. As we discuss below, the Commission apparently did not recognize the importance of this directive or did not take adequate advantage of this opportunity to understand the ramifications of the proposed BGE settlement.

In Section III, we review BGE's restructuring proposal and the basis for its initial $1.1 billion transition costs request, including about $1 billion in stranded costs and $85 million for anticipated restructuring costs. We explain BGE's method and the assumptions its experts used to value stranded assets, as well as the methods and assumptions that other parties used to develop their own estimates of BGE's stranded costs. We then considered the Commission's actions in approving a final settlement of BGE's restructuring proceeding in the context of the 1999 Act's requirements and what we believe would be prudent practice. In doing so, we also considered the fact that, as permitted by the 1999 Act, the Commission approved comprehensive negotiated settlements to effectuate each utility's restructuring rather than fully adjudicating the disputed facts.

In evaluating the result of that settlement, we are mindful of the need to avoid "hindsight" judgment based on information we know today but that was not and could not have been known at the time of the settlement. Rather, we base our questions and concerns about the stranded cost determinations on information that we believe the Commission knew at the time or, with reasonable inquiry, should have known. Even considering that the determination of the amount of the stranded costs were part of broader, comprehensive settlements for each of the utilities and involved tradeoffs among their various elements, certain aspects of the record and the Commission's processes raise questions about whether the BGE settlement best served ratepayers' interests.

The extensive written testimony from a variety of parties raised a particular concern because witnesses proposed hugely divergent estimates for the stranded costs associated with BGE's assets, especially for the Calvert Cliffs nuclear plant. The parties' proposed values ranged from BGE's more than $800 million in stranded ***costs*** to OPC's $1.5 billion in stranded ***benefits*** – a difference of well over $2 billion. Of course, neither of these extreme litigation positions was likely to prevail if the Commission had made factual determinations based on the evidence, but all the parties recognized that these administrative estimates rested entirely on tenuous assumptions about the fledgling wholesale power markets, future fuel prices, and expectations about the viability of nuclear power plants. The testimony showed that all the estimates were uncertain, speculative, and subject to large swings up or down based on even modest assumption changes. For example, the evidence before the Commission showed that a change of only $1 MW/hour in energy prices materially affected projected future revenues and created a swing of $200 million in stranded cost estimates.

Because of this uncertainty, several parties, including BGE and Commission Staff, recommended deferring any stranded cost determination until the value of BGE's generation assets – particularly Calvert Cliffs – could be ascertained more accurately. Before the passage of the 1999 Act, even BGE argued that valuing the assets at one point in time, based on the prevailing uncertainties created significant risks for shareholders and ratepayers because of the possibility that market values would change in a few years based on evolving market conditions. Rather than accommodating this uncertainty, however, the Commission-approved settlement agreement simply permitted BGE to transfer its generation facilities to affiliate companies immediately at book value. Market conditions began to change soon after the Commission approved the settlement, and if the Commission had followed the initial recommendation by BGE and Commission Staff to delay the ultimate valuation of BGE's assets, ratepayers probably would not have been responsible for any stranded costs.

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. In approving the proposed settlement without conducting meaningful public hearings on the previously disputed issues, the Commission did not test the reasonableness of valuation assumptions in the crucible of adjudicatory proceedings, *i.e.*, including questioning and cross examining experts. In the absence of such proceedings, the Commission had no real basis to assess the reasonableness of the settlement and may not have fully apprehended the risk associated with immediately valuing BGE's generating assets at the time of its divestiture in June 2000. Whether or not the Commission recognized the degree of future uncertainty, it did not hedge those risks by proceeding more slowly into deregulation – as BGE had initially proposed. The settlement reflected a bargain that traded risk for certainty and implemented deregulation on a fast-track schedule, but the Commission did not have a rational basis for determining whether that tradeoff was in ratepayers' long-term interests.

As part of our analysis of stranded costs, we also investigated BGE's collection of transition costs from Maryland customers through the 1999 Act's competitive transition charge ("CTC") mechanism, compared CTC collections with the settlement-approved transition cost amounts, and analyzed how those collections were allocated between BGE and its Constellation Energy Group ("Constellation") affiliates. BGE's formal filings with the Commission and documents that it provided for this investigation suggest that BGE's before-tax CTC collections reasonably matched the after-tax settlement amounts.

Nevertheless, we found that BGE and its affiliates established circuitous, abstruse procedures for allocating and transferring the CTC collections among themselves. Rather than assigning the stranded cost collections to follow the stranded Calvert Cliffs assets (which produced virtually all of the calculated stranded costs), BGE used CTCs to offset its "losses" incurred in purchasing non-competitive standard offer service ("SOS") from another Constellation affiliate between June 2000 and June 2003. In turn, that affiliate sold BGE the SOS supply at margins well above its costs for power from Calvert Cliffs and perhaps above market prices. Our review shows that of the $975.25 million in pre-tax collections from ratepayers for transition costs, BGE used the majority – $527 million – to fund its electricity purchases for rate-capped SOS service.[2] BGE has not adequately identified a business justification for these unorthodox arrangements, but it may have structured these affiliate transactions to use CTC collections to fund its price-freeze rates or to subsidize its power supply affiliate.

The allocation and transfer of the CTC collections raises a second, more general potential concern stemming from the fact that that ratepayers' stranded cost payments had been justified on grounds that the rate-regulated value of the assets (*i.e.*, the book value) was higher than market value, and, consequently, the unregulated owner may not fully recover this deficit in a non-regulated environment. In the case of the BGE asset transfer at book value, the post-settlement agreement between BGE and its affiliate diverted stranded cost payments received from ratepayers from what many viewed as its intended purpose – primarily to compensate Calvert Cliffs for its stranded costs. Instead, those funds went to another, unrelated purpose – purchasing SOS power from a BGE affiliate – thereby arguably running afoul of the assumed rationale for stranded costs. There is no evidence that the Commission or the settling parties contemplated that these ratepayer payments would be used essentially to fund the rate cap rather than to compensate Calvert Cliffs for assets whose fair market value was less than their book value.

For these reasons, we recommend that the Commission initiate a further inquiry to document and verify the circumstances surrounding the agreements and contracts between BGE and its affiliates, the precise amounts that were diverted, and whether such agreements and actions in any way violated either the 1999 Act, or the Settlement Agreement, or deviated

[2] The collections exceeded the commonly used stranded cost number of $528 million because the settlement permitted BGE to recover $528 million after-tax, and it paid CTC collections to its affiliate on a pre-tax basis.

from the objectives and intentions of the General Assembly or the parties at the time of settlement.

In Section IV, we explain the basis for BGE's asset transfers to Constellation affiliates and assess whether these transactions complied with applicable law and treated customers fairly. As described earlier, BGE's transfer of generation assets to affiliates at book value neither realized the value for ratepayers that a public auction would have produced nor permitted diversification of wholesale supply within Maryland, although the 1999 Act precluded Commission action to compel a different course. Thus, the Commission's only role was to ensure that BGE complied with the Settlement Agreement, the 1999 Act, and the Commission's divestiture requirements, and we determined that it did. Because BGE could not transfer some generation-related debt without adverse tax consequences, the transactions initially left BGE in a highly leveraged position, but its subsequent filings with the Commission show that the utility recovered its pre-divestiture capital structure, as it promised the Commission it would.

In Section V, we assess BGE's retention of some regulatory assets even though they are associated with divested generation assets. These assets reflect costs that BGE incurred and that could have been expensed but that the Commission required or permitted to be recovered in future rates through 2017. Among the retained regulatory assets were nuclear facility costs, labor costs associated with early retirement programs and post-retirement benefits, and income taxes to be recovered in future rates. The settlement agreement permitted BGE to continue to recover 80% of those regulatory assets through rates, but the Commission did not analyze this aspect of the settlement in any detail. The Commission may wish to consider the continuing treatment of these regulatory assets in the next BGE rate case.

Although not strictly a part of BGE's stranded costs, at the Commission's request, Section VI examines the steps taken during and since restructuring to allocate decommissioning funding obligations for Calvert Cliffs. Following the example of some other states, the Commission-approved settlement made BGE's ratepayers responsible for decommissioning funding up to $520 million in 1993 dollars, escalated to the date of actual decommissioning. The settling parties reasoned that customer funding was appropriate to assure safe disposition of a potentially hazardous nuclear plant site. The settlement permitted BGE to collect $18.7 million annually through June 2006, for this purpose, with revisions thereafter to ensure that ratepayer funding would produce $520 million in 1993 dollars by the decommissioning date.

The settlement's allocation of decommissioning costs to ratepayers is problematic in many significant respects. ***First***, at the time of the settlement, ratepayers' outstanding funding obligation was already almost half a billion dollars in 1999 dollars, and the authorized collections rate through mid-2006 was almost certainly going to be insufficient. ***Second***, customers' decommissioning funding obligation remains uncertain today because the amount that they must pay depends on when Constellation chooses to decommission Calvert Cliffs, the rate of inflation in decommissioning costs (which has been higher than in the general economy), and the earnings attributed to the decommissioning fund. Based on BGE's most recent projections, the customer funding obligation if Calvert Cliffs operates until the end of its licensed life in 2036 will be almost $5.3 billion. BGE calculated in 2006 that the rate of collections would need to increase to $25 million annually to satisfy that liability, but proposed to defer any change in the rate for ten years – when, under the same assumptions, annual collections would have to increase to more than $33 million. ***Third***, BGE remits all of its decommissioning collections to its Constellation affiliate, leaving the Commission with no direct control over how those funds are managed for ratepayers' benefit. Recently, instead of placing most of the decommissioning collections in an external fund that receives favorable tax treatment and that is protected from creditors, Constellation has allocated the majority to an internal reserve that can be used for its own profit-creating purposes but has none of the expected protections that would be available with a segregated, external fund. ***Fourth***, Senate Bill 1, which became effective in 2007 and requires BGE to "credit" residential customers with the amount of the annual nuclear decommissioning charge "collected," does nothing to reduce ratepayers' ultimate obligation. BGE continues to collect the decommissioning charge and transfers it to Constellation, so Constellation is unaffected. BGE then refunds that same amount to residential customers, reducing their rates nominally, but possibly eroding BGE's earnings and perhaps opening the door for it to request a higher rate of return.

Finally, decommissioning funding represents a larger ratepayer liability than stranded costs but has received little attention to date. Compared with the extensive written testimony about asset valuation, nuclear decommissioning and its potential impact on ratepayers apparently received relatively little attention, and the Commission may not have fully understood the ramifications of ratepayers' decommissioning responsibility under the settlement. In its order affirming the settlement, the Commission merely notes its finding that capping "customer responsibility for Calvert Cliffs nuclear decommissioning costs at $520 million (in 1993 dollars) is reasonable." Order 75757, Order 75757, *In re Baltimore Gas & Elec. Co.*, 90 MD PSC 197, 236 (8804/235) (Nov. 10, 1999). There is no evidence that the Commission knew that at the time of the settlement in 1999, ratepayers' liability had already risen to $778 million, and customers were already "short" of their funding obligation by more than $490 million. Nor did we find any sensitivity analysis to determine, as BGE recently reported, that this liability will mushroom to possibly over $5 billion by 2036, when the second Calvert Cliffs unit is now scheduled for decommissioning.

In light of these issues and the scope of this decommissioning liability, we recommend that the Commission consider further proceedings to identify steps that it should take to protect ratepayers' interests. The magnitude of this liability, coupled with the apparent lack of transparency regarding the decommissioning funding deficit and its magnitude raise legitimate questions about whether the settlement, even at the time it was approved, reached a reasonable balance of ratepayer costs and benefits.

II. Overview of Retail Market Deregulation and Utility Restructuring

Beginning with the Public Utility Regulatory Policies Act of 1978 ("PURPA")[3] that permitted competition with integrated utilities for wholesale generation, and continuing with the Energy Policy Act of 1992[4] and the Federal Energy Regulatory Commission's ("FERC's") Order Nos. 888 and 889,[5] the federal government opened the door to competition in providing generation services. Maryland responded in the late 1990s by restructuring its retail regulatory structure and permitting utilities to divest their generation assets and to introduce retail competition. This section will describe that process and its effect on Maryland's four investor-owned utilities. Figures 1 and 1a provide timelines showing key events in the restructuring and its aftermath, particularly as it impacted BGE and its customers. We will describe the legislation that controlled the restructuring and the determination of stranded costs and the settlement agreements that established the terms for the restructuring that would follow.

A. The Regulatory Regime before 1999 and the Predicate for Stranded Costs

Before Maryland restructured its electric industry, utilities owned all distribution, transmission, and generation resources, and supplied electricity services to all customers within their service areas. State regulators set prices for electricity services using cost-of-service regulation, an accounting-based methodology that permitted utilities to recover their costs and earn a reasonable rate of return on their investments. Utilities determined the need for new generation investments and demand-side management through Integrated Resource Planning ("IRP") based on forecasts of demand, fuel costs, and expected supply resources. Order 72136, *In re Elec. Servs., Mkt. Competition, and Regulatory Policies*, 86 Md. PSC 271, 292 (8678/101) (Aug. 18, 1995).

Regulated utilities invested in generation with the assurance that they would recover prudently incurred costs based on a return of and on their investments. In order to meet growing demand and pursuant to approved IRPs, utilities built new generation – including baseload coal and nuclear plants. Retail customers were essentially captives to their utilities for all electricity services, so utilities bore little risk when they invested in new generation. As long as a utility owned generation assets that it used to serve customers, it could expect to recover the full costs of those assets through rates. If it sold or transferred those assets without recovering all its investment – *i.e.*, if a portion of the investment cost was "stranded" and not fully recovered in rates – the utility could expect to be made whole.

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3 Public Utility Regulatory Policies Act of 1978, Pub. L. No. 95-617, 92 Stat. 3117 (1978).

4 Energy Policy Act of 1992, Pub. L. No. 102-486, 106 Stat. 2776 (1992).

5 Order No. 888, *Promoting Wholesale Competition through Open Access Non-Discriminatory Transmission Services by Public Utilities; Recovery of Stranded Costs by Public Utilities and Transmitting Utilities*, 61 Fed. Reg. 21540 (May 10, 1996); Order No. 889, *Open Access Same-Time Information System (Formerly Real-Time Information Network) and Standards of Conduct*, 61 Fed. Reg. 21737 (May 10, 1996).

Figure 1
Timeline of Key Events in Maryland's Retail Electric Restructuring

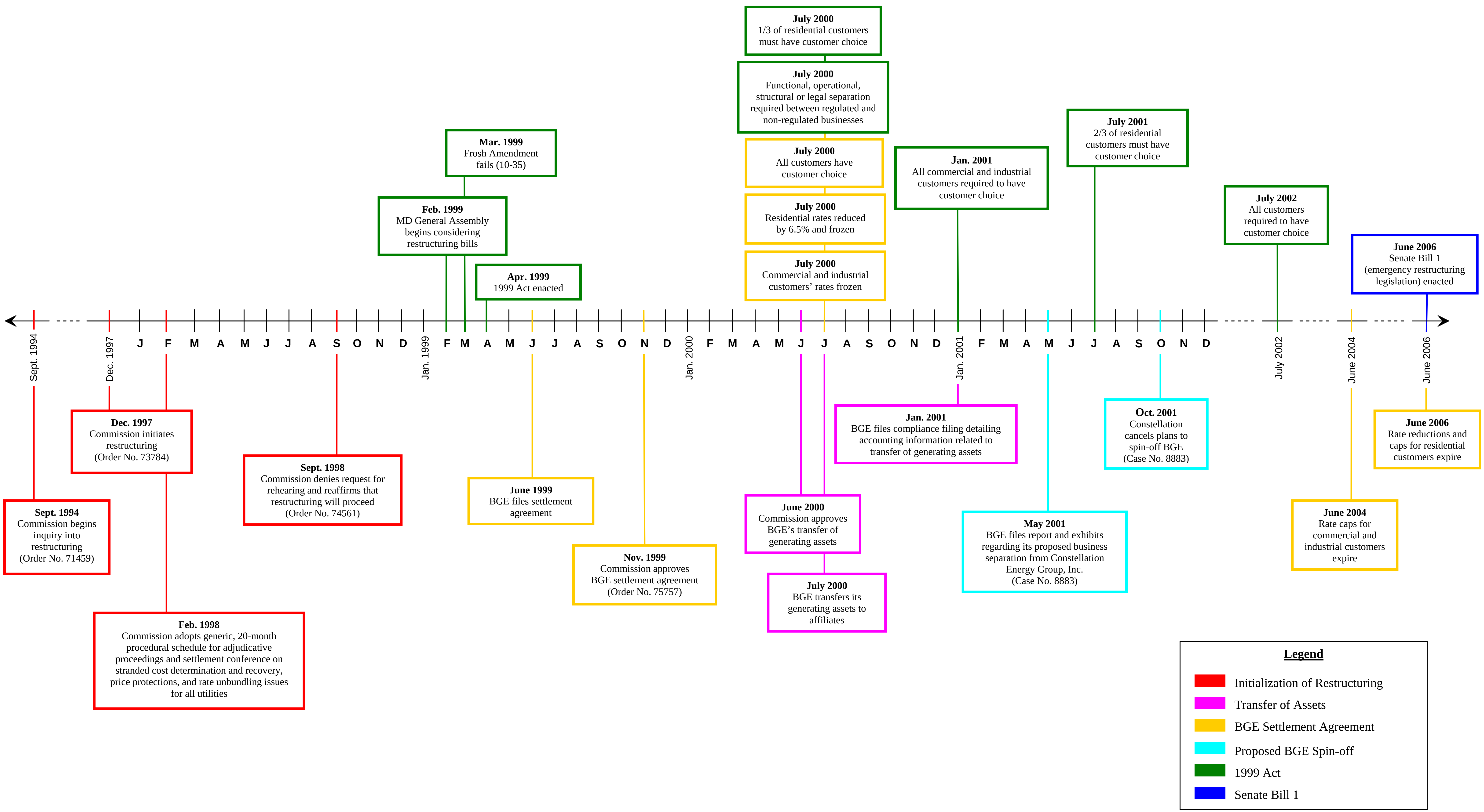
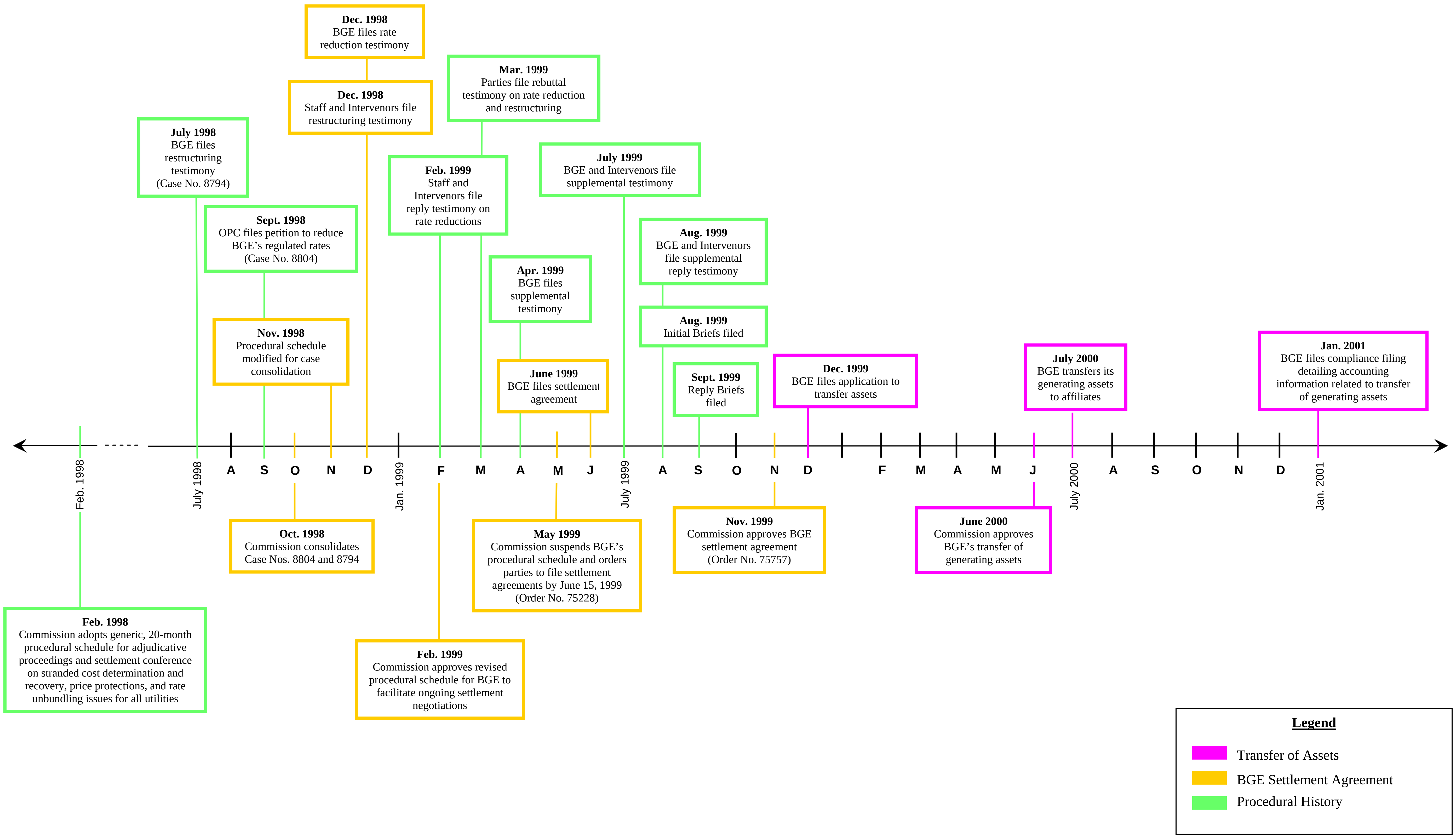


Figure 1a
Procedural Schedule of Case 8794/8804



B. The 1999 Act

The General Assembly created the framework for the settlements and restructuring that would follow. Those legislative choices dictated many aspects of the restructuring – *e.g.*, the method for divestiture, the determination of stranded costs, and the timetable for implementation – and precluded consideration of alternatives that might have afforded customers greater protections. This section reviews the Commission's role in the process, the latitude given to utilities in divesting their generation assets, the impact of restructuring on retail competition and rates, the procedures for determining stranded costs, and alternatives that the General Assembly considered but did not adopt.

1. The Commission's Role

The 1999 Act generally removed the Commission's traditional authority to regulate the utilities' generation, sale, or supply of electricity, as well as related facilities and assets, once the utilities implemented customer choice. PUC § 7-509(a). The Commission retained authority, however, (1) to set the price for standard offer service ("SOS"), the default electricity supply used by customers who are unable or choose not to purchase electricity from other suppliers (*id.* § 7-510(c)(2)) and (2) to review and approve the utilities' transfers of generation assets by either sale or divesture to an affiliate. *Id.* §§ 7-509(a), 7-508(a).

Although the 1999 Act granted the Commission authority to review regulated utilities' generation asset transfer to affiliates, it limited the Commission's review and approval authority to three determinations: (1) whether the utility followed appropriate accounting methods; (2) whether the transfer would create an undue adverse effect on the proper functioning of a competitive market; and (3) whether the utility used an appropriate transfer price and rate making treatment. *Id*. § 7-508(c)(2). The statute did not permit the Commission to disapprove affiliate transfers on any other grounds, and specifically provided that the Commission could not require a utility to divest a generation asset or prevent a utility from voluntarily divesting itself of a generation asset in connection with transition costs. *Id.* § 7-505(b)(9).

Even before the Maryland General Assembly passed the 1999 Act, the Commission ordered utilities to submit restructuring plans detailing their proposed unbundled rates, price protection mechanisms, stranded cost estimates, and methods for recovering stranded costs. *See* Letter Order, *In re the Comm'n's Inquiry into the Provision and Regulation of Elec. Servs.*, (8738/240) (Feb. 19, 1998). Complying with that order, utilities filed testimony describing their restructuring plans and the rationale behind them.[6] Other parties (*e.g.*, OPC, the Maryland Retailers Association ("MRA"), the Mid-Atlantic Power Supply Association ("MAPSA"), and MEA) and the Commission's Staff also filed testimony during this period addressing the restructuring plans. The 1999 Act authorized the Commission to assess and approve each utility's restructuring plan and to oversee the transition process. PUC § 7-505(a)(1). In so doing, the Commission was to focus on five key factors: (1) the plan should assure a smooth transition from the regulated regime to competition; (2) restructuring should not jeopardize the

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6 As we describe below, the Office of the People's Counsel ("OPC") also filed a complaint seeking to reduce BGE's rates, thus linking restructuring and rate reductions.

historic standards for system reliability; (3) the restructuring plan should respect all environmental requirements; (4) the plan should treat retail customers, utilities and their investors, and electricity suppliers fairly; and (5) restructuring should distribute expected economic benefits across all customer classes. *Id*. Negotiations among the Commission staff, the utilities, and the other intervening parties ultimately produced settlement agreements with each of the utilities that the Commission approved pursuant to the statute.

2. Divestiture of Generation Assets

The 1999 Act provided that by July 1, 2000, the Commission would require "functional, operational, structural, or legal separation" of each utility's regulated and unregulated assets. *Id*. § 7-505(b)(10)(iii). The statute did not specify any particular mechanism for divestiture (*e.g.*, sale by auction to the highest competitive bidder), but it did expressly permit utilities to transfer their generation assets or facilities to an affiliate.[7] *Id*. §§ 7-508(a), 7-509(b)(2)(ii). Consequently, the Commission had no authority to compel any utility to take steps that would ensure the greatest value to ratepayers from divested assets. If a utility chose to divest to an affiliate, the Commission's only continuing control over the relationship between the utility and any affiliate providing electricity supply and related services was its authority to approve a code of conduct. *Id*. § 7-505(b)(10)(ii)(1), (b)(13)(ii). The legislature specified that utilities' codes of conduct should "prevent regulated service customers from subsidizing the services of unregulated businesses or affiliates of the electric company." *Id*. § 7-505(b)(13)(ii). The statute contained no requirement that the asset transfer transaction be conducted at arm's length or have any other assurances of corporate propriety. Moreover, even though the Commission had statutory authority to determine the appropriate transfer price in an affiliate sale (*id*. § 7-508(c)(2)(iii)), the Commission was not permitted to consider the fact that a utility transferred its generating assets to an affiliate in determining those assets' value for purposes of transition costs (*id*. § 7-508(b)).

Although the 1999 Act authorized divestiture of generating assets generally, the utility could maintain some generation facilities as regulatory assets pursuant to a settlement agreement. The statute does not specifically authorize this retention, but it does note that the Commission's prohibition on regulating the generation, sale, and supply of electricity does not apply to "costs of nuclear generation facilities or purchased power contracts that, as part of a settlement approved by the Commission, remain regulated or are recovered through the distribution function." *Id.* § 7-509(a)(2)(ii). The clear implication of this language was to authorize the Commission to approve settlement agreements in which utilities retained some generating assets that would remain under the Commission's jurisdiction.

3. Customer Choice and Price Protection

The statute specified a schedule for implementing customer choice. *Id.* § 7-510. Commercial and industrial customers were expected to transition expeditiously into a competitive market, with choice required for all such customers by January 1, 2001. *Id.* § 7-

[7] The 1999 Act defined "affiliate" as a "person that directly or indirectly, or through one or more intermediaries, controls, is controlled by, or is under common control with, or has, directly or indirectly, any economic interest in another person." *Id.* § 7-501(b).

510(a)(1)(ii). Residential customers would exercise choice in phases over a term of years, starting on July 1, 2000, with all customers required to have the opportunity to choose among electric suppliers by July 1, 2002.[8] *Id*. § 7-510(a)(1)(iv).

To help ensure a smooth transition into deregulation and to prevent price volatility as the competitive electricity market developed, the 1999 Act implemented price protections for customers in the form of rate caps and reductions. Rates for commercial and industrial customers were capped and frozen for four years. *Id.* § 7-505(d)(1). The cap was set at the price in effect the day before implementation of customer choice in each utility's distribution area (*id.*) and applied to the recovery of transition costs, certain costs included in rates as of January 1, 2000, and costs for the universal service program established for low-income customers (*id.* § 7-505(d)(2)(ii)). (New public service programs that mandated additional utility costs would be exempt from rate caps. *Id.* §§ 7-505(d)(2)(i), 7-512(c).) The statute also allowed the Commission to approve settlement agreements that included rate caps of differing duration or that adopted alternative price protection plans that it determined to be equally protective of ratepayers. *Id.* § 7-505(d)(3).

In addition to the rate caps set for commercial and industrial customers, the 1999 Act required a rate rollback for residential customers. The statute required rate reductions of between three percent and 7.5% of base rates as of June 30, 1999, but the Commission determined the actual amount. *Id.* § 7-505(d)(4)(i)(1). In determining that amount, the legislature instructed the Commission to consider, *inter alia*, net transition costs and benefits (*id.* § 7-505(d)(4)(ii)(4)), suggesting that the legislature anticipated some interrelation between the amount of stranded costs the utility collected and the rates it charged to residential customers. *See also id.* §7-505(d)(2)(ii)(1). The rolled back "price freeze" rates were to take effect immediately upon implementation of customer choice and, like the rate caps, to extend for four years. *Id.* § 7-505(d)(4)(i)(2). As with the rate caps, the terms of settlement agreements with utilities could supersede the rate reduction requirements of the 1999 Act so long as they were at least as favorable to customers. *Id.* § 7-505(d)(5).

4. <u>Transition Costs</u>

The 1999 Act permitted utilities to recover two types of "prudently incurred" and "verifiable" net transition costs (*id*. § 7-513(a)) – (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.[9] *Id*. § 7-501(p)(1), (2). The Commission determined which transition costs would be allowed, set the recoverable value of transition costs each electric utility could collect (*id*. § 7-513(b)), and designated recovery periods of different lengths and for different types of transition costs (*id*. § 7-513(a)(3)(ii)). In determining transition costs, the statute required the Commission to hold public hearings (*id*. § 7-

[8] The statutory schedules could be adjusted upon a showing of good cause. *Id.* § 7-510(b).

[9] As used throughout this Interim Report, "restructuring costs" are utilities' new costs resulting from restructuring, "stranded costs" (or benefits) are the difference between a generation regulatory asset's or a generation asset's market value and value under a regulation when that value is negative (or positive), and "transition costs" are the sum of restructuring costs and stranded costs (or benefits). Stranded costs are reviewed, *infra*, in Section III.A, at 23-26.

513(e)(1)(i)), examine appropriate evidence of the divested assets' value, and consider the following factors: (1) book and fair market value; (2) auctions and other sales of similar generation assets; (3) appraisals of the assets; (4) the revenue rate-of-return regulation would yield for the utility; (5) the utility's anticipated revenue from the restructured market; and (6) computer simulations submitted to the Commission. *Id.* § 7-513(e)(1)(ii).

As part of its assessment of transition costs, the 1999 Act required the Commission to allocate costs and benefits fairly between customers and the utilities' shareholders. In so doing, the statute required the Commission to consider (1) the "prudence and verifiability" of the utility's original investment in the generating asset; (2) the current use and usefulness of the investment; (3) whether investors reasonably bore the risk of the loss caused by divestiture; and (4) whether investors were already compensated for their risk. *Id.* § 7-513(e)(2). The General Assembly did not address expressly how the Commission should consider the substantial funds that BGE had already collected from ratepayers to pay for decommissioning the Calvert Cliffs nuclear units or the funds that would be required for decommissioning when the plant terminated operations.

The statute authorized utilities to recover transition costs from ratepayers through a CTC, which would be a line-item recovery mechanism added to customers' bills. *Id*. §§ 7-501(d), 7-513(a)(2), 7-513(a)(3)(1). Each retail customer class was responsible to pay its fair share of transition costs. *Id*. § 7-513(a)(2) (allocation method should avoid interclass and intraclass cross subsidies). As part of this structure, the Commission had to conduct an annual review and reconcile each utility's CTC revenues with allowed transition costs, which were to be amortized annual investments for the duration of the collection period. *Id.* § 7-513(d)(1). In so doing, the Commission had to compare the previous year's actual kilowatt-hour ("kWh") sales with previous estimates of those sales. The Commission then was to adjust the CTC accordingly based on over- or under-recovery of the approved amount of transition costs. *Id.* The statute authorized the Commission to approve alternative reconciliation mechanisms as part of a settlement agreement (*id.* § 7-513(d)(2)(iii)), indicating that the legislature expected the Commission to conduct some form of review over settlement agreement implementation.

5. The Proposed Frosh Amendment

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.[10] 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 contracts should be auctioned with generation

[10] *See* Amendments to Senate Bill 300, as amended (SB0300/603616/1, unofficial copy) (Mar. 25, 1999), *available at* http://mlis.state.md.us/PDF-Documents/1999rs/amds/bil_0000/sb0300_60361601.pdf (last visited January 11, 2008).

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.[11]

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.

C. Utility Settlement Agreements

1. Overview

BGE, Delmarva Power & Light Company ("Delmarva"), Potomac Electric Power Company ("Pepco"), and Potomac Edison Company/Allegheny Power ("Potomac Edison") each filed a restructuring proposal, but in the end, the Commission approved negotiated settlements for each utility, thereby avoiding full adjudication or any analysis of the parties' significantly conflicting positions. Throughout this process many parties submitted testimony on the contested issues, but the settlements – even when contested[12] – obviated the need for hearings, cross examination, or Commission findings, except when necessary to resolve narrow disputes.

Each settlement agreement specified (1) a divestiture process for utilities' generation assets – *e.g.*, transfer to an affiliate at book value or auction sale to unaffiliated companies – (2) the allowable amount of recoverable transition costs, (3) an allocation of transition cost collections to each customer class, (4) CTC rates and collection periods, (5) a period during which rates were frozen, (6) dates for customer choice, and (7) other negotiated provisions. Each settlement agreement also included a nonseverability provision that required the Commission to approve the settlement in full without modification. *See, e.g.*, Stipulation and Settlement Agreement, *In re Baltimore Gas and Elec. Co.* (8804/141) (June 29, 1999) ("BGE Settlement Agreement"), ¶ 53.[13] This provision protected the compromises reflected in the parties' negotiated terms. If the Commission altered any single provision, the parties intended the settlements to unravel.

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11 The March 25, 1999 voting record (seq. no. 0568) for the Frosh floor amendment is available at http://mlis.state.md.us/1999rs/votes/senate/0568.htm (last visited January 11, 2008).

12 BGE's settlement and PEPCO's settlement were contested settlements.

13 BGE's settlement agreement and other filings are available in case files published on the Commission's website. The designation "(8804/141)" for BGE's settlement agreement indicates the case number and entry number of the filing. Many documents filed in Commission's cases may be accessed through "Case Search," available at http://webapp.psc.state.md.us/Intranet/CaseNum/ CaseForm.cfm.

