ORDER NO. 75757

<table>
<tr><td>IN THE MATTER OF THE BALTIMORE GAS AND ELECTRIC COMPANY'S PROPOSED: (A) STRANDED COST QUANTIFICATION MECHANISM; (B) PRICE PROTECTION MECHANISM; AND (C) UNBUNDLED RATES.</td><td>*
*
*
*</td><td>BEFORE THE
PUBLIC SERVICE COMMISSION
OF MARYLAND

CASE NO. 8794</td></tr>
<tr><td>IN THE MATTER OF THE PETITION OF THE OFFICE OF PEOPLE’S COUNSEL FOR A REDUCTION IN THE RATES AND CHARGES OF THE BALTIMORE GAS AND ELECTRIC COMPANY.</td><td>*
*
*</td><td>CASE NO. 8804</td></tr>
</table>

Before: Glenn F. Ivey, Chairman
Claude M. Ligon, Commissioner
Susanne Brogan, Commissioner
Catherine I. Riley, Commissioner
J. Joseph Curran, III, Commissioner

Filed: November 10, 1999

TABLE OF CONTENTS

APPEARANCES

Daniel P. Gahagan, George D. Billinson, Robert S. Fleishman and Lisa M. Decker, for Baltimore Gas and Electric Company.

Michael J. Travieso and William F. Fields, for Maryland Office of People's Counsel.

Gary R. Alexander, Thomas W. Kinnane and Chantel Ornstein, for Mid-Atlantic Power Supply Association.

Robin M. Nuschler, for Statoil Energy, Inc.

Thomas C. Gorak, for Maryland Retailers Association and Building Owners and Managers Association of Metropolitan Baltimore, Inc.

Marc D. Machlin, for National Railroad Passenger Corporation.

M. Brent Hare, for Department of Natural Resources/Maryland Energy Administration.

Frank C. Derr and Linda C. Barclay, for the Mayor and City Council of Baltimore.

Allen J. Malester, for Maryland Industrial Group and Millennium Inorganic Chemicals, Inc.

Jeral A. Milton, for Bethlehem Steel Corporation.

Neal M. Janey, for Board of County Commissioners of Calvert County, Maryland.

Matthew W. Nayden, for Baltimore Steam Company t/a Trigen Energy Baltimore.

Daniel Clearfield, for Enron Energy Services, Inc.

David A. McCormick, for the United States Department of Defense and Federal Executive Agencies.

Denise Ferguson-Southard, for Maryland Department of the Environment.

Sarah R. Lazarus and M. Catherine Dowling, for Maryland Public Service Commission Staff.

ORDER NO. 75757

IN THE MATTER OF THE BALTIMORE GAS AND ELECTRIC COMPANY'S PROPOSED: (A) STRANDED COST QUANTIFICATION MECHANISM; (B) PRICE PROTECTION MECHANISM; AND (C) UNBUNDLED RATES.	* * * *	BEFORE THE PUBLIC SERVICE COMMISSION OF MARYLAND CASE NO. 8794
IN THE MATTER OF THE PETITION OF THE OFFICE OF PEOPLE'S COUNSEL FOR A REDUCTION IN THE RATES AND CHARGES OF THE BALTIMORE GAS AND ELECTRIC COMPANY.	* * *	CASE NO. 8804

I. BACKGROUND

A. Preface

This Order approves the Stipulation and Settlement Agreement[1] entered into by and between the Baltimore Gas and Electric Company ("BGE" or "the Company") and parties representing all customer classes, environmental interests and the public interest at large.[2] It establishes a restructuring plan for the Company that implements two policies: first, the Public Service Commission's ("the Commission" or "PSC") own policy initiatives designed to restructure Maryland's electric industry, which were formally promulgated in Order No. 73834 in Case No.

[1] Hereinafter "the Settlement" or "the Settlement Agreement."

[2] The signatories to the Settlement are Baltimore Gas and Electric Company; Maryland Office of People's Counsel ("OPC"); the Maryland Department of Natural Resources-Maryland Energy Administration and The Power Plant Research Program ("DNR/MEA); Maryland Industrial Group and Millennium Inorganic Chemicals, Inc. ("MIG"); Maryland Retailers Association ("MRA") and Building Owners and Managers Association of Baltimore, Inc. ("BOMA"); the Johns Hopkins University and Johns Hopkins Health System Corporation ("Johns Hopkins"); Department of Defense/Federal Executive Agencies ("DOD/FEA"); Board of County Commissioners of Calvert County, Maryland ("Calvert County"); Enron Energy Services, Inc. ("Enron"); National Railroad Passenger Corporation ("Amtrak"); and Staff of the Maryland Public Service Commission ("Staff"), (collectively referred to as the "Settling Parties").

8738;[3] and second the Electric Customer Choice and Competition Act of 1999 ("the Act")[4] enacted by the General Assembly and signed into law by Governor Glendening during the 1999 legislative session. In addition, it resolves Case No. 8804, relating to OPC's petition for rate reduction.

This Order approves an overall 6.5 percent rate reduction for BGE's residential customers, which will become effective on July 1, 2000, and a freeze for residential Schedule R/ES[5] customers for six years. For Schedule RL[6] customers, rates will be reduced beginning July 1, 2000 and will remain frozen for four years until June 30, 2004. On July 1, 2004, the Schedule RL rate reduction decreases and will then remain frozen until June 30, 2006. The overall 6.5 percent rate reduction for residential customers is the average of a 7 percent reduction for residential Schedule R/ES customers and a 3 percent reduction for residential Schedule RL customers. Residential Schedule R/ES rates will be reduced to achieve a total revenue reduction of $50.2 million annually through June 30, 2006. Residential Schedule RL rates will be reduced to achieve a total revenue reduction of $3.6 million annually through June 30, 2004.[7]

The Commission also approves a four-year rate freeze for the Company's non-residential customers, based upon rates in effect on June 30, 1999. In approving the Settlement Agreement and the rates for residential and non-residential customers, the

---

[3] Entered December 3, 1997 *In the Matter of the Commission's Inquiry into the Provision and Regulation of Electric Service*, Case No. 8738, 88 MD PSC 249 (1997); hereinafter "Order No. 73834." The Commission's initial order in this proceeding was Order No. 72938, issued October 9, 1996.
[4] Public Utility Companies Article of the Annotated Code of Maryland, § 7-501 *et seq*.
[5] Schedule R/ES applies to Residential and Economy Service customers.
[6] Schedule RL applies to Residential Service Large customers. Upon implementation of the Settlement, Schedule RL will be closed to new customers after a new residential time-of-use schedule is filed with the Commission.
[7] On July 1, 2004, Schedule RL rates will be adjusted to achieve a total revenue reduction of $1.8 million annually through June 30, 2006.

Commission determines that the Settlement comports with the outcomes envisioned by the policies set forth in Order No. 73834 and the Act and provides for the implementation of rates and customer price protections that are just and reasonable and in the public interest.

Maryland is not alone in taking action to restructure the electric industry and create customer choice. The Federal Energy Regulatory Commission and many sister states, including Pennsylvania, Virginia, Delaware, and New Jersey have created frameworks for competition in markets subject to their jurisdiction. The Congress of the United States has enacted legislation that authorizes markets for certain wholesale providers of electricity, and continues to debate national legislation establishing customer choice for all customers.

However, Maryland's actions came only after extensive research, deliberation and debate undertaken by the Commission and members of the General Assembly and the Executive Branch. In December, 1997, the Commission issued Order No. 73834 which determined that retail competition in the electric industry was in the public interest because it would allow citizens the prospect of benefiting from reduced costs, economic efficiencies, technological innovations, and opportunities for choice of electric generation supplier. It established a process and timeframe for the development of a competitive electric supply environment.

The General Assembly established a task force in 1997 on electric restructuring and spent two years developing legislation to create customer choice and retail competition and a revenue neutral tax reform structure for the electric and gas industries.[8] The Act sets forth the legal framework for restructuring and includes a variety of price protection mechanisms to safeguard customers during the transition period to a competitive market.

---

[8] The Electric and Gas Utility Tax Reform Act of 1999 ("Tax Act").

The Act directs the Commission to oversee that transition and requires that it should "be orderly, maintain electric system reliability, and ensure compliance with federal and state environmental regulations, be fair to customers, electric company investors, customers of municipal electric utilities, electric companies, and electricity suppliers, and provide economic benefits to all customer classes."[9]

Both Order No. 73834 and the Act determined that the citizens of Maryland would benefit from a competitive electric market and established a process for assuring an orderly transition with price protections and safeguards for customers when electric restructuring is accomplished and generation is no longer regulated.

B. <u>Overview of Commission Initiatives</u>

By Order No. 73834, the Commission determined that retail competition (or "retail choice") in the electric industry was in the public interest because it "offers the prospect of reduced costs and increased choices, as well as innovative services, for Maryland ratepayers."[10] As the Commission recognized, a number of issues must be addressed in connection with the implementation of retail electric competition.

Among these issues is the matter of the recovery of "stranded" costs, which essentially are costs incurred by the utility in providing regulated monopoly services that, in the transition to retail choice, may not be recoverable from ratepayers. The Commission also concluded that Maryland utilities should be given "a fair opportunity to recover their verifiable and prudently incurred stranded costs subject to full mitigation."[11]

---

9 Section 7-505(a).
10 88 MD PSC 249, 271 (1997).
11 *Id*. at 293.

A second issue concerns price protection mechanisms that may be necessary to insulate ratepayers from rate instability during the transition to retail electric competition. In this regard, the Commission has stated that during the transition period, it would be appropriate to require the incumbent utilities to provide "default" service ("Standard Offer Service") at capped rates for customers in their service territories who are unable or unwilling to choose a new supplier.[12] Finally, there is the issue of how the costs of and the rates for providing retail electric service will be unbundled into deregulated generation service and regulated transmission and distribution services.

In Commission Order No. 73834, the Commission established a process for each of the four investor-owned electric utilities operating in Maryland to develop company-specific restructuring plans addressing these issues.[13] BGE's restructuring proceeding was docketed as Case No. 8794.

C. <u>Overview of Maryland's Electric Restructuring Act</u>

The purposes of the Act[14] are to establish customer choice, create competitive electric markets, deregulate the provision of generation, provide economic benefits to all customer classes and ensure compliance with environmental standards.[15] The Commission must ensure that the transition to competition is orderly; maintains electric system reliability; complies with environmental regulations; is fair to customers, electric companies, their investors, and electric suppliers; and provides benefits to all customer classes.[16] The Act also provides an electric company with a fair

[12] *Id*. at 286.
[13] In that Order, the Commission also directed the formation of Statewide Roundtables charged with investigating and proposing a process for resolving various issues related to the transition to competitive electric generation markets. Six broad topics were addressed in the Roundtable process: Customer Education; Demand-Side Management; Supplier Authorization; Universal Service; Consumer Protection; and Competitive Billing. The Commission will consider the recommendations of the Roundtables and adopt appropriate Orders and regulations.
[14] Hereinafter, all references to Code sections will be to this Act, unless specified otherwise.
[15] Section 7-504.
[16] Section 7-505(a)(1).

opportunity to recover all of its prudently incurred and verifiable net transition costs,[17] subject to full mitigation.[18] The Commission shall determine the transition costs and the amount thereof that a company will be provided an opportunity to recover.[19] In determining the appropriate transition costs, the Commission is directed to hold public hearings, and consider appropriate evidence of generation asset values.[20] Further, the Commission is to consider an equitable allocation of costs or benefits between shareholders and ratepayers based upon an analysis of the generation investment and risk of loss.[21] The Commission is authorized to implement a Competitive Transition Charge or Credit ("CTC") or other appropriate mechanism for the recovery of net transition costs or benefits.[22]

The Commission is also directed to implement certain price protections for electric customers. Residential base rates are to be reduced between 3 percent and 7.5 percent as measured on June 30, 1999, and all customers are to receive a four-year rate freeze beginning with the implementation of customer choice.[23] The Commission may consider and approve settlements that differ from these provisions and may approve a rate cap for a different time period or implement an alternative price protection plan that the Commission determines is "equally protective of ratepayers."[24] In addition, the Commission may adopt a settlement that does not apply the required rate reduction if the settlement is "equally protective of ratepayers."[25] Further, in identifying stranded costs and permitting their recovery, the Commission is authorized to accept "any other [transition]

[17] Section 7-501(p) defines "transition cost" as "a cost, liability, or investment that: (1) traditionally would have been or would be recoverable under rate-of-return regulation, but which may not be recoverable in a restructured electricity supply market; or (2) arises as a result of electric industry restructuring and is related to the creation of customer choice.
[18] Section 7-513(a)(1).
[19] Section 7-513(b).
[20] Section 7-513(e)(1).
[21] Section 7-513(e)(2).
[22] Section 7-513(a)(2).
[23] Section 7-505(d).
[24] Section 7-505(d)(3).
[25] Section 7-505(d)(5).

mechanism as part of a settlement" rather than those enumerated in the Act.[26] The Act also provides for the phased-in implementation of customer choice. Under the Act, one-third of the residential class is eligible for customer choice July 1, 2000, another one-third is eligible for customer choice July 1, 2001, and the final one-third of residential customers is eligible for customer choice July 1, 2002. Industrial and commercial customers are all eligible for customer choice January 1, 2001.[27] However, if the Commission finds it to be in the public interest, the Commission may accelerate any of the implementation dates and phase-in percentages.[28]

Section 7-510(c) of the Act states that an electric company will provide Standard Offer Service (or "SOS") until July 1, 2003, unless the Commission finds that the electricity supply market is not competitive, in which case it may extend this obligation. The Commission is to determine the terms, conditions and rates for Standard Offer Service.[29] The Commission shall also require the unbundling of electric company rates, charges and services into standardized categories. Customer bills are to reflect these individual charges.[30]

Section 7-508 of the Act enumerates the responsibilities of the Commission regarding the transfer of generation assets by electric companies. It permits electric companies to transfer generation assets to affiliates.[31] However, the Commission's review is not restricted to a determination of the value of an asset for purposes of determining a company's stranded costs.[32] Pursuant to § 7-508(c), the Commission may review and approve the transfer for the sole purpose

---

[26] Section 7-513(d)(2)(iii).
[27] Section 7-510(a).
[28] Section 7-510(b).
[29] Section 7-505(b)(8).
[30] Section 7-505(b)(5). Unbundling issues concerning competitive metering and billing (see § 7-511) will be addressed by the Commission in other proceedings. Likewise, code of conduct issues that are not addressed herein will be addressed in Case No. 8820.
[31] Section 7-508(a).
[32] Section 7-508(b).

of determining: that the appropriate accounting has been followed; that the transfer does not or would not result in an undue adverse effect on the proper functioning of a competitive electric supply market; and the appropriate price and rate making treatment. In addition, the Act provides that the Commission may make appropriate adjustments that take into account generation asset sales by an electric company or an affiliate to a non-affiliate that are consummated by June 30, 2005.[33]

D. Procedural Summary

On July 1, 1998, BGE filed for approval of certain stranded costs and pricing mechanisms as the Company prepares to enter a competitive electricity marketplace. This filing was in response to Commission Order No. 73834, which directed the four investor-owned electric companies in the State to submit their restructuring plans. BGE's restructuring proceeding was docketed as Case No. 8794.

On September 3, 1998, the Maryland Office of the People's Counsel ("OPC") filed a Petition for a reduction in the Company's rates and charges for electricity services.[34] OPC maintained that BGE's rates exceeded just and reasonable levels by $109.9 million annually. As a result, the Commission instituted Case No. 8804 to review the Company's current rates. BGE filed a Response to OPC's Petition on September 28, 1998.[35] In its Response, the Company argued that the Commission should permit the resolution of these rate case issues in

[33] Section 7-513(d)(2).
[34] Case No. 8804. Petition of People's Counsel For A Reduction In Rates And Charges of The Baltimore Gas and Electric Company.
[35] Baltimore Gas and Electric Company's Response to The Office of People's Counsel's Petition For A Reduction In Rates and Charges.

the context of the impending restructuring proceeding. Accordingly, the Company requested that the Commission either stay OPC's Petition or consolidate it with BGE's electric restructuring plan proceeding.

On October 20, 1998, the Commission held a Prehearing Conference in Case No. 8804. After considering the positions of the parties, the Commission consolidated Case No. 8804 with Case No. 8794.[36] On November 5, 1998, the Commission adopted a procedural schedule for the consolidated proceeding. The parties entered into settlement discussions and continued those discussions while meeting the filing deadlines established in the procedural schedule.[37] A substantial amount of discovery occurred and, in accordance with the procedural schedule, the parties filed direct, reply, supplemental, and rebuttal testimony on all aspects of the Company's restructuring plan and on OPC's requested rate reduction. On April 29, 1999, BGE filed supplemental testimony and exhibits in support of its restructuring plan.

