BEFORE THE PUBLIC SERVICE COMMISSION

OF THE STATE OF DELAWARE

IN THE MATTER OF THE APPLICATION OF CHESAPEAKE UTILITIES CORPORATION FOR APPROVAL OF A CHANGE IN ITS GAS SALES SERVICE RATES ("GSR") TO BE EFFECTIVE NOVEMBER 1, 2012 (FILED SEPTEMBER 21, 2012)	))))))	PSC DOCKET NO. 12-450F

ORDER NO. 8430

AND NOW, this 13th day of August, 2013, the Delaware Public Service Commission (the "Commission") having reviewed the record in this case; and having received and reviewed the Findings and Recommendations of the Hearing Examiner dated July 2, 2013 (the "HE's Report"), a copy of which is attached as **Attachment "A"**, which were submitted after a duly-noticed public evidentiary hearing; and having deliberated in public at its August 13, 2013 meeting; and

WHEREAS, the Hearing Examiner recommends that the Proposed Settlement Agreement dated May 23, 2013, which is endorsed by all the parties and which is attached as **Attachment "B"**, be approved because such settlement results in just and reasonable rates and is in the public interest;

NOW, THEREFORE, IT IS HEREBY ORDERED BY THE AFFIRMATIVE VOTE OF NO FEWER THAN THREE COMMISSIONERS:

1. That, pursuant to 26 Del. C. §512(c) and 29 Del. C. §10128, the Commission hereby adopts the Findings and Recommendations of the Hearing Examiner, which is attached as **Attachment "A"** and the Proposed Settlement, which is attached as **Attachment "B"**, and finds that, for the reasons set forth in the Hearing Examiner's Report, the Proposed

Settlement Agreement is in the public interest and results in just and reasonable rates.

2. That Chesapeake Utilities Corporation's proposed rates per Ccf are approved, effective on a permanent basis for service rendered on and after November 1, 2012, until further order of the Commission:

Service	Effective for Service Rendered On and After November 1, 2012
RS-1, RS-2, GS, MVS, LVS	$0.997 per Ccf
GLR/GLO	$0.519 per Ccf
HLFS	$0.817 per Ccf
Firm Balancing Rate (LVS)	$0.063 per Ccf
Firm Balancing Rate (HLFS)	$0.022 per Ccf
Interruptible Balancing Rate (ITS)	$0.001 per Ccf

3. That no later than two business days from the date of this Order, Chesapeake Utilities Corporation shall file revised Tariffs which comply with this Order.

4. That the Commission reserves the jurisdiction and authority to enter such further Orders in this matter as may be deemed necessary or proper.

BY ORDER OF THE COMMISSION:

/s/ Dallas Winslow
Chair

/s/ Joann T. Conaway
Commissioner

/s/ Jaymes B. Lester
Commissioner

/s/ Jeffrey J. Clark
Commissioner

Commissioner

ATTEST:

/s/ Alisa Carrow Bentley
Secretary

A T T A C H M E N T "A"

BEFORE THE PUBLIC SERVICE COMMISSION

OF THE STATE OF DELAWARE

IN THE MATTER OF THE APPLICATION OF	)	
CHESAPEAKE UTILITIES CORPORATION	)	
FOR APPROVAL OF A CHANGE IN ITS	)	PSC DOCKET NO. 12-450F
GAS SALES SERVICE RATES ("GSR")	)	
TO BE EFFECTIVE NOVEMBER 1, 2012	)	
(FILED SEPTEMBER 21, 2012)	)	

FINDINGS AND RECOMMENDATIONS OF THE HEARING EXAMINER

DATED: JULY 2, 2013

CONNIE S. MCDOWELL
HEARING EXAMINER

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BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF DELAWARE

IN THE MATTER OF THE APPLICATION OF CHESAPEAKE UTILITIES CORPORATION FOR APPROVAL OF A CHANGE IN ITS GAS SALES SERVICE RATES ("GSR") TO BE EFFECTIVE NOVEMBER 1, 2012 (FILED SEPTEMBER 21, 2012)	))))))	**PSC DOCKET NO, 12-450F**

FINDINGS AND RECOMMENDATIONS OF THE HEARING EXAMINER

Connie S. McDowell, duly appointed Hearing Examiner in this Docket pursuant to 26 *Del. C.* §502 and 29 *Del. C. ch.* 101 and by Commission Order No. 8296 dated February 21, 2013, reports to the Commission as follows:

I. APPEARANCES

On behalf of the Applicant, Chesapeake Utilities Corporation ("Chesapeake") or ("the Company"):

By: WILLIAM A. DENMAN, ESQ., PARKOWSKI, GUERKE AND SWAYZE, P.A.
JEFFREY R. TIETBOHL, VICE PRESIDENT
SARAH E. HARDY, REGULATORY ANALYST II
MARIE E. KOZEL, GAS SUPPLY ANALYST II

On behalf of the Public Service Commission Staff ("Staff"):

By: JULIE M. DONOGHUE, ESQ., DEPUTY ATTORNEY GENERAL
JASON R. SMITH, PUBLIC UTILITY ANALYST
JEROME D. MIERZWA, CONSULTANT, EXETER ASSOCIATES, INC.

On behalf of the Division of the Public Advocate ("DPA"):

By: RUTH ANN PRICE, DEPUTY PUBLIC ADVOCATE
ANDREA B. MAUCHER, PUBLIC UTILITIES ANALYST

On behalf of Joseph R. Biden, III, Attorney General of the State of Delaware ("AG"):

By: JAMES ADAMS, DEPUTY STATE SOLICITOR
ANDREA C. CRANE, CONSULTANT, THE COLUMBIA GROUP, INC.
REGINA A. IORII, ESQ., DEPUTY ATTORNEY GENERAL

II. BACKGROUND

A. CHESAPEAKE'S 2012-2013 GSR APPLICATION

1. On September 21, 2012, Chesapeake filed with the Delaware Public Service Commission ("the Commission") an application seeking approval to change its GSR Rates effective on November 1, 2012 as follows: (1) decrease the Company's current GSR rate from $1.027 per Ccf to $0.997 per Ccf for customers served under rate schedules RS-1, RS-2, GS, MVS and LVS; (2) decrease the Company's current GSR rate from $0.592 per Ccf to $0.519 per Ccf for customers served under rate schedules GLR and GLO; (3) decrease the Company's current GSR rate from $0.830 per Ccf to $0.817 per Ccf for customers served under rate schedule HLFS; (4) maintain the Company's firm balancing rate for transportation customers served under rate schedule LVS at $0.063 per Ccf; (5) increase the Company's firm balancing rate for transportation customers served under rate schedule HLFS from $0.021 per Ccf to $0.022 per Ccf; and (6) maintain the Company's interruptible balancing rate for transportation customers served under rate schedule ITS at $0.001 per Ccf.

2. The Company also requested an extension of time to file this application, which was due sixty days prior to November 1st (pursuant to 26 *Del. C.* §304 and Chesapeake's current GSR tariff) because of staffing vacancies. The Commission Staff supported this time extension.

3. Comparing the proposed rates in this application to the rates approved in the last GSR filing, an average RS-2 customer using 700 CCF per year will experience an annual decrease of approximately

2% or $1.75 per month. During the winter heating season, a typical RS-2 customer on Chesapeake's system using 120 Ccf per month will experience a decrease of approximately 2% or $3.60 per winter month.

4. With its Application, Chesapeake also submitted prefiled testimony from two witnesses: (1) Jeffrey R. Tietbohl, Vice President of Chesapeake Utilities Corporation and (2) Marie E. Kozel, Gas Supply Analyst II.

5. In the Company's prior GSR case (PSC Docket No. 11-384F) the Commission approved a Settlement Agreement which stated that Chesapeake would include in its testimony in its next GSR filing an update on steps taken to mitigate the effects of changes in gas costs, information on the total sales volumes, costs and margins by month for Interruptible Gas Transportation sales, and a calculation of the impact on its proposed GSR rates had a thirty-year average degree day methodology been used, when and if requested.

6. In Order No. 8227 dated October 9, 2012, the Commission authorized the proposed GSR rates, firm balancing rates and interruptible balancing rate and other revisions to the Company's tariff to become effective for usage on or after November 1, 2012, subject to refund and pending further review and final decision and approved Chesapeake's request to extend the time for it to file its GSR application. The Commission designated Robert J. Howatt as Hearing Examiner and directed him to: (1) schedule and conduct all necessary and appropriate public evidentiary hearings to develop a full and complete record concerning the matter; (2) report his proposed findings and recommendations based on the evidence presented

to the Commission; (3) grant or deny petitions to intervene; and (4) determine the content, form and manner of any further required public notice. The Commission further directed Chesapeake to publish notice of its Application with the proposed rate changes and the Commission's actions in this Order in the The News Journal on October 16, 2012 and the Delaware State News on October 17, 2012, and to submit proof of publication no later than the commencement of the evidentiary hearings concerning this matter. Finally, the Commission notified Chesapeake that it would be charged the costs incurred in this proceeding pursuant to 26 *Del. C.* §114(b)(1).

7. In February 2013, Hearing Examiner Howatt was appointed as the Executive Director of the Commission and was no longer able to act as a Hearing Examiner. In Order No. 8296 dated February 21, 2013, the Commission appointed me as Hearing Examiner in this matter and directed me to assume the duties listed in ¶6 above.

8. The DPA exercised his statutory right of intervention on October 9, 2012. On or about March 15, 2013, Michael Sheehy, Public Advocate, resigned from his position. On March 18, 2013, the Attorney General petitioned the Commission for leave to intervene out of time because the consumers' interests would not be otherwise represented. By Order No. 8333 dated March 18, 2013, the Hearing Examiner granted the Petition.

B. THE PUBLIC COMMENT SESSION

9. As part of Hearing Examiner Howatt's approved procedural schedule, a duly noticed public comment session was conducted by Mr. Howatt at 7:00 p.m. on December 5, 2012 in the Delaware Public Service Commission Hearing Room located at 861 Silver Lake Boulevard, Cannon Building, Dover, Delaware. Public notice of the hearing included a publication in the legal classified section of The News Journal and the Delaware State News newspapers on October 19, 2012, in accordance with PSC Order No. 8227. No members of the public attended. In addition, no written comments were received by the Commission.

III. SUMMARY OF THE EVIDENCE

A. THE EVIDENTIARY HEARING

10. The evidentiary hearing was held on Thursday, May 23, 2013 beginning at 10 a.m. The record, as developed at the evidentiary hearing, consists of a verbatim transcript of thirty-five (35) pages and nine (9) hearing exhibits. The parties stipulated to the admissibility of all hearing exhibits (Tr. 24-26). The evidence from the evidentiary hearing is discussed in Section IV of this Report.