2. Delmarva Power & Light Company

The Delmarva agreement consisted of two settlements. Delmarva, Commission Staff, the OPC, other state agencies, and users' groups filed the first in May 1999. Joint Motion for Approval and Implementation of Settlement Agreement, *In re Delmarva* (8795/69) (May 5, 1999) ("Delmarva Settlement Agreement"). MAPSA opposed this settlement proposal. Three months later the settling parties, now joined by MAPSA, filed a Supplemental Agreement of Settlement, *In re Delmarva* (8795/94) (Aug. 4, 1999) ("Supplemental Agreement"). The Commission approved both settlements without modification by Order 75680, issued on October 8, 1999. *In re Delmarva*, 90 Md. PSC 115 (8795/98).

The Delmarva settlements identified $16 million of transition costs on a Maryland-retail basis. Delmarva Settlement Agreement, § II.A.1. The actual recoverable amount of transition costs – $8 million – would be collectable through CTCs from nonresidential customers over a three-year period starting July 1, 2000. *Id*. These transition costs would be collected through CTC charges without a reconciliation or true-up between the actual and allowed collections. *Id*., § II.A.2. The remaining $8 million, which was allocated to residential ratepayers, would not be collected from any customers and was "deemed to be zero" for settlement purposes. *Id*., § II.A.1.

Delmarva's settlements implemented customer choice for all customer classes by July 1, 2000 – ahead of the statute's implementation time frame. *Id.*, § II.D.1. Residential customers received a 7.5% reduction of rates (*id*., § II.B.1) – the maximum provided under the 1999 Act – and their rates were frozen for a four-year period through June 30, 2004. *Id*., § II.B.2. Commercial and industrial customers' rates were frozen as of July 1, 2000, for a three-year period ending on June 30, 2003. *Id*. The settlement agreements also provided for shopping credits, which offset the generation charge in the utility's rates, thereby allowing customers to shop for cheaper generation suppliers.[14] The Supplemental Agreement clarified and modified contested provisions of the first settlement and increased the floor for the average annual shopping credit for generation and ancillary services by 0.077 cents per kWh to 4.92 cents per kWh for residential customers. Supplemental Agreement, ¶ 1; Order 75680, 90 Md. PSC at 123 (8759/98). Shopping credits could not fall below this amount before June 30, 2004. Supplemental Agreement, ¶ 1. The Supplemental Agreement also provided a nonreconcilable mechanism to allocate the cost of shopping credit adjustments by reducing Delmarva's distribution charges. Order 75680, 90 Md. PSC at 123-124 (8759/98).

The Commission's Order 75680 approving Delmarva's settlement indicated that the company intended to sell 2,200 megawatts ("MW") of nuclear and coal-fired baseload assets with an estimated book value of $1.3 billion. *Id*. at 131. Delmarva would transfer its remaining assets to an affiliate at net book value, as permitted by the 1999 Act. *Id*. at 132.[15]

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[14] These credits are not addressed in the 1999 Act, but are a negotiated device intended to facilitate shopping and development of retail competition. Customers choosing a competitive retail supplier could reduce their bills from the utility by the amount of the shopping credit.

[15] The Maryland-jurisdictional assets, all fossil fuel assets, were transferred to an affiliate at a book value of approximately $105 million. *See* Delmarva Power & Light Company's Application for Approval of Accounting Treatment for the Transfer of Generation Facilities (8795/138) (Apr. 14, 2000), ¶¶ 5-6, App. B. For information on sale of nuclear assets by Delmarva's affiliate, Connectiv, *see infra* note 72, at 50.

As part of this settlement, the Commission was precluded from reviewing the effect of the transfer on the competitive electric supply market or the appropriate price and ratemaking treatment. *Id*.

3. Potomac Electric Power Company

Pepco's settlement consists of two phases. The Phase I Settlement addressed quantification of stranded costs and price protections. Agreement of Stipulation and Settlement, *In re Potomac Elec. Power Co.* (8796/69) (Feb. 3, 1999) ("Phase I Settlement"), as amended by Amendment to Agreement of Stipulation and Settlement, (8796/133) (Sept. 23, 1999) ("Phase I Amendment"). The Phase II Settlement resolved outstanding unbundled rate issues. Agreement of Stipulation and Settlement Regarding Unbundled Rate Issues, *In re Potomac Elec. Power Co.* (8796/133) (Sept. 23, 1999) ("Phase II Settlement"). The Commission approved the settlement without modification in Order 75850. *In re Potomac Elec. Power Co.*, 90 Md. PSC 329 (8796/189) (Dec. 22, 1999). The MRA opposed the settlement because it did not specify rules for the auction of Pepco's generation assets (*id.* at 365), but did not seek review of the Commission's order approving the auction. Pepco later filed a second amendment providing further reductions in distribution service rates and discontinuing the demand-side management ("DSM") surcharge. Second Amendment to Agreement of Stipulation and Settlement, *In re Potomac Elec. Power Co.* (8796/198) (Mar. 17, 2000) ("Second Amendment"). The Commission approved this amendment in Order 76078. *In re Potomac Elec. Power Co.*, 91 Md. PSC 170 (8796/207) (Apr. 12, 2000).

The Pepco settlement did not set allowable transition costs, but instead, Pepco agreed to sell all generation and related assets in an open and competitive auction that excluded company affiliates. Sale proceeds established the market value measure of assets sold. Phase I Settlement, § 1.02(a). Customers would be required to pay CTCs only if auction proceeds (pre-tax) were less than the assets' net book value. The CTC would equal the auction proceeds less the sum of the assets' book value, other regulatory assets, and transition costs. *Id*., §§ 2.01, 2.02. Alternatively, if the auction proceeds were greater than the company's assets and transition costs, customers would be paid a share of the proceeds through Competitive Transition *Credits*. *Id*., § 2.03; *see also* Order 75850, 90 Md. PSC at 350, 367-68 (8796/189). Charges or credits would be applied to delivery rates for a period of time to be determined. Phase I Settlement, § 2.04. Pepco was also permitted to recover the costs of its unamortized DSM programs through June 2003, and to maintain its Energy Use Management programs that helped Pepco meet PJM's installed capacity requirements. Order 75850, 90 Md. PSC at 343-44 (8796/189). Order 76078 approved the Second Amendment to the settlement, terminated DSM collections, and designated DSM assets as generation regulatory assets. Order 76078, 91 Md. PSC at 172 (8796/207).

Pepco's asset sale produced $1.48 billion in settlement proceeds, exceeding book value by $457 million. Application of Potomac Electric Power Co. for Approval of Divestiture Sharing Plan, Ex. A, *In re Potomac Elec. Power Co.* (8796/269) (Apr. 26, 2001). Pepco proposed to apply proceeds to $107 million of generation-related regulatory assets and $17 million of unrecovered DSM costs to reduce these stranded benefits and $182.3 million of the remaining $333 million would be paid to customers through a Competitive Transition Credit. *See* Application of Potomac Electric Power Co. for Approval of Divestiture Sharing Plan, *In re*

Potomac Elec. Power Co. (8796/269) (Apr. 26, 2001) at 1; Ex. B ($188.6 million remitted to ratepayers included $6.3 million of accrued interest). Pepco transferred two facilities that were not sold, Benning Road and Buzzard Point, to an affiliate at book value.[16] No transition costs or benefits were incurred on these facilities.

The settlement accelerated customer choice to July 1, 2000 (ahead of statutory requirements), and made two types of service available to customers – Standard Offer Service ("SOS") and Market Price Service.[17] Phase II Settlement Agreement, ¶ 11; Order 75850, 90 Md. PSC at 363 (8796/189). The settlement also applied shopping credits and billing charges (a monthly charge for certain types of alternate supplier services) to bills for both residential and nonresidential customer classes. *Id.* at 346. Each customer class with SOS would be capped through July 1, 2003, at rates effective June 30, 2000, subject to certain tax law changes. Phase I Settlement, §§ 5.01, 5.02. The settlement later reduced residential rates effective June 30, 2000, by three percent of 1999 revenues – about $10.147 million annually. Phase I Amendment, ¶ 2 (amending § 5.02, Phase I Settlement). Commercial customers' rates were reduced by $3 million annually – about 0.83% of 1999 rates. Second Amendment, § 1(a). The Commission's order anticipated that, due to treatment of the DSM surcharge by the Phase II Settlement, Pepco would provide rate reductions of about seven percent for residential customers and four percent for nonresidential customers. Order 75850, 90 Md. PSC at 368 (8796/189). Additionally, customers could share 50% of Pepco's annual net profits from providing generation services under SOS rates once Pepco had recovered the first $10.147 million or $3 million, whichever applied. *Id*. at 341-43; Phase I Amendment, § 2(b). Pepco reports that its customers received $63.3 million under this profit-sharing provision through a Generation Procurement Credit. *See* Direct Testimony of Mark Browning on Behalf of Potomac Electric Power Co., *In re Investigation Required by Section 11, 2006 Md. Laws 1st Special Session, Pub. Serv. Comm'n Elec. Indus. Restructuring* (9073/29) (Dec. 15, 2006) at 8:20-23.

4. <u>Potomac Edison Company (Allegheny Power)</u>

Potomac Edison, Commission Staff, OPC, state and federal agencies, and supplier interest groups submitted a settlement agreement with the Commission on September 23, 1999. Settlement Agreement, *In re Potomac Edison Co.* (8797/86) (Sept. 23, 1999) ("Potomac Edison Settlement Agreement"). On October 4, 1999, Potomac Edison filed its unbundled rates. Unbundled Rates for the Years 2000 to 2008, *In re Potomac Edison Co.* (8797/93) (Oct. 4, 1999). The Commission approved Potomac Edison's restructuring plan in Order 75851, *In re Potomac Edison Co*., 90 Md. PSC 439 (8797/113) (Dec. 23, 1999), and later issued its analysis in Order 76009. *In re Potomac Edison Co.*, 91 Md. PSC 106 (8797/129) (Mar. 15, 2000).

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16 Phase I Settlement, § 1.02(a); Order 75850, 90 Md. PSC at 338 (8796/189). An amendment to the Phase I Settlement exempted two PEPCO generating stations, Benning Road and Buzzard Point, located in Washington, D.C., and barred the company from later claiming transition costs associated with transfer of these facilities to an affiliate at book value. *See* Letter Order, *In re Potomac Elec. Power Co.* (8796/260) (Nov. 22, 2000).

17 MPS is a market-based rate set by formula using wholesale prices for customers who are not eligible for SOS.

The settlement set rates for Potomac Edison customers through 2008. Potomac Edison Settlement Agreement, ¶ 15. It accelerated the transition to customer choice for all customers to July 1, 2000 (ahead of statutory requirements), except for customers with certain individual contracts. *Id.*, ¶¶ 14, 28 (rate unbundling); Order 75851, 90 Md. PSC at 441 (8797/113). The settlement required Potomac Edison to provide SOS to residential customers from July 1, 2000, through December 31, 2008, and to other customers through December 31, 2004. Potomac Edison Settlement Agreement, ¶¶ 18, 19-21 (explaining SOS contract terms); Order 76009, 91 Md. PSC at 112-13 (8797/129).

As part of the settlement, Potomac Edison reduced rates effective December 31, 2001, providing residential customers with annual savings of $10.4 million through December 31, 2008 – *i.e.*, a total of $72.8 million. Potomac Edison Settlement Agreement, ¶¶ 15, 22; Order 76009, 91 Md. PSC at 112 (8797/129) (acknowledging a seven percent rate reduction). Commercial customers received $10.5 million in savings ($1.5 million annually). Potomac Edison Settlement Agreement, ¶ 15; Order 76009, 91 Md. PSC at 112 (8797/129). Potomac Edison would implement these rate reductions as a credit to distribution charges (Potomac Edison Settlement Agreement, ¶ 15), without affecting shopping credits (Order 76009, 91 Md. PSC at 115-16 (8797/129)). Shopping credits, available beginning January 1, 2001, were set at an average 4.47 cents per kWh for residential customers, 3.83 cents per kWh for industrial customers, and 4.30 cents per kWh for commercial customers. *Id*. at 115.

The settlement allowed Potomac Edison to transfer its generation assets to an affiliate at book value or to a third party. Potomac Edison Settlement Agreement, ¶ 31. Potomac Edison agreed that it would collect no stranded costs and would levy no CTCs on customers. Order 76009, 91 Md. PSC at 120 (8797/129). Nevertheless, if Potomac Edison or its affiliate realized proceeds from any sale of generating assets to a non-affiliated company prior to June 30, 2005, they were "subject to recapture for the benefit of customers." Potomac Edison Settlement Agreement, ¶ 27.

5. Baltimore Gas & Electric Company

In July 1998, BGE filed a restructuring proposal and estimates of its stranded costs in response to the Commission's Order 73834 and as part of a broader restructuring proposal. In October 1998, the Commission consolidated the OPC's petition requesting a reduction in BGE's regulated rates[18] in Case No. 8804 with Case No. 8794. *See* Letter Order, *In re Baltimore Gas and Elec. Co.* (8804/15) (Oct. 23, 1998). As Figure 1a shows, BGE filed testimony in the consolidated docket in December 1998 and February 1999, rebuttal testimony in March 1999, and supplemental testimony in April 1999. Intervening parties (*e.g.*, OPC, MEA, MAPSA, National Railroad Passenger Corporation, Bethlehem Steel Corp., Calvert County, Maryland Industrial Group (*et al.*), the Department of Defense) and Commission Staff filed testimony responding to BGE's restructuring proposal in December 1998. Intervenors and Staff also filed testimony on the regulated rate case in February 1999, and filed rebuttal or supplemental testimony on restructuring in March 1999.

[18] Petition of People's Counsel for a Reduction in the Rates and Charges of the Baltimore Gas and Electric Company, *In re Baltimore Gas and Elec. Co.* (8804/1) (Sept. 3, 1998).

Shortly after BGE, Commission Staff and intervenors filed testimony in March 1999, the General Assembly passed the 1999 Act – which allowed alternative restructuring provisions if agreed by settlement – and the Commission granted a motion to suspend the hearing schedule to allow additional time for settlement discussions. *See* Notice of Emergency Hearing, *In re Baltimore Gas and Elec. Co.* (8804/131) (May 7, 1999). Two months later, on June 29, 1999, the OPC, Commission Staff, and educational, industrial, and state and federal government parties filed a comprehensive settlement agreement. *See* BGE Settlement Agreement (8804/141). On July 9, 1999, the Commission issued a procedural schedule instructing parties to file initial briefs by July 23 and to file reply briefs by August 3. Notice of Procedural Schedule, *In re Baltimore Gas and Elec. Co.* (8804/146) (July 9, 1999). Briefs were to address "(1) whether the proposed settlement is in the public interest; (2) how the proposed settlement advances the purposes enumerated in §7-504 of the recently-enacted Electric Customer Choice and Competition Act of 1999; and (3) whether the proposed settlement is reasonably designed to ensure the creation of competitive electricity supply and electricity supply services markets." *Id.* The Commission scheduled three days of public hearings on August 11, 12, and "if necessary," August 13, 1999. *Id.* Unlike the other Maryland utilities' settlements, BGE's settlement included collection of substantial transition costs[19] – $528 million (after-tax, on a present-value basis as of January 1, 2000) (BGE Settlement Agreement, ¶ 2) – from Maryland's retail electric customers.

The settlement agreement provided retail choice for all customers by July 1, 2000 (ahead of the statutory schedule). *Id.*, ¶¶ 9, 21. It created two forms of SOS for generation services – a rate-reduced Price Freeze Service ("PFS") and Default Service ("DS"). *Id.*, ¶ 12. PFS satisfied the 1999 Act's retail rate reduction provision for residential customers and rate cap provisions for commercial and industrial customers. (Price freeze rates excluded Commission assessments, the kWh franchise tax, and the environmental surcharge, each of which BGE could pass through as surcharges reflecting actual costs. *Id.*, ¶ 36.) For customers who did not receive PFS, BGE offered DS rates, which it set by a formula based on wholesale prices. *Id.*, ¶¶ 16-17.

The settlement's price protection provisions stipulated that all PFS residential customers would receive a total of $53.8 million annually in rate reduction benefits through June 30, 2004, and Schedule R/ES residential customers would receive $50.2 million annually for two additional years.[20] *Id.*, ¶¶ 24 (Schedule R/ES), 25 (Schedule RL). This translated into a 6.5% rate reduction allocated between generation and distribution rates. *See* Order 75757, 90 Md. PSC at 209 (8804/235). Residential customers received PFS for six years (through June 30, 2006, BGE Settlement Agreement, ¶ 13), *i.e.*, two years beyond the four-year statutory

[19] The settlement's transition costs include both stranded costs and new restructuring costs that BGE incurred as part of the deregulation process. *See supra* note 9, at 12.

[20] Schedule R/ES ratepayers received $50.2 million annually in rate reductions for six years and Schedule RL ratepayers received a $3.6 million rate reduction annually for four years.

minimum. Nonresidential customer classes[21] received PFS for two to four years. *Id.*, App. A (Part 2).

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 CTC line-item on customers' bills. As Table 1 shows, each customer class was allocated a share of transition costs. *Id.*, ¶ 2.

TABLE 1 TRANSITION COST COLLECTIONS BY RATE SCHEDULE	
Rate Schedule	**Transition Costs (millions)**
R, RL, ES (residential)	$193.8
G, GS[22]	$53.8
GL	$112.6
P[23] (primary voltage)	$100.7
SL[24] (street lighting)	$5.1
NRP (Amtrak)	$2.5
PL[25] and individual customer contracts	$59.5
Total	**$528**

For commercial and industrial classes, the settlement provided for annual reconciliations of CTC collections against the allowed amount. For these customers, CTC rates were adjusted to calibrate collected revenues against anticipated revenues over the remaining period. *Id.*, ¶ 3. By contrast, for residential classes, the settlement fixed the CTC rate for its full six-year collection period. CTC rates were "to remain unchanged during the applicable recovery period without true-up or reconciliation between actual collections and the transition cost amount." *Id.* Instead, residential customers' CTC rates were linked to their PFS rates. As PFS rates increased, the CTC declined, keeping the generation and CTC components of rates at a constant 4.553 cents per kWh. *Id.*, App. A (Part 2).

The settlement gave nonresidential customer classes different time period options to pay their allocated share of transition costs and to receive PFS. Some customers could pay transition fees to BGE through a one-time, lump sum payment or spread CTCs over a four- to

21 "Nonresidential" or "commercial and industrial" customers, as used in this report, include Schedules G, GS, GL, PL, P and private contracts. For additional information about customer schedules in BGE's tariff, *see* http://www.psc.state.md.us/psc/electric/SOSrates.htm.

22 Schedule G (general service) is for traffic signal service, telecommunications network service, and where the customer does not qualify for any of BGE's other rate schedules. Schedule GS (general service small) is available by request for Schedule G customers and where the customer's consumption is 2,000 kWh or more in any month. Schedule GL (general service large) is for customers with a monthly demand of 60 kW or more.

23 Schedule P is primary voltage service for demands of 1,500 kW or more.

24 Schedule SL (street lighting) is for unmetered street lighting service supplied from overhead or underground facilities on dedicated public streets and roads where required by a city, town, county, or other municipal or public agency, or by an incorporated association of local residents.

25 Schedule PL is private area lighting.

six-year period.[26] *Id.*, ¶¶ 4, 27-33. BGE could adjust these CTC rates annually if they did not match total collections, but such adjustments could not produce rates above the total frozen rate for each PFS rate option. *Id.*, ¶ 36. For each nonresidential customer class with comparable options, both CTC and PFS rates varied according to the duration of the collection period. *Id.*, App. A (Part 2) (*compare*, *e.g.*, Schedule P Option 2 *with* Schedule P Option 3).

The settlement agreement offered a shopping credit during the duration of the price freeze. *Id.*, App. A (Parts 2, 3). BGE explained that these shopping credits were payments that a customer would avoid by switching to an electricity supply competitor and provided the price to compare when considering taking service from an electricity supply competitor. *See* Initial Brief of Baltimore Gas and Electric Company, *In re Baltimore Gas and Elec. Co.* (8804/212) (Aug. 30, 1999) at 7, 15. Residential customers' shopping credits tracked the PFS rate and, therefore, increased over the price freeze period, but commercial and industrial customer classes' shopping credits remained fixed. BGE Settlement Agreement, App. A (Part 3).

BGE's settlement agreement reiterated the company's statutory right to transfer generation assets to affiliated or non-affiliated entities. *Id.*, ¶ 6. The settlement stipulated that BGE could transfer its generation assets to an affiliate at book value, *i.e.*, "the original cost less the related accumulated depreciation and accumulated deferred tax effects." *Id.* As part of the settlement, BGE was permitted to recognize $150 million (pre-tax) in accelerated depreciation or amortization on generating assets for the 12-month period ending June 30, 2000. *Id.*, ¶ 1. BGE agreed not to change its depreciation rates before its next electric rate case. *Id.*, ¶ 49. BGE and other parties agreed that they would not use gains or losses from post-settlement generation asset transactions "in any future proceeding to adjust rates in any way." *Id.*, ¶ 6. Finally, the settlement agreement stipulated that market power studies were "not needed at this time" (*i.e.*, at restructuring (*id.*, ¶ 51)) and required the parties to support or take no position before the Commission regarding various principles related to a "GENCO" code of conduct (which the Commission was required to approve under PUC § 7-505(b)(13)(ii)) (*id.*, ¶ 44). These provisions, when accepted with the entire settlement, effectively gave BGE's generation affiliate significant market power within the BGE service area and sheltered BGE from a thorough review of its affiliate relationships.

The settlement agreement 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 fixed total fund contributions at $520 million in 1993 dollars. Customers would be responsible to maintain the $520 million, adjusted by the Nuclear Regulatory Commission's ("NRC's") published inflation adjustment factor, until decommissioning of the plants. BGE Settlement Agreement, ¶ 22.

Although MAPSA, Trigen Energy, Inc., Statoil, Bethlehem Steel, and the City of Baltimore opposed parts of the settlement, the Commission approved the settlement proposal in Order 75757, 90 Md. PSC 197 (8804/235), and approved BGE's proposed transfer of generation assets to its affiliates by letter order on June 19, 2000 ("June 2000 Letter Order"). MAPSA, a trade association of companies interested in becoming retail electricity suppliers in

[26] Schedule G/GS and SL customers did not have an option for lump sum payment and would have to pay over a period of five or six years. *Id.* ¶¶ 29, 33.

Maryland, appealed the Commission's orders to the Circuit Court for Baltimore City and then to the Maryland Court of Special Appeals, which affirmed the Commission's decisions on each issue. *Mid-Atlantic Power Supply Assoc. v. Md. Pub. Serv. Comm'n*, 795 A.2d 160 (Md. Ct. Spec. App. 2002). MAPSA sought judicial review, *inter alia*, of the following issues: (1) whether the Commission's determination that the $528 million transition costs was supported by the record and in compliance with the 1999 Act, (2) whether the deferral of a market power investigation to investigate market power issues in BGE's service territory is allowed, (3) whether BGE's rate reduction package violated the statute, and (4) whether the Commission could approve BGE's transfer of its generating assets to unregulated affiliates at book value.

The Court resoundingly affirmed the Commission's approval of BGE's settlement agreement. First, finding no error in the Commission's approval of the $528 million transition cost value, the Court held that the Commission was not required to state its findings on each factor enumerated in section 7-513(e) to determine the allocation of transition costs and benefits. *Id.* at 170. The Court found that the settlement transition costs were adequately supported, commending the Commission on its "comprehensive analysis of the evidence." *Id.* at 176. Thus, the Court affirmed unequivocally the Commission's order approving the settlement's $528 million transition costs, adding that because of the settling parties' disparate positions, the settlement was "probative of its own reasonableness." *Id.* at 175.

Second, the Court found the Commission's approval of the settlement, which deferred a market power proceeding to investigate the impact of restructuring on retail markets, was not contrary to the 1999 Act. The Commission had not bargained away its powers or limited its rights to initiate an investigation on its own. *Id.* at 177.

Third, the Court found the Commission's approval of BGE's rate package for residential customers complied with the statutory provisions giving the Commission discretion to make complex policy choices. MAPSA opposed the six-year, 6.5% rate reduction for customers, the share of the rate reduction allocated between BGE's generation and distribution charges, and the amount of transition costs to be collected from residential customers ($193.8 million). The Court held that the Commission had discretion to approve the six-year rate cap (which was greater than the four-year cap provided by statute) if the Commission found that the provision was equally protective of ratepayers, which the statute permitted. The Court rejected MAPSA's objections to the settlement's allocation of 68% of the total statutory rate reduction to the generation component of rates. MAPSA contended that this allocation adversely affected competition in the unregulated retail generation market. Finding that the statute gave the Commission "broad discretionary power," (*id.* at 179), the Court held that the Commission's determination was supported by sufficient evidence on the record.

Fourth, the Court found MAPSA's objections to the Commission's approval of BGE's application to transfer its assets were "no more than a reiteration of its earlier arguments attacking the stranded cost recovery amount." *Id.* at 183. Determining that the Commission "was not even required by the Act to review the transfer," the Court nevertheless found "substantial evidence in the record supporting the Letter Order." *Id*.

III. Transition Costs of BGE's Generation Asset Divestiture

A. Overview of Stranded Costs

Stranded costs are the value of potential losses incurred by an electric utility as a result of restructuring the regulated retail generation supply market to allow for competition. Maryland's restructuring statute defined stranded costs as one type of transition cost for generation assets that "traditionally would have been . . . recoverable under rate-of-return regulation, but which may not be recoverable in a restructured electricity supply market." PUC § 7-501(p)(1). Sources of stranded costs include the cost of investments in generation facilities that were not fully recovered under cost-of-service regulation and that may not be recoverable in a competitive market, long-term contracts for power or power purchase agreements, "regulatory assets" such as income tax liabilities that utility regulators required to be deferred, investments in social programs, and labor benefits costs. *See* Cong. Budget Office, Electric Utilities: Deregulation and Stranded Costs 7-12 (1998) ("CBO Report").

Stranded costs are measured by the amount that utilities' generation assets in a regulated regime exceed their value in a competitive market. Stranded costs are derived by taking the difference between the asset's "regulated" value (which is based on its depreciated book value) and its fair market value (which is its forward-looking value under a competitive market structure or its sale price). At the time Maryland was evaluating whether to deregulate retail generation, the principal 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. *Id.* at 13-15. The 1999 Act required the Commission to consider six factors (1) book value and fair market value, (2) auctions and sales of comparable assets, (3) appraisals, (4) the revenue the company would receive under rate-of-return regulation, (5) the revenue the company would receive in a restructured electricity supply market, and (6) computer simulations provided to the Commission, in addition to other evidence of value. PUC § 7-513(e)(ii).

Expert witnesses considered each of these valuation methods in BGE's restructuring proceeding. For those believing that a reasonable stranded cost value could be derived despite market uncertainty, the predominant method used was an administrative calculation of the present value of cash flows under regulation (*i.e.*, book value) and competition (*i.e.*, market value). In light of that uncertainty, not all parties supported immediate divestiture of BGE's generating assets. BGE, Commission Staff, and others proposed to defer the stranded cost valuation to a later date,[27] particularly for the Calvert Cliffs nuclear generation

[27] *See, e.g.,* Prepared Direct Testimony of David A. Brune on Behalf of Baltimore Gas and Electric, *In re Baltimore Gas and Elec. Co.* (8794/2) (July 1, 1998) ("Brune Test. (8794/2)") at 15:15-21 (recommending deferring market value to 2002, or later, anticipating "more will be known about market prices and asset sales"); Direct Testimony of Matthew I. Kahal on Behalf of the Maryland Energy Administration Power Plant Research Program, *In re Baltimore Gas and Elec. Co.* (8804/47) (Dec. 21, 1998) ("Kahal Test. (8804/47)") at 22-23, 30 (recommending final stranded cost determination be deferred for about five years); Direct Testimony and Exhibits of Steven J. Baron on Behalf of the Maryland Industrial Group and Millennium Inorganic Chemicals Inc., *In re Baltimore Gas and Elec. Co.* (8804/54) (Dec. 22, 1998) ("Baron Test. (8804/54)") at 8:31-35 ("Two to four years after the initiation of retail competition, the Commission should initiate a proceeding to determine the final market valuation of

assets.[28] Postponement of divestiture – which even BGE initially supported – would almost certainly have produced a higher, more accurate valuation of Calvert Cliffs, the determinative component of BGE's stranded costs.[29]

Market-based stranded cost valuations can be derived by auctioning assets or by negotiating sales in private transactions. A competitive auction for assets definitively establishes fair market value.[30] An auction can clearly specify what assets – including associated liabilities – are being transferred and conclusively determine their value. Some auction approaches and rules may produce more efficient, revenue maximizing outcomes. *See* Peter Cramton *et al.*, Using Auctions to Divest Generation Assets, 10 Elec. J. 22 (1997). Some states required utilities to auction their generation assets because valuation by an auction could be less controversial than administrative valuations and could produce more revenue than other valuation methods. Moreover, auctions could reduce vertical market power that would otherwise be preserved by an affiliate's ownership. Non-incumbent auction winners could also reduce horizontal market power in the relevant market for generation services.

Some intervening parties in BGE's divestiture proceeding believed that the only reliable way to determine market value was by an asset sale.[31] Pepco's sale of generating assets certainly underscores the opportunity for error of an administrative valuation. Pepco estimated

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BGE's generating assets. If there are any net stranded costs determined in such a proceeding, these would be recovered during a short, [sic] extension to the transition period.").

28 *See* Rebuttal Testimony of Paul Chernick on Behalf of Maryland Office of People's Counsel, *In re Baltimore Gas and Elec. Co.* (8804/104) (Mar. 22, 1999) ("Chernick Test. (8804/104)") at 11:17-12:1 ("It is possible that waiting until 2004 or later will maximize the value of Calvert Cliffs . . . . [but] plants that have sold in recent years indicate substantial values for plants that are less desirable than Calvert Cliffs"); Direct Testimony and Exhibits of James Akers, Jr. (Commission Staff), *In re Baltimore Gas and Elec. Co.* (8804/60) (Dec. 22, 1998) ("Akers Test. (8804/60)") at 4:1-4 (recommending Calvert Cliffs stay under cost-of-service regulation).

29 As late as March 1999, BGE continued to support a divestiture plan that would keep Calvert Cliffs as a regulated asset under the Commission's jurisdiction. *See* Prepared Rebuttal Testimony of David A. Brune on Behalf of Baltimore Gas and Electric Company, *In re Baltimore Gas and Elec.* (8804/106) (Mar. 22, 1999) ("Brune Test. (8804/106)") at 8:1-9.

30 This is true even for assets with negative value. For example, reverse auctions can be used to sell above-market power purchase contracts that are under water, with the winning party willing to take the least amount of money to assume the contract.

31 MAPSA's expert witness rejected BGE's cash flow valuation because the computer simulations excluded choices that would be made by a competitive supplier. Direct Testimony of Mark D. Younger (MAPSA), *In re Baltimore Gas and Elec. Co.* (8804/61) (Dec. 23, 1998) ("Younger Test. (8804/61)") at 5:5-6:6 (citing examples of how a bidder's analysis would differ from BGE's model). Rather than calculating the assets' market value by computer modeling, MAPSA recommended auctioning the assets. *Id*. at 8:11-9:1; *see also*, Direct Testimony of Kenneth L. Kincel for U.S. Department of Defense, et al., *In re Baltimore Gas and Elec. Co.* (8804/50) (Dec. 21, 1998) ("Kincel Test. (8804/50))" at 11:2-11 (recommending marketplace bids to check administrative valuation); Testimony of Peter A. Bradford on Behalf of the Office of People's Counsel, *In re Baltimore Gas and Elec. Co.* (8804/55) (Dec. 22, 1998) ("Bradford Test. (8804/55)") at 65:14-65:19 (auction is the best way to separate vertically integrated companies and determine asset value); Direct Testimony of Paul Chernick on Behalf of the Office of People's Counsel, *In re Baltimore Gas and Elec. Co.* (8804/55) (Dec. 22, 1998) ("Chernick Test. (8804/55)") at 32:1-8 (most direct way to determine market value is to conduct an auction).

its stranded costs at $600.4 million (Order 75850, 90 Md. PSC at 352-53 (8796/189)), but when it auctioned assets to non-affiliates, sale proceeds produced $457 million of stranded benefits, which were applied to the company's regulatory assets and DSM, with the remainder returned to customers. BGE was not open to a sale of its generation assets, however, and because the General Assembly had rejected amendments to the 1999 Act that would have required a competitive auction to divest assets,[32] the Commission had no authority to require a sale. In the absence of an auction to establish the definitive value, fair market value estimations may also be extrapolated from past sales of comparable generating assets. Subject to significant error, Staff, OPC, MAPSA and other parties attempted to use this alternative market valuation method.

Administrative stranded cost valuations may be calculated two ways – *ex ante* or *ex post*. The *ex ante* approach is a DCF calculation of the difference between the present values of expected revenues under regulation and under competition. To perform a cash flow analysis, experts may rely on financial accounting data reflecting the generation assets' regulated value as recorded in state regulators' administrative dockets to derive the assets' value under regulation. Compared with the market valuation method, an administrative estimation of assets' fair market value is much more subjective. Small changes in assumptions and data can have a "significant impact." Direct Testimony and Exhibits of Tracey M. Stuart-Paul (Commission Staff), *In re Baltimore Gas and Elec. Co*. (8804/60) (Dec. 22, 1998) ("Stuart-Paul Test. (8804/60)") at 7:6. Cash flow projections made at the time of BGE's divestiture relied on historical data to forecast future costs and revenues. Such projections were also extremely sensitive to expectations about the future performance of restructured wholesale markets regulated by FERC, as well as expectations about how the retail generation market would operate. For before March 1999, FERC required BGE and other companies with generating assets to base their offers on the marginal costs of supplying energy, but after that time, suppliers submitted market-based offers based on FERC's expectation that competition would discipline price. Wholesale energy prices – the most significant component of the revenue stream – were also particularly dependant on expectations about fuel prices, and the parties' experts uniformly underestimated fuel prices in their administrative valuations.

An administrative *ex post* estimate defers the market valuation until realized – rather than forecast – market prices become available to support the valuation. This method is identical to the administrative *ex ante* method, but instead requires a backward-looking calculation of the assets' regulated value (*i.e.*, the value of the asset if regulation had continued). Several parties, including BGE, proposed to defer divestiture to allow for a more certain valuation.[33]

Capital market stranded cost valuations require splitting the regulated utility's capital stock into an "A" stock (status quo, voting stock) and a "B" stock (associated with the right to recover stranded costs). CBO REPORT at 15 (citing Michael K. Block, Robert Franciosi, and Melinda L. Ogle, *The ABC's of Stranded Costs* (Phoenix, Ariz: Goldwater Institute, no date)).

32 *See supra* Section II.B.5, at 13-14 (discussing the Frosh Amendment).

33 *See supra* notes 27-29, at 23-24.

Traded separately for a period, the stranded costs would be the net book value before restructuring less the average market value of "A" stock, if "A" stock fell below book value.

Expert witnesses in BGE's restructuring proceeding considered each of these methods, or some derivation. *See infra* Sections III.C.1-2, at 29-46. The predominant method in pre-settlement testimony, however, was an administrative *ex ante* calculation based on determining the present value of cash flows under the two regimes, regulated and competitive.

