BEFORE THE DELAWARE PUBLIC SERVICE COMMISSION

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, 2017	)))))	P.S.C. DOCKET NO. 17-

DIRECT TESTIMONY OF MATTHEW M. EVERNGAM

On Behalf of Chesapeake Utilities Corporation

Delaware Division

Submitted for filing: September 1, 2017

Q. PLEASE STATE YOUR NAME, OCCUPATION AND BUSINESS ADDRESS.

A. My name is Matthew M. Everngam and I am a Regulatory Analyst III with Chesapeake Utilities Corporation. My business address is 350 S. Queen Street, Dover, Delaware 19904.

Q. BRIEFLY DESCRIBE YOUR EDUCATION AND RELEVANT PROFESSIONAL BACKGROUND.

A. I received a Bachelor of Science degree in Business Administration and a Masters of Business Administration from Salisbury University in Salisbury, MD. I was hired by Chesapeake as a Regulatory Analyst II in October 2010. As a Regulatory Analyst III, I have been involved in gas cost recovery, rate of return analysis, rate case preparation, and budgeting for Chesapeake Utilities – Delaware & Maryland natural gas distribution divisions, and Sandpiper Energy Inc. I have also performed economic analysis related to capital expenditure projects. Prior to joining Chesapeake, I was employed by Edward Jones Investments as a Financial Advisor. In this position I held Series 7 and Series 66 licenses with the National Association of Securities Dealers ("NASD").

Q. WHAT IS THE PURPOSE OF YOUR DIRECT TESTIMONY IN THIS PROCEEDING?

A. The purpose of my testimony is to discuss the mechanics of the three GSR charges, explain the development of the firm and interruptible sales volumes and total system requirements, and discuss the development of the unaccounted for gas volumes. In addition, my testimony will support the overall calculation of the Delaware Division's three proposed GSR charges to be effective with service rendered on and after November 1, 2017, as well as the mechanics of the Delaware Division's proposed balancing rates for transportation service under the General Service ("GS"), Expansion Area General Service ("EGS"), Medium Volume Service ("MVS"), Expansion Area Medium Volume Service ("EMVS"), Large Volume Service ("LVS"), High Load Factor Service ("HLFS") and Interruptible Service ("ITS") rate schedules. I will be illustrating the impact of the proposed GSR charges on an average residential customer's bill and ensuring compliance with the gas cost provisions outlined in previous Commission Orders. Additionally, my testimony will support a request to add tariff language which gives the Company the option of filing for new GSR rates should the projected over under balance fall outside of 3% of actual firm gas costs incurred plus projected firm gas costs over the remainder of the over/under collection period.

Q. ARE THERE ANY SCHEDULES INCLUDED WITH YOUR DIRECT TESTIMONY?

A. Yes. My direct testimony includes Schedules A.1, A.2, B, C.1, C.2, D.1, D.2, E, F, G, H, I, J, L, and M. Schedule K, which is a comparison of Chesapeake's GSR rates with those of other utilities in the area, will be submitted under separate cover to the Commission within forty-five (45) days after filing this GSR application, as required by Order 7607 issued on July 7, 2009, in PSC Docket No. 08-269F.

Q. IS THE COMPANY FILING ANY OTHER DIRECT TESTIMONY IN THIS PROCEEDING?

A. Yes. Chesapeake is also filing the direct testimony of William R. Kriss, Manager of Gas Supply and Transportation Services. Mr. Kriss will be presenting testimony regarding the Company's gas supply and procurement activities.

Q. WHAT PRESCRIBES THE METHODOLOGY FOR DETERMINING THE COMPANY'S GAS SALES SERVICE RATES?

A. The three Gas Sales Service Rates proposed to be effective with service rendered on and after November 1, 2017 have been developed in accordance with the approved gas cost recovery mechanism as contained in the Delaware Division's natural gas tariff, specifically Sheet Nos. 42 through 42.3.

Q. WHAT GAS SALES SERVICE RATE LEVELS ARE YOU PROPOSING IN THIS PROCEEDING TO BE EFFECTIVE WITH SERVICE RENDERED ON AND AFTER NOVEMBER 1, 2017?

A. The Company proposes the following Gas Sales Service Rates to be effective for service rendered on and after November 1, 2017: $1.023 per Ccf for customers served under rate schedules RS-1, ERS-1, RS-2, ERS-2, GS, EGS, MVS, EMVS, and LVS, $0.468 per Ccf for customers served under rate schedules GLR and GLO, and $0.782 per Ccf for customers served under rate schedule HLFS. Chesapeake is also proposing the following balancing rates to be effective for service rendered on and after November 1, 2017: $0.093 per Ccf for transportation customers served under rate schedules GS and EGS, $0.111 per Ccf for transportation customers served under rate schedules MVS and EMVS, $0.084 per Ccf for transportation customers served under rate schedule LVS, $0.014 per Ccf for transportation customers served under rate schedule HLFS, and $0.011 per Ccf for transportation customers served under rate schedule ITS.

Q WHAT EFFECT WILL THIS PROPOSED INCREASE IN THE GSR HAVE UPON THE AVERAGE RESIDENTIAL HEATING CUSTOMER?

A. As compared to the rates that were in effect November 1, 2016, an average RS-2 customer using 700 Ccf per year will experience an annual increase of approximately 15.13% or $11.96 per month. During the winter heating

season, a typical RS-2 customer on Chesapeake's system using 110 Ccf per month will experience an increase of approximately 17.08% or $22.55 per winter month. A typical RS-2 customer using 120 Ccf per winter month will experience an increase of approximately 17.38% or $24.60 per winter month.

Q. PLEASE DESCRIBE HOW YOU CALCULATED THE PROPOSED GAS SALES SERVICE RATE LEVELS TO BE IMPLEMENTED IN THIS PROCEEDING.

A. The rates were calculated based on the estimated purchased gas costs and estimated sales volumes for the twelve months ending October 31, 2018 and are summarized on Schedule A.1. As shown on Schedule A.1, total projected firm gas costs recoverable through the gas cost recovery mechanism are $44,848,424. This total is comprised of $29,223,381 of fixed costs and $15,625,043 of variable costs. The three gas cost rates shown at the top of Schedule A.1, which include a fixed rate (used to calculate separate demand rates), a variable / commodity rate, and a total rate or system average rate, are the key components for calculating separate Gas Sales Service Rates for different services.

Q. CAN YOU BRIEFLY SUMMARIZE THE REASONS WHY THE THREE GSR CHARGES ARE CHANGING FROM THE COMPANY'S PREVIOUS FILING?

A. The analysis of the change in gas costs and Gas Sales Service Rates from the Company's last gas cost recovery filing is summarized on Schedule E. As shown on this schedule, variable or commodity gas costs are anticipated to increase by $4,674,932 since the last GSR filing. The variable costs contained in this filing are increasing primarily due to the Company's current under-collection balance of $3,232,359, which was a result of lowered volumes due to a warmer than normal winter heating season.

As shown on this schedule, fixed costs are anticipated to increase by $6,565,376 since the last GSR filing. The increase in fixed gas costs is attributable to the addition of 16,500 dt of capacity anticipated to be placed in service in May 2018 and anticipated increased reservation rates as a result of the ongoing rate case for the FERC regulated Eastern Shore Natural Gas "ESNG" pipeline.

The above mentioned factors result in an increase to the system average cost per Ccf of $1.081 per Ccf in this filing versus $0.882 in the November 1, 2016 filing.

Q. PLEASE DESCRIBE THE PROCESS THE COMPANY USED TO DETERMINE ITS GSR LEVELS AND THE VARIOUS COMPONENTS OF THE DELAWARE DIVISION'S GSR CALCULATIONS AS SHOWN ON SCHEDULE A.1.

A. Schedule A.1 is a summary of the calculation of the three proposed GSR levels. The calculations of the proposed GSR levels have been made in

accordance with the provisions set forth in the Delaware Division's GSR tariff clause. The process to determine the GSR charges consists of three major steps:

1. Develop the sales and associated gas supply requirements forecast.
2. Forecast supplier rates and calculate annual purchased gas costs associated with serving the Company's firm sales customers.
3. Derive the GSR charges utilizing the results of the first two steps and the process below:

Step 3 is summarized on Schedule A.1. Initially, three gas cost rates must be established to calculate the three separate GSR charges: a fixed rate, a commodity rate and a system average rate. Based on total firm gas costs recoverable through the gas cost recovery mechanism for the GSR levels to be effective November 1, 2017, the three gas cost rates are calculated as follows:

Fixed Rate - $33.19/ Ccf	(Total fixed costs of $29,223,381 divided by the firm peak day capacity requirements of 880,370 Ccf)
Commodity Rate - $0.377 / Ccf	(Total firm commodity costs of $15,625,043 divided by firm sales volumes of 41,474,993 Ccf for the period November 2017 through October 2018)

System Average Rate -$1.081 / Ccf (Divide total firm gas costs of $44,848,424 by the firm sales volume of 41,474,993 Ccf)

From these three rates, different methodologies are applied in order to calculate the Gas Sales Service Rates that more closely align the Gas Sales Service Rates with actual gas costs identified for providing services associated with different rate schedules or customer classes.

Q. PLEASE EXPLAIN THE THREE METHODOLOGIES UTILIZED TO CALCULATE THREE SEPARATE GAS SALES SERVICE RATES USING THE FIXED RATE, COMMODITY RATE AND SYSTEM AVERAGE RATE AS PREVIOUSLY DESCRIBED.

A. Schedule A.1 also provides a summary of the development of the three separate Gas Sales Service Rates by applying the tariff language described in the Delaware Division's tariff on Sheet No. 42.2.

<u>Rate Schedule HLFS</u>

This GSR charge, applicable to any customer qualifying for High Load Factor Service (HLFS), is calculated based on the combination of a weighted average demand and commodity rate developed on an overall 86.81% load factor for the customer class and the overall system weighted average cost rate. The 86.81% load factor is included on Schedule J. This means that the fixed gas cost rate of $33.19 per Ccf, as previously described, is divided by 317days (86.81% of 365 days in a year) to calculate

a demand rate of $0.105 per Ccf. This rate is then added to the commodity rate, as previously described, of $0.377 per Ccf to calculate a volumetric rate of $0.482 per Ccf. The arithmetic average of this volumetric rate ($0.482 per Ccf) and the system average rate ($1.081 per Ccf) is $0.782 per Ccf, which equals the GSR charge for HLFS customers. Total costs associated with HLFS $2,408,318) are projected by multiplying the GSR charge $0.782 per Ccf) by the projected sales volumes for HLFS (3,079,690 Ccf).

Rate Schedules GLO and GLR

All customers served under these Gas Lighting rate schedules will be subject to the same GSR charge. This rate is calculated using weighted average demand and commodity rates through a single gas cost rate per Ccf, based on a 100% load factor. The demand rate of $0.091 per Ccf ($33.19 / 365) plus the commodity rate of $0.377 per Ccf, produces a GSR charge of $0.468 per Ccf. Total costs associated with Gas Lighting Services of $0 are a result of multiplying the $0.468 per Ccf GSR charge by the annual sales volumes for these services of 0 Ccf.

Rate Schedules RS-1, ERS-1, RS-2, ERS-2, GS, EGS, MVS, EMVS and LVS

These rate schedules are assigned the remaining firm purchased gas costs after the firm purchased gas costs have been calculated for the above mentioned rate schedules ($44,848,424 - $2,408,318 - $0 = $42,440,106). Associated costs are divided by the remaining volume (41,474,993 –

3,079,690 – 0 = 38,395,303) to develop a rate of $1.105 per Ccf, less the portion of any shared margins ($0.082 per Ccf) as shown on Schedule A.2. All customers served under rate schedules RS-1, ERS-1, RS-2, ERS-2, GS, EGS, MVS, EMVS, and LVS will be charged $1.023 per Ccf for service rendered on and after November 1, 2017.

Q. PLEASE DEFINE THE TERM “SHARED MARGINS”.

A. Shared Margins are defined as any margins that the Company receives as a result of interruptible transportation service, off system sales or capacity releases. There are different thresholds for sharing each type of margins received.

Q. PLEASE DESCRIBE THE EFFECTIVE MARGIN SHARING PERIOD AND THE THRESHOLDS THAT HAVE BEEN APPROVED BY THE COMMISSION.

A. Pursuant to the settlement agreement reached in PSC Docket 12-450F, the Company will retain 7.5% of all capacity release credits received from the Company’s Asset Manager and credit 92.5% to the firm ratepayers. Also, as outlined in the settlement agreement reached in PSC Docket No. 09-398F, the Company is permitted to retain 100% of all interruptible transportation margins up to $675,000 per year and 10% of all interruptible transportation margins over $675,000 per year. As shown on Schedule A.2, the Company is not projected to reach the sharing threshold for interruptible

transportation margins in this twelve month determination period. Schedule A.2 does show the calculation of the $0.822 per Mcf margin sharing rate, proposed to be effective November 1, 2017, as a result of the sharing of the capacity valuation credit from the Asset Manager. The Company is not projecting any off system sales for this determination period.

Q. IN THIS FILING, WAS THE FULL BENEFIT OF PROJECTED CAPACITY RELEASES TO TRANSPORTATION CUSTOMERS ON EASTERN SHORE NATURAL GAS COMPANY'S ("EASTERN SHORE") SYSTEM CREDITED TO THE DELAWARE DIVISION FIRM RATEPAYERS?

A. Yes. The Company believes, as stated in prior GSR filings, that crediting 100% of the revenue received from capacity released to the Delaware Division's transportation customers to the firm sales customers is appropriate due to the market on Eastern Shore for this capacity. The Company has estimated this capacity release value to be $5,042,314 for the twelve-month period ending October 2018 as calculated on Schedule I and shown as a reduction to fixed demand costs on Schedule B.

Q. AS INDICATED IN YOUR TESTIMONY, THE FIRST STEP IN CALCULATING THE PROPOSED GSR CHARGES IS THE DEVELOPMENT OF THE SALES AND ASSOCIATED GAS SUPPLY REQUIREMENTS FORECAST. HOW ARE THE SALES AND SUPPLY REQUIREMENTS FORECASTS DEVELOPED IN THIS PROCEEDING?