On May 6, 1999, the Mid-Atlantic Power Supply Association ("MAPSA")[38] filed a motion with the Commission requesting that the Commission maintain the procedural schedule in this consolidated proceeding. In its motion MAPSA stated that the April 29, 1999 "supplemental filing" by BGE failed to address all aspects of the Act required for the Commission to make an informed decision; that a proposed settlement being negotiated

[36] This was conditioned on the Company's agreement to make the rates subject to refund effective July 1, 1999.
[37] All entities that requested leave to intervene in these consolidated proceedings were granted party status. On July 30, 1999, the Maryland Department of the Environment ("MDE") filed a Motion to Intervene and for an Expedited Decision. In its motion, MDE stated that it would participate in the proceedings "consistent with the current procedural schedule." The Commission responded promptly on August 3, 1999, granting MDE's Motion to Intervene, provided that MDE enter the proceedings as they then stood. On August 17, 1999, the Mayor and City Council of Baltimore ("Baltimore City") also filed a Motion to Intervene and for an Expedited Decision. The Commission granted the Motion on August 19, 1999, provided Baltimore City take the proceedings as they then stood, consistent with Commission practice.
[38] MAPSA is a trade association founded in 1991 and is composed of independent suppliers of competitive power in Maryland, Delaware, Virginia, the District of Columbia, New Jersey, and Pennsylvania.

among several parties to the case had created controversy; that if implemented, the settlement would be destructive to the development of a competitive market; and, that the parties were in a position to litigate the case.

On May 7, 1999, the Public Service Commission Staff ("Staff") filed a motion for suspension of the procedural schedule. In its motion, Staff advised the Commission that a majority of the parties had reached an agreement in principle on the major issues in the consolidated proceeding and that memorialization of the agreement was in progress. By letter order dated May 7, 1999, the Commission granted Staff's motion and suspended the procedural schedule.

On May 11, 1999, the Commission held an emergency hearing to address the issues raised by MAPSA. The Commission considered the arguments raised by all the parties and affirmed that suspending the procedural schedule was in the public interest.[39] The Commission further directed that the parties file a settlement agreement by June 15, 1999.[40] A Stipulation and Settlement Agreement ("Settlement" or "Settlement Agreement") was filed with the Commission on June 29, 1999.

On July 9, 1999, the Commission established a procedural schedule for consideration of the Settlement, including dates for the filing of testimony and comments with regard to the Settlement and for evidentiary hearings. The Commission specifically directed the parties 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

[39] Order No. 75228 (May 11, 1999).

[40] By letter order, dated June 11, 1999, the Commission granted a request by BGE and OPC to extend the time to file a proposed settlement to June 25, 1999. On June 25, 1999, a further extension for filing a proposed settlement was granted to June 29, 1999.

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.

On July 23, 1999, BGE, OPC, DNR/MEA, and Staff submitted testimony in support of the Settlement. Letters in support of the Settlement were submitted by MIG, MRA, Enron, Johns Hopkins, and Calvert County. MAPSA submitted testimony opposing the Settlement and Statoil submitted comments in opposition to the Settlement. BGE, OPC, DNR/MEA, Staff and MAPSA filed reply testimony on August 3, 1999. Trigen Energy, Inc. ("Trigen") and Bethlehem Steel Corporation ("Bethlehem Steel") filed reply testimony only on August 3, 1999 opposing the Settlement.

The parties engaged in extensive discovery during the pre-settlement phase of these proceedings. MAPSA also engaged in discovery with regard to the Settling Parties' positions in support of the Settlement. The Commission held evidentiary hearings on the Settlement on August 11, 12 and 13, 1999. Evening public hearings were held on August 16, 17 and 19, 1999, in Annapolis, Baltimore and Bel Air, respectively.

E. Summary of Decision

The Commission has a long-standing practice of considering settlements proposed by parties representing divergent interests in its proceedings. The Act contains several provisions specifically related to settlements submitted to the Commission in electric restructuring cases and establishes a framework for reviewing settlements under certain circumstances. The Act states that a settlement that incorporates a different rate cap period or price protection mechanism from those enumerated in the Act must also be found to be "equally protective of ratepayers"[41] in order to be approved. Further, in identifying stranded costs and permitting their recovery, the Commission is authorized to accept "any other [transition] mechanism as part of a settlement" rather than those enumerated in the Act.[42]

The Commission recognizes that intricate compromises are often necessary for parties to present a settlement to the Commission. Historically, a settlement that is submitted by parties who normally have adverse interests is an indication that the overall agreement reached is a reasonable one. The Commission recognizes that, within this specific Settlement, delicate compromises have been reached, and this is reaffirmed by the provision in the Agreement requiring the Commission to adopt the Settlement as a whole without modification or condition.

The Commission has thoroughly analyzed the Settlement, the record in this proceeding and given careful consideration to the recently-adopted legislation. The Commission concludes that the Settlement is not inconsistent with its policies and the Act and comports with the outcome envisioned therein. It provides for a sensible transition to a competitive electric generation market with appropriate customer safeguards in the interim and represents a reasonable accommodation among parties with adverse interests. Further, it reduces residential electric rates and provides other price protections, both for residential and non-residential customers, that establish just and reasonable rates and service provisions.[43] Therefore, the Commission hereby adopts and approves the Settlement.

---

[41] Section 7-505(d)(3).
[42] Section 7-513(d)(2)(iii).
[43] *See* Public Utility Companies Article § 3-112 (relating to rate cases).

II. SUMMARY OF SETTLEMENT AGREEMENT

The Settlement Agreement, in this case, addresses stranded costs, price protection mechanisms, unbundled rates, and associated issues. It provides both a restructuring plan for deregulation of BGE's electric generation and a resolution of issues raised by OPC in its rate reduction petition. The Commission held evidentiary hearings in August 1999 to examine the Settlement and to hear the testimony and positions of the parties. The findings and conclusions of the Commission reflect consideration of the evidentiary record as well as careful consideration of the recently-enacted legislation.

The Settlement provides for choice for all customers (except certain contract customers) beginning July 1, 2000; resolves OPC's rate reduction petition by reducing residential electric rates an average of 6.5 percent beginning July 1, 2000 and freezing Schedule R/ES and Schedule RL rates for six years and four years, respectively; freezes delivery service rates in effect on June 30, 1999 for non-residential customers for four years through June 30, 2004; caps customer responsibility for BGE's nuclear decommissioning costs for Calvert Cliffs at 1993 dollar values, adjusted for inflation; provides that BGE shall immediately reflect $150 million in accelerated depreciation for its generation-related assets; provides for the removal of all generation-related assets, including Calvert Cliffs, from rate base, by transfer, sale or other disposal; provides for recovery of $528 million of stranded generation costs by BGE through a competitive transition charge ("CTC");[44] provides for Standard Offer Service for all customers at reasonable rates; provides for unbundling of rates into the separate components consisting of generation, transmission, CTC, universal service, distribution

[44] Notwithstanding BGE's recovery of stranded costs, customers will experience the rate reductions outlined above. Recovery of BGE's stranded cost does not diminish the scheduled rate reductions and is under the price caps.

wires, competitive billing, and other metering and billing to give customers a basis of comparison when shopping for electricity services; provides for lump sum payments by non-residential customers of their CTC obligations; limits adjustments that may be made to frozen rates; and, provides a code of conduct that governs the relationship between BGE as an electricity distribution utility and its affiliates.

A. Customer Choice Availability

The Settling Parties agree that good cause is shown pursuant to § 7-510(b) to implement 100 percent retail customer choice on July 1, 2000, except that certain individual contract customers will be subject to the terms of their contract. If BGE experiences system difficulties, it may delay implementation of residential choice until October 1, 2000, with prior Commission approval.

B. Rate Reductions and Price Freezes

The Settlement provides for an average 6.5 percent residential rate reduction (7 percent for Schedule R/ES customers and 3 percent for Schedule RL customers) and a six-year and four-year rate freeze for Schedule R/ES and Schedule RL customers, respectively.

Schedule R/ES rates will be reduced to achieve a revenue reduction of $50.2 million annually through June 30, 2006. Schedule RL rates will be reduced to achieve a revenue reduction of $3.6 million annually for four years through June 30, 2004.[45] These rate reductions and price cap periods for residential customers will begin July 1, 2000. The rates set forth in the Settlement meet the rate reduction requirements of the Act and resolve the rate issues raised by OPC in Case No. 8804.

[45] On July 1, 2004 the Schedule RL rate reduction decreases and will then remain frozen until June 30, 2006.

Delivery service rates for non-residential customers are frozen at the level in effect on June 30, 1999 and will remain frozen for a period of four years, from July 1, 2000 through June 30, 2004.

C. Deregulation of Generation

Full customer choice begins on July 1, 2000 according to the Settlement. BGE's generation function will be deregulated at that time. To effect deregulation, BGE shall transfer, sell, lease, assign, mortgage, or otherwise dispose of or encumber some or all of its generation-related assets, including Calvert Cliffs, to either affiliated or non-affiliated entities. If transferred or sold to an affiliate, BGE's affiliate shall retain or absorb 100 percent of revenues, gains, or losses on the transfer of generating assets. Any transfer(s) from BGE to an affiliate shall be at book value (i.e., original cost minus accumulated depreciation and accumulated deferred tax effects). Any generation-related asset(s) not sold, transferred or otherwise disposed of, shall nonetheless be completely removed from rate base and will not affect any determination of future rates to be charged to customers. Pursuant to § 7-508(c)(3), BGE shall file with the Commission its application to transfer generating assets by December 31, 1999.

D. Standard Offer Service

BGE will provide Standard Offer Service pursuant to § 7-510(c) of the Act. Standard Offer Service will include energy, capacity, line losses, transmission and related ancillary services. There will be two forms of SOS, standard offer Price Freeze Service (or "PFS") and standard offer Default Service ("DS"). PFS is electric supply provided by BGE to certain customers at set prices for a fixed time period. Unless they choose an alternative supplier, Schedule R (Residential), Schedule ES (Economy Service) and Schedule RL (Residential Large Service) customers will be PFS customers from July 1, 2000 through June 30, 2006. Schedule G (General Service), Schedule GS (General Service Small), Schedule GL (General Service Large), Schedule P (Primary Voltage Service) and Schedule NRP (National Railroad Passenger Corporation Service) customers will have the option of choosing PFS. While customers may leave PFS at any time, returning non-residential customers generally will be required to sign a minimum one-year contract. If a supplier defaults, a residential customer may return to PFS but may choose an alternative supplier at any time. Non-residential customers may return to PFS, with restrictions.

Default Service (or "DS") is electric supply provided by BGE at formula prices to non-residential customers who are not PFS customers and who: a) contract for electricity with a supplier and it is not delivered; b) cannot arrange for electricity from an electricity supplier; or c) do not choose an electricity supplier. DS will also be provided to non-residential customers who are denied service or referred to SOS by an electricity supplier pursuant to § 7-507(e)(6). The DS tariff will include the PJM[46] locational marginal price for energy for the BGE zone, the PJM market capacity price, transmission and ancillary services, and line losses (or their functional equivalents) plus applicable taxes, and a fixed retail adder of 7 mills per kilowatt-hour ("kWh"). DS rates may vary by customer class and shall reflect actual costs.

BGE will have discretion to arrange for generation service for its SOS customers prior to July 1, 2003. Thereafter, BGE will obtain generation supply for PFS and DS through a competitive bidding process. At no time will BGE accept an SOS bid that exceeds any of its PFS prices. An

[46] PJM Interconnection, L.L.C. provides independent regional transmission system operator services.

unregulated Constellation[47] subsidiary shall offer retail competitive supply service from July 1, 2000 through June 30, 2006. BGE shall not offer a competitive supply service.

E. Transition Costs

Under the Settlement, residential customers' share of stranded costs will be recovered under the level at which their rates are frozen ("the rate cap"). BGE shall first recognize accelerated depreciation or amortization totaling $150 million (on a pre-tax basis) on its generation assets over the 12-month period from July 1, 1999 through June 30, 2000. The after-tax stranded costs, then to be recovered from customers, will be $528 million on a present value basis as of January 1, 2000. Additionally, BGE will be permitted to recover $333 million in generation-related regulatory assets[48] (e.g., deferred taxes), and the Company will be permitted to recover from retail customers the nuclear decommissioning costs of Calvert Cliffs subject to the cap. The cost of both generation-related regulatory assets and nuclear decommissioning costs of Calvert Cliffs will be recovered as components of BGE's unbundled distribution rates, but ratepayers will have no liability above the $520 million of capped decommissioning costs.

The determination of BGE's stranded costs in this case is based upon the difference between the net book value and fair market value of the Company's generation-related assets. The Settling Parties agree that this mechanism, and the mechanism for developing the CTC, are appropriate and in accordance with §§ 7-513(b) and 7-513(d)(2)(ii). "Transition costs" include BGE's stranded investment for its generating assets (including capital improvements, facilities directly related to

[47] Constellation Energy Group, Inc. is the parent company of BGE.
[48] The recovery period ends 2017.

generation but recorded as transmission facilities, and the allocation of common plant), purchased power contracts, and "restructuring costs" (expenses related to implementing customer choice).[49]

The Settlement provides that recovery of $193.8 million of these costs is allocated to residential customers; $53.8 million to Schedules G (General Service) and GS (General Service Small); $112.6 million to Schedule GL (General Service Large); $100.7 million to Schedule P; $5.1 million to Schedule SL (Street Lighting); and $2.5 million to Schedule NRP (National Railroad Passenger Corporation Service). The remaining $59.5 million is allocated to Schedule PL (Private Area Lighting) and individual contract customers. During the transition period, the CTC for residential and Schedule NRP and SL customers will be applied without reconciliation (or true-up). Schedule P, NRP and certain GL customers and individual contract customers may elect to make a lump sum payment of stranded costs in lieu of the CTC.

Schedule NS (Negotiated Service) will lapse in accordance with the terms of that tariff on December 31, 1999. Schedule NS contracts that were under negotiation as of June 30, 1999, may be recognized by the Commission. Schedule NS customers shall have a one time option, exercisable on or before July 1, 2000, to terminate their contracts with BGE without penalty. Schedule NS customers' CTC obligations may be negotiated. If a Schedule NS customer terminates its contract with BGE and returns to its former schedule, the customer's CTC obligation shall remain as established by contract only.

F. Unbundling and Price Protections

[49] Metering stranded costs are not included in the calculation.

BGE will unbundle rates effective July 1, 2000 into generation, transmission, CTC, universal service, distribution wires, competitive billing, other billing and metering, environmental surcharge, franchise tax, and PSC assessment. Unbundled rates will also include charges for generation-related regulatory assets. Approximately $333 million in regulatory asset expenses will be recovered through 2017. The Settling Parties agreed that $520 million (in 1993 dollars) in nuclear decommissioning costs shall be recovered pursuant to Commission Order No. 72240.[50] This amount is adjusted for inflation after June 30, 2006. Any actual decommissioning costs above the inflation adjusted $520 million amount will be borne by BGE, and it likewise will retain any savings. The Conservation Surcharge shall be allocated by customer class, 90 percent to SOS and 10 percent to the wires portion of delivery service.

The Settlement provides for a number of price protections for customers, subject to certain adjustments explained below. Rates presently in effect for electric service will remain unchanged through June 30, 2000. Retail transmission rates will be adjusted for non-residential customers to reflect changes in Federal Energy Regulatory Commission ("FERC") regulated rates prior to July 1, 2004 with an equal and opposite adjustment in distribution rates. Based upon June 30, 1999 rates, residential (Schedule R and ES) customers will receive an annual revenue reduction of $50.2 million from July 1, 2000 through June 30, 2006. Residential Schedule RL (Residential Service Large) customers will receive an annual revenue reduction of $3.6 million from July 1, 2000 through June 30, 2004. From July 1, 2004 through June 30, 2006, Schedule RL rates will be reduced $1.8 million annually. The revenue reductions shall be allocated to PFS rates and distribution rates in proportion to their contribution to total rates. A CTC will apply to Schedule R, ES and RL rates

[50] *Re Baltimore Gas and Electric Company*, 86 MD PSC 376 (1995).

from July 1, 2000 through May 31, 2006, and BGE will provide PFS through June 30, 2006. The Settling Parties agree that these residential rate reductions satisfy § 7-505(d)(4)(i)(3). In addition, Schedule RL shall be closed to new customers after the Settlement is approved or December 1, 1999, whichever is later. BGE had also agreed to file for approval of an optional time-of-use rate schedule by November 1, 1999.[51]

Non-residential rates will be frozen from July 1, 2000 through June 30, 2004, subject to the transmission adjustment. These customers will be permitted a one-time election among a number of available service options. Rates will be based to achieve, to the extent reasonably practicable, bill and customer class revenue neutrality. CTCs for certain non-residential customers will be reconciled annually.