B. BGE's Estimates of Transition Costs and Proposal for Phased Retail Deregulation

Well before the 1999 Act became law, BGE proposed a restructuring plan to phase in retail choice and to freeze real retail electricity prices for an indeterminate transition period until generation assets were transferred. Beginning with one-third of its customers by July 2000, retail choice would be fully phased in two years later. Brune Test. (8794/2) at 6:17-19. BGE proposed to unbundle its rates and offer standard offer service to all customers (*id.* at 7:3-13), along with a shopping credit to permit customers to purchase from alternative suppliers that would provide "full credit for the market value of the services [(*i.e.*, energy, capacity, ancillary service)] that customers no longer purchase from BGE."[34] Under BGE's proposal, retail electricity prices would be frozen (in nominal terms) through June 2002, at rates in effect at year-end 1998. Beginning July 2002, prices would be adjusted annually by an inflation index, such as the consumer price index. *Id.* at 5:19-6:10.

BGE defined the transition period as the time during which its customers would receive price protection and during which BGE would continue to receive regulated rate-of-return treatment on its generation assets. *Id.* at 8:7-12, 9:4, 12:4-9. BGE could maintain its regulatory books of account and would accelerate depreciation (to reduce the regulatory book value of assets) beginning in calendar year 1999. *Id.* at 12:7-11. During the transition period, the company would take steps to assure that the total return on rate base did not exceed the "currently allowed level" of 9.4%. *Id.*

Under BGE's proposal, the transition period would end when stranded costs were nearly eliminated, and at this time, BGE would transfer assets to an affiliate. *Id.* at 15:15-20 (recommending deferring market value to 2002, or later, anticipating that "more will be known about market prices and asset sales"). With this approach, BGE would,

> track market value and [] end the transition period when the book value is first observed to be less than 110% of market value or on June 30, 2008, whichever is earlier. Our best estimate of when book value and market value will converge is in 2004. In this case, the transition period and the price protection would end in 2004. However, there is significant uncertainty associated with the projection of market price. If, for whatever reason, market prices are lower or higher than

[34] *Id.* at 6:21-7:1. The proposed shopping credit would be based on wholesale energy priced at the actual PJM locational market price (hourly, actual, or estimated depending on customer size) for the BGE service territory, and would include ancillary services, transmission and other avoided costs, less a mark-up for electric losses at the retail delivery level. *Id.* at 9:14-10:18. PSC Staff, OPC, and other parties opposed BGE's shopping credit proposal.

BGE anticipates, the convergence of book value and market value would be deferred or accelerated, respectively.

Id. at 9:6-13.

BGE proposed market value appraisals of its generation assets, conducted by an "independent and objective professional organization(s) with the requisite expertise," on an annual basis beginning December 31, 2002, through 2007. *Id.* at 13:9-16. The appraisers would consider factors such as generation market prices, condition and operating costs of plants, needs for capital improvement, sale value of comparable assets, and other factors. Brune Test. (8794/2) at 13:16-13:20. The first appraisal would be deferred to 2002 because "[t]he range of plausible market valuations . . . are too uncertain at present" to be reliable. *Id.* at 15:3-20 (referencing, *e.g.*, the newly restructured wholesale energy market in PJM[35]). The final determination of stranded costs/benefits would be paid by or credited to customers, over a two- or three-year amortization period. *Id.* at 14:5-8. This approach, had it been adopted, would have reflected the substantial increases in generation values that occurred after 2000 and would have eliminated any ratepayer liability for stranded costs.

BGE proposed to keep certain regulatory assets relating to generation and totaling approximately $370 million in its rate base.[36] Regulatory assets associated with expenses deferred by the Commission would continue to be recovered as if electric deregulation had not occurred. *Id.* at 20:6-21:3. These included nuclear assets, labor-related benefits programs, energy conservation programs, federal decommissioning-related costs, income taxes and tax credits, costs incorporated into fuel rate no longer recoverable, deferred electric fuel costs, and emission allowances sales. Prepared Direct Testimony of Richard M. Bange, Jr. on Behalf of Baltimore Gas and Electric Co., *In re Baltimore Gas and Elec. Co.* (8794/2) (July 1, 1998) ("Bange Test. (8794/2)") at 7:7-8:4; Ex. RMB-4 (8794/2) (approximately $370 million of regulatory assets, by line item).

BGE proposed to continue collecting decommissioning funds for Calvert Cliffs from ratepayers through a non-bypassable charge. Brune Test. (8794/2) at 17:11-14. BGE explained that this approach assured funding of the decommissioning trust in a deregulated environment (addressing the NRC's safety concerns) and was consistent with practices contemplated by other state utility commissions in New Jersey, Pennsylvania, and California. *Id.* at 17:14-22, 19:18-20:5.

Finally, the costs of restructuring – *i.e.*, new, out-of-pocket costs projected to be about $85 million (Ex. RHB-1 (8794/2)) – would be absorbed by BGE within the price cap, which was anticipated to extend through the transition period. Brune Test. (8794/2) at 22:19-23:22. BGE would also collect any ongoing restructuring costs after the transition period. *Id.*

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35 PJM Interconnection, L.L.C. ("PJM") is a FERC-jurisdictional regional transmission organization ("RTO") that manages the wholesale electricity markets in all or parts of Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia and the District of Columbia. For more information, *see* PJM Overview, available at http://www.pjm.com/ about/overview.html (last visited January 11, 2008).

36 For further discussion of regulatory assets, *see infra* Section V, at 72-77; *see also* CBO Report at 10-11.

C. Stranded Cost Estimation Methodologies

Despite its proposal to defer divestiture and asset valuation until energy markets could be predicted with greater certainty, BGE estimated stranded costs by calculating the "present value of the cash flow derived from the asset" so that BGE's stranded costs would be "the difference between the value, or cash flow, of assets operating under two different market structures – regulation and competition." Prepared Direct Testimony of Ralph H. Bourquin, Jr. on Behalf of Baltimore Gas and Electric Co., *In re Baltimore Gas and Elec. Co.* (8794/2) (July 1, 1998) ("Bourquin Test. (8794/2)") at 7:10-21; *see also* Prepared Direct Testimony of Jerome E. Hass on Behalf of Baltimore Gas and Electric Co., *In re Baltimore Gas and Elec. Co*. (8794/2) (July 1, 1998) ("Hass Test. (8794/2)") at 5:10-13 ("The stranded investment associated with an electricity generation asset is equal to the difference between the yet-unrecovered original cost base of the investment and the value of the asset in the competitive marketplace.").

Although this cash flow analysis was the primary methodology used by most parties filing comprehensive stranded cost valuations, some rebuttal witnesses proposed other valuation methods, as the 1999 Act required. Some parties proposed to compare recent sales of fossil plants as a way to measure the market value of BGE's fossil assets. For example, Commission Staff witness Akers proposed market valuation based on average sales price of generation assets within the PJM footprint.[37] MAPSA did the same.[38] Bethlehem Steel's expert witness Phillips used the net book values of BGE's generation assets, adjusted to reflect going-forward assumptions related to capital, taxes, and operating costs, and found that BGE could recover its fixed investment costs if market prices allowed the company to recover at least $35 per MWh. OPC expert witness Hill proposed another option for valuation – for the company to effectuate a corporate spin-off, as AT&T did with Bell Labs (Lucent Technologies), or split into two or more tracking stocks so that value would be determined in the marketplace. Testimony of Stephen G. Hill on Behalf of the Maryland Office of People's Counsel, *In re Baltimore Gas and Elec. Co.* (8804/55) (Dec. 22, 1998) ("Hill Test. (8804/55)") at 9-10.

Many intervenors agreed that auctioning assets was the best way to derive their market value. Chernick Test. (8804/55) at 21:19-22:10; 32:1-8; 5:13-14 ("only way to determine definitively the market value of generation assets is to determine who will pay the most for them"); *see supra* note 31, at 24. Fossil assets could have been auctioned immediately, but, as noted above, the Commission had no authority under the 1999 Act to require BGE to divest by auction.

By contrast, most believed Calvert Cliffs' market value was too speculative to be useful. There were few nuclear plant sales from which to extrapolate a fair market value for Calvert Cliffs. *See* Akers Test. (8804/60) at 2:19-3:18 (declining to file testimony on comparable market valuation for Calvert Cliffs because no basis existed for a "valid market

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[37] *See, e.g.*, Akers Test. (8804/60) at 1:13-17 (testifying on comparable sales of fossil generating plants).

[38] MAPSA witness Younger presented data showing median sales of fossil-fueled plants were 170% of book value (Younger Test. (8804/61) at 16:5-7) and estimated a market value of $750 million for Calvert Cliffs (*id.* at 17:2-4).

evaluation"); Kahal Test. (8804/47) at 32 (comparable market asset sales "are not available" for nuclear plants); *cf.* Chernick Test. (8804/104) at 11:7-20:4 (deals are "complex and difficult to value precisely" but pessimism is not warranted, citing pending sales of Pilgrim and Three Mile Island). The nuclear plants that had been sold reflected the perceived risks of nuclear energy – *e.g.*, an uncertain regulatory environment, the possibility of accidents anywhere that could impact operations, the poor performance records of nuclear plants (*e.g.*, low capacity factors), the costs of repairs or upgrades to equipment like steam generators, the lack of an assured disposal site for spent nuclear fuel, the costs of decommissioning, and the adequacy of decommissioning trust funds[39] – making it difficult to assign a value to Calvert Cliffs based on comparable sales. *See* Akers Test. (8804/60) at 3:15-3:18 (nuclear sales evaluation is "further complicated" by "unresolved issues," *i.e.*, NRC licensing, spent fuel disposition, nuclear fuel, and decommissioning expenses).

Because markets for the sale of Calvert Cliffs and other nuclear facilities were so thin, BGE and other parties recommended that the Commission defer BGE's divestiture of Calvert Cliffs and offered alternatives in the interim. *See, e.g.*, Chernick Test. (8804/104) at 11:18-21 ("waiting until 2004 or later will [possibly] maximize the value of Calvert Cliffs, [although the sale] is likely to be feasible sooner than 2004"); Chernick Test. (8804/55) at 23:1-18 (recommending the Commission impute a market value equivalent or, alternatively, continue cost-of-service ratemaking for the facility); Direct Testimony of Jeffrey V. Conopask (Commission Staff), *In re Baltimore Gas and Elec. Co.* (8804/60) (Dec. 22, 1998) ("Conopask Test. (8804/60)") at 30-31 (recommending that Calvert Cliffs' net costs be included in distribution rates and any asset sale be deferred). The Commission-approved settlement did not follow this universally held view.

1. <u>BGE's Stranded Cost Estimates of Generation Assets</u>

BGE filed transition costs[40] of $1.13 billion (Ex. RHB-1 (8794/2), Bourquin Test. (8794/2) at 3:17-18), $911 million attributed to stranded nuclear assets,[41] $137 million to stranded non-nuclear generation assets, and the remaining ($85 million) to newly incurred

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39 Of course, BGE had proposed that ratepayer continue to fund decommissioning through a non-bypassable charge. Continued ratepayer funding for decommissioning materially reduced the decommissioning risk and increased the fair market value of the Calvert Cliffs plant.

40 BGE filed for two categories of transition costs: (1) generation assets, including wholly-owned fossil and nuclear generation facilities and ownership interests in the Keystone and Conemaugh generation facilities and the Safe Harbor Water Power Corporation, and (2) restructuring costs that are "new expenditures" related to "initiation, implementation and ongoing provision of utility activities to accommodate a competitive retail market." Bourquin Test. (8794/2) at 5:16-6:16. As used here, "stranded costs" refers only to the first category of transition costs. As explained *infra* in Section V, at 72-77, BGE excluded $370 million of its regulatory assets from its stranded cost valuation and sought to recover them separately. *See* Bange Test. (8794/2)" at 7:7-12:8; Ex. RMB-4 (8794/2) ($370 million of regulatory assets, by line item).

41 BGE's stranded cost valuations of Calvert Cliffs assume that the NRC would grant the facility's application for a license renewal and the facility would continue operation until its renewed licenses expired in 2034 and 2036. *See* Ex. RHB-2 (8794/2) at 5-8.

restructuring costs.[42] Ex. RHB-1 (8794/2), *cf.* Bourquin Test. (8794/2) at 3:17-4:2 (citing approximately $910 million and $140 million in stranded nuclear and fossil assets, respectively). BGE made two modifications to its stranded cost valuation during pre-settlement proceedings. First, it filed a $17 million upward adjustment to the book values of nuclear and fossil assets – increasing the book value of nuclear assets by $5 million and the non-nuclear assets by $12 million. *See* Ex. RMB-3 (revised Dec. 22, 1998) (8804/57); Rebuttal Testimony of Ralph H. Bourquin, Jr. on Behalf of Baltimore Gas and Electric Co., *In re Baltimore Gas and Elec. Co.* (8804/106) (Mar. 22, 1999) ("Bourquin Test. (8804/106)") at 3:8-13 (noting revision). This adjustment – which increased BGE's stranded cost estimate of its nuclear assets to $916 million and its non-nuclear assets to $149 million – reflected removal of accumulated deferred income taxes related to conservation costs. Letter from Lisa M. Decker to Felecia L. Greer, *In re Baltimore Gas and Elec. Co.* (Dec. 22, 1998) (8804/57) ("Decker Letter (8804/57)") (explaining that enclosed exhibits are being filed to revise Bange's testimony to make "minor corrections" related to the "removal of accumulated deferred income taxes related to conservation costs").

BGE made a second adjustment that reduced its stranded cost estimate by $253 million, to $812 million. This adjustment captured the increase in market value of BGE's generating assets resulting from revisions to the Maryland tax code. Prepared Supplemental Testimony of Ralph H. Bourquin, Jr. on Behalf of Baltimore Gas and Electric Co., *In re Baltimore Gas and Elec. Co*. (8804/127) (Apr. 29, 1999) ("Bourquin Test. (8804/127)") at 1:20-22; Ex. RHB-2 (8804/127).

By April 1999, BGE's restructuring proposal as filed supported a request for stranded costs for its nuclear and non-nuclear assets of $812 million, as reflected in Table 2. We explain BGE's assumptions used to calculate regulated book value in Section III.C.1.a and its assumptions used to determine market value in Section III.C.1.b.

TABLE 2
BGE'S TRANSITION COST PROPOSAL

	Nuclear Assets	Non-Nuclear Generation Assets	Total Assets
	(in millions)		
Market Value of Generation Assets	$438	$1,546	$1,984
Book Value of Generation Assets	$1,221	$1,575	$2,796
Stranded Investment in Generation Assets	***$783***	***$29***	***$ 812***
Restructuring Costs			$85
Transition Costs			**$897**
Regulatory Assets			**$370**

Source: Ex. RHB-1 (8804/127), RHB-4 (8794/2).

42 S*ee also* Bourquin Test. (8794/2) at 7:16-21. BGE derived the $1.13 billion in transition costs by computing the difference between the assets' $1.7 billion market value in a competitive market (*i.e.*, "competitive market value") and the $2.779 billion book value of assets under regulation (*i.e.*, "regulatory book value").

As explained *infra*, because BGE anticipated a 20-year extension of its Calvert Cliffs' operating license, but was not certain, it used computer modeling to simulate two wholesale market scenarios – with and without Calvert Cliffs. If the NRC granted a license to continue the facility's operation for another 20 years, it would need to replace its steam generators. BGE estimated the renewed license's value to be about $160 million, but the market value of the facility fell by about the same amount if the steam generators were not replaced.[43] Thus, in its testimony, the company appeared indifferent to continuing operations at its nuclear facility.

a. <u>Book Value</u>

BGE estimated its generating assets' value under a regulated market structure by calculating the present value of cash flows from the book value of its regulated generation assets, as of December 31, 1999. Bourquin Test. (8794/2) at 7:9-8:9. "In a regulated market, the present value of the cash flows associated with generation assets are equivalent to the rate base of those assets, given that tariffs have been appropriately established to fully recover the original investment." *Id.* at 7:14-16. A regulated utility's accounting book value is derived from plant in service, construction work in progress ("CWIP"), property, fuel, inventories, accumulated depreciation, and accumulated deferred income taxes ("ADIT"). Ex. RMB-1 (8794/2).

BGE's stranded cost calculation assumed a regulated book value of $2.78 billion for generation assets based on 1997 year-end accounting data that had been projected two years forward to December 31, 1999.[44] The book value of fossil assets was $1.56 billion and the nuclear assets' value was $1.22 billion. Ex. RMB-3 (8794/2); *see also* Ex. RMB-2 (8794/2) (showing book value by generation station as of December 1997). As noted above, BGE filed corrections on December 22, 1998, reflecting small increases in the book value of nuclear ($5 million) and non-nuclear generation ($12 million) after removing accumulated deferred income taxes related to conservation costs. Bourquin Test. (8804/106) at 3:8-12, RMB-3 (revised) (8804/57); Decker Letter (8804/57).

b. <u>Fair Market Value</u>

BGE estimated the December 31, 1999 market value of its generation assets at $1.73 billion – $305 million for Calvert Cliffs and $1.43 billion for the non-nuclear assets. Bourquin Test. (8794/2) at 9:12-15; RHB-2 (8794/2). Following changes to Maryland's tax code in April 1999,[45] BGE filed supplemental testimony to increase its market value estimates by $253

[43] Bourquin Test. (8794/2) at 16:12-22.

[44] Bange Test. (8794/2) at 4:1-5:9. The total book value of BGE's nuclear and non-nuclear assets (as of December 1997) was $2.848 billion (Ex. RMB-1 (8794/2)) and the projected book value (as of December 1999) was $2.779 billion (Ex. RMB-3 (8794/2)), revised to $2.796 billion (Ex. RMB-3 (revised) (8804/57)). The 1997 book value and the 1999 projected book value show differences in plant in service (due to anticipated capital projects and anticipated retirements), projections of CWIP and allowance for funds used during construction ("AFUDC"), fuel and materials/supplies inventories, depreciation, and ADIT. Bange Test. (8794/2) at 6:6-7:6.

[45] The Electric and Gas Utility Tax Reform Act and tax-related provisions in the Electric Utility Restructuring Act assessed a Maryland corporate income tax of seven percent, gave a corporate income tax credit of 60% of the property tax on public utility property (excluding land), phased in a 50% personal

million to $1.98 billion. *See* Bourquin Test. (8804/127) at 1:20-22; RHB-2 (8804/127). The adjustment increased Calvert Cliffs' market value to $438 million and the non-nuclear assets increased to $1.55 billion. *See* RHB-2 (8804/127). Bourquin's adjustment to market value reduced BGE's filed stranded costs by $253 million to $812 million, as reported in Table 2. Bourquin Test. (8804/127) at 1:20-22; Ex. RHB-1 (8804/127).

BGE calculated the value of assets under a competitive market structure by taking the present value of the "projected after-tax cash flows associated with selling our generation output into competitive wholesale markets, discounted at an after-tax cost of capital appropriate for a generation company operating in a competitive market," including recovery of projected operating expenditures for the facility. Bourquin Test. (8794/2) at 8:10-17. Thus, market values were based on the present value of the electricity generation assets, assuming that the assets would sell certain levels of output at forecasted prices and would incur certain operating expenses. Hass Test. (8794/2) at 7:19-8:14.

To make these calculations BGE had to make assumptions about plants' expected revenues and costs, as well as assumptions about a hypothetical after-tax cost of capital for merchant plants. BGE also made assumptions about future federal income taxes and other state and federal taxes, debt costs, inflation, nuclear and fossil plant lives, costs of retiring fossil plants, fuel prices (for coal, gas, uranium), wholesale market prices (for energy, capacity, and ancillary services), operations and maintenance ("O&M") expense (by plant), and plant capital expenditures. Forecasted expenses to operate the plants at production output levels assumed in the revenue stream projections included fuel, O&M, retirement costs, and capital improvements. *See generally* Ex. RHB-4 (8794/2). BGE's bases for these assumptions are summarized below.

Fuel Prices. BGE's fuel cost projections for natural gas, fuel oil, coal, and uranium were inputs to its wholesale energy revenue projections as well as expected costs of production. BGE assumed at the time that oil and natural gas prices would fluctuate in a narrow range around their long-run price, which "tend[ed] to be flat, rather than upward sloping" (Prepared Direct Testimony of Dr. Scott T. Jones on Behalf of Baltimore Gas and Electric Co., *In re Baltimore Gas and Elec. Co.* (8794/2) (July 1, 1998) ("Jones Test. (8794/2)" at 7:5-6) and recommended that the Commission use fuel price projections incorporating these assumptions. *See id.* at 10:18-12:7 (competing fuels revert toward a long-term average price, citing Exs. STJ-3 – STJ-6 (8794/2)); *id.* at 13:8-14:8 (demand-side variables affecting high forecasts in the 1980s wrongly ignored supply-side variables, such as growing natural gas reserves).

The price trajectories for fuel reflected BGE's belief that fuel was at its long-run equilibrium price.[46] Coal price forecasts (excluding any emissions allowances), provided by

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property tax reduction, eliminated a gross receipts tax on generation revenue, and eliminated an environmental surcharge on each kilowatt of generation. Prepared Supplemental Testimony of Richard M. Bange, Jr. on Behalf of Baltimore Gas and Electric Co., *In re Baltimore Gas and Elec. Co.* (8804/127) (Apr. 29, 1999) at 2:3-6:11.

46 The company used a "commodity price plus transportation costs/fees and inflation" calculation for natural gas, and a "[c]ompany fuel price forecast and inflation" calculation for the delivered price of coal, fuel oil, and uranium. *Id.* at 2:20-3:2.

BGE's Fuels and Business Planning Department, predicted no nominal increase in delivered coal prices though 2002, but expected those prices to rise thereafter by 1.5% per year. *Id.* at 3:23-4:15. Natural gas price forecasts were based on a short-term outlook (through 2000) using a New York Mercantile Exchange ("NYMEX") quote at Henry Hub, plus a 1.5 cent per mmBtu markup. BGE's estimate included pipeline charges such as transportation, retainage, and released capacity. After 2000, BGE assumed natural gas prices would increase with inflation (*i.e.*, at three percent per year). *Id.* at 5:3-6:3. BGE's uranium forecasts assumed prices would remain flat in nominal terms – *i.e.*, decline in real terms. *Id.* at 6:4-7. Petroleum fuel forecasts were also based on a short-term forecast through 2000, escalated by the rate of inflation thereafter with seasonal price patterns. *Id.* at 6:8-17.

Wholesale Market Revenues. BGE assumed generating plants would receive energy, capacity, and ancillary services revenues. Bourquin Test. (8794/2) at 10:12-16. Plant revenues from the wholesale energy market were based on energy market prices forecast by a modeling program, PROMOD, through 2007 and estimated thereafter.[47] PROMOD is a production cost simulator that forecasts future energy prices based on assumptions about demand (load characteristics) and supply, *i.e.*, generator performance, fuel, technology and marginal costs of producing energy, and system-wide assumptions such as imports/exports, transmission constraints, system capacity, and capacity additions. PROMOD assumed the system was unconstrained, so that its market price outputs did not reflect any modeling for transmission congestion.[48] PROMOD-based forecasts and extrapolations showed energy prices slowly increasing over a fifteen-year projection period.[49] *See* Bourquin Test. (8794/2) at 10:19-11:3; RHB-3 (8794/2) (showing projected PJM time-weighted average annual energy price at $24.10 per MWh (in 2000) rising to $35.40 (2015) and a production-weighted price received by BGE assets at $25.00 per MWh (in 2000) rising to $36.30 (2015)); *see also* Ex. JSF2 (8794/2) at 2 (showing projected PJM load-weighted energy prices).

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,

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47 Bourquin Rebuttal Test. (8804/106) at 13:12-23. For more information about PROMOD, *see* Prepared Direct Testimony of Jonathan S. Falk on Behalf of Baltimore Gas and Electric Co., *In re Baltimore Gas and Elec. Co.* (8794/2) (July 1, 1998) ("Falk Test. (8794/2)") at 6:1-10.

48 Bourquin Test. (8794/2) at 12:6-13. Bourquin concluded, "If BGE were to estimate the effect of transmission congestion on its generation revenues, and it was assumed that historic conditions within PJM were an indication of future conditions, BGE's generation revenues would be lower during times of congestions than those assumed in this analysis." *Id.* at 12:9-13. If transmission constraints had been modeled and predicted, BGE witnesses testified that prices in Maryland would be lower. Falk Test. (8794/2) at 2:17-21, 16:8-14 (predicting energy prices would be lower if transmission constraints were modeled because wholesale prices in the BGE service are "generally equal to or lower than the PJM average"). This assumption proved to be quite mistaken because Maryland – and particularly SWMAAC – is now highly constrained, thus substantially increasing both energy and capacity prices above those assumed in the pre-restructuring proposals.

49 OPC expert witness Biewald reviewed BGE's PROMOD and the NERA LP model outputs produced in discovery. He reported in rebuttal testimony that BGE's productions were incomplete and Bourquin's testimony was inconsistent with PROMOD's reporting results. *See* Testimony of Bruce E. Biewald on Behalf of the Maryland Office of People's Counsel, *In re Baltimore Gas and Elec. Co.* (8804/55) (Dec. 22, 1998) ("Biewald Test. (8804/55)") at 24:1-29:12 (confidential portions redacted). BGE denied all of these accusations in its next round of testimony.

stranded costs. Significantly for our analysis, a $1 per MWh increase in the forecasted average wholesale market price would increase BGE's generation assets' market value by $200 million. Bourquin Test. (8794/2) at 15:21-16:2. 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 per MWh by 2004 and by $1 per MWh by 2007. *Id.* at 16:2-7. 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 per MWh. Bourquin Test. (8794/2) at 16:8-11.

BGE retained an outside expert to review the reasonableness of its energy market price forecasts by comparing PROMOD outputs with price forecasts from a backup forecasting model, NERA LP.[50] The expert agreed that pricing models required many input assumptions, and "minor changes" in inputs – *e.g.*, generation's minimum load characteristics, and heat rates – have "substantial effects" on market price predictions because these assumptions changed plants' dispatch orders. Likewise "outputs depend critically on fuel price inputs." Falk Test. (8794/2) at 3:1-11. Over-investment in generation, which would also reduce wholesale electric market revenues, was not modeled, but was expected to depress forecasted prices. *Id.* at 14:11-15:19.

BGE estimated capacity market revenue as the total fixed and variable cost of a simple-cycle combustion turbine, less energy market revenue, adjusted for surplus capacity conditions in the PJM footprint, for a total cost of $36.50 per kW-year in 2000, rising to $48.40 per kW-year by 2015.[51] Bourquin Test. (8794/2) at 11:9-19; RHB-3 (8794/2) (showing BGE's projected capacity value within PJM); JSF2 (8794/2) at 2 (showing projected capacity prices). Revenues from ancillary services – anticipated to be small relative to capacity and energy – were projected to be a flat $.50 per MWh for the 2000-2015 period. Bourquin Test. (8794/2) at 11:20-12:5; RHB-3 (8794/2) (estimating ancillary services revenues).

Operating costs for generation facilities included in BGE's market valuation analyses relied on assumptions about fuel prices, O&M costs, costs of retiring facilities, capital expenditures, and taxes. We explain the bases for these inputs' values below.

Fuel Prices. BGE assumed total fuel cost for its generation assets would be $320 million in 2000. Thereafter, fuel prices' trajectories would be flat – *i.e.*, (i) coal prices would remain flat in nominal terms (and decline in real terms by three percent – the assumed rate of inflation – through 2002, and 1.5% thereafter); (ii) oil and gas prices would be flat in real

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50 For a summary of these results, *see* Falk Test. (8794/2) at 11:10-12:8; JSF2 (8794/2).

51 By contrast, the SWMAAC capacity price for 2009/2010, as determined in the October 2007 Base Residual Auction under PJM's Reliability Pricing Model ("RPM") is significantly higher – $86.63 per kW-year ($237.37 per MW-day). *See* PJM's 2009/2010 Base Residual Auction Results at http://www.pjm.com/markets/rpm/downloads/2009-2010-base-residual-auction-results.xls.

terms[52]; and (3) uranium fuel prices would stay flat in nominal terms (*i.e.*, experience a real decline). Bourquin Test. (8794/2) at 12:20-13:2.

O&M Expenses. Total O&M estimates for 2000 were $366 million. Nuclear O&M would decline in real terms through 2001 and remain flat thereafter with the exception of reduced costs associated with new steam generators by 2003. *Id.* at 13:3-8. Fossil plants' O&M would decline in real terms through 2001, and remain flat thereafter. *Id.*

Fossil Retirement Expenses. BGE estimated the cost of retiring fossil generation assets to be $60,000 per MW in 1998 dollars and to remain flat in real terms. *Id.* at 13:9-13. Bourquin explained in rebuttal that this estimate was "generally based on estimates used by Pennsylvania utilities in their restructuring proceedings." Bourquin Test. (8804/106) at 5:30-31. The total anticipated fossil retirement cost was about $90 million. *Id.* at 5:30-34.

Taxes. BGE included expenses related to federal income taxes and other taxes including property tax, payroll tax, gross receipts tax, Department of Energy decommissioning fund, and an environmental surcharge tax. For 2000, witness Bourquin estimated income taxes would be $43 million and other taxes would be $108 million. Bourquin Test. (8794/2) at 13:14-14:2.

Capital Expenditures. BGE estimated annual capital expenditures of $55 million in 1998 dollars, remaining flat in real terms, plus (1) $140 million of environmental-related expenditures at fossil facilities to comply with NO_x emission reduction requirements (to be incurred over the 1998-2005 period), and (2) $300 million of investments at Calvert Cliffs to replace steam generators (to be incurred between 1998-2003). *Id.* at 14:3-15.

Cost of capital. The discount rate used to derive the present value of revenues less expenditures was 8.89%, the weighted cost of capital for a hypothetical merchant plant. Hass Test. (8794/2) at 8:15-10:7 (explaining basis for setting the discount rate equal to a hypothetical merchant investment); Bourquin Test. (8794/2) at 8:18-9:5. BGE derived this value by calculating the cost of capital from a hypothetical new merchant plant, assuming a debt/equity structure of 55% debt (*i.e.*, the cost of borrowing or bonds issuances) and 45% equity (*i.e.*, common stock). *Id.*

The assumed cost of debt was 8.5%, which was the June 1998 approximate yield to maturity for 15-20 year corporate bonds with ratings of BB/BB-. Hass Test. (8794/2) at 16:3-5, 14:12-15:14 (debt costs for a BB/BB- rating). BGE calculated the cost of equity using a Capital Asset Pricing Model ("CAPM"), which calculates the required return equal to the risk-free rate plus a volatility measure, beta, times a market risk premium.[53] BGE's required return for merchant plants was based on the risk-free rate (long-term treasury bonds, at 5.85%), a beta of 0.95, and a market risk premium (based on 1997 data published by Ibbotson Associates) at 7.5%. *Id.* at 16:6-17:9.

[52] Because inflation is assumed to be three percent, the nominal price will increase by three percent annually if the estimated rate remains flat in real terms.

[53] Required Return = Risk-Free Rate + (Beta x Market Risk Premium).

Cost of Replacing Steam Generators. BGE's filed testimony provides variable information about the costs of replacing Calvert Cliffs' steam generators. In initial testimonies, BGE claimed it required about $300 million to replace the steam generators. *See, e.g.,* Bourquin Test., (8794/2) at 14:11-15; Prepared Direct Testimony of David Schlissel on Behalf of the Office of People's Counsel, *In re Baltimore Gas and Elec. Co.* (8804/55) (Dec. 22, 1998) ("Schlissel Test. (8804/55)") at 5:27-6:1 ($305 million). Subsequent testimony states, however, that replacement costs will be only $275 million. Prepared Direct Testimony of James H. Aikman on Behalf of Baltimore Gas and Electric Co., *In re Baltimore Gas and Elec.* Co., (8804/87) (Feb. 5, 1999) at 17:16-18. In discussing the sale of Calvert Cliffs, the Commission quoted BGE witness Brune for the proposition that a potential purchaser or transferee of Calvert Cliffs "will have to pay the cost of replacing steam generators at approximately $230 million." Order 75757, 90 Md. PSC at 231 (8804/235). The timing and cost of replacing the steam generators had a significant effect on Calvert Cliffs' stranded costs.[54] BGE's own estimates of the cost to replace Calvert Cliffs' steam generators varied by $75 million – from $305 million to $230 million – and this variance could have significantly affected the stranded cost estimates.

License Renewal for Calvert Cliffs. BGE believed that it would be granted a 20-year extension of its current operating license and that the facility would operate for the full license extension period.[55] Bourquin Test. (8794/2) at 9:16-10:11. BGE ran a sensitivity analysis in PROMOD assuming the NRC would grant the license renewal, thus extending operating life of Calvert Cliffs for another 20 years. Hass Test. at 11:10-16 (8794/2) (explaining that BGE estimated the economic value of the plant under two scenarios, with and without a license extension). The license's extended value, Bourquin estimated, was about $160 million. Bourquin Test. (8794/2) at 16:12-17. Without replacement of the steam generators at a cost of $305 million, however, the market value of Calvert Cliffs fell $150 million because the units would not run beyond 2004-2006. *Id.* at 16:18-17:5. In other words, BGE's early analysis showed that license extension and replacement of the steam generators together offset any impact on fair market value. BGE did not update this analysis based on later, lower estimates of steam generator replacement costs.

2. Intervenors' and Commission Staffs' Estimates of BGE's Stranded Costs

The OPC, the Maryland Industrial Group, MEA, Calvert County, MRA, Bethlehem Steel Corporation, National Railroad Passenger Corporation, MAPSA, and Commission Staff each filed testimony responding to BGE's stranded cost estimates. We summarize the three most comprehensive testimonies – by OPC, MEA, and Commission Staff – below and at the end of this section in Table 9.

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[54] *See, e.g.,* Commission Staff witness Stuart-Paul's sensitivity analysis summarized at Ex. TSP-8 (8804/60).

[55] In June 2001, the NRC granted BGE's license renewal application to extend operation of Calvert Cliffs. *See* NRC - license renewal applications, *available at* http://www.nrc.gov/reactors/operating/licensing/renewal/applications/calvert-cliffs.html; Baltimore Gas and Electric Company's Comments Regarding the Business Separation of Constellation Energy Group, Inc., *In re Business Separation* (June 29, 2001) (8883/25) (notifying Commission of same).

a. Office of the People's Counsel

The OPC's experts concluded that BGE had no stranded costs – and instead found significant stranded benefits – using two methods to value BGE's assets: (1) a DCF analysis identical to BGE's method, but with modified assumptions, and (2) sales prices of comparable power plants.[56] Using these methods, OPC Witness Chernick estimated that BGE's non-nuclear portfolio had a market value of $2.8 to $3.0 billion, which was $1.3 to $1.4 billion greater than book value. *See* Table 3. He estimated Calvert Cliffs' market value at $1.35 billion, slightly above its book value. Chernick Test. (8804/55) at 5:19-23. OPC's expert treated three purchased power contracts as BGE treated them, *i.e.*, with no stranded costs or benefits. *Id.* at 65:8-66:7. Chernick excluded $85 million of restructuring costs because (1) BGE provided no supporting documentation and (2) "to the extent that [these costs] occur and are allowed, [they] are not related to the value of the generation plants, and should be recovered through distribution rates, not the CTC." *Id.* at 52:3-11.