A. A forecast of purchased gas costs must start with a forecast of demand or sales volumes for the Company's distribution system. Based on meeting the sales forecast, the Company develops a forecast of the associated purchases or supply requirements. For the purpose of this proceeding, the sales forecast began with an analysis of the major variables that affect sales volumes. These variables include such items as the number of customers to be served, the rate schedule classification of those customers (i.e. large volume, high load factor, etc.), 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 2006 through June 2017.

Q. HAS A SCHEDULE BEEN INCLUDED SETTING FORTH THE ESTIMATED VOLUMES OF GAS TO BE BILLED TO CUSTOMERS DURING THIS PERIOD?

A. Yes. Schedule C.1 shows Chesapeake's projected sales volumes by customer class for the determination period of the twelve months ending October 31, 2018.

Q. PLEASE DISCUSS FURTHER THE DEVELOPMENT OF THE SALES FORECAST SHOWN ON SCHEDULE C.1

A. Forecasted sales were used for the entire twelve-month period of November 2017 through October 2018. Forecasted sales 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.

Q. HOW ARE THESE CUSTOMER ADJUSTMENTS REFLECTED IN THE TWO RESIDENTIAL SERVICE CLASSES?

A. For the twelve month period ending October 31, 2018, the Company has projected an increase of approximately 2,575 RS-2 customers over the current GSR determination period, with the a large portion of the increase representing growth in new customers and customer conversions in southeastern Sussex County, Delaware. For the twelve month period ending October 31, 2018, the Company has projected in increase of approximately 391 RS-1 customers from the current GSR determination period.

Q. HOW ARE THESE CUSTOMER ADJUSTMENTS REFLECTED IN THE FIRM COMMERCIAL AND INDUSTRIAL CLASSES?

A. With respect to the Commercial and Industrial customers, the Company projects an overall increase of approximately 95 customers over the previous twelve-month period.

Q. DOES THE COMPANY HAVE ANY PROJECTIONS FOR THE NUMBER OF FIRM COMMERCIAL AND INDUSTRIAL CUSTOMERS THAT MAY

CHOOSE TO TRANSPORT ON ITS DISTRIBUTION SYSTEM AND THE VOLUMES ASSOCIATED WITH THESE CUSTOMERS FOR THIS PERIOD?

A. Yes. The Company has not included in its projections any firm commercial or industrial customers switching from sales service to transportation service during the determination period. This filing includes projections for gas to be transported on the Company's distribution system for those customers who are currently receiving transportation service based on the Company's current eligibility requirements, as well as new natural gas customers that the Company anticipates will choose transportation service. There are 355 firm commercial / industrial customers and two (2) interruptible commercial / industrial customers who will be transporting their own gas on the Delaware Division's distribution system. The Company has estimated the firm commercial / industrial transportation volumes to be approximately 4,041,963 Mcf and the interruptible commercial / industrial transportation volumes to be approximately 77,933 Mcf during this period. The estimated firm commercial / industrial transportation volume is an slight decrease over the projection from the previous GSR filing.

Q. PLEASE EXPLAIN HOW THE PROJECTED SALES VOLUMES WERE USED TO CALCULATE THE ASSOCIATED GAS SUPPLY REQUIREMENTS NEEDED BY THE DELAWARE DIVISION DURING THE DETERMINATION PERIOD.

A. Using the projected sales volumes from Schedule C.1 as a starting point, adjustments due to cycle billing, unaccounted for gas, pressure compensation and company use gas were derived in order to calculate the total gas supply requirements for the period.

Q. PLEASE EXPLAIN THE CYCLE BILLING ADJUSTMENT AS SHOWN ON SCHEDULE C.1.

A. All sales volume projections included in this GSR filing are associated with a respective billing month while the Delaware Division's purchases are recorded on a calendar month basis. Chesapeake includes a cycle billing adjustment in its calculation of the GSR charges for the purpose of accounting for the difference between a billing month and a calendar month. 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.

Q. WHAT IS THE LEVEL OF COMPANY USE GAS PROJECTED DURING THE DETERMINATION PERIOD?

A. Company Use Gas is projected to be 1,292 Mcf for this determination period. This projection is approximately the same level of volume

experienced by the Company during the actual twelve months ended June 30, 2017.

Q. PLEASE EXPLAIN HOW YOU CALCULATED THE PROJECTED UNACCOUNTED FOR GAS AS SET FORTH IN SCHEDULE C.1.

A. An unaccounted for gas volume of 25,935 Mcf has been projected for the twelve months ending October 31, 2017. Unaccounted for gas is calculated by multiplying the respective sales volumes for each month by 2.15% and subtracting the estimated Company Use and Pressure Compensation for the month. The 2.15% utilized in this GSR calculation includes volumes attributed to metering pressure differential and is representative of five-year history of unaccounted for gas volumes. The use of a five year history of unaccounted for gas volumes was approved by the Public Service Commission by Order No. 4189 in PSC Docket No. 95-206.

Q. PLEASE EXPLAIN HOW YOU CALCULATED THE PROJECTED PRESSURE COMPENSATION VOLUMES AS SET FORTH IN SCHEDULE C.1.

A. The pressure compensation projection of 61,946 Mcf is calculated by multiplying the total projected Mcf sales by the factor 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.

Q. PLEASE EXPLAIN HOW YOU CALCULATED THE PROJECTED COST OF FIRM SALES FOR THE TWELVE-MONTH PERIOD ENDING OCTOBER 31, 2017.

A. The projected cost of firm sales is detailed on a monthly basis throughout the seven pages of Schedule C.2. In calculating the proposed cost of gas for the period November 1, 2017 through October 31, 2018, the total projected supply requirements were allocated between the different categories of gas (commodity and storage) available to meet the projected demand. Pages 1 and 2 of Schedule C.2 primarily calculate the fixed costs of firm transportation on Columbia Gas Transmission ("Columbia"), Columbia Gulf Transmission ("Columbia Gulf"), Transcontinental Gas Pipe Line ("Transco"), Eastern Shore Natural Gas ("ESNG"), and Texas Eastern Transmission ("TETCO"). As the ENSG rate case is currently ongoing, the rates that Chesapeake Utilities Corporation Delaware Division will pay during the upcoming GSR period are not settled. Based on the rates filed in ESNG's rate case application, the Company would see an overall increase in the reservation costs on the pipeline of 56%. As rate cases are typically finalized at rates other than those which are originally filed, for the purposes of appraising the fixed gas costs for the GSR period, the Company has utilized total Eastern Shore Natural Gas reservation costs representing the simple midpoint between the historical Eastern Shore rates and the as filed rate request. Should the rate case reach a settlement prior to the

November 1, 2017 date for GSR rates to go into effect, the Company will amend this filing to be reflective of ESNG settlement rates.

A summary of storage demand, capacity charges, and LNG peaking charges is also included on these two pages. Pages 3, 4 and 5 calculate the gas commodity costs associated with firm transportation service. As summarized on Page 4 of Schedule C.2, the projected cost of storage gas commodity for withdrawals during this period has been calculated using the actual purchases and costs for the months of April 2017 through July 2017 and projected purchases and costs for August 2017 through October 2017. The twelve-month period ending March 2018 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 2017 through October 2018 are based on natural gas commodity futures market prices during the second week of August 2017, as well as any gas that had been previously purchased under the Company's "Natural Gas Commodity Procurement Plan" for this determination period.

Q. PLEASE EXPLAIN THE CHANGE IN THE PROJECTED FIRM COST OF GAS FOR THE TWELVE MONTHS ENDING OCTOBER 31, 2018 AS SHOWN ON SCHEDULE F COMPARED TO NINE MONTHS OF ACTUAL COSTS AND THREE MONTHS OF PROJECTED COSTS FOR THE TWELVE-MONTH PERIOD ENDING OCTOBER 31, 2017.

A. Schedule F compares the projected firm cost of gas for the twelve months ending October 31, 2018 utilized in this proceeding to the nine months of actual gas costs and three months of projected gas costs for the twelve-month period ending October 31, 2017. In addition, for informational purposes, the actual firm cost of gas for the three prior determination periods ended October 2016, 2015, and 2014 are shown. Chesapeake anticipates an increase in firm gas costs per Mcf from $9.8716 per Mcf to $10.4274 per Mcf from the twelve months ending October 31, 2017.

Q. PLEASE EXPLAIN SCHEDULES D.1 AND D.2 IN THIS GSR FILING.

A. Schedule D.1 sets forth the calculation of the purchased gas over/under collection by month for the twelve-month period ending October 31, 2017. The projected under collection balance at October 31, 2017 that is carried forward into this annual filing is $3,232,359.

Schedule D.2 reflects the shared margins over/under refund for the twelve-month determination period ending October 31, 2017. Based on this twelve-month determination period, the Company's under refunded shared margins are $381,619. This amount is also included in the shared margin calculation on Schedule A.2.

Q. PURSUANT TO THE PROVISIONS OF THE TARIFF CONCERNING THE UNACCOUNTED FOR GAS INCENTIVE MECHANISM APPROVED BY ORDER NO. 3648, THE COMPANY AS PART OF ITS ANNUAL GSR

FILING IS REQUIRED TO PROVIDE THE COMMISSION STAFF WITH ACTUAL UNACCOUNTED FOR GAS VOLUMES FOR THE PRECEDING TWELVE MONTH PERIOD ENDED JULY 31. HAS THE COMPANY INCLUDED A SCHEDULE SHOWING THE REQUIRED INFORMATION?

A. Yes. Schedule G represents the actual unaccounted for gas volumes for the twelve months ended July 31, 2017.

Q. WHAT WERE THE UNACCOUNTED FOR GAS TARGET PERCENTAGE AND DEAD BAND PERCENTAGES APPROVED FOR THE UNACCOUNTED FOR GAS INCENTIVE MECHANISM IN PSC DOCKET NO. 92-87F?

A. The Unaccounted For Gas Target approved was 3.20% of total gas sendout or total gas requirements. The Dead Band approved was +/- 0.5% points around the 3.20% target level. Unaccounted For Gas Volumes that are within 2.70% to 3.70% of total gas sendout are considered to be within this band and meeting the objectives of this mechanism.

Q. WHAT WAS THE ACTUAL LEVEL OF UNACCOUNTED FOR GAS VOLUMES FOR THE TWELVE MONTHS ENDED JULY 31, 2016 COMPARED TO THE INCENTIVE MECHANISM TARGETS?

A. The actual unaccounted for gas percentage, as established by the approved guidelines in PSC Docket No. 92-87F, for the twelve months ended July 31, 2017, was 0.26% of total gas requirements. This percentage is under the

targeted percentage of 3.20% and is also under the dead band range of 2.70% to 3.70%.

Q. EARLIER IN THIS TESTIMONY YOU MENTIONED THAT YOU WERE PROPOSING A CHANGE TO THE DELAWARE DIVISION'S FIRM BALANCING RATES FOR TRANSPORTATION CUSTOMERS. PLEASE EXPLAIN WHY THE CHANGES TO THE GAS SALES SERVICE RATES AND THE BALANCING RATES ARE BEING PROPOSED IN THE SAME DOCKET.

A. Chesapeake's firm transportation balancing rates are calculated in accordance with the methodology approved in PSC Docket No. 95-73, Phase II, by Order No. 4400, and later modified in PSC Docket No. 13-383, by Order No. 8752, and are based on Chesapeake's annual purchased gas costs. As a result of Order No. 4400, Chesapeake is required to update its balancing rates for Rate Schedules LVS and HLFS on an annual basis at the time of its annual Gas Sales Service Rate application. Chesapeake also agreed to update its balancing rate for ITS during its annual Gas Sales Service application as a result of Order No. 7434 issued on September 2, 2008 in PSC Docket No. 07-186. Also as a result of Order No. 8752 in PSC Docket No. 13-383, the Company now calculates balancing rates for transportation customers served under rate schedules GS, EGS, MVS, and EMVS; these rates are also to be updated on an annual basis at the time of the Company's annual Gas Sales Service Rate application.

The relationship between the GSR charges and the transportation balancing rates exist because the gas costs being presented in this GSR filing are the same gas costs that are used to calculate the transportation balancing rates.

Q. PLEASE STATE THE BALANCING RATES THAT ARE BEING PROPOSED IN THIS FILING.

A. Chesapeake is proposing the following changes to its balancing rates, to be effective for service rendered on and after November 1, 2017, in this application: (a) increase in the current firm balancing rate for transportation customers served under rate schedules GS and EGS of $0.076 per Ccf to $0.093; (b) increase to the current firm balancing rate for transportation customers served under rate schedules MVS and EMVS from $0.100 per Ccf to $0.111 per Ccf; (c) decrease to the current firm balancing rate for transportation customers served under rate schedule “LVS” from $0.089 per Ccf to $0.084 per Ccf, (d) increase to the current firm balancing rate for transportation customers served under rate schedule “HLFS” from $0.012 per Ccf to $0.014 per Ccf, and (e) decrease to the current interruptible balancing rate for transportation customers served under rate schedule “ITS” from $0.012 per Ccf to $0.011 per Ccf.

Q. PLEASE EXPLAIN THE UPSTREAM FIRM TRANSPORTATION COSTS INCURRED AND RECOVERED WITHIN THE BALANCING RATES?

A. The balancing rates effective with service on and after November 1, 2017, shall include the upstream firm transportation costs incurred by the Company in order to balance transportation customers' aggregate design day requirements. The amount of capacity included in the balancing rate calculation is 16,374 Dts, as shown on Schedule J. This represents the difference between the transportation customers' aggregate 2017-2018 design day requirements (32,308 Dts) and the average demand that the transportation customers' cumulative delivered daily contract quantities are structured to cover (15,934 Dts). The total cost included in the balancing rate calculation for the 16,374 Dt of balancing requirements is $2,743,656 as shown on Schedule J; this is based on a calculated blended weighted average annual cost of capacity of $167.5617 per Dt.