BGE will provide PFS to schedule G/GS customers through June 30, 2004. These customers will have the option of selecting either a six-year or five-year CTC which will apply beginning July 1, 2000. Schedule GL customers may choose a supplier other than BGE and elect to pay a CTC for either a four-year or five-year period. Alternatively, Schedule GL customers may choose Price Freeze Service (through June 30, 2004) with a five-year CTC. A Schedule GL customer with a maximum annual kWh demand of at least 500 kW may elect to make a lump sum payment in lieu of a CTC and may choose a supplier other than BGE. If such a customer desires to make a lump sum payment after July 1, 2000, BGE agrees to negotiate a payment in good faith. Customers who elect the lump sum CTC payment option will be subject to a true-up of stranded costs only if actual customer sales vary by 7 percent or more from the projected sales used in the original calculation.

[51] By letter order, dated October 21, 1999, the Commission deferred this filing.

Schedule P (Primary Voltage Service) customers may choose a supplier other than BGE. These customers may then choose a four-year or five-year CTC. A Schedule P customer may choose PFS with a five-year or six-year CTC. Schedule P customers may choose to make a lump sum payment in lieu of a CTC, before or after competitive choice is implemented, as described above. BGE shall unbundle Schedule NRP July 1, 2000 and negotiate individual CTC payment schedules. Stranded costs for Schedule NRP total $2.5 million.

Beginning July 1, 2000, BGE shall unbundle Schedule SL, and a CTC shall apply to Schedule SL customers for a six-year period. Schedule SL stranded costs amount to $5.1 million. Appendix A of the Settlement contains the negotiated rate schedules.

G. <u>Adjustments to Frozen Rates</u>

The PSC assessment, the kilowatt-hour ("kWh") franchise tax and the environmental surcharge shall appear as separately stated charges beginning July 1, 2000 and will be adjusted periodically to reflect actual costs, subject to Commission review. The CTC will be adjusted annually for some non-residential customers to reflect differences between actual and projected sales. Additional charges above the applicable frozen rates include the one-time deferred fuel balance true-up charge, a residential public benefit charge if the Commission determines at a later date that residential public benefit programs are appropriate and certain public purpose program costs.

The universal service charge will be recovered from BGE's residential customers under the rate cap. After costs for universal service have been surcharged, BGE will make a revenue neutral reduction in SOS and distribution rates. The Settling Parties agree that this satisfies § 7-512(b)(5).

In any year when there are unexpended universal service funds, these funds will be returned to the customer classes on a proportional basis pursuant to

§ 7-512.1(h)(5).

The Settlement provides that the Commission may approve and institute Demand Side Management ("DSM") programs, programs that promote the use of renewable resources, and programs that provide aggregation technical assistance. If such programs are recommended to the Commission and are approved at a later date, the Settlement provides that a public benefits surcharge (not to exceed 1.0 mill per kWh) may be imposed on residential customers to fund the public benefit programs.

The Settlement does not prohibit BGE from requesting cost based fees for new services or for customer-specific non-recurring costs or revisions to service extension provisions. BGE agrees not to file for an increase in non-residential electric distribution rates before December 1, 2003 or for residential rates before December 1, 2005. The other Settling Parties will not request rate revisions prior to July 1, 2004 and July 1, 2006, respectively. BGE may seek a qualified rate order to securitize transition costs. Seventy-five percent of any savings derived from securitization shall be used to reduce the CTC.

H. Rate Design

BGE has agreed not to file for rate design changes prior to July 1, 2001. It also agreed to file a cost of service study showing equalized rates of return at the time of its next electric rate case.

I. Code of Conduct[52]

[52] The Commission is examining code of conduct issues in Case No. 8820.

The Settling Parties have agreed to certain BGE-affiliated generating company ("GENCO") code of conduct principles. BGE agrees not to promote SOS, but it may provide unbiased information. Until June 30, 2006, the BGE-GENCO shall be a separate subsidiary and must sell all generation (except output sold to BGE for SOS) into the wholesale market. Until June 30, 2003, the BGE-GENCO shall not offer, to its affiliates for resale to "retail electric customers in the BGE distribution service territory," power or ancillary services at preferential prices or terms. BGE shall not market or promote the competitive supply service, nor imply that its affiliation allows the affiliate to provide service superior to competitors, nor promote the warranty of this service. These principles apply until the Commission adopts another code.

J. Competitive Metering

Competitive metering will begin January 1, 2002 for customers with hourly demand meters greater than 1500 kW and on April 1, 2002 for all other customers consistent with § 7-511. Until April 1, 2002, all non-residential customers with an annual maximum demand of 500 kW or more shall have the right to have advanced metering installed at their facility. BGE will file unbundled rates in time to permit the Commission to establish costs and the recovery methodology for competitive metering which the Settling Parties suggest should be completed no later than October 1, 2001.

III. COMMENTS OF THE PARTIES REGARDING THE SETTLEMENT

A. Proponents of the Settlement

1. Baltimore Gas and Electric (BGE)

David A. Brune, Eugene T. Meehan and Sheldon Switzer testified on behalf of the Company in support of the Settlement.[53] Mr. Brune, Vice President and Chief Financial

[53] BGE Exs. 1 – 5.

Officer for BGE, was the Company's principal policy witness. His testimony outlined and addressed how the Settlement satisfies the requirements of the Act; the Commission's authority to accelerate the availability of customer choice; certain aspects of the transfer of BGE's assets resolved by the Settlement; the transition cost amount and the recovery mechanism agreed upon by the Settling Parties; how the residential rate reduction was determined; and why approval of the Settlement is in the public interest.

In his testimony, Mr. Brune emphasized that the Act requires that transition to competition in the electric industry should be orderly, maintain electric system reliability, and ensure compliance with federal and state environmental regulations, be fair to customers, electric company investors electric companies and electricity suppliers, and provide economic benefits to all customer classes.[54] He stated that the Settlement furthers the goals of the Act and in so doing will provide for a restructured electric industry in Maryland.[55] In his opinion, the Settlement is in the public interest.

Mr. Brune stated that, under the Act, customer choice is phased-in for residential customers from July 1, 2000 through July 1, 2002**,** while under the Settlement, choice is available to all customers (except certain contract customers) beginning July 1, 2000. Mr. Brune stated that by accelerating the availability of customer choice the Settlement furthers the purpose of the Act.[56] Mr. Brune also addressed BGE's generation deregulation plan under the Settlement, noting that upon deregulation, by transfer or sale, or other disposal, the Company's generation assets will become available for supply into the competitive market. He stated that as part of the process of deregulating generation, the Settling Parties

[54] BGE Ex. 1 at 4; Section 7-505(a)(1).
[55] BGE Ex. 1 at 4.
[56] *Id*. at 5.

agreed to a figure of $528 million in stranded costs on an after-tax basis. According to Mr. Brune, the $528 million figure in the Settlement represents all transition and transition-related costs.[57]

With regard to resolving OPC's rate reduction petition, Mr. Brune stated that the parties agreed to a straight-forward rate reduction.[58] He also testified that the Company's rate of return therefore was not relevant to the Settlement.[59]

Mr. Brune emphasized that the Settlement stranded cost amount is a compromise figure. It is not, he stated, "a precise mathematical calculation."[60] However, in support of the Settlement stranded cost figure, Mr. Brune noted that before the Settlement (in the Company's July 1, 1998 testimony) BGE estimated its stranded investment at $1.048 billion (based on a comparison of book and market values) and its total stranded costs at $1.133 billion.[61] BGE's market value estimate of its non-nuclear assets was $1.426 billion, and the estimated market value of the Company's nuclear assets was $305 million.[62] He stated that, in making its pre-settlement estimates, the Company used a discounted cash flow ("DCF") methodology to calculate its stranded investment, comparing the book value of its generation assets to the revenue it expected to receive in a restructured electricity supply market.

In performing these analyses, Mr. Brune stated that "the Company as well as other parties estimated stranded investment in BGE's generating assets through the use of computer simulations

---

[57] *See* Tr. at 127.
[58] Tr. at 293.
[59] BGE's currently authorized rate of return is 9.4 percent. According to Mr. Brune, the Company's future rate of return will vary based upon a number of factors including load size. He stated that "the rate of return of the distribution company is going to be its revenues divided by its rate base: whether that . . . is going to be the current rate [or] (lower or higher) . . . it is going to be sales driven." *Id*.
[60] *See* BGE Ex. 2 at 8. The Settling Parties agreed that the figure, $528 million, represents an equitable allocation of stranded costs between shareholders and ratepayers in full consideration of the factors in § 7-513(e)(2).
[61] BGE Ex. 1 at 9.
[62] *Id*.

that incorporated and considered the revenue the Company would receive." Further, he remarked that:

> BGE, in its March 22, 1999 rebuttal testimony, offered testimony comparing the appraisal and auction processes. The Company presented testimony that the sole use of comparable sales data produced unreliable results and did not support a contention that the market value of BGE's assets exceeds book value . . . In addition, BGE witness Bourquin, in testimony filed April 29, 1999, updated the asset valuation to account for the impact of the Restructuring Act and the Electric and Gas Utility Tax Reform Act . . . and re-estimated BGE's transition cost[s] to be $897 million, [or] $253 million less than the $1.150 million filed July 1, 1998. . . .[63]

In sum, according to Mr. Brune, the Settlement is in the public interest, and the rate reduction and price cap mechanism provided in the Settlement are equally protective of ratepayers.

Mr. Meehan, Vice President of National Economic Research Associates, Inc., testified that in his opinion the Settlement is designed to ensure the creation of competitive electric markets. As the basis of his opinion, he commented that the Settlement:

- allows all customers the opportunity to choose a retail supplier of generation services (including, energy, ancillary services and transmission) as of July 1, 2000;
- establishes standard offer price freeze service which is priced at a reasonable level with respect to the market and lasts for varying durations;
- provides suppliers with open and nondiscriminatory access to BGE's distribution system in order to offer supply services to retail customers;
- through its code of conduct, governing BGE's relationship with affiliated unregulated retailers, prevents BGE from adversely using its position as the incumbent supplier;
- commits BGE to having an unregulated affiliate offer retail competitive supply services to the commercial market;
- prevents BGE from promoting SOS (mandating that BGE provide only unbiased information about SOS), and restricts BGE, as a utility, from offering competitive retail supply services;

[63] *Id*. at 11 – 12. *See also* Tr. at 137.

- provides larger customers with options regarding the duration of price protection, and the level and duration of the CTC, including a CTC buyout option;

- requires BGE to support initiation of a proceeding in 2003 to examine whether the responsibility for provisioning SOS to customers be determined by a bid process;

- provides a date certain for implementation of competitive billing and metering, per the legislation, and commits BGE to offer to install (at no cost) and maintain advanced metering;

- provides for complete deregulation of BGE's generation assets as of July 1, 2000 and the sale or transfer of BGE's generation assets to an unregulated affiliate;

- contains commitments that the BGE-GENCO must sell all generation output (excluding all output sold to BGE for SOS) in the wholesale market for the duration of the transition period and requires that the BGE-GENCO not offer power or ancillary services incident to the delivery of power to its affiliates for resale to retail electric customers in BGE's distribution service territory at prices or terms more favorable than those available to non-affiliated electric suppliers; and,

- requires BGE to procure supply for SOS through a competitive bidding process beginning in 2003.[64]

He defined a "competitive market" as a market in which "competitors are free to enter the market, and unreasonable barriers to entry do not exist or are not imposed."[65] He observed that in order for the electricity supply market to be competitive, competitors must be provided access to monopoly services needed to effectively enter the market. Competitors must be permitted a fair opportunity to gain market share and prosper. While incumbents must not be permitted to gain competitive advantage by discriminating in the supply of monopoly services neither should they use their position as a regulated service supplier to advantage their unregulated business activities.

[64] BGE Ex. 3 at 3 – 5.
[65] *Id*. at 6.

However, they should not be hindered from taking advantages of economies of scale and scope and competing fairly in the new marketplace.[66]

Mr. Meehan testified that the Settlement provides customers with choice and suppliers with non-discriminatory access to the distribution facilities needed to supply electricity to retail customers.[67] Additionally, he stated that BGE's retail marketing affiliates will have no preferential access to wholesale markets or retail customers and will not be able to use the sale of regulated services to gain an advantage in the unregulated supply or supply services market.[68] Large (non-residential) customers will also have a variety of CTC payment options that can be combined with alternate supply service offerings from competing retailers. Mr. Meehan opined that, under the Settlement, competing retailers will have a fair opportunity to provide electric supply services at the retail level and to gain market share and enhance revenues by providing value-added services.[69] He also emphasized that under the Settlement: prices will be deregulated; new capacity additions will be market based; incentives for efficient generation plant operation will be market based; the risk of plant operation will fall solely on plant owners; and, there will be no restrictions on entry into the wholesale market based on regulatory assessments of need or plant economics. These provisions, he stated, are designed to ensure the creation of a competitive electric supply services market in BGE's existing service territory.[70]

He stated, however, that the movement by customers from BGE to competitors "is not likely to be rapid."[71] In his view, creation of a competitive market is not measured by how many competitors develop in the short term or how quickly customers switch from incumbents to

[66] *Id*.
[67] *Id*. at 5.
[68] *Id*.
[69] *Id*.

competitors. Instead "the marketplace will mature and broaden over time as competitors begin to develop service offerings and attract customers."[72] Forcing customers to make a choice, mandating a customer's supplier, or overpricing SOS, he stated, are not reasonable ways to induce switching.[73]

Mr. Meehan stated that in his opinion, the Standard Offer Service rates and the shopping credits in the Settlement reflect proper levels for creating a competitive market. He stated that, the best SOS rate floats with the PJM market and passes through actual market prices with an adjustment for losses and incremental retailing costs.[74] Additionally, Mr. Meehan stated that the data indicates that the SOS rates proposed in the Settlement are reasonably aligned with the market.[75]

With regard to the residential shopping credit, he observed that by comparison, the Settlement shopping credit in this case is favorable, and that customers in other states have switched even though the shopping credit in some states has been as low as three cents across all classes.[76] Additionally, he stated that the market itself is not frozen and that shopping credits will increase over the transition period. The residential customer shopping credit escalates from 4.22 cents to 5.22 cents over the transition period, as the CTC charges decline.