TABLE 3
OPC TRANSITION COST VALUATION

	Nuclear Assets	Non-Nuclear Generation Assets	Total Assets
	(in millions) (approximate)		
Market Value of Generation Assets	$1,350	$2,800 – $3,000	$4,150 – $4,350
Book Value of Generation Assets	$1,200	$1,600	$2,800
Stranded Investment in Generation Assets	($150)	($1,300) – ($1,400)	($1,600)
See Ex. PLC-9 (8804/55) for DCF estimates.			

The differences between BGE's stranded costs estimates of $1.05 billion and Chernick's finding of $1.6 billion in stranded benefits were "primarily from differences in projections of future market prices, and to a lesser extent from differing treatments of the costs of BG&E plants." *Id.* at 6:1-5; 56:7-59:16 (explaining two major differences in modeling assumptions – fuel prices and capacity and operating costs of new combined-cycle plants). We explain these underlying assumptions below.

Fuel Price Projections. The OPC's expert developed prices for five fuels using forecasts from federal and commercial sources relied on by utilities, including the Energy Information Administration, Standard & Poor's DRI, Gas Research Institute, the Wefa Group, and Energy Ventures. *Id.* at 54:3-23; Ex. PLC-7 (8804/55). Chernick believed that BGE's fuel price mis-forecasts caused distortions in PROMOD's outputs. Chernick Test. at 58:7-59:16 (8804/55) ("low gas prices used by BG&E will tend to reduce market energy prices, while the high oil price will tend to increase market energy prices but reduce the market value of [gas-fired plants]"). According to OPC's expert, BGE underestimated gas prices because it used mistaken assumptions about merchant generators' interruptible contracts, delivery charges, and other confidential factors. *Id.*

[56] *See* Chernick Test. (8804/55) at 5:18-19 and Exs. PLC-4, PLC-12 – PLC-15 (8804/55) for an asset sales analysis. Chernick found that non-nuclear assets' sales prices, if applied to the BGE fleet, would produce a market value of $2.7 billion, which is relatively close to the OPC's $2.98 billion market value derived from its cash flow analysis. Chernick Test. (8804/55) at 71:8-72:11.

Wholesale Market Prices. Like BGE, plant revenues were the sum of forecasted capacity revenues, ancillary-service revenues, and energy (dispatch) revenues. OPC expert witness Biewald analyzed BGE's PROMOD simulations and ran energy price forecasts using ELFIN, a modeling program similar to PROMOD and NERA LP. Biewald Test. (8804/55) at 11:5-12:2; *see also* Ex. PLC-6 (8804/55) (comparison of OPC and BGE prices for capacity, energy, and ancillary services). These price forecasts were incorporated into Chernick's stranded costs estimations. Biewald Test. (8804/55) at 5:12-14. Biewald ran four market simulations: two reference cases – (1) public data reference case, (2) confidential data reference case – and two sensitivity cases – (3) high-price oil and gas and (4) low-price oil and gas. Except for the Public Data Reference Case, Biewald's analyses contain confidential data for BGE's units, including coal prices, variable O&M costs, and NO_x emissions rates.[57]

The Public Data Reference Case shows time-weighted[58] energy prices in the PJM footprint increasing from $27.30 per MWh in 2000 to $40.20 per MWh in 2010. Ex. BEB-3 (8804/55); Biewald Test. (8804/55) at 6:9-11. For this case, Biewald used publicly available data relating to O&M costs, capacity and heat rates, emissions data, load data, and generator availability data. *See* Biewald Test. (8804/55) at 16:1-19:2; Ex. BEB-5 (8804/55) (summarizing data). Biewald assumed a 20% target reserve margin, with natural gas combustion turbines (peakers) and combined cycle (baseload and intermediate) added as optimal capacity additions. In the reference case, 500 MW of combined cycle capacity was assumed annually to capture new investment and to produce a conservative market price and stranded cost estimate. Biewald Test. (8804/55) at 17:12-18:3. Biewald considered but did not model the effect of underinvestment by the market.[59] *Id.* at 18:6-14.

Capacity revenues are the product of the market capacity price times the summer rated capacity of each facility. The assumed capacity price – capacity cost ($45.09 per kW-year) less energy revenues ($9.23 per kW-year) – was $35.86 per kW-year (1996 dollars).[60] Chernick calculated the capacity cost by proxy to the fixed cost of a new combustion turbine (peaker technology), assuming a capital cost of $305 per kW, a real-levelized carrying charge of 11.28% as the pre-tax cost of capital, fixed operating costs of $6.20 per kW-year, and property taxes and insurance costing two percent of gross plant in service. Chernick Test. (8804/55) at 52:21-53:14. The energy revenue deduction was taken from Biewald's energy price forecasts. *Id.* at 53, n.56.

Chernick adopted BGE's estimates of ancillary service revenues. *Id.* at 56:3-5; 54:23-55:2; Ex. PLC-2 (8804/55) (discovery responses).

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57 Biewald recommended the Commission adopt the Confidential Data Reference case, but we have reported the public data reference case here.

58 Time-weighted averages are energy prices averaged over all hours in a year. Other measures of average price are "generation-weighted" or "load-weighted" and will produce higher numbers than time-weighted averages.

59 Underinvestment – *i.e.*, the addition of fewer new generators than required to meet load growth – will increase energy and capacity prices as demand approaches the amount of available supply.

60 This assumption would produce a capacity price of about $60.53 per kW-year in 2009 dollars, significantly less than the actual RPM capacity price in 2009 of $86.63 per kW-year.

Other Revenues. The OPC's market valuation also included emissions allowance revenues. Because BGE estimated that plants' operating costs included the cost of emissions allowances, Chernick included anticipated revenues from environmental allowances, noting however, that the costs of environmental compliance were net costs to BGE. Chernick Test. (8804/55) at 51:1-8.

Operating Cost Characteristics. Chernick included the same operating costs that BGE's experts proposed – *i.e.,* fuel costs, O&M, annual capital expenditures, administrative and general ("A&G") expenses, property and payroll taxes, and income taxes – but excluded BGE's line item for decommissioning fossil plants. For BGE's fleet, he developed confidential plant-specific inputs for each facility relating to plant capacity, annual capacity factor, remaining plant life, fuel cost, O&M, A&G, decommissioning cost, environmental emissions cost, property and payroll tax, and income tax. *Id.* at 60:4-66:7.

New Plant Additions. Chernick estimated costs for two proxy plant types, a combustion turbine and a gas-fired combined cycle. *Id.* at 55:4-17. Different assumptions about capital and operating costs of new combined cycles contributed to the significant differences in BGE and OPC's stranded cost valuations. According to Chernick, BGE underestimated the average O&M costs for these units by a factor of three. *Id.* at 56:6-58:6; *see also* Ex. PLC-8 (8804/55).

Cost of capital. OPC assumed that the after-tax cost of capital was 8.95%. *Id.* at 52:12-14 (adopting witness Hill's testimony).

Depreciation. OPC expert witness Majoros analyzed depreciation of fossil plants and concluded that the operating lives of BGE's fossil plants would be extended past the end dates BGE assumed in testimony. Testimony of Michael J. Majoros, Jr. on Behalf of the Maryland Office of People's Counsel, *In re Baltimore Gas and Elec. Co.* (8804/55) (Dec. 22, 1998) ("Majoros Test. (8804/55)") at 2:11-16. Majoros objected to BGE's proposal to accelerate plant depreciation because it was unnecessary to provide BGE a return on its invested capital. According to OPC, BGE's accumulated depreciation reserve balances as of December 1997, were already excessive. *Id.* at 5:1-6:7; *see also* Chernick Test. (8804/55) at 27:8-28:19 (suggesting that BGE's proposal used over-earnings to fund accelerated depreciation, to ratepayers' detriment).

Replacement of Calvert Cliffs Steam Generators. OPC expert witness Schlissel raised a number of issues related to the replacement of steam generators at Calvert Cliffs, including that (1) BGE failed to take mitigating actions to prolong the units' operating lives once it decided to replace the steam generators, and (2) BGE could have sought recovery from the equipment supplier, as others had. Schlissel Test. (8804/55) at 10:1-14, 19:14-19, 16:8-17.

b. **Maryland Energy Administration**

Direct testimony filed by MEA's expert witness Kahal showed stranded costs for all of BGE's assets ranging from $58 million to $673 million, with a midpoint of $365 million. Kahal Test. (8804/47) at 33; Ex. MIK-3 (8804/47). *See* Table 4. BGE's non-nuclear fleet had stranded benefits ranging from $50 million to $485 million and Calvert Cliffs' stranded costs ranged between $543 million and $723 million.

TABLE 4 MEA TRANSITION COST VALUATION		
	Assumed Discount Rate	
	6.75%	8.89%
	(in millions)	
Base Case		
Calvert Cliffs	$543	$723
Non-Nuclear	($485)	($50)
Stranded Costs, All Generation Assets	**$58**	**$673**
Market Revenue Sensitivity		
Calvert Cliffs	$271	$548
Non-Nuclear	($822)	($276)
Stranded Costs, All Generation Assets	**($551)**	**$272**
Source: Ex. MIK-3 (8804/47).		

MEA conducted two types of analyses to calculate the fleet's market value. Kahal Test. (8804/47) at 31-33. First, Kahal adjusted Bourquin's key assumptions and inputs, as described below. Second, he looked at other utilities' experiences auctioning portfolios of non-nuclear generation assets (*id.* at 49-53), but did not make a similar comparison for nuclear generation assets (*id.* at 32 (comparable market asset sales "are not available" for nuclear plants)).

Kahal modified BGE witness Bourquin's assumptions by (1) reducing BGE's filed discount rate from 8.89% to 6.75%, (2) recognizing savings resulting from enhanced productivity and cost controls, (3) increasing market prices for electricity, (4) incorporating an anticipated tax reform that would reduce the utility's tax obligations, and (5) eliminating BGE's unsupported expenses for fossil plant decommissioning. *Id.* at 32-34, 35. Table 5 summarizes the impact of these adjustments on generation assets' market value.

TABLE 5 MEA ADJUSTMENTS TO BGE MARKET VALUE		
	@ 6.75% Discount Rate	@ 8.89% Discount Rate
	(in millions)	
BGE Market Value of Generation Assets	**$2,234**	**$1,731**
Productivity Adjustment	+$126	+89
Franchise and PSC Taxes	+206	+163
Income Tax Increase	($129)	($102)
Fossil Retirement	+$80	+56
MEA Market Value	**$2,721**	**$2,106**
Market Revenue Sensitivity Analysis	+$609	+$401
MEA Market Value (with Market Revenue Sensitivity Analysis)	**$3,330**	**$2,507**
Source: MIK-3 (8804/47).		

Cost of Capital. MEA adopted a 6.75% cost of capital (net of tax costs). Ex. MIK-2 (8804/47) (showing 8.08% pre-tax weighted cost of capital). MEA's expert rejected BGE's proposal to use a hypothetical merchant plant capital structure, and adopted the company's actual debt, preferred stock, and common stock ratios. Kahal Test. (8804/47) at 36-38[61]; Ex.

[61] Witness Kahal's confidential cost of equity study was not available for our review.

MIK-2 (8804/47). He applied a 6.71% rate to the cost of debt and a 6.18% return to preferred stock, and reduced the return on common equity to ten percent. Ex. MIK-2 (8804/47). He assumed a tax rate of 39%, which was higher than BGE witness Hass' assumed tax rate of 35%. Kahal Test. (8804/47) at 56.

Productivity Adjustment. MEA accepted BGE's non-fuel O&M expenses but expected that unregulated plants would realize additional productivity gains through improved heat rates, availability, and savings on capital additions. Kahal's "productivity adjustment" reduced BGE's assumed rate of increase in O&M expense by 0.5% per year beginning in 2002, and continuing for 10 years. This adjustment – which Kahal believed was extremely conservative based on FERC and Department of Energy studies and recent determinations by the Pennsylvania Public Utility Commission ("PA PUC") – reduced BGE's stranded costs between $89 million (using BGE's 8.89% discount rate) and $126 million (using MEA's 6.75% discount rate). *See id.* at 38-41.

Wholesale Market Prices. MEA did not conduct an independent analysis of wholesale prices in PJM. *Id.* at 35. Although Kahal agreed with BGE's concerns about predicting future prices, Kahal criticized BGE's PROMOD price forecast because it ran the study only through 2007. After 2007, BGE's witness Bourquin assumed that market prices would increase only 2.5% per year (*i.e.,* declining in real terms) for the next 30 years. *Id.* at 42. Kahal also criticized Bourquin's assumption that ancillary services revenues would remain flat in nominal dollars for the full study period. *Id.*

Kahal ran a sensitivity analysis, modifying BGE's price path by escalating nominal prices by three percent per year beginning in 2005. *See* Ex. MIK-1 (8804/47). This sensitivity analysis produced an escalation rate marginally higher than BGE's (2.86% in MIK-1 compared with 2.22% by BGE) but substantially lower than the price projections accepted by the PA PUC (4.67%). *Id*. The after-tax net revenue adjustment ranged from $401 million (using BGE's discount rate) to $609 million (using MEA's discount rate). *See* Ex. MIK-3 (8804/47).

TABLE 6
MEA TRANSITION COST VALUATION
(Market Revenue Sensitivity) (8.89% Discount Rate)

	Nuclear Assets	Non-Nuclear Generation Assets	Total Assets
	(in millions)		
Market Value of Generation Assets	$493	$1,613	$2,106
Book Value of Generation Assets	$1,216	$1,563	$2,779
Stranded Investment in Generation Assets	***$723***	***($50)***	***$673***
Stranded Investment (Market Revenue Sensitivity Analysis)	*$548*	*($276)*	*$272*
Source: Ex. MIK-3 (8804/47).			

Table 6 shows the MEA's stranded costs for BGE's nuclear and non-nuclear generation assets using BGE's proposed 8.89% discount rate. The last row is a sensitivity analysis showing the change in market value from an increase in the generation plants' net revenue by increasing the company's revenue at the rate of inflation (three percent) after 2005, rather than 2.5%. The revenue increase is conservatively set off by a 0.5% increase to fuel expense. Kahal

Test. (8804/47) at 42-43. This sensitivity analysis reduces stranded costs by $401 million, to $272 million.

Changes in Taxes. Kahal's tax assumptions proposed three modifications to BGE's assumptions: (1) removing the franchise and PSC taxes that would no longer apply to a fully deregulated utility, (2) assuming a 50% reduction of property taxes, and (3) applying state income taxes to deregulated operations. Kahal Test. (8804/47) at 43-45; Ex. MIK-3. These tax adjustments increase market value by $102 to $129 million. Kahal recommended that the Commission not adopt these tax assumptions until more was known about how state utility taxes would be restructured.

Fossil Retirement Costs. Like the OPC, Kahal excluded all of BGE's fossil unit retirement costs. *Id.* at 46-47.

Environmental Costs. Kahal also recommended that $100 million (in nominal pre-tax dollars) for an Environmental Surcharge obligation be removed from BGE's stranded costs, though he did not make an adjustment for its removal in his calculations. BGE calculated this expense based on a per kWh charge to the company's plants over their remaining lives, but Kahal argued that if BGE was allowed to continue charging customers directly, then this expense category should be excluded from the stranded cost valuation. *Id.* at 46.

Other reasonable adjustments Kahal considered but did not build into his stranded cost valuation included plant life extensions, increases in coal plant output, accelerated depreciation, materials and supplies allowances, market value of materials, supplies, and fuel inventory, and environmental upgrades related to NO_x emissions. *Id.* at 47-49.

Kahal also surveyed power plant utility sales through November 1998, and extrapolated to assume that BGE's non-nuclear assets would have a pre-tax market value of $2.17 billion. *Id.* at 50. This estimate is higher than his range of modeling values, which were between $2.05 billion and $1.61 billion (depending on the discount rate used). Kahal recommended that the Commission defer BGE's stranded cost determination until 2003 for Calvert Cliffs (and other fossil assets). Although he believed the facility had "considerable economic value," comparable sales data for nuclear facilities did not exist. *Id.* at 51-52.

Regulated Book Value. Kahal had "no serious objection" to BGE's proposal to use a projected net book value as of December 31, 1999 (*id.* at 34), and agreed with BGE's proposal to accelerate deprecation (*id.* at 18, 34).

c. **Commission Staff**

As Table 7 summarizes, Commission Staff estimated BGE's stranded costs to be about $227 million. Ex. TSP-8 (8804/60); Stuart-Paul Test. (8804/60) at 2:10-11.

TABLE 7 STAFF TRANSITION COST VALUATION	
	Total Assets (in millions)
Market Value of Generation Assets	$2,552
Book Value of Generation Assets	$2,779
Stranded Investment in Generation Assets	*$227*
Restructuring Costs	$0
Total Transition Costs	***$227***
Regulatory Assets	$0
Source: Ex. TSP-8 (8804/60).	

Staff expert witness Stuart-Paul based this valuation on changes to BGE's assumptions about electricity prices (ten percent increase in electric prices offset by a ten percent increase in fuel costs at marginal plants), O&M expenses (ten percent decrease in O&M at fossil plants), fossil decommissioning expenses (removed), timing of capital expenditures for Calvert Cliffs' turbine replacement (one-year delay),[62] and SO_2 allowance costs (removed). Table 8 shows the cumulative effect of these adjustments on BGE's market value. The ten percent upward adjustment to BGE's energy price had the most significant effect on market value. Stuart-Paul found that this adjustment was reasonable, noting that Pepco's price forecast, if applied to BGE, would boost prices about 19% on average for the period 2000-2010. Stuart-Paul Test. at 17:17-24 (8804/60).

TABLE 8 STAFF ADJUSTMENTS TO BGE MARKET VALUE	
	Total Assets (in millions)
BGE's Market Value of Generation Assets	$1,730.7
10% Increase in Market Electricity Prices	+$644.0
10% Increase in Fuel at Marginal Plants	-$53.0
10% Decrease in O&M	+$105.0
Remove Fossil Decommissioning Costs	+$60
One Year Delay in Calvert Cliffs Outlays	+$17
Remove SO_2 Allowance Costs	+48.3
Staff Market Value	**$2,552.0**
Source: Ex. TSP-8 (8804/60).	

Stuart-Paul expressed concerns about the accuracy of an administrative valuation (*see id.* at 7:6 ("even small variations [in input assumptions] can have significant impact")), observing that Maryland utilities' assumptions during each of the divestiture proceedings

62 Staff Witness Stuart-Paul found that "approximately 40% of the BGE's calculated stranded costs [for Calvert Cliffs] are tied up in capital outlays in the first 4 years of the analysis. A delay in the schedule for these capital outlays at Calvert Cliffs will increase the market value and reduce stranded costs." Stuart-Paul Test. (8804/60) at 6:26-30.

varied considerably even though they participated in the same wholesale market. Significantly, Stuart-Paul found that BGE's estimated wholesale energy prices were much lower than Pepco's projections. *See* Ex. TSP-1 (8804/60) (ten years of energy price forecasts used by BGE, Pepco, Allegheny Power System ("APS"), and Delmarva).[63] Even so, however, BGE and Pepco assumed similar trends in natural gas prices. *See* Ex. TSP-4 (8804/60).

Capacity prices in each restructuring docket also varied significantly, but in all cases were less than the $58 per kW-year deficiency charge.[64] Stuart-Paul Test. (8804/60) at 8:20-10:17 (utilities' forecasts were "purely speculative"); 12:9-16 (reserve requirements between 17% and 20%; one percent decrease in reserve requirement is associated with a reduction of 63 MW of capacity); Ex. TSP-2 (showing capacity price trends). Maryland utilities' stranded cost analyses showed a 50% variance in O&M costs growth rates. Stuart-Paul Test. (8804/60) at 11:8-12:7. Utilities offered different, but reasonable assumptions to model new plant additions. *Id.* at 12:18-13:3 (verifying with independent sources); Ex. TSP-5 (8804/60) (assumptions concerning capacity additions).

Commission Staff accepted BGE's direct testimony establishing book value for non-nuclear assets. Akers Test. (8804/60) at 10:13-16.

Asset Sale Comparison. Commission Staff witness Akers' market value calculation used an average of the subset of total sales data to derive an estimated market value of $2.1 billion for BGE's non-fossil assets. Accepting BGE's book value of $1.6 billion, he derived $543 million in stranded benefits for BGE's non-nuclear assets. *Id.* at 10:13-16. Commission Staff did not perform a valuation of the Calvert Cliffs facility and recommended the Commission keep it under cost-of-service regulation.

Akers' $2.1 billion market valuation of BGE's non-nuclear assets was based on comparable generation asset sales across the United States. Akers first reviewed the market prices for generation capacity, including (1) 30,774 MW of non-nuclear generation sold inside and outside the PJM footprint at an average price of $326 per kW, excluding asset sales associated with recent mergers (Akers Test. (8804/60) at 4:6-5:9; 7:1-20 (high and low range of sales); Ex. JLA-2 (8804/60)), (2) plans for new generation in PJM and whether excess transmission capacity in PJM was available to support new generation capacity (Akers Test. (8804/60) at 5:11-6:11), and (3) commercially available data on asset sales (*id.* at 9:11-18). Akers recognized the limited value of these comparative sales. Asset sales were not reported on a per asset basis, so it was impossible to assign an individual asset value by fuel type or technology comparable to BGE assets. *Id.* at 8:4-6. Additionally, Akers had no information about real property sales associated with the plant. *Id.* at 8:6-8. Nor was Akers able to include other material factors such as plant age and location (except for locations within PJM) in his analysis.

[63] On rebuttal, BGE witness Bourquin pointed out that PEPCO's price forecasts were load-weighted and BGE's were generation-weighted thus presenting "distinctly different measures of price [that] are not comparable." Bourquin Test. (8804/106) at 9:25-27; *see generally id.* at 9:19-11:25.

[64] *See supra* note 60, at 38.

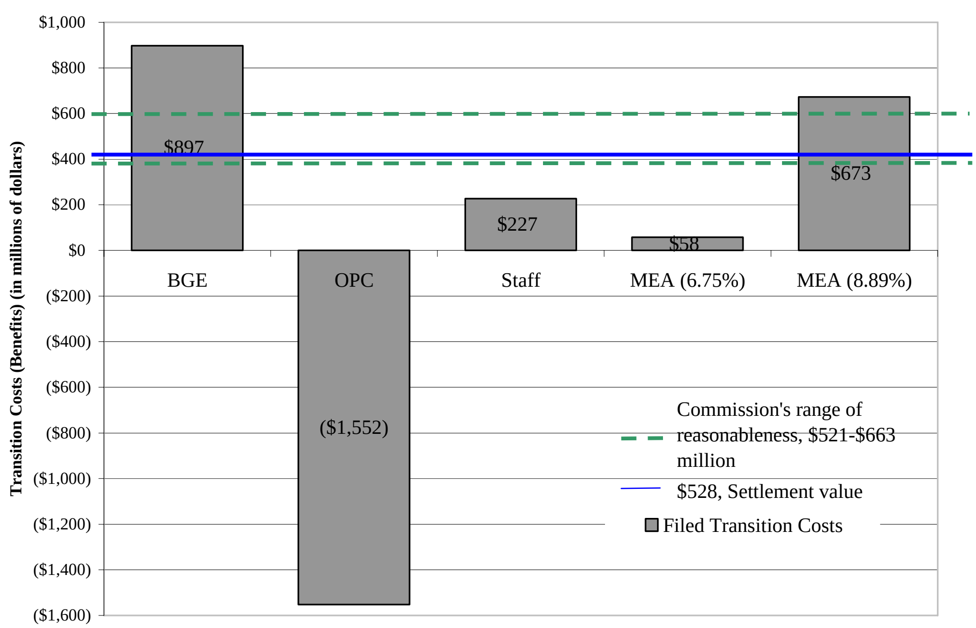
Akers did not submit testimony calculating a market valuation for Calvert Cliffs because he found no basis for a "valid market evaluation." *Id.* at 2:19-3:18 (noting evaluation of nuclear sales is "further complicated" by "unresolved issues," *i.e.*, NRC licensing, spent fuel disposition, nuclear fuel, and decommissioning expenses). The market had "very limited" experience with sales of nuclear facilities – only the sales of Pilgrim, Three Mile Island No. 1, and ownership interests in Seabrook, Kewaunee, and Beaver Valley Nos. 1 and 2. *Id.* For this reason, Akers recommend that the Commission keep Calvert Cliffs under cost-of-service regulation until the market matured. *Id.* at 4:1-4.

TABLE 9 COMPARISON OF PARTIES' KEY ASSUMPTIONS FOR ADMINISTRATIVE MARKET VALUATIONS				
	BGE	**OPC**	**MEA**	**Staff**
Revenues (wholesale)				
Energy	$25 per MWH in 2000 and trending upward to $36 per MWH by 2015	$27 per MWH in 2000 and trending upward to $42 per MWH by 2010	(modified in sensitivity analysis)	Ten percent increase in BGE's electricity prices
Capacity	$36 per kW-year in 2000, and trending upward to $48 per kW-year by 2015	About $36 per kW-year (1996 dollars), based on the cost of a combined cycle plant		Adopt BGE's revenue assumptions
Ancillary Services	Flat $.50 per MWh rate for the 2000-2015 period	Adopt BGE's revenue assumptions		Adopt BGE's revenue assumptions
Expenses				
Fuel Price Trends (oil, coal, gas, uranium)	Fuel prices assumed to remain flat or decline in real terms	Fuel prices based on commercial sources show stable real prices, but changes to delivery terms increase price. (BGE underestimated fuel costs.)	(modified in sensitivity analysis)	Ten percent increase in fuel costs
Operations & Maintenance	Decline in real terms through 2001, and remain flat in real dollars thereafter	Plant-specific or based on proxy plant. BGE underreported its operating costs	"Productivity adjustment" reducing BGE's annual increase in O&M expenses by 0.5% from 2002-2010	Ten percent decrease in O&M costs
Fossil Retirement	$90 million (present discounted value)	Excluded	Excluded	Excluded
Capital Expenditures	Flat at about $55 million (1998 dollars), plus $140 million of environmental related expenditures to comply with reduced emissions requirements			
Steam Generator Replacement (Calvert Cliffs)	$300 million			No cost adjustment, one-year delay
Environmental Costs				Remove $48.3 million of SO_2 allowance costs
Cost of Capital	8.89%	8.95%	6.75% or 8.89%	
Tax Rates/Obligations	Includes state and federal taxes (and BGE later updated its market valuation to show changes in Maryland tax law.)		Modified BGE's tax assumptions (to reflect anticipated changes in the tax law)	

3. Analysis and Conclusions

The Commission approved the settlement's $528 million transition costs (inclusive of stranded costs and anticipated restructuring costs) finding that the settlement amount was "a compromise figure." Order 75757, 90 Md. PSC at 227 (8804/235). As Figure 2 shows, however, the record before the Commission included a wide range of estimated transition costs or benefits. The settlement amount of $528 million is about 60% of the transition costs that BGE originally sought and likely reflects a concession by some intervenors for which they would have expected gains in other settlement components. In approving this settlement amount, the Commission relied on record evidence showing that Calvert Cliffs' stranded costs were about $783 million. *Id.* at 230. The Commission also accepted the Maryland Department of Natural Resources ("DNR")/MEA's expert witness Kahal's recommendation that a reasonable range of stranded costs was between $521 million and $663 million. *Id.* at 229.

FIGURE 2. TRANSITION COSTS ESTIMATES AND SETTLEMENT VALUE



a. Market Value Estimations

Because the 1999 Act did not require BGE to offer its generation assets for sale, thus precluding the most accurate valuation, the Commission determined a stranded cost value using the market proxies that the 1999 Act permitted. PUC § 7-513 (e)(1)(ii). The statute required the Commission to consider "computer simulations" in addition to "other appropriate evidence of value," such as comparative asset sales. *Id.* Only BGE and the OPC used computer simulations to forecast energy prices and costs for generation assets. BGE filed testimony using two market simulation models, PROMOD and NERA LP. The OPC used its own program, ELFIN. Staff did not offer its own analysis, but asked BGE to adjust its models and report the results. MEA did not model its own price projections, but adjusted BGE's data. Staff and MEA's reliance on BGE's computer simulations might partially explain the substantial differences between the OPC's stranded cost valuation and other parties valuations offered in filed testimony.

The market simulation models' price forecasts followed cost-based modeling rules, *i.e.*, energy prices reflect the marginal cost of electricity production for the last dispatched unit. Thus, changes to inputs and assumptions significantly impacted the assets' estimated market values. BGE's sensitivity analyses confirmed that changes in fuel prices or imports and exports produced huge swings in the market value. Similarly, Staff's and MEA's price sensitivity analyses confirmed the impact of even small price changes on the stranded cost value. The choice of discount rate and timing affected the predicted stranded cost value as well. For example, 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. Thus, the Commission's record clearly showed that the market valuations were largely subjective and extremely sensitive to changes in input assumptions. Because the parties settled, however, the Commission did not test these assumptions' reasonableness in adjudicatory proceedings. 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.

With the benefit of hindsight, settling parties grossly underestimated the generation assets' market value. Energy prices increased to reflect rising fuel prices (a key determinant of wholesale energy prices), new bidding rules in the wholesale market rules, and transmission constraints in PJM that exacerbated congestion and limited access to cheaper suppliers. Expected low energy prices and low capacity prices driven by a competitive wholesale market never materialized. BGE and OPC both mistakenly assumed that competition from new generation suppliers would discipline the wholesale market, and both mistakenly modeled new entry in their computer simulations. BGE assumed excess capacity would be gone by 2001 (Bourquin Test. (8804/106) at 14:11-13) and modeled new capacity additions. The OPC assumed that it could be gone by 2000, and added 500 MW of combined cycle plants annually. *Id.* (citing Biewald Test. at 18-19). Indeed, BGE was critical of the OPC's energy price forecast because, in its view, that forecast was inconsistent with a competitive market outcome. Bourquin Test. (8804/106) at 16:18-29. Neither the parties nor the Commission anticipated the conditions that have transpired since restructuring that have substantially increased the value of the generation assets that BGE formerly owned.

b. Comparative Sales of Nuclear Facilities

The parties' collective reluctance to value BGE's Calvert Cliffs plant reflected market conditions for nuclear power plants and events at the time those evaluations were made. Given the waning tolerance for the risks of nuclear energy, the parties' recommendations to defer divesting or valuing Calvert Cliffs were reasonable, and subsequent circumstances proved them to be correct. Based on the nuclear environment and sales of nuclear power plant facilities at about the time of BGE's divestiture of Calvert Cliffs, we found that the market did not begin to turn favorably until after the Commission approved BGE's settlement, and, therefore, the settlement did not reflect this subsequently recognized value for nuclear generation assets.

By the late 1990s, tolerance for the risks of nuclear energy had deteriorated following the near-meltdown at the Three Mile Island plant near Harrisburg, Pennsylvania, in 1979. Despite passage of the Nuclear Waste Policy Act of 1982 (amended in 1987), there was still no permanent solution to disposal of radioactive waste. Utilities halted plans to build new facilities. The last facility to be licensed was the Tennessee Valley Authority's Watts Bar Nuclear Plant, Unit 1 reactor, in 1996.[65] Plans for about 100 new reactors were canceled, including all plants ordered since 1973.[66] Citing safety and/or economic justifications, owners had permanently shut down several nuclear plants, including the Trojan Nuclear Plant, Unit 1 (Oregon, 1992), San Onofre Nuclear Generating Station Unit 1 (California, 1992), Millstone Nuclear Power Station, Unit 1 (Connecticut, 1995), Maine Yankee Atomic Power Plant (Maine, 1996), and Haddam Neck Plant (Connecticut, 1996). *See* DOE Report at 10-11. Rather than new licenses, the NRC was largely focused on decommissioning plans for these plants and for earlier shutdown facilities, as well as developing decommissioning regulation and policy.

Depressed sale prices of nuclear facilities reflected the mistakenly anticipated decline of nuclear energy. In each of these transactions, the transition contracts, decommissioning fund amounts and responsibility for continuing funding obligations, and NRC compliance requirements significantly – and negatively – impacted the sales price. In 1999, Boston Edison sold Pilgrim Nuclear Power Station (665 MW, Massachusetts) to Entergy Nuclear for $81 million,[67] Illinois Power sold Clinton Power Station (930 MW, Illinois) to AmerGen Energy

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65 U.S. Dep't of Energy, DOE/NE-0118, Nuclear Reactors Built, Being Built, or Planned: 2003 ("DOE Report") (Dec. 2003), at 3-9. The Tennessee Valley Authority suspended construction on its three other reactors in Tennessee and Alabama. *Id.* at 10.

66 Mark Holt and Carl Behrens, CRS Issue Brief for Congress: Nuclear Energy Policy, Cong. Res. Serv. (June 4, 2003) ("CRS Report"), at 1.

67 *See* NSTAR, Annual Report (Form 10-K), at 3 (Mar. 30, 2000) ("Boston Edison sold the Pilgrim Nuclear Generating Station (Pilgrim) on July 13, 1999, for $81 million to Entergy Nuclear Generating Company. As part of the sale, Boston Edison transferred approximately $228 million in decommissioning funds to the purchaser. The purchaser, by contract, assumed all future liability related to the ultimate decommissioning of the plant. The difference between the total proceeds from the sale and the net book value of the Pilgrim assets plus the net amount to fully fund the decommissioning trust is included in regulatory assets on the accompanying Consolidated Balance Sheets, as such amounts are collected from customers"); Entergy Corporation, Annual Report (Form 10-K) (Mar. 16, 2001) ("Pilgrim has firm power purchase agreements with Boston Edison and other utilities that expire at the end of 2004. One hundred percent of the plant's output is committed to those parties through 2001, and that commitment decreases to 50% by 2003"); NRC News, NRC Approves Transfer of Pilgrim Plant Operating License from Boston

Company for $12.4 million,[68] and GPU Nuclear Inc. sold Three Mile Island Nuclear Station (Unit 1, 786 MW) to AmerGen.[69] In late 2000, the Power Authority of the State of New York sold Indian Point, Unit 3 (980 MW, New York) and James A Fitzpatrick Power Plant (825 MW, New York) to Entergy Corporation for $600 million.[70] In November 2000, Consolidated Edison agreed to sell its interest in Indian Point, Units 1 (ret.) and 2 (1000 MW, New York), to Entergy for about $602 million.[71] In early 2001, Connectiv sold minority interests in Salem Nuclear Generating Station (Units 1 & 2) (New Jersey), Hope Creek Nuclear Generating Station (New Jersey) and Peach Bottom Atomic Power Station (Units 2 & 3) (Pennsylvania) for $11.3 million.[72] The view at the time was that the decommissioning wave of the preceding decade would continue. Although BGE's settlement occurred before most of these

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Edison to Entergy Nuclear (May 3, 1999), *available at* http://www.nrc.gov/reading-rm/doc-collections/news/1999/99-093.html. The NRC's approval of Pilgrim's sale was contingent on Entergy maintaining a decommissioning fund of at least $396 million, a $70 million special trust fund to pay taxes as a result of the decommissioning fund's transfer to Entergy, and assurances of access to a $50 million contingency fund.