The transportation balancing rates shall also include a component related to upstream capacity cost recovery. Under the terms of the Settlement Agreement approved in PSC Docket No. 13-383, the Company is required to release, pursuant to FERC's bidding rules, its upstream capacity in excess of the sum of the capacity needed to meet sales customers' aggregate demand on a design day plus the capacity needed to balance transportation customers on a design day. For this GSR determination period, that upstream capacity release amount is projected to be 8,017 Dts (77,942 Dts of total upstream firm transportation entitlements less the sales customers' design day requirements of 50,933 Dts less the 15,934 Dts reserved for transportation balancing needs). The Company's average

annual cost of this 8,017 Dts is calculated to be $1,343,342 (based on the calculated blended weighted average annual cost of capacity of $167.56). However, the Company would note that the actual release of capacity entitlements that it intends to make will be reflective of the terms of its Asset Management Agreement, under which the Company may release into the open market certain assets without negatively impacting the Asset Management credit or the basket pricing set by the Asset Manager. Therefore, the underlying cost of the capacity released will be different from the blended weighted average annual cost. Although the capacity release prices actually attained will be a function of market conditions, for this GSR determination period, based on the actual recovery of the prior GSR period's capacity release, the Company is projecting that it can recover approximately twenty-two percent (23.6%) of the $1,343,342 in costs calculated above, which results in capacity release revenues of $317,517. Ninety percent of these revenues ($285,766) are credited directly to firm sales customers as shown on Schedule B, and the remaining ten percent ($31,752) is retained by the Company as margin. The remaining "unrecovered" cost of the 8,017 Dts is $1,057,577 ($1,343,342 less $285,766). This amount shall be allocated to sales and transportation customers based on their respective proportions of design day demand for the 2017-2018 season. Based on current projections, transportation customers' demand on a design day represents approximately fourty-one percent (41%) of total design day demand and therefore, fourty-one percent

(41%) of the “unrecovered” costs, or $430,186, are allocated to them. This amount is then divided by the projected consumption (4,119,896 Mcfs) for the 2017-2018 GSR determination period to get an upstream capacity cost recovery rate for all transportation customers of $0.1044 per Mcf, or $0.0104 per Ccf. This rate is then added to the calculated balancing rate for each Rate Schedule to come up with the total balancing rate applicable for that Rate Schedule. Additional detail regarding the development of this upstream capacity cost recovery rate is shown on the attached Exhibit 1.

Q. WHAT GAS SUPPLY RESOURCES IS THE COMPANY USING IN DEVELOPING THE BALANCING SERVICE RATES BEING SUBMITTED IN THIS FILING?

A. Schedule J, Page 1 of 4 shows the Delaware Division’s gas supply resources being used in developing the balancing service rates along with the purchased gas costs associated with these gas supply resources. All of these resources provide firm deliveries that vary in daily entitlements and duration.

Q. PLEASE BRIEFLY EXPLAIN HOW THE OVERALL COSTS OF THE GAS SUPPLY RESOURCES WERE DEVELOPED ON SCHEDULE J.

A. The Delaware Division’s gas costs associated with the gas supply resources for balancing services are based on the same costs contained in the development of the GSR charges. The gas supply resources and their

costs are separated into fixed gas supply resources and variable gas supply resources. The Delaware Division's storage demand and capacity, firm transportation capacity reserved for balancing, 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.

Q. HOW WAS THE AVERAGE ANNUAL RATE OF APPROXIMATELY $159.1051 PER DT FOR THE FIXED GAS SUPPLY RESOURCES DETERMINED ON SCHEDULE J, PAGE 1 OF 4?

A. The gas costs were determined for each of the fixed gas supply resources to be used by the Company in performing this balancing service. The total annualized gas supply costs of $6,936,824 were divided by the daily entitlements of 43,599 Dts to derive the annual amount of $159.1051 per Dt for these fixed gas supply resources in the balancing service.

Q. HOW WAS THE COST OF THE VARIABLE GAS SUPPLY RESOURCES DETERMINED IN THIS PROCEEDING?

A. The overall variable rate of $0.0108 per Dt was determined based on the current storage injection and withdrawal capacities of the Delaware Division's storage resources. This rate was cut in half to arrive at separate rates for injections and withdrawals. This is important because a transportation customer on any given day will either over deliver (the Company would inject the excess gas into storage) or under deliver (the

Company would withdraw from storage to meet the demand) the customer-owned gas into the system on the customer's behalf. The resulting rate used for the variable gas supply component of the balancing services is $0.0108 per Dt.

Q. WERE THESE OVERALL FIXED GAS SUPPLY RESOURCE COSTS AND VARIABLE GAS SUPPLY RESOURCE COSTS UTILIZED IN THE DEVELOPMENT OF THE BALANCING SERVICE RATES?

A. Yes. The variable gas supply rate was used as the basis for the variable component in developing the balancing service rates. The fixed gas supply rate will differ between the balancing services due to the specific nature of the service being provided and the fact that the balancing rate is charged on consumption, not just the imbalance volumes. The fixed gas supply portion of the balancing service rates is based on specific load factors along with the percentage of the Company's gas supply needed to balance the requirements of specific customer class requirements. This percentage of the Company's gas supply will be the difference between their average day requirements and design day requirements.

Q. HOW WAS THE FIRM BALANCING SERVICE RATE FOR GENERAL SERVICE AND EXPANSION AREA GENERAL SERVICE DEVELOPED?

A. Schedule J, Page 2 of 6 shows the development of the firm balancing service rate for this specific transportation customer class. The Delaware

Division developed an average cost from the fixed rate of $159.1051 per Dt based on the General Service load factor of 24.08%. This load factor resulted in an average cost of $1.808 per Dt. Since the Company's analysis determined that the DCQ method would provide approximately 56.02% of the peak day requirements, the Company would need to supply the remaining 43.98% with its gas supply resources. In other words, these firm customers would pay for 43.98% of peak day requirements through the balancing service rate. The resulting rate for the fixed capacity based on this 43.98% would be approximately $0.7952 per Dt applicable to all consumption. The variable commodity rate of $0.0108 per Dt was multiplied by the estimated imbalance volume percentage of 29.94% to derive the variable rate of $0.0032 per Dt. The fixed capacity rate was added to the variable commodity rate to develop a balancing rate per Dt of $0.7984, which was then converted to a per Mcf rate of $0.8263. In addition, the Upstream Capacity Cost Recovery rate of $0.1044 per Mcf was applied, resulting in a total balancing rate of $0.9307 per Mcf, or $0.093 per Ccf for transportation customers served under Rate Schedules GS and EGS, as shown on Schedule J, page 2 of 6.

Q. HOW WAS THE FIRM BALANCING SERVICE RATE FOR MEDIUM VOLUME SERVICE AND EXPANSION AREA MEDIUM VOLUME SERVICE DEVELOPED?

A. Schedule J, Page 3 of 6 shows the development of the firm balancing service rate for this specific transportation customer class. The Delaware Division developed an average cost from the fixed rate of $159.1051 per Dt based on the Medium Volume Service load factor of 20.89%. This load factor resulted in an average cost of $2.0935 per Dt. Since the Company's analysis determined that the DCQ method would provide approximately 53.74% of the peak day requirements, the Company would need to supply the remaining 46.26% with its gas supply resources. In other words, these firm customers would pay for 46.26% of peak day requirements through the balancing service rate. The resulting rate for the fixed capacity based on this 46.26% would be approximately $0.9684 per Dt applicable to all consumption. The variable commodity rate of $0.0108 per Dt was multiplied by the estimated imbalance volume percentage of 36.56% to derive the variable rate of $0.0039 per Dt. The fixed capacity rate was added to the variable commodity rate to develop a balancing rate per Dt of $0.9723, which was then converted to a per Mcf rate of $1.0063. In addition, the Upstream Capacity Cost Recovery rate of $0.1044 per Mcf was applied, resulting in a total balancing rate of $1.1107 per Mcf, or $0.111 per Ccf for transportation customers served under Rate Schedules MVS and EMVS, as shown on Schedule J, page 3 of 6.

Q. HOW WAS THE FIRM BALANCING SERVICE RATE FOR LARGE VOLUME SERVICE DEVELOPED?

A. Schedule J, Page 4 of 6 shows the development of the firm balancing service rate for this specific transportation customer class. The Delaware Division developed an average cost from the fixed rate of $159.1051 per Dt based on the Large Volume Service load factor of 26.17%. This load factor resulted in an average cost of $1.6573 per Dt. Since the Company's analysis determined that the DCQ method would provide approximately 57.49% of the peak day requirements, the Company would need to supply the remaining 42.51% with its gas supply resources. In other words, these firm customers would pay for 42.51% of peak day requirements through the balancing service rate. The resulting rate for the fixed capacity based on this 42.51% would be approximately $0.7045 per Dt applicable to all consumption. The variable commodity rate of $0.0108 per Dt was multiplied by the estimated imbalance volume percentage of 26.11% to derive the variable rate of $0.0028 per Dt. The fixed capacity rate was added to the variable commodity rate to develop a balancing rate per Dt of $0.7463, which was then converted to a per Mcf rate of $0.7073. In addition, the Upstream Capacity Cost Recovery rate of $0.1044 per Mcf was applied, resulting in a total balancing rate of $0.8365 per Mcf, or $0.084 per Ccf for transportation customers served under Rate Schedule LVS, as shown on Schedule J, page 4 of 6.

Q. HOW WAS THE FIRM BALANCING SERVICE RATE FOR HIGH LOAD FACTOR SERVICE DEVELOPED?

A. Schedule J, Page 5 of 6 shows the development of the firm balancing service rate for this specific transportation customer class. The Delaware Division developed an average cost from the fixed rate of $159.1051 per Dt based on the High Load Factor Service load factor of 86.81%. This load factor resulted in an average cost of $0.5019 per Dt. Since the Company's analysis determined that the DCQ method would provide approximately 92.27% of the peak day requirements, the Company would need to supply the remaining 7.73% with its gas supply resources. In other words, these firm customers would pay for 7.73% of peak day requirements through the balancing service rate. The resulting rate for the fixed capacity based on this 7.73% would be approximately $0.0388 per Dt applicable to all consumption. The variable commodity rate of $0.0108 per Dt was multiplied by the estimated imbalance volume percentage of 1.48% to derive the variable rate of $0.0002 per Dt. The fixed capacity rate was added to the variable commodity rate to develop a balancing rate per Dt of $0.0500, which was then converted to a per Mcf rate of $0.0390. In addition, the Upstream Capacity Cost Recovery rate of $0.1044 per Mcf was applied, resulting in a total balancing rate of $0.1448 per Mcf, or $0.014 per Ccf for transportation customers served under Rate Schedule HLFS, as shown on Schedule J, page 5 of 6.

Q. WHAT ABOUT THE BALANCING RATE FOR INTERRUPTIBLE CUSTOMERS?

A. Schedule J, Page 6 of 6 shows the development of the balancing service rate for this specific transportation customer class. The Delaware Division developed an average cost from the fixed rate of $159.1051 per Dt based on the Interruptible Transportation Service load factor of 100%. This load factor resulted in an average cost of $0.4359 per Dt. The rate for the fixed capacity based on average cost at 1.00% would be approximately $0.0044 per Dt applicable to all consumption. The variable commodity rate of $0.0108 per Dt was multiplied by the estimated imbalance volume percentage of 19.83% to derive the variable rate of $0.0021 per Dt. The fixed capacity rate was added to the variable commodity rate to develop a balancing rate per Dt of $0.0065, which was then converted to a per Mcf rate of $0.0067. In addition, the Upstream Capacity Cost Recovery rate of $0.1044 per Mcf was applied, resulting in a total balancing rate of $0.1111 per Mcf, or $0.011 per Ccf for transportation customers served under Rate Schedule ITS, as shown on Schedule J, page 6 of 6.

Q. PLEASE DESCRIBE THE REQUESTED TARIFF LANGUAGE ALLOWING THE COMPANY THE OPTION TO FILE FOR NEW GAS SALES SERVICE RATES SHOULD THE PROJECTED OVER OR UNDER COLLECTION BALANCE FALL OUTSIDE A 3% BAND.

A. The Company's current tariff sheet 42 provides that:

"The rates computed under this rate schedule shall remain in effect for the projected period provided the latest estimated over collection does not

exceed 4½% or the latest estimated under collection does not exceed 6% of the actual firm gas costs incurred to date along with the Company's latest firm gas cost estimates for the remainder of the over/under collection period (over/under period)."

Should the over/under collection balance fall outside of this projected 4½% over or 6% under collection balance, the Company must apply to the Commission for revised rates to be effective until the next annual adjustment in the rates. The Company proposes that it may also have the *option* to file revised rates with the Commission should the projected over or under collection balance fall outside of 3%. The Company's proposed language would keep in place the current over/under limits which require revised rates to be filed, but would add flexibility for the Company to keep it's over/under balance lower by having the option to file revised rates at a 3% over/under estimate. By allowing the Company to manage the over/under collection balance more proactively, rate swings to the customers will be lessened when this balance is rolled into the Gas Sales Service Rates on an annual basis. Sheet No. 42 "Rate Schedule 'GSR'" includes the Company's proposed tariff language.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes, it does.

DATED: SEPTEMBER 1, 2017

STATE OF DELAWARE)
)
COUNTY OF KENT)

AFFIDAVIT OF WILLIAM R. KRISS

WILLIAM R. KRISS, being first duly sworn according to law, on oath deposes and says that he is the witness whose testimony appears as "Chesapeake Utilities Corporation, Delaware Division, Direct Testimony of William R. Kriss"; that, if asked the questions which appear in the text of the direct testimony, he would give the answers that are therein set forth; and that he adopts this testimony as his sworn direct testimony in these proceedings.

William R. Kriss

Then personally appeared this 1st day of September 2017 the above-named William R. Kriss and acknowledged the foregoing Testimony to be his free act and deed. Before me,

CHRISTOPHER JAMES METZGER NOTARY PUBLIC MY COMMISSION EXPIRES ON 07-05-20 STATE OF DELAWARE

Notary Public
My Commission Expires:
July 05, 2020

DATED: SEPTEMBER 1, 2017

STATE OF DELAWARE)
)
COUNTY OF KENT)

AFFIDAVIT OF MATTHEW M. EVERNGAM

MATTHEW M. EVERNGAM, being first duly sworn according to law, on oath deposes and says that he is the witness whose testimony appears as "Chesapeake Utilities Corporation, Delaware Division, Direct Testimony of Matthew M. Everngam"; that, if asked the questions which appear in the text of the direct testimony, he would give the answers that are therein set forth; and that he adopts this testimony as his sworn direct testimony in these proceedings.