Mr. Switzer, Director of BGE's Electric Pricing and Tariffs Unit, testified with regard to Settlement rate design and unbundling. He described the Company's goal in unbundling prices as one "to ensure fair and accurate separation of the relevant costs into the four major components of electric service."[77] He also stated that the goals of unbundling are to ensure

---

[70] *Id*.
[71] *Id*. at 6.
[72] *Id*. at 7.
[73] *Id*. at 6.
[74] Under the Settlement the ranges of SOS rates for residential customers reflect the declining CTC from years 2000–2006. The ranges of SOS rates for non-residential customers reflect the various CTC payment and price protection options offered to those customers. BGE Ex. 3 at 10.
[75] *Id*. at 10.
[76] *See* Tr. at 177.
[77] *Id*.

that the regulated business bears its fair allocation of costs, earns a reasonable rate of return and does not subsidize the competitive business.[78] Under the Settlement, electric prices are presented on an unbundled basis and in a revenue neutral manner across rate schedules. Rates are unbundled into individual components including generation, transmission, CTC, universal service, distribution wires, competitive billing, other metering and billing, environmental surcharge, franchise tax, and PSC assessment.[79]

Mr. Switzer filed written testimony in response to MAPSA witness Terry L. Murray's recommendation that the full residential rate reduction be allocated to the distribution or wires charge rather than apportioned to generation and to distribution as it is under the Settlement. In his supplemental reply testimony, Mr. Switzer remarked that MAPSA is opposed to the Settlement's residential rate reduction allocation because it has the effect of lowering the shopping credit during the transition period.[80] In response, he stated that "the allocation of the residential rate reduction, per the Settlement, is balanced between generation and distribution, is reasonable and is cost-based."[81] He stated that Ms. Murray's proposal, if adopted by the Commission, would ensure that the Company's shareholders would not achieve a reasonable return on assets used in providing distribution and billing and metering services. Further, Mr. Switzer testified that allocating the full residential rate reduction to the distribution component would represent a more than 20 percent reduction in the wires rate. Such a reduction, he asserted, would deprive shareholders of a reasonable return on their investment in providing regulated services and would place at risk the

---

[78] *Id*. at 7.
[79] BGE Ex. 6 at 21.
[80] BGE Ex. 5 at 6.
[81] *Id*. at 8.

regulated utility's ability to provide reliable and safe distribution service.[82] He noted also that, the generation/distribution allocation ratio in the Settlement is similar to the ratio in the Delmarva settlement, which MAPSA supported.[83]

He criticized Ms. Murray's proposal as one which would simply afford competitive suppliers the opportunity to earn higher profits. He remarked that the purpose of the shopping credit is not to create an artificially high price merely for the purpose of providing a greater incentive for customers to switch. The purpose, he stated, is to ease the transition to a competitive market while BGE is still required to provide Standard Offer Service from the beginning of customer choice through the transition period as a competitive market develops over time.[84]

2. **Office of People's Counsel (OPC)**

Jonathan F. Wallach, Vice President of Resource Light, Inc., submitted testimony on behalf of OPC.[85] Mr. Wallach concluded that the Settlement is in the public interest, advances the purposes enumerated in § 7-504 of the Act, and is reasonably designed to ensure the creation of competitive electricity supply and electricity supply services markets. He commented, however, that the goal of creating a competitive electricity supply market should not be elevated over the other goals set forth in the Act.[86] In Mr. Wallach's opinion, the Settlement advances the purposes of § 7-504(1) by providing more benefits to customers than required in the Act. He noted that "[w]hat is required in the statute is that residential customers [be] phased in[to retail choice] over 3 years

[82] *Id*. at 9.
[83] Tr. at 230.
[84] *Id*. at 6; Tr. at 212 – 213.
[85] OPC Exs. 2 – 4; Tr. at 649-709.
[86] OPC Ex. 2 at 4.

starting July 1, 2000 and commercial and industrial customers [enter] . . . on January 1, 2001."[87] In his view, the creation of competitive retail electricity supply services markets is enhanced by:

- advancing the date of customer choice;
- adopting a code of conduct to prevent unfair or anticompetitive practices;
- designing a residential CTC that declines over the transition period, so that the residential shopping credit against which marketers will have to compete rises each year; and,
- offering the option to commercial and industrial customers to make lump sum payment for their portion of stranded costs, giving those customers flexibility to enter the competitive market under the most favorable terms and conditions.[88]

Mr. Wallach said that although the residential shopping credit is reduced by the CTC, the portion of stranded costs allocated to the residential class, and collected through the CTC, is substantially less than what could have been allocated to residential customers under

§7-513(a)(2) of the Act.[89] He remarked that if the Company's current rate structure and cost allocation methodologies were applied under the Settlement, nearly 50 percent of the stranded costs would be allocated to residential customers.[90] Under the Settlement, 37 percent, a lesser amount, of the Company's stranded costs are allocated to residential customers.[91] Additionally, Mr. Wallach stated that the carrying charge is lower than the BGE's current cost of capital. The lower carrying charge has the effect of increasing the shopping credit.[92]

---

[87] Tr. at 658.
[88] *See* OPC Ex. 2 at 7.
[89] *Id*. at 8. Section 7-513(a)2) provides that stranded costs are to be allocated in a manner that, as nearly as reasonably possible, does not exceed the cost of providing service to those classes of customers, avoiding where possible interclass and intraclass cross subsidy.
[90] *Id*. at 8.
[91] *Id*. *See also* Tr. at 670.
[92] *Id*. at 9.

Mr. Wallach added that the Settlement both advances the choice date for commercial and industrial customers as well as eliminates the phase-in altogether for residential customers.[93] Under the Settlement all customers have the opportunity to begin retail choice on July 1, 2000, including the opportunity to shop for value-added services such as green power. Additionally, for residential customers, he noted that the 6.5 percent rate reduction is at the upper end of the range provided for under the Act. He calculated that, maintaining the 6.5 percent rate reduction for six years is equivalent to a 9percent rate reduction for the four-year period provided under the Act.[94] Mr. Wallach opined that the Commission is authorized to approve the alternative 6.5 percent rate reduction for six years as a price protection mechanism that is "equally protective or ratepayers."[95]

In Mr. Wallach's opinion, other benefits of the Settlement include the following: BGE will recover its share of the costs of the universal service program for the first three years under the rate cap; BGE will recognize accelerated depreciation or amortization totaling $150 million on generation assets over the twelve-month period from July 1, 1999 through June 30, 2000; and, the total customer liability for nuclear decommissioning costs is frozen at $520 million in 1993 dollars.[96] The witness also believed that the transfer of Calvert Cliffs from the regulated utility to an unaffiliated GENCO is beneficial to residential ratepayers, and reduces the risk to all ratepayers associated with the plant's future operation and economic viability.[97]

---

[93] *Id*.
[94] *Id*. at 10. Mr. Kahal estimated that the 6.5 percent rate reduction over 4 years would be equivalent to approximately 9.7 percent. Tr. at 775.
[95] OPC Ex. 2 at 11.
[96] *Id*. at 6.
[97] Tr. at 701. Someone, other than BGE's ratepayers will be responsible for future nuclear decommissioning costs. *See* Tr. at 683.

3. Department of Natural Resources/Maryland Energy Administration (DNR/MEA)

Matthew I. Kahal of Exeter Associates testified on behalf of DNR/MEA.[98] In addition to the goals noted by other proponents of the Settlement, Mr. Kahal stated that another goal, pertinent to the Commission's evaluation, is "whether the Settlement fairly balances the interests of customers and BGE's investors."[99]

In his testimony, Mr. Kahal noted that the main purpose of stranded cost recovery is to compensate the utility for its uneconomic generation costs.[100] Residential customers, who will pay stranded costs over the six-year transition period, will pay carrying costs on the unrecovered balance.[101] However, the CTC methodology agreed upon under the Settlement allows non-residential customers the option to pay their stranded costs obligations in a lump sum. According to Mr. Kahal, this approach allows customers to save the return (or carrying charge) associated with their stranded costs payment. The non-residential customers selecting the lump sum option have the maximum incentive to select an alternative supplier since the CTC is eliminated up front.[102]

Additionally, Mr. Kahal stated that the Settlement establishes the mills per kWh CTC payment with relative certainty.[103] In Mr. Kahal's opinion, "[c]ertainty relating to the CTC (and therefore the shopping credit) tends to facilitate competition because it enables the customer to evaluate the attractiveness [of] competitive offers."[104] In terms of balance, Mr. Kahal said that since the $528 million stranded cost amount, in conjunction with payment for regulatory assets and nuclear

---

[98] DNR/MEA Exs. 1 – 4; Tr. 723 – 793.
[99] DNR/MEA Ex. 2 at 2.
[100] *Id*. at 5.
[101] *Id*. at 4 – 5.
[102] *Id*.
[103] In addition to the mills per kWh identified under the Settlement, a true-up related to sales variation for some customer classes will occur.
[104] *Id*.

decommissioning costs**,** is acceptable to the Company, it can be presumed that it is fair to the Company's shareholders. Further, he observed that the $528 million is within the range of stranded costs which he identified in his direct testimony.[105]

With regard to the price protection mechanisms provided under the Settlement, Mr. Kahal observed that "[the price protection mechanisms provided under the Settlement] help ensure rate stability and protections for a period of several years during a time when competitive markets are developing and maturing."[106]

DNR/MEA also emphasized that an added benefit of the Settlement is the protection of customers against potentially substantial nuclear decommissioning costs.[107] DNR/MEA noted that BGE must live with the cost estimate of $520 million in 1993 dollars and cannot submit a new nuclear decommissioning cost study. "The expected re-licensing of 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. Ratepayers would receive the retirement deferral under standard regulation and will continue to retain the benefit under the Settlement."[108]

4. <u>Commission Staff (Staff)</u>

Calvin L. Timmerman, Director of the Commission's Rate Research and Economics Division, testified for Staff.[109] He is supportive of the Settlement as a whole and stated that the agreement among diverse parties is strong evidence that the Settlement satisfies the public interest.[110]

[105] *Id*. at 5 – 6. In his December 1999 direct testimony (using Mr. Bourquin's market price forecast), Mr. Kahal estimated Calvert Cliffs' stranded costs at $543 to $723 million. Using a higher sensitivity case market price forecast, he estimated that Calvert Cliffs' stranded cost would be $271 to $548 million. Based on these comparisons, Mr. Kahal concluded that the $528 million is consistent with the range of potential stranded costs for BGE. *Id*.
[106] *Id*. at 7. Mr. Kahal also noted that non-residential customers are given accelerated access to the competitive market.[106]
[107] DNR/MEA Br. at 17 – 18.
[108] *Id*. at 18.
[109] Staff Exs. 1 and 2; Tr. at 803 – 860.

Mr. Timmerman provided a summary of the stranded cost estimates of all of the parties, which ranged from $1.023 billion in stranded benefits to $897 million[111] in stranded costs. Staff estimated BGE's stranded costs at $242 million.[112] The Settlement result of $528 million, Mr. Timmerman observed, is within the range of the parties' filed positions.[113]

As additional support for the Settlement, Mr. Timmerman emphasized that paragraph 52 of the Settlement provides that if BGE securitizes all or part of the stranded cost amount, then 75 percent of the savings from securitization will be returned to customers through a reduction in the CTC.[114] In his opinion, the Settlement resolves price protection and rate reduction issues in a manner that is consistent with the public interest.

In his prefiled rebuttal testimony[115] and in his oral surrebuttal testimony, Mr. Timmerman addressed criticisms made by MAPSA witnesses Younger and Murray, and by Statoil. He suggested that Mr. Younger's estimate should be discredited because its sole purpose was to provide guidance for Ms. Murray's recommendation to eliminate the CTC entirely. Mr. Timmerman stated that if accepted, the result of Ms. Murray's recommendation would put BGE's ability to provide reliable service at risk.[116]

Mr. Timmerman also suggested that Ms. Murray's recommendation, that 100 percent of the residential rate reduction be allocated to the distribution component of BGE's unbundled rates, is based on a notion of "competition at any price" which, in his view, is inconsistent with the Act. He remarked that:

---

[110] Staff Ex. 1 at 23.
[111] BGE's initial stranded cost claim was $1.133 billion.
[112] *See* Staff Ex. 1, CLT-2.
[113] Staff Ex. 1 at 4.
[114] *Id*. at 4-5.
[115] Staff Ex. 2.
[116] *See* Staff Ex. 2 at 8.

> Section 7-505(d)(4)(i)(3) specifies that: the Commission shall determine the allocation of the rate reduction among the generation, transmission, and distribution residential rate components. Because the Act requires a balancing of interests as stated in §7-505(a)(1), the Act implies an allocation to the different unbundled rate components, not just to distribution. Allocating the entire rate reduction to distribution would essentially require a rate decrease of more than 15 percent for that portion of BGE's business that will remain regulated by this Commission.[117]

Moreover, he stated:

> It is unlikely there [would] be a rate finding in this proceeding that BGE's distribution business was overearning to the extent that a 15 percent rate reduction was justified and that such a reduction would adversely impact BGE's ability to provide safe and reliable service. Consequently, MAPSA's recommendation would most likely have a serious financial impact on BGE, and perhaps also on the safety and reliability of distribution service. This would clearly be inconsistent with §7-505(a)(1) and §7-505(c)(2)(ii) of the Act.[118]

He stated also that the Settlement achieves the balancing of residential customers' interest in reduced rates and BGE's interest that a reduction in rates from its former bundled service be applied with reasonable uniformity to the unbundled components of those formerly bundled services.[119]

Mr. Timmerman is more optimistic than some other witnesses regarding the prospects for competition in the electricity supply markets in Maryland. Although customers are not assigned by lottery to new suppliers, he observed that a number of price offers to the Pennsylvania residential consumer market indicates the possibility of residential competition in Maryland.[120] The annual reductions in the residential CTC make staying on Price Freeze Service less desirable every year as the shopping credit increases.

As a guide, Mr. Timmerman described shopping credits of Philadelphia Electric Company ("PECO"), Pennsylvania Power and Light ("PP&L") and General Public Utilities ("GPU") in

[117] *Id*. at 11.
[118] *Id*.
[119] *Id*. at 12.
[120] *See id*. at 16.

neighboring Pennsylvania. He noted that BGE's residential shopping credit of 4.224 cents per kWh is within the range of PECO's 5.43 cents per kWh and PP&L's 4 cents per kWh.[121] He also testified that three competitive marketers have offers out to residential customers in the GPU market, whose shopping credits range from 4.23 cents to 4.32 cents per kWh.[122]

Mr. Timmerman also testified that under the Settlement, the residential CTC is "front-loaded," it is highest in the first year and declines over the remaining transition period, thereby increasing the shopping credit.[123] As a result, he stated, the "price to compare" increases more than two percent each year, which has the effect of making marketers' prices more attractive to customers.[124]

5. Other Proponents of the Settlement

Several other parties, in addition to BGE, OPC, DNR/MEA, and Staff, supported the Settlement. While they did not sponsor witnesses to testify, Enron, MRA/BOMA, Johns Hopkins and Calvert County submitted briefs or letters in support of the Settlement. In its brief, Enron, a competitive electric supplier, stated that "from [its] perspective, the Settlement, on balance, represents a reasonable trade off among the various competing objectives of the [Act] and is a reasonable transition to competitive retail electric supply and electric supply services market."[125] MRA/BOMA in its brief noted that the options for non-residential customers with respect to payment of the CTC are valuable and will permit commercial and industrial customers "flexibility in deciding how, when and under what conditions they will make the transition to a competitive electric

[121] *Id*. at 19.
[122] *Id*.
[123] *Id*. at 20.
[124] *Id*.

supply market."[126] Likewise, Johns Hopkins also observed that the Settlement embodies options by which non-residential customers can choose to buy out of the CTC and pay their stranded cost obligation in a lump sum. Johns Hopkins, a large commercial customer, remarked that the Settlement fairly balances the issues of OPC's claim for a rate reduction with BGE's claim for stranded cost recovery.[127] In its view, this will allow those customers to avoid carrying charges and would give them the incentive to shop sooner.[128]

B. Opponents of the Settlement

MAPSA, Trigen and Statoil opposed the Settlement on broad policy grounds. Each argued that the Settlement does not foster the development of a competitive electricity supply market and does not further the goals of the Act. Mark D. Younger, Vice President of Slater Consulting, and Terry L. Murray, President of Murray & Cratty, LLC, testified for MAPSA.[129] James Abromitis, President of Trigen Energy Corporation, Inc., testified on behalf of Trigen. Statoil filed comments but did not sponsor a witness to testify during the proceedings.

1. Mid-Atlantic Power Supply Association (MAPSA)

MAPSA asserted that the settled stranded cost amount for BGE in this case is too high, the allocation of the rate reduction (largely to generation) is improper, and that the unbundling of rates under the Settlement improperly inflates BGE's distribution rates. Mark D. Younger filed testimony on behalf of MAPSA in opposition to the Settlement stranded cost amount and the valuation of

---

[125] Enron Br. at 1.
[126] MRA/BOMA Br. at 2.
[127] Johns Hopkins Br. at 2.
[128] *Id*.

BGE's generation assets. Terry L. Murray testified on behalf of MAPSA regarding the residential rate reduction allocation and unbundling of rates.

