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Via Electronic Filing

December 21, 2009

Terry J. Romine, Executive Secretary
Maryland Public Service Commission
William Donald Schaefer Tower
6 St. Paul Street
Baltimore, Maryland 21202 – 6806

Re: Supplement 337 to P.S.C. G-9; Rider 7 – Gas Choice and Reliability Charges

Dear Ms. Romine:

Baltimore Gas and Electric Company (BGE) files herewith Supplement 337, Rider 7 – the Gas Choice and Reliability Charges (GCRC) to P.S.C. Md. G-9 with attached red-lined and clean versions of the revised tariff page. The calculation of the proposed GCRC rates is in compliance with the Stipulation and Settlement Agreement filed in Phase II of Case No. 8950, which was accepted by the Hearing Examiner in a Proposed Order issued on August 17, 2004.¹

The “System Growth Capacity Costs” and the “Gas Choice Programs Costs” rate totals \$(0.0010) per therm and will be applied to the throughput for all firm distribution customers (exclusive of customers equipped with Daily Metering Equipment). Customers equipped with Daily Metering Equipment electing Standby Service will pay only the “System Growth Capacity Costs” rate of \$(0.0021) per therm. The rate for third-party suppliers is \$0.0199 per therm.

Included in this filing is a budget of approximately \$715,000 for IT costs, as part of the estimated Gas Choice Program expenditures, associated with Rulemaking 35 which relates to Competitive Gas Supply. Primarily these are the costs the Company will incur in 2010 are to make the necessary system changes for programs common to gas and electric to facilitate the purchase of receivables of gas suppliers using BGE’s bill by April 2010. Also, associated with Rulemaking 35, BGE has to develop and implement uniform electronic transactions among the Maryland gas utilities and suppliers. The utilities and suppliers are still actively participating in working groups to identify and define these

¹ The Hearing Examiner’s Proposed Order became final on August 31, 2004, and was assigned Order No. 79472.

Terry J. Romine, Executive Secretary
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transactions and BGE will not be able to complete and test these programming changes until the working group finalizes the requirements. BGE anticipates completing programming associated with this effort in 2010.

BGE respectfully requests that this matter be considered no later than the Commission's January 20, 2010 Administrative Meeting so that a decision can be rendered by that date and the GCRC rates can become effective with bills rendered in February 2010 as provided in the Case No. 8950, Phase II Stipulation and Agreement.

Very truly yours,

A handwritten signature in blue ink, appearing to read "J. Manuel", written in a cursive style.

Jason Manuel

Attachments

cc: Cynthia Green-Warren, Assistant People's Counsel
Michael A. Dean, Staff Attorney
Merwin Sands, Director, Telecommunications, Gas and Water Division
Telemac N. Chryssikos, Esq. – WGES

BALTIMORE GAS AND ELECTRIC COMPANY
CALCULATION OF RIDER 7 - GAS CHOICE AND RELIABILITY CHARGES (GCRC)