Matthew M. Everngam

Then personally appeared this 1st day of September 2017 the above-named Matthew M. Everngam and acknowledged the foregoing Testimony to be his free act and deed. Before me,

CHRISTOPHER JAMES METZGER NOTARY PUBLIC MY COMMISSION EXPIRES ON 07-05-20 STATE OF DELAWARE

Notary Public
My Commission Expires:
July 05, 2020

Chesapeake Utilities Corporation
Delaware Division
Development of Gas Sales Service Rates Effective November 1, 2017

Based on Total Firm Gas Costs Recoverable through GSR effective November 1, 2017

Description	Allocator	Total System Costs	Volume (Ccf)	Cost / Ccf
Fixed Gas Costs	Peak Day Capacity Entitlements	$29,223,381	880,370	$33.19
Variable Gas Costs	Annual Volume	$15,625,043	41,474,993	$0.377
Total Firm Gas Costs	Annual Volume	$44,848,424	41,474,993	$1.081

Development of High Load Factor Service Rates per CCF (86.81% Load Factor)

Description		Peak Day Cap. Method	System Average Cost	HLFS Average Rate
Demand Rate	($33.19 / 317)	$0.105		
Commodity Rate		$0.377		
Total Gas Sales Service Rate		**$0.482**	**$1.081**	**$0.782**

Total High Load Factor Dollars

Projected Sales	Rate	Total Cost
3,079,690	**$0.782**	**$2,408,318**

Development of Gas Lighting Rate per CCF (100% Load Factor)

Description		Peak Day Cap. Method
Demand Rate	($33.19 / 365)	$0.091
Commodity Rate		$0.377
Total Gas Sales Service Rate		**$0.468**

Total Gas Lighting Dollars

Projected Sales	Rate	Total Cost
0	**$0.468**	**$0**

Development of RS1, ERS1, RS2, ERS2, GS, EGS, MVS, EMVS, and LVS Rate per CCF

Description	Firm Gas Cost	Volume (CCF)	Rate per CCF	Margin Sharing Rate per CCF	Final Rate per CCF
Total System Gas Cost	$44,848,424	41,474,993			
Less : Allocated to HLFS	$2,408,318	3,079,690			
Less : Allocated to GL	$0	0			
Total Remaining System	$42,440,106	38,395,303	**$1.105**	**($0.082)**	**$1.023**

Schedule A.2

Chesapeake Utilities Corporation
Delaware Division
Development of Gas Sales Service Rates Effective November 1, 2017

Determination of Margin Sharing Credit for November 1, 2017 - October 31, 2018

Projected Interruptible Margin, Off-System Sales Margin and Capacity Valuation Credits for the Period

Description	2017 November Projected	2017 December Projected	2018 January Projected	2018 February Projected	2018 March Projected	2018 April Projected	2018 May Projected	2018 June Projected	2018 July Projected	2018 August Projected	2018 September Projected	2018 October Projected	Total
Interruptible Transportation	$12,081	$12,105	$10,720	$8,428	$10,423	$8,019	$12,169	$22,962	$18,463	$21,877	$15,029	$15,709	**$167,985**
Capacity Valuation	$250,000	$250,000	$250,000	$250,000	$250,000	$250,000	$250,000	$250,000	$250,000	$250,000	$250,000	$250,000	**$3,000,000**
Total Margins	$262,081	$262,105	$260,720	$258,428	$260,423	$258,019	$262,169	$272,962	$268,463	$271,877	$265,029	$265,709	**$3,167,985**

Amount of Margins Subject to Sharing to be Credited to RS-1,RS-2,GS,MVS,LVS Customers

Level of Margins Subject to Sharing	Eligible Margin Amounts	Customer Sharing (%)	Customer Sharing ($)
Interruptible Transportation First $675,000	$167,985	0%	$0
Interruptible Transportation over $675,000	$0	90%	$0
Capacity Valuation	$3,000,000	92.5%	$2,775,000
Total	$3,167,985		$2,775,000

Determination of Margin Sharing Credit Per Ccf For RS-1,RS-2,GS,MVS.LVS Customers

Month	Total Projected Firm Sales For Period	Gas Lighting Sales For Period		High Load Sales For Period	Projected RS-1,RS-2,GS, MVS & LVS Sales For Period
Nov-16	262,295	0		(22,325)	239,970
Dec-16	524,649	0		(25,506)	499,143
Jan-17	778,090	0		(34,111)	743,979
Feb-17	770,809	0		(31,504)	739,305
Mar-17	644,650	0		(31,139)	613,511
Apr-17	430,107	0		(26,909)	403,198
May-17	201,184	0		(28,185)	172,999
Jun-17	121,776	0		(21,394)	100,382
Jul-17	88,591	0		(20,175)	68,416
Aug-17	77,718	0		(19,749)	57,969
Sep-17	99,089	0		(19,996)	79,093
Oct-17	148,544	0		(26,976)	121,568
Total	4,147,501	0		(307,969)	3,839,532

Customer Sharing ($)	Prior Period Under Refund (Nov 16 - Oct 17)	Refund through Nov. 1, 2017 GSR	RS,GS,MVS, & LVS Sales In Mcf	Margin Sharing Rate Per Mcf	Margin Sharing Rate Per Ccf
($2,775,000)	($381,619)	($3,156,619)	3,839,532	**($0.822)**	**($0.082)**

Schedule B

Chesapeake Utilities Corporation
Delaware Division
Current Firm Gas Costs
Effective November 1, 2016

				November 1, 2016			Change		
	Total Gas Costs	Volume (Mcf)	Avg Cost/Mcf	Total Gas Costs	Volume (Mcf)	Avg Cost/Mcf	Total Gas Costs	Volume (Mcf)	Avg Cost/Mcf
Demand Rate:									
		88,037			85,138			2899	
Columbia FT Reservation	$853,433		$9.694	$814,109		$9.56	$39,324		$0.13
Transco FT Reservation	$3,939,697		$44.750	$3,943,588		$46.32	($3,891)		($1.57)
Texas Eastern FT Reservation	$6,294,765		$71.501	$6,294,765		$73.94	$0		($2.43)
Storage Demand & Capacity & Peaking	$2,068,757		$23.499	$2,325,076		$27.31	($256,319)		($3.81)
ESNG FT Reservation	$19,703,213		$223.806	$15,101,338		$177.37	$4,601,875		$46.43
ESNG 2017 Expansion FT Reservation	$3,037,339		$34.501	$0		$0.00	$3,037,339		$34.50
ESNG Capacity Release for Transp.	$ (5,042,314)		($57.275)	($3,887,019)		($45.66)	($1,155,295)		($11.62)
Balancing Rate Credit	($1,345,742)		($15.286)	($1,594,430)		($18.73)	$248,688		$3.44
GSR Settlement Adjustment			$0.000	($19,897)		($0.23)	$19,897		$0.23
Upstream Capacity Release	($285,766)		($3.246)	($319,523)		($3.75)	$33,757		$0.51
Total Firm Fixed Gas Costs	$29,223,381		$331.94	$22,658,007		$266.13	$6,565,375		$65.81
Peak Day Capacity (Mcf)	88,037			85,138			2,899		
Annual Fixed Cost per Mcf	$331.94			$266.13			$65.81		
Annual Fixed Cost per Ccf	$33.19			$26.61			$6.58		
Monthly Fixed Cost per Mcf	**$27.66**			**$22.18**			**$5.48**		
Monthly Fixed Cost per Ccf	**$2.766**			**$2.218**			**$0.548**		
Commodity Rate:									
		4,147,499			3,808,776			338,723	
Flowing Commodity	$10,800,033		$2.604	$8,770,861		$2.30	$2,029,172		$0.30
Storage I/W & Commodity	$1,527,188		$0.368	$1,490,767		$0.39	$36,421		($0.02)
ESNG FT Commodity	$66,565		$0.016	$61,535		$0.02	$5,030		($0.00)
CNG for Vehicular Use	($1,103)		($0.000)	($667)		($0.00)	($436)		($0.00)
(Over)/Under Collection	$3,232,359		$0.779	$627,615		$0.16	$2,604,744		$0.61
Total Firm Variable Gas Costs	$15,625,043		$3.77	$10,950,111		$2.87	$4,674,932		$0.89
Total Firm Sales Volumes (Mcf)	4,147,499			3,808,776			338,723		
Total Firm Sales Volumes (Ccf)	41,474,993			38,087,760			3,387,233		
Commodity Rate per Mcf	**$3.77**			**$2.87**			$0.90		
Commodity Rate per Ccf	**$0.377**			**$0.287**			$0.09		
System Average Rate:									
Total Firm Fixed Gas Costs	$29,223,381			$22,658,007			$6,565,375		
Total Firm Variable Gas Costs	$15,625,043			$10,950,111			$4,674,932		
Total Firm Gas Costs	**$44,848,424**	**4,147,499**	**$10.81**	**$33,608,118**	**3,808,776**	**$8.82**	**$11,240,306**		**$1.99**

Schedule C.1

Chesapeake Utilities Corporation
Projected Sales and Requirements Summary
November 1, 2016 - October 31, 2017

	Projected Nov-16	Projected Dec-16	Projected Jan-17	Projected Feb-17	Projected Mar-17	Projected Apr-17	Projected May-17	Projected Jun-17	Projected Jul-17	Projected Aug-17	Projected Sep-17	Projected Oct-17	Total
Mcf Sales													
Firm													
Residential Service - 1	5,954	14,336	23,377	23,017	18,956	12,381	5,045	2,115	1,424	1,199	1,492	2,949	112,244
Residential Service - 2	184,781	379,445	562,716	561,133	468,690	312,184	134,203	77,134	50,540	41,905	56,777	90,597	2,920,103
General Service	16,680	38,849	67,413	65,709	52,165	35,468	12,977	7,468	4,911	4,308	5,778	9,070	320,796
Medium Volume Service	19,804	41,145	54,214	54,776	46,433	27,827	12,555	7,403	5,607	4,943	6,873	9,943	291,523
Large Volume Service	12,751	25,368	36,259	34,670	27,267	15,338	8,219	6,262	5,934	5,614	8,173	9,009	194,864
High Load Factor Service	22,325	25,506	34,111	31,504	31,139	26,909	28,185	21,394	20,175	19,749	19,996	26,976	307,969
Gas Lighting	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Firm Mcf Sales	262,295	524,649	778,090	770,809	644,650	430,107	201,184	121,776	88,591	77,718	99,089	148,544	4,147,499
Natural Gas Vehicles	3	4	3	2	9	5	12	17	7	9	6	7	84
Total Mcf Sales	262,298	524,653	778,093	770,811	644,659	430,112	201,196	121,793	88,598	77,727	99,095	148,551	4,147,583
Mcf Requirements													
Mcf Sales	262,298	524,653	778,093	770,811	644,659	430,112	201,196	121,793	88,598	77,727	99,095	148,551	4,147,585
Adjusted Mcf Sales	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Mcf Sales	262,298	524,653	778,093	770,811	644,659	430,112	201,196	121,793	88,598	77,727	99,095	148,551	4,147,585
Cycle Billing Adjustment	68,423	80,986	93,659	(61,804)	(58,796)	(114,744)	(47,300)	(27,351)	(2,995)	0	18,268	51,670	16
Subtotal	330,721	605,639	871,752	709,007	585,863	315,368	153,896	94,442	85,603	77,727	117,363	200,221	4,147,601
Company Use	88	273	273	256	263	93	17	6	3	4	4	11	1,292
Unaccounted For	3,104	4,912	6,848	3,475	2,705	263	287	206	514	506	1,039	2,076	25,935
Pressure Compensation	3,918	7,836	11,621	11,512	9,628	6,424	3,005	1,819	1,323	1,161	1,480	2,219	61,946
Total Mcf Requirements	337,831	618,660	890,495	724,251	598,459	322,148	157,205	96,473	87,443	79,398	119,886	204,526	4,236,773
Dt Requirements													
Total Dt Requirements	349,656	640,313	921,662	749,601	619,405	333,424	162,707	99,850	90,504	82,177	124,082	211,684	4,385,065
Eastern Shore Fuel (0.0109)	3,853	7,056	10,157	8,261	6,826	3,674	1,793	1,100	997	906	1,367	2,333	48,323
Requirements Upstream of ESNG (Dt)	353,509	647,369	931,819	757,862	626,231	337,098	164,500	100,950	91,501	83,083	125,449	214,017	4,433,388