B. CHESAPEAKE'S DIRECT TESTIMONY

11. Along with its Application, the Company filed the direct testimonies of Jeffrey R. Tietbohl, Vice President, (Exh. 4) and Marie E. Kozel, Gas Supply Analyst II (Exh. 3).

12. ***JEFFREY R. TIETBOHL.*** Jeffrey R. Tietbohl, Vice President, submitted pre-filed direct testimony dated September 21, 2012. (Exh. 4). Mr. Tietbohl also sponsored the Company's schedules filed in the Application. Mr. Tietbohl testified to the mechanics of the three

separate GSR rates, the development of the firm and interruptible sales volumes and total system requirements and the development of the lost and unaccounted for gas ("LAUF") volumes. He also provided support for the overall calculation of the proposed three separate GSR rates to be effective with service rendered on and after November 1, 2012, as well as the mechanics of the proposed balancing rates for transportation service under the Large Volume Service ("LVS"), High Load Factor Service ("HLFS") and Interruptible Transportation Service ("ITS") rates. He explained the impact of the proposed GSR rates on an average residential customer's bill and ensured compliance with the gas cost provisions required by previous Commission orders. *Id.* at 4.

13. Mr. Tietbohl explained that the three separate GSR rates proposed in this Application were developed in accordance with the approved gas cost recovery mechanism contained in the Company's natural gas tariff on Sheet Nos. 42 through 42.3. *Id.* at 5.

14. Mr. Tietbohl compared the rates that were in effect November 1, 2011 to the proposed rates that were made effective on November 1, 2012. An average RS-2 customer using 700 Ccf per year will experience an annual decrease of approximately 2% or $1.75 per month. During the winter heating season, a typical RS-2 customer on Chesapeake's system using 110 Ccf per month will experience a decrease of approximately 2% or $3.30 per winter month. A typical RS-2 customer using 120 Ccf per winter month will experience a decrease of approximately 2% or $3.60 per winter month. *Id.* at 6.

15. Mr. Tietbohl described how he calculated the proposed GSR rate levels. The rates were calculated based on the estimated

purchased gas costs and estimated sales volumes for the twelve months ending October 31, 2013. For this Application, the total projected firm gas costs recoverable through the gas cost recovery mechanism is $35,830,541. This total is comprised of $20,407,460 of fixed costs and $15,423,081 of variable costs. The fixed rate (used to calculate separate demand rates), the variable/commodity rate and the total rate or system average rate are the key components for calculating separate GSR rate levels for different services. In this Application, the Company calculated the fixed rate to be $26.02 per Ccf, the variable/commodity rate to be $$0.448 per Ccf and the system average rate to be $1.042 per Ccf. *Id.* at 6-9 and Schedule A.1.

16. Mr. Tietbohl summarized the reasons why the GSR rates are changing from last year’s GSR filing. In this year’s filing, the variable or commodity gas costs are anticipated to decrease by $3,006,050. These costs are decreasing primarily due to the projected cost of flowing commodity gas for the upcoming year and a reduction in volume. The fixed costs are anticipated to increase by $3,535,727. These costs are increasing primarily due to the capacity entitlements associated with the Texas Eastern Transmission TEAM 2012 project. *Id.* at 7.

17. Mr. Tietbohl explained that the first GSR rate level for the HLFS was calculated based on the combination of a weighted average demand (a fixed rate) and a variable/commodity rate (see ¶16 above) developed on an overall fifty percent (50%) load factor for the customer class and the overall system weighted average cost rate. In this Application, the fixed gas cost rate of $26.02 per Ccf (See ¶16

above) is divided by 182.5 days (50% of 365 days in a year) to calculate a demand rate of $0.143 per Ccf. This rate is added to the variable/commodity rate of $0.448 per Ccf (see ¶16 above) to calculate a volumetric rate of $0.591 per Ccf. The HLFS rate is calculated by averaging the volumetric rate of $0.591 and the system average rate of $1.042 per Ccf or $0.817 per Ccf. The gas costs associated with HLFS are projected by multiplying the HLFS rate of $0.817 by the projected sales volume of 3,133,171 Ccf or $2,559,801. *Id.* at 9-10 and Sch. A.1.

18. Mr. Tietbohl explained that the second GSR rate level for Gas Lighting Services (GLO and GLR) was calculated using weighted average demand (a fixed rate) and variable/commodity rates through a single gas cost rate per Ccf, based on a 100% load factor. In this Application, the fixed gas cost rate of $26.02 per Ccf (see ¶16 above) is divided by 365 days (100% load factor) to calculate a demand rate of $0.071 per Ccf. This demand rate of $0.071 plus the variable/commodity rate of $0.0448 per Ccf (see ¶16 above) or $0.519 per Ccf is the GLO and GLR rate. The gas costs associated with the Gas Lighting Services are projected by multiplying the GLO/GLR rate of $0.521 by the projected annual sales volume of 1,440 Ccf, or $747. *Id.* at 10 and Sch. A.1.

19. Mr. Tietbohl stated that the third GSR rate level for all other rate classes (RS-1, RS-2, GS, MVS, and LVS) was calculated by assigning the remaining firm purchased gas costs after deducting the gas costs for the other two GSR rate levels (HLFS, GLO and GLR) ($33,269,993) to these rate classes and dividing that number by the

remaining estimated sales volume after deducting the sales volumes for the other two GSR rate levels (HLFS, GLO and GLR) to develop a rate of $1.064 per Ccf. This rate is then changed if the Company received any margins that are shared with the ratepayers. In this Application, Chesapeake estimated that the amount of margins to be applied to these ratepayers is $2,095,763 (estimated for this GSR period plus prior period over refunds). These margins, divided by the sales volumes for RS-1, RS-2, GS, MVS and LVS, results in a credit of $0.67 per Ccf. This is deducted from the $1.064 rate, resulting in the final rate of $0.997 per Ccf for RS-1, RS-2, GS, MVS and LVS rate schedules. *Id.* at 10-11 and Sch. A.1 and A.2.

20. Mr. Tietbohl defined the term "Shared Margins" as any margins that the Company receives as a result of interruptible transportation service, off system sales or capacity releases, with each type having different sharing percentages. The capacity release credits received from the Company's Asset Manager are shared 90% firm ratepayer and 10% Company. *Id.* at 11. In this Application, the Company is estimating that capacity release credits for the prior period and the current determination period to be $2,095,763 for the firm ratepayers. *Id.* at A.2. The interruptible transportation service margins (according to the Settlement Agreement in PSC Docket No. 09-398F) are shared 90% firm ratepayers and 10% Company after the Company retains the first $675,000 of margins per year. The Company did not reach the $675,000 threshold this determination period; therefore, there are no margins to be shared with the firm ratepayers. Also, the Company is not projecting any off system sales for this

determination period. The shared margins for the capacity releases produce a credit of $0.067 per Ccf ($2,095,763 divided by 31,261,513 Ccf of RS-1, RS-2, GS, LVS, and MVS sales). (See ¶19 for this offset to the RS-1, RS-2, GS, LVS and MVS rate calculation). *Id.* at 11-12 and Sch. A.1 and A.2.

21. Mr. Tietbohl explained that the full benefit of projected capacity releases to transportation customers on Eastern Shore's system was credited to the Delaware Division firm ratepayers. In this Application, it was estimated to be $4,826,009 for the twelve-month period ending October 2013 and was deducted from the estimated fixed demand costs. *Id.* at 12 and Sch. B and I. The total peak day entitlements on Eastern Shore are projected to be 70,654 Dts per day for this determination period, of which 17,602 Dts per day of Daily Contract Quantity entitlements are projected to be released to transportation customers, or approximately twenty-five percent (25%) of the Delaware Division's peak day capacity on the Eastern Shore pipeline. *Id.* at 12.

22. Mr. Tietbohl described the first step in calculating the proposed GSR charges, which is the development of the sales and associated gas supply requirements forecast. First, the Company forecasts the demand or sales volumes for the distribution system. Based on meeting the demand or sales forecasts, a forecast of associated purchases or supply requirements is developed. The sales forecast begins with an analysis of the major variables that affect sales volumes. These include the number of customers to be served, the rate schedule classification of those customers, temperature and

the larger individual commercial and industrial customer sales volumes or demands. Sales volumes are normalized based on a ten-year average of degree days for the months of July 2002 through June 2012. *Id.* at 12-13. Forecasted sales volumes for the twelve-month period of November 2012 through October 2013 were developed based upon the actual sales volumes billed to each customer class during each month for the prior year with adjustments to reflect average temperature, customer growth and customers switching among rate classes. In this Application, the Company has projected approximately 902 additional RS-2 customers (new and switched customers), approximately 707 additional RS-1 customers (new and switched customers), approximately 62 additional Commercial and Industrial customers, and no change in Gas Lighting customers. *Id.* at 13-14. The Company has projected that none of its firm commercial or industrial customers will be switching from sales service to transportation service during this determination period. The Company is projecting that 222 firm commercial/industrial customers with an estimated volume of 3,579,385 Mcf and two (2) interruptible commercial/industrial customers with an estimated volume of 104,863 Mcf will be transporting their own gas on the Delaware Division's distribution system during this GSR period. *Id.* at 15.

23. Mr. Tietbohl explained how the projected sales volumes were used to calculate the associated gas supply requirements needed for this determination period. The total gas supply requirements for this determination period were derived by starting with the projected sales volumes detailed in ¶22 and adjusting for cycle billing, LAUF, pressure compensation and company use. *Id.* at 15-16. The cycle

billing adjustment is the difference between a billing month and a calendar month of gas purchases. The cycle billing adjustment is calculated by first dividing the projected, normalized firm sales volumes for each month into a base load and a heating load. The heating load is then multiplied by the difference between the normal calendar month degree days and the normal billing month degree days to calculate the cycle billing adjustment. *Id.* at 16. The Company Use Gas is projected to be 1,041 Mcf, or approximately the same level of volume used by the Company during the actual twelve months ended June 30, 2012. *Id.* at 16 and Sch. C.1. The LAUF adjustment is calculated by multiplying the projected sales volumes for each month by 3.28% (the 5 year historical rate approved by the Commission in PSC Order No. 4189 in PSC Docket No. 95-206) and subtracting the estimated Company Use and the Pressure Compensation. For the twelve months ending October 2013, the LAUF is estimated to be 60,409 Mcf. *Id.* at 17 and Sch. C.1. The Pressure Compensation Adjustment is calculated by multiplying the total project Mcf sales by the factor of 0.0149355. This factor represents the calculation used to pressurize gas received from Eastern Shore to a standard pressure of 14.73 PSI for delivery on the Company's distribution system. *Id.* at 17 and Sch. C.1.