EFFECTIVE 02/01/10

FILED 12/21/09

Rider 7

		<u>SYSTEM GROWTH CAPACITY COSTS</u>	<u>POLR CAPACITY COSTS</u>	<u>TOTAL</u>
<u>A. CAPACITY COST COMPONENT</u>				
<u>1. ESTIMATED UNMITIGATED COST OF FIRM PIPELINE CAPACITY</u>				
a. Estimated Total Available Capacity - Winter 2009/10	(Filing Attachment 2a)			953,769
b. Estimated Capacity to serve BGE Gas Commodity Service, Schedule C Standby and Critical Use customers - Winter 2009/10	(Filing Attachment 2a)			913,090
c. Estimated Capacity for System Growth and POLR	= a - b			40,679
d. Estimated Total Requirements as POLR four winters in future	2013/14	1,023,742	(Filing Attachment 2b)	
e. Estimated Total Requirements as POLR for current winter	2009/10	974,213	(Filing Attachment 2b)	
f. Estimated System Growth Capacity	= d - e	49,529		
g. Estimated POLR Capacity	= if f > c then g = 0, else g = c - f		0	0
g1. Estimated System Growth Capacity	= if g = 0 then g1 = c, else g1 = f	40,679		40,679
g2. Estimated Capacity for System Growth and POLR	= g + g1			40,679
 h. Weighted Average Cost of Capacity				
<u>Firm Transportation</u>	<u>Capacity</u>	<u>Cost</u>	<u>WACC</u>	
Columbia	374,369	\$ 3,315,685		
Dominion	188,994	1,423,479		
Hardy	23,017	317,183		
Transco	48,764	474,916		
	635,144	\$ 5,531,263	\$	8.71
i. Estimated Annualized Cost of Capacity	= g1 x h x 12 and g x h x 12	\$ 4,251,813	\$ -	\$ 4,251,813
j. Estimated Incremental Cost of Peaking Contracts	(Filing Attachment 1 - section D)		\$ 86,885	\$ 86,885
k. Total Estimated Unmitigated Cost of Capacity	= i + j	\$ 4,251,813	\$ 86,885	\$ 4,338,698
 <u>2. ESTIMATED MITIGATION OF RESERVED CAPACITY</u>				
a. Total Estimated Mitigation Revenues Applicable to Capacity Costs	(Filing Attachment 1 - section B)			\$ 1,512,306
b. Allocated Capacity from Part 1 (in Dth)	= 1.g1, 1.g and 1.g2	40,679	-	40,679
c. Percent of Mitigation Allocated to Category	= Category Total / Grand Total	100.00%	0.00%	
d. Allocated Mitigation to Category	= a x c	\$ 1,512,306	\$ -	\$ 1,512,306
e. Estimated Amount of Capacity to be Released as Recalable (in Dth)	(Filing Attachment 1 - section C)			35,679
f. Estimated Incremental Cost of Releasing Recalable Capacity	(Filing Attachment 1 - section C)			\$ 1,343,666
g. Adjustment of Capacity Costs	= f and neg(f)	\$ 1,343,666	\$ (1,343,666)	
h. Total Estimated Mitigation Revenue Credited to Capacity	= d + g	\$ 2,855,972	\$ (1,343,666)	\$ 1,512,306
 <u>3. ESTIMATED MITIGATED COST OF FIRM PIPELINE CAPACITY</u>				
a. Estimated Unmitigated Capacity Cost from Part 1	= 1k	\$ 4,251,813	\$ 86,885	\$ 4,338,698
b. Estimated Mitigation from Part 2	= 2h	\$ 2,855,972	\$ (1,343,666)	\$ 1,512,306
c. Estimated Mitigated Capacity Cost	= a - b	\$ 1,395,841	\$ 1,430,551	\$ 2,826,392
 <u>4. RECONCILIATION COMPONENT FOR CAPACITY COSTS</u>				
a. Actual Mitigated Capacity Cost for 2008-09	(Filing Attachment 5)	\$ (2,631,810)	\$ 1,667,723	\$ (964,087)
b. Actual Revenue Collected for 2008-09	(Filing Attachment 4)	\$ (1,636,760)	\$ (1,142,913)	\$ (2,779,672)
c. Prior Year Imbalance		\$ (1,784,834)	\$ (1,571,630)	\$ (3,356,464)
d. Excess or Shortage of Actual Costs vs. Estimated Costs	= a - b + c	\$ (2,779,885)	\$ 1,239,006	\$ (1,540,879)
e. Total Estimated Mitigated Cost plus Reconciliation	= 3c + 4d	\$ (1,384,044)	\$ 2,669,557	\$ 1,285,513
 <u>5. CALCULATION OF RATES FOR CAPACITY COST</u>				
a. Estimated Annual Throughput for Firm Supplier Gas Commodity Service Customers (excl CL AMR) - Dth			13,691,935	
b. Estimated Annual Throughput for all Firm Distribution Customers (excl. CL AMR non-standby) - Dth		66,868,433		
c. Rate for Capacity Costs (\$/Dth)	= 4e / 5b	\$ (0.021)		
d. Third Party Suppliers Rate for POLR (\$/Dth)	= 4e / 5a		0.195	