Chesapeake Utilities Corporation Schedule C.2

Delaware Division

	Projected November-16	Projected December-16	Projected January-17	Projected February-17	Projected March-17	Projected April-17	Projected May-17	Projected June-17	Projected July-17	Projected August-17	Projected September-17	Projected October-17	Total
	30	31	31	28	31	30	31	30	31	31	30	31	365
FIXED COSTS													
Columbia Gas Transmission FT													
FTS Firm Transportation Service													
Reservation Rates	$6.4890	$6.4890	$6.4890	$6.4890	$6.4890	$6.4890	$6.4890	$6.4890	$6.4890	$6.4890	$6.4890	$6.4890	
Billing Units (MDTQ)	10,960	10,960	10,960	10,960	10,960	10,960	10,960	10,960	10,960	10,960	10,960	10,960	
Reservation Costs	$71,119.44	$71,119.44	$71,119.44	$71,119.44	$71,119.44	$71,119.44	$71,119.44	$71,119.44	$71,119.44	$71,119.44	$71,119.44	$71,119.44	$853,433.28
FTS-1 Columbia Gulf													
Reservation Rates	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	
Billing Units (MDTQ)	0	0	0	0	0	0	0	0	0	0	0	0	
Reservation Costs	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Columbia Reservation Costs	$71,119.44	$71,119.44	$71,119.44	$71,119.44	$71,119.44	$71,119.44	$71,119.44	$71,119.44	$71,119.44	$71,119.44	$71,119.44	$71,119.44	$853,433.28
Transco FT													
FT Firm Transportation													
Reservation Rates:													
Transco Zone 1 (Sta 30)													
Fixed Cost Rate	$0.50064	$0.50064	$0.50064	$0.50064	$0.50064	$0.50064	$0.50064	$0.50064	$0.50064	$0.50064	$0.50064	$0.50064	
Electric Power Rate	$0.00392	$0.00392	$0.00392	$0.00392	$0.00392	$0.00392	$0.00392	$0.00392	$0.00392	$0.00392	$0.00392	$0.00392	
Transco Zone 2 (Sta 45)													
Fixed Cost Rate	$0.48538	$0.48538	$0.48538	$0.48538	$0.48538	$0.48538	$0.48538	$0.48538	$0.48538	$0.48538	$0.48538	$0.48538	
Electric Power Rate	$0.00377	$0.00377	$0.00377	$0.00377	$0.00377	$0.00377	$0.00377	$0.00377	$0.00377	$0.00377	$0.00377	$0.00377	
Transco Zone 3 (Sta 50 and 62)													
Fixed Cost Rate	$0.45641	$0.45641	$0.45641	$0.45641	$0.45641	$0.45641	$0.45641	$0.45641	$0.45641	$0.45641	$0.45641	$0.45641	
Electric Power Rate	$0.00350	$0.00350	$0.00350	$0.00350	$0.00350	$0.00350	$0.00350	$0.00350	$0.00350	$0.00350	$0.00350	$0.00350	
Billing Units (MDTQ):													
Transco Zone 1 (Sta 30)	1,889	1,889	1,889	1,889	1,889	1,889	1,889	1,889	1,889	1,889	1,889	1,889	
Transco Zone 2 (Sta 45)	2,778	2,778	2,778	2,778	2,778	2,778	2,778	2,778	2,778	2,778	2,778	2,778	
Transco Zone 3 (Sta 50 and 62)	6,445	6,445	6,445	6,445	6,445	6,445	6,445	6,445	6,445	6,445	6,445	6,445	
Total FT Units	11,112	11,112	11,112	11,112	11,112	11,112	11,112	11,112	11,112	11,112	11,112	11,112	
Reservation Costs:													
Transco Zone 1 (Sta 30)	$28,593.30	$29,546.41	$29,546.41	$26,687.08	$29,546.41	$28,593.30	$29,546.41	$28,593.30	$29,546.41	$29,546.41	$28,593.30	$29,546.41	$347,885.15
Transco Zone 2 (Sta 45)	$40,765.80	$42,124.66	$42,124.66	$38,048.08	$42,124.66	$40,765.80	$42,124.66	$40,765.80	$42,124.66	$42,124.66	$40,765.80	$42,124.66	$495,983.90
Transco Zone 3 (Sta 50 and 62)	$88,923.60	$91,887.72	$91,887.72	$82,995.36	$91,887.72	$88,923.60	$91,887.72	$88,923.60	$91,887.72	$91,887.72	$88,923.60	$91,887.72	$1,081,903.80
Transco	$158,282.70	$163,558.79	$163,558.79	$147,730.52	$163,558.79	$158,282.70	$163,558.79	$158,282.70	$163,558.79	$163,558.79	$158,282.70	$163,558.79	$1,925,772.85
Transco Zone 5 (Cove Point)													
Reservation Rates	$0.55176	$0.55176	$0.55176	$0.55176	$0.55176	$0.55176	$0.55176	$0.55176	$0.55176	$0.55176	$0.55176	$0.55176	
Billing Units (MDTQ)	10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000	
Reservation Costs	$165,528.00	$171,045.60	$171,045.60	$154,492.80	$171,045.60	$165,528.00	$171,045.60	$165,528.00	$171,045.60	$171,045.60	$165,528.00	$171,045.60	$2,013,924.00
Transco Reservation Costs	$323,810.70	$334,604.39	$334,604.39	$302,223.32	$334,604.39	$323,810.70	$334,604.39	$323,810.70	$334,604.39	$334,604.39	$323,810.70	$334,604.39	$3,939,696.85
Texas Eastern													
Reservation Rates	$15.3831	$15.3831	$15.3831	$15.3831	$15.3831	$15.3831	$15.3831	$15.3831	$15.3831	$15.3831	$15.3831	$15.3831	
Billing Units (MDTQ)	34,100	34,100	34,100	34,100	34,100	34,100	34,100	34,100	34,100	34,100	34,100	34,100	
Tetco Reservation Costs	$524,563.71	$524,563.71	$524,563.71	$524,563.71	$524,563.71	$524,563.71	$524,563.71	$524,563.71	$524,563.71	$524,563.71	$524,563.71	$524,563.71	$6,294,764.52

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		Projected November-16	Projected December-16	Projected January-17	Projected February-17	Projected March-17	Projected April-17	Projected May-17	Projected June-17	Projected July-17	Projected August-17	Projected September-17	Projected October-17	Total
Eastern Shore Natural Gas														
	Rate Case General Increase as %	28%												
FT	Firm Transportation - Receipt Zone 1													
	Reservation Rates:													
	Reservation - FT	$5.6084	$5.6084	$5.6084	$5.6084	$5.6084	$5.6084	$5.6084	$5.6084	$5.6084	$5.6084	$5.6084	$5.6084	
	Billing Units (MDTQ):													
	Reservation - FT	34,050	34,050	34,050	34,050	34,050	34,050	34,050	34,050	34,050	34,050	34,050	34,050	
	Reservation Costs:													
	Reservation - FT	$190,967.65	$190,967.65	$190,967.65	$190,967.65	$190,967.65	$190,967.65	$190,967.65	$190,967.65	$190,967.65	$190,967.65	$190,967.65	$190,967.65	$2,291,611.80
	Reservation Costs - Receipt Zone 1	$190,967.65	$190,967.65	$190,967.65	$190,967.65	$190,967.65	$190,967.65	$190,967.65	$190,967.65	$190,967.65	$190,967.65	$190,967.65	$190,967.65	$2,291,611.80
FT/ST	Firm Transportation - Receipt Zone 2													
	Reservation Rates:													
	Reservation - FT	$2.1908	$2.1908	$2.1908	$2.1908	$2.1908	$2.1908	$2.1908	$2.1908	$2.1908	$2.1908	$2.1908	$2.1908	
	Billing Units (MDTQ):													
	Reservation - FT	64,626	70,851	70,851	70,851	70,851	64,626	58,785	58,785	58,785	58,785	58,785	58,785	
	Reservation - ST	5,081	5,081	5,081	5,081	5,081	5,081	1,846	1,846	1,846	1,846	1,846	1,846	
		68,607	74,832	74,832	74,832	74,832	68,607	59,531	59,531	59,531	59,531	59,531	59,531	
	Reservation Costs:													
	Reservation - FT	$141,585.74	$155,223.77	$155,223.77	$155,223.77	$155,223.77	$141,585.74	$128,789.00	$128,789.00	$128,789.00	$128,789.00	$128,789.00	$128,789.00	$1,676,800.56
	Reservation - ST	$11,131.70	$11,131.70	$11,131.70	$11,131.70	$11,131.70	$11,131.70	$4,044.31	$4,044.31	$4,044.31	$4,044.31	$4,044.31	$4,044.31	$91,056.06
	Reservation Costs - Receipt Zone 2	$152,717.44	$166,355.47	$166,355.47	$166,355.47	$166,355.47	$152,717.44	$132,833.31	$132,833.31	$132,833.31	$132,833.31	$132,833.31	$132,833.31	$1,767,856.62
FT	Firm Transportation -Delivery Zone 2													
	Reservation Rates:													
	Reservation - FT	$16.1827	$16.1827	$16.1827	$16.1827	$16.1827	$16.1827	$16.1827	$16.1827	$16.1827	$16.1827	$16.1827	$16.1827	
	Billing Units (MDTQ):													
	Reservation - FT	38,180	43,386	43,386	43,386	43,386	38,180	34,328	34,328	34,328	34,328	34,328	34,328	
	Reservation - ST	3,349	3,349	3,349	3,349	3,349	3,349	1,217	1,217	1,217	1,217	1,217	1,217	
	Reservation Costs:													
	Reservation - FT	$617,853.81	$702,100.71	$702,100.71	$702,100.71	$702,100.71	$617,853.81	$555,518.22	$555,518.22	$555,518.22	$555,518.22	$555,518.22	$555,518.22	$7,377,219.78
	Reservation - ST	$54,195.71	$54,195.71	$54,195.71	$54,195.71	$54,195.71	$54,195.71	$19,694.29	$19,694.29	$19,694.29	$19,694.29	$19,694.29	$19,694.29	$443,340.00
	Reservation Costs -Delivery Zone 2	$672,049.52	$756,296.42	$756,296.42	$756,296.42	$756,296.42	$672,049.52	$575,212.51	$575,212.51	$575,212.51	$575,212.51	$575,212.51	$575,212.51	$7,820,559.78
FT	Firm Transportation - Delivery Zone 3													
	Reservation Rates:													
	Reservation - FT	$22.8809	$22.8809	$22.8809	$22.8809	$22.8809	$22.8809	$22.8809	$22.8809	$22.8809	$22.8809	$22.8809	$22.8809	
	Billing Units (MDTQ):													
	Reservation - FT	26,446	27,462	27,462	27,462	26,446	26,446	24,457	24,457	24,457	24,457	24,457	24,457	
	Reservation - ST	1,732	1,732	1,732	1,732	1,732	1,732	629	629	629	629	629	629	
	Reservation Costs:													
	Reservation - FT	$605,108.18	$628,355.17	$628,355.17	$628,355.17	$605,108.18	$605,108.18	$559,598.07	$559,598.07	$559,598.07	$559,598.07	$559,598.07	$559,598.07	$7,057,978.47
	Reservation - ST	$39,629.71	$39,629.71	$39,629.71	$39,629.71	$39,629.71	$39,629.71	$14,392.08	$14,392.08	$14,392.08	$14,392.08	$14,392.08	$14,392.08	$324,130.74
	Reservation Costs - Delivery Zone 3	$644,737.89	$667,984.88	$667,984.88	$667,984.88	$644,737.89	$644,737.89	$573,990.15	$573,990.15	$573,990.15	$573,990.15	$573,990.15	$573,990.15	$7,382,109.21
GS	Incremental Rate - GreenSpring													
	Reservation Rates:													
	Reservation - FT	$33.4148	$33.4148	$33.4148	$33.4148	$33.4148	$33.4148	$33.4148	$33.4148	$33.4148	$33.4148	$33.4148	$33.4148	
	Billing Units (MDTQ):													
	Reservation - GS	1,100	1,100	1,100	1,100	1,100	1,100	1,100	1,100	1,100	1,100	1,100	1,100	
	Reservation Costs:													
	Reservation - GS	$36,756.26	$36,756.26	$36,756.26	$36,756.26	$36,756.26	$36,756.26	$36,756.26	$36,756.26	$36,756.26	$36,756.26	$36,756.26	$36,756.26	$441,075.12
	Reservation Costs - GS	$36,756.26	$36,756.26	$36,756.26	$36,756.26	$36,756.26	$36,756.26	$36,756.26	$36,756.26	$36,756.26	$36,756.26	$36,756.26	$36,756.26	$441,075.12
2017	2017 Expansion													
	Reservation Rates:													
	Reservation - FT							$30.6802	$30.6802	$30.6802	$30.6802	$30.6802	$30.6802	
	Billing Units (MDTQ):													
	Reservation - FT							16,500	16,500	16,500	16,500	16,500	16,500	
ESNG E-3 Surcharge		$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$506,223.17	$506,223.17	$506,223.17	$506,223.17	$506,223.17	$506,223.17	$3,037,339.01
Eastern Shore Reservation Costs		$1,697,228.76	$1,818,360.68	$1,818,360.68	$1,818,360.68	$1,795,113.69	$1,697,228.76	$2,015,983.05	$2,015,983.05	$2,015,983.05	$2,015,983.05	$2,015,983.05	$2,015,983.05	$22,740,551.54
Capacity Reservation		$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Capacity Release Credits		$ (424,524.91)	$ (416,624.52)	$ (409,167.08)	$ (409,109.11)	$ (412,376.65)	$ (418,657.54)	$ (419,674.81)	$ (421,107.86)	$ (411,167.01)	$ (417,462.21)	$ (441,800.42)	$ (440,642.00)	($5,042,314.11)
Storage Demand & Capacity														
Reservation Costs:														
Columbia:														
	FSS Firm Storage Service	$151,390.53	$151,390.54	$151,390.53	$151,390.54	$151,390.53								$756,952.67
Transco:														
	GSS General Storage Service	$24,600.27	$24,600.27	$24,600.27	$24,600.27	$24,600.27								$123,001.35
	LSS Leidy Storage Service	$7,624.12	$7,624.12	$7,624.12	$7,624.12	$7,624.12								$38,120.60
	WSS Washington Storage Service	$5,620.27	$5,620.27	$5,620.27	$5,620.27	$5,620.27								$28,101.35
	ESS Eminence Storage Service	$11,637.66	$11,637.66	$11,637.66	$11,637.66	$11,637.66								$58,188.30
	PS Peaking Service	$7,275.35	$7,275.36	$7,275.35	$7,275.36	$7,275.35								$36,376.77

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	Projected November-16	Projected December-16	Projected January-17	Projected February-17	Projected March-17	Projected April-17	Projected May-17	Projected June-17	Projected July-17	Projected August-17	Projected September-17	Projected October-17	Total
Total Transco	$56,757.67	$56,757.68	$56,757.67	$56,757.68	$56,757.67								$283,788.37
Total Storage Demand & Capacity Costs	$208,148.20	$208,148.22	$208,148.20	$208,148.22	$208,148.20								$1,040,741.04
LNG Peaking Facility		$257,003.89	$257,003.89	$257,003.89	$257,003.89								$1,028,015.54
TOTAL FIXED COSTS	$2,400,345.90	$2,797,175.80	$2,804,633.23	$2,772,310.14	$2,778,176.67	$2,198,065.07	$2,526,595.78	$2,514,369.04	$2,535,103.57	$2,528,808.38	$2,493,676.48	$2,505,628.59	$30,854,888.66