24. Mr. Tietbohl explained how the projected cost of firm sales was calculated for the twelve-month period ending October 31, 2013. In calculating the proposed cost of gas for the period November 1, 2012 through October 31, 2013, the total projected supply requirements were allocated between the different categories of gas, commodity and storage, available to meet the projected demand. To calculate the

proposed cost of gas, the fixed costs of firm transportation on the pipelines, Columbia Gas Transmission ("Columbia Gas"), Columbia Gulf Transmission ("Columbia Gulf"), Transcontinental Gas Pipeline ("Transco"), Eastern Shore and Texas Eastern Transmission ("TETCO") are calculated on a monthly basis along with the storage demand and capacity charges and the gas commodity costs associated with firm transportation. *Id.* at 18 and Sch. C.2 p.1-7. The projected cost of storage gas commodity for withdrawals during this determination period has been calculated using the actual purchases and costs for the months of April 2012 through July 2012 and projected purchases and costs for August 2012 through October 2012. The twelve-month period ending March 2013 is used for the calculation of the storage gas demand cost to properly reflect the amounts to be expensed during the determination year. The rates used in the commodity gas purchase projections for flowing commodity gas for November 2012 through October 2013 are based on natural gas commodity futures market prices during the first week of September 2012, as well as any gas that had been previously purchased under the Company's Hedging Plan for this determination period. *Id.* at 18.

25. Mr. Tietbohl compared the projected firm cost of gas for the twelve months ending October 31, 2013 to the nine months of actual costs and 3 months of projected cost for the twelve month period ending October 31, 2012 as shown on Schedule F in the Application. Chesapeake anticipates a decrease in firm gas costs per Mcf of $0.9066 per Mcf for the twelve months ending October 31, 2013 due to a significant increase in total firm Mcf sales for this period. The

Company believes that this time period will experience colder weather than the actual data from the twelve months ended October 31, 2012 period. *Id.* at 19.

26. Mr. Tietbohl stated that modifications had been made to the layout of Schedule C.2 pages 2 and 5 pertaining to gas costs of Eastern Shore due to a change in its rate design structure. Eastern Shore changed its rate design from a two-zone Dth-mile, settlement modified rate design to a zone-gate method rate design that includes two receipt zones and three delivery zones. *Id.* at 20 and Sch. C.2, p.2 and p.5.

27. Mr. Tietbohl explained that he had prepared a calculation of the purchased gas over/under collection by month for the twelve-month period ending October 31, 2012. The projected under collection balance at October 31, 2012 that is carried forward into this filing is $2,638,029. He also prepared a calculation of the shared margins over/under refund for the twelve-month determination period ending October 31, 2012. The Company's under refunded shared margins at October 31, 2012 was $683,296. *Id.* at 20 and Sch. D.1, D.2 and A.2., F.

28. Mr. Tietbohl testified that in PSC Order No. 3648 in PSC Docket 92-87F, the Commission approved the provisions of the Company's tariff concerning the LAUF Incentive Mechanism and required the Company as part of its annual GSR filing to provide the Staff with actual LAUF volumes for the preceding twelve-month period ended July 31. The LAUF Incentive Mechanism included an approved target of 3.2% of total gas sendout or total gas requirements and an approved dead

band of +/- 0.5% points around the 3.2% target. The actual LAUF percentage for the twelve months ended July 31, 2012 was 4.07%, which is outside the dead band range. The Company is currently reviewing this situation to determine any potential causes for this increase over the past year. *Id.* at 21-22.

29. Mr. Tietbohl testified that Chesapeake is required to file in its annual GSR application an update to its balancing rates for Rate Schedules LVS and HLFS pursuant to PSC Order No. 4400 in PSC Docket No. 95-73, Phase II and to its balancing rate for Rate Schedule ITS pursuant to PSC Order No. 7434 in PSC Docket 07-186. The relationship between the GSR rates and the transportation balancing rates exists because the projected gas costs in this Application are the same gas costs that are used to calculate the transportation balancing rates. The gas supply resources and their costs are separated into fixed supply resources and variable supply resources. The Delaware Division's storage demand and capacity, and propane peak shaving facilities are related to the fixed gas supply resources, while storage injection and withdrawal volumes are related to the variable gas supply resources. In this Application, Chesapeake is proposing no change to LVS and ITS rates and an increase in HLFS rates from $0.021 per Ccf to $0.022 per Ccf. Mr. Tietbohl states that the reason for the increase in the HLFS rate is that there was a decrease in the annual load factor for this class from 56.42% to 50.23%. *Id.* at 22-28 and Sch. J, pp. 1-4.

30. Mr. Tietbohl described the information provided in this Application as being in compliance with the Settlement Agreement

approved in PSC Order No. 8168 in PSC Docket No. 11-384F. The first information request was with respect to the Company's Natural Gas Commodity Procurement Plan ("Hedging Plan"). Chesapeake would review the dollar cost averaging framework for possible implementation at the time of the next review of the Hedging Plan which was September 2012. Chesapeake would track transactions utilizing the dollar cost averaging framework and provide an update on the paper program as part of its quarterly reporting. Actual purchases would still be made in accordance with the currently approved program, but Chesapeake would summarize the results of the dollar cost averaging tracking in this Application and submit its recommendations of whether or not to implement dollar cost averaging. The second information request was for the Company to provide on (a confidential basis) information on its expansion into eastern Sussex County as part of the GSR filing. The Company provided a schedule which lists monthly levels of customers, their Mcf consumption, and the level of Eastern Shore capacity serving these customers for the past four years and the forecast for this determination period. The third information request was for the Company to provide information concerning any capacity release revenues received outside of an Asset Management Agreement ("AMA") and if so, one hundred percent of these capacity release revenues would be credited to the GSR. The Company has not projected any capacity release revenues to be received outside of the AMA. Finally, the fourth information request was for the Company to notify the parties of any supplier refunds that may impact the GSR rates, an update on the steps taken to mitigate the effects of changes in gas costs, the total sales volumes, costs and margins by month for Interruptible Gas Transportation sales in its Application, and the impact on its proposed GSR rates had a thirty-year average degree days been used, when and if requested during the discovery process. The Company provided this information in a schedule that was submitted under a separate cover because it contained confidential commercial and financial information. *Id.* at 28-32.

31. Mr. Tietbohl addressed the remaining Settlement Provision Items from the last GSR to be covered in this Application. The Company was to report potential supplier refunds. The Company has estimated a $420,000 in potential supplier refunds related to a pending Eastern Shore Cash In/Out filing with the Federal Energy Regulatory Commission ("FERC") and the potential for a Columbia refund based on its "TCO Modernization Program" recently filed with FERC. Also with respect to gas cost change mitigation measures, the Company was to encourage customers to enroll in its budget billing program and to provide tips to promote conservation. The Company has included messages on its customer bills during the summer months about budget billing and information as to how to sign up for the program that begins in September. The Company also has included messages on its customer bills, customer guides and pamphlets about conservation. *Id.* at 31.

32. Lastly, Mr. Tietbohl testified that in this Application, the Company has included $216,040 of certain pre-certification costs associated with the Eastern Shore E3 Project that Eastern Shore elected to abandon. The Company also has submitted under a separate

cover an Annual Report of all of its hedging activities and transactions, including results. *Id.* at 34.

33. ***Marie E. Kozel***. Ms. Kozel testified on the support documentation for the gas costs used in the calculation of the Delaware Division's GSR rates in this Application and discussed the Company's gas supply and procurement activities as required by PSC Order No. 4757 in PSC Docket 97-294F. *Id.* at 3.

34. Ms. Kozel explained that the Delaware Division is currently receiving a mix of transportation and storage service from five interstate pipeline suppliers: Transco, Columbia Gas, Columbia Gulf, TETCO and Eastern Shore. Ms. Kozel also explained that Delaware Division's maximum daily upstream entitlements on these upstream pipelines are 71,003 Dts/day. *Id.* at 4 and Sch. L.

35. Ms. Kozel testified that the Delaware Division changed its capacity entitlements on some of these pipelines since the last GSR filing. The Delaware Division obtained 1,550 Dts/day of firm transportation capacity on Eastern Shore. The Company had originally requested 4,050 Dts/day and had anticipated the request to be effective November 1, 2011. However, only 2,500 Dts/day was available on November 1, 2011 and the remaining capacity was made available at different times throughout the year. 650 Dts/day of capacity became effective March 1, 2012, 250 Dts/day of capacity became effective April 1, 2012, and 650 Dts/day of capacity became effective May 1, 2012. She also reported that Delaware Division requested additional capacity in 2009 to serve its firm customers and one new large industrial customer. Based on that request, an additional 491 Dts/day

became available on April 1, 2012. The Company is anticipating 30,000 Dts/day from TETCO on November 1, 2012 and will be relinquishing 26,250 Dts/day of interim capacity it currently holds. The Company will also receive an increase in Eastern Shore entitlements for 3,750 Dts/day (related to the TETCO project). This capacity provides additional access to the TETCO receipt point but does not increase the Company's design day deliverability. The Company anticipates reduced capacity and demand entitlements for Transco's Eminence Storage Service ("ESS") due to an application filed by Transco requesting authorization to partially abandon facilities due to a Force Majeure Event that occurred on December 26, 2010. All of these entitlements were used in the calculation of fixed demand costs for the determination period. *Id.* at 5-6 and Sch. L.

36. Ms. Kozel further explained in greater detail the change in capacity entitlements. She stated that in 2009 Chesapeake requested 1,650 Dts/day of capacity to serve a large industrial customer and other firm customers. On April 1, 2010, 1,159 Dts/day became effective and the Company was able to serve the new large industrial customer. The remaining 491 Dts/day became effective April 1, 2012 and serves the Company's other firm customers. The 4,050 Dts/day of Eastern Shore capacity provides deliverability at various points in Sussex County, including three new gate stations. This capacity was requested to provide additional capacity where customer load was exceeding contracted quantities and allowed Chesapeake to continue to expand natural gas service into portions of eastern Sussex County. She also explained that the Company has been reducing its reliance on

firm winter bundled peaking supply arrangements. Chesapeake made a request to Eastern Shore to extend its pipeline to run from a new interconnect with TETCO at Honeybrook, PA to the existing Eastern Shore pipeline at Parkesburg, PA. She states these capacity additions provide the Company with firm upstream deliverability to enhance its ability to provide reliable service to its customers on a design day, to diversify its supply from sources other than the South Central United States and the Gulf of Mexico (such as the Rocky Mountains and the Marcellus Shale) and to reduce its reliance on bundled peaking supply. *Id.* at 6-8.

37. Ms. Kozel explained that the Company anticipated additional capacity from Eastern Shore during this determination period. However, there has been a delay in obtaining federal authorization and anticipates the effective date of this capacity to be November 1, 2013. *Id.* at 8.