In his testimony, Mr. Younger asserted that the Settlement overstates BGE's stranded costs and undervalues the Company's generation assets.[130] He testified that a fair valuation of BGE's fossil generating assets would eliminate almost all of BGE's stranded costs.[131] To support his analysis, Mr. Younger described BGE's generation assets as a "highly desirable set of resources" and that bidders, generally, have been more willing to pay more per MW for hydro and coal resources.[132] As the principal basis of his valuation, Mr. Younger used the GPU auction for comparison as to what a sale of BGE's generation mix could bring. He commented that GPU assets sold for 25 percent more per kW of installed capacity than the valuation of BGE's fossil assets implicit in the Settlement. Upon evaluation of the generation assets done by other parties, Mr. Younger concluded that BGE's stranded costs should be less than $120 million. After further reducing that amount by another $150 million for accelerated depreciation of BGE's generation-related assets, Mr. Younger concluded that BGE's stranded cost is less than zero.[133]

Ms. Murray advocated an increase in the shopping credit as a means of fostering greater competition in electricity markets after deregulation. In order to achieve increased shopping credits, Ms. Murray recommended elimination of the CTC, allocation of the full

---

[129] MAPSA Exs. 4 – 9; Tr. at 340 – 643.
[130] MAPSA Ex. 4 at 3.
[131] *Id*. at 8.
[132] *Id*. at 5.
[133] MAPSA Ex. 5 at 8.

residential rate reduction to the distribution component of unbundled rates, and treating 50 percent of competitive billing and other billing and metering rate elements as avoided costs.[134]

Ms. Murray relied on her colleague, Mr. Younger, to support elimination of the CTC.[135] With regard to the residential rate cut, Ms. Murray commented that "a rate cut applied to the unbundled generation component . . . reduces the shopping credit and makes it less attractive for . . . customer[s] to consider alternative suppliers."[136]

In her testimony, Ms. Murray maintained that there is no sound evidentiary basis for the 6.5 percent annual rate reduction for residential customers. She argued that the Settling Parties do not cite to any revenue requirement analysis or other cost based indicator to support the reasonableness of the proposed rates.[137] In her view, a larger rate reduction is not better than a smaller one, all other things being equal, and the Commission should be concerned when there is an appearance of trading off the development of a competitive market against the certainty of rate reductions for the incumbent's services.[138] She views the Settlement as shielding the incumbent (BGE) from competition. In her words, "only those customers who choose to remain with the incumbent supplier will receive the benefit of [the] rate reduction; therefore, customers will be less likely to switch suppliers."[139]

Ms. Murray also advocated treating 50 percent of competitive billing and other billing and metering costs as avoided costs and moving them to the shopping credit for competitors performing the billing and other "customer-facing" functions of a retail electricity supplier.[140] She asserted that

[134] MAPSA Ex. 8 at 3.
[135] *Id*. at 2; Tr. at 381.
[136] MAPSA Ex. 8 at 3.
[137] MAPSA Ex. 9 at 14.
[138] *Id*.
[139] *Id*. at 17.
[140] MAPSA Ex. 8, at 3 and 19.

with competitive billing and other billing and metering costs as structured, BGE will continue to recover all of its historical expenses for such categories as customer records through unavoidable charges levied on each customer, even if a customer ceases to be a retail customer of BGE.

Further, Ms. Murray suggested that as customers migrate to competitors, BGE's customer service expenses will decrease, as will its administrative and general expenses. On the other hand, she said, competitors will incur the "customer-facing" costs and will need to recover them through the rates they charge. As a consequence, in her view, "potential competitors will be at a severe disadvantage if a shopping customer must pay for customer service functions twice, once to BGE through unavoidable rate elements and a second time to the alternative electric supplier.[141]

She also asserted that competing retail suppliers must create and maintain individual customer accounts regardless of whether that provider does its own billing. To address this perceived deficiency, she recommended that the Commission assign 75 percent of the increment of avoided customer costs to unbundled generation and the remaining 25 percent to competitive billing.[142] In sum, the three changes or modifications she recommended would increase the shopping credit for Schedule R from 4.224 cents/kWh to 5.741 cents/kWh.[143]

Notwithstanding her perception of the Settlement as deficient with respect to the shopping credits provided, Ms. Murray urged the Commission to adopt the Settlement's code of conduct provisions.[144] In her view "the code of conduct is a very valuable tool once competitive entry is possible to prevent other kinds of anti-competitive behavior." *Id*.[145]

[141] *Id*. at 12.
[142] MAPSA Ex. 9 at 21.
[143] *See* MAPSA Ex. 10.
[144] *See* Tr. at 544.
[145] Ms. Murray stated that: "I'm not imposing any modification to the code of conduct to make the settlement acceptable." *Id*. at 547.

2. **Trigen Energy, Inc. (Trigen)**

Trigen, a competitive supplier, argued that the Settlement is lacking with regard to the potential development of a competitive electric market.[146] James Abromitis, President of Trigen Energy Corporation, testified for Trigen.[147]

In his prefiled written testimony, Mr. Abromitis stated that in order for competitive markets to develop, suppliers must have a reasonable economic opportunity to offer to supply electricity to customers at rates which are competitive with those of BGE. However, he suggested, competitors will not be able to do so if potential customers of competitors must pay "sizeable" transition charges and distribution rates set forth in the Settlement.[148] Further, he stated, that the Settlement rate structure, including the customer transition charge, will preclude competitors such as Trigen from being able to successfully compete for customers against BGE and its affiliates. *Id*.

In addition, Mr. Abromitis asserted that Trigen offers lower cost, more efficient and more environmentally sound electricity supply. However, he stated that customers will be prevented from choosing Trigen as an option if they must also bear the "excessive" price burden to support BGE. He recommended that this barrier to entry be reduced and restructured to encourage competition.[149]

---

[146] Trigen Br. at 2.
[147] Trigen Ex. 1; Tr. 794 – 803.
[148] Trigen Ex. 1 at 3.
[149] *Id*.

3. Other Opposing Parties

Statoil, a MAPSA member that chose to state its position separately, asserted that the Settlement is unlawful. It stated that the Settlement fails to allow for customer choice and for the creation of a competitive retail electricity market within the timeframe established by the statute.

Bethlehem Steel, a large industrial customer, and the City of Baltimore opposed the Settlement on selective grounds. Bethlehem Steel argued that the allocation of transition costs under the Settlement has been thrust upon special contract customers without their input.[150] Nicholas Phillips, Jr. of Brubaker & Associates, Inc. testified for Bethlehem Steel.[151]

In his prefiled testimony, Mr. Phillips stated that BGE has presented cost of service studies in this proceeding which show that the Company is overearning from Bethlehem Steel with respect to the system average rate of return. According to Mr. Phillips, these studies show that Bethlehem Steel is paying rates that are $4 million in excess of BGE's authorized rate of return as established in Case No. 8487, BGE's most recent base rate case.[152]

Under the Settlement, Schedule PL (Private Area Lighting) and individual contract customers (including Bethlehem Steel) are allocated $59.5 million of BGE's stranded costs. Since it is a contract customer, Bethlehem Steel, unlike other non-residential customers, will not be allowed to exercise choice beginning July 1, 2000. Instead, Bethlehem Steel must continue to obtain its power requirements from BGE. In his opinion, because he perceives BGE as overearning with respect to Bethlehem Steel, and because Bethlehem Steel is unable to exercise immediate choice, Mr. Phillips

[150] Bethlehem Steel Br. at 3.
[151] Bethlehem Steel Ex. 1; Tr. 644-648.
[152] Bethlehem Steel Ex. 1 at 8.

does not believe BGE should be allowed to impose or collect any stranded costs from Bethlehem Steel.[153]

The City of Baltimore also opposed the Settlement. However, the City did not file testimony or sponsor a witness to testify on its behalf. In a brief filed by the City, the City objected to the Settlement to the extent that it increased the "maintenance charges" under the Company's Street Lighting Tariff.[154] Additionally, the City opposed what it characterized as "the small, unrepresentative portion of the distribution costs allocated to competitive billing."[155] According to the City, the minute allocation of costs to competitive billing as compared to non-bypassable other billing and metering charges defeats the purpose of the Act, because it allows no practical opportunity for competitive billing and metering.[156] In sum, the City stated that: "[i]n spite of the many advantageous features [of the Settlement] for residential customers . . . large street lighting customers like the City, Anne Arundel County, and Baltimore County will suffer rate increases unlike other customer class[es]."[157] The City recommended that the Commission adopt the Settlement with the exception of the increased maintenance charges in the Street Lighting Tariff.

IV. COMMISSION ANALYSIS

The Commission appreciates the efforts of all parties in generating a fruitful debate of the important issues raised by these proceedings. In considering and approving a settlement, whether contested or otherwise, the Commission must determine that the settlement is in the public interest

[153] *Id*.
[154] Baltimore City Br. at 4.
[155] *Id*. at 5.
[156] *Id*. at 5 – 6.

and that it is supported by substantial evidence of record.[158] In addition, the Commission may also consider economic evidence, the desirability of avoiding costly and time consuming litigation, whether the settling parties represent interests that are normally adverse to another, and the reasonableness of the effects of the particular settlement upon particular customer classes.[159] Further, the Commission may also consider the likelihood that the results of the settlement reached by the parties would have approximated the outcome had the case been fully litigated.[160]

In this and other restructuring proceedings, the Commission must also ensure that particular statutory standards, outlined in the Act, are satisfied. Because this contested restructuring Settlement also involves ratemaking issues due to OPC's rate reduction petition, the Commission has also assessed whether the proponents of the Settlement have satisfied their burden of proof as required under § 3-112(b) of the Public Utility Companies Article.[161] The following is the Commission's analysis of the Settlement in relation to the provisions of the Act, the Public Utility Companies Article, and the Commission's restructuring policies.

A. <u>Statutory Requirements and Settlement Summary</u>

The Act requires the Commission to deliberate and act upon a number of issues which affect the implementation of retail electric competition in Maryland. This proceeding includes a focus upon three specific transition issues: quantification of stranded generation costs; price protection mechanisms; and unbundled rates. As a threshold matter, the Commission must determine the appropriate method to resolve these issues. This case could have been resolved through litigation of

---

[157] *Id*.
[158] *See Re Potomac Electric Power Company*, 80 MD PSC 61, 64 (1989).
[159] *Id*.
[160] *Re Potomac Edison Company*, 85 MD PSC 181, 182 (1994).

each and every detail pertaining to the transition issues in this proceeding. However, as previously stated, the Act envisions the Commission employing the use of its longstanding practice of considering settlements in lieu of litigation.

The Commission believes that, in restructuring proceedings, settlements can be particularly useful in helping assess whether the best interests of the public are met. This is particularly true in these cases because, ultimately, the Commission and the public require the cooperation of all parties to successfully ensure the transition to a competitive electric market.

Under the Public Utility Companies Article, the Commission has inherent authority to consider and accept settlements that it finds in the public interest. The Act provides that, as part of a settlement, the Commission may approve an "alternative price protection plan if it determines that the plan is equally protective of ratepayers."[162] While the Act enumerates various transition cost issues that must be resolved, it also authorizes the Commission to approve "any other mechanism as part of a settlement"[163] that the Commission determines is appropriate for the recovery of transition costs. As discussed in greater detail below, the Commission finds that the Settlement comports with the Act because it appropriately resolves stranded costs, provides price protections that meet the requirements of the Act or are "equally protective of ratepayers," establishes just and reasonable rates, establishes a sensible transition to a competitive generation marketplace, and is in the public interest.

In addition to the quantification of stranded costs and the resolution of price protection mechanisms, the Act imposes on the Commission the responsibility to consider certain other issues in

---

[161] Section 3-112(b) of the Public Utility Companies Article requires the proponents of a rate change to demonstrate the reasonableness of the proposed rates by clear and satisfactory evidence.
[162] Section 7-505(d)(3).
[163] Section 7-513(d)(2)(iii).

assessing each electric company's restructuring plan. Section 7-505(a)(1) requires the Commission to ensure that the transition to competition is orderly; maintains electric system reliability; complies with environmental regulations; is fair to customers, electric companies, their investors, and electric suppliers; and provides benefits to all customer classes. In initiating the restructuring process, the Commission provided a framework which, in conjunction with legislative enactments, is intended to ensure an orderly transition to competition. This proceeding is one part of that process.

Inasmuch as the Company, Staff, OPC, Enron, MRA/BOMA, and DNR/MEA (representing the majority of the active stakeholders in this case) are signatories to the Settlement, it is evident that those parties deem the Settlement fair to all concerned. On the other hand, MAPSA, also another major stakeholder representing competitive suppliers, Trigen, Statoil, Baltimore City, and Bethlehem Steel object. Their objections were fully considered by the Commission in reaching this decision.

The proponents of the Settlement testified at length about the benefits all customer classes receive under the Settlement. Summarizing, these include: immediate customer choice; a residential rate reduction averaging 6.5 percent; a six-year rate cap for residential customers and a four-year rate cap for non-residential customers; a cap on nuclear decommissioning costs; the transfer of Calvert Cliffs out of rate base to an affiliate; and a code of conduct applicable to BGE and its affiliates. The opponents, however, believe that the Settlement's stranded cost amount is excessive, the Settlement does not foster the development of a competitive market for electricity, and one opponent, Bethlehem Steel, disputed the allocation of stranded costs to it as excessive. These and other associated issues are addressed in turn below.

BGE is required by § 7-510(c) to provide Standard Offer Service through at least July 1, 2003,[164] thereby ensuring that customers will have generation service available in conjunction with monopoly delivery services during the transition period. In response to Commission questions during the hearing, Mr. Brune testified that the Company does not anticipate any problems with reliability on the distribution system during the transition period. He stated that:

> [T]he challenge for us is to keep the rate at that level, keep our costs down so that we can serve reliably. Since 1993 we have had these same rates in effect. During that time period we have been able to keep our costs in check so we have not had a problem with reliability in the distribution system. We anticipate that the same thing will be true . . . over the next six or seven years.[165]

According to Mr. Brune, however, BGE has reduced the number of employees in order to reduce costs. Specifically, Mr. Brune stated that:

> [F]rom 1993 to the present, [BGE] eliminated over 2,000 jobs, 2,000 people either voluntarily or involuntarily, most of them on a voluntary basis. [The Company] reduced [its] head count at the utility by 23 percent in that time period. What we are talking about here is the need to continue to do that if we are going to continue to keep these current rates in effect. And the current reductions that you are talking about in the distribution business of 250 to 350 which some of it will occur through attrition, some will occur by voluntary separation, is another 3 to 5 percent reduction over the 23 percent reduction we have already done in the last six years. So this is really just a continuation of our striving to cut costs so we can keep current rates in effect.[166]

Nothing in the Settlement alters BGE's responsibility to provide reliable electric service to all customers. The Commission is concerned that significant personnel reductions, particularly in the transmission and distribution segment of the Company's operations, may have a negative effect on the Company's ability to provide reliable service. Although the Settlement is silent with respect to

---

[164] BGE has agreed as part of the Settlement to provide SOS to residential customers through June 30, 2006. Through July 1, 2003, BGE shall have discretion in how it arranges for generation supply for its SOS customers. Beginning July 1, 2003, BGE shall obtain electric supply for SOS customers through a competitive bidding process open to all suppliers.
[165] Tr. at 287.
[166] *Id*. at 300-301.

the operation and maintenance of the existing transmission and distribution system, the Commission expects BGE to maintain the reliability of its delivery system. BGE shall maintain the reliability of its distribution system in accordance with § 7-506 of the Act and with various provisions of the Public Utility Companies Article.

Additionally, Mr. Brune testified that the transferee of any of the Company's generation assets would be subject to the same licensing requirements, regulations and environmental safeguards imposed on BGE.[167] He stated that "when we transfer these assets, all . . . certificates continue to apply to those assets. So the assets in the hands of our affiliate would be subject to the same environmental constraints that the assets were in the hands of BG&E."[168] The Commission therefore expects that existing environmental standards will continue to be met by any transferee of BGE's generation assets.

Inasmuch as the Company, OPC, Staff, MRA/BOMA (representing commercial customers), Enron (a competitive supplier), MIG (representing industrial customers), and others, including Johns Hopkins and Calvert County, are signatories to the Settlement, it is evident that the Settling Parties deem the Settlement fair to all concerned. Although MAPSA, Statoil, Trigen, Bethlehem Steel and the City of Baltimore opposed or objected to the Settlement, their opposition or objections were limited in scope. MAPSA's primary interest was in increasing the shopping credit in order to increase the potential for competitive suppliers to compete. Statoil and Trigen also were concerned essentially about the effect the Settlement would have on fostering a competitive marketplace and on concentration of market share. Bethlehem Steel was solely concerned about the

---

[167] *See* Tr. at 255-257.
[168] *Id*. at 256.

level of stranded costs allocated to it as a contract customer, and the City of Baltimore objected to the maintenance charges for street lighting.

Based upon the testimony of the proponents in these proceedings, the Commission is persuaded that the objections to the Settlement are not meritorious and are insufficient to overcome the numerous advantages of the Settlement and should be rejected. For the reasons discussed herein, the Commission finds that the Settlement comports with the requirements enumerated in the Act and the Public Utility Companies Article, is in the public interest and should be approved.

1. Residential Rate Reduction and Other Price Protections

Section 7-505(d)(4) of the Act requires the Commission to implement a four-year residential electric rate reduction of between 3 percent and 7.5 percent of base rates, as measured on June 30, 1999. The Commission can, however, approve as part of a settlement a different set of price protections if the Commission finds that such terms are "equally protective of ratepayers."[169] Under the Settlement, BGE’s total rates for all customers, inclusive of all surcharges and riders, are to be frozen from June 30, 1999 through June 30, 2000.[170] BGE and the Settling Parties agreed to reduce residential electric rates by an average of 6.5 percent. Under the Settlement, residential Schedule R/ES rates will be reduced to achieve a $50.2 million annual rate reduction for six years through June 30, 2006. Residential Schedule RL rates will be reduced to achieve a $3.6 million annual rate reduction for four years through June 30, 2004. On July 1, 2004, Schedule RL rates will be adjusted to achieve a $1.8 million annual rate reduction through June 30, 2006.