68 Illinois Power Company, Annual Report (Form 10-K), at 9 (Mar. 30, 2000) ("IP agreed to transfer to AmerGen the existing decommissioning trust funds in the amount of $98.5 million on the sale closing date and to make an additional payment of $113.4 million to the decommissioning trust funds. In addition, IP is responsible for five future annual payments of approximately $5 million to the decommissioning trust funds. AmerGen bears all other costs and risks of decommissioning."); NRC News, NRC Approves Transfer of Clinton Power Plant Operating License to AmerGen Energy Company (Nov. 29, 1999), *available at* http://www.nrc.gov/reading-rm/doc-collections /news/1999/99-251.html (requiring AmerGen provide decommissioning funding assurance of no less than $210 million).

69 NRC News, NRC Approves Transfer of Three Mile Island Plant Operating License to AmerGen Energy Co. (Apr. 13, 1999), *available at* http://www.nrc.gov/reading-rm/doc-collections/news/ 1999/99-075.html (requiring decommissioning funding assurance of no less than $303 million).

70 Entergy Corporation, Annual Report (Form 10-K), at "Domestic Non-Utility Nuclear" (Mar. 16, 2001) ("Indian Point 3 has a firm power purchase agreement with NYPA that expires at the end of 2004 for 100% of the plant's output. FitzPatrick has firm power purchase agreements with NYPA that expire at the end of 2004 for 100% of the plant's output through 2003 and approximately 45% of the plant's output in 2004"); NRC News, NRC Approves Transfer of Operating Licenses for Indian Point 3 and Fitzpatrick to Entergy (Nov. 13, 2000) *available at* http://www.nrc.gov/reading-rm/doc-collections/news/2000/00-175.html.

71 *See* Entergy Corporation, Annual Report (Form 10-K) (Mar. 16, 2001) ("In November 2000, Entergy's domestic non-utility nuclear business agreed to purchase Consolidated Edison's (Con Edison) 957 MW Indian Point 2 nuclear power plant (IP2) located in Westchester County, New York. In the transaction, Entergy has agreed to acquire Indian Point 1 nuclear power plant (IP1), which has been shut down and in safe storage since the early 1970s. Entergy will pay $600 million in cash at the closing of the purchase and will receive the plant, nuclear fuel, and other assets, including a power purchase agreement ("PPA"). Under the PPA, Con Edison will purchase 100% of IP2's output through 2004. Con Edison will also transfer a $430 million decommissioning trust fund, along with the liability to decommission IP2 and IP1, to Entergy's nuclear business."); Consolidated Edison Inc., Annual Report (Form 10-K), at 36 (Apr. 2, 2001); *id.* at 40 (power purchase agreement through 2004 at 3.9 cents per kwh); NRC News, NRC Staff Approves Transfer of Operating Licenses for Indian Point 1 and 2 to Entergy Corporation (Aug. 27, 2001), *available at* http://www.nrc.gov/reading-rm/doc-collections/news/2001/01-106.html.

72 Connectiv Unit Sells Interests in Nukes (Oct. 19, 2001), *available at* http://www.energyonline.com/ Industry/News.aspx?NewsID=5231&Conectiv_Unit_Sells_Interests_in_Nukes (reporting Connectiv sold a 7.51% (164 MW) interest in the Peach Bottom Atomic Power Station Units 2 and 3, a 7.41% (167 MW) interest in the Salem Nuclear Generation Station Units 1 and 2 and a five percent (52 MW) interest in the Hope Creek Nuclear Generation Station Units 1 and 2 for about $11.3 million, excluding fuel inventory).

transactions, testimony filed by many intervenors about the problematic divestiture of Calvert Cliffs echoed this sentiment.

That view began to change in 2000 with developing electricity shortages and rising fossil fuel prices. Nuclear operating companies began reconsidering investments in new commercial nuclear reactors and canceling decommissioning plans.

For example, in early 1999, the owner of the Oyster Creek Nuclear Power Plant in Toms River, New Jersey, announced it was considering decommissioning the facility in 2000, if a buyer for the facility could not be found.[73] The facility was not shut down, however, and ownership of the facility was eventually transferred to Exelon Corporation, which continued operations and in 2005 sought a 20-year operating license extension. Rising fossil fuel prices also raised the value of existing facilities, and the market turnaround became apparent in March 2001 – more than a year after the Commission approved the BGE settlement and nine months after BGE transferred Calvert Cliffs to its corporate affiliate – when Dominion Energy purchased interests in the 2,000 MW Millstone Power Station in Waterford, Connecticut for $1.3 billion.[74] At the time of the BGE stranded cost determination, however, the parties' estimates of the value of Calvert Cliffs were not inconsistent with industry expectations of fair market value.

D. <u>BGE Retail Customers' Rate Package of Price Freeze Service, Shopping Credits, and Transition Cost Collections.</u>

The settlement agreement resolved all issues in consolidated Case Nos. 8794 and 8804 relating to quantification and recovery of transition costs, regulatory assets that would stay in BGE's rate base, price protection measures for retail classes, retail rate unbundling, and BGE's regulated rates and charges.[75] Table 10 compares BGE's original restructuring proposal with the agreed settlement terms.[76] In general, the settling parties opted for six years of certainty instead of permitting rates and other terms to change during the transition period, as BGE had

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[73] *See* NRC News, GPU to Update NRC on Oyster Creek Decommissioning Planning (Mar. 24, 1999), *available at* http://www.nrc.gov/reading-rm/doc-collections/news/1999/99-021i.html.

[74] Dominion recorded $302 million of goodwill representing the excess of the purchase price over amounts allocated to Millstone's assets acquired and liabilities assumed. *See* Dominion Resources, Annual Report (Form 10-K), at 56 (Mar. 11, 2002) (100% ownership interest in Units 1 and 2 and 93.47% interest in Unit 3 for a total of 1,954 MW; Unit 1 was being decommissioned and no longer in service). As part of the purchase agreement Dominion also acquired decommissioning trusts for the three units that were funded to the regulatory minimum and assumed the decommissioning liability. *See also* NRC News, NRC Approves Transfer of Operating Licenses for Millstone Units 1, 2, and 3 (Mar. 9, 2001), *available at* http://www.nrc.gov/reading-rm/doc-collections/news/2001/ 01-026.html.

[75] Other issues related to electric restructuring not addressed by the settlement, such as consumer education, supplier authorization, consumer protection and universal service, would be addressed through the Commission's roundtable process. *See* Prepared Supplemental Testimony of David A. Brune on Behalf of Baltimore Gas and Electric Company, *In re Baltimore Gas and Elec. Co.* (8804/163) (July 23, 1999) ("Brune Test. (8804/163)") at 3:1-14.

[76] BGE filed a 10-page "Alternative Framework" in March 1999, leaving too little time for other parties to respond without a change in the Commission's procedural schedule. Brune Test. (8804/106) at 16:4-26:15.

proposed. The settlement's non-severability (BGE Settlement Agreement, ¶ 53) and confidentiality (*id.*, ¶ 55) clauses specified that parties intended the settlement to reflect a "black box" negotiation. Thus, the settlement's $528 million (after-tax, present values as of January 1, 2000) transition costs were set as a function of other negotiated provisions, *e.g.*, the rate reduction measures and duration of rate freezes, shopping credits, acceleration of retail choice, and perhaps other negotiated provisions.

TABLE 10
COMPARISON OF BGE'S RESTRUCTURING PROPOSAL AND SETTLEMENT

	BGE Proposal	Settlement
Retail Choice	Two-year phase-in period, beginning with one-third of the customer base by July 2000.	All customers by July 2000.
Transition Period	Allows for a transition period with its duration tied to reduction of stranded costs, *i.e.*, when book value is less than ten percent market value, expected in 2004, but not later than 2008.	No transition.
Retail Rate Reduction	Rates frozen at December 1998 rates until June 2002, thereafter adjusted by an index such as the Consumer Price Index until the end of the transition period.	Residential rates reduced by 6.5% (about $50.2 million annually) and frozen for six years (Schedule R/ES); other residential customer rates reduced by three percent ($3.6 million annually) and frozen for four years (Schedule RL); commercial and industrial customers' rates frozen for up to four years (depending on rate class).
Generation Prices	BGE's SOS will be priced at its regulated rate of return treatment until divestiture at the end of the transition period.	Residential SOS prices set by auction beginning 2003, but capped at frozen rates until 2006.
Generation Asset Divestiture	Transfer to BGE affiliates, at the end of the transition period.	Transfer at book value to BGE affiliates by July 2000.
Generation Assets' Stranded Costs	Valuation by independent appraiser at the end of the transition period; ratepayers retain responsibility for stranded costs, if any.	$528 million black box value (includes restructuring costs).
Generation Regulatory Assets	$370 million to remain in BGE's ratebase.	$416 million of generation regulatory assets, with 80% ($332 million) to be recovered in BGE's distribution rates through 2017 and the remaining 20% written off.
Calvert Cliffs' Decommissioning Trust	Ratepayers to continue funding Calvert Cliffs' decommissioning.	Ratepayers responsible to fund $520 million (1993 dollars) at the time of decommissioning (date uncertain).
Restructuring Costs	Actual costs to be recovered.	Part of the black box settlement, about $58 to $85 million.

The settlement allocated each customer class a share of the $528 million transition costs. Residential customers' share was $193.8 million, about one-third of the settlement amount. *Id.*, ¶ 2 (Schedules R, RL, and ES). Governmental entities and commercial and industrial customers paid the remaining two-thirds: $166.4 to General Service customers (Schedules G, GL, GS), $100.7 million to primary voltage service (Schedule P), $59.5 million to (Schedule PL and individual customer contracts), $5.1 million to street lighting (Schedule SL), and $2.5 million to Amtrak (Schedule NRP). *Id.*

As Table 11 shows, the settlement authorized BGE to collect transition costs from each customer class through a CTC, a line-item recovery mechanism added to customers' bills. The settlement fixed CTC rates for residential and other classes for the full collection period. Because residential rates were fixed, BGE would not adjust rates or true-up actual collections against those classes' designated share of total transition costs. *Id.*, ¶ 3 ("per kWh charges are to remain unchanged during the applicable recovery period without true-up or reconciliation between actual collections and the transition cost amount" for Schedules R, RL, ES, NRP, and SL). Other customer's CTC rates were not fixed and collections would be reconciled annually.[77] *Id.*

TABLE 11
TRANSITION COSTS AND CUSTOMER COLLECTIONS

Rate Schedule	Transition Costs (millions)	Collection Period	CTC Rates (dollars per kW-hour)
R, RL, ES (residential)	$193.8	6 years, beginning July 2000.	$0.00800 – $0.00264
G, GS	$53.8	5 or 6 year options, beginning July 2000.	$0.00576 – $0.00674 (depending on option selected)
GL	$112.6	4 or 5 year options, beginning July 2000.	$0.00661 – $0.01500 (depending on option selected)
P (primary voltage)	$100.7	4, 5, 6 year options, beginning July 2000.	$0.00661 – $0.01400 (depending on option selected)
SL (street lighting)	$5.1	6 years, beginning July 2000.	$0.00705
NRP (Amtrak)	$2.5	4 or 5 years, beginning July 2000.	$0.00766 – $0.02000 (depending on option selected)
PL and individual customer contracts	$59.5	lump sum, beginning July 2000.	
Total	**$528**		

The settlement agreement accelerated implementation of retail choice for all customers to July 1, 2000. *Id.*, ¶¶ 9-10, 21. BGE offered two forms of SOS for generation services – PFS and DS. *Id.*, ¶ 12. PFS implemented the statutory retail rate rollbacks for residential customers and the rate caps for commercial and industrial customers. Universal service program costs, consumer education programs, and deferred fuel balance true-up charges would be excluded from PFS rates and charged separately to customers. *Id.*, ¶ 37. DS rates, which were not price freeze rates, were set by formula based on wholesale prices, and were charged to nonresidential customers who were not PFS customers. *Id.*, ¶¶ 16-17.

1. Residential Customers' Retail Rate Package

The settlement agreement's price protection provisions stipulated that all residential customers would receive $53.8 million annually in rate reduction benefits through June 30, 2004, and Schedule R/ES residential customers would receive $50.2 million annually for two additional years.[78] *Id.*, ¶¶ 24 (Schedule R/ES), 25 (Schedule RL). Residential customers received PFS for six years (through June 30, 2006, *id.*, ¶ 13) – *i.e.*, two years beyond the four-

[77] This would not apply to eligible customers who chose to pay a lump sum in lieu of a CTC.

[78] *See supra* note 20, at 19.

year statutory period. PUC § 7-505(d)(4)(i)(2). Rate reductions were allocated between generation and distribution rates, now "unbundled" on customers' bills.[79]

In concert with rate protection and unbundling provisions, the settlement agreement provided residential customers with an integrated package of PFS, CTCs, and shopping credits. BGE increased PFS rates gradually. BGE Settlement Agreement, App. A (Part 1). When PFS rates increased, the CTC declined by an identical amount, keeping the total price fixed at 4.553 cents-per-kWh. *Id.* Residential customers' shopping credits gradually increased as well over the price freeze period. *Id.*, App. A (Part 3) (approximately 0.8 cents per kWh increase from July 2000, to June 2006, for R, ES, and RL customers). The interrelation among these settlement provisions suggests likely trade offs and complicates any analysis of the relationship between six years of more than $50 million annual residential rate reductions – collected in part through reduced PFS rates – and the allowed $193.8 million residential transition cost collections.

2. <u>Commercial and Industrial Customers' Retail Rate Package</u>

The settlement required BGE to offer commercial and industrial customer classes a menu of electricity pricing options, including various rates, durations, and interrelated combinations of PFS, CTC, and shopping credits. Customers were given a one-time, irrevocable choice to choose among available service options.

Under the settlement's price schedule, BGE offered PFS to commercial and industrial customers for periods of zero, one, two, or four years. *Id.*, App. A (Part 2). PFS rates remained the same for the full period. In this way, PFS rates for commercial and industrial classes differed from residential PFS rates, which increased over the price freeze period.

Eligible customers who elected not to pay transition costs in a one-time, lump sum payment could pay CTCs over a four- to six-year period. *Id.*, ¶¶ 4, 27-33. Some schedules permitted BGE to continue collecting CTCs for two more years after the price freeze ended. *Id.*, App. A (Part 2). The settlement schedule fixed CTC rates, but indicated that CTC rates would be adjusted annually if they did not match expected total collections. *Id.*, ¶ 36. (These fixed CTC rates operated as a cap, because the settlement provided that adjustments would not result in rates above the total frozen rate for each non-residential PFS rate option. *Id.*)

The settlement agreement also offered customers shopping credits during the price freeze period. Commercial and industrial customer classes' shopping credits were fixed at a constant rate for the full term of the applicable period. *Id.*, App. A (Part 3). The value of the shopping credit depended on which option the customer selected.

The correlative relationship between rates for PFS, CTCs, and shopping credits suggests that generation supply prices were not based on cost, but on the levels of stranded costs collections and the duration of PFS. For example, under Schedules G (General Service) and

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[79] Rate reductions that were implemented through lower generation rates dampened the potential for growth of retail competition in generation supply because it would be difficult for alterative suppliers to compete with BGE's low generation rates.

GS (General Service Small), BGE unbundled all rates by July 1, 2000. From July 1, 2000, to June 30, 2004, BGE offered PFS to GS/G customers under two options: Option 1 (the default option) PFS would extend until June 30, 2004, at a rate of $0.04248 per kWh (summer) and $0.02557 per kWh (non-summer), CTC would be collected for a *six-year* period (July 1, 2000 through June 30, 2006) at $0.0576 per kWh (subject to adjustment), and the shopping credit would be $0.04766/kWh; Option 2 PFS would extend until June 30, 2004, at $0.04148 per kWh (summer) and $0.02459 per kWh (non-summer), CTC would be collected for a *five-year* period (July 1, 2000 through June 30, 2006) at $0.0674 per kWh (subject to adjustment), and the shopping credit would be $0.04668 per kWh. Schedules P, NRP, GS, GL Secondary and GL Primary offered similar combinations of PFS, CTCs, and shopping credits.

3. <u>Analysis and Conclusions</u>

Based on our review of publicly available materials, non-public documents in the Commission's files, and interviews with Commission Staff, we found that the BGE settlement package – including $528 million in transition costs – reflected a variety of compromises and tradeoffs from the parties' litigation positions. 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 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. Without meaningful evidentiary hearings that the 1999 Act required, the Commission apparently approved the settlement based on four factors.

First, the 1999 Act constrained the Commission's discretion to determine stranded costs. Without doubt, the most reliable method for setting the fair market value of BGE's generating assets would have been a Commission-supervised auction open to all interested parties. Pepco's experience showed that the company's estimate of $600 million in stranded ***costs*** turned out to be $457 million in stranded ***benefits*** when it auctioned its generation. Other states (*e.g.*, Connecticut) also realized substantially more than expected when utilities used the marketplace to value their generation assets instead of relying on administrative estimates. If BGE had auctioned its fossil plants – and perhaps Calvert Cliffs as well – there would be no dispute today about the reasonableness of the stranded cost determination, and ratepayers would likely have received more value for the divested assets. The 1999 Act foreclosed that option, however, by expressly permitting utilities to transfer their generation assets to affiliates, which BGE chose to do. Thus, without BGE's agreement, the Commission had no choice but to rely on administrative estimates to determine fair market value.

Second, the approved $528 million transition costs – which included about $85 million in BGE's out-of-pocket restructuring costs, leaving about $443 million in stranded costs – fall within the range of the parties' administrative estimates of the fair market value for divested assets. All parties agreed that the analyses of projected cash flows that were the foundation for predicted valuations depended heavily on underlying assumptions about future energy and fuel prices. Small changes in expectations about trends in natural gas prices or operation of then-emerging PJM markets dramatically impacted the anticipated value of generation resources. Not surprisingly, some of the parties' estimates produced radically divergent results, but none of the parties' testimony anticipated the current energy prices that are now driving generation valuations or the absence of effective competition to discipline wholesale prices. Although no administrative estimate in 1999 could accurately predict the future value of BGE's generation assets, the settlement's agreed stranded costs represented an obvious compromise among the competing positions, and those costs fell within the very broad range of submissions in the administrative record before the Commission.

Third, the BGE settlement agreement reflected a complex set of tradeoffs, including the amount of allowed stranded costs. Consequently, it is impossible to consider the settlement of stranded costs without considering other agreed customer benefits that exceeded statutory requirements – *e.g.*, greater rate reductions, extended rate cap periods, and immediate implementation of retail choice. The settlement's interaction between the PFS rates and CTC suggests that the parties may have consciously conceded their positions on stranded costs in return for concessions on rates. Thus, any analysis of the approved stranded costs must take into account the offsetting short-term customer rate benefits, which the parties valued at about \$300 million. When considered narrowly with these rate components, the Commission – evaluating the settlement as a package – concluded that the agreed stranded costs were reasonable. The entire package included ratepayer obligations for Calvert Cliffs' decommissioning, however, and, as we describe in Section VI, the Commission did not evaluate adequately the adverse consequences for ratepayers of that element of the agreement.

Fourth, the timing of the stranded costs determination adversely affected its accuracy. Several parties suggested that the number of uncertainties in 1999 made it impossible to set reliable fair market values and that the Commission should defer establishing the amount of stranded costs until more was known. BGE and Commission Staff agreed, for instance, that Calvert Cliffs should continue under cost-of-service regulation until there was more information about the value of nuclear generating assets. The settlement accelerated the process, however, and concluded all transition issues without further proceedings. Such expedition had perceived value at the time, and the Commission proceeded with a global resolution, even if it meant sacrificing a significant degree of certainty.[80] Given the uncertainties in all of the parties' estimates, the Commission could reasonably have deferred a final determination of stranded costs, but it may have construed the provision in the 1999 Act requiring action on the transfer request within 180 days as dictating an immediate resolution.

In hindsight, all of the projections about the fair market value of generation assets were much too low. Expectations of low energy and capacity prices driven by a competitive wholesale market have proven to be illusory. Instead, the confluence of transmission constraints, load growth, fuel price increases, and no new generation have driven up the value

[80] The Commission commented that prior to the settlement, BGE had intended to keep Calvert Cliffs in its rate base as a regulatory asset, but the Commission concluded that settlement provisions removing Calvert Cliffs and other generation-related assets from the rate base was in the public interest. Order 75757, 90 Md. PSC at 234-35 (8804/235).

of BGE's divested assets to several times what all the experts anticipated in 1999.[81] Judging the Commission's approval of stranded costs by the evidence available at the time, however, there was a basis for that decision. As we show in Section VI, however, the Commission gave inadequate attention to some key aspects of the settlement – particularly the terms requiring ratepayers to continue funding Calvert Cliffs' decommissioning – thereby likely burdening ratepayers with substantial costs for decades.

E. BGE's Methodology for Collecting Transition Costs from Ratepayers and BGE's Allocation of CTC Revenues

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.[82] BGE Settlement Agreement, ¶ 2. 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. *See* Response to PSCIR1-1 (revised).

As an initial matter, we are aware of suggestions that BGE did not actually collect any transition costs from customers because those costs were subsumed within the overall rate cap. Under that analysis, the rate cap would not have been lower, regardless of the amount of stranded costs, and, therefore, the settlement's stranded costs were little more than window dressing. This argument is belied, however, by two facts. First, the BGE rate cut of 6.5% below existing rates was less than the statutory maximum of 7.5%. Thus, if stranded costs had been less than the agreed-upon $528 million, the parties could have reduced the total rate by an additional one percent, *i.e.*, to the statutory maximum of 7.5%. Second, BGE actually collected stranded costs as a part of the frozen rates and accounted for those revenues separately. From customers' standpoint, they were certainly paying for stranded costs as one component of their rates.

In this section, we explain the mechanisms by which BGE collected transition costs from residential and commercial and industrial ratepayers. By the settlement agreement's terms, BGE filed reconciliations and rate adjustments for some customer classes. Other customer classes, including residential, had fixed rates that were not subject to reconciliation under the settlement terms. Next, we explain how BGE allocated the transition cost collections. Our evaluation of this issue requires further information from BGE, and we

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81 The appendix to this report includes an analysis of the current fair market value of all Maryland's power generators and finds that if those assets were purchased today, a reasonable estimate for the amount that utilities would have to pay would by $18 to $24 billion. Using the same estimating methodology, the value of BGE's former Maryland assets is between $9.7 and $12.5 billion.

82 The settlement value was expressed on a present value and after-tax basis, which means that BGE collected more than $528 million from ratepayers. For example, the present value of $100 that BGE collected from ratepayers on January 1, 2001, assuming a discount rate of 7.25%, would be equal only $93 in January 1, 2000 dollars. Similarly, because the settlement amount was an after-tax value, to collect an after-tax value of $100 (and assuming a 35% tax rate), BGE would need to collect $158 from ratepayers.

recommend that the Commission continue its inquiries to assure that BGE's collections comported with the terms of the negotiated settlement.

1. Residential Customers' Share of Transition Costs

The settlement fixed CTC rates for residential and other classes (Schedules R, RL, ES, NRP, SL) but specified that the actual collected amount would not be reconciled or trued-up against those classes' designated share of total transition costs. BGE Settlement Agreement, ¶ 3 ("per kWh charges are to remain unchanged during the applicable recovery period without true-up or reconciliation between actual collections and the transition cost amount"). The settlement allowed BGE to collect $193.8 million (after-tax, present value) from residential customers but provided no assurance that BGE's actual collections would be limited to the settlement amount. Some parties apparently sought a fixed CTC rate that would ensure price certainty for residential customers, but the potential downside of this trade-off was to sacrifice the possibility of a later adjustment. By fixing the CTC rate, BGE could have over-collected (or under-collected), depending on whether the number of kilowatt hours actually consumed by these classes over their respective collection periods exceeded forecasts or whether any other assumption that was the basis for the settlement changed.[83]

Because the settlement stipulated that the CTC collections from residential ratepayers would not be subject to a reconciliation or true-up between actual collections and the transition cost amount used to set the per-kWh charge, BGE did not file this information with the Commission. To compare actual collections with the settlement, we requested from BGE data reporting kWh sold by year and by customer schedule. *See* Response to PSCIR1-2. BGE provided a document showing six years of collections from the CTC by Schedules R, RL, and ES by 12-month periods ending each June. To compare BGE's actual collections with the settlement value of $193.8 million, we adjusted BGE's data by using methods similar to those that BGE used to true-up collections and set new annual CTC rates for commercial and industrial customers. We applied a discount rate of 7.25%, a 35% federal tax rate, and a gross receipts tax of about $0.02 per kW. Our calculations, which are highly dependent on these assumptions, show that BGE's collections exceeded the allowed settlement amount by about five percent. (By comparison, BGE under-collected from Schedule SL by about 20%.)

Even if BGE intended to over-collect transition costs from residential classes and actually did as a consequence of the settlement's non-reconciliation provisions, a question remains whether BGE would have attempted to collect these revenues through some other settlement mechanism. For example, BGE's price freeze rates for residential customers provided an average 6.5% rate reduction and approached the statute's high end for residential customers' rate rollback requirements. PUC § 7-505(d)(4). Instead of fixing the CTC collections rate, BGE could have simply negotiated a lower rate reduction in settlement. These negotiated tradeoffs among BGE's settlement components complicates analysis of stranded costs because six years of more than $50 million in annual residential rate reductions –

[83] All parties had access to discovery documents that BGE produced showing its anticipated GWh distribution sales to residential rate classes over the rate-freeze period. BGE, Settlement Data Responses, *In re Baltimore Gas and Elec. Co.* (8804/151) (July 20, 1999) at 8.

collected in part through a reduction of PFS rates – may have been a function of the settlement's transition cost value.

2. Commercial and Industrial Customers' Share of Transition Costs

With respect to the commercial and industrial customer classes, BGE was authorized to collect $166.4 million from General Service customers (Schedules G, GL, GS),[84] and $100.7 million from primary voltage service (Schedule P), and $59.5 million from individual customers and private area lighting (Schedule PL) (all after tax and present value as of January 1, 2000). Unlike transition cost collections from residential classes, the settlement required that BGE adjust CTCs to ensure that annual revenues did not exceed or fall short of the allowed collection amount.[85]

Customers that did not elect to pay transition costs to BGE in a one-time, lump sum payment, selected an option to pay transition costs over a four- to six-year period.[86] For these customers, the CTC rates were expected to be adjusted annually if they did not match anticipated collections. BGE Settlement Agreement, ¶ 36. For these customer classes, too, the expected CTC rates and PFS rates varied by the duration of the collection period. *See supra* Section III.D.2, at 54-55. For this reason, the correlative relationship between the rate components suggests it would be extremely difficult to separate the actual costs of transition from the cost of generation supply during this period or to determine whether one subsidized the other.

Our review of available documents suggests that BGE's actual collections from these customer classes were close to the amounts authorized by paragraph 2 of the settlement. BGE filed with the Commission an annual true-up or reconciliation for CTC collections under these schedules.[87] The CTC rate was a levelized rate based on anticipated distribution sales over the

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84 The settlement agreement further allocated $53.8 million in transition cost collections to Schedules G (general service) and GS (general service – small) and $112.6 million to Schedule GL (general service – large).

85 BGE Settlement Agreement, ¶ 3. The settlement provided for annual adjustments to CTC rates charged to these customer classes for the "sole purpose of reconciling, by CTC option within each rate schedule, the annual revenues received from the CTC charge to take account of differences between the actual kilowatt hour sales for the CTC option within each rate schedule times the applicable CTC in the prior year and the previously estimated kilowatt hour sales for the CTC option within each rate schedule times the applicable CTCs for that same year." *Id.*

86 No customers elected GL (Option 3) or P (Option 4), so these options were removed from BGE's rate schedules. *See* Cover Letter to BGE's Supplement No. 347 to P.S.C. Md. E-6, Rider 2 - Competitive Transition Charge, Maillog No. 77917 (May 25, 2001), at 2. Many documents registered in the Commission's maillog may be accessed through "Official Filings" on the Commission's website at http://webapp.psc.state.md.us/Intranet/Maillog/maillogitems.cfm.

87 *See, e.g.*, Supplement No. 347 to P.S.C Md. E-6, Rider 2 - Competitive Transition Charge (CTC), Maillog No. 77917 (May 25, 2001); Supplement No. 358 to P.S.C Md. E-6, Rider 2 - Competitive Transition Charge (CTC) Maillog No. 83296 (May 22, 2002); Supplement No. 362 to P.S.C Md. E-6, Rider 2 - Competitive Transition Charge (CTC), Maillog No. 87991 (May 14, 2003); Supplement No. 373 to P.S.C Md. E-6, Rider 2 - Competitive Transition Charge (CTC), Maillog No. 97457 (May 25, 2005) (rejected in part due to challenge to BGE's rates for Schedule P (Option 3)); Supplement No. 373 to P.S.C Md. E-6, Rider 2 - Competitive Transition Charge (CTC), Maillog No. 97923 (June 30, 2005)

collection period and applied a 7.25% discount rate. (The settlement set the 7.25% after-tax discount rate and applied a mid-year discounting convention. *See* Settlement Agreement, ¶ 5.) Because the transition costs were specified in after-tax dollars, BGE's annual reconciliations also accounted for a gross receipts tax/PSC fees ("GRT/PSC") of about two percent and federal income taxes of 35%.

BGE adjusted CTC rates based on a comparison of the previous year's load forecast and actual load. *See, e.g.,* Attachment 2 to Supplement No. 381 to P.S.C. Md. E-6, Rider 2 - Competitive Transition Charge. In 2003 BGE proposed a true-up to reconcile actual transition cost payments with the Settlement Agreement's allowed collections at the end of each option's collection period. *See* Cover Letter to Supp. 362 Compliance Filing (May, 14, 2003), at 3. We were unable to locate BGE's 2004 compliance filing in the Commission's files, but BGE's subsequent filings indicate that the Commission authorized true-ups for options with shorter CTC collection periods.

In 2005, a dispute arose over BGE's attempt to collect additional money from Schedule P (Option 3) customers. *See* Letter Order, *In re Baltimore Gas and Elec. Co.* (8804/316) (July 15, 2005). BGE anticipated under-collections from Schedule P (Option 3) customers by about $6.2 million, and proposed to increase the CTC rate by about 30% to mitigate the impact of final true-up. The Commission rejected BGE's proposal, *see* Letter Order, Maillog No. 97457 (June 24, 2005), and BGE refiled Schedule P (Option 3) rates using an adjustment methodology identical to the method applied in prior filings. *See* BGE's Supplement 373 to P.S.C. Md. E-6 Rider 2 - Competitive Transition Charge (CTC) (June 30, 2005). The final reconciliation was resolved by a settlement agreement that extended Schedule P (Option 3) customers' CTC payments for three additional months. Settlement Agreement between Baltimore Gas and Electric Company and Maryland Industrial Group, *In re Baltimore Gas and Elec. Co.* (8804/337) (Dec. 14, 2005). The Commission approved the settlement in Order 80527. *In re Baltimore Gas and Elec. Co.*, 97 Md. PSC 4 (8804/339) (Jan. 25, 2006).

3. <u>Transition Costs Fully Collected by 2006</u>

BGE no longer charges a CTC rate to retail customers. In September 2006, BGE filed a request to revise its tariff to recognize expiration of the CTC. BGE's Supplement No. 390 to P.S.C. Md. E-6 of its Retail Electric Service, Maillog No. 103102 (Sept. 19, 2006). The Commission accepted BGE's filing by letter order. *See* Letter Order, Maillog No. 103102 (Oct. 4, 2006).

4. <u>BGE's Transfer of Transition Cost Revenues to Constellation</u>

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. *See* Attachment 3 to Response to PSCIR1-3 (CTC Collection Agent Agreement), Section 1(c) at ¶ C. 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

(replacement rates for Schedule P (Option 3)); Supplement No. 381 to P.S.C Md. E-6, Rider 2 - Competitive Transition Charge (CTC), Maillog No. 101174 (Apr. 18, 2006).

affiliate CCNPP (*id.* ¶ 2) 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 (*id.* ¶ 1) 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." *Id.* ¶ 4.

If BGE paid or accrued more for standard offer service under its supply contract than the revenues it collected for SOS from ratepayers, that "deficiency" was considered a Negative SOS Offset. If the SOS revenues that BGE collected from ratepayers exceeded the amount that it paid, the "excess" was a Positive SOS Offset. *Id.* BGE recorded the SOS Offsets for the fiscal year in an SOS Balance Account. *Id.* At the end of any fiscal year, if the Negative SOS Offset exceeded the share of CTCs to be paid to CCNPP, BGE would not pay CCNPP but would instead apply CTC collections to offset the negative balance in the SOS Balance Account. *Id*. ¶ 1(b)(i). In other words, under the CTCCA Agreement, instead of CTC payments going to CCNPP as compensation for the stranded costs associated with the Calvert Cliffs nuclear plant, those payments reimbursed BGE for the shortfall between customer rates and supply costs during the rate-freeze period. If the CTCs exceeded the Negative SOS Offset, BGE remitted to CCNPP its share of CTC revenues less the Negative SOS Offset. *Id.* If the SOS Offset for the fiscal year was positive, BGE would remit to CCNPP its share of CTC revenues plus the Positive SOS Offset but would never remit "an amount that exceed[ed] 90% of the gross cumulative CTC's [sic] collected." *Id.* ¶ 1(c).

For at least the 2000-2003 fiscal period, the Negative or Positive SOS Offsets that BGE recorded in the SOS Balance Account represented transactions between BGE and its affiliate, Constellation Power Source, Inc. ("CPSI"), under a full requirements service agreement to supply SOS service. *See* Attachment 8 to Response to PSCIR1-3 (Full Requirements Service Agreement Between Constellation Power Source, Inc. and Baltimore Gas and Electric Company). By this agreement, also dated June 14, 2000, BGE agreed to purchase all-requirements electric service for its SOS customers at prices fixed by month through June 2003. The Commission-approved Settlement Agreement authorized this non-competitive procurement, declaring that BGE "shall have discretion in how it arranges for generation supply service for its SOS customers prior to July 1, 2003." BGE Settlement Agreement, ¶ 18. (The CTCCA Agreement also references this affiliate supply agreement in the definition for "Negative SOS Offset." CTCCA Agreement, at ¶ 1(b)).

BGE produced documents showing that it or its affiliates entered into two additional agreements on June 14, 2000. These agreements may be related to the BGE, CPSI, and CCNPP arrangements establishing the intracompany allocation of transition cost collections and provision of standard offer service for the 2000-2003 period. First, CCNPP and CPSI entered a three-year power purchase agreement for marketing and wholesale sales of Calvert Cliffs' net output. Constellation's Nuclear application to the NRC for transfer and amendment of Calvert Cliffs' licenses references this contract. *See* Exhibit 6 to Report and Exhibits regarding the business separation of Constellation Energy Group, Inc., *In re Business Separation*, (8883/10) (May 9, 2001) (NRC Application for the Transfer of Renewed Operating Licenses for Calvert Cliffs Nuclear Power Plant and Application for the Transfer of Materials License for the Calvert Cliffs Independent Spent Fuel Storage Installation filed by Calvert

Cliffs Nuclear Power Plant, Inc. (Dec. 20, 2000)). Second, BGE and CPSI entered a Power Purchase and Sale Agreement to transfer three power purchase agreements to CPSI. *See* Attachment 11 to Response to PSCIR1-3 (Power Purchase and Sale Agreement between BGE and CSPI).