38. Ms. Kozel described the Company's storage services. At the present time, Chesapeake has three storage services in the AMA, Washington Storage Service ("WSS"), Firm Storage Service ("FSS") and Eminence Storage Service ("ESS"), and in addition contracts for three storage services, General Storage Service ("GSS"), Leidy Storage Service ("LSS") and Liquefied Natural Gas Storage Service ("LGA"), with Eastern Shore. On September 29, 2011, Transco filed an application with FERC for the partial abandonment of facilities, storage capacity and deliverability at the ESS Field. The Company anticipated FERC's decision regarding Transco's application to be

issued prior to the beginning of the upcoming GSR period. *Id.* at 8-10 and Sch. L.

39. Ms. Kozel described the Company's Gas Supply Procurement activities since November 1, 2011. The Company has a contract with an Asset Manager for gas supply, procuring monthly baseload and spot purchases. As of the date of Ms. Kozel's pre-filed testimony, this contract was due to expire on March 31, 2013 and before the end of December, the Company intended to issue a Request For Proposal ("RFP") for the purpose of evaluating potential future asset management services beyond March 31, 2013. Chesapeake is developing relationships with producers and marketers that operate in the Marcellus Shale to potentially purchase some of its gas supply from those suppliers rather than exclusively relying on the Asset Manager. During the last GSR period, a portion of the Company's requirements were purchased using short-term agreements from third party suppliers. *Id.* at 11-13.

40. Ms. Kozel testified that in this Application the Company is seeking recovery of costs for a one-year trial subscription of Planalytics *EnergyBuyer*® software and service. This software provides a price analysis and risk management solution to assist natural gas buyers in effectively hedging both their physical and financial forward natural gas purchases to reduce the impact of changes in volatile energy markets. *Id.* at 13 and Natural Gas Supply Procurement Plan Annual Report p. 7.

41. Ms. Kozel testified that in this GSR period that 50% of the winter's expected requirements will be procured utilizing the Hedging

Plan dated August 31, 2012. Also, the Company intends to seek agreements with producers and/or marketers that will provide beneficial pricing for supply delivered on the new TETCO capacity. The Asset Manager contract ensures the availability of a supply resource to supplement supply and storage already procured to meet the forecasted demand requirements. The Company will continue to maintain "no requirements" contracts with several natural gas suppliers to ensure that alternative gas supply resources are readily available when needed. *Id.* at 14.

C. TESTIMONY OF THE ATTORNEY GENERAL

42. ***Andrea C. Crane, Consultant, Columbia Group, Inc.*** Ms. Crane testified that she offered the following recommendations in this proceeding: (1) Delaware Division acquiring additional capacity from Eastern Shore may not be in the best interests of ratepayers since Eastern Shore is an affiliate of Chesapeake Utilities Corporation and has a direct financial interest; (2) the Company's need for future capacity will be impacted by the outcome of PSC Docket No. 12-292, a filing seeking to implement new charges to accelerate growth in eastern Sussex County; (3) Delaware Division should continue to utilize its Supply Plan to identify the need for all new capacity additions well in advance of executing agreements for new capacity; (4) the Company should not enter into any new capacity agreements, either with Eastern Shore or upstream pipelines, without providing prior notification to the DPA/AG's Office and Staff, and if the additional capacity was not included in the Supply Plan, the DPA/AG and Staff should be notified of the need for additional capacity prior

to any agreements being executed; (5) the Company has not kept the DPA/AG adequately informed about its AMA solicitation activities, which violates the Settlement Agreement approved in PSC Order No. 8168 in PSC Docket 11-384F, and a penalty of $1,000 per day should be imposed on the Company effective December 27, 2012 until it furnishes the parties with this information; (6) if the Company extends the current AMA or executes a new agreement, the payments received from this agreement should be credited 100% to the ratepayers; (7) the gas hedging program is working well and should be continued for another year; (8) the Company's request to recover $50,000 associated with the review of the Gas Hedging Program by Planalytics should be denied; and (9) the proposed GSR rates should be approved, subject to true-up in next year's GSR filing for actual costs and recoveries, but excluding the $50,000 for the Planalytics trial review. *Id.* at 6-7.

43. Ms. Crane described the background of the Company and its procurement process. Delaware Division provides natural gas service to approximately 41,430 customers, of which approximately 91.6% are residential customers. Customers are located in southern New Castle, Kent and Sussex Counties. Delaware Division is connected to only one natural gas pipeline, Eastern Shore. Therefore, in order to access natural gas, the Company has had to acquire capacity on two pipelines, Eastern Shore and an upstream pipeline, to transport gas to its territory. Residential growth over the past four years has averaged 2.63%. *Id.* at 11.

44. Ms. Crane explained the reasons for the change in GSR rates from last year's filing to this year's filing. The projected

commodity costs are almost 19% lower this year compared to last year and the fixed costs are 10.7% higher primarily due to the new TETCO capacity. This year's filing also reflects a slight decrease in sales volumes compared to last year's filing. *Id.* at 11.

45. Ms. Crane explained that the Company had provided a comparison of its GSR rates to 11 other natural gas companies. The Company's rates have historically been higher and one of the reasons is that the Company is only directly connected to Eastern Shore and therefore, it generally has to acquire capacity on two pipelines to transport gas to its service territory. *Id.* at 11.

46. Ms. Crane recounted her issues in the last GSR proceeding, PSC Docket No. 11-384F. In that proceeding, she had the following conclusions and recommendations: (1) The Company executed agreements for new capacity or agreements relating to management of its assets without providing proper notification to Staff and/or DPA; (2) Eastern Shore has a direct financial interest in Chesapeake Utilities Corporation and Delaware Division acquiring additional capacity from Eastern Shore may create a situation that is not in the ratepayers' best interests; (3) Delaware Division acquired Eastern Shore capacity to serve eastern Sussex County based on optimistic forecasts of future growth; (4) the Company has adequate capacity, both upstream capacity and capacity from Eastern Shore, for the foreseeable future; (5) in the Annual Supply Plan, the Company should identify the need for all new capacity additions well in advance of executing agreements; (6) the Company's design day forecasting methodology should be reviewed prior to the Company acquiring any additional capacity; (7) if the

Company wants to continue using an Asset Manager, then in the next GSR filing, the Company should provide a detailed timeline for soliciting a new AMA; (8) any new AMA should contain a requirement for full disclosure of all transactions impacting affiliates; (9) there should be discussions with the Staff and DPA concerning if Delaware Division should accelerate the purchase of any gas hedges and the Company should monitor results simulating dollar-cost averaging to determine if dollar-cost averaging should be adopted; and (10) the Commission should approve the proposed GSR rates in the Application. *Id.* at 12-13.

47. Ms. Crane described how the issues that were raised in PSC Docket 11-384F were resolved. The Settlement Agreement that was approved in PSC Order No. 8168 included the following provisions: (1) The Company agreed to continue to track paper transactions utilizing a dollar cost averaging framework as an alternative to the current Hedging Plan, summarize the results of the dollar cost averaging tracking in this Application and submit its recommendations regarding whether or not to implement dollar cost averaging; (2) the Company agreed to utilize its annual Supply Plan as a mechanism to notify the parties of the need for all new capacity additions and if the annual Supply Plan did not identify the specific capacity that the Company wanted to acquire either from Eastern Shore or upstream pipelines, the Company agreed to provide notification to the parties prior to obtaining such capacity; (3) the Company agreed to provide an annual status report on its expansion activities in eastern Sussex County as part of its main extension report filed in the spring of each year;

(4) the Company agreed to issue a RFP for Asset Management services prior to December 31, 2012 and to provide information to the parties about the AMA solicitation, and agreed that if it elected to enter into a new AMA, it would include a provision that any capacity released by the Company to the Asset Manager cannot be re-released; (5) the parties agreed that Delaware Division could recover the costs of incremental upstream TETCO capacity through the GSR and that any such capacity released outside of an AMA would be credited 100% to the GSR; (6) the Company agreed to provide periodic updates to the parties with regard to intervention by the Company in FERC proceedings; and (7) the Company agreed to notify the parties of any supplier refunds, to continue to include information in future GSR filings on steps taken to mitigate the impact of gas costs, to continue to provide information in its GSR filings on volumes, costs and margins relating to interruptible sales and to continue to calculate the impact on its GSR of a thirty-year degree day average, if requested in discovery. *Id.* at 13-14.

48. Ms. Crane testified that she did not believe that the Company complied with two of the provisions of the Settlement Agreement. The first one was that the Company provide information to the parties regarding its AMA solicitation process. The second one was that the Company provide a recommendation whether or not to adopt dollar cost averaging. *Id.* at 14-15.

49. <u>AMA Solicitation Process</u>. Ms. Crane pointed out that in virtually every GSR filing since at least PSC Docket No. 05-315F, the AMA has been an issue. Since that filing, Ms. Crane alleges that the

Company has continuously failed to issue RFPs for AMA services, extended the existing AMA without the benefit of competitively bidding, and renegotiated terms of existing AMAs without providing prior notice to the parties. Ms. Crane claims that year after year, the Company has failed to provide the information until it was requested through the discovery process. Ms. Crane states that the AMA is very important to the ratemaking process because the entity has control over the Company's gas supply assets and how the Company will be compensated for the use of those assets. Currently, the Company receives a fixed fee (shared 90% with the ratepayers) for the services provided by the Asset Manager and the Asset Manager retains any margins earned from the assets under its control. Ms. Crane's concern with the Company's past renegotiations of the AMA is that the Company included an amendment transferring certain TETCO capacity to the Asset Manager. Ratepayers are paying 100% of this capacity costs and being credited 90% of the AMA fee. Also, she is concerned that the Asset Manager could possibly release this TETCO capacity to a Chesapeake Utilities Corporation affiliate and that the affiliate would not be charged at the full maximum FERC-approved rate for that capacity (which Ms. Crane contended would violate Chesapeake's cost allocation manual and code of conduct). In this proceeding, the Company stated in response to a data request that it would not provide the agreed-to details of the procurement process until it had concluded the process and that this was not in violation of the Settlement Agreement. Ms. Crane felt this refusal to provide the information prior to selecting an Asset Manager did not give the Staff or DPA the opportunity to provide input and to ensure the terms of the Agreement was in compliance with prior GSR Settlement Agreements. Ms. Crane recommended that (1) if the Company enters into a new AMA, or extends the current AMA, and the AMA provides for a fixed payment from the Asset Manager, then the ratepayers' share of the fixed payment should be 100%; (2) the Asset Manager should be required to provide information to the parties regarding the actual amount of margins earned each year from the Company's assets under its control so that the Commission can properly evaluate the performance of the Asset Manager and the benefits of the agreement, if any, to the ratepayers; (3) the Commission impose a penalty of $1,000 a day from December 27, 2012 to the date the Company files the required information for failing to provide the information outlined in the Settlement Agreement approved in PSC Order No. 8168 in PSC Docket No. 11-384F; (4) the Commission order the Company to provide the information that it agreed to in the Settlement Agreement (PSC Docket No. 11-384F); and (5) the ratemaking implications of any new AMA should be deferred until the parties have had a full opportunity to review the AMA and evaluate its terms and conditions. *Id.* at 15-22.