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	Projected November-16	Projected December-16	Projected January-17	Projected February-17	Projected March-17	Projected April-17	Projected May-17	Projected June-17	Projected July-17	Projected August-17	Projected September-17	Projected October-17	Total
COMMODITY COSTS													
Columbia Gas Transmission FT													
Swing Purchases - TCO (FTS)													
Commodity Rate	$3.0124	$3.1246	$3.2116	$3.1894	$3.1184	$2.7795	$2.7247	$2.7170	$2.7210	$2.6922	$2.4259	$2.6755	
Commodity in DT	22,113	35,058	51,705	41,920	36,605	24,549	11,307	7,082	6,488	5,866	8,795	15,059	266,546
Commodity Cost	$66,613.72	$109,541.12	$166,054.57	$133,699.79	$114,147.77	$68,234.62	$30,806.87	$19,240.72	$17,654.23	$15,791.53	$21,336.12	$40,291.06	$803,412.12
Columbia - TCO 1278													
Commodity Rate	$3.0967	$3.2353	$3.3381	$3.3279	$3.2762	$2.9283	$2.8942	$2.9193	$2.9456	$2.9499	$2.9253	$2.9448	
Commodity in DT	0	0	0	0	0	0	0	0	0	0	0	0	0
Commodity Cost	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Total FTS Commodity Volume	22,113	35,058	51,705	41,920	36,605	24,549	11,307	7,082	6,488	5,866	8,795	15,059	266,546
Total FTS Commodity Costs	$66,613.72	$109,541.12	$166,054.57	$133,699.79	$114,147.77	$68,234.62	$30,806.87	$19,240.72	$17,654.23	$15,791.53	$21,336.12	$40,291.06	$803,412.12
TCO Pool through SST to ESNG													
Commodity Rate	$3.0967	$3.2353	$3.3381	$3.3279	$3.2762	$2.9283	$2.8942	$2.9193	$2.9456	$2.9499	$2.9253	$2.9448	
Commodity in DT	0	0	0	0	0	0	0	0	0	0	0	0	0
Commodity Cost	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Columbia Storage Injections													
Weighted Average Rate	$3.0124	$3.1246	$3.2116	$3.1894	$3.1184	$2.7795	$2.7247	$2.7170	$2.7210	$2.6922	$2.4259	$2.6755	
Commodity in DT	0	0	0	0	0	0	0	0	0	0	0	0	0
Commodity Cost	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Columbia Gas Transmission													
Commodity Volumes	22,113	35,058	51,705	41,920	36,605	24,549	11,307	7,082	6,488	5,866	8,795	15,059	266,546
Commodity Costs	$66,613.72	$109,541.12	$166,054.57	$133,699.79	$114,147.77	$68,234.62	$30,806.87	$19,240.72	$17,654.23	$15,791.53	$21,336.12	$40,291.06	$803,412.12
Transco FT													
FT Zone 1 to Zone 6 - (Sta 30)													
Commodity Rate	$3.1953	$3.3245	$3.4046	$3.3847	$3.3169	$2.9471	$2.9096	$2.9327	$2.9598	$2.9640	$2.7353	$2.9626	
Commodity in DT	12,403	19,664	29,001	23,513	20,532	13,770	6,342	3,972	3,639	3,290	4,933	8,447	149,507
Commodity Cost	$39,632.66	$65,373.17	$98,738.37	$79,585.22	$68,101.78	$40,581.07	$18,452.39	$11,649.03	$10,771.42	$9,751.82	$13,493.92	$25,024.60	$481,155.45
FT Zone 2 to Zone 6 - (Sta 45)													
Commodity Rate	$3.1980	$3.3270	$3.4069	$3.3871	$3.3194	$2.9502	$2.9128	$2.9358	$2.9629	$2.9671	$2.7388	$2.9656	
Commodity in DT	18,261	28,950	42,697	34,617	30,227	20,272	9,337	5,848	5,358	4,844	7,263	12,436	220,108
Commodity Cost	$58,397.38	$96,316.21	$145,463.03	$117,250.21	$100,336.53	$59,807.19	$27,195.90	$17,168.09	$15,874.54	$14,371.86	$19,891.46	$36,879.08	$708,951.48
FT Zone 3 to Zone 6 - (Sta 65)													
Commodity Rate	$3.1947	$3.3233	$3.4030	$3.3833	$3.3167	$2.9476	$2.9103	$2.9333	$2.9603	$2.9645	$2.7368	$2.9630	
Commodity in DT	42,378	67,186	99,088	80,337	70,150	47,047	21,668	13,571	12,434	11,241	16,855	28,860	510,816
Commodity Cost	$135,386.15	$223,277.71	$337,197.56	$271,803.69	$232,667.06	$138,675.51	$63,060.85	$39,808.99	$36,808.58	$33,324.33	$46,129.50	$85,512.27	$1,643,652.20
Total FT Commodity Volume	73,042	115,799	170,786	138,467	120,909	81,089	37,347	23,391	21,431	19,375	29,051	49,742	880,431
Total FT Commodity Costs	$70,150.17	$384,967.09	$581,398.96	$468,639.12	$401,105.37	$239,063.77	$108,709.14	$68,626.11	$63,454.54	$57,448.01	$79,514.88	$147,415.95	$2,833,759.13
FT Zone 5 to Zone 6 - (Cove Point)													
Commodity Rate	$3.0860	$3.2241	$3.3266	$3.3163	$3.2649	$2.9182	$2.8842	$2.9092	$2.9354	$2.9397	$2.9152	$2.9346	
Commodity in DT	0	0	0	0	0	0	0	0	0	0	0	0	0
Commodity Cost	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Swing Purchases - Transco Zone 6													
Commodity Rate	$3.0524	$3.1890	$3.2903	$3.2802	$3.2293	$2.8864	$2.8528	$2.8775	$2.9034	$2.9077	$2.8834	$2.9026	
Commodity in DT	0	0	0	0	0	0	0	0	0	0	0	0	0
Commodity Cost	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Transco Storage Injections													
Weighted Average Rate	$0.9604	$3.3244	$3.4042	$3.3845	$3.3174	$2.9482	$2.9108	$2.9338	$2.9609	$2.9651	$2.7370	$2.9636	
Commodity in DT	0	0	0	0	0	0	0	0	0	0	0	0	0
Commodity Cost	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Transco													
Commodity Volume	73,042	115,799	170,786	138,467	120,909	81,089	37,347	23,391	21,431	19,375	29,051	49,742	880,431
Commodity Costs	$70,150.17	$384,967.09	$581,398.96	$468,639.12	$401,105.37	$239,063.77	$108,709.14	$68,626.11	$63,454.54	$57,448.01	$79,514.88	$147,415.95	$2,670,493.11
TETCO FT													
Commodity Rate	$2.6505	$2.8734	$3.0231	$3.0440	$2.9505	$2.5120	$2.4347	$2.4322	$2.4588	$2.4453	$2.1498	$2.3933	
Commodity in DT	218,062	345,710	509,869	413,382	360,965	242,085	111,496	69,833	63,981	57,842	86,731	148,502	2,628,457
Commodity Cost	$577,973.85	$993,363.36	$1,541,385.28	$1,258,333.36	$1,065,026.85	$608,116.90	$271,458.66	$169,847.91	$157,315.94	$141,441.98	$186,453.24	$355,410.42	$7,326,127.77
TETCO FT													
Commodity Volume	218,062	345,710	509,869	413,382	360,965	242,085	111,496	69,833	63,981	57,842	86,731	148,502	$2,628,457.22
Commodity Costs	$577,973.85	$993,363.36	$1,541,385.28	$1,258,333.36	$1,065,026.85	$608,116.90	$271,458.66	$169,847.91	$157,315.94	$141,441.98	$186,453.24	$355,410.42	$7,326,127.77

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Delaware Division

		Projected November-16	Projected December-16	Projected January-17	Projected February-17	Projected March-17	Projected April-17	Projected May-17	Projected June-17	Projected July-17	Projected August-17	Projected September-17	Projected October-17	Total
Storages														
Columbia Gas Transmission Storage														
FSS Firm Storage Service														
Charges:	Avg Commodity Inc Inj	$2.1178	$2.1178	$2.1178	$2.1178	$2.1178								
	Withdrawal Inc. Trans	$0.0153	$0.0153	$0.0153	$0.0153	$0.0153								
Billing Units:	Withdrawal	21,251	85,005	127,508	106,256	42,503	0	0	0	0	0	0	0	382,523
Cost:	Reservation	$151,390.53	$151,390.54	$151,390.53	$151,390.54	$151,390.53								$756,952.67
	Avg Commodity Inc Inj	$45,005.90	$180,023.59	$270,035.38	$225,029.49	$90,011.79								$810,106.15
	Withdrawal	$325.14	$1,300.58	$1,950.86	$1,625.72	$650.29								$5,852.59
		$196,721.57	$332,714.71	$423,376.77	$378,045.75	$242,052.61								$1,572,911.41
Transco Storages														
GSS General Storage Service														
Charges:	Avg Commodity Inc Inj	$2.5818	$2.5818	$2.5818	$2.5818	$2.5818								
	Withdrawal	$0.04267	$0.04267	$0.04267	$0.04267	$0.04267								
Billing Units:	Withdrawal	0	18,788	25,050	25,050	18,788	0	0	0	0	0	0	0	87,676
Cost:	Reservation	$24,600.27	$24,600.27	$24,600.27	$24,600.27	$24,600.27								$123,001.35
	Avg Commodity Inc Inj	$0.00	$48,506.34	$64,675.12	$64,675.12	$48,506.34								$226,362.92
	Withdrawal	$0.00	$801.68	$1,068.90	$1,068.90	$801.68								$3,741.16
		$24,600.27	$73,908.29	$90,344.29	$90,344.29	$73,908.29								$353,105.43
LSS Leidy Storage Service														
Charges:	Avg Commodity Inc Inj	$2.5369	$2.5369	$2.5369	$2.5369	$2.5369								
	Withdrawal	$0.02195	$0.02195	$0.02195	$0.02195	$0.02195								
Billing Units:	Withdrawal	0	5,800	8,700	7,250	5,800	0	0	0	0	0	0	0	27,550
Cost:	Reservation	$7,624.12	$7,624.12	$7,624.12	$7,624.12	$7,624.12								$38,120.60
	Avg Commodity Inc Inj	$0.00	$14,714.02	$22,071.03	$18,392.53	$14,714.02								$69,891.60
	Withdrawal	$0.00	$127.31	$190.97	$159.14	$127.31								$604.73
		$7,624.12	$22,465.45	$29,886.12	$26,175.79	$22,465.45								$108,616.93
WSS Washington Storage Service														
Charges:	Avg Commodity Inc Inj	$2.4824	$2.4824	$2.4824	$2.4824	$2.4824								
	Withdrawal	$0.01456	$0.01456	$0.01456	$0.01456	$0.01456								
Billing Units:	Withdrawal	14,283	28,566	42,849	28,566	14,283	0	0	0	0	0	0	0	128,547
Cost:	Reservation	$5,620.27	$5,620.27	$5,620.27	$5,620.27	$5,620.27								$28,101.35
	Avg Commodity Inc Inj	$35,456.12	$70,912.24	$106,368.36	$70,912.24	$35,456.12								$319,105.08
	Withdrawal	$207.96	$415.92	$623.88	$415.92	$207.96								$1,871.64
		$41,284.35	$76,948.43	$112,612.51	$76,948.43	$41,284.35								$349,078.07
ESS Eminence Storage Service														
Charges:	Avg Commodity Inc Inj	$2.7906	$2.7906	$2.7906	$2.7906	$2.7906								
	Withdrawal	$0.04113	$0.04113	$0.04113	$0.04113	$0.04113								
Billing Units:	Withdrawal	0	6,332	9,498	9,498	6,332	0	0	0	0	0	0	0	31,660
Cost:	Reservation	$11,637.66	$11,637.66	$11,637.66	$11,637.66	$11,637.66								$58,188.30
	Avg Commodity Inc Inj	$0.00	$17,670.08	$26,505.12	$26,505.12	$17,670.08								$88,350.40
	Withdrawal	$0.00	$260.44	$390.65	$390.65	$260.44								$1,302.18
		$11,637.66	$29,568.18	$38,533.43	$38,533.43	$29,568.18								$147,840.88
PS Peaking Service														
Charges:	Reservation	$7,275.35	$7,275.36	$7,275.35	$7,275.36	$7,275.35								$36,376.77
Columbia Storage Volume		21,251	85,005	127,508	106,256	42,503	0	0	0	0	0	0	0	382,523
Columbia Storage Commodity Costs		$45,331.04	$181,324.17	$271,986.24	$226,655.21	$90,662.08	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$815,958.74
Transco Storage Volume		14,283	59,486	86,097	70,364	45,203	0	0	0	0	0	0	0	275,433
Transco Storage Commodity Costs		$35,664.08	$153,408.03	$221,894.03	$182,519.62	$117,743.95	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$711,229.71
Total Storage Volume		35,534	144,491	213,605	176,621	87,705	0	0	0	0	0	0	0	657,956
Total Storage Commodity Costs		$80,995.12	$334,732.20	$493,880.27	$409,174.83	$208,406.03	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$1,527,188.45

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	Projected November-16	Projected December-16	Projected January-17	Projected February-17	Projected March-17	Projected April-17	Projected May-17	Projected June-17	Projected July-17	Projected August-17	Projected September-17	Projected October-17	Total
Eastern Shore Natural Gas													
Total Upstream Volume	348,752	641,058	945,965	770,389	606,184	347,723	160,149	100,306	91,900	83,083	124,577	213,304	4,433,390
Eastern Shore Fuel	(3,801)	(6,988)	(10,311)	(8,397)	(6,607)	(3,790)	(1,746)	(1,093)	(1,002)	(906)	(1,358)	(2,325)	(48,324)
Eastern Shore Volume	344,951	634,070	935,654	761,992	599,577	343,933	158,403	99,213	90,898	82,177	123,219	210,979	4,385,067
Delivery Zone 2													
Commodity Rate	$0.0118	$0.0118	$0.0118	$0.0118	$0.0118	$0.0118	$0.0118	$0.0118	$0.0118	$0.0118	$0.0118	$0.0118	
Commodity in DT	120,733	221,925	327,479	266,697	209,852	120,377	55,441	34,725	31,814	28,762	43,127	73,843	
Commodity Cost	$1,424.65	$2,618.71	$3,864.25	$3,147.03	$2,476.25	$1,420.44	$654.20	$409.75	$375.41	$339.39	$508.89	$871.34	$18,110.31
Interruptible Commodity Rate	$0.4837	$0.4837	$0.4837	$0.4837	$0.4837	$0.4837	$0.4837	$0.4837	$0.4837	$0.4837	$0.4837	$0.4837	
Interruptible Commodity in DT	0	0	0	0	0	0	0	0	0	0	0	0	
Interruptible Commodity Cost	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Commodity Max Check	2,091,210	2,353,892	2,353,892	2,126,096	2,353,892	2,091,210	1,879,561	1,818,930	1,879,561	1,879,561	1,818,930	1,879,561	
Delivery Zone 3													
Commodity Rate	$0.0170	$0.0170	$0.0170	$0.0170	$0.0170	$0.0170	$0.0170	$0.0170	$0.0170	$0.0170	$0.0170	$0.0170	
Commodity in DT	224,218	412,146	608,175	495,295	389,725	223,556	102,962	64,488	59,084	53,415	80,092	137,136	
Commodity Cost	$3,811.71	$7,006.47	$10,338.98	$8,420.01	$6,625.33	$3,800.46	$1,750.35	$1,096.30	$1,004.42	$908.06	$1,361.57	$2,331.32	$48,454.98
Interruptible Commodity Rate	$0.6610	$0.6610	$0.6610	$0.6610	$0.6610	$0.6610	$0.6610	$0.6610	$0.6610	$0.6610	$0.6610	$0.6610	
Interruptible Commodity in DT	0	0	0	0	0	0	0	0	0	0	0	0	
Interruptible Commodity Cost	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Total Commodity	$5,236.36	$9,625.18	$14,203.23	$11,567.04	$9,101.58	$5,220.90	$2,404.55	$1,506.05	$1,379.83	$1,247.45	$1,870.46	$3,202.66	$66,565.29
Eastern Shore Imbalance	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Third Party Transportation Credit	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Total Eastern Shore Commodity	$5,236.36	$9,625.18	$14,203.23	$11,567.04	$9,101.58	$5,220.90	$2,404.55	$1,506.05	$1,379.83	$1,247.45	$1,870.46	$3,202.66	$66,565.29
TOTAL COMMODITY COSTS	$800,969.22	$1,832,228.95	$2,796,922.31	$2,281,414.14	$1,797,787.60	$920,636.19	$413,379.22	$259,220.79	$239,804.54	$215,928.97	$289,174.70	$546,320.09	$12,393,786.74