BALTIMORE GAS AND ELECTRIC COMPANY
CALCULATION OF RIDER 7 - GAS CHOICE AND RELIABILITY CHARGES (GCRC)
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B. GAS CHOICE PROGRAM COST COMPONENT

		<u>TOTAL</u>
1. Estimated Gas Choice Program Expenditures	<i>(Filing Attachment 3 Section C)</i>	\$ 832,000
2. Reconciliation Component for Gas Choice Program Costs		
a. Actual Expenditures for Gas Choice Programs (Dec08-Nov09)		\$ 493,099
b. Revenue Collected for Gas Choice Programs (Dec08-Nov09)	<i>(Filing Attachment 4)</i>	\$ 214,489
c. Prior Year Imbalance		\$ (367,014)
d. Excess or Shortage of Costs vs. Revenues	= a - b + c	\$ (88,404)
3. Total Estimated Expenditures plus Reconciliation	= 1+2d	\$ 743,596
4. Estimated Annual Throughput for all Firm Distribution Customers (excl all CL AMR) - Dth		66,721,477
5. Gas Choice Program Cost Rate Before Cap - \$/Dth	=3 / 4	\$ 0.011
6. Rate Cap - \$/Dth		\$ 0.050
7. Gas Choice Program Cost Rate After Cap - \$/Dth	= smaller of 5 or 6	\$ 0.011

C. DETERMINATION OF GCRC BILLING RATES

			<u>SYSTEM GROWTH CAPACITY COSTS</u>	<u>POLR CAPACITY COSTS</u>
1. Rate for System Growth Capacity Costs	= A5c	(\$ / Dth)	\$ (0.021)	
2. System Growth Capacity Costs adjusted for GRT and PSC Assessment	= "1" / (1-.021684)	(\$ / Dth)	\$ (0.021)	
3. System Growth Capacity Costs adjusted for GRT and PSC Assessment	= "2" / 10 rounded	(\$ / th)	\$ (0.0021)	
4. Rate for POLR Capacity Costs	= A5d	(\$ / Dth)		\$ 0.195
5. POLR Capacity Costs adjusted for GRT and PSC Assessment	= "4" / (1-.021684)	(\$ / Dth)		\$ 0.199
6. POLR Capacity Costs adjusted for GRT and PSC Assessment	= "5" / 10 rounded	(\$ / th)		\$ 0.0199
7. Rate for Gas Choice Programs Costs	= B7	(\$ / Dth)	\$ 0.011	
8. Gas Choice Programs Costs adjusted for GRT and PSC Assessment	= "7" / (1-.021684)	(\$ / Dth)	\$ 0.011	
9. Gas Choice Programs Costs adjusted for GRT and PSC Assessment	= "8" / 10 rounded	(\$ / th)	\$ 0.0011	
Billing Rate for all firm distribution customers (excl. CL AMR customers)	= "3" + "9"	(\$ / th)	\$ (0.0010)	
Billing Rate for CL AMR standby service customers	= "3"	(\$ / th)	\$ (0.0021)	
Billed Rate for Third Party Suppliers	= "6"	(\$ / th)	\$ 0.0199	

Filing Attachment 1

**BALTIMORE GAS AND ELECTRIC COMPANY
CALCULATION OF RIDER 7 - GAS CHOICE AND RELIABILITY CHARGES (GCRC)
CALCULATION OF MITIGATION REVENUE, INCREMENTAL COST AND PEAKING CONTRACT COST**