50. Capacity Additions. Ms. Crane points out that over the past few years Delaware Division has acquired significant additional pipeline capacity. In the past, Delaware Division reported a shortfall in its upstream capacity in that it did not have sufficient capacity to meet its design day requirement. It met its requirements by acquiring bundled peaking service on the coldest days of the year. The Company then committed to purchase 30,000 Dts of upstream capacity

effective November 1, 2012 from TETCO. An additional 4,100 Dts of capacity on TETCO is anticipated to go into service November 1, 2013. In the interim the Company obtained 15,000 Dts of TETCO capacity effective January 1, 2011 and an additional 11,250 Dts effective November 1, 2011. Since incremental upstream capacity requires a corresponding amount of capacity from Eastern Shore, the Company had to similarly increase its Eastern Shore capacity. With the acquisition of TETCO capacity, the Company now has 74,753 Dts/day of upstream pipeline capacity available. Currently, the Company's annual Supply Plan is based on a design day requirement of 73,994 Dts/day for this GSR period. The Company notified the parties that a new high demand was reached on January 22, 2013, when demand reached 58,163 Dts. The actual peak demand for the prior five year period was 49,973 Dts, which occurred on December 14, 2010. (DPA-15). With the additional capacity acquired by Delaware Division, it appears that the Company had a significant reserve between its capacity allocations and its actual requirements over the past several years. Delaware Division has been increasing its downstream capacity allocation from Eastern Shore in order to serve its projected growth in eastern Sussex County. According to Ms. Crane, the Company has overestimated this projected growth and some of this capacity is not being utilized. The Company increased its capacity in eastern Sussex County from 2,238 Dts in 2008 to an estimated 9,154 Dts in October 2012. In 2008, the Company projected by 2012 it would serve 1,414 residential customers in eastern Sussex County. As of July 2012, it serves 364 residential customers and 74 commercial customers. Although the Company received capacity release revenues in 2012, the ratepayers still paid for more capacity than required to serve the customers in eastern Sussex County. The Company currently has a pending proceeding, PSC Docket No. 12-292, seeking Commission approval of new rates and offerings to facilitate the proposed expansion of natural gas service in eastern Sussex County. The Company assumed this expansion proposal would be approved and developed its 2012 Supply Plan to include the capacity requirements needed for the future growth in eastern Sussex County. Therefore, the outcome of PSC Docket 12-292 is likely to significantly impact the Company's need for additional capacity and its future gas procurement costs, especially its fixed capacity costs. In May, 2012, the Company notified the parties that it was proposing to acquire additional capacity of 1,100 Dts/day effective November 1, 2012. The DPA had concerns about needing this capacity and notified the Company that there may be an objection to recovering these additional capacity costs from ratepayers. The Company has now entered into an agreement to add this capacity on November 1, 2013, which will affect the next GSR filing, instead of November 1, 2012. At that time the DPA will evaluate the need for this additional capacity. If the Company obligates excess capacity that is not utilized, ratepayers still bear the fixed costs associated with that excess capacity. Ms. Crane recommended that the Company provide its need for additional capacity with all the supporting documentation and analysis in its Annual Supply Plans or, if not included in its Annual Supply Plan, all of supporting documentation and analysis must be submitted to the parties before acquiring the capacity. Also, she is recommending that the

2013 Supply Plan should reflect the outcome of PSC Docket 12-292 and the Company should not acquire any additional pipeline capacity not included in the 2013 Supply Plan. *Id.* at 23-33.

51. Gas Commodity Costs. Ms. Crane described the Company's Gas Hedging Program. In PSC Docket 06-287F, the parties entered into a Stipulation to implement a hedging program effective July 1, 2007. The parties agreed to a Gas Hedging Plan ("Plan") under which the Company hedges 70% of its firm supply requirements over a twelve-month period prior to the month of delivery with 30% of the hedged volumes "hedged" at market prices. The Plan contemplates that approximately 50% (70% less (70%X30%)) of the Company's firm supply requirements will effectively be hedged prior to the month of delivery. The Plan is also limited to physical hedges and on a quarterly basis, the Company files Gas Hedging Reports with Staff and DPA showing the results of its hedging activities. There were modifications to the Plan as a part of the Settlement Agreement in PSC Docket No. 09-398F. The most important one was that the Company could accelerate the purchases of hedges in the event that natural gas prices for a specific delivery month decreased below 75% of the weighted average cost of gas used in the most recent GSR filing, and could delay the purchases of hedges in the event that natural gas prices for a specific delivery month rose above 125% of the weighted average cost of gas used in the most recent GSR filing. The Company would not be required to provide prior notification to Staff or DPA, but must report such actions within five business days of the transactions. If the Company wants to exceed the 70% hedging threshold, it must obtain

prior approval from the Staff and DPA. In PSC Docket 10-296F, the Company agreed to track and monitor a dollar-cost averaging mechanism. The intent of this tracking was to determine if ratepayers and the Company would benefit from adopting a dollar-cost averaging mechanism for hedging natural gas. The Company provided the Gas Hedging Report for quarter ending December 2012 on March 22, 2013. Ms. Crane reviewed the Company's hedging results to the NYMEX last day settle prices for the period November 1, 2011 through October 30, 2012. The Company used the average NYMEX high/low of the preceding twelve months. Ms. Crane believed her comparison was a better measure of the success/failure of the Plan because the Company would acquire the majority of its market-priced supply in the absence of the program. The result of her comparison was that the Company's actual cost of gas was $2.31 million, or 32.9%, above the NYMEX last day settle prices for the period November 1, 2011 through October 30, 2012. In the Settlement Agreement approved in PSC Order No. 8168 in PSC Docket 11-384F, the Company agreed to summarize the results of dollar cost averaging tracking in this GSR filing and submit its recommendation of whether or not to implement dollar cost averaging. The Company did not file this information with its Application. However, on January 9, 2013 the Company filed its Annual Report of its Natural Gas Supply Procurement Plan. In this report, the Company reported "Approximately 2% more gas is hedged in the current plan that (sic) would have been using dollar cost averaging. The average variance between the hedged price under the current methodology versus dollar cost averaging is approximately 2.4%. The two methodologies produced differences in both the quantity of gas hedged as well as the hedge price, but with little variance." According to Ms. Crane, the Company did not provide a recommendation with regard to dollar cost averaging as required in the Settlement Agreement. The Company did include a request for a one year trial study to be performed by Planalytics (propriety software for energy procurement recommendations) which analyzes dollar cost optimization and compares results to the Company's current hedging program. The Company previously made a presentation of this study to Staff and DPA on June 14, 2012 and the DPA informed the Company it did not see a benefit to ratepayers and would recommend that the Commission not approve this request if the Company proposed it. Ms. Crane believes the current hedging program is working relatively well and recommends that it continue for two more years, unless the Company formally requests changes to the program, such as the adoption of dollar cost averaging. *Id.* at 33-39.

C. <u>STAFF'S TESTIMONY</u>

52. ***JASON R. SMITH***. Mr. Smith, Case Manager, testified to the just and reasonableness of the proposed GSR rates, whether the rates were in compliance with the Company's tariff, and whether the Company was in compliance with the Settlement Agreement approved in PSC Order No. 8168 in PSC Docket No. 11-384F. *Id.* at 2 and 3.

53. Mr. Smith reviewed and verified the mathematical accuracy of the Company's schedules and calculations provided in the Application, and determined that they conform with the Company's GSR tariff. Therefore, he recommended that the Commission approve the GSR and firm

balancing rates as submitted by the Company because the rates are just and reasonable and in the public interest. *Id.* at 5.

54. Mr. Smith summarized the provisions of the Settlement Agreement approved in PSC Order No. 8168 in PSC Docket 11-384F and provided his opinion of the Company's compliance with those provisions. The following terms of the Agreement were: (1) Chesapeake agreed to review the dollar cost averaging framework for possible implementation as part of the next GSR filing and the Company agreed to continue tracking paper transactions utilizing the dollar cost averaging framework and provide the results as part of its quarterly report. The Company filed this information on January 9, 2013 as part of its Annual Report of the Company's Hedging Program. The Company summarized the results of the dollar cost averaging as "The two methodologies produced differences in both the quantity of gas hedged as well as the hedge price, but with little variance.", (2) the Company agreed to continue to utilize its annual Supply Plan as a mechanism by which to notify the DPA and Staff of the need for all new capacity additions, to notify the DPA and Staff of the need to add new capacity additions from either Eastern Shore or upstream pipelines not included in the Supply Plan, to continue to review its design day forecasting methodology each year, and to review and comment on any alternative design day forecasting methodology proposals submitted by either Staff or DPA during the course of any review of the Supply Plan. Staff believes the Company has complied with these terms and has given notice to Staff and DPA of any capacity acquisitions, (3) The Company has agreed to provide an annual status

report on its expansion activities in eastern Sussex County as part of the Company's main extension report that is filed in the spring of each year. The Company filed its main extension report on February 28, 2013 and included an update on the Company's eastern Sussex County expansion, (4) the Company's AMA was scheduled to expire on March 31, 2013 and to ensure that potential qualified service providers were afforded the opportunity to submit competitive proposals with regard to an AMA, the Company agreed to issue a formal RFP on or before December 31, 2012. The Company also agreed to provide (on a confidential basis) Staff and the DPA with (a) a copy of the RFP, (b) the number of entities receiving the Company's RFP, (c) the number of responses, (d) evaluation criteria relied upon by the Company, (e) analysis of bids, and (f) other documents as may be reasonably requested by Staff and DPA. Further, the Company agreed that if it entered into another AMA, a provision would be included in the AMA that any capacity released by the Company to the AMA cannot be re-released. The Company issued its RFP on December 27, 2012 with required proposals to be submitted by January 23, 2013. The Company met with Staff and DPA on February 5, 2013, but it advised Staff and the DPA that it had not finished reviewing the bids and would provide the confidential information after it had made a decision. On March 25, 2013, the Company informed Staff and the DPA that it had made a selection and would have a new AMA in effect as of April 1, 2013. Staff and DPA were working with the Company to coordinate a date for the Company to meet and provide the confidential information agreed to in the Settlement Agreement in PSC Order No. 8168 in PSC Docket 11-

384F, (5) the Company was permitted to continue to recover the TETCO capacity costs and the Eastern Shore capacity costs associated with the TETCO inter-connect and 100% of any capacity release revenues received outside of an AMA associated with that capacity will be credited to GSR. Staff believes there are no issues with this activity, (6) the Company agreed to provide Staff and the DPA with periodic updates regarding any intervention by the Company in FERC proceedings and the actions taken by the Company on behalf of its ratepayers. Staff continues to monitor FERC proceedings which may involve intervention by the Company. Staff believes the Company has complied with this provision, and (7) the Company agreed to continue the following practices: (a) notify Staff and DPA of any supplier refunds that may impact the GSR charges, (b) continue to include in future GSR filings an update on steps taken to mitigate the effects of changes in gas costs, (c) provide information on the total sales volumes, costs and margins by month for Interruptible Gas Transportation sales as part of its GSR filings, and calculate the impact on its proposed GSR rates had a thirty-year average degree day been used and provide such information as part of the discovery process, when and if requested. Staff is not aware of any failures by the Company to provide this information. *Id.* at 5-11.