[169] Section 7-505(d)(5).
[170] BGE Ex. 6 at 15.

The proponents of the Settlement are diverse parties: residential customers, represented by OPC; commercial customers, represented by MRA/BOMA; industrial customers, represented by MIG; Enron, a competitive supplier; and the general public interest, represented by the Commission Staff. Individually, each of these diverse parties found the residential rate reductions and price protections afforded by the Settlement to be in the interests of their constituents and in the public interest.

MAPSA, on the other hand, argued that the price protection mechanism afforded customers under the Settlement is not in the public interest. According to Ms. Murray, the price protection mechanism "fails to provide economic benefits to residential customers beyond the short-term benefits of a rate reduction."[171] In her view, the Settlement rate reduction mechanism adversely affects the emergence of a competitive electricity supply market.[172] She stated that, "[a] rate cut applied to the unbundled generation component, for example, reduces the shopping credit and makes it less attractive for customers to consider alternative suppliers."[173] As noted earlier, Ms. Murray argued that all of the residential rate reduction should be applied to BGE's distribution function.[174] She acknowledged, however, that allocation of the entire rate reduction to the distribution component would reduce the Company's ability to earn a reasonable rate of return.[175] Since the class rate of return for residential customers has traditionally been below the system average rate of return, Ms. Murray also acknowledged that the effect of applying 100 percent of the rate reduction to the distribution component would depress the residential class rate of return even

[171] MAPSA Ex. 9 at 2.
[172] *Id*. at 8.
[173] *Id*.
[174] *Id*. at 9.
[175] *See* Tr. at 481.

further below the system average, posing the risk of interclass subsidization.[176] Her contentions regarding the need to apply the rate reduction in the manner she recommended were disputed by the Settling Parties, including OPC and Staff.

OPC stated that "[a]n allocation of the residential rate reduction to generation and distribution is consistent with OPC's filed position on BGE's current costs and rates."[177] In its petition to reduce BGE's rates, OPC argued that BGE's rates should be reduced "across all functions."[178] Therefore, OPC stated, "it is a reasonable resolution of the rate case petition for BGE and OPC to agree on a certain level of annual rate reduction to be applied to generation and distribution [sic] 'in proportion to their contribution to total rates.'"[179] Staff witness Timmerman stated that allocation of the entire residential rate reduction to BGE's distribution function would result in a residential rate decrease of 15 percent for that part of BGE's regulated business, substantially above any level of overearning argued by any party.[180] The Commission finds the arguments raised by OPC and Staff persuasive. Responsible ratemaking would indicate a proportionate sharing of the rate reduction between the generation and distribution components of the rates.

As parties to the Settlement, OPC, MRA/BOMA, and MIG negotiated a number of price protection mechanisms that provide economic benefits to the various customer classes they represent. The Settlement provides that total residential rates will be reduced 6.5 percent. Once reduced, residential rates will be capped at the reduced rates for six years. Rates for non-residential customers will be capped for four years. MRA/BOMA and Johns Hopkins (a large commercial

[176] *Id*.
[177] OPC Br. at 40; Tr. at 473.
[178] OPC Rep. Br. at 17.
[179] *Id*.

customer) both stated that acceleration of choice for commercial customers from January 1, 2001 to July 1, 2000 is a benefit to commercial customers. They also stated that the option to pay their CTC share in a lump sum payment, is a significant benefit, inasmuch as it allows customers who elect the lump sum option to avoid associated CTC carrying costs and also gives them flexibility in deciding when to choose to shop. The representatives of the residential and non-residential classes stated that the alternative price protection mechanisms, taken as a whole, are "equally protective of ratepayers." The Commission agrees with this conclusion.

In addition to the above benefits, all customers will have the opportunity to select SOS generation at capped rates during the transition period. This guarantees all customers protection from any adverse effect that may occur during the transition to a competitive generation market.

The Commission has reviewed the negotiated price protection mechanisms contained in the Settlement and finds them appropriate. The Commission finds that the alternative price protections provided under the Settlement are "equally protective of ratepayers" pursuant to § 7-505(d)(3). The Commission finds that the price protections provided under the Settlement will ensure an orderly transition to a competitive market pursuant to § 7-505(a)(1). The Commission also finds that the rate reduction and price protection provisions of the Settlement comport with the requirements of the Act.[181]

2. <u>Creation of Competitive Retail Markets and Customer Choice</u>

---

[180] Staff Br. at 15; Staff Ex. 2 at 9.
[181] *See* § 7-505(d)(1) and (4).

The Act promotes the creation of customer choice with regard to the provisioning of electricity services.[182] Under § 7-510(a)(1) of the Act, residential choice is to be phased in beginning July 1, 2000 through July 1, 2002. Industrial and Commercial customer choice is allowed to begin January 1, 2001. However, the Settlement provides that all customers, except certain contract customers, will be able to choose their generation supplier beginning on July 1, 2000.[183]

During the proceedings, a number of witnesses commented on the prospects, or lack thereof, of any significant residential customer shopping once the opportunity for retail choice becomes available. BGE witness Meehan observed that residential customers will move very slowly unless forced to choose a retailer or assigned a retailer or if the SOS rate is set extremely high.[184] During cross examination, he stated that:

> [T]here is a difference between the transition to competition and the development of competitors in competition. It may be semantic but we have a transition to the competitive environment immediately that takes a while for competitors to develop and pull customers away from the utility.[185]

Mr. Meehan also noted that there will be proceedings for placing SOS out for competitive bidding and that it is inappropriate to speculate what effect the outcome of those proceedings will have on residential shopping.

The goal of electric deregulation, in part, is to make the electric supply market competitive and to allow prices and available capacity to be determined by market forces. In his testimony, Mr. Meehan stated that wholesale competition drives generation owners to operate existing plants efficiently and provides strong incentives for cost reductions. He further testified that deregulating

---

182 Section 7-504(1).
183 BGE Ex. 6 at 9.
184 BGE Ex. 3 at 6.

wholesale markets also properly shifts the risk of constructing, operating and financing new power plants away from customers, who have traditionally borne a substantial portion of market risk, to the generation owners.[186] The role of retail competition, he stated, is to efficiently pull through to customers the benefits achieved from deregulating the wholesale market.[187] He observed that the way for competitive suppliers to compete is to add to economic efficiency and to add some value over and above the value that the customer gets from the Standard Offer Service.[188]

MAPSA argued that the Settlement-derived CTC and the allocation of the majority of the residential rate cut to the generation component are detriments to the development of a competitive marketplace.[189] As discussed above, MAPSA vigorously opposed the amounts presented in the Settlement as BGE's stranded costs, asserting that the Company's generation assets were substantially undervalued.[190] As a result, according to MAPSA, the price to compare "shopping credit" is below the level needed for other suppliers to compete with BGE.[191] Ms. Murray recommended that the CTC be eliminated or reduced; that 100 percent of the residential rate reduction be allocated to the distribution rate; and, that customer costs be reallocated to ensure that BGE does not over-recover when a customer chooses another supplier. She recommended that the shopping credit or price to compare, established by the Settlement, be increased from 3.828 cents

---

[185] Tr. at 221.
[186] *Id*. at 7.
[187] *Id*. at 8.
[188] *See* Tr. at 173. He stated, "[y]ou can't recreate the benefits of resale generation overnight. It will take time for retailers to develop services and this settlement provides a reasonable means in a transition period for generation benefits to come through. It does not push customers out into the competitive retail market. It lets retailers pull them out by offering attractive offerings and I think that is economically efficient." *Id*. at 198.
[189] MAPSA Br. at 25.
[190] *See id*. Br. at 10 – 24.
[191] The "shopping credit" is the cost of generation that the regulated utility avoids when the customer purchases generation from an alternative supplier. Thus, the shopping credit is the price that the competitors will target (to beat) in order to attract customers.

per kWh for rate Schedule P to 4.480 cents per kWh, and from 4.224 cents to 5.741 cents for Schedule R in order to ensure a competitive playing field.[192]

Trigen argued that the Settlement treats some goals of the Act as essential, yet leaves the development of competition as an expendable option.[193] Like MAPSA, Trigen argued that the CTC resulting from the settled stranded cost amount is too high.[194] Trigen, however, did not sponsor a witness to testify as to what the appropriate level of stranded costs should be.

The Commission finds the testimony of the Settling Parties persuasive with regard to this matter. The Settling Parties support the immediate choice for customers that is offered under the Settlement. Under its terms, customers will be able to purchase not only electricity from alternate suppliers, but also transmission and ancillary services as well as billing services.[195]

In addition to the accelerated shopping date, non-residential customers who elect to make a lump sum payment of their allocated share of BGE's stranded costs will avoid associated carrying costs. Several witnesses, including Mr. Kahal, testified that this feature will give customers an even greater incentive to venture into the competitive marketplace. In its brief in support of the Settlement, Johns Hopkins, a large commercial customer, also emphasized the lump sum CTC payment option, combined with the advanced shopping date, as a significant benefit for non-residential customers.[196] For the reasons discussed herein, the Commission finds that "good cause" has been shown for advancement of non-residential customer choice in accordance with § 7-510(b), and that the acceleration is in the public interest. Additionally, the Commission finds that the

---

[192] MAPSA Ex. 10, Attachment TLM-R-2.
[193] Trigen Br. at 2.
[194] *Id*.
[195] *See* OPC Br. at 20.
[196] Johns Hopkins Br. at 2.

mechanisms provided for customer choice under the Settlement will foster the development of a competitive electricity supply market in Maryland.[197]

The Commission also finds that good cause has been shown to accelerate the implementation date of customer choice and phase-in percentages for residential customer choice pursuant to § 7-510(b). Notwithstanding the acceleration of choice, residential customers are protected against market turbulence by a substantial rate reduction and price freeze and by reasonable provisions for Standard Offer Service. Residential and non-residential customers who choose not to switch are assured of rate certainty for as few as four years and as many as six years during the transition period.

Additionally, beginning choice for all customers (except certain contract customers) simultaneously will reduce or eliminate customer confusion, and avoid the queing up approach provided under the Act. It also provides competitors a broader base from which to solicit customers, enhances their opportunities for volume efficiencies and affords them the opportunity to maximize the return on their marketing investments. Competitors are provided with a reasonable shopping credit (when compared to the shopping credits available in other regional markets) and will be able immediately to target the Company's unbundled rates to introduce alternative electricity supplies, including "green power" and other value-added offerings to customers. The level of unbundling and price protections provided for under the Settlement will both increase competitive opportunities and protect customers at the same time. Also, shopping credits will not be so high as to impair the Company's financial integrity during the transition period.

---

[197] Under the Settlement, BGE shall provide Standard Offer Service through June 30, 2006. Beginning July 1, 2003, the Company will procure the electric supply for SOS through a competitive bidding process. Pursuant to § 7-510(c)(3)(ii), "[i]f the Commission finds that the electricity supply market is not competitive or that no acceptable proposal has been

3. Stranded Costs

The Settling Parties agree that BGE's after-tax figure for stranded costs, to be recovered through the CTC, is $528 million. Of the total amount, $193.8 million is allocated to residential customers; $53.8 million to Schedule G (General Service) customers and GS (General Service Small) customers; $112.6 million to Schedule GL (General Service Large); $100.7 million to Schedule P (Primary Voltage Service) customers; $5.1 million to Schedule SL (Street Lighting) customers; $2.5 million to Schedule NRP (National Railroad Passenger Corporation Service) customers; and the remaining $59.5 million to Schedule PL (Private Lighting) and contract customers.[198] Company witness Brune testified that the Settlement amount represents "a compromise, agreed to by the Settling parties, as a fair value within the range of values supported by the various parties."[199]

The Settlement amount is a compromise figure. Indeed, several parties, including Staff, OPC, and DNR/MEA, filed testimony during the pre-settlement phase of the proceedings claiming that BGE's stranded costs were less than the amount agreed to in the Settlement. BGE had previously filed testimony in this case claiming that its stranded costs were significantly greater than the amount agreed to in the Settlement. Based on a comparison of book and market value, the Company claimed $1.133 billion in stranded investment and transition costs.[200] At that time, according to Mr. Brune, market value for the Company's non-nuclear assets was estimated to be $1.426 billion and the market value of the Company's nuclear assets was estimated to be $304

---

received to supply electricity to customers . . . [t]he Commission shall extend the [Company's] obligation to provide Standard Offer Service to residential and small commercial customers. . . ."

198 BGE Ex. 6 at 3 – 4.

199 BGE Ex. 1 at 8.

million.[201] Later in rebuttal, Mr. Brune adopted a higher market value amount of $2.305 billion for the Company's non-nuclear assets and a lower amount of $100 million for Calvert Cliffs.[202]

Mr. Brune testified that "[i]n consideration of such information, as well as any other information available . . . the amount of stranded cost recovery, $528 million, was agreed to by the Settling Parties."[203] He emphasized that "[i]n settling on this amount, the parties presumably considered the available information, considered the possible outcome of continued litigation, and considered other benefits to be gained through [s]ettlement."[204] These parties, he stated, "represent many diverse interests and the final amount was necessarily the result of extended confidential negotiations between the parties. As such, he said, "the Settlement itself provides appropriate evidence that the agreed upon value represents a fair level of transition cost recovery for the Company. . . ."[205]

MAPSA argued that BGE's stranded cost amount under the Settlement is exorbitant and not subject to mathematical calculation.[206] It argued that since the Settlement amount is not subject to precise quantification, the Commission is deprived of its ability to properly evaluate the transition cost under §§ 7-508(c)(2)[207] and 7-513(a)(1).[208] MAPSA witness Younger asserted that "a reasonable balancing of positions between the parties should have resulted in little or no transition costs."[209] According to his testimony, the BGE internal fossil

---

200 *Id*. at 9. Based on Tax Act adjustments, that figure was later adjusted downward to $897 million. *See* n. 111, *supra*.
201 *Id*. at 9-10.
202 *See infra* at 63. The total book value for BGE's generation assets, as proffered by the Company, is $3.309 billion.
203 *Id*. at 12.
204 *Id*.
205 *Id*.
206 *See* MAPSA Br. at 10.
207 Section 7-508(c)(2) provides that the Commission may review and approve the transfer for the sole purpose of determining: (1) that the appropriate accounting has been followed; (2) 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 (3) the appropriate transfer price and rate making treatment.

plant valuation combined with the Company's filed valuation for Safe Harbor and Calvert Cliffs result in no stranded cost for the Company, and the $150 million accelerated depreciation from the Settlement is more than sufficient to address the corrected stranded cost estimates of the parties. In Mr. Younger's opinion, the Commission should find that BGE's stranded costs are between zero and $252 million.[210]

In an effort to illustrate his point, Mr. Younger made adjustments to the Staff's and MEA's analyses. He proposed that two adjustments be made to Staff's estimate of stranded costs. First, Mr. Younger stated, Staff's preliminary estimate of stranded costs should be updated to account for the implications of the Electric and Gas Utility Tax Reform Act and Electric Customer Choice and Competition Act. According to Mr. Younger, accepting BGE's estimate of the impact of the Acts eliminates all stranded costs in Staff's initial estimate, and results in an $11 million stranded benefit.[211] He also argued that Staff's analysis should have included the net value of common and general plant and should have removed deferred income taxes from the estimate of the book value of BGE's generating assets.[212]

Mr. Younger also criticized Staff witness Timmerman for an alleged overstatement of MEA's estimate of stranded costs. According to Mr. Younger, Mr. Timmerman's analysis of BGE's stranded cost was based upon MEA's preliminary analysis of generation plant market value rather

---

[208] Section 7-513(a)(1) provides that: "… an electric company shall be provided a fair opportunity to recover all of its prudently incurred and verifiable net transition costs, subject to full mitigation.…"
[209] MAPSA Ex. 5 at 3.
[210] MAPSA Br. at 6 and 12.
[211] According to Mr. Younger, BGE estimated that the Acts reduced stranded costs by $253 million. MAPSA Ex. 5 at 7-8.
[212] According to Mr. Younger, the Settlement allows BGE to collect deferred income taxes as part of the generation regulatory assets and directly removes these from the delivery service rate. Consequently, he asserted that it is inconsistent with the Settlement terms to estimate the stranded costs based upon a book value that also includes the deferred income taxes.

than final results. Using MEA's latter assessment of BGE's estimated plant valuation, according to Mr. Younger, would yield BGE stranded costs between $118 million and negative $94 million.[213]