Mitigation Calculation Estimate

A. Reserve Capacity Breakdown

1. Estimated Capacity for System Growth and POLR		40,679	Attachment 2a (from Capacity Plan - Appendix A)
2. Non-recallable		<u>0</u>	
3. Recallable	=A.1-A.2	40,679	

B. Mitigation Revenue Estimate

Off-System Sales			Days	Daily margin	Winter Margin
1. Non-recallable	=A.2	0	151	\$0.4956	\$0.00
2. Recallable	=A.3	40,679	151	<u>\$0.2462</u>	<u>\$1,512,306.22</u>
3. Difference	=B.1 - B.2			\$0.2494	
				Estimated Mitigation	\$1,512,306.22

C. Incremental Cost of Releasing Recallable Capacity

1. Growth Capacity (Dth)		49,529	Attachment 2b (from Capacity Plan - Appendix B)
2. Growth Capacity Held (under contract) (Dth)		40,679	
3. Adjustment (Dth)		<u>5,000</u>	
4. Potential Non-Recallable (Dth)	=C.2 - C.3.	35,679	
5. Actual Non-Recallable (Dth)		<u>0</u>	
6. Difference & Incremental Cost	=C.4 - C.5.	35,679	Days 151 Daily margin \$0.2494
			\$1,343,665.51

D. Peaking Contract Cost - Winter 09-10 required

	20,444 Dth/day	\$86,885.46
	Attachment 2b (from Capacity Plan - Appendix B)	

BALTIMORE GAS AND ELECTRIC COMPANY
CALCULATION OF RIDER 7 - GAS CHOICE AND RELIABILITY CHARGES (GCRC)
DAILY RESERVE CAPACITY - GAS COMMODITY SERVICE, SCHEDULE C STANDBY, & CRITICAL USE LOAD

(FROM THE 2009 CAPACITY PLAN)

CITY GATE DELIVERABILITY			CAPACITY AVAILABLE FOR THE WINTER OF:	2010 (09-10)	2011 (10-11)	2012 (11-12)	2013 (12-13)	2014 (13-14)
EXPIRATION DATE								
TRANSCO MAINLINE	FT	3/03*		2,264	2,264	2,264	2,264	2,264
TRANSCO	FT-NT	10/12		21,500	21,500	21,500	21,500	21,500
COLUMBIA	FTS	10/14&19&24		112,218	112,218	112,218	112,218	112,218
	NTS	10/14&19&24		63,000	63,000	63,000	63,000	63,000
	FSS / SST	3/15&20&25		141,937	141,937	141,937	141,937	141,937
	FSS / SST	3/15&20&25		53,214	53,214	53,214	53,214	53,214
DOMINION	GSS / FTNN	3/13		39,929	39,929	39,929	39,929	39,929
	FTNN	3/13		60,071	60,071	60,071	60,071	60,071
MID-ATL EXP	FT	10/14		50,000	50,000	50,000	50,000	50,000
TCO RLSD FT CAPACITY	FT	10/16		4,000	4,000	4,000	4,000	4,000
HARDY STORAGE	HSS / HTS	3/23		23,017	23,017	23,017	23,017	23,017
TRANSCO POTOMAC	FT	10/27		25,000	25,000	25,000	25,000	25,000
DTI USA STORAGE	GSS / FT	3/24		38,994	38,994	38,994	38,994	38,994
TRANSCO MAC	FT	10/32		-	-	-	10,000	10,000
DTI STORAGE FACTORY	GSS / FT	10/29		-	-	-	-	-
TOTAL PIPELINE CAPACITY				635,144	635,144	635,144	645,144	645,144
PEAK SHAVING CAPACITY								
SPRING GARDENS LNG				311,500	311,500	311,500	311,500	311,500
NOTCH CLIFF PROPANE AIR				85,000	85,000	85,000	85,000	85,000
LESS OPERATIONAL CONTINGENCY				<u>77,875</u>	<u>77,875</u>	<u>77,875</u>	<u>77,875</u>	<u>77,875</u>
PEAK SHAVING CAPACITY AVAILABLE				318,625	318,625	318,625	318,625	318,625
LESS OSS / CAPACITY RELEASE				-	-	-	-	-
PLUS PEAKING CONTRACT				-	-	-	-	-
TOTAL AVAILABLE CAPACITY				953,769	953,769	953,769	963,769	963,769
TOTAL DESIGN DAY FIRM LOAD				973,295	989,829	1,003,500	1,013,894	1,022,761
LESS DRS CUSTOMER LOAD				120,667	120,669	120,669	120,670	120,670
PLUS CL AMR STANDBY				761	776	792	808	824
PLUS CRITICAL USE				157	157	157	157	157
FIRM DESIGN DAY LOAD FOR SALES CUSTS				853,546	870,093	883,780	894,189	903,072
PLUS PEAK SHAVING FOR DRS				26,747	26,748	26,748	26,748	26,748
PLUS RESERVE FOR PARKING & BALANCING				<u>32,796</u>	<u>32,796</u>	<u>32,797</u>	<u>32,797</u>	<u>32,797</u>
TOTAL CAPACITY REQUIREMENTS				913,090	929,637	943,325	953,734	962,617
DAILY RESERVE CAPACITY				40,679	24,132	10,444	10,035	1,152