55. Mr. Smith then noted that the Company included in its Application a request to recover through the GSR $50,000 for the use of EnergyBuyer® software provided by Planalytics. This software is advertised as a risk management solution to assist buyers in hedging both their financial and physical forward natural gas purchases. It

provides a price analysis and in theory is supposed to reduce the impact of price changes in volatile energy markets. The Company is proposing a one-year testing period to allow the Company to analyze dollar cost optimization and compare the results to the Company's current hedging program. Mr. Smith stated that Staff does not support the inclusion of this cost in the development of the commodity rate for the Company's current firm gas costs and asks that it be disallowed. The Company has not provided detailed information to show that this service is beneficial to the ratepayers since it is not being utilized for actual gas purchases. Other jurisdictions have allowed recovery of this cost, but it was based on key differences. The utilities used the software to make hedge purchases and/or had negotiated a performance based fee structure, neither of which exists here. *Id.* at 11-14.

56. ***Jerome D. Mierzwa, Consultant, Exeter Associates, Inc.*** Mr. Mierzwa testified on the reasonableness of the Company's gas procurement practices and policies and other issues raised by the Application. He summarized his findings and recommendations as follows: (1) Chesapeake's most recent LAUF gas experience has increased by more than 40 percent over historical levels. The Company has not yet been able to determine the cause. Mr. Mierzwa recommended that the Company file a report with the Commission on its investigation of the increased LAUF and that the Commission should not accept Chesapeake's claim for the increased LAUF until the reasonableness of the increase can be assessed. (2) He also stated that Chesapeake reserves capacity on Eastern Shore to meet the design

peak day demands of its firm sales and firm transportation customers. Firm transportation customers pay for the capacity reserved on their behalf by acquiring this capacity through capacity release. He commented that Chesapeake has reserved sufficient Eastern Shore capacity to meet the demands of all of its customers for the foreseeable future and Chesapeake should not acquire additional Eastern Shore capacity unless it receives Commission approval to do so. and (3) Mr. Mierzwa noted that Chesapeake reserves capacity on interstate pipelines upstream of Eastern Shore to meet the design peak day demands for its firm sales and firm transportation customers. This upstream capacity is not released to firm transportation customers and is largely paid for by firm sales customers. Mr. Mierzwa believes this is unreasonable and recommends that Chesapeake be required to reduce its non-storage upstream capacity by 17,602 Dth, on a non-recallable basis and terminating contracts where feasible. The Company should be required to make a filing with the Commission within 30 days of the final order in this proceeding identifying how it intends to reduce its upstream capacity, implement the solution after receiving Commission approval and credit any resulting cost reductions 100 percent to firm sales customers. *Id.* at 3-4.

57. <u>LAUF.</u> Mr. Mierzwa explained that LAUF is the difference between the measured volume of gas supply delivered to a gas utility's distribution system and the measured volume of gas disposition. Gas disposition includes both gas billed to customers and company use. There are several reasons why gas is unaccounted for. These include meter inaccuracies, cycle billing, temperature and pressure

conditions, pipeline leakages and meter tampering and other kinds of theft. Chesapeake's GSR commodity charge is determined by dividing the cost of all volumes purchased to serve GSR customers by the volume of gas sold to GSR customers. LAUF costs are recovered through the GSR commodity charges. For transportation customers, LAUF is recovered through a retainage charge, which is set based on the Company's actual five-year LAUF experience which is currently 3.86 percent. This is the current retainage charge. Chesapeake's most recent LAUF experience for the period ending July 31, 2012 is 5.50% or 40% higher than the five year average rate of 3.86%. The Company has indicated that it has not been able to determine the cause for this increase. Therefore, Mr. Mierzwa is recommending that the Commission require the Company to investigate this matter and upon completion, file a report with the Commission presenting its findings. The Commission should not accept Chesapeake's claim for increased LAUF until the investigation is complete and the reasonableness of the increase can be assessed. *Id.* at 4-6.

58. Capacity Planning and Management. Mr. Mierzwa described Chesapeake's interstate pipeline transportation and delivery arrangements. Chesapeake is directly connected to one interstate pipeline, Eastern Shore. All of the Company's gas supplies are physically delivered to it by Eastern Shore. Chesapeake reserves capacity on 3 pipelines, Transco, TETCO and Columbia, that are upstream of Eastern Shore and provide for delivery to Eastern Shore. Chesapeake also reserves capacity on Columbia Gulf which is delivered through Columbia. Chesapeake has upstream capacity arrangements with

Transco, TETCO, Columbia and Columbia Gulf. Typically, a gas utility reserves pipeline capacity to meet the design peak day demands of its firm retail sales customers. Design peak day is an extremely cold day that a gas utility selects and uses for capacity planning purposes. Chesapeake uses a day with an average temperature of 5°F. Also, it is common for gas utilities to reserve pipeline capacity to meet the design peak day demands of firm transportation customers or the balancing requirements of its firm transportation customers. If the utility reserves pipeline capacity for its firm transportation customers, those customers pay for that capacity. Chesapeake reserves pipeline capacity sufficient to meet the design peak day demands of its firm retail sales and the total design peak day demands of its firm transportation customers. Mr. Mierzwa provided a table comparing the Company's capacity entitlements and its firm design peak day demands for the current year and the next five years. The difference in these two is the Company's reserve margin. In this GSR Application, Mr. Mierzwa believes that Chesapeake has overstated the growth in design peak day demand. The Company's forecasts assume average annual customer growth of 6.5 percent through the winter of 2016-2017. The actual average annual growth rate is 2.7 percent for the last 4 years. This increase in growth rate is assuming that the anticipated growth in eastern Sussex County will materialize. Based on Chesapeake's current excess direct capacity position on Eastern Shore and the uncertainty of the outcome of the Company's expansion proceeding, PSC Docket 12-292, Mr. Mierzwa is recommending that Chesapeake not acquire any additional Eastern Shore capacity unless approved by the Commission. He believes that the Company has sufficient capacity committed through the winter of 2014-15 and if the Company needs to acquire capacity, it appears that long lead times are not required to acquire additional Eastern Shore capacity. Chesapeake reserves both upstream and direct Eastern Shore capacity on behalf of its firm transportation customers. The Company releases Eastern Shore capacity to its firm transportation customers and these customers pay for that capacity. The upstream capacity that the Company reserves for its firm transportation customers is not released to them and the cost of that upstream capacity is mainly paid by the firm sales customers. The only portion of that upstream capacity being paid for by the firm transportation customer is through the balancing charges. Mr. Mierzwa believes that this is unfair to GSR ratepayers. Therefore, since the total design peak day demand for firm sales and transportation customers for the winter of 2012-2013 is 73,994 Dts (51,481 Dts attributable to firm sales customers and 22,513 Dts attributable to firm transportation customers) and the Company needs to maintain some upstream capacity to meet the balancing requirements of the firm transportation customers and Chesapeake is projecting that 17,602 Dts of direct Eastern Shore capacity will be assigned to firm transportation customers, then Mr. Mierzwa is recommending that Chesapeake reduce its non-storage upstream capacity by 17,602 Dts. This would include releasing upstream capacity on a non-recallable basis and terminating contracts where feasible. The Company should make a filing with the Commission within 30 days of an order in this proceeding on how it intends to accomplish this and the resulting cost reductions should be credited 100% to the firm sales customers. Mr. Mierzwa estimated the value of the 17,602 Dts to be $3 million.

E. CHESAPEAKE'S REBUTTAL TESTIMONY

59. ***JEFFREY R. TIETBOHL.*** Trial Testing the EnergyBuyer® Software By Planalytics. Mr. Tietbohl disputed the arguments made by Staff Witness Jason Smith and Attorney General's Witness Andrea C. Crane concerning the disallowance of the $50,000 included in the GSR gas cost for a one year trial testing of the EnergyBuyer® Software by Planalytics. Mr. Tietbohl states that the software is a financial and volumetric approach to dollar cost averaging and is used by a large number of reputable gas companies. The Company is currently testing this software for this GSR period in parallel with the Company's current hedging program. He believes that testing the product is a reasonable course of action in light of the Company's commitment to study alternatives to the hedging program and that the cost of the one year trial period of $50,000 was reasonable whether the Company ultimately implemented the product or not. *Id.* at 6.

60. LAUF. Mr. Tietbohl disputed Mr. Mierzwa's recommendation concerning the LAUF gas. He explained that the five-year average of 3.86% that Mr. Mierzwa was using as the Company's LAUF also includes Company use gas and pressure compensation. Mr. Tietbohl states that the actual five-year average of LAUF (without Company Use and pressure compensation) is 2.39% based on total sales and 2.30% based on total receipts or send-out. He further points out that the LAUF (without Company Use and Pressure Compensation) is 4.07% for the time period

ended July 31, 2012, which is above the dead-band upper range (3.7%) in the Company's tariff. The Company investigated this matter and found no specific cause to date, but it did replace certain connections and meters. For the twelve months ending March 31, 2013, the LAUF (without Company Use and pressure compensation) is 3.22% which is below the dead band upper range of 3.7%. Also, Mr. Tietbohl points out that the Company used a five-year average of 3.28% (the same percentage used in PSC Docket 11-384F ignoring the increase of LAUF for the 2011-2012 time period) in this GSR Application and that figure includes LAUF, Company Use and Pressure Compensation. *Id.* at 7-10.

61. Acquisition of Additional Eastern Shore Capacity. Mr. Tietbohl disputed Mr. Mierzwa's recommendation that Chesapeake should obtain Commission approval before it acquires additional Eastern Shore capacity. Mr. Tietbohl argues that the terms of the Settlement Agreement in PSC Order No. 8168 in PSC Docket 11-384F state that the Company will provide prior notification and analysis to the parties for both Eastern Shore and upstream capacity additions and allow for a 15-day comment period. Mr. Tietbohl also states that in AG Witness Crane's testimony, she recommends that the Company continue to follow this provision. Finally, Mr. Tietbohl states that the Commission has final authority regarding the cost recovery for any capacity additions it may undertake. *Id.* at 10-11.