In response to MAPSA's request for discovery, BGE provided three proprietary studies prepared for the Company addressing the value of its generating assets; one NERA study, and two Metzler Associates studies dated November 2, 1998 and January 14, 1999. Based on these studies, Mr. Younger concluded that option value may have been missing from BGE's valuation. Additionally, Mr. Younger argued that the studies indicated that the market appeared to value plants substantially higher than BGE's analyses indicated based on price forecasts.[214]

Also, according to Mr. Younger, based upon a summary analysis of the BGE Generation Strategy Working Group, fossil plant valuation for Safe Harbor and valuation for Calvert Cliffs resulted in an estimated generation asset value in excess of the estimates presented by the Company.[215] He combined the total generation valuations with BGE's estimated book costs and $85 million of restructuring costs to find a BGE stranded cost figure between $94 million and $118 million. He concluded that BGE's stranded costs should be less than $120 million.[216] Accordingly, he suggested that once the $150 million accelerated depreciation of generation assets is recognized, stranded costs do not exist.[217]

In response, Company witness Brune stated that Mr. Younger's analysis ignored market prices for nuclear plants.[218] Mr. Brune testified that, on a comparative basis, recent

---

[213] *Id*. at 7.
[214] MAPSA Ex. 5 at 6.
[215] *Id*. at 7.
[216] *Id*. at 8.
[217] *Id*.
[218] *See* BGE Ex. 2 at 11. Mr. Younger estimated the market value of Calvert Cliffs to be $438 million that, when combined with the Company's Generation Strategy Working Group fossil plant valuation and a $214 million value for Safe Harbor produced a total generation valuation of $2.763 billion and $2.796 billion. MAPSA Ex. 5 at 7.

nuclear plant sales have achieved substantially less than the sales relied on by Mr. Younger. He noted that a July 1998 GPU sales agreement for its 786 MW Three Mile Island-Unit One nuclear plant was announced to be $100 million.[219] Additionally, he testified that two other sales, one 670 MW nuclear plant sale by Pilgrim achieved $80 million and another, a 950 MW sale of a Clinton Power nuclear facility, achieved $20 million in June 1999.[220] (According to Mr. Brune, Calvert Cliffs has a rated capacity of 1600 megawatts).[221] Based on these comparables, Mr. Brune adjusted Mr. Younger's analysis using an assumed market value for Calvert Cliffs of $100 million.[222] He stated that:

> When I look at comparable sales, if that is the basis we are going to use, if I were to sell Calvert Cliffs, I would still estimate that the market value would be zero or, in the best of circumstances, perhaps $100 million . . . based it upon looking at the sale of TMI more than anything else because TMI is a similar type unit. It is a pressurized water reactor. It sold for approximately $100 million. Calvert Cliffs is twice the size of TMI so perhaps Calvert Cliffs could get $200 million in that marketplace, but then I have to factor in the fact that Calvert Cliffs is going to spend $230,000,000 to replace the steam generators. So just eyeballing it, I figure Calvert Cliffs is worth 100 to 200 million in that kind of a market.[223]

In his rebuttal, Mr. Brune provided the following computations for recalculating Mr. Younger's stranded cost amount:[224]

Total Assumed Sale Value	$2,305 million
Total Generation Book Value	3,309 million
Accelerated Depreciation	(150) million
Restructuring Costs	85 million
Deficiency	$ 939 million

[219] *Id*.
[220] *Id* at 12.
[221] Tr. at 276.
[222] *Id*. The Commission notes that although Mr. Younger's testimony was filed under seal, Mr. Brune's testimony with regard to the sales values and estimates was not. Since any confidentiality privilege lies with the Company, such claims have been waived by Mr. Brune's use of them in his written supplemental reply testimony and during cross examination. *See* Tr. at 133-134.
[223] Tr. at 124.
[224] BGE Ex. 2 at 14.

After-Tax Stranded Costs	$ 610 million

Other parties, including Staff, OPC, and DNR/MEA endorsed the Settlement stranded cost amount. Staff noted that the magnitude of stranded cost/benefit valuations filed in the case ranged from $897 million in stranded costs filed by BGE to $1.023 in stranded benefits filed by OPC. According to Staff, the record evidence supported the negotiated $528 million in the Settlement as reasonable and within the range that is supported by the submissions of the parties in this case.

DNR/MEA also supported the Settlement and argued that the stranded cost amount is reasonable. In its brief, DNR/MEA stated that "[w]hile we agree with witnesses for the supporting parties that the $528 million is a negotiated figure, we believe that it is also a figure which is reasonably and fully supported by the record in this case."[225]

Based upon DNR/MEA witness Kahal's analysis, the Commission is persuaded that the reasonable range of BGE's stranded costs is a more narrow range, from $521 million to $663 million, as opposed to the broader range proffered by BGE and OPC.[226] The range estimated by Mr. Kahal was demonstrated utilizing several methods including corrections or adjustments to MAPSA witness Younger's estimates.

Mr. Kahal's stranded cost estimates, which the Commission accepts for purposes of providing the appropriate range of stranded cost for BGE, was based upon a determination that the Company's stranded costs associated with the Calvert Cliffs nuclear generation facility would be approximately $783 million. This is also supported by Mr. Kahal's oral testimony, in which he suggested that in his opinion the entire $528 million in Settlement stranded cost could reasonably be attributable to Calvert Cliffs. He stated that:

[225] *Id*.
[226] *Id*. at 14.

> Although, clearly the true value of Calvert Cliffs, from which its stranded cost would be determined, cannot be known until it is sold or otherwise disposed of on the market--for purposes of estimating stranded costs--the Calvert Cliffs stranded cost figure of $783 million appears reasonable based on Calvert Cliffs capacity rating and nuclear sales to date as compared to Calvert Cliffs recorded book value.[227]

Mr. Younger also accepted $783 million as the reasonably appropriate and estimated stranded cost amount for Calvert Cliffs in his calculations.[228] On that basis, Mr. Kahal recalculated, in a manner that the Commission believes was appropriate, Mr. Younger's overall BGE stranded cost amount. For the benefit of the record, Mr. Kahal recalculated Mr. Younger's stranded cost estimate in conformance with appropriate accounting and tax principles.

According to Mr. Kahal, Mr. Younger first erred by assuming an incorrect value for BGE's non-nuclear investment.[229] The difference between the values stated by Messrs. Younger and Kahal, according to Mr. Kahal, is accumulated deferred income taxes (or "ADITs").[230] Mr. Younger's second error, according to Mr. Kahal, was in ignoring income taxes associated with a "stranded benefit."[231] According to Mr. Kahal, Mr. Younger failed to comprehend the distinction between the after-tax stranded cost which the Company's DCF model correctly produces and a valuation from a comparable sales approach which is pre-tax.[232] He stated that Mr. Younger double

---

[227] Tr. at 773.

[228] Mr. Younger accepted (at least for purposes of discussion) BGE's claimed Calvert Cliffs stranded cost amount of $783 million and transition expenses of $85 million. As stated in MAPSA's brief: "In response to Mr. Brune's criticisms, Mr. Younger . . . adopted Mr. Brune's tax methodology and his imputed conservative market values for both Calvert Cliffs . . . and Safe Harbor." MAPSA Br. at 15-16. Implicit in Mr. Brune's testimony is a figure of $783 million in stranded costs for Calvert Cliffs.

[229] DNR/MEA Br. at 10.

[230] *Id*. "ADITs are the taxes that ratepayers have prepaid to the Company for future tax obligations associated mainly with accelerated depreciation." Tr. at 731-732.

[231] *Id*.

[232] *Id*. at 12.

counted the ADITs, once to pay the taxes and a second time to reduce book value.[233] Mr. Younger also ignored the unfunded income tax obligations on the sales proceeds in excess of book value.[234]

As Mr. Kahal explained, BGE used a financial simulation model which derived market value as the cumulative net present value of the after tax margins (or cash flow) which each generating asset is projected to provide. That model nets out income taxes from the asset's cash flow stream. Consequently, according to Mr. Kahal, it was necessary for BGE to subtract the balance of accumulated deferred income taxes from plant net book value. Based on that analysis, he stated the Company's stranded cost definition as:

Net Book Value - ADITs = After Tax Market Value[235]

In its brief, DNR/MEA summarized the use of Mr. Kahal's definition, as it applies to Mr. Younger's stranded cost calculation and other parties' as follows:[236]

Overall Stranded Costs
(million $)

	MAPSA Valuation	Other Parties' Valuation
Calvert Cliffs[237]	$783	$783
Restructuring Costs	85	85
Stranded Benefit (Non-Nuclear)	(347)	(205)
Total Stranded Cost	$521	$663

In adopting Mr. Kahal's analysis, the Commission notes that the Settlement amount, $528 million, is at the lower end of the $521 to $633 million range. As noted above, during the course of the evidentiary proceedings, although Mr. Younger and MAPSA had an ample opportunity to refute Mr. Kahal's analysis and reassessment of his calculations, they did not.

233 *Id*. at 11.
234 *Id*.
235 DNR/MEA Ex. 4 at 5.
236 *See* DNR/MEA Br. at 14.

The Commission finds this lack of rebuttal as very telling with respect to the accuracy and reasonableness of Mr. Kahal's assessment and provides the Commission with even greater confidence in accepting the stranded cost amount agreed to by the Settling Parties. Additionally, the Commission notes that Company witness Brune's adjustments to Mr. Younger's stranded cost estimate also puts Mr. Younger's estimate within the range demonstrated by Mr. Kahal. MAPSA's stranded cost quantification, as corrected by Mr. Kahal, is within that range demonstrated by Mr. Kahal and falls squarely in line with the negotiated figure of $528 million. In it brief, MAPSA attempted to refute Mr. Kahal's analysis by arguing that his tax analysis was based solely on a sale of Calvert Cliffs which, it stressed, was not the Company's intention.[238] The Commission, however, is not persuaded by MAPSA's arguments and the ultimate conclusions MAPSA reaches.

As noted by Mr. Brune and by DNR/MEA, any purchaser or transferee of Calvert Cliffs will have to pay the cost of replacing steam generators at approximately $230 million, which would further depress the sale or retention value of that facility.[239] This factor, which the Commission believes is a significant one, was not refuted or otherwise addressed by MAPSA.

Further, the Commission also notes that OPC endorsed the Settlement stranded cost amount. OPC commented that:

> [T]he fact that BGE presented a claim for over $1 billion in stranded costs recovery, supported by numerous witnesses and extensive materials provided in discovery, shows that it is reasonable for the parties to come to a settlement which provides BGE with some significant level of stranded cost recovery.[240]

---

[237] MAPSA accepted BGE's $783 million valuation for Calvert Cliffs.
[238] *See* MAPSA Br. at 17.
[239] *See* Tr. at 124 and 275; *see also* DNR/MEA Rep. Br. at 10.
[240] *Id*. at 35-36.

In supporting the Settlement, OPC also pointed out various benefits associated with the Settlement transition cost amount including the fact that the Company cannot petition the Commission for any future transition costs due to deregulation. Also, as observed by OPC, under the Settlement, the residential CTC mechanism does not permit a true-up in any manner. Therefore, residential customers cannot be charged any amount for stranded cost recovery that is in addition to the CTC contained in the Settlement.[241] Taken as a whole, the Commission finds that the residential CTC provisions of the Settlement establish an appropriate mechanism for stranded cost recovery.

OPC also noted that the Settlement requires BGE to recognize on its books accelerated depreciation totaling $150 million during the 12-month period from July 1, 1999 through June 30, 2000. This provision requires BGE to write down the book value of its generating assets. OPC observed that the Company had not proposed a voluntary write down as part of its transition plan. The write down brings the difference between the Company's book value of the assets and its valuation of the generating plants more in line with the amount of transition cost being paid under the Settlement.[242] In sum, according to OPC, "the diversity of the interests of the Settling Parties alone is persuasive that the level of transition cost in the [Settlement] is reasonable."[243]

It is clear from the testimony in this case that the parties' quantification of stranded costs was based upon valuations of BGE's generation assets using the methods enumerated in § 7-513(e)(1). In their written testimony and during the hearings, the parties' generation asset valuations incorporated, at a minimum, the book value of the Company's generation-related

[241] OPC Br. at 12.
[242] *Id*. at 12 – 13.
[243] OPC Rep. Br. at 6.

assets, comparable sales, appraisals, and the revenue the Company would receive under rate of return regulation. The Commission concludes that the record evidence that supports the negotiated amount was predicated upon the considerations and methodologies prescribed in the Act.

For the foregoing reasons, the Commission finds that the Settlement figure is within the range of reasonableness based upon the record in this proceeding. Finally, as previously stated, the Settlement requires accelerated depreciation of $150 million on the Company's generation assets over the 12-month period from July 1, 1999 through June 30, 2000. The Commission notes that accelerated depreciation generally is considered an acceptable method of mitigation. Therefore, the Commission also finds that the Settlement comports with
§ 7-513(a)(1).

4. Unbundled Rates

Unbundling of electric service rates into their component elements is a fundamental part of electric restructuring. In Case No. 8738, the Commission directed the parties to file unbundled rates showing four components: generation; transmission; distribution; and metering and billing.[244] This unbundling requirement is codified in § 7-505(b)(5) of the Act.

BGE first presented its proposed unbundled electricity pricing structure on a revenue neutral basis in July 1998. Those rates were adjusted by the Company's April 1999 filing to account for the effects of the Tax Act and the Act.[245] According to BGE witness Switzer, under the Settlement, the residential rate reduction is applied to the separate components of generation and distribution on a

[244] 88 MD 249, 279 (1997).
[245] BGE Ex. 6, Appendix A-Part 1 shows the unbundled rates for each rate schedule as proposed in the Settlement.

ratio of 65 percent and 35 percent, respectively.[246] He also observed that the allocation to generation under the Settlement is actually only slightly lower than in the Delmarva case.[247]

The other proponents of the Settlement supported the unbundled rates as filed. As an initial premise, Staff witness Timmerman stated that:

> [A]n orderly transition, fairness to customers and utility investors and economic benefits for all customers indicates that the equity considerations that Staff and the Commission has always employed in evaluating cost allocations and rate designs must continue to have prominence in this proceeding.[248]

MAPSA opposed the Settlement rate design and, as mentioned earlier, opposed the allocation of any portion of the residential rate reduction to the generation component. According to Ms. Murray, "[a]ny allocation of a mandatory rate cut to unbundled rate components that are subject to competition . . . has the potential to distort customer choice. . . ."[249] Ms. Murray also argued that under the Settlement, BGE would recover all of its historical expenses for customer records and collection, miscellaneous customer accounts, and customer assistance even if a customer ceases to be a retail customer of BGE.[250] In her view, some of those costs are avoided whenever a customer switches from BGE to a competitor.[251] She suggested that 50 percent of the total competitive billing and other billing and metering costs would be avoided and should be moved to the shopping credit for competitors performing the billing and other "customer-facing" functions of a retail electric supplier.