* Primary term ended March 16, 2003. Subject to termination thereafter on 3 years prior notice to Transco.

BALTIMORE GAS AND ELECTRIC COMPANY
CALCULATION OF RIDER 7 - GAS CHOICE AND RELIABILITY CHARGES (GCRC)
DAILY RESERVE CAPACITY AS POLR FOR 100% OF FIRM LOAD
(FROM THE 2009 CAPACITY PLAN)

			CAPACITY AVAILABLE FOR THE WINTER OF:	2010 (09-10)	2011 (10-11)	2012 (11-12)	2013 (12-13)	2014 (13-14)
CITY GATE DELIVERABILITY			EXPIRATION DATE					
TRANSCO MAINLINE	FT	3/03*		2,264	2,264	2,264	2,264	2,264
TRANSCO	FT-NT	10/12		21,500	21,500	21,500	21,500	21,500
COLUMBIA	FTS	10/14&19&24		112,218	112,218	112,218	112,218	112,218
	NTS	10/14&19&24		63,000	63,000	63,000	63,000	63,000
	FSS / SST	3/15&20&25		141,937	141,937	141,937	141,937	141,937
	FSS / SST	3/15&19&25		53,214	53,214	53,214	53,214	53,214
DOMINION	GSS / FTNN	3/13		39,929	39,929	39,929	39,929	39,929
	FTNN	3/13		60,071	60,071	60,071	60,071	60,071
MID-ATL EXP	FT	10/14		50,000	50,000	50,000	50,000	50,000
TCO RLSD FT CAP	FT	10/16		4,000	4,000	4,000	4,000	4,000
HARDY STORAGE	HSS / HTS	3/23		23,017	23,017	23,017	23,017	23,017
TRANSCO POTOMAC	FT	10/27		25,000	25,000	25,000	25,000	25,000
DTI USA STORAGE	GSS / FT	3/24		38,994	38,994	38,994	38,994	38,994
TRANSCO MAC	FT	10/32		-	-	-	10,000	10,000
DTI STORAGE FACTORY	GSS / FT	10/29		-	-	-	-	-
BGE PIPELINE CAPACITY				635,144	635,144	635,144	645,144	645,144
SUPPLIER LONG TERM DELIVERABILITY				-	-	-	-	-
CITY GATE DELIVERABILITY				635,144	635,144	635,144	645,144	645,144
PEAK SHAVING CAPACITY								
SPRING GARDENS LNG				311,500	311,500	311,500	311,500	311,500
NOTCH CLIFF PROPANE AIR				85,000	85,000	85,000	85,000	85,000
LESS OPERATIONAL CONTINGENCY				77,875	77,875	77,875	77,875	77,875
PEAK SHAVING CAPACITY AVAILABLE				318,625	318,625	318,625	318,625	318,625
PLUS SUPPLIER SHORT TERM DELIVERABILITY				-	-	-	-	-
LESS OSS / CAPACITY RELEASE (non-recallable)				-	-	-	-	-
PLUS PEAKING CONTRACT				-	-	-	-	-
TOTAL AVAILABLE CAPACITY				953,769	953,769	953,769	963,769	963,769
TOTAL DESIGN DAY FIRM LOAD				973,295	989,829	1,003,500	1,013,894	1,022,761
LESS DRS CUSTOMER LOAD				-	-	-	-	-
PLUS CL AMR STANDBY				761	776	792	808	824
PLUS CRITICAL USE				157	157	157	157	157
FIRM DESIGN DAY LOAD				974,213	990,762	1,004,449	1,014,859	1,023,742
PLUS PEAK SHAVING FOR DRS				-	-	-	-	-
PLUS RESERVE FOR PARKING & BALANCING				-	-	-	-	-
TOTAL CAPACITY REQUIREMENTS				974,213	990,762	1,004,449	1,014,859	1,023,742
DAILY RESERVE CAPACITY				(20,444)	(36,993)	(50,680)	(51,090)	(59,973)