A document obtained from Commission Staff shows that in April 2001, BGE forecast CTC collections, the SOS Balance Account Projection, the SOS Offset Projection, and payments to CCNPP under these various arrangements. *See* SOS Projections (Apr. 26, 2001). After nine months experience, BGE anticipated that CCNPP would receive only about $28.14 million of the eligible $864.52 million of CTC collections for the full six-year period, 2000–2006. *Id.* CCNPP anticipated two payments, $16.5 million and $11.7 million for the 2005 and 2006 fiscal years ending June 30, respectively. The remaining transition cost collections would be applied to the SOS Balance Account, and would be offset by $836.4 million of anticipated losses from BGE's SOS supply contracts. *Id*. This forecast shows significant monthly Negative SOS Offsets accruals though the end of the price-freeze period. *Id.* Those forecasts proved incorrect because the settlement required BGE to obtain its electric supply for its SOS customers "through a competitive bidding process open to all suppliers" after July 1, 2003. BGE Settlement Agreement, § 18. Because BGE was precluded under the settlement from "accept[ing] an SOS bid that exceeds any of its PFS prices" (*id.*), it no longer incurred Negative SOS Offsets.

In response to our requests, BGE summarized data for actual CTC collections, SOS account balances, SOS Offsets, and payments to CCNPP. *See* Response to PSCIR1-1 (revised). Three facts emerge from these documents (summarized in Table 12). First, 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 Settlement Agreement, ¶ 2. Second, 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." Settlement Agreement, ¶ 18. Third, CCNPP received no CTC payments through 2003 but received four payments totaling $329.85 million from 2004 through 2006. Payments to CCNPP increased because the settlement capped rates BGE could pay for SOS supply, which constrained BGE and its affiliates' intracompany transactions for the remainder of the period.

TABLE 12
CTC COLLECTIONS (in millions)

	2001 Forecast	Reported
CTC revenues collected from ratepayers	$982.92	$975.25
CTC revenues applied to offset losses from SOS agreements with affiliate	$835.71	$527
CTC collections remitted to CCNPP	**$28.14**	**$329.85**
Source: Attachment 1 to PSCIR1-1; SOS Projections (Apr. 26, 2001).		

BGE's second duty as CCNPP's fiscal agent was to remit "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." *Id.* ¶ 4.BGE reports,

> For income tax purposes, the CTC revenues recorded in the SOS Balance Account were not recorded by BGE's as operating revenue. Therefore, BGE did not record any income tax liability for these revenues. However, . . . between BGE and CCNPP, 100% of the CTC revenues were recorded as operating revenues.
>
> For income tax purposes, CCNPP's share of the monthly CTC revenues (approximately 87-88% of the total CTC revenues) were treated as operating income. (Note: the remittance of cash from BGE to CCNPP is not the event that triggered the income tax obligation. Rather, the monthly accrual of CCNPP's share of CTC revenues over the entire six year term was treated as taxable income.)

Response to PSCIR3-3 (revised); *see also* Responses to PSCIR4-27, 4-29, 4-30 (explaining intracompany accounting transactions between BGE and CCNPP).

5. <u>Analysis and Conclusions</u>

Although we did not have access to all the BGE and Constellation documents that would be necessary to answer definitively all outstanding questions about the disposition of CTC collections, we can infer several conclusions. First, to the extent that the Commission or the settling parties intended that CTC collections would compensate the Calvert Cliffs nuclear plant owner for the difference between that asset's book value and fair market value, they did not do so directly. Under the logic of the Settlement Agreement, BGE transferred that facility to CCNPP 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 CCNPP, 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.

Second, to the extent that the SOS supply contract between BGE and CPSI reflected market rates – as BGE has represented to us it did – the allocation of CTC revenue to offset those costs that were above SOS revenues may have acted as a barrier to the development of retail competition.[88] If the market price was actually above the PFS rate and the only way that BGE could offer that rate was by using CTC revenues to cover the difference, it would be impossible for another would-be retail competitor to offer a lower price. Effectively, therefore, the CTC revenues could have acted as a half-billion dollar subsidy that would preclude retail competition for at least the first three years of the price-freeze period.

[88] *See supra* note 79, at 54; Section II.C.5 at 21-22 (discussing MAPSA's appeal of the rate package).

Third, there is some evidence – although hardly conclusive – that BGE's SOS supply contract with CPSI charged rates that were actually well above market prices. Constellation's application to the NRC on the Calvert Cliffs' license transfer indicated that its rates charged to CPSI would remain essentially steady throughout the price-freeze period. In contrast, CPSI'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. It is not possible from the data that BGE supplied to determine the exact relationship between the rates CCNPP charged CPSI and the SOS rates that CPSI or other suppliers charged BGE, partly because the figures reported are for calendar years, and the supply sources changed mid-year in 2000 and 2003. Nevertheless, comparable information is available for four years. As Table 13 demonstrates, in 2001 and 2002, CCNPP's rates were about 75% of the SOS wholesale cost that CPSI charged BGE under the full requirements service agreement between them, but in 2004 and 2005, when BGE had to solicit competitive suppliers, the CCNPP rates were 80% and 77%, respectively, of the wholesale cost. These 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. Given the lack of clarity about BGE's use of the stranded cost collected from ratepayers, we recommend that the Commission conduct further proceedings to review the circumstances surrounding the post-settlement agreements between BGE and its Constellation affiliates and to determine whether their actions complied with the spirit and letter of the 1999 Act and the settlement agreement.

TABLE 13
BGE'S COST FOR SOS SUPPLY PURSUANT TO BGE-CPSI CONTRACT
COMPARED WITH CCNPP'S ANTICIPATED REVENUES FROM CCNPP-CPSI CONTRACT

	Per MWh dollars reported by calendar year (n/a indicates not applicable; n/r indicates not reported)						
	2000	2001	2002	2003	2004	2005	2006
BGE's reported SOS Wholesale Expense (average contract cost, July 2000-July 2006)	$55	$45	$43	$40	$41	$43	$42
CCNPP-CPSI Affiliate Contract, July 2000-June 2003	n/r	$33.73	$32.37	$26.65	n/a	n/a	n/a
CCNPP's future power sales arrangements with CPSI, July 2003-TBD	n/a	n/a	n/a	$35.57	$32.89	$33.14	n/r

Source: Response to PSCIR3-3 (revised). CCNPP's forecast of SOS-related revenues are from its Statement of Income, 2001-2005 (as of Dec. 20, 2001), included in Exhibit 6 to Report and Exhibits regarding the business separation of Constellation Energy Group, Inc., *In re Business Separation* (8883/10) (May 9, 2001) (NRC Application for the Transfer of Renewed Operating Licenses for Calvert Cliffs Nuclear Power Plant and Application for the Transfer of Materials License for the Calvert Cliffs Independent Spent Fuel Storage Installation filed by Calvert Cliffs Nuclear Power Plant, Inc. (Dec. 20, 2000) at Att. 1 at 8-11, Att. 2 at 8-11, Exs. B-3, B-4).

Finally, although BGE has not fully explained the business reason for using CTC collections to offset SOS "losses," it does not appear that BGE or Constellation avoided paying any income tax on the CTC revenues. The settlement provided for $528 million in CTC collections after tax and in 2000 dollars, and BGE's collection of $975 million appears to have grossed up the settlement amount to reflect taxes and a 7.25% discount rate. In light of BGE's use of the SOS Balance Account to reduce the amount that it paid CCNPP, we examined the impact, if any, on Constellation's tax payments. We concluded that because Constellation filed consolidated tax returns and CCNPP recognized the CTC revenues as income on its books when BGE received them, Constellation paid appropriate taxes on those revenues. The SOS costs above SOS revenues were treated as deductions, like other legitimate business expenses.

IV. <u>Generation Assets' Transfer to BGE's Affiliates</u>

Following the Commission's Settlement Order approving BGE's divestiture of fossil and nuclear generation assets to affiliates at book value, the Commission examined the asset transfer in accordance with the limited authority granted by the 1999 Act to review a regulated utility's transfer of generating assets to its affiliates. The 1999 Act authorized the Commission to "review and approve the transfer for the sole purpose of determining: (i) that the appropriate accounting has been followed; (ii) that the transfer does not or would not result in an undue adverse effect on the proper functioning of a competitive electricity supply market; and (iii) the appropriate transfer price and rate making treatment." PUC § 7-508 (c)(2).

The Commission-approved settlement agreement established the scope of its review of BGE's asset transfer.[89] BGE applied for divestiture on December 22, 1999, and the Commission's approval by letter order on June 19, 2000 (June 2000 Letter Order) required BGE to make a second compliance filing showing the actual transaction accounting information for the executed transfers (*id.* at 4), which BGE did on January 22, 2001. *See* Baltimore Gas and Electric Co. Generating Asset Transfer - Compliance Filing, Maillog No. 76124 (Jan. 22, 2001) ("2001 Asset Transfer Filing"). Commission Staff and OPC conducted extensive discovery and analysis of this transaction, but we have been unable to determine from Staff whether the Commission issued an order addressing BGE's compliance filing showing its actual transfer.

BGE's compliance filing indicates that it transferred $2.425 billion in net utility generation plants – including both fossil and nuclear – from BGE to its corporate affiliates at book value.[90] BGE transferred $1.472 billion of net utility generating plant (fossil) to Constellation Power Source Generation Inc. ("CPSGI") and $953 million of net utility generating plant (nuclear) to CCNPP. BGE also entered into assignment and assumption agreements with affiliates to secure payment of $278 million tax-exempt debt – with $47 million transferred to CCNPP and $231 million to CPSGI – and an agreement for $366 million in inter-affiliate notes receivable from CPSGI. Because the divestiture transactions caused BGE to be highly leveraged, the company promised to shore up its capital structure with

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89 Order 75757, 90 Md. PSC at 234-35 (8804/235) (summarizing asset transfer provisions, and noting its "continuing jurisdiction to review the transfer of generation assets" under sections 7-508 and 7-509), *aff'd Mid-Atlantic Power Supply Ass'n*, 795 A.2d at 182 (finding Commission was not divested of jurisdiction over matters not considered fully by that order, *i.e.*, authorization of the transfer or approval of accounting procedures associated with the transfer).

90 Book value equals the original capitalized costs, plus any additional capital investments, less any assets retired, less depreciation.

dividend payments from affiliates, by retaining earnings, or by some other method, over the next four to five years (*i.e.*, through about 2006). Our review of Commission and Securities and Exchange Commission filings shows that BGE has since successfully rebalanced its debt-equity capitalization to pre-divestiture levels, as it promised.

A. Settlement Agreement Provisions Governing Divestiture

BGE's settlement agreement did not specify a divestiture method, but allowed BGE to "transfer, sell, lease, assign, mortgage, or otherwise dispose or encumber some or all of its generation assets to either affiliated or non-affiliated entities" without objection from any settling party. BGE Settlement Agreement, ¶ 6. Settling parties also agreed that BGE would retain or absorb any gains or losses on any transaction after June 30, 1999. BGE and the other settling parties agreed that they would not use the company's gains or losses from post-settlement generation asset transactions "in any future proceeding to adjust rates in any way." *Id*., ¶ 6. Despite the likelihood of high ownership concentrations following divestiture, all parties' stipulated that market power studies were "not needed at this time," *i.e.*, at the time of the restructuring. *Id*., ¶ 51.

The settlement stipulated that transfer of generation assets to an affiliate would take place at book value, *i.e.*, "the original cost less the related accumulated depreciation and accumulated deferred tax effects." *Id*., ¶ 6. From a regulatory perspective, a transfer at book value meant that BGE's affiliates might accept some assets at a greater value than they could realize by selling them. In other words, if the stranded cost conclusions were correct, the aggregate discounted cash flow for all the generation assets over their remaining lives was less than their current depreciated value. BGE agreed to file an application for a transfer of generation assets at book value with the Commission by December 31, 1999. The settlement stipulated all parties' agreement to "support or take no position before the Commission regarding any such transfer at book value." *Id.* Additionally, parties agreed to support or take no position regarding BGE's request for the Commission's determination that a transfer at book value and removal of that amount from BGE's rate base was an appropriate regulatory accounting in accordance with PUC §7-508(c). *Id.* Parties were not precluded from protesting other elements of BGE's generation asset transfer filing. *Id.*, ¶ 7.

BGE was also permitted to recognize, as part of the settlement, $150 million (pre-tax) in accelerated depreciation or amortization for the 12-month period ending June 30, 2000. *Id*., ¶ 1. Accelerated depreciation reduced the book value of assets, and closed the negative gap between the assets' assumed market value and regulated value.

B. BGE's December 1999 Proposed Divestiture Filing

In compliance with Order 75757 and the settlement, BGE filed an application with the Commission on December 22, 1999, to effectuate the divestiture of all its generating assets. *See In re Application of The Baltimore Gas and Electric Company's Application for Transfer of Its Generating Assets and For Exempt Wholesale Generator Status Determinations*, Maillog No. 69971 (Dec. 22, 1999) ("1999 Transfer Application"). BGE explained that on June 30, 2000, it would transfer ownership of ten wholly-owned electric generating plants, including Calvert Cliffs, as well as interests in two coal-fired facilities, Keystone and Conemaugh, and

Safe Harbor Water Power Corporation ("Safe Harbor"), a hydroelectric power producer in Pennsylvania, to two special-purpose wholly-owned indirect subsidiaries.[91] *See id.* at 5, Att. A (listing facilities). BGE also proposed to transfer its interests in power purchase agreements to affiliates. *Id.* at 5. BGE further planned to transfer the Calvert Cliffs decommissioning trust fund – which was not part of the utility rate base – and BGE's internal decommissioning reserve to CCNPP. *Id.* at 6. All transfers would be made at book value.

The application explained that the anticipated net book value of generation-related assets to be transferred to BGE affiliates as of June 30, 2000, was $2.38 billion. *See id.* at 6, Att. B. This amount was less than earlier filed testimony projecting a net book value of $2.80 billion as of December 31, 1999, or $2.71 billion as of June 30, 2000.[92] *Id.* at 6-7, Att. C; Ex. RMB-3 (revised) (8804/57). The differences between the book values of the proposed transfer (1999 Transfer Application, Att. C, column (6)) and the projected transfer (*id.*, Att. C, column (3)) (based on pre-settlement testimony and post-settlement adjustments) are a result of (1) removing $159 million (*id.*, Att. C, column (4)) from BGE's rate base, and (2) transferring $177 million of generation related assets that were excluded from rate base in filed testimony (*id*. at 8). BGE allocated the share of common assets to its electric and gas businesses based on their A&G ratios, and allocated between generation and transmission/distribution based on 1998 direct labor ratios. *Id.* at 9, *id.*, Att. C at 2.

Because the Commission did not assign BGE's transfer application to Case No. 8804/8794 or open a new docket, the procedural history is not straightforward. Available documents show that the Commission allowed comments on the application before approving BGE's asset transfer by a June 19, 2000 letter order. *See* June 2000 Letter Order. The Commission's letter order indicates that OPC and Commission Staff filed comments supporting BGE's application, and MAPSA and Shell Energy, LLC filed comments opposing the transfer.[93] Parties also provided comments during the Commission's June 7, 2000 administrative meeting. At that time, BGE provided an accounting update of the proposed transfer. BGE followed with a June 12, 2000 letter to the Commission notifying parties of changes to the filing.

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91 BGE's filing did not include a diagram of its corporate structure, but its Section 203 filings with FERC about a year later attached diagrams of actual and proposed structures. *See* Joint Application under Section 203 of the Federal Power Act for the Disposition of Jurisdictional Facilities and Request for Expedited Consideration, *Constellation Generation Group, LLC*, FERC Docket No. EC00-57-000 (Feb. 11, 2000) (showing that BGE wholly owned Constellation Generation, Inc. and Calvert Cliffs, Inc.); Attachment B-1 to Application Under Section 203 of the Federal Power Act for the Disposition of Jurisdictional Facilities; and Notices of Succession, *Constellation Energy Group Inc.*, FERC Docket No. EC01-50 (Dec. 28, 2000) (Constellation Energy Group Current Structure showing fossil and nuclear generation assets moved to become subsidiaries of new Constellation affiliates).

92 The amount in the December 22, 1999, application is also different than the actual transferred value that BGE submitted in a later compliance filing. The difference is mostly attributable to accelerated depreciation authorized by the settlement. (Attachment C to 1999 Transfer Application (Column (2) and notes). BGE's filing indicated that the "cost and associated reserve for transmission facilities, primarily step-up transformers, associated with the generating assets to be transferred" also modified book value from the filed testimony. *Id*. (column (2) showing additional $68.1 million utility plant in service and additional $29.16 million in "common & general" CWIP).

93 These comments are not available for our review.

The Commission's letter order summarizing the proposed transaction explained that BGE would transfer approximately $2.05 billion (net book value) of generation assets to Constellation Generation Inc.[94] and Calvert Cliffs, Inc.,[95] a subsidiary of Constellation Nuclear Group, LLC.[96] The transfer, in total, would remove about $2.71 billion in assets from BGE's electric rate base. In summarizing its evaluation of the transfer's reasonableness, the Commission explained that BGE's outstanding debt obligations totaled about $2.4 billion, including $278 million in pollution control debt related to its electric generation stations, $819 million in Medium-Term Notes, and $1.3 billion in First Mortgage Bonds. *Id.* at 4-5. The pollution control debt would be transferred to affiliates. Because the Medium-Term Notes and First Mortgage Bonds could not be assigned to an affiliate, the Commission explained that BGE would receive a one-year (or shorter term) note from affiliates for about $426 million. Additionally, BGE would be provided a "debt offset . . . to achieve a total $1.1 billion debt removal."[97] *Id.* at 4. The Commission found this accounting method to be "both reasonable and appropriate." *Id.*

The Commission also addressed the ratemaking treatment of the asset transfer, noting that "pursuant to the approved Settlement, ratepayers will be protected from any rate effects of the proposed transfer since rates will be frozen for a period of years." *Id.* at 5. Finally, responding to MAPSA's objection[98] about the appropriateness of transfers at book value as "essentially a reiteration of prior arguments in opposition to the Settlement," the Commission found that "these proposed transfers do not violate the 1999 Act, and further [found] that the transfers conform with the approved Settlement." *Id.* at 4. Nevertheless, the Commission required BGE to file actual transaction accounting information when the transfers were complete. *Id.*

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94 Constellation Generation Inc. became CPSGI after the Commission issued its letter order approving the transfer.

95 Calvert Cliffs, Inc. became CCNPP in May 2000.

96 Constellation Nuclear Group, LLC became Constellation Nuclear, LLC (May 2000), then Constellation Generation Group, LLC (July 2002), and is now Constellation Energy Nuclear Group, LLC (Oct. 2007).

97 This order approving the transaction seems to overlook BGE's June 12, 2000, letter to the Commission stating that BGE was unable to secure a favorable ruling from the IRS to carry out its plan

> to receive approximately $1.1 billion in unsecured promissory notes from our non-regulated subsidiaries as part of the transfer of BGE's electric generating assets to non-regulated subsidiaries. Repayments of the notes by our non-regulated subsidiaries would be used to service certain long-term debt of BGE. As we have indicated to the Commission, we were unable to receive a favorable ruling from the Internal Revenue Service. . . . Therefore, as that amount of BGE debt matures over the next 4-5 years, we plan to manage our finances to enable BGE's capital structure at the end of this period to mirror the capital structure that would have occurred had the IRS ruled favorably with respect to the contemplated $1.1 billion in promissory notes.

Letter from Thomas E. Ruszin, Jr. to Ms. Felicia Greer (June 12, 2000).

98 The June 2000 Letter Order reports that MAPSA "objects to the transfers at book value and argues the Commission expressly reserved authority in the Settlement Order . . . that would allow further hearing or rejection of [BGE's] application." *Id*. at 2.

MAPSA's appeal – discussed above in the context of the stranded costs determination – requested the court's review of the Commission's orders approving the asset transfer, contending that the Commission had divested itself of jurisdiction over BGE's transfer application when it approved the settlement and that BGE's transfer at book value was not supported by substantial evidence.[99] *Mid-Atlantic Power Supply Ass'n*, 795 A.2d at 180. The court denied both claims, finding "the Commission did properly consider and approve the transfer of BGE's generating assets to its unregulated affiliates." *Id.* at 185. In so holding, the court interpreted PUC § 7-508 to find that the Commission had no statutory obligation to review the asset transfer. In the court's view, the Commission's review of the transfer was permissive. The court found that MAPSA's arguments about the appropriateness of the transfer price were merely reiterations of its claim that the $528 million was not supported by substantial evidence – a claim the court also rejected.

C. BGE's Asset Transfer at Book Value

Our review of BGE's transfer of generation assets to affiliates at book value shows that the transaction accounted for ratepayers' interests in the company's divested assets. BGE's transfer application explained that it would effectuate the transfer by,

> removing from the books of BGE and recording on the books of the affiliate the amounts shown on the books of BGE as of the date of transfer for the (i) original cost of the generation assets transferred; (ii) accumulated depreciation on the generation assets transferred; and (iii) accumulated deferred taxes on the generation assets transferred.

1999 Transfer Application at 3. Because parties to the settlement were precluded from opposing BGE's transfer method (BGE Settlement Agreement, ¶ 6), the Commission did not have the benefit of most parties' views on whether the transaction satisfied the 1999 Act's evaluative criteria (PUC § 7-508(c)) that the Commission was permitted to review – *i.e.*, whether the transaction conformed with appropriate accounting principles, the transfer's competitive effect on the electricity supply market, and the appropriateness of the transfer price and ratemaking treatment.

Based on our review of the available evidence, BGE's transfer price and methodology were appropriate. BGE's book value transfer did not give Constellation value that rightfully belonged to ratepayers. Unlike disputes related to Pepco's excess deferred income taxes or accumulated deferred investment tax credits and the proper amount of stranded benefits that should be returned to ratepayers,[100] in BGE's case, ratepayers should be unaffected by an internal transaction between a utility and its affiliate when there are stranded costs and the

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[99] The two asset transfer issues for which MAPSA sought the court's review were "[w]hether the circuit court erred in upholding the Commission's Letter Order approving BGE's transfer of its generating assets to its unregulated affiliates" and "[w]hether the Commission lacked jurisdiction to approve the transfer of BGE's generating assets while the Settlement Order was being appealed." *Mid-Atlantic Power Supply Ass'n*, 795 A.2d at 164.

[100] *See, e.g.,* Office of People's Counsel, Comments on PEPCO's Application for Approval of a Divestiture Sharing Plan, *In re Potomac Elec. Power Co.* (8796/271) (May 18, 2001).

transfer is at book value. Assuming, as the settlement did, that there were stranded costs, the transaction does not affect Maryland ratepayers because after deregulation ratepayers had no financial interest or claim in the book value of the divested generation assets. Before deregulation, ratepayers "rented" BGE's generation assets, and the rental price was reflected in Commission-approved cost-of-service rates for electricity. Cost-of-service rates included payments for these assets equal to the return on equity of the undepreciated plant plus the current depreciation. Ratepayers had no further interest or ownership claim to the facility. Thus, when their "rental" term expired – *i.e.*, when Maryland deregulated – ratepayers were essentially indifferent to internal accounting transfers between the utility and its affiliate. For this reason, BGE's ratepayers have no claim to any compensation so long as the transfer did not impair BGE's capital structure.

D. BGE's January 2001 Asset Transfer Filing

In compliance with the Commission's June 2000 Letter Order, BGE also filed accounting information relating to the actual transfer of generation assets. *See* 2001 Asset Transfer Filing. This filing included BGE's balance sheet before and after the asset transfer, asset transfer journal entries, and information regarding the transferred plant in service, transferred long-term debt, and employee transfer issues. *Id.* at 1-2. The Commission's Accounting Investigations Division and the OPC reviewed the transfer and discovery materials obtained from BGE, and Staff recommended that the Commission accept BGE's 2001 Asset Transfer Filing. Staff's analysis explained that BGE transferred approximately $2.43 billion in net utility generation plants to affiliates, and the variance between the actual transfer and BGE's compliance filing was less than two percent. Comments of the Accounting Investigations Division (Apr. 24, 2001) ("Staff Analysis") at 2. We have not been able to locate – and the Commission may not have issued – an order on BGE's 2001 Asset Transfer Filing.

BGE executed assignment and assumption agreements with affiliates to secure payment of $278 million tax-exempt debt – $47 million to CCNPP and $231 million to CPSGI – with varying maturity dates through 2027. *See* Attachment 4 to 2001 Asset Transfer Filing, Response to Staff Data Request 1-1(d) (and Attachment), 3-3. Pursuant to these assignment and assumption agreements, affiliates repaid the debt as it matured. Response to Staff Data Request 2-3. If affiliates were unable to retire the debt as it came due, BGE remained liable, but it asserted that it would nevertheless have a claim under the assignment and assumption agreements. Response to Staff Data Request 3-3.

CPSGI, BGE's generation affiliate, also tendered unsecured notes receivable for $366.27 million to cover BGE's mortgage debt that would mature in one year. Attachment 1 to 2001 Asset Transfer Filing, at 1; Response to Staff Data Request 1-1(d) (attachment); 2-2(a); 2-2(c); 2-2(e) (attachment); 3-3 (confirming mortgage debt remained with BGE); Attachment 2 to Response to PSCIR1-3, (Agreement and Plan of Reorganization and Corporate Separation (Fossil)). BGE affirmed that this note would be fully satisfied by March 2001, when subsidiaries transferred cash to BGE. *See* Response to Staff Data Request 1-1(c); 1-1(e); 2-3 (confirming obligation fully paid).

The total of $645 million in debt transfers "[did] not represent the totality of funds that BGE might receive from affiliates to satisfy utility debt obligations." *See* Response to Staff Data Request 5-1. As Staff's analysis explained, BGE had planned to transfer a larger portion of debt associated with the asset transfer ($1.1 billion), but could not do so without incurring significant tax consequences that would be adverse for ratepayers. *See* Staff Analysis at 2; Response to Staff Data Request 1.1(e) (quoting Letter from T. Ruszin to F. Greer (June 12, 2000)); 3-1 (response discussing IRS' Private Letter Rulings). Instead, BGE transferred $278 million in debt that was tax exempt[101] and received a note from Constellation for $366 million to cover some of the remaining debt. Because BGE did not transfer all of the debt associated with its generating assets, BGE's capital structure after divesture was more heavily weighted to debt than before. Staff noted that assignment of less than the full amount of the debt to affiliates caused BGE to be highly leveraged, with an outstanding debt balance of $1.96 billion, but that the utility would "shore up" its capital structure over the next four to five years (Staff Analysis at 2), presumably with dividend payments from non-regulated affiliates. Response to Staff Data Request 1-1(e) at 2 (noting that October 2000 and January 2001 dividend payments to BGE of $126.4 million from non-regulated affiliates had been applied to rebuild BGE's equity balance). BGE also anticipated readjusting the leverage between BGE and non-regulated companies by "paying BGE Corp. dividends out of the non-regulated companies; raising capital at BGE Corp. and/or liquidating non-regulated or non-core assets and then contributing equity to BGE; and retaining BGE earnings." Response to Staff Data Request 5-1. The Commission noted its concern with BGE's capital structure following divestiture in a related proceeding.[102] Reminding the company that it had made a commitment to restore its equity ratio, the Commission ordered BGE to notify the Commission of any deviations from this plan and to explain the reasons for such change.[103] *See also* Ex. TER-1 (debt retirement schedule) (8883/35).

Following divestiture, BGE did rebalance its debt-equity capitalization to pre-divestiture levels. We reviewed excerpts of BGE's quarterly statements provided by Staff for the twelve-month periods ending the first quarter 2001, through the third quarter 2004. These filings show that BGE's electric capital structure nine months after divestiture (*i.e.*, by March 31, 2001) was 75% long-term debt, 19% common equity, and six percent preferred stock. *See* Letter from Anne Hahn to Charles Senseney (May 15, 2001) (enclosing statements for twelve months ending March 31, 2001). (By comparison, its gas capital structure was 48.4% long-term debt, 47.2% common equity, and 4.4% preferred stock. *Id.*) These filings show that BGE modified its electric capital structure to reduce the share of long-term debt and increase the share of common equity. For the twelve months ending December 31, 2002, BGE reported that its electric capital structure was 48% long-term debt, 46% common equity, and six percent preferred stock, which was the same as the capital structure for its gas business. The remaining

[101] *See* Attachment 1 to Response to PSCIR1-3 (Agreement and Plan of Reorganization and Corporate Separation (Nuclear)), Ex. A ($47 million of pollution control debt).

[102] Subsequent to divestiture, BGE filed a corporate reorganization plan to separate Constellation's regulated businesses from its unregulated businesses. *In re Business Separation of Constellation Energy Group*, Case No. 8883. BGE cancelled reorganization plans. *See* Order 78045, 93 Md. PSC 275 (8883/75) (Oct. 3, 2002).

[103] Ex. TER-3 (8883/35) is not available for our review.

filings available to us (2003 Q1 through Q3 2004), show that BGE maintained identical electric and gas capital structures at approximately these ratios. *See, e.g.*, Letter from Anne Hahn to Charles Senseney (Nov. 15, 2004) (showing 48% long-term debt, 46% common equity and six percent preferred stock).

E. Analysis and Conclusions

We reviewed BGE's divestiture filings to explain the basis for BGE's transfer of assets to Constellation and to determine whether this transaction treated customers fairly. Our review of BGE's filings with the Commission, documents provided by BGE, and discovery by Staff and the OPC shows that BGE complied with the Settlement Agreement, the 1999 Act, and the Commission's requirements for divestiture. The transaction left BGE in a highly leveraged position, but the company recovered its pre-divestiture capital structure, as it indicated it would. Because we found no apparent unfairness or element of the transaction that violated the 1999 Act, at this time we find no basis for recovery of stranded costs from BGE or Constellation arising from the divestiture to affiliates at book value. Of course, as we noted previously, the 1999 Act precluded the Commission from requiring BGE to divest its generation assets through an independent auction that included non-affiliates. Such an auction would likely have produced two desirable outcomes for ratepayers: (1) a higher transfer price – thereby reducing or eliminating stranded costs – and (2) diversified ownership of Maryland's generation fleet and, therefore, more robust competition in wholesale markets.

V. Generation-Related Regulatory Assets Retained on BGE's Books

A regulatory asset is a cost that would ordinarily be treated as a current expense but that a regulator authorizes the utility to defer to its balance sheet for later collection from ratepayers. A utility usually collects its regulated rate of return on its regulatory assets, which it charges to customers through regulated rates. When a utility divests its generation assets to affiliates, as BGE did, treatment of its regulatory assets can affect its stranded costs. In a competitive market regime, a regulatory asset is an expense and has a negative market value. If regulatory assets are transferred with the physical plant, an administrative cash flow valuation would reduce the plant's value by the amount of the regulatory asset and thereby increase stranded costs. If regulatory assets are not transferred with the associated generation assets, customers still pay for them, but through a different recovery mechanism bundled into the utility's regulated rates.

The 1999 Act permits utilities to maintain some generation-related costs as regulatory assets pursuant to a settlement agreement. The statute does not expressly authorize utilities to retain their generation-related regulatory assets, but it provides that the prohibition on Commission regulation of the generation, sale, and supply of electricity does not apply to "costs of nuclear generation facilities or purchased power contracts that, as part of a settlement approved by the Commission, remain regulated or are recovered through the distribution function." PUC § 7-509(a)(2)(ii).

BGE initially proposed that the Commission continue to treat $370 million of its generation-related assets and liabilities "as if electric deregulation had not taken place." Brune Test. (8794/2) at 20:6-13. The subsequently negotiated settlement allowed BGE to retain such generation-related obligations, *e.g.*, unamortized deferred nuclear costs[104] and retirement/employment costs.[105] Consequently, BGE did not transfer them to affiliates but retained them on its books as generation-related assets to be recovered in its distribution charges. BGE consolidated these regulatory assets as a "new single generation-related regulatory asset in accordance with the Settlement Order" that relieved the company from accounting for the assets by line-item. Attachment 1 to Response to Staff Data Request 4-3. These regulatory assets are not part of the $528 million transition cost value, but the negotiated regulatory asset value retained by BGE may have affected the negotiated transition costs.

A. BGE's Proposal for Treatment of Regulatory Assets

As of December 31, 1997, BGE's regulatory assets totaled about $506 million (*see* Ex. RMB-4 (8794/2)) and included the following:

- Nuclear facility costs associated with nuclear pipe supports, pressurizer costs, and other nuclear operations and maintenance activities. These costs are "1) costs incurred between 1979 and 1982 related to inspecting and repairing seismic pipe supports; 2) costs incurred in 1990 for investigating leaks in the pressurizer heater sleeves; and 3) costs incurred from 1989 through 1994 associated with nonrecurring phases of certain nuclear operations projects." Bange Test. (8794/2) at 8:5-15.

- Labor costs associated with voluntary special early retirement programs ("VSERP"), post-retirement benefits ("PRB"), and other post-employment benefits ("OPEB"). The VSERP balance is the unamortized portion of costs associated with two early retirement programs in 1992 and 1994. BGE explained that the PRB and OPEB regulatory assets were the difference between costs recorded by the company pursuant to financial accounting standards and costs the Commission authorized BGE to charge customers. *Id.* at 8:16-9:5. BGE's testimony indicates the Commission had recently allowed BGE to amortize the deferred PRB and OPEB costs over a 15 year period, beginning in 1998.

- Energy conservation programs offered by BGE. *Id.* at 9:6-12.

- Deferred costs of decommissioning and decontaminating federal uranium enrichment facilities as required by the National Energy Policy Act of 1992. The statute required BGE's nuclear facility, beginning in 1993 and continuing through 2008, to contribute to a decommissioning and decontamination fund.

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104 These unamortized deferred costs related to nuclear pipe supports, nuclear pressurizer costs, and nuclear operating costs.

105 These are unamortized deferred costs associated with Voluntary Special Early Retirement Program costs, postretirement benefit costs, and other post-employment benefit costs. *See* Appendix B to BGE Settlement Agreement; *see also* Response to Staff Data Request 2-7 (reductions post retirement and post-employment benefit obligations).

BGE's contribution to the fund was determined by its share of uranium fuel enriched at federal facilities. *Id.* at 9:13-22.

- Income taxes recovered through future rates were treated by BGE as a regulatory asset for future revenue to be recovered from customers when "future increases in income taxes payable occur." *Id.* at 9:23-10:18.

- Accumulated deferred investment tax credits were BGE's unamortized investment tax credits associated with its electric utility operations. *Id.* at 10:19-11:1.