62. Eliminate 17,602 Dts of Its Upstream Capacity. Mr. Tietbohl disputed Mr. Mierzwa's recommendation that the Company eliminate 17,602 Dts of its upstream capacity. He explains that it is not

practical to release this upstream capacity on a permanent basis. The Company's service territory on the Delmarva Peninsula is isolated from the major interstate pipelines, which limits the Company's opportunities to acquire additional capacity that will ultimately benefit its firm customers. New pipeline capacity projects are taking an increasing amount of time to gain approval and may take several years before completion. He also believes the Company should be prepared for the possibility that a number of firm transportation customers could switch to firm sales service in which case the Company could be in a position of not having adequate capacity to meet the firm daily requirements of its firm sales service customers on a design day. *Id.* at 11-12.

63. Firm Transportation Customers Need to Contribute a More Appropriate Portion of the Cost of Upstream Pipeline Capacity. In response to Mr. Mierzwa's discovery request, the Company noted that it intends to make a regulatory filing with the Commission under a separate docket to propose an alternative approach whereby firm transportation customers contribute a more appropriate portion of the cost of upstream pipeline capacity. *Id.* at 13.

64. Asset Management Agreement. Mr. Tietbohl denied that the Company violated the spirit or the terms of the Settlement Agreement in PSC Docket No. 11-384F (PSC Order No. 8168) relating to the Company's new AMA. The Company asserts that it met the requirements of that Agreement as of April 22, 2013 when it met with DPA and Staff. Mr. Tietbohl points out that Staff does not believe that the Company violated either the letter or spirit of the Settlement Agreement

(pertaining to the AMA provision). Regarding AG Witness Crane's recommendation that 100 percent of any fixed payment to the Company under the AMA be credited to ratepayers, Mr. Tietbohl states that the Company's negotiating practices have a positive impact on the amount of the fixed monthly fee and accordingly, a sharing arrangement is reasonable. Mr. Tietbohl states that the current sharing approach was designed to provide the Company with an extra incentive to maximize the fixed monthly fee. Because the Company's actions do affect the fixed monthly fee recovered, Mr. Tietbohl believes the current sharing mechanism of 90% credit to the GSR and 10% to the Company is appropriate. Mr. Tietbohl also points out that the Company did not choose a variable payment because there is no guarantee that a fee would be received every month. Under a variable payment or margin sharing arrangement, the level of revenues is solely dependent upon how effective the Asset Manager is at utilizing the Company's portfolio of Assets. Finally, Mr. Tietbohl wanted to clarify that although the Company did not include language that prohibited the Asset Manager from re-releasing the Company's capacity in its RFP, the final AMA did include this language. The Company provided a copy of the AMA with this language at its meeting on or about April 22, 2013. *Id.* at 13-17.

65. Whether Or Not To Adopt Dollar Cost Averaging. Mr. Tietbohl clarified the Company's position on whether or not to adopt dollar cost averaging. The Company provided in its Natural Gas Procurement Plan, filed on January 9, 2013, the results of its analysis of dollar cost averaging versus its currently approved hedging plan. The

analysis, as previously noted, shows the difference in the two methodologies is insignificant. Accordingly, the Company does not support a change at this time. Therefore, the Company proposed to continue to hedge under its currently approved guidelines pending the finalization of its analysis of the EnergyBuyer® software one-year trial period. *Id.* at 17.

66. Other Recommendations by Staff and the AG. Mr. Tietbohl did agree with Staff and the AG Witnesses that the GSR rates are just and reasonable and in the public interest. The only objection to this was the recommended denial of recovery of the $50,000 for the EnergyBuyer® costs that were included in the GSR calculation. He also agreed with the AG Witness Crane that the Company's need for future capacity will be impacted by the outcome of the expansion in Sussex County proceeding, PSC Docket No. 12-292; that the Company should continue to utilize the Supply Plan to identify the need for all new capacity additions well in advance of executing contracts; and that the current gas hedging program is working well and should be continued for another year. *Id.* at 18-19.

IV. PROPOSED SETTLEMENT AGREEMENT

67. On May 23, 2013, Chesapeake, Staff and the Attorney General's Office presented me with the fully-executed Settlement Agreement (Exh. 8) resolving the issues in this docket. The signatories agreed to the following:

- The proposed GSR rates are just and reasonable and should be approved, subject to the next two bullet points that will be reflected in a subsequent true-up;

- Chesapeake shall be allowed to continue to recover the TETCO capacity costs and Eastern Shore capacity costs associated with the TETCO inter-connect. With respect to any capacity release revenues received outside of an AMA associated with this capacity, one hundred percent (100%) of any capacity release revenues associated with the release of this capacity will be credited to the GSR;

- The Settling Parties agree that no part of any fees paid to Planalytics, Inc. for the use of their EnergyBuyer® software in connection with the Company's pilot program will be recovered in the Company's GSR rates;

- With respect to the Company's Hedging Plan, as agreed to in the settlement of the prior GSR proceeding, Chesapeake has reviewed the dollar cost averaging framework for possible implementation. Based on that review, the Settling Parties agree that the Company, in the context of its Hedging Plan, will not implement dollar cost averaging at this time;

- The Company agrees to continue to utilize its annual Supply Plan as a mechanism by which to notify the Settling Parties of the need for all new capacity additions. When the Company needs to acquire capacity in any given year that was not previously identified in its most recent Supply Plan as being required in that year, the Company agrees to continue to provide the information agreed to in the Settlement Agreements in PSC Docket Nos. 08-296F and 09-398F regarding Eastern Shore capacity acquisitions and agrees to provide this information for potential upstream capacity additions as well. The Company will provide this information for both Eastern Shore and upstream capacity on a confidential basis only. The Company will continue to review its design day forecasting methodology each year at the time the Supply Plan is developed to ensure its validity. The Company will also review and comment on any alternative design day forecasting methodology proposals submitted by either the Staff or the DPA during the course of the Company's Supply Plan;

- The Company's AMA that expired on March 31, 2013 has been replaced with a new AMA with a different Asset Manager. Under the new AMA the Company will receive certain fixed margins on a monthly basis. The Settling Parties agree that with respect to said fixed margins, the Company shall be allowed to retain seven and one half percent (7.5%) of the fixed margins, with the remaining ninety-two and one half percent (92.5%) being credited to ratepayers in the Company's GSR rates, effective June 1, 2013;

- The Company recently experienced an increase in the LAUF (without Company use and Pressure Compensation) and has been investigating the source of this increase. The Company has begun to take corrective actions based on the results of its investigation, such as replacing certain connections and meters. The LAUF (without Company use and Pressure Compensation) is currently within the dead-band target range. The Company will continue to investigate the source(s) of the prior increase in LAUF (without Company use and Pressure Compensation) and will file with the Commission a written report of the Company's final findings on or before the date on which the Company files its next GSR application;

- On or before October 1, 2013, the Company agrees to submit a regulatory filing with the Commission in which the Company will propose changes to its current transportation program mechanics for commercial and industrial customers and which will propose an alternative approach regarding the allocation of the cost of upstream pipeline capacity to transportation customers;

- Chesapeake agrees to provide the Staff and DPA with periodic updates regarding any intervention by the Company in FERC proceedings and the actions taken by the Company on behalf of the Company's ratepayers, including, but not limited to, an enumeration of each issue and the position that the Company is actively pursuing. The Company will provide such periodic updates to the Staff and DPA subject to the Company's ability to provide this information on a confidential basis when appropriate; and

- As agreed in prior dockets, the Company will continue with the following practices: (a) the Company will notify the parties of any supplier refunds that may impact the GSR charges; (b) the Company will continue to include in future GSR applications an update on steps taken to mitigate the effects of changes in gas costs; (c) the Company will provide information on the total sales volumes, costs, and margins by month for Interruptible Gas Transportation sales as part of its GSR applications; and (d) the Company will calculate the impact on its proposed GSR rates had a thirty-year average degree days been used and provide such information to the Staff and DPA as part of the discovery process, when and if requested.

(Exh. 8 at 2-5.)

IV. **DISCUSSION AND RECOMMENDATIONS**

68. The Commission has jurisdiction in this matter pursuant to *26 Del. C.* §303(b), §304 and §306.

69. Pursuant to the Commission's instructions, I hereby submit for consideration these proposed Findings and Recommendations.

70. After having reviewed the entire record, I conclude that the Settlement Agreement is in the public interest, results in just and reasonable rates and should be approved.

71. First, 26 Del. C. §512(a) provides that "[i}nsofar as practicable, the Commission shall encourage the resolution of matters brought before it through stipulations and settlements." Clearly, this reflects a legislative intent that the Commission welcomes settlements of part or all of a case.

72. Second, I note that each of the Settlement's signatories represents a different constituency and comes to the case with different interests. Chesapeake's interest is in recovering all of its actual gas costs (as 26 Del. C. §303(b) permits). Staff is required to balance the utility's and ratepayers' interests. And 29 Del. C. §8716(d)(2) charges the Division of the Public Advocate (represented by the Attorney General's Office) with advocating the lowest reasonable rates for consumers consistent with maintaining adequate utility service and an equitable distribution of rates among all the utility's customer classes. Despite these disparate interests and responsibilities, the parties have reached agreement. This, in my view, is a significant factor weighing in favor of approving the Settlement.

73. Third, the witnesses for both Staff and the Attorney General's Office testified that they had reviewed Chesapeake's forecasts, methodologies and calculations of the proposed GSR rates and found them to be in compliance with previous Commission Orders, reasonable and accurate. Therefore, the proposed GSR rates were not challenged.

74. Fourth, the Company has agreed to increase the GSR ratepayers' sharing percentage from 90 percent to 92.5 percent of the fixed fee paid by the Asset Manager to Chesapeake, to forego recovery of the $50,000 cost for the one-year trial program to use the EnergyBuyer® software, to inform Staff and the DPA on the results of its investigation of LAUF gas, to submit a regulatory filing with the Commission that will propose an alternative approach regarding the allocation of the cost of upstream pipeline capacity to transportation customers, and to keep Staff and the DPA informed of any new additional capacity needs, ways it can mitigate gas cost, participation in FERC proceedings, potential supplier refunds, and Interruptible Gas Transportation sales.

75. Fifth, the Settlement is in the public interest because it avoids additional administrative and hearing costs which results in savings of rate case expense.

76. For the foregoing reasons, I conclude that the Settlement Agreement, attached hereto as Exhibit "1", results in just and reasonable rates and is in the public interest, and recommend that the Commission approve it. I attach a form of Order implementing my recommendations hereto as Exhibit "2".