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	Projected November-16	Projected December-16	Projected January-17	Projected February-17	Projected March-17	Projected April-17	Projected May-17	Projected June-17	Projected July-17	Projected August-17	Projected September-17	Projected October-17	Total
Pipeline Summary													
Columbia Gas Transmission													
Columbia/Columbia Gulf FT Costs													
Fixed Costs	$71,119.44	$71,119.44	$71,119.44	$71,119.44	$71,119.44	$71,119.44	$71,119.44	$71,119.44	$71,119.44	$71,119.44	$71,119.44	$71,119.44	$853,433.28
Commodity Costs	$66,613.72	$109,541.12	$166,054.57	$133,699.79	$114,147.77	$68,234.62	$30,806.87	$19,240.72	$17,654.23	$15,791.53	$21,336.12	$40,291.06	$803,412.12
Total Costs	$137,733.16	$180,660.56	$237,174.01	$204,819.23	$185,267.21	$139,354.06	$101,926.31	$90,360.16	$88,773.67	$86,910.97	$92,455.56	$111,410.50	$1,656,845.40
Columbia/Columbia Gulf Storage Costs													
Fixed Costs	$151,390.53	$151,390.54	$151,390.53	$151,390.54	$151,390.53	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$756,952.67
Commodity Costs	$45,331.04	$181,324.17	$271,986.24	$226,655.21	$90,662.08	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$815,958.74
Total Costs	$196,721.57	$332,714.71	$423,376.77	$378,045.75	$242,052.61	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$1,572,911.41
Columbia/Columbia Gulf Total Costs													
Fixed Costs	$222,509.97	$222,509.98	$222,509.97	$222,509.98	$222,509.97	$71,119.44	$71,119.44	$71,119.44	$71,119.44	$71,119.44	$71,119.44	$71,119.44	$1,610,385.95
Commodity Costs	$111,944.76	$290,865.29	$438,040.81	$360,355.00	$204,809.85	$68,234.62	$30,806.87	$19,240.72	$17,654.23	$15,791.53	$21,336.12	$40,291.06	$1,619,370.86
Total Costs	$334,454.73	$513,375.27	$660,550.78	$582,864.98	$427,319.82	$139,354.06	$101,926.31	$90,360.16	$88,773.67	$86,910.97	$92,455.56	$111,410.50	$3,229,756.81
Columbia FT Volume	22,113	35,058	51,705	41,920	36,605	24,549	11,307	7,082	6,488	5,866	8,795	15,059	266,546
Columbia Storage Volume	21,251	85,005	127,508	106,256	42,503	0	0	0	0	0	0	0	382,523
Columbia Total Volume	43,364	120,063	179,212	148,176	79,107	24,549	11,307	7,082	6,488	5,866	8,795	15,059	649,068
Transco													
Transco FT Costs													
Fixed Costs	$323,810.70	$334,604.39	$334,604.39	$302,223.32	$334,604.39	$323,810.70	$334,604.39	$323,810.70	$334,604.39	$334,604.39	$323,810.70	$334,604.39	$3,939,696.85
Commodity Costs	$70,150.17	$384,967.09	$581,398.96	$468,639.12	$401,105.37	$239,063.77	$108,709.14	$68,626.11	$63,454.54	$57,448.01	$79,514.88	$147,415.95	$2,670,493.11
Total Costs	$393,960.87	$719,571.48	$916,003.35	$770,862.44	$735,709.76	$562,874.47	$443,313.53	$392,436.81	$398,058.93	$392,052.40	$403,325.58	$482,020.34	$6,610,189.96
Transco Storage Costs													
Fixed Costs	$56,757.67	$56,757.68	$56,757.67	$56,757.68	$56,757.67	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$283,788.37
Commodity Costs	$35,664.08	$153,408.03	$221,894.03	$182,519.62	$117,743.95	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$711,229.71
Total Costs	$92,421.75	$210,165.71	$278,651.70	$239,277.30	$174,501.62	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$995,018.08
Transco Total Costs													
Fixed Costs	$380,568.37	$391,362.07	$391,362.06	$358,981.00	$391,362.06	$323,810.70	$334,604.39	$323,810.70	$334,604.39	$334,604.39	$323,810.70	$334,604.39	$4,223,485.22
Commodity Costs	$105,814.25	$538,375.12	$803,292.99	$651,158.74	$518,849.32	$239,063.77	$108,709.14	$68,626.11	$63,454.54	$57,448.01	$79,514.88	$147,415.95	$3,381,722.82
Total Costs	$486,382.62	$929,737.19	$1,194,655.05	$1,010,139.74	$910,211.38	$562,874.47	$443,313.53	$392,436.81	$398,058.93	$392,052.40	$403,325.58	$482,020.34	$7,605,208.04
Transco FT Volume	73,042	115,799	170,786	138,467	120,909	81,089	37,347	23,391	21,431	19,375	29,051	49,742	880,431
Transco Storage Volume	14,283	59,486	86,097	70,364	45,203	0	0	0	0	0	0	0	275,433
Transco Total Volume	87,325	175,285	256,884	208,831	166,112	81,089	37,347	23,391	21,431	19,375	29,051	49,742	1,155,865
TETCO													
TETCO FT Costs													
Fixed Costs	$524,563.71	$524,563.71	$524,563.71	$524,563.71	$524,563.71	$524,563.71	$524,563.71	$524,563.71	$524,563.71	$524,563.71	$524,563.71	$524,563.71	$6,294,764.52
Commodity Costs	$577,973.85	$993,363.36	$1,541,385.28	$1,258,333.36	$1,065,026.85	$608,116.90	$271,458.66	$169,847.91	$157,315.94	$141,441.98	$186,453.24	$355,410.42	$7,326,127.77
Total Costs	$1,102,537.56	$1,517,927.07	$2,065,948.99	$1,782,897.07	$1,589,590.56	$1,132,680.61	$796,022.37	$694,411.62	$681,879.65	$666,005.69	$711,016.95	$879,974.13	$13,620,892.29
Eastern Shore Natural Gas													
ESNG FT													
Fixed Costs	$1,697,228.76	$1,818,360.68	$1,818,360.68	$1,818,360.68	$1,795,113.69	$1,697,228.76	$2,015,983.05	$2,015,983.05	$2,015,983.05	$2,015,983.05	$2,015,983.05	$2,015,983.05	$22,740,551.54
Commodity Costs	$5,236.36	$9,625.18	$14,203.23	$11,567.04	$9,101.58	$5,220.90	$2,404.55	$1,506.05	$1,379.83	$1,247.45	$1,870.46	$3,202.66	$66,565.29
Total Costs	$1,702,465.12	$1,827,985.86	$1,832,563.91	$1,829,927.72	$1,804,215.27	$1,702,449.66	$2,018,387.60	$2,017,489.10	$2,017,362.88	$2,017,230.50	$2,017,853.51	$2,019,185.71	$22,807,116.83
Total Commodity Volume	313,218	496,567	732,360	593,768	518,479	347,723	160,149	100,306	91,900	83,083	124,577	213,304	3,775,434
Total Storage Volume	35,534	144,491	213,605	176,621	87,705	0	0	0	0	0	0	0	657,956
Total Volume	348,752	641,058	945,965	770,389	606,184	347,723	160,149	100,306	91,900	83,083	124,577	213,304	4,433,390

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	Projected November-16	Projected December-16	Projected January-17	Projected February-17	Projected March-17	Projected April-17	Projected May-17	Projected June-17	Projected July-17	Projected August-17	Projected September-17	Projected October-17	Total
	1.035	1.035	1.035	1.035	1.035	1.035	1.035	1.035	1.035	1.035	1.035	1.035	1.035
Flowing Commodity WACOG													
Transco Station 30	$39,632.66	$65,373.17	$98,738.37	$79,585.22	$68,101.78	$40,581.07	$18,452.39	$11,649.03	$10,771.42	$9,751.82	$13,493.92	$25,024.60	$481,155.45
Transco Station 45	$58,397.38	$96,316.21	$145,463.03	$117,250.21	$100,336.53	$59,807.19	$27,195.90	$17,168.09	$15,874.54	$14,371.86	$19,891.46	$36,879.08	$708,951.48
Transco Station 65	$135,386.15	$223,277.71	$337,197.56	$271,803.69	$232,667.06	$138,675.51	$63,060.85	$39,808.99	$36,808.58	$33,324.33	$46,129.50	$85,512.27	$1,643,652.20
Transco Storage Injections	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Transco Zone 5 (Cove Point)	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Transco 6	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
TCO 1278	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
TCO	$66,613.72	$109,541.12	$166,054.57	$133,699.79	$114,147.77	$68,234.62	$30,806.87	$19,240.72	$17,654.23	$15,791.53	$21,336.12	$40,291.06	$803,412.12
Columbia Gulf	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Columbia Storage Injections	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
TETCO	$577,973.85	$993,363.36	$1,541,385.28	$1,258,333.36	$1,065,026.85	$608,116.90	$271,458.66	$169,847.91	$157,315.94	$141,441.98	$186,453.24	$355,410.42	$7,326,127.77
ESNG Commodity	$5,236.36	$9,625.18	$14,203.23	$11,567.04	$9,101.58	$5,220.90	$2,404.55	$1,506.05	$1,379.83	$1,247.45	$1,870.46	$3,202.66	$66,565.29
ESNG Imbalance	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
	$883,240.12	$1,497,496.75	$2,303,042.04	$1,872,239.31	$1,589,381.57	$920,636.19	$413,379.22	$259,220.79	$239,804.54	$215,928.97	$289,174.70	$546,320.09	$11,029,864.31
Dt	313,218	496,567	732,360	593,768	518,479	347,723	160,149	100,306	91,900	83,083	124,577	213,304	3,775,434
Unit Cost per Dt	$2.8032	$2.9963	$3.1253	$3.1337	$3.0479	$2.6326	$2.5662	$2.5693	$2.5944	$2.5839	$2.3062	$2.5462	$2.9039
Unit Cost per Dt w/ESN Com	$2.8199	$3.0157	$3.1447	$3.1531	$3.0655	$2.6476	$2.5812	$2.5843	$2.6094	$2.5990	$2.3213	$2.5612	$2.9215
Unit Cost per Mcf w/ESN Com	$2.9186	$3.1212	$3.2548	$3.2635	$3.1728	$2.7403	$2.6715	$2.6748	$2.7007	$2.6900	$2.4025	$2.6508	$3.0238
Unit Cost per Mcf w/ESN Com + UFG	$2.9813	$3.1883	$3.3248	$3.3337	$3.2410	$2.7992	$2.7289	$2.7323	$2.7588	$2.7478	$2.4542	$2.7078	$3.0888
TOTAL COSTS													
Fixed Costs													
Other Pipeline FT Reservation	$919,493.85	$930,287.54	$930,287.54	$897,906.47	$930,287.54	$919,493.85	$930,287.54	$919,493.85	$930,287.54	$930,287.54	$919,493.85	$930,287.54	$11,087,894.65
Storage Demand & Capacity	$208,148.20	$208,148.22	$208,148.20	$208,148.22	$208,148.20	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$1,040,741.04
LNG Peaking Facility	$0.00	$257,003.89	$257,003.89	$257,003.89	$257,003.89	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$1,028,015.54
ESNG FT Reservation	$1,697,228.76	$1,818,360.68	$1,818,360.68	$1,818,360.68	$1,795,113.69	$1,697,228.76	$2,015,983.05	$2,015,983.05	$2,015,983.05	$2,015,983.05	$2,015,983.05	$2,015,983.05	$22,740,551.54
Add: Capacity Reservation	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Less: Capacity Release Credits	($424,524.91)	($416,624.52)	($409,167.08)	($409,109.11)	($412,376.65)	($418,657.54)	($419,674.81)	($421,107.86)	($411,167.01)	($417,462.21)	($441,800.42)	($440,642.00)	($5,042,314.11)
Fixed Costs	$2,400,345.90	$2,797,175.80	$2,804,633.23	$2,772,310.14	$2,778,176.67	$2,198,065.07	$2,526,595.78	$2,514,369.04	$2,535,103.57	$2,528,808.38	$2,493,676.48	$2,505,628.59	$30,854,888.66
Commodity Costs													
Flowing Commodity	$714,737.74	$1,487,871.57	$2,288,838.81	$1,860,672.27	$1,580,279.99	$915,415.29	$410,974.67	$257,714.74	$238,424.71	$214,681.52	$287,304.24	$543,117.43	$10,800,033.00
Storage I/W & Commodity	$80,995.12	$334,732.20	$493,880.27	$409,174.83	$208,406.03	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$1,527,188.45
ESNG FT Commodity	$5,236.36	$9,625.18	$14,203.23	$11,567.04	$9,101.58	$5,220.90	$2,404.55	$1,506.05	$1,379.83	$1,247.45	$1,870.46	$3,202.66	$66,565.29
Commodity Costs	$800,969.22	$1,832,228.95	$2,796,922.31	$2,281,414.14	$1,797,787.60	$920,636.19	$413,379.22	$259,220.79	$239,804.54	$215,928.97	$289,174.70	$546,320.09	$12,393,786.74
Less: CNG Use	($64.29)	($109.50)	($126.47)	($135.01)	($145.84)	($79.18)	($101.77)	($77.79)	($45.04)	($48.49)	($116.28)	($53.18)	($1,102.84)
Total Firm Cost of Gas	$3,201,250.83	$4,629,295.25	$5,601,429.07	$5,053,589.28	$4,575,818.43	$3,118,622.08	$2,939,873.23	$2,773,512.05	$2,774,863.08	$2,744,688.87	$2,782,734.91	$3,051,895.50	$43,247,572.56