BGE's filing identified three regulatory liabilities totaling approximately $136 million, including the following:

- Deferred investment tax credits were "unamortized investment tax credits associated with electric utility operations" that were not deducted from BGE's ratebase but "represent a regulatory liability to ratepayers." *Id.* at 10:19-11:1. BGE's proposal for treatment of this $119 million liability to ratepayers is unclear, but it does not appear that BGE used this credit to reduce its transition costs. *See* Exs. RMB-3 (revised) (8804/57), RMB-4 (8804/127).

- Deferred electric fuel costs were associated with an electric fuel rate clause that allowed BGE to defer the difference between its actual costs of fuel and energy and the fuel rate amounts collected from customers. BGE's testimony indicated that it included the deferred fuel costs in its ratebase, net of associated deferred income taxes. Under BGE's restructuring proposal, this liability would be "applied towards the mitigation of stranded costs." Bange Test. (8794/2) at 11:2-18.

- BGE's net gains from the sales of SO_2 emission allowances were also treated as a regulatory liability and would be used to mitigate stranded costs. *Id.* at 11:19-12:8.

B. <u>Settlement Provisions Establishing Generation-Related Regulatory Assets</u>

BGE's Settlement Agreement provides "customer funding" for generation-related regulatory assets through BGE's service rates and refers to a "schedule of generation-related regulatory assets and related annual amortization" provided in an appendix. BGE Settlement Agreement, ¶ 22. The table, "Amortization Schedule - Generation Regulatory Assets and Liabilities," shows $416 million[106] of generation regulatory assets (as of December 31, 1997). The table indicates that about $332.8 million (80% of this amount) would be collected through BGE's distribution rates by 2017.

[106] It is unclear why BGE "ROUNDED" up the subtotal of generation regulatory assets of $413.278 million by more than $2.5 million to $416 million.

Approximately one-third of the recoverable regulatory assets – about $112 million – remained in BGE's ratebase to allow BGE to collect a rate of return on these assets. The two regulatory assets excluded from BGE's ratebase were deferred costs of decommissioning federal uranium enrichment facilities ($42.4 million) and income taxes recoverable through future rates ($231 million). *Id.*, Appendix B.

The settlement authorized BGE to collect 80% of the amortized value of regulatory assets and a rate of return on ratebase assets in its rates charged to customers through 2017. Part 1 to Appendix A of BGE's settlement agreement shows BGE's delivery service rates that include a component for recovery of regulatory assets. *Id.*, Appendix A, pt.1. BGE bundled this rate component into its distribution rates later filed with the Commission. *See* Response to PSCIR4-15.

Lastly, the Commission-approved settlement allowed BGE to roll up its regulatory asset line items into a single regulatory asset. *See* Attachment 1 to Response to Staff Data Request 4-3. BGE's 2002 Form 10-K explains,

> BGE wrote-off all of its individual, generation-related regulatory assets and liabilities. BGE established a single, new generation-related regulatory asset for amounts to be collected through its regulated transmission and distribution business. The new regulatory asset is being amortized on a basis that approximates the pre-existing individual regulatory asset amortization schedules.

BGE's asset transfer compliance filing shows regulatory assets as a single line item, "Other regulatory assets." *See* Attachment 1 to 2001 Asset Transfer Filing.

Table 14 compares BGE's regulatory assets included in its filed testimony and the settlement values. The differences between BGE's filed testimony and the settlement suggest that the parties agreed to modify the treatment of regulatory assets as part of the black box settlement. Alternatively, the settlement may have left issues open that later became apparent in BGE's asset transfer filings. Extensive discovery conducted by settling parties on the regulatory asset/liability transfer issues in BGE's 2001 Asset Transfer Filing suggests that the settlement did not clearly resolve all outstanding issues related to regulatory assets.

For example, BGE's filed testimony proposed that certain accumulated deferred taxes and accumulated deferred investment tax credits treated as regulatory liabilities remain as a regulatory liability on BGE's books and be treated as an offset against regulatory assets. For this reason, they were not included in book value (*i.e.*, excluded from Exhibit RMB-3) and were excluded from BGE's calculations of its stranded costs. If included, they might have reduced book value and narrowed the negative gap between book value and market value. The settlement also excludes them from the regulatory asset/liability line item. *See* Table 14. BGE's asset transfer filings confirmed that BGE did not treat them as an offset against its regulatory assets. The settlement also modified the December 31, 1997 asset values for labor benefits and income taxes recoverable for future rates. Because these adjustments were the product of confidential settlement negotiations, the Commission record does not explain why they were made.

The settlement may have implicitly captured BGE's regulatory liabilities, however, by reducing the recoverable regulatory assets by 20%. Table 14 summarizes the difference between BGE's initial proposed regulatory assets and the settlement and shows the final write-down of about $80 million. *See also* Table 10. Neither the settlement agreement nor the Commission's order approving the settlement explains treatment of the generation regulatory assets that are not recovered by 2017. Commission Staff testimony in another proceeding, however, indicates that the

> parties agreed to a "black box" 20 percent reduction to regulatory assets to account for the various regulatory liabilities, including EDIT and ITC. Because the reduction was presented in a black box, the components of the reduction are not explicitly addressed in the settlement agreement. . . . The 20 percent reduction is represented by approximately $70.9 million of regulatory liability reversals.

Direct Testimony of Randy M. Allen on Behalf of the Staff of Public Service Commission of Maryland, *In re Potomac Electric Power Company* (8796/293) (Dec. 10, 2001) at 38:10-39:14.

TABLE 14
COMPARISON OF REGULATORY ASSETS AS OF DECEMBER 31, 1997
(in thousands)

DESCRIPTION	Exhibit RMB-4	Settlement Agreement, Appendix B	Difference
Unamortized deferred nuclear pipe support costs	$4,656	$4,656	$0
Unamortized deferred nuclear pressurizer costs	$3,738	$3,738	0
Unamortized deferred nuclear operating costs	$69,289	$69,289	0
Unamortized deferred VSERP costs	$18,193	$10,898	$7,295
Unamortized deferred postretirement benefit costs	$40,880	$24,487	$16,393
Unamortized deferred other post-employment benefit costs	$44,780	$26,823	$17,957
Unamortized deferred energy conservation costs	$43,896	N/A	$43,896
Deferred cost of decommissioning federal uranium enrichment facilities	$42,404	$42,404	0
Income taxes recoverable through future rates	$238,616	$230,983	$7,633
Deferred investment tax credits	($116,754)	N/A	($116,754)
Accumulated deferred electric fuel costs	($19,011)	N/A	($19,011)
Deferred gains on sale of emissions allowances	($848)	N/A	($848)
Subtotal -- Generation Regulatory Assets	**$369,839**	**$413,278**	**($43,439)**
Generation Regulatory Assets ("ROUNDED")		$416,000	
Generation Regulatory Assets To Be Recovered Through Distribution Rates		$332,800	

Certain regulatory liabilities in BGE's Exhibit RMB-4 that may have been included in the 20% reduction of regulatory assets were transferred to BGE's generation affiliates. BGE's asset transfer filings show the company intended to transfer approximately $176.8 million of generation-related regulatory assets – $97.7 million of accumulated deferred taxes and $79.1 million of tax investment credits – that "were not included in the rate base." *See* 1999 Transfer Application at 8 ("certain generation related deferred taxes and credits with a projected June 30, 2000 net book value of ($176,779,000) which were not included in rate base will also be transferred to BGE's affiliates"). BGE maintained that these unamortized tax credits belong to utility generation assets transferred to affiliates. According to BGE, the treatment of accumulated deferred income tax credits ("ADITC") had been reviewed during settlement proceedings and could not be "returned to ratepayers by amortizing the amounts for cost of service purposes," and, furthermore, the IRS subsequently issued two private letter rulings finding that once BGE transferred the underlying asset, there would be no regulated depreciation expense and, therefore, no portion of an unamortized ADITC could be returned to ratepayers. *See* Response to Staff Data Request 4-5; *see also* Response to OPC Data Request 1-11 (and attachment) (Accumulated Deferred Investment Tax Credits Applicable to Generation – CPSGI/CCNPP).

C. Analysis and Conclusions

The BGE Settlement Agreement, BGE's initial proposals for its generation asset transfer, and later compliance filing showing actual transfers do not clearly explain how the final number for BGE's regulatory assets was determined as part of the negotiated settlement. Without the benefit of a hearing record, we are unable to explain the basis for changes in these assets' treatment. The Commission required no substantive analysis nor made any substantive findings on this component of the settlement. Order 75757 90 Md. PSC at 236 ("BGE should be permitted to collect $333 million in regulatory expenses, consisting primarily of accumulated deferred income taxes"). In theory, these regulatory assets represented earlier costs that could have been expensed but that the Commission authorized to be collected over time, and because ratepayers received their benefits, they retained the obligation to pay for these assets. Because the treatment of regulatory assets in the settlement is not well-documented, however, and the portion of the regulatory asset included in BGE's ratebase is not specified, we recommend that the Commission review BGE's regulatory assets and customer collections related to those assets as part of BGE's next rate case to determine how BGE has interpreted this provision of the Settlement and whether it may continue to include these assets in its rates.

VI. Decommissioning Funding Obligation that Remained with BGE Ratepayers

BGE's settlement agreement assigns to ratepayers the obligation to continue funding Calvert Cliffs' decommissioning, despite transferring that facility to an unregulated BGE affiliate. The settlement fixes a ratepayers' obligation of $520 million (1993 dollars) for Calvert Cliffs' decommissioning, escalated until decommissioning at an NRC inflation factor. The value of this obligation in current dollars at about the time of settlement was $778.50 million, but BGE had accumulated only $287.5 million of decommissioning funds. Thus, the settlement locked in ratepayers' obligation for the difference – nearly $491 million (1999 dollars) – and an ongoing responsibility to assure the equivalent of the $520 million (1993 dollars) when Calvert Cliffs' owner eventually decommissions the facility, now expected to be in 2034 (Unit 1) and 2036 (Unit 2).

As with the transition costs and rate freezes, this provision is also a black-box, negotiated component of the settlement agreement. Based on our review of available documents, we believe this settlement provision was intended to provide certainty to ratepayers by capping their financial obligation to decommission the plant and to shift to BGE's affiliate the costs of its management decisions associated with maintenance and decommissioning if those costs exceeded $520 million (1993 dollars). Such retention of ratepayer responsibility for decommissioning funding at nuclear plants was not usual at the time of BGE's settlement. For example, utilities in New Jersey and Illinois retained responsibility for collecting decommissioning funds from ratepayers. On the other hand, some states, like Connecticut, closed out the decommissioning funding obligation with divestiture by including that unfunded cost in the sales price of the nuclear units, thereby reducing the amount realized in the sale. Filed testimony before the Commission indicates that some parties considered terminating ratepayers' obligations to fund Calvert Cliffs' decommissioning trust, but this approach was ultimately rejected. Termination of ratepayers' obligation would probably have increased ratepayers' transition costs under BGE's divestiture plan authorized by the 1999 Act's permissive asset transfer provisions.

This section of the Interim Report analyzes BGE's and intervenors' proposals to fund Calvert Cliffs' decommissioning, the settlement agreement's decommissioning funding provisions, and the transfer of the decommissioning funds from BGE to CCNPP. We also explain how BGE collects funds that are transferred to CCNPP for decommissioning and identify outstanding issues that the Commission may wish to consider further.

A. Background of Calvert Cliffs' Decommissioning Funding

The Commission authorized BGE to establish an internal reserve for decommissioning funds in 1983. Order 66415, *In re Baltimore Gas and Elec. Co.*, 74 Md. PSC 480 (Oct. 5, 1983). In a rate case the year before, the Commission briefly explored alternatives by which BGE could record the funds available for Calvert Cliffs' decommissioning, but did not order changes. Order 65648, *In re Baltimore Gas and Elec. Co.*, 73 Md. PSC 61, 77-78 (Feb. 8, 1982). BGE implemented its reserve in June 1984. Before Order 66415, BGE reported that its recovered Calvert Cliffs' nuclear decommissioning costs through its regulated nuclear depreciation rate. *See* Response to PSCIR4-9.

Order 66415 approved BGE's proposal to create a separate internal sinking fund ("ISF") for decommissioning Calvert Cliffs. BGE transferred amounts accumulated through the nuclear depreciation rate to a separate sub-account of accumulated depreciation. Response to PSCIR4-9. The Commission approved BGE's investment of the ISF's after-tax annuity to be credited annually to the decommissioning reserve "in utility plant and included in the rate base, earning the same present 9.18% after-tax return as all other rate base elements." Order 66415, 74 Md. PSC at 488 ("ALJ order"). The ISF's earnings rate would equal BGE's regulated rate of return, *i.e.*, the "actual, unadjusted overall rate of return which is earned on [BGE's] rate base." *Id.* at 482.

In that order the Commission contemplated, but rejected, creating an external sinking fund ("ESF") for decommissioning funds. Order 66415, 74 Md. PSC at 488 (adopting major elements of hearing examiner's order). The Commission rejected the ESF because, at the time, it was not exempt from federal taxation, "would cause some administrative expense[,] and possibly produce a lower return." *Id.* Additionally an ESF "would deny BG&E the use of the funds and would require external financing of plant investment at higher incremental rates." *Id.*

In other words, an ESF was not necessary so long as BGE reserved ratepayers' funds for decommissioning.

New federal tax provisions acknowledged in the Commission's Order 66415 were implemented in July 1984. Section 468A of the tax code allowed the nuclear plant owner to claim a tax deduction for "qualified" funds. Deficit Reduction Act of 1984, Pub. L. No. 98-369, § 91, 98 Stat. 494, 604-06 (1984) (codified at I.R.C. § 468A). Prior to this, the plant owner had to determine whether or not to defer claiming a tax deduction until economic performance, *i.e.*, when the funds were used for decommissioning. Qualified funds under section 468A have two advantages. First, the plant owners' contributions are not taxed. 26 C.F.R. § 1.468A-2 (2007). The annual deductible contribution is set at the lesser of decommissioning costs collected in regulated cost-of-service rates during the tax year or a "ruling amount" of the allowed deductible contributions for tax year. 26 C.F.R. § 1.468A-3 (2007). Second, the trust funds' earnings are taxed at a federal rate of 20% – not the typical 35%. 26 C.F.R. § 1.468A-4 (2007). This reduced rate allows the fund to grow faster.

BGE explains that it established an external trust in 1988, when the NRC issued a regulation that "required all nuclear utilities to provide financial assurance that either a NRC prescribed minimum level of funds would be available to pay for the costs of decommissioning, or that funds would be deposited based on a site specific study." Response to PSCIR4-9; *see also* Order 68591, *In re Baltimore Gas and Elec. Co.*, 80 Md. PSC 380, 394 (Oct. 18, 1989) ("BG&E is required by the NRC to establish an external decommissioning trust fund to insure that monies will be available for the decommissioning of its nuclear generating units."). This NRC regulation excluded an internal reserve as an acceptable funding method for decommissioning, concluding

> the internal reserve does not provide reasonable assurance that funds will be available when needed to pay the costs of decommissioning and hence does not provide reasonable assurance that decommissioning will be carried out in a manner which protects public health and safety. Accordingly, the proposed rule has been modified to eliminate the internal reserve as a possible method of providing funds for decommissioning.

General Requirements for Decommissioning Nuclear Facilities, 53 Fed. Reg. 24,018, 24,033 (June 27, 1988) (to be codified at 10 C.F.R. pts. 30, 40, 50, 51, 70, 72).

BGE began making quarterly contributions to a qualified external trust in late 1988. Response to PSCIR4-9 ("first deposit of $4.761 million was made in November 1988"); Order 68591, 80 Md. PSC at 395; Order 68648, *In re Baltimore Gas and Elec. Co.*, 80 Md. PSC 496, 512 (Dec. 15, 1989) (contributions to the external trust to be made on a quarterly basis); Order 72240, *In re Baltimore Gas and Elec. Co.,* 86 Md. PSC 376, 377 (Oct. 27, 1995) (showing quarterly contributions as one assumption to derive cost-of-service based decommissioning contributions).

BGE reports that during this period it developed a decommissioning plan for Calvert Cliffs' Independent Spent Fuel Storage Installation ("ISFSI"). Response to PSCIR4-9. An ISFSI stores spent nuclear fuel at the nuclear plants' site until the U.S. Department of Energy can take physical control of the spent fuel. Order 70476, *In re Baltimore Gas and Elec. Co.*, 84 Md. PSC 145 (Apr. 23, 1993). BGE filed its plan with the NRC in 1990 and placed the facility into service by December 1992. The Commission's 1993 order indicates that BGE intended to place the full amount of ISFSI decommissioning costs into a qualified external trust. *Id.*

BGE continued to make nominal contributions to an internal reserve, despite the NRC's findings that an internal reserve did not provide assurances that the funds would be available. *See* Response to PSCIR4-9 (and attachments, showing contributions). The Commission did not require the company to establish a second trust for nonqualified funds in response to the NRC rule, but the company did establish an external nonqualified trust in 1993. Table 15 shows BGE's fund balances for the period 1989-1999, as reported to the Commission.

TABLE 15
AVAILABLE DECOMMISSIONING FUNDS REPORTED TO THE MARYLAND PUBLIC SERVICE COMMISSION, 1989-1999

12 months ending Dec. 31, -	Qualified External Trust	Nonqualified External Trust	Internal Reserve	Reported Balance
	(thousands of dollars)			
1988	$7,982		$25,520	$33,412
1989	$12,423		$28,712	$41,135
1990	$21,300		$30,726	$52,026
1991	$31,828		$32,482	$64,310
1992	$42,997		$34,811	$77,808
1993	$55,505	$330	$37,557	$93,392
1994	$68,184	$614	$40,991	$109,789
1995	$89,863	$1,126	$45,701	$136,690
1996	$111,215	$1,525	$51,106	$163,846
1997	$143,091	$2,104	$56,375	$201,570
1998	$178,313	$2,954	$62,730	$243,997
1999	$213,833	$3,996	$69,648	$287,477

Source: Attachment 1 to Response to PSCIR4-9.

The Commission continued to allow BGE to fund the internal reserve, but the reasons are unclear. We have found no documents explaining whether the Commission analyzed the complex set of trade-offs required to make this allocation. Discovery from BGE indicates that the company "informed the [Commission] in a December 1984 letter that funding decommissioning costs in an internal reserve resulted in lower revenue requirements than an external trust because the trust rate of return, if external funding were used, would probably be lower than the Company's return on rate base if an internal reserve was used." *Id.* Thus, the differential in the rates of return may have been a determinative factor for the Commission. Because of the different tax treatments for an internal reserve and the qualified external trust fund, however, it is not clear that an internal reserve will give ratepayers a higher after-tax return.

B. **BGE's Proposal to Maintain Ratepayer Funding for Calvert Cliffs' Decommissioning**

BGE's filed restructuring proposal continued customers' obligations to fund Calvert Cliff' decommissioning costs. Under BGE's plan, the facility would recover its costs for nuclear decommissioning through a non-bypassable charge levied by BGE. *See* Brune Test. (8794/2) at 17:9-19:6; Prepared Direct Testimony of Sheldon Switzer on Behalf of Baltimore Gas & Electric Co, *In re Baltimore Gas and Elec.* (8794/2) (July 1, 1998) ("Switzer Test.") at 21:1-17 (explaining decommissioning rates). BGE intended that its proposal to maintain customer funding would comply with a proposed NRC rulemaking revising the definition of electric utility to include "licensees with rates established by a regulatory authority either through cost of service mechanisms or through other non-bypassable charge mechanisms." Brune Test. (8794/2) at 18:11-13. Continuing collections though a non-bypassable charge would qualify funding to the external trust as tax deductible, "thereby reducing the total costs to customers." *Id.* at 19:7:17.

BGE opposed transferring responsibility for decommissioning to its unregulated affiliate, suggesting that "BGE may be required to prefund into its external trust its entire estimated unfunded decommissioning cost." *Id.* at 19:5-6. Moreover, as noted above, some deregulating states had already approved divesture plans that maintained customers' obligations to fund decommissioning costs. *Id.* at 19:18-20:5.

The OPC, MEA, and other intervenors supported continuing customers' obligations to fund Calvert Cliffs' decommissioning until the plant would be retired from service. The MEA's expert witness testified that "nuclear decommissioning cost recovery should remain with regulated utility service. The ultimate cost of decommissioning (and even more important, trust fund earnings) are uncertain, and this uncertainty is heighten [sic] by the Calvert Cliffs relicensing. It is imperative that the integrity of the decommissioning trust fund be protected and not subjected to market risk." Kahal Test. (8804/47) at 20; *see also* Baron Test. (8804/54) at 16:10-13 (BGE's approach "is probably reasonable" because "there is significant uncertainty associated with the actual future decommissioning costs for Calvert Cliffs (as well as the years remaining of its life)"); Bradford Test. (8804/55) at 71:10-72:7 ("[b]ecause decommissioning costs do not increase much with future operation, some justification exists for not including them in the future operating costs that should be subject to the market").

In rebuttal testimony, BGE's witness opined that,

> other parties have generally been supportive of the Company's position on this issue because it provides a greater level of assurance to the NRC as well as the citizens of Maryland that the funds will be available when they are needed to decommission the plant. In the grand scheme of things, the annual revenue requirement necessary to provide for decommissioning Calvert Cliffs is relatively minor when compared to the assurance that such a rate design provides.

Brune Test. (8804/106) at 9:10-15. Some intervenors, including Staff, opposed BGE's proposal. *See* Direct Testimony of Calvin L. Timmerman on Behalf of the Public Service Commission, *In re Baltimore Gas and Elec. Co.* (8804/60) (Dec. 22, 1998) at 25:11-19 ("At this time Staff believes the responsibility for nuclear decommissioning costs should be with the asset owners"); Direct Testimony and Exhibits of Thomas J. Prisco for the Department of Defense and the Federal Executive Agencies, *In re Baltimore Gas and Elec. Co.* (8804/50) at 7-8 (similar).

C. <u>Decommissioning Provisions of BGE's Settlement Agreement</u>

BGE's Settlement Agreement established the method and amounts of customer collections for BGE's "Nuclear Decommissioning Trust Fund." BGE Settlement Agreement, ¶ 22. 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." *Id.* 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. *Id.* 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. *Id.*

The settlement fixes the *level* of customer collections at an annual rate of $18,661,980 until June 30, 2006. Thereafter, calculations of customer contributions for nuclear decommissioning costs would be derived based on three components: the NRC's "adjustment factor for inflation" (and a reasonable forecast of the same), the "actual balance of the Nuclear Decommissioning Trust Fund," and a "reasonable forecast of expected future after-tax earnings" of the fund. *Id*.

The settlement establishes that customer funding for nuclear decommissioning will be included as a component in BGE's "unbundled delivery service rates" – not a part of the PFS rates. *Id*. (Decommissioning collections are not separately itemized on customers' bills.)

The settlement requires BGE to continue to report "the performance of the fund" as specified in Order 66415. 74 Md. PSC 480 (Oct. 5, 1983). Order 66415 directed BGE to provide an annual financial report of "the calculation of the earned rate of return, the amount credited to the account during the year, a summary of the customers' payments in the fund, and the year-end balance of the fund." *Id.* at 483.

The Commission's Order approving the Settlement contains very little analysis of the decommissioning provision. The Commission's general review found that "the provisions in the Settlement which cap customer responsibility for Calvert Cliffs nuclear decommissioning costs at $520 million (in 1993 dollars) is reasonable" and declared, "With the adoption of the Settlement, customer responsibility for Calvert Cliffs nuclear decommissioning costs are [sic] resolved." Order 75757, 90 Md. PSC at 236; *see also id.* at 211 (summarizing settlement agreement and explaining "ratepayers will have no liability above the $520 million of capped decommissioning costs").

The Commission's Order also found that "the treatment of those [decommissioning] funds as prescribed under the Settlement are [sic] fair and beneficial both to ratepayers and to the Company." *Id*. The basis for the Commission's finding is unclear, however, because the settlement does not define the frequently used term "Nuclear Decommissioning Trust Fund" as applied to BGE's various decommissioning accounts nor does it establish going-forward procedures for the BGE affiliate's treatment of funds collected from ratepayers, *i.e.*, whether the funds are to be deposited in an external qualified trust, an external non-qualified trust, or an internal reserve. These distinctions are material for ratepayers because they will affect the future after-tax returns that will, in turn, affect the amount of ratepayer contributions that will be necessary to assure a fund of $520 million (in 1993 dollars) when decommissioning finally begins.

The Order reports that proponents of the decommissioning provision, the DNR and MEA, supported these provisions as a "protection of customers against potentially substantial nuclear decommissioning costs." *Id.* at 218. These parties anticipated that re-licensing Calvert Cliffs "may mean a 20-year deferral of decommissioning and hence 20 years of additional Trust Fund earnings to help pay for decommissioning costs." *Id.; see also* Initial Brief of the Maryland Energy Administration and the Maryland Department of Natural Resources' Power Plant Research Program, *In re Baltimore Gas and Elec. Co.* (Aug. 30, 1999) ("MEA/DNR Initial Brief") (8804/206) at 19. The Commission's order reports no opposition to this settlement provision. Significantly, however, 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.

Nor does the Commission's Order evaluate the reasonableness of settlement's fixed contributions set at $18.7 million through mid-year 2006, or the need for future collections. The record provides little insight to assess the reasonableness of the annual funding contributions fixed through 2006. MEA/DNR's Initial Brief explained that the $18.7 million cost-of-service funding amount was approved by the Commission in its Order 72240. *Id.* at 18.[107] MEA/DNR's brief suggests that if Calvert Cliffs' decommissioning is deferred for another twenty years, then additional customer collections after 2006 may be unnecessary. MEA/DNR Initial Brief at 18-19. ("customer funding level ***(if any)*** required for decommissioning for 2006 and future years. . . . To help ensure the integrity of the Trust Fund, the present customer funding level will continue through June 2006, and the need for continued customer funding will be reassessed at that time") (emphasis added).

Our analysis of BGE's asset divestiture compliance filings, Commission orders, and Staffs' analyses provided little insight about treatment of these funds as they were transferred to CCNPP and afterwards. BGE's 1999 asset transfer application explains only that "BGE also intends to transfer the decommissioning trust fund and internal reserve. This transfer will

[107] That Order authorized BGE to revise its decommissioning cost-of-service accounting provisions to collect $20.6 million annually (presumably also including collections for ISFSI decommissioning). Order 72240, 86 Md. PSC 376-377 (Oct. 27, 1995).

provide the assurance of decommissioning funding required by the Nuclear Regulatory Commission." 1999 Transfer Application at 6. The Commission's letter order approving the proposed transaction acknowledges, but does not analyze in any depth, the transfer of the decommissioning fund and BGE's internal reserve. June 2000 Letter Order at 3 ("Nuclear-related assets will be transferred to Calvert Cliffs, Inc. ("CCI"), a subsidiary of Constellation Nuclear Group."). Staff's analysis to the Commission of BGE's January 22, 2001 compliance filing of actual transfers also does not include an analysis of the decommissioning funds' transfer to CCNPP. *See* Staff Analysis.

Staff and OPC conducted discovery relating to the balances in and actual transfers of the decommissioning trust fund and BGE's accumulated decommissioning reserve, as reflected in its January 2001 asset transfer filing. Documents produced in a separate proceeding, Commission Case No. 8883, also provide insight into the treatment of the decommissioning funds at transfer.

BGE reported that it transferred to CCNPP all of its collected and accrued decommissioning funds – $303.6 million (as of July 1, 2000). BGE reported separately on its Balance Sheet the share of these funds maintained as external qualified or nonqualified decommissioning funds – $230.332 million. Attachments 1, 2 to 2001 Asset Transfer Filing.

The remaining $73.4 million of funds for decommissioning was maintained in BGE's "internal reserve" that was also transferred to CCNPP. *See* Attachment 2 to 2001 Asset Transfer Filing, at 4 (showing decommissioning reserve of $73.396 million in accounts 1089102 and 1089202 transferred to CCNPP); Response to Staff Data Request 2-1; Response to Staff Data Request 1-1(b). The $73.4 million of internal reserve funds are not reported separately on BGE's balance sheet in the way that the qualified and nonqualified nuclear decommissioning trust funds are reported because the internal funds are not maintained in a segregated account like the external funds. Rather, they had been invested in BGE's generation plants that were transferred at divestiture and had earned the same return that BGE earned from all its equity investments.

Effective July 1, 2000, BGE and Calvert Cliffs entered into a Decommissioning Funds Collection Agent Agreement, to transfer customer collections through BGE to CCNPP. *See* Attachment 4 to Response to PSCIR1-3 (Decommissioning Funds Collection Agent Agreement) ("DFCA Agreement"). BGE reports that the agreement has not been amended. Response to PSCIR4-1. Under the terms of this agreement, BGE collects funds from its electric customers to provide for decommissioning of Calvert Cliffs. BGE acts as a fiscal agent to collect funds "in the same manner as it has prior to the transfer of assets" to CCNPP. DFCA Agreement, §1. BGE remits all decommissioning funds to CCNPP and "under no circumstances will BGE make any payment for decommissioning expenses . . . unless and only to the extent" decommissioning expenses are received by BGE. *Id.*, §2.

The Decommissioning Funds Collection Agent Agreement provides specific instructions for BGE to remit funds to CCNPP:

> Upon receipt of Decommissioning Funds, BGE will, as fiscal agent for [CCNPP], (i) hold such Decommissioning Funds in trust for the benefit of [CCNPP] and will (ii) remit such Decommissioning Funds to [CCNPP], by wire transfer in immediately available funds, every week to the account designated from time to time by [CCNPP]. If BGE should over-collect from its electric customers any Decommissioning Funds and pay them to [CCNPP], [CCNPP] agrees to promptly reimburse BGE any such funds, upon BGE's request.

Id., §2.

The accumulated decommissioning funds earn a return on their balances that offsets the amount of ratepayers' annual contributions to assure that the funds are sufficient to meet the $520 million (1993 dollars) settlement obligation. BGE explains that the rate of return on the external qualified and nonqualified decommissioning funds is "the actual amount [] earned on the external trust funds' investments, net of fees and taxes." Response to PSCIR4-8. The rate of return of Calvert Cliffs' internal reserve, however, is the rate of return of BGE's regulated business – even though the funds are held and used by Calvert Cliffs for its unregulated business interests, not for the benefit of BGE's ratepayers, as they were before restructuring. *See* Order 78045, 93 Md. PSC at 276. BGE explains that the rate of return on the internal reserve is "an imputed amount based on BGE's actual overall earned rate of return for the year." Response to PSCIR4-8. BGE's "actual overall rate of return" is based on its rate of return in both its electric and gas businesses. Response to OPC Data Request 2-3 (explaining that the CCNPP internal decommissioning reserve's "return is calculated monthly based on the balance of the internal reserve at the end of the prior quarter multiplied by BGE's total (electric and gas) average rate of return for the prior calendar year divided by 12 months. The return is recorded as a debit to decommissioning expense and a credit to accumulated decommissioning reserve.").

D. Analysis of Ratepayers' Obligations Created by the BGE Settlement Agreement

The Settlement Agreement retained ratepayers' responsibility for decommissioning Calvert Cliffs, but sought to cap ratepayers' total liability. Several arguments might justify ratepayer retention of this obligation. For example, ratepayer retention may be reasonable if market-based decommissioning funding would increase the likelihood of the unregulated plant owner's default and consequent State responsibility for decommissioning. Under this scenario, continuing customer collections through the life of the plant will assure adequate funds to decommission the facility safely. Other approaches, however, might also mitigate these risks. For example, the legislature could have required greater statutory protections and assurances – *e.g.*, bonding, insurance, or parental guarantees – that would ensure decommissioning at the end of Calvert Cliffs' nuclear life.[108] While settling parties may have intended this settlement provision to secure funds for decommissioning when needed, our analysis reveals several infirmities. Ultimately, this settlement provision may prove very costly for BGE's ratepayers.

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[108] *See, e.g.,* CONN. GEN. STAT. § 16-19q (liability for decommissioning nuclear plant resides with operating license holders).

First, the Commission does not appear to have examined in any depth the $520 million decommissioning estimate fixed by settlement. Moreover, the settlement agreement does not describe the decommissioning responsibilities of the BGE affiliate so the settlement is unclear about exactly what type of decommissioning obligation has been transferred.

In an earlier proceeding, the Commission accepted the $520 million[109] proposed value only as the basis to allow BGE to receive its tax exemption on decommissioning collections. Order 72240, 86 Md. PSC at 376. In that proceeding, BGE sought a Commission order allowing it to increase the share of its annual decommissioning collections to the qualified trust. Prior to this order, BGE's decommissioning contribution to the qualified trust was based on a generic NRC formula producing a decommissioning cost of $336 million (1992 dollars). The NRC revised the formula, and BGE determined that the revised formula produced a decommissioning cost estimate of more than $700 million (1992 dollars).[110] Because the NRC rule also allowed utilities to use site-specific studies as an alternative to its generic formula, BGE hired consultants to conduct a study that produced a decommissioning estimate of $520 million (1993 dollars). The Commission's order indicates that the Commission's technical staff found the engineering cost methodology "appropriate." Order 72240, 86 Md. PSC at 377.

BGE asked the Commission to approve its study for the limited purpose of enabling the company to qualify the accruals for a tax deduction, which the Commission did. Thus, by that Order BGE revised its decommissioning cost-of-service accounting provisions to increase recorded contributions from $11.3 million to $20.6 million annually. BGE did not increase customers' rates at that time. Order 72240, 86 Md. PSC at 376, 377. Perhaps because this case did not involve a rate increase, the Commission made no findings about the adequacy of the decommissioning plan or the reasonableness of the cost estimates in this order. In our experience evaluating many similar cost estimates, they are frequently based on assumptions and extrapolations that may bear very little relationship to actual decommissioning methods or costs.