* Primary term ended March 16, 2003. Subject to termination thereafter on 3 years prior notice to Transco.

**BALTIMORE GAS AND ELECTRIC COMPANY
CALCULATION OF RIDER 7 - GAS CHOICE AND RELIABILITY CHARGES (GCRC)
ESTIMATED GAS CHOICE PROGRAM EXPENDITURES - Dec. 2009 - Nov. 2010**

SECTION A - Metering Costs

These are costs related to the maintenance of sample meters used to forecast daily consumption of DRS customers performed by Metering and IT personnel.

\$ 117,000

SECTION B - Gas Choice Related System Enhancements

\$ 715,000

SECTION C - Total Gas Choice Program Expenditures = (A+B)

\$ 832,000

Attachment 4

**BALTIMORE GAS AND ELECTRIC COMPANY
CALCULATION OF RIDER 7 - GAS CHOICE AND RELIABILITY CHARGES (GCRC)
GCRC REVENUE COLLECTED (Dec08-Nov09)**

	<u>System Growth Capacity Revenue Collected</u> (a)	<u>POLR Capacity Revenue Collected</u> (b)	<u>Subtotal</u> (c)=(a)+(b)	<u>Gas Choice Revenue Collected</u> (d)	<u>Total GCRC Revenue Collected</u> (e)=(c)+(d)
GCRC Revenue Collected (Dec08-Nov09) - See Note	(\$1,636,760)	(\$1,142,913)	(\$2,779,672)	\$214,489	(\$2,565,184)

Note: Net of GRT and PSC Assessment.

Attachment 5

**BALTIMORE GAS AND ELECTRIC COMPANY
CALCULATION OF RIDER 7 - GAS CHOICE AND RELIABILITY CHARGES (GCRC)
TRUE-UP OF THE ESTIMATED MITIGATION CAPACITY COST FROM PREVIOUS FILING**