In response, Mr. Switzer stated that "with respect to the kinds of costs Ms. Murray was talking about, my expectation is that those costs would go up and [it is] very unlikely [that there are]

---

246 Tr. at 215.
247 *See id*. at 230. MAPSA was a signatory to the Delmarva Settlement.
248 Staff Ex. 1 at 8.
249 MAPASA Ex. 9 at 8.

going to be many billing and metering avoided costs, particularly the billing function."[252] He remarked that there may be some avoided costs to the extent that a competitor does billing for BG&E's distribution services. However, he said, the costs avoided would be minimal, such as postage, envelopes and processing, and those costs are recognized in the competitive billing rate.[253] Additionally, he testified that for most purposes, the costs Ms. Murray suggested would be avoided would remain with BGE because the Company needs to continue to have customer contact and render bills to customers as it relates to the ongoing distribution function of the utility. He also observed that approximately one-half of the calls to the Company are related to distribution rather than to generation.[254] Such calls, he stated, relate to service connections or distribution outage concerns and roughly the other 50 percent of those calls are related to billing issues, or meter reading issues, but few are related to generation.[255]

In response to Ms. Murray's criticisms and recommendations with regard to the Settlement shopping credit, Mr. Wallach noted that MAPSA did not rely on the margin analysis it advocated. As an example, he pointed out that MAPSA had signed onto the Delmarva Settlement in which the residential shopping credit floor is 4.92 cents per kWh, only 0.69 cents above that of the BGE Settlement. He also emphasized that it is not in the public interest to decrease the residential rate reduction in order to increase the shopping credit.[256] Further, he opined that were the rate reduction

---

[250] *Id*. at 12.
[251] MAPSA Ex. 9 at 18.
[252] Tr. at 314.
[253] *Id*. at 315.
[254] *Id*. at 316.
[255] *Id*.
[256] OPC Ex. 3 at 4-5.

to be decreased, residential customers who might be unable to shop would be denied a major economic benefit guaranteed to them under the Settlement.[257] Moreover, he said:

> I believe that the Settlement agreement . . . promote[s] the development of a competitive market through some transition period and focusing just on the level of the shopping credits, I believe that the level of the shopping credits, particularly the fact that they do rise over time, is a reasonable approach to promoting the development of a competitive market during that transition period.[258]

Mr. Kahal also pointed out that Ms. Murray's recommendations for total elimination of the CTC was based upon what Mr. Kahal demonstrated was Mr. Younger's erroneous generation asset valuation. Mr. Kahal contended that Ms. Murray's recommendations, therefore, are equally erroneous.[259] He observed also that to the extent that BGE had excess earnings, as alleged in OPC's petition for rate reduction, such an excess would arise from the decline in the cost of capital or sales growth, and thus a major portion of the excess would relate to the generation function.[260]

Additionally, Staff witness Timmerman noted that the gas customer choice programs (which will have been in place in Maryland for three or four years when electric choice starts) give marketers the opportunity to leverage an existing gas customer base into a combined gas-electric customer base. An equivalent opportunity is difficult to find anywhere else in the country, and is almost non-existent in Pennsylvania.[261] Finally, he observed that many electric suppliers will have already incurred their start-up costs in Pennsylvania and elsewhere by the time electric choice comes to Maryland next year. These factors, he suggested, make the prospects of competitive service

[257] *Id*. at 3.
[258] Tr. at 691.
[259] *See id*.
[260] DNR/MEA Ex. 4 at 8 – 9.
[261] Staff Ex. 2 at 21.

offerings for customers under this Settlement far more likely than MAPSA would have the Commission believe.[262]

The Commission finds that the Settlement rates are unbundled in an appropriate manner that reflects BGE's historic allocation of costs and also provides reasonable shopping credits for the benefit of consumers and competitive suppliers. The Commission agrees with Company witness Switzer and Staff witness Timmerman that acceptance of MAPSA's recommendations to allocate a larger share (or all) of the residential rate reduction to the distribution component would be inappropriate and could negatively affect the reliability of the distribution system.

The Commission also notes that MAPSA was a signatory to the settlement in the Delmarva case in which the shopping credit (which was fixed) was only marginally higher. While the shopping credit in this Settlement is lower than in the Delmarva Settlement, it will increase over the transition period, thus increasing the potential of customer switching from BGE to competitive suppliers. The Commission also notes that the shopping credit compares favorably to that found in other markets, including Pennsylvania, as testified to by Staff witness Timmerman.

Bethlehem Steel argued that none of BGE's stranded costs should be allocated to Bethlehem Steel because, currently and historically, Bethlehem Steel has paid above the system average rate of return in the rates charged to it by BGE. The Company responded that Bethlehem Steel's complaint is premature.

In its reply brief, BGE commented that as yet no CTC amounts have been allocated to contract customers such as Bethlehem Steel. As provided under the Settlement, the allocation of stranded costs to individual contract customers shall be based upon "individually negotiated

[262] *See id.* at 17.

agreements to be separately filed with the Commission."[263] Also, in his testimony, Mr. Switzer observed that over the years the Company and Bethlehem Steel have amicably negotiated terms mutually beneficial to both and in the interest of this State's economy.[264] Given the provisions of the Settlement with regard to individual contract customers, the Commission expects that negotiations of the type referenced by the Company's representative will continue as they have in the past. For these reasons, the Commission finds that Bethlehem Steel's complaint with regard to the allocation of stranded costs under the Settlement is premature.

The City of Baltimore argued that the unbundling provisions of the Settlement adversely affect the City by increasing the maintenance charges for street lighting.[265] The City claimed that the Settlement rates, as they affect street lighting, were not unbundled on a revenue neutral basis. The City acknowledged, however, that overall it could expect to save approximately $1.7 million annually because of reductions in the electricity component of the street lighting tariff (Schedule SL) under the Settlement.[266]

In response to the City's claims, the Company stated that the street lighting tariff was unbundled in a manner identical to the method used for all other tariffs.[267] BGE explained that its "tax-adjusted 1997 Fully Embedded Cost of Service Study" was used to set maintenance charges for the street lighting tariff that produced the same rate of return as produced under the current SL tariff.[268] The Company also stated that the Schedule SL rate of return has historically been lower than the system average.[269]

---

[263] BGE Rep. Br. at 20; BGE Ex. 6 at 10-11.
[264] *See* Tr. a 251-252.
[265] *See* City Br. at 3.
[266] *Id*. at 4.
[267] BGE Rep. Br. at 22.
[268] *Id*.
[269] *Id*.

Additionally, in its reply brief, the Company stated that it had met with the City and explained that if the City chose to purchase its electricity from an alternative supplier, the City's street lighting bill would likely be less than both current and unbundled BGE rates.[270] BGE's shopping credit for street lighting is 3.255 cents per kWh.[271] According to the Company, "this is an extremely high shopping credit for off-peak energy."[272] BGE stated that off-peak energy can be obtained for about 2 cents per kWh.[273] If that is true and if the City shops for alternative energy for off-peak street lighting, it can save one cent per kWh or more. This is a savings of approximately $700,000 annually in addition to the $1.7 million in other electricity savings the City will have under the Settlement.[274]

The Commission notes that BGE's tax-adjusted 1997 Embedded Cost of Service Study was used by the Company in unbundling rates for all rate classes.[275] Thus, the Commission finds that the Settlement rates for BGE's street lighting tariff (Schedule SL) were developed in a manner consistent with the development of all other rate schedules. The Commission finds that the maintenance charges provided under the Settlement for street lighting are reasonable. Further, the Commission finds that the Settlement provides a reasonable shopping credit for street lighting service that would allow the City to obtain electricity for off-peak street lighting at a substantial savings.

For the reasons detailed in the preceding paragraphs, the Commission finds the unbundled rates, as provided in the Settlement, to be reasonable and in the public interest. The Commission finds that the unbundled rates proposed in the Settlement provide for an orderly transition, do not

[270] *Id*. at 21.
[271] *See* BGE Ex. 6, Appendix A, Part 3; BGE Rep. Br. at 22.
[272] BGE Rep. Br. at 22.
[273] *Id*. at 23.
[274] *See id*.
[275] *See* Tr. at 223-224; 245, 251, 265, 293.

impair reliability of the distribution system, meet the reasonable standards of economic efficiency and are supported by a diverse group of customers.

5. Transfer of Generation Assets

Under the Settlement, after the implementation of full customer choice, BGE will transfer, sell, assign or otherwise dispose of all of its generation-related assets, including Calvert Cliffs.[276] When BGE transfers, sells or otherwise disposes of its generation-related assets, the Company alone will be entitled to any and all gains or be responsible for any and all losses on the disposition of the assets.[277] In accordance with § 7-508(c)(3) of the Act, by December 31, 1999, BGE shall file an application with the Commission for the transfer of its generation-related assets. The Settling Parties have agreed that they will support or take no position before the Commission regarding any application by BGE to transfer the generating assets at book value to an affiliate.[278]

Under § 7-508 of the Act, the Commission may review and approve the transfer for the purpose of determining: that the appropriate accounting has been followed; 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 the appropriate transfer price and ratemaking treatment.

Upon the implementation of full customer choice, the Company shall remove all generation-related assets, including Calvert Cliffs, from rate base. The Commission notes that in testimony, prior to the Settlement, BGE had intended to retain Calvert Cliffs as a regulated

[276] BGE Ex. 6 at 6 – 9.
[277] *Id*.
[278] *See* OPC Br. at 14.

asset in rate base. However, under the Settlement, Calvert Cliffs along with all other generation-related assets will be removed from rate base. The Commission finds that the removal of Calvert Cliffs from rate base, along with all other generation-related assets, is in the public interest and comports with the requirements of § 7-513(d)(2)(ii). Additionally, the Commission's authority under §§ 7-508 and 7-509 is expressly reserved.

B. Statement of Commission Findings

The record in this proceeding, including the Stipulation and Settlement Agreement, the testimony and exhibits of the parties, the provisions of the Electric Customer Choice and Competition Act of 1999, the Commission's policies in Order No. 73834, and provisions of the Public Utility Companies Article, provide the basis for the following findings by the Commission:

1. The Commission finds that the Settlement will allow all customers (except certain contract customers) to choose their electricity supplier beginning on July 1, 2000. In this regard, approval of the Settlement will establish customer choice as required under § 7-505(1) of the Act. The Act provides for a three year phase-in of customer choice beginning on July 1, 2000. In accordance with § 7-510(b) of the Act, the Commission finds that good cause has been shown by the testimony of the proponents of the Settlement for acceleration of choice for all Maryland residential and non-residential customers and that such acceleration is in the public interest.

2. The Commission finds that the Settlement also resolves the Office of People's Counsel's petition for a rate reduction and results in rates that are just and reasonable. Under the Settlement, BGE shall reduce residential electric rates an average of 6.5 percent and shall freeze the new rates for each schedule six years and four years, respectively. With regard to Schedule R/ES, BGE shall reduce rates to achieve a $50.2 million rate reduction annually for six years from July 1, 2000 through June 30, 2006. For Schedule RL, BGE shall reduce rates to achieve a $3.6 million rate reduction annually for four years from July 1, 2000 through June 30, 2004. On July 1, 2004, the rate reduction will decrease and rates will remain frozen through June 30, 2006.[279]

3. The Settlement provides for rate reductions and price protections for residential customers that are an alternative to the protections provided under the Act. The Commission finds that the 6.5 percent average residential electric rate reduction capped for six years is equivalent to more than a 9 percent rate reduction over four years (calculated on a present value basis) for residential customers. Thus, the rate reduction exceeds the price protections provided for residential customers under the Act.

4. The Commission finds that the alternative price protection mechanism provided under the Settlement is "equally protective of ratepayers," in accordance with § 7-505(d)(3). Further, the Commission finds the rate reduction for residential customers does not increase the rates charged to non-residential customers.

5. Under the Settlement, non-residential customer rates are frozen for a period of four years, from July 1, 2000 to June 30, 2004, at the level in effect on June 30, 1999. The Commission finds that the rate cap for non-residential customers provided under the Settlement is reasonable and fair to all customer classes, is in the public interest, and results in just and reasonable rates for non-residential customers.

[279] *See* n. 7, *supra*.

6. The Commission finds that under the Settlement, following the implementation of full customer choice for all customers (July 1, 2000): BGE shall transfer, sell or otherwise dispose of all of its generation-related assets, including Calvert Cliffs; that all generation-related assets of the Company shall be removed from rate base; and, that thereafter no generation-related assets shall be used in determining the rates charged to BGE's customers. The Commission finds that the removal of BGE's generation-related assets will deregulate the generation, supply and pricing of electricity provided to BGE's customers in accordance with §§ 7-504 and 7-509(a) of the Act. The Commission notes its continuing jurisdiction to review the transfer of generation assets and to review issues of market power as authorized by the Act.

7. The Commission finds that the range of $521 million to $663 million, estimated by DNR/MEA witness Kahal, is a reasonable range for determining BGE's stranded costs, and that the Settlement stranded cost amount is within the range of reasonableness. This finding is bolstered by the stranded cost estimates presented by the opponents of the Settlement, when properly adjusted in accordance with generally accepted accounting and tax principles.

8. The Commission also finds that in determining the Company's stranded cost, the parties determined the value of the Company's generation-related assets utilizing the methods provided under § 7-513(e).

9. Under the Settlement, stranded costs will be collected using a CTC. The Commission finds that the following Settlement stranded cost allocation is reasonable: $193.8 million (or 37 percent) of BGE's stranded costs should be allocated to residential customers; $3.8 million should be allocated to Schedules G and GS; $112.6 million should be allocated to Schedule GL; $100.7 million should be allocated to Schedule P; $5.1 million should be allocated to Schedule SL; $2.5 million should be allocated to Schedule NRP; and $59.5 million should be allocated to Schedule PL and individual contract customers. The residential CTC will decline annually and will not be subject to any true-up mechanism. The non-residential CTC, in some cases, will be subject to an annual true-up. However, non-residential customers will have the option to pay their CTC share in a lump sum payment and avoid associated carrying costs. The Commission finds that the amount of stranded cost allocated to each of the customer classes is reasonable.

10. The Commission finds that BGE should be permitted to collect $333 million in regulatory expenses, consisting primarily of accumulated deferred income taxes. These costs were approved by the Commission in previous rate cases and were determined to be reasonable at that time. Under the Settlement, these costs are to be recovered in distribution rates through 2017.

11. The Commission finds that the provisions in the Settlement which cap customer responsibility for Calvert Cliffs nuclear decommissioning costs at $520 million (in 1993 dollars) is reasonable. BGE shall refund to customers any balance in the nuclear decommissioning trust fund at the time of decommissioning that is in excess of that amount. The Commission affirms that $520 million (in 1993 dollars) is the reasonable amount that customers should pay for the Company's nuclear decommissioning costs. The Commission also finds that limitation of customer responsibility for BGE's nuclear decommissioning costs at that level and the treatment of those funds as prescribed under the Settlement are fair and beneficial both to ratepayers and to the Company. With the adoption of the Settlement, customer responsibility for Calvert Cliffs nuclear decommissioning costs are resolved.

12. The Commission finds that the rates under the Settlement are just and reasonable, and are reasonably and appropriately unbundled into the four components of generation, transmission, distribution, and metering and billing as prescribed in Order No. 73834. Costs are allocated to the rate schedules on a revenue neutral basis. The Commission finds that the allocation of 65 percent of the residential rate reduction to the generation component, and 35 percent to the distribution component, is in accordance with accepted rate design principles. The Commission is satisfied that this allocation is proper. The Commission is also satisfied that the allocation ratio allows for a reasonable shopping credit allowance for competitive suppliers seeking to encourage switching among residential customers, and should not impair the reliability of electric supply on the Company's distribution system. The Commission also finds the maintenance charges for Schedule SL and the street lighting shopping credit to be reasonable.

13. The Commission finds that the Settlement provides for an initial 4.224 cent residential shopping credit. The amount will increase over the transition period as the CTC declines. The Commission also finds that the shopping credits prescribed under the Settlement are comparable to those in the PJM region. The Commission is satisfied that the shopping credits provided under the Settlement are reasonable and will allow for sufficient incentive to competitive suppliers to foster a competitive supply market in Maryland.

14. The Settlement provides a code of conduct that will govern the relationship between BGE and any BGE generation (BGE-GENCO) affiliate after generation is deregulated. Until

June 30, 2006, the BGE-GENCO shall sell all generation (except that required to provide Standard Offer Service) into the wholesale market. The Commission finds that the code of conduct prescribed by the Settlement is reasonable and should govern the relationship between BGE and its affiliates until such time as the Commission may adopt other code of conduct provisions.

V. CONCLUSION

The Commission has thoroughly reviewed and analyzed the testimony and filings of the parties in this proceeding. In addition, the Commission has reviewed and appropriately considered the impact of the Electric Customer Choice and Competition Act of 1999 and the Electric and Gas Utility Tax Reform Act of 1999. The Commission finds that the Settlement comports with both Acts, including the provisions of §§ 7-504 and 7-505, and with Order No. 73834 and that it is in the public interest. The Commission further finds that the Settlement will foster a competitive electric market, appropriately resolves stranded costs issues, provides comprehensive price protections for customers, and establishes just and reasonable unbundled rates. Therefore, the Commission concludes that it is appropriate to approve the Settlement as filed by the Settling Parties in this case.

The Commission maintains the right to review the appropriateness of actual accounting procedures used upon the sale or transfer of generation assets pursuant to § 7-508(c)(2)(i) and all other authority prescribed under §§ 7-508 and 7-509 of the Act. Further, the Commission notes that nothing in the Settlement alters BGE's responsibility to provide safe and reliable service to customers. The Commission expects BGE to maintain the reliability of its distribution system. Likewise, the Commission expects that existing environmental standards will continue to be met by any transferee of the Company's generation assets.

ORDERED PARAGRAPHS

IT IS, THEREFORE, this 10th day of November, in the year Nineteen Hundred and Ninety-nine, by the Public Service Commission of Maryland,

ORDERED: (1) That the Stipulation and Settlement Agreement is hereby approved and adopted;

(2) Beginning on July 1, 2000, Baltimore Gas and Electric Company shall implement the rate reductions and other price protections prescribed in the Settlement; and

(3) The Baltimore Gas and Electric Company shall comply with all other provisions of the Stipulation and Settlement Agreement approved herein.

____

____

____

____

____

Commissioners