Second, some intervenors' expectations that ratepayers' annual decommissioning funding obligations would decrease or perhaps terminate by June 30, 2006, were wildly unrealistic. *See* MEA/DNR Initial Brief at 18-19. ("customer funding level (if any) required for decommissioning for 2006 and future years"). At the time parties agreed to settlement, the balances in the decommissioning trusts and internal reserve were far lower than the estimated decommissioning costs agreed by settlement. As Figure 3 shows, the $520 million (1993) escalated to 1999 dollars totaled $778.50 million, but nuclear decommissioning funds available were $287.5 million. *See* Response to PSCIR4-10. Thus, ratepayers began with a $491 million shortfall. Moreover, those intervenors mistakenly assumed that the NRC's inflation formula

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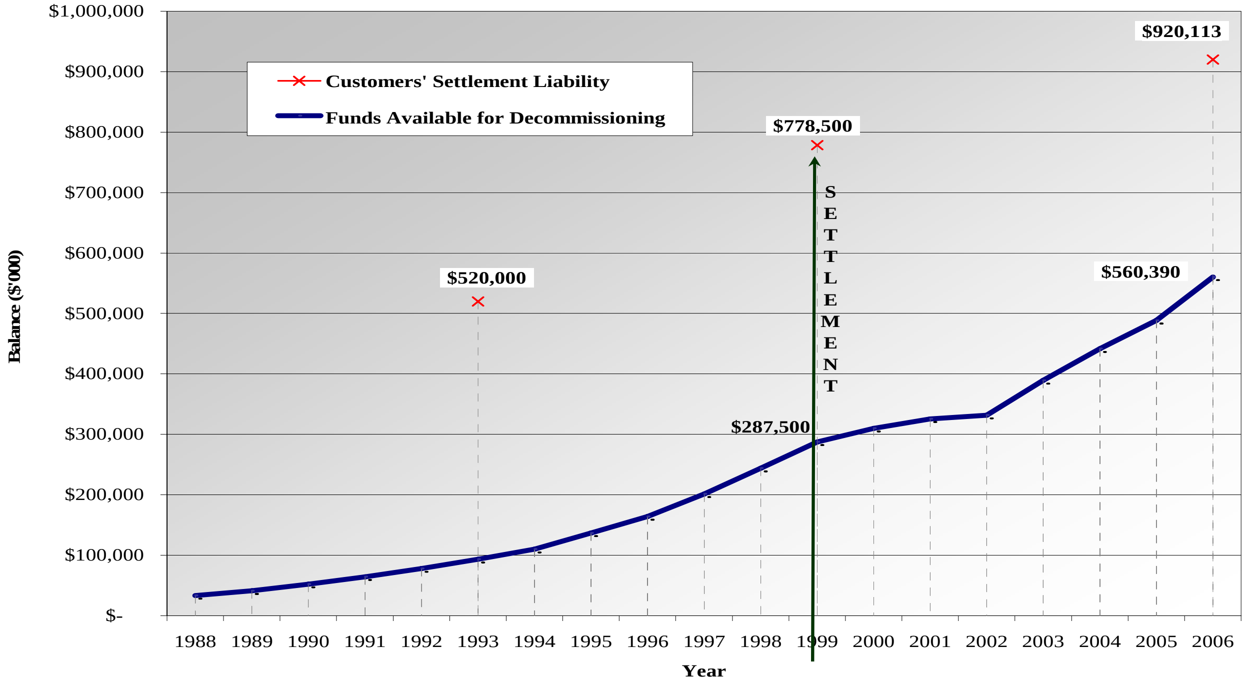
109 BGE derived this $520 million (1993 dollars) from the estimate of $502 million (in 1993 dollars) for the immediate decommissioning plan of both Calvert Cliffs units (excluding the costs of spent fuel storage or disposal or site restoration), plus $18 million (1993 dollars) for the estimated decontamination of the ISFSI. *See* Attachment 6 to BGE Compliance Filing, *In re Baltimore Gas and Elec. Co.* (8804/340) (Apr. 3, 2006) ("2006 Compliance Filing") at 1 (Determination of Escalation Rates for the Calvert Cliffs Nuclear Power Plant Decommissioning Cost Estimate).

110 Had BGE used this generic formula, BGE could have increased decommissioning collections and increased its share allocated to the qualified trust.

would be so much lower than the funds' rate of return that it would not require additional payments to make up for this shortfall.[111]

FIGURE 3. DECOMMISSIONING FUNDS GAP REPORTED TO THE MARYLAND PUBLIC SERVICE COMMISSION



Indeed, BGE recently made a compliance filing with the Commission showing that the fixed annual contributions of $18.7 million have not been sufficient to supply the $520 million agreed-upon amount in 1993 dollars, escalated at forecasts of the NRC rate, to the time when decommissioning is now expected to occur. BGE's compliance filing estimates that with Calvert Cliffs' extended life, funding will have to be increased to $25.3 million annually for the next 30 years, *i.e.*, through 2034 (Unit 1) and 2036 (Unit 2), to fund the decommissioning trust fully, in accordance with the settlement. 2006 Compliance Filing at 2; *id*. at Att. 4. Nevertheless, BGE did not request an immediate increase in the current funding rate of $18.6 million annually but proposed to defer any modification until 2016, when it could make a more accurate estimate of required funding. *Id*. at 4. The Commission accepted BGE's plan to defer any adjustment until 2016. Letter Order, *In re Baltimore Gas and Elec. Co.* (8804/343) (June 30, 2006). BGE reports that, applying the same assumptions, this deferral will increase the customers' required annual collections from to $33.5 million beginning in 2017. Response to PSCIR4-34.

111 At the time, experience with decommissioning some nuclear facilities was proving costs had been underestimated. The NRC's inflation formula incorporated changes in these costs and has since varied considerably year to year. For example, BGE reports that the NRC inflation factors ranged from highs of 12.0%, 9.3%, and 7.9% in 2002, 2000, and 1998 to lows of 0.6%, 1.3%, and -7.5% in 2001, 2003, and 2004. *See* Attachment 1 to 2006 Compliance Filing.

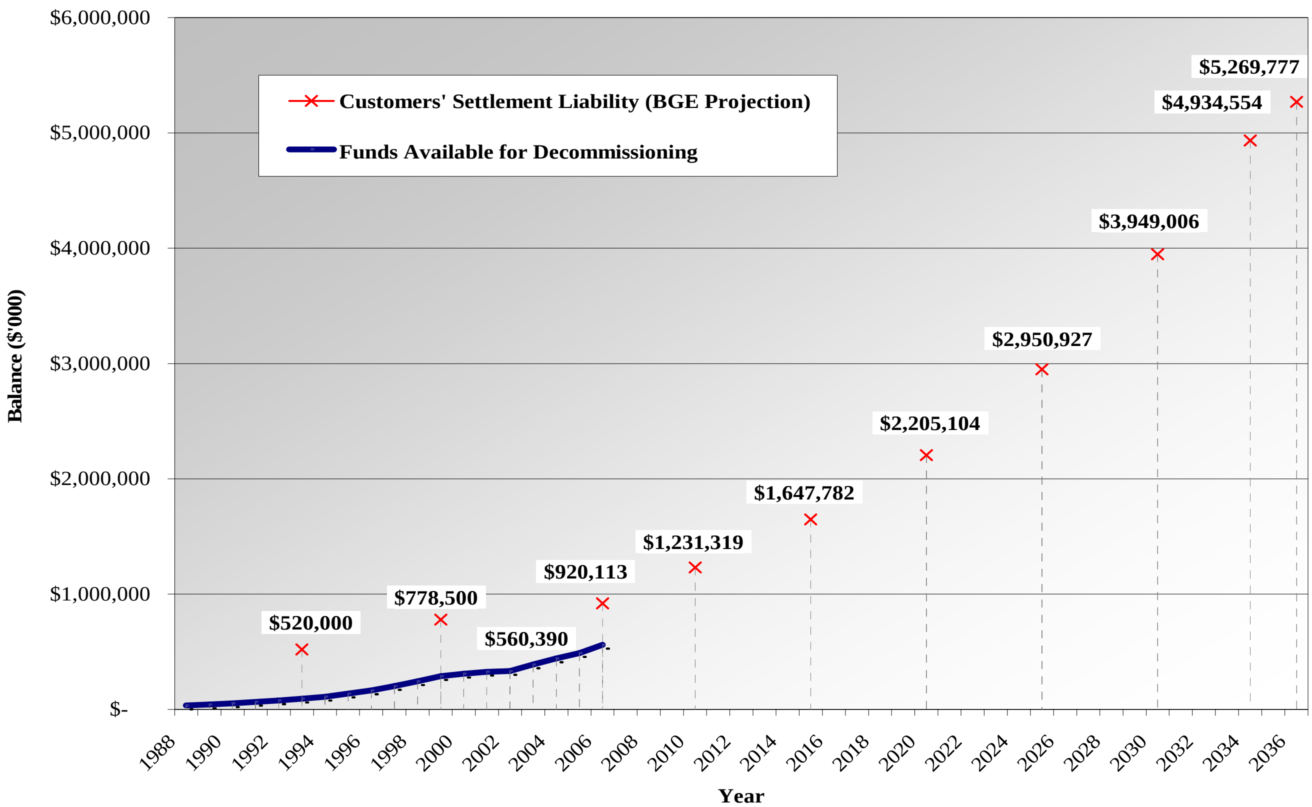
Third, the settlement does not fully cap ratepayers' future liabilities. Even though the settlement caps ratepayers' base obligations at $520 million (1993 dollars), customers' liability for annual contributions is uncertain because the time of decommissioning is uncertain. Customers' obligations to maintain Calvert Cliffs' decommissioning fund continue until CCNPP decides to begin decommissioning the plant.

Serious questions should have been asked about the reasonableness of obligating ratepayers to fund decommissioning that will take place in 2034 or at an even later, unspecified date, thereby requiring ratepayer collections for 20 years or more to meet an ever-escalating obligation of $520 million in 1993 dollars. MEA and DNR acknowledged this burden, stating "ratepayers will continue to accept the risks for cost escalation (under the NRC's formula), Trust Fund earnings and the date of plant retirement." MEA/DNR Initial Brief at 19. Indeed, the MEA and DNR viewed the 20 additional years' delay in decommissioning as a benefit, believing that Trust Fund earnings would grow faster than the escalated decommissioning costs. *Id.*

If BGE's decommissioning assumptions are reliable, customers' $520 million obligation (1993 dollars) grows to $5.269 billion (2036 dollars) (*see* Figure 4), assuming a six percent NRC inflation factor, various rates of return on the funds, and decommissioning commences at license expiration in 2034 (Unit 1) and 2036 (Unit 2). *See* Attachment 4 to 2006 Compliance Filing. We believe BGE's estimate is speculative, however, because it is highly dependent on assumptions used. Response to PSCIR4-34 (explaining a 36 basis point reduction in the average NRC inflation rate requires no increase in customer contributions beyond $18.7 million).

Notably Calvert Cliffs has no obligation to decommission the plants immediately when the licenses expire. BGE's responses estimating obligations do not address this uncertainty (*id.*), and BGE has not provided information that would help the Commission to estimate customers' total decommissioning obligations more accurately. *See* Response to PSCIR4-22. Instead, BGE's response indicates that the Commission cannot exclude the possibility that CCNPP may take up to 60 years to fully decommission the plant. *Id.* (citing 10 C.F.R. § 50.82). It is unclear whether CCNPP construes the settlement to require customers' to continue funding during such an extended period. *Id.*

FIGURE 4. ESTIMATED CUSTOMER LIABILITY FOR DECOMMISSIONING BY 2024/2036 REPORTED TO THE MARYLAND PUBLIC SERVICE COMMISSION



Fourth, the Settlement contains no assurances or protections for ratepayers' contributions. Despite divestiture and transfer of the decommissioning fund to BGE's unregulated affiliate, the settlement did not require additional safeguards for customer funds. Without improved oversight, ratepayers' contributions may be adversely affected by CCNPP's private, corporate decisions that may not adequately protect customers' contributions. At the very minimum, CCNPP must provide assurances that customer funds related to the $520 million obligation will be available, *e.g.*, by placing these funds into external trusts or providing additional assurances or guarantees these funds will be available.

BGE has not responded fully to our request for internal policies and procedures related to Calvert Cliffs' treatment of decommissioning funds. Response to PSCIR4-5. The Commission retains jurisdiction over the decommissioning provisions of settlement, and BGE's representations that the funds are maintained in accordance with NRC regulation are not related to this settlement provision and provide no assurances that all funds collected from its customers are appropriately secured for decommissioning use. *See, e.g.*, Responses to PSCIR4-5, 4-6, 4-7. Testimony from BGE in a related case suggests that NRC regulations provide sufficient controls, but the funds at issue are not reported to the NRC. Prepared Reply Testimony of Richard M. Bange, Jr., *In Re Business Separation*, (8883/35) (July 23, 2001) ("Bange Reply Test." (8883/35)) at 4:10-5:6. Moreover, NRC's reporting and recordkeeping regulations for nuclear decommissioning planning expressly provide that "[f]unding for the decommissioning of power reactors may also be subject to the regulation of Federal or State

Government agencies (*e.g.*, Federal Energy Regulatory Commission (FERC) and State Public Utility Commissions) that have jurisdiction over rate regulation." NRC requirements "are in addition to, and not substitution for, other requirements, and are not intended to be used, by themselves, or by other agencies to establish rates." 10 C.F.R. § 50.75(a) (2007).

CCNPP reports to the NRC are based on the NRC's own generic reporting criteria. For example, a recently-filed report for 2005 shows $643.976 million – well below the ratepayer funding obligation under the settlement – as the "minimum decommissioning fund estimate" representing

> decommissioning costs anticipated to be incurred in removing the Calvert Cliffs units safely from service and reducing residential radioactivity to levels that permit release of the property for unrestricted use and termination of the license. The cost of dismantling non-radioactive systems and structures is not included in this estimate, nor is the cost of managing and storing spent fuel on the site until transfer to the U.S. Department of Energy.

See Attachment 1 to Response to PSCIR4-24 (Annual Report: Status of Decommissioning Funding per 10 CFR 50.57(f)(1) (Feb. 8, 2006)). This report does not provide the full decommissioning cost estimate, Calvert Cliffs' funds available (as reported to the Commission), or any indication of Calvert Cliffs' decommission plans. The NRC relies on this report to evaluate the availability of Calvert Cliffs' decommissioning funds.[112] The data supplied in the report is informative (and is summarized in Table 16 below), but the NRC has no responsibility for monitoring the funding issues negotiated in BGE's Settlement Agreement.

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[112] Interestingly, some NRC data was included in Constellation's 2006 report to the Commission (*see* Attachment 1 to 2006 Compliance Filing ("50.75 funding calculation,") but the NRC annual funding calculations reported in the compliance filing do not always match the annual funding requirements actually filed with the NRC. *See* Attachment 1 to Response to PSCIR4-24. In any event, the General Accounting Office reported that NRC's oversight of nuclear facilities' accumulation of decommissioning funds is inadequate. U. S. General Accounting Office, Nuclear Regulation: NRC Needs More Effective Analysis to Ensure Accumulation of Funds to Decommission Nuclear Power Plants, GAO-04-32 (Oct. 2003).

TABLE 16 DECOMMISSIONING EXTERNAL TRUST: 1999-2006 (thousands of dollars)				
Status Report Year		**Unit 1**	**Unit 2**	**Total**
1999	The amount accumulated as of December 31, 1998 in the external decommissioning trust pursuant to 10 CFR 50.75 (b) and (c)	$80,097	$97,293	$177,390
	Schedule of the annual amounts remaining to be collected (Actual amount being deposited to the trust as approved by Maryland Public Service Commission in 1995, and Internal Revenue Service in 1996)	$6,887	$9,730	$16,617
2001	The amount accumulated as of December 31, 2000 in the external decommissioning trust pursuant to 10 CFR 50.75 (b) and (c)	$98,392	$121,835	$220,227
	Schedule of the annual amounts remaining to be collected (Actual amount being deposited to the trust as approved by Maryland Public Service Commission in 1999, and Internal Revenue Service in 2001)	$6,887	$9,730	$16,617
2003	The amount accumulated as of December 31, 2002 in the external decommissioning trust pursuant to 10 CFR 50.75 (b) and (c)	$98,826	$123,905	$222,731
	Schedule of annual amounts remaining to be collected	$6,887	$9,730	$16,617
2005	The amount accumulated as of December 31, 2004 in the external decommissioning trust pursuant to 10 CFR 50.75 (b) and (c)	$142,588	$181,721	$324,309
	Schedule of the annual amounts remaining to be collected	$6,887	$9,730	$16,617
2006	The amount accumulated as of December 31, 2005 in the external decommissioning trust pursuant to 10 CFR 50.75 (b) and (c)	$155,227	$198,674	$353,791
	Schedule of the annual amount remaining to be collected	$3,443	$4,865	$8,308

The Commission should require assurances from BGE that ratepayers' collections will be protected from CCNPP's actions that may have rate of return or tax consequences. The settlement provides no protections for the internal reserve that BGE transferred to Calvert Cliffs in 2000. *See* Response to Staff Request 2-1(c) ("Calvert Cliffs Nuclear Power Plant is the owner of the internal reserve funds effective July 1, 2000"). The imputed balance is currently more than $135 million. This internal reserve is not a separate account (like the external reserves), and ratepayers' funds collected by BGE are imputed to this account but are used for other purposes. Perhaps for this reason, Constellation does not report the internal reserve as funds available for decommissioning in financial reports subject to federal securities law and regulation. BGE explains that "financial statements and related footnotes and disclosures contained within the 10-K are prepared in conformance with GAAP and SEC requirements." Response to PSCIR4-18. Similarly, the internal reserve funds accumulated for Calvert Cliffs are not included in its NRC reports pursuant to 10 C.F.R. § 50.75(f) (2007). *See also* NRC Standard Review Plan on Power Reactor Licensee Financial Qualifications and Decommissioning Funding Assurance, NUREG-1577 (Rev. 1, Feb. 1999).

We recommend that the Commission investigate the external trusts transferred to Calvert Cliffs. BGE reports that its 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." Response to PSCIR4-3(b)(c). BGE explains that it "began to invest a portion of the decommissioning trust fund in equities beginning in April 1996 after both the IRS and [FERC] permitted decommissioning trust funds to invest in equities." Response to PSCIR4-9. We have not investigated the trust funds' management since divestiture.[113]

Fifth, the settlement contains no instructions to assure proper allocation of ratepayers' contributions to the decommissioning accounts. The settlement provides that "customer contributions for nuclear decommissioning costs shall be made at a fixed annual rate of $18,661,980 until June 30, 2006" and thereafter determines customers' contribution obligation based on specified factors, including the "actual balance of the Nuclear Decommissioning Trust Fund" and anticipated rates of return on the funds. BGE Settlement Agreement, ¶ 22. BGE maintains that its procedures and policies related to the decommissioning funding obligations were "governed entirely" by Paragraph 22 of the settlement. Response to PSCIR4-5. BGE reports that since the asset transfer, customers' payments were allocated to Calvert Cliffs' qualified, nonqualified, and internal nuclear decommissioning reserves using the following procedures:

1. Determine the liability to decommission the plant in current day dollars based on a site-specific study;

2. Escalate the liability to the date of decommissioning by an escalation rate representing a composite of the rates applicable to different kinds of costs;

3. Determine the portion of the liability allowed by the IRS to be funded in a "qualified" trust;

4. Determine the contributions to the trust that would fund that portion of the liability assuming a reasonable qualified trust after-tax rate of return to the time of decommissioning;

5. Determine if the NRC requires that additional amounts be funded externally above and beyond the qualified portion;

6. Determine the contributions required to be made to a non-qualified trust (the trust that would fund the excess portion of the liability assuming a reasonable non-qualified trust after-tax rate of return to the time of decommissioning);

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113 Additionally , because Calvert Cliffs is a licensee that is not an "electric utility" as defined by NRC regulations (10 C.F.R. § 50.2 (2007)), the Commission should determine whether Calvert Cliffs fully complies with federal regulations requiring financial assurances for its external funds related to the segregation and management of those funds or other surety methods, insurance, or other guarantees. 10 C.F.R. § 50.75(h)(1), (3) (2007).

7. Any additional site-specific study liability exceeding this amounts funded externally would be funded by an internal reserve that would accrue earnings based on BGE's earned rate of return.

Response to PSCIR4-6(c). Table 17 shows contributions made to the external qualified, external non-qualified, and internal reserves during the 2000-2006 period.

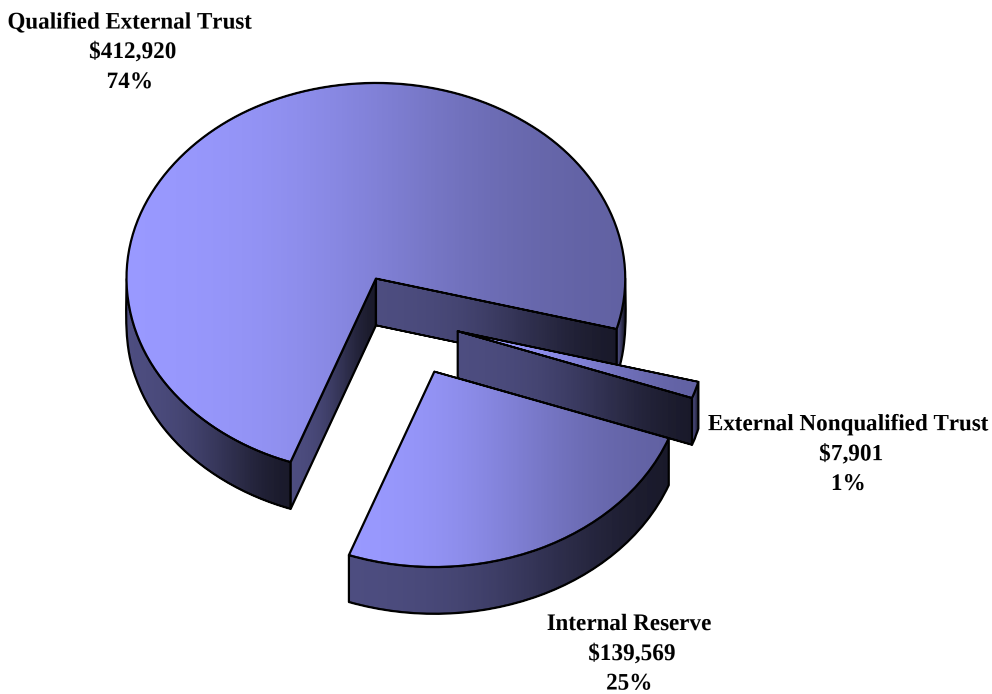
TABLE 17
CONTRIBUTIONS, EARNINGS, AND AVAILABLE DECOMMISSIONING FUNDS REPORTED TO THE MARYLAND PUBLIC SERVICE COMMISSION

12 months ending -	Description	External (Qualified)	External (Nonqualified)	Internal Reserve	Total Funds
		(thousands of dollars)			
2000	Balance 12/31/1999	$213,833	$3,996	$69,648	$287,477
	Customers' Payments	$12,910	$314	$5,438	$18,662
	Earnings	$3,047	$44	$6,545	$9,636
	Change in Unrealized Gains	$5,509	$216		$5,725
	Funds Available for Decommissioning	$224,281	$4,138	$81,631	$310,050
2001	Customers' Payments	$21,516	$523	$3,377	$18,662
	Earnings	$3,960	$49	$6,631	$10,640
	Change in Unrealized Gains	$33,872	$855		$34,727
	Valuation Allowance for Market	$20,668	$282		$20,950
	Funds Available for Decommissioning	$236,554	$4,137	$84,885	$325,576
2002	Customers' Payments	$17,213	$419	$1,030	$18,662
	Net Earnings	$4,109	$52	$6,274	$12,127
	Change in Unrealized Gains	($20,669)	($281)		($20,950)
	Valuation for Market	($1,435)	($444)		($1,879)
	Funds Available for Decommissioning	$235,772*	$3,883*	$92,189	$331,844*
2003	Customers' Payments	$17,213	$419	$1,030	$18,662
	Net Earnings	$6,725	$63	$7,362	$14,150
	Net Unrealized Gains	$22,773	$80		$22,853
	Funds Available for Decommissioning	$283,918	$4,889	$100,581	$389,388
2004	Customers' Payments	$17,213	$419	$1,030	$18,662
	Net Earnings	$2,951	$80	$7,785	$10,816
	Net Unrealized Gains	$22,223	$508		$22,731
	Funds Available for Decommissioning	$326,305	$5,896	$109,396	$441,597
2005	Customers' Payments	$17,213	$419	$1,030	$18,662
	Net Earnings	$11,344	$122	$7,878	$19,344
	Net Unrealized Gains	$8,671	$364		$9,035
	Funds Available for Decommissioning	$363,533	$6,801	$118,304	$488,638
2006	Customers' Payments	$8,607**	$209	$9,846**	$18,662
	Earnings	$8,314	$149	$11,419	$19,702
	Net Unrealized Gains	$32,646	$742		$33,388
	Funds Available for Decommissioning	$412,920	$7,901	$139,569	$560,390

* A negative $1.879 million adjustment, “Valuation Allowance for Market” reported here is excluded in the following years’ reports.
** Response to PSCIR4-3 (b)(a) indicates that Calvert Cliffs made an additional contribution of $8.8 million to the external trusts for 2006 in early 2007.

BGE’s description of how the $18.662 million collections from customers (to maintain $520 million in 1993 dollars) is allocated to CCNPP’s external qualified trust, external nonqualified trust, and internal reserve is helpful, but is deficient in numerous respects. BGE's response does not provide the Commission with the full information necessary to understand, why, for example, BGE now reports "all of the funds collected since the effective date of Senate Bill 1 have been placed in the [CCNPP] internal reserve." Response to PSCIR4-7(c). According to BGE, "none of the funds are required to be placed externally by the NRC." *Id.* Additionally, BGE's response does not adequately explain why CCNPP has modified the allocation of funds between the external trust and the internal reserve. Reports to the NRC explain that "Calvert Cliffs is obligated to deposit [decommissioning collections from BGE's electric customers] into the decommissioning trusts." *See* Attachment 1 to Response to PSCIR4-24 (Annual Report: Status of Decommissioning Funding per 10 CFR 50.75(f)(1) (Feb. 8, 2006) at Attachment (1)). In fact, however, as Figure 5 shows, Constellation does not deposit all customer collections into external trusts and about one-quarter is currently in internal reserves that are only imputed to decommissioning.

FIGURE 5. DECOMMISSIONING FUND BALANCE ALLOCATIONS (AS OF DECEMBER 31, 2006) (IN THOUSANDS)



BGE has not provided sufficient information to determine whether there may be a tax-related rationale for placing all collected funds in internal reserves, but some of its responses raise additional questions. BGE reports that the $18.6 million collection from ratepayers is the "after-tax fixed annual contribution authorized by the Commission in Order No. 72240."[114] In order to identify the before-tax decommissioning collections, we asked BGE to provide its unbundled rates for the decommissioning component of its charge. This segregation of

[114] *See* Response to PSCIR4-12. The order that BGE cites did not authorize a "contribution" from ratepayers, however, but instead allowed BGE to qualify for a tax deduction on the amount of the accruals. Order 72240, 86 Md. PSC at 376.

decommissioning charges is important because the federal Internal Revenue Code provides that "[t]he amount of any payment to the nuclear decommissioning fund . . . is excluded from gross income."[115] In other words, decommissioning collections paid into the qualified trust fund (as defined in 26 C.F.R. § 1.468A-5) are not subject to federal income tax and BGE should not gross up those amounts in its decommissioning charge collections. BGE responded to our requests, however, claiming that it could not provide disaggregated decommissioning collections because its tariff contains only a "separate aggregate rate for broad categories of Delivery Service, Generation, Transmission and Competitive Transmission Service." *See* Response to PSCIR4-15. Thus, we cannot tell the extent to which BGE may have grossed up its collections to pay taxes that would not have been due if it had made those payments to the qualified decommissioning trust fund instead of to an internal reserve.

Nor has BGE provided the IRS ruling amount setting annual contributions to Calvert Cliffs' qualified trust fund. *See* Response to PSCIR4-9. If these funds were not eligible for deposit in the qualified trust, we would expect that Calvert Cliffs would credit customers' funds to the external non-qualified trust, but it has not done so. The allocation of all collections to the internal reserve may be related to provisions of Senate Bill 1, which we address below. In any case, customers' funds that are not placed in an external account are not protected from total loss if Calvert Cliffs declares bankruptcy and dissolves. In that case, because the funds allocated to CCNPP's internal reserve would not be available for decommissioning, the State may be left with the obligation to pay again for decommissioning – precisely the dilemma that the settling intervenors sought to avoid.

Sixth, the settlement contains no assurances that ratepayers' contributions are earning the optimal return on their contributions. *See generally* Response to PSCIR4-9. Calvert Cliffs' imputes a rate of return on the internal reserve using BGE's earned rate of return. *See* Response to PSCIR4-8. No basis exists for this practice, because Calvert Cliffs and BGE are independent corporate entities with very different risk and earnings profiles. Indeed, Calvert Cliffs is a highly profitable, unregulated merchant plant, and is likely earning a far higher return than BGE's earnings on regulated operations. Moreover, internal reserves' earnings do not benefit from tax treatment available to qualified decommissioning funds. Tax treatment of contributions and earnings in the "internal reserve" is not favorable compared with tax treatment for funds and accrued earnings on funds in the external qualified trust. Consequently, imputing a lower ROE to funds that CCNPP can freely use may increase the gap between decommissioning funding and the required $520 (in 1993 dollars) and require greater ratepayer collections.

Seventh, the settlement's reporting requirements are outdated and insufficient to monitor the security of the customer-funded decommissioning trust. Our investigation found that the Commission has no current information about the treatment of these funds. The Commission could require Constellation to provide: (1) copies of decommissioning assurance reports filed with the NRC (*see* Bange Reply Test. (8883/35) at 4:23-5:4) and other communications between NRC and Constellation related to the decommissioning funds; (2) copies of tax filings for the external trust (*see* Response to PSCIR4-9); (3) updates on the external funds' performance, (4) prior notification at any time Constellation may to take steps

[115] 26 C.F.R. § 1.468A-4(b)(1) (2007).

that might adversely affect customers contributions to this and decommissioning fund rate of return, and (5) any audit of the internal reserve funds, including sufficient information to determine the value of those funds to Constellation. The Commission may want to consider additional reporting requirements that would provide assurance that collected funds are secure and are being properly reported. Table 18 below shows the difference in reported external qualified funds to the Commission and to the NRC.

TABLE 18
EXTERNAL QUALIFIED FUND BALANCES REPORTED TO THE NRC AND THE MARYLAND PUBLIC SERVICE COMMISSION

12 months ending Dec. 31,-	"External Decommissioning Trust" balance reported to NRC	"External Qualified Fund" balance reported to PSC	Difference
	(in thousands of dollars)		
1998	$177,390	$178,313	($923)
2000	$220,227	$224,281	($4,054)
2002	$222,731	$237,207	($14,476)
2004	$324,309	$326,305	($1,996)
2005	$353,791	$363,533	($9,742)

Finally we recommend further examination of how customer collections are treated in Constellation's intra-affiliate transactions. Although the Decommissioning Funds Collection Agent Agreement procedures require keeping funds "in trust for the benefit of the Company" and "remit . . . to the Company, by wire transfer in immediately available funds, every week" (DFCA Agreement, § 2), discovery from BGE indicates that it has not followed this procedure. *See* Response to PSCIR4-6(b).

E. Treatment of Decommissioning Funds under Senate Bill 1

The Senate Bill 1 provision related to decommissioning may trade short-term savings for residential customers with long-term costs for all customers. Section 6 of Senate Bill 1 mandates that as of January 1, 2007, BGE must begin providing credits to residential electric customers in the form of a non-bypassable credit or suspension on the customers bill related to decommissioning. The statute provides that "for a period of 10 years, a credit of the $18,661,980 annual nuclear decommissioning charge collected . . . [is] to be imputed as deposits in the Nuclear Decommissioning Trust Fund and to be credited against residential electric customer bills." An Act Concerning Public Service Commission-Electric Industry Restructuring, 2006 Md. Laws 5, § 6(b)(2) ("Senate Bill 1"). Senate Bill 1 further requires that the "nuclear decommissioning charge . . . may not be altered during the 10-year period of the credit." *Id.*, § 6(c).

Under this statutory requirement, BGE continues to collect the $18.662 million annually (in after-tax dollars) from all customer classes through a bundled component of its delivery rates, approximately one-half of which comes from residential customers. The ***full*** amount of the decommissioning collections is "credited against ***residential electric customer*** bills," along with the qualified rate stabilization charge in a line item called "RSP Chg/Misc Credit."[116] *Id.*, § 6(b)(2) (emphasis added). Thus, even though residential customers only pay half of the annual decommissioning funds, they are credited back the full amount.[117] BGE prices this credit at $0.00137 per kWh (in 2007) so customers' refund depends on their electricity consumption. A typical residential customer consuming 1,000 kWh in a month receives a nominal $1.37 reduction of their RSP charge on their bill. Because the Senate Bill 1 decommissioning mechanism refunds residential customers twice their contribution to the Calvert Cliffs decommissioning fund, the provision is an intra-period subsidy from BGE's commercial and industrial customer classes to residential customer classes.

The decommissioning provision of Senate Bill 1 has two additional, undesirable effects. First, the legislation requires decommissioning collections "to be imputed as deposits" into Calvert Cliffs' "Nuclear Decommissioning Trust Fund." *Id*. BGE reports that "all of the funds collected since the effective date of Senate Bill 1 have been placed in the internal reserve." Response to PSCIR4-7(c). Although complying with the letter of Senate Bill 1's direction to "impute" decommissioning collections "as deposits in the Nuclear Decommissioning Trust Fund," Calvert Cliffs' internal reserve is an accounting fiction and provides no assurance that funds will be available at decommissioning. CCNPP may be able to satisfy minimal NRC requirements – which do not necessarily require an external trust fund sufficient to cover all decommissioning costs – with the amounts already contributed to the external fund while continuing to use ongoing ratepayer collections to supply its internal capital requirements.

Second, because BGE is the regulated subsidiary of a larger corporate entity, Constellation may direct the financial burdens of Senate Bill 1 to BGE and shield its unregulated merchant businesses from those costs. For example, if Senate Bill 1 erodes BGE's earnings, as Constellation contends in earnings calls, BGE may then argue in an upcoming rate case that its cost of capital increased. Because BGE is regulated, it fully recovers these increased costs through its regulated rates charged to customers.

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[116] Although BGE implemented credits in accordance with the provisions of Senate Bill 1, it and its affiliate CCNPP entered an agreement with the Attorney General of Maryland reserving their rights to pursue litigation challenging the validity of Section 6 of Senate Bill 1. BGE agreed, however, that it would not seek to recover any credits or suspensions provided to residential customers during the period of time that the agreement with the Attorney General is in effect. Letter from L. Wayne Harbaugh to O. Ray Bourland, Interim Compliance Filing – Supplement No. 391 to P.S.C. Md. E-6 Maryland General Assembly – Senate Bill 1 (Dec. 1, 2006) at 2 and Attachment B. Pursuant to an April 2007 addendum, the agreement terminates upon the earlier of (1) 30 days written notice by a party or (2) the settlement of all issues related to the validity of Section 6 of Senate Bill 1. Letter from Beverly A. Sikora to O. Ray Bourland, Maillog No. 105671 (Apr. 16, 2007).

[117] The Commission Staff concluded that BGE "properly implement[ed] the credits as directed by Senate Bill 1." Comments of the Accounting Investigations Division Re: BGE Compliance Filing, Maillog No. 103915 (Dec. 13, 2006) at 3. The Commission accepted BGE's compliance filing. Letter from O. Ray Bourland to L. Wayne Harbaugh, Maillog No. 103915 (Dec. 20, 2006). The tax treatment of collections and credits may raise additional questions, however. If BGE could have excluded decommissioning collections from gross income by paying those amounts into the decommissioning trust fund instead of "imputing" them to decommissioning through an internal reserve, it may have collected more than required from ratepayers by grossing up its collections while crediting residential ratepayers with only the after-tax amount.

In sum, Senate Bill 1's decommissioning provision creates a discriminatory rate provision to the detriment of commercial and industrial customers, continues to collect decommission funds through intra-corporate account transactions but then "imputes" them to an insecure account, and may erode BGE balance sheet, thereby ultimately increasing customer rates. Although Constellation is able to protect itself in this transaction, Senate Bill 1 does not assure a real reduction in customers' bills (however small) and does not protect ratepayers from even greater long-term cost increases.