Rider 7

		<u>SYSTEM GROWTH CAPACITY COSTS</u>	<u>POLR CAPACITY COSTS</u>	<u>TOTAL</u>
<u>A. CAPACITY COST COMPONENT</u>				
<u>1. ESTIMATED UNMITIGATED COST OF FIRM PIPELINE CAPACITY</u>				
a. Estimated Total Capacity Available (Previous Filing Attachment 2a)				911,375
b. Estimated Capacity to serve BGE Gas Commodity Service, Schedule C Standby and Critical Use customers (Previous Filing Attachment 2a)				<u>899,840</u>
c. Estimated Capacity for System Growth and POLR (Previous Filing Attachment 2a)	= a - b			11,535
d. Estimated Total Requirements as POLR four winters in future	2012/13	1,007,448	(Previous Filing Attachment 2b)	
e. Estimated Total Requirements as POLR for current winter	2008/09	<u>968,906</u>	(Previous Filing Attachment 2b)	
f. Estimated System Growth Capacity (Previous Filing Attachment 2a)	= d - e	38,542		
g. Estimated POLR Capacity (Previous Filing Attachment 2a)	= if f > c then g = 0, else g = c - f		0	0
g1. Estimated System Growth Capacity (Previous Filing Attachment 2a)	= if g = 0 then g1 = c, else g1 = f	11,535		<u>11,535</u>
g2. Estimated Capacity for System Growth and POLR (Previous Filing Attachment 2a)	= g + g1			11,535
h. Actual Weighted Average Cost of Capacity (WACC)	\$ 8.30			
i. Actual Annualized Cost of Capacity	= g1 x h x 12 and g x h x 12	\$ 1,148,886	\$ -	\$ 1,148,886
j. Actual Incremental Cost of Peaking Contracts	(Filing Attachment 6 - section D)		\$ 190,950	\$ 190,950
k. Total Actual Unmitigated Cost of Capacity	= i + j	<u>\$ 1,148,886</u>	<u>\$ 190,950</u>	<u>\$ 1,339,836</u>
		<u>SYSTEM GROWTH CAPACITY COSTS</u>	<u>POLR CAPACITY COSTS</u>	<u>TOTAL</u>
<u>2. ESTIMATED MITIGATION OF RESERVED CAPACITY</u>				
a. Total Actual Mitigation Revenues Applicable to Capacity Costs	(Filing Attachment 6 - section B)			\$ 2,303,923
b. Allocated Capacity from Part 1 (in Dth)	1.g1, 1.g and 1.g2	11,535	0	11,535
c. Percent of Mitigation Allocated to Category	= Category Total / Grand Total	100.00%	0.00%	
d. Allocated Mitigation to Category	= a x c	\$ 2,303,923	\$ -	\$ 2,303,923
e. Actual Amount of Capacity to be Released as Recallable (in Dth)	(Filing Attachment 6 - section C)			36,684
f. Actual Incremental Cost of Releasing Recallable Capacity	(Filing Attachment 6 - section C)			\$ 1,476,773
g. Adjustment of Capacity Costs	= f and neg(f)	\$ 1,476,773	\$ (1,476,773)	
h. Total Actual Mitigation Revenue Credited to Capacity	= d + g	<u>\$ 3,780,696</u>	<u>\$ (1,476,773)</u>	<u>\$ 2,303,923</u>
<u>3. ACTUAL MITIGATED COST OF FIRM PIPELINE CAPACITY</u>				
a. Actual Unmitigated Capacity Cost from Part 1	= 1k	\$ 1,148,886	\$ 190,950	\$ 1,339,836
b. Actual Mitigation from Part 2	= 2h	<u>\$ 3,780,696</u>	<u>\$ (1,476,773)</u>	<u>\$ 2,303,923</u>
c. Actual Mitigated Capacity Cost (Dec08-Nov09)	= a - b	<u>\$ (2,631,810)</u>	<u>\$ 1,667,723</u>	<u>\$ (964,087)</u>

Attachment 6

**BALTIMORE GAS AND ELECTRIC COMPANY
CALCULATION OF RIDER 7 - GAS CHOICE AND RELIABILITY CHARGES (GCRC)
TRUE-UP CALCULATION OF
MITIGATION REVENUE, INCREMENTAL COST AND PEAKING CONTRACT COST**

Mitigation Calculation

A. Reserve Capacity Breakdown

1. Estimated Capacity for System Growth and POLR	11,535	<i>(Previous Filing, Attachment 1)</i>
2. Non-recallable	0	<i>(Previous Filing, Attachment 1)</i>
3. Recallable	=A.1-A.2	11,535 <i>(Previous Filing, Attachment 1)</i>