Respectfully Submitted,

Date: July 2, 2013

____
Hearing Examiner

A T T A C H M E N T "B"

BEFORE THE PUBLIC SERVICE COMMISSION

OF THE STATE OF DELAWARE

IN THE MATTER OF THE APPLICATION OF CHESAPEAKE UTILITIES CORPORATION FOR APPROVAL OF A CHANGE IN ITS GAS SALES SERVICE RATES ("GSR") TO BE EFFECTIVE NOVEMBER 1, 2012 (FILED SEPTEMBER 21, 2012)	))))))	PSC DOCKET NO. 12-450F

PROPOSED SETTLEMENT

On this 23rd day of May, 2013, Chesapeake Utilities Corporation, a Delaware corporation (hereinafter "Chesapeake" or the "Company"), and the other undersigned parties (all of whom together are the "Settling Parties") hereby propose a settlement that, in the Settling Parties' view, appropriately resolves all issues raised in this proceeding.

I. INTRODUCTION

1. On September 21, 2012, Chesapeake filed with the Delaware Public Service Commission (the "Commission") an application (the "Application") for a change in its Gas Sales Service Rates to be effective for service rendered on and after November 1, 2012. By Commission Order No. 8227 dated October 9, 2012, the Commission allowed Chesapeake's proposed rates to go into effect on November 1, 2012, on a temporary basis, and subject to refund, pending a full evidentiary hearing and a final decision of the Commission.

2. The Delaware Public Advocate ("DPA") intervened in this docket. Subsequent to his intervention, the Public Advocate resigned from office, and has yet to be replaced. In the interim, the Attorney

General of the State of Delaware ("AG") was granted leave to intervene. On or about March 26, 2013, the Delaware Public Service Commission Staff ("Staff") and the AG filed their respective testimonies, raising certain cost recovery and reporting issues with respect to Chesapeake's Application.

3. Subsequently, on or about May 2, 2013, Chesapeake filed its rebuttal testimony pursuant to which Chesapeake took issue with various Staff and AG recommendations.

4. During the course of this proceeding, the Settling Parties have conducted substantial written discovery in the form of both informal and formal data requests.

5. The Settling Parties have conferred in an effort to resolve all cost recovery and reporting issues raised in this proceeding. The Settling Parties acknowledge that the parties differ as to the proper resolution of many of these issues. Notwithstanding these differences, the Settling Parties have agreed to enter into this Proposed Settlement on the terms and conditions contained herein because they believe that this Proposed Settlement will serve the interest of the public and the Company, while meeting the statutory requirement that rates be both just and reasonable. The Settling Parties agree that subject to the approval of the Hearing Examiner, the terms and conditions of this Proposed Settlement will be presented to the Commission for the Commission's approval.

II. SETTLEMENT PROVISIONS

6. The Settling Parties agree that the Company's proposed rates as set forth in the Company's Application are just and

reasonable, subject to the provisions of paragraphs 10 and 11 that will be reflected in a subsequent true-up.

7. With respect to the Company's Natural Gas Commodity Procurement Plan ("Hedging Plan"), as agreed to in the settlement to the prior GSR proceeding, Chesapeake has reviewed the dollar cost averaging framework for possible implementation. Based on that review, the Settling Parties agree that the Company, in the context of its Hedging Plan, will not implement dollar cost averaging at this time.

8. The Company agrees to continue to utilize its annual Long-Term Supply and Demand Strategic Plan ("Supply Plan") as a mechanism by which to notify the Settling Parties of the need for all new capacity additions. When the Company needs to acquire capacity in any given year that was not previously identified in its most recent Supply Plan as being required in that year, the Company agrees to continue to provide the information agreed to in the Settlement Agreements to PSC Docket Nos. 08-296F and 09-398F regarding Eastern Shore Natural Gas Company ("ESNG") capacity acquisitions and agrees to begin providing this information for potential upstream capacity additions as well. The Company will provide this information for both ESNG and upstream capacity on a confidential basis only. The Company will also continue to review its design day forecasting methodology each year at the time the Supply Plan is developed to ensure its validity. The Company will also review and comment on any alternative design day forecasting methodology proposals submitted by either the Staff or the DPA during the course of any review of the Company's Supply Plan.

9. The Company’s AMA that expired on March 31, 2013 has been replaced with a new AMA with a different Asset Manager. Under the new AMA the Company will receive certain fixed margins on a monthly basis. The Settling Parties agree that with respect to said fixed margins, the Company shall be allowed to retain seven and one half percent (7.5%) of the fixed margins, with the remaining ninety-two and one half percent (92.5%) being credited to ratepayers in the Company’s GSR rates, effective June 1, 2013.

10. Chesapeake shall be allowed to continue to recover the Texas Eastern capacity costs and the ESNG capacity costs associated with the Texas Eastern inter-connect. With respect to any capacity release revenues received outside of an Asset Management Agreement associated with this capacity, one hundred percent (100%) of any capacity release revenues associated with the release of this capacity will be credited to the GSR.

11. The Settling Parties agree that no part of any fees paid to Planalytics, Inc. for the use of their EnergyBuyer software in connection with the Company’s pilot program will be recovered in the Company’s GSR rates.

12. The Company recently experienced an increase in the unaccounted-for-gas cost (“UFG”) and has been investigating the source of this increase. The Company has begun to take corrective actions based on the results of its investigation, such as replacing certain connections and meters. The UFG is currently within the dead-band target range. The Company will continue to investigate the source(s) of the prior increase in UFG and will file with the Commission a

written report of the Company’s final findings on or before the date on which the Company files its next GSR application.

13. On or before October 1, 2013, the Company agrees to submit a regulatory filing with the Commission in which the Company will propose changes to its current transportation program mechanics for commercial and industrial customers and which will propose an alternative approach regarding the allocation of the cost of upstream pipeline capacity to transportation customers.

14. Chesapeake agrees to provide the Staff and DPA with periodic updates regarding any intervention by the Company in Federal Energy Regulatory Commission (“FERC”) proceedings and the actions taken by the Company on behalf of the Company’s ratepayers, including, but not limited to, an enumeration of each issue and the position that the Company is actively pursuing. The Company will provide such periodic updates to the Staff and DPA subject to the Company’s ability to provide this information on a confidential basis when appropriate.

15. As agreed in prior dockets, the Company will continue with the following practices: (a) the Company will notify the parties of any supplier refunds that may impact the GSR charges; (b) the Company will continue to include in future GSR applications an update on steps taken to mitigate the effects of changes in gas costs; (c) the Company will provide information on the total sales volumes, costs, and margins by month for Interruptible Gas Transportation sales as part of its GSR applications; and (d) the Company will calculate the impact on its proposed GSR rates had a thirty-year average degree days been used

and provide such information to the Staff and DPA as part of the discovery process, when and if requested.

III. STANDARD PROVISIONS AND RESERVATIONS

16. The provisions of this Proposed Settlement are not severable except by written agreement of the Settling Parties.

17. This Proposed Settlement represents a compromise for the purposes of settlement and shall not be regarded as a precedent with respect to any rate making or any other principle in any future case or in any existing proceeding, except that, consistent with and subject to the provisos expressly set forth below, this Proposed Settlement shall preclude any Settling Party from taking a contrary position with respect to issues specifically addressed and resolved herein in proceedings involving the review of this Proposed Settlement and any appeals related to this Proposed Settlement. No party to this Proposed Settlement necessarily agrees or disagrees with the treatment of any particular item, any procedure followed, or the resolution of any particular issue addressed in this Proposed Settlement other than as specified herein, except that each Settling Party agrees that the Proposed Settlement may be submitted to the Commission for a determination that it is in the public interest and that no Settling Party will oppose such a determination. Except as expressly set forth below, none of the Settling Parties waives any rights it may have to take any position in future proceedings regarding the issues in this proceeding, including positions contrary to positions taken herein or previously taken.

18. If this Proposed Settlement does not become final, either because it is not approved by the Commission or because it is the subject of a successful appeal and remand, each of the Settling Parties reserves its respective rights to submit additional testimony, file briefs, or otherwise take positions as it deems appropriate in its sole discretion to litigate the issues in this proceeding.

19. This Proposed Settlement will become effective upon the Commission's issuance of a final order approving this Proposed Settlement and all the settlement terms and conditions without modification. After the issuance of such final order, the terms of this Proposed Settlement shall be implemented and enforceable notwithstanding the pendency of a legal challenge to the Commission's approval of this Proposed Settlement or to actions taken by another regulatory agency or Court, unless such implementation and enforcement is stayed or enjoined by the Commission, another regulatory agency, or a Court having jurisdiction over the matter.

20. The obligations under this Proposed Settlement, if any, that apply for a specific term set forth herein shall expire automatically in accordance with the term specified and shall require no further action for their expiration.

21. The Settling Parties may enforce this Proposed Settlement through any appropriate action before the Commission or through any other available remedy. The Settling Parties shall consider any final Commission order related to the enforcement or interpretation of this Proposed Settlement as an appealable order to the Superior Court of

the State of Delaware. This shall be in addition to any other available remedy at law or in equity.

22. If a Court grants a legal challenge to the Commission's approval of this Proposed Settlement and issues a final non-appealable order which prevents or precludes implementation of any material term of this Proposed Settlement, or if some other legal bar has the same effect, then this Proposed Settlement is voidable upon written notice by any of the Settling Parties.

23. This Proposed Settlement resolves all of the issues specifically addressed herein; provided, however, that this Proposed Settlement is made without admission against or prejudice to any factual or legal positions which any of the Settling Parties may assert (a) if the Commission does not issue a final order approving this Proposed Settlement without modifications; or (b) in other proceedings before the Commission or other governmental body. This Proposed Settlement is determinative and conclusive of all of the issues addressed herein and, upon approval by the Commission, shall constitute a final adjudication as to the Settling Parties of all of the issues in this proceeding.

24. This Proposed Settlement is expressly conditioned upon the Commission's approval of all of the specific terms and conditions contained herein without modification. If the Commission fails to grant such approval, or modifies any of the terms and conditions herein, this Proposed Settlement will terminate and be of no force and effect, unless the Settling Parties agree in writing to waive the application of this provision. The Settling Parties will make their

best efforts to support this Proposed Settlement and to secure its approval by the Commission.

25. It is expressly understood and agreed that this Proposed Settlement constitutes a negotiated resolution of the issues in this proceeding and any related court appeals.

IV. CONCLUSION

Intending to legally bind themselves and their successors and assigns, the undersigned parties have caused this Proposed Settlement to be signed by their duly authorized representatives.

Chesapeake Utilities Corporation

Dated: 5/23/13 By: /s/Jeffrey R. Tietbohl

Delaware Public Service Commission Staff

Dated: 5/23/2013 By: /s/Robert Howatt

Attorney General of the State of Delaware

Dated: 5/23/13 By: /s/ James Adams