B. Actual Mitigation Revenue

	<u>Actual Nov08-Mar09</u>			
Off-System Sales	Avg Daily Volume (Dth)	Days	Avg Margin	Total Winter Margin
1. Non-recallable	9,751	151	\$0.5127	\$754,900
2. Recallable	41,684	151	<u>\$0.2461</u>	<u>\$1,549,023</u>
Difference			\$0.2666	
		Actual Mitigation		\$2,303,923

C. Incremental Cost of Releasing Recallable Capacity

1. Mitigated Capacity	=B.1+B.2	51,435		
2. Adjustment		<u>5,000</u>		
3. Potential Non-Recallable	=C.1-C.2	46,435		
4. Actual Non-Recallable	=B.1	<u>9,751</u>		
Difference & Incremental Cost	=C.3-C.4	36,684	Days 151	Avg Margin \$0.2666
				<u>\$1,476,773</u>

D. Peaking Contract Cost

\$190,950

the estimated costs incurred plus the Reconciliation Component for Gas Choice Program Cost by BGE's estimated annual throughput in therms for all firm distribution customers, excluding the volumes transported for Daily-Metered Customers. This rate will be charged to all firm distribution customers, except for Daily-Metered Customers.

2. The Reconciliation Component for Gas Choice Program Cost is calculated by comparing the actual expenditures for gas choice programs to the revenues collected to determine if there is an excess or shortage of revenues collected.
3. The amount charged under the Gas Choice Program Cost Component, including any over or under recovery from a prior period shall not exceed 0.5 cents per therm. If the charge calculated exceeds 0.5 cents per therm, recovery of the costs above that amount will be deferred, with carrying costs, and a review will be initiated by BGE before the Maryland Public Service Commission to examine the cause(s) of the costs as well as the proper recovery of the remaining costs.

BGE will file the calculation of the charges for the Capacity Cost Component, the Gas Choice Program Cost Component, plus the two Reconciliation Components with the PSC by December 31 of each year with the revised rates to be effective with February billings of the following year pending Commission approval.

The Delivery Prices for Schedules D and C are increased, as applicable, by the rates for System Growth Capacity cost and / or the Gas Choice Programs Component adjusted for Gross Receipt Taxes and PSC Assessment. The rate for all firm distribution customers (exclusive of customers equipped with Daily Metering Equipment) is \$(0.0010) per therm. The rate for customers equipped with Daily Metering Equipment electing Standby Service is \$(0.0021) per therm.

The rate charged to Suppliers will be the rate for POLR Capacity cost adjusted for Gross Receipt Taxes and PSC Assessment. The rate for Suppliers is \$0.0199 per therm.

8. Monthly Rate Adjustment

The Delivery Price under Schedules D and C is adjusted to reflect test year base rate revenues established in the latest base rate proceeding, after adjustment to recognize the change in the number of customers from the test year level. The change in revenues associated with the Customer Charge is the change in number of customers multiplied by the Customer Charge for the rate schedule. The change in revenues associated with throughput is the test year average use per customer multiplied by the net number of customers added since the like-month during the test year and multiplying that product by the Delivery Price for the rate schedule. The change in revenues associated with Customer Charge and throughput is added to test year revenue to restate test year revenues for the month to include the revised values. Actual revenues collected for the month are compared to the restated test year revenues and any difference is divided by estimated sales for the second succeeding month to obtain the adjustment to the applicable Delivery Price. Any difference between actual and estimated sales is reconciled in the determination of the adjustment for a future month. The Monthly Rate Adjustment is calculated separately for Schedule D, Schedule C, excluding Daily Metered customers, and Schedule C Daily Metered customers only. Details of the calculation of the billing adjustment are filed monthly with the Public Service Commission.

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