Schedule D.1

Chesapeake Utilities Corporation
Delaware Division
Projected Gas Cost Over/(Under) Collection
For The Twelve Months Ending October 31, 2017

	Actual Nov-16	Actual Dec-16	Actual Jan-17	Actual Feb-17	Actual Mar-17	Actual Apr-17	Actual May-17	Actual Jun-17	Estimated Jul-17	Estimated Aug-17	Estimated Sep-17	Estimated Oct-17	Total
Calculation of Current Over/(Under) Collections													
GSR Revenue (RS, GS, MVS, LVS)	$1,499,800.99	$4,036,145.06	$6,140,909.36	$4,986,622.59	$4,491,225.39	$3,020,175.70	$1,155,904.25	$736,324.00	$523,519.94	$517,887.00	$558,688.00	$981,372.00	$28,648,574.28
GSR Revenue (HLFS, SFS)	$124,257.92	$166,412.52	$193,060.46	$168,928.90	$176,579.18	$149,718.40	$160,587.75	$144,154.35	$126,202.25	$125,700.00	$118,141.00	$139,768.00	$1,793,510.73
GSR Revenue (GLR, GLO, GCR, GCO)	$7.03	$15.54	$15.54	$15.54	$15.54	$15.54	$15.54	$15.54	$0.00	$25.00	$25.00	$25.00	$190.81
Total GSR Revenue	$1,624,065.94	$4,202,573.12	$6,333,985.36	$5,155,567.03	$4,667,820.11	$3,169,909.64	$1,316,507.54	$880,493.89	$649,722.19	$643,612.00	$676,854.00	$1,121,165.00	$30,442,275.82
Less: Regulatory Assessment	$4,872.20	$12,607.72	$19,001.96	$15,466.70	$14,003.46	$9,509.73	$3,949.52	$2,641.48	$1,949.17	$1,930.84	$2,030.56	$3,363.50	$91,326.84
Net Collections	$1,619,193.74	$4,189,965.40	$6,314,983.40	$5,140,100.33	$4,653,816.65	$3,160,399.91	$1,312,558.02	$877,852.41	$647,773.02	$641,681.16	$674,823.44	$1,117,801.50	$30,350,948.98
Natural Gas Cost	$2,901,194.20	$4,569,237.36	$4,460,081.44	$3,636,102.70	$3,983,343.11	$2,333,014.06	$2,197,329.92	$2,099,767.50	$1,929,655.54	$1,988,977.71	$1,969,092.00	$2,236,543.75	$34,304,339.29
Propane Costs	$0.00	$14,252.18	$11,179.89	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$25,432.07
Cost of Interruptible Sales	($4.57)	($9.08)	($9.51)	($6.70)	($30.03)	($15.21)	($36.60)	($51.40)	($16.33)	$0.00	$0.00	$0.00	($179.43)
GSR Settlement Adjustment	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Prior Period Adjustments to Interest	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Capacity Amortization	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Transition Fee	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Miscellaneous Adjustments	$0.00	$11,427.77	$0.00	$0.00	$0.00	($8,289.45)	($7,805.49)	($6,027.12)	($5,820.25)	$0.00	$0.00	$0.00	($16,514.54)
Upstream Capacity Release Credits	($18,202.86)	($18,809.62)	($18,809.62)	($16,989.34)	($18,809.62)	$0.00	$0.00	$0.00	$0.00	($43,513.51)	($43,513.51)	($43,513.51)	($222,161.59)
Transportation Balancing Rate Credit	($17,569.60)	$17,530.97	$33,597.74	$147,510.29	$37,789.65	$100,982.47	($13,646.26)	($3,770.66)	$2,438.95	($67,245.00)	($87,974.00)	($107,215.00)	$42,429.55
Transportation Cash In/Out Credit	($128,450.35)	($218,188.60)	($211,421.41)	($189,910.60)	($205,777.56)	($111,202.44)	($96,999.18)	($88,103.01)	($68,190.90)	$0.00	$0.00	$0.00	($1,318,244.05)
Net Cost	$2,736,966.82	$4,375,440.98	$4,274,618.53	$3,576,706.35	$3,796,515.55	$2,314,489.43	$2,078,842.39	$2,001,815.31	$1,858,067.01	$1,878,219.20	$1,837,604.49	$2,085,815.24	$32,815,101.30
Current (Over)/Under Collection	$1,117,773.08	$185,475.58	($2,040,364.87)	($1,563,393.98)	($857,301.10)	($845,910.48)	$766,284.37	$1,123,962.90	$1,210,293.99	$1,236,538.04	$1,162,781.05	$968,013.74	$2,464,152.32
Calculation of Carrying Charge on Account #191													
Balance in #191 in the Beginning of Month	$781,251.32	$1,900,313.44	$2,088,972.52	$52,101.11	($1,511,337.60)	($2,371,403.50)	($3,221,741.75)	($2,461,467.05)	($1,348,105.37)	($140,328.52)	$1,095,917.86	$2,260,481.72	
Prior Period Adjustments	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	
Prior Period Adjustments to Interest	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	
Adjusted Beginning Balance	$781,251.32	$1,900,313.44	$2,088,972.52	$52,101.11	($1,511,337.60)	($2,371,403.50)	($3,221,741.75)	($2,461,467.05)	($1,348,105.37)	($140,328.52)	$1,095,917.86	$2,260,481.72	
Times Effective Tax Rate	40.655%	40.655%	40.655%	40.655%	40.655%	40.655%	40.655%	40.655%	40.655%	40.655%	40.655%	40.655%	
Deferred Income Tax	$317,617.72	$772,572.43	$849,271.78	$21,181.71	($614,434.30)	($964,094.09)	($1,309,799.11)	($1,000,709.43)	($548,072.24)	($57,050.56)	$445,545.41	$918,998.84	($1,168,971.84)
Balance Net of Income Tax & Capacity Amortization	$463,633.60	$1,127,741.01	$1,239,700.74	$30,919.40	($896,903.30)	($1,407,309.41)	($1,911,942.64)	($1,460,757.62)	($800,033.13)	($83,277.96)	$650,372.45	$1,341,482.88	($1,706,373.98)
Times 1/12 of Annual Interest Rate	0.292%	0.292%	0.292%	0.292%	0.292%	0.309%	0.309%	0.309%	0.309%	0.292%	0.292%	0.292%	
Interest (Revenue) or Expense	$1,353.81	$3,293.00	$3,619.93	$90.28	($2,618.96)	($4,348.59)	($5,907.90)	($4,513.74)	($2,472.10)	($243.17)	$1,899.09	$3,917.13	($5,931.22)
Calculation of Ending Balance in Account #191													
Balance in #191 in the Beginning of Period	$781,251.32	$1,900,313.44	$2,088,972.52	$52,101.11	($1,511,337.60)	($2,371,403.50)	($3,221,741.75)	($2,461,467.05)	($1,348,105.37)	($140,328.52)	$1,095,917.86	$2,260,481.72	$781,251.32
Current (Over)/Under Collections	$1,117,773.08	$185,475.58	($2,040,364.87)	($1,563,393.98)	($857,301.10)	($845,910.48)	$766,284.37	$1,123,962.90	$1,210,293.99	$1,236,538.04	$1,162,781.05	$968,013.74	$2,464,152.32
Supplier Refunds	($0.48)	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	($6,009.69)	$0.00	$0.00	$0.00	$0.00	($6,010.17)
CNG Vehicular Fuel	($64.29)	($109.50)	($126.47)	($135.01)	($145.84)	($79.18)	($101.77)	($77.79)	($45.04)	($48.49)	($116.28)	($53.18)	($1,102.84)
Interest Revenue or (Expense)	$1,353.81	$3,293.00	$3,619.93	$90.28	($2,618.96)	($4,348.59)	($5,907.90)	($4,513.74)	($2,472.10)	($243.17)	$1,899.09	$3,917.13	($5,931.22)
Ending Balance #191 (Over)/Under Collections	$1,900,313.44	$2,088,972.52	$52,101.11	($1,511,337.60)	($2,371,403.50)	($3,221,741.75)	($2,461,467.05)	($1,348,105.37)	($140,328.52)	$1,095,917.86	$2,260,481.72	$3,232,359.41	$3,232,359.41
	($1,900,313.44)	**($2,088,972.51)**	**($52,101.11)**	**$1,511,337.60**	**$2,371,403.50**	**$3,221,742.06**	**$2,461,467.67**	**$1,348,106.29**	**$140,459.39**	**$0.00**	**$0.00**	**$0.00**	
RS, GS, MVS, LVS Mcf's	179,259	447,430	680,828	552,851	498,351	334,829	128,151	81,634	58,039	57,415	61,939	108,800	3,189,526
HLFS, SFS Mcf's	22,146	26,499	30,742	26,900	28,117	23,841	25,571	22,955	20,096	19,984	18,782	22,221	287,854
GLR, GLO, GCR, GCO Mcf's	3	3	3	4	4	4	4	4	4	7	7	7	54
Total Firm Mcf's + Adjusted Sales	201,408	473,932	711,573	579,755	526,472	358,674	153,726	104,593	78,139	77,406	80,728	131,027	3,477,434
RS, GS, MVS, LVS GSR Rate	$9.02	$9.02	$9.02	$9.02	$9.02	$9.02	$9.02	$9.02	$9.02	$9.02	$9.02	$9.02	
HLFS Rate	$6.29	$6.29	$6.29	$6.29	$6.29	$6.29	$6.29	$6.29	$6.29	$6.29	$6.29	$6.29	
GLR, GLO Rate	$3.60	$3.60	$3.60	$3.60	$3.60	$3.60	$3.60	$3.60	$3.60	$3.60	$3.60	$3.60	
Annual Interest Rate	3.250%	3.250%	3.250%	3.250%	3.250%	3.250%	3.250%	3.250%	3.250%	3.250%	3.250%	3.250%	
Effective Tax Rate	40.655%	40.655%	40.655%	40.655%	40.655%	40.655%	40.655%	40.655%	40.655%	40.655%	40.655%	40.655%	
Supplier Refunds	$0.48	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$6,009.69	$0.00	$0.00	$0.00	$0.00	
	$0.00	$0.01	$0.00	$0.00	$0.00	$0.31	$0.62	$0.92	$130.87	$1,095,917.86	$2,260,481.72	$3,232,359.41	

Schedule D.2

Chesapeake Utilities Corporation
Delaware Division
Projected Shared Margins Over/(Under) Refund
For The Twelve Months Ending October 31, 2017

	Actual Nov-16	Actual Dec-16	Actual Jan-17	Actual Feb-17	Actual Mar-17	Actual Apr-17	Actual May-17	Actual Jun-17	Estimated Jul-17	Estimated Aug-17	Estimated Sep-17	Estimated Oct-17	Total
Calculation of Current Shared Margins Over/(Under) Refund													
Total Shared Margins	$242,823.92	$242,823.92	$242,823.92	$242,823.92	$242,823.92	$242,823.92	$242,823.92	$242,823.92	$242,823.92	$242,823.92	$242,823.92	$242,823.92	$2,913,887.07
Shared Margin Inherent in Rate	$150,577.56	$375,841.20	$571,895.52	$464,394.84	$418,614.84	$281,256.36	$107,646.84	$68,572.56	$48,752.76	$48,228.95	$52,028.56	$91,391.63	$2,679,201.62
Less: Regulatory Assessment	$451.73	$1,127.52	$1,715.69	$1,393.18	$1,255.84	$843.77	$322.94	$205.72	$146.26	$144.69	$156.09	$274.17	$8,037.60
Net Margin Refunded Through Rate	$150,125.83	$374,713.68	$570,179.83	$463,001.66	$417,359.00	$280,412.59	$107,323.90	$68,366.84	$48,606.50	$48,084.26	$51,872.47	$91,117.46	$2,671,164.02
Shared Margins Expensed	($224,613.62)	($224,612.00)	($224,612.00)	($224,612.00)	($224,612.00)	($231,249.06)	($231,250.00)	($231,250.00)	($231,250.00)	($231,250.00)	($231,250.00)	($231,250.00)	($2,741,810.68)
Current Over/(Under) Refund	($74,487.79)	$150,101.68	$345,567.83	$238,389.66	$192,747.00	$49,163.53	($123,926.10)	($162,883.16)	($182,643.50)	($183,165.74)	($179,377.53)	($140,132.54)	($70,646.66)
Calculation of Ending Balance in Account #191SM													
Balance in #191SM in the Beginning of Period	($310,972.24)	($385,460.03)	($235,358.35)	$110,209.48	$348,599.14	$541,346.14	$590,509.67	$466,583.57	$303,700.41	$121,056.91	($62,108.83)	($241,486.36)	($310,972.24)
Prior Period Adjustment	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Adjusted Beginning Balance	($310,972.24)	($385,460.03)	($235,358.35)	$110,209.48	$348,599.14	$541,346.14	$590,509.67	$466,583.57	$303,700.41	$121,056.91	($62,108.83)	($241,486.36)	($310,972.24)
Current Over/(Under) Refund	($74,487.79)	$150,101.68	$345,567.83	$238,389.66	$192,747.00	$49,163.53	($123,926.10)	($162,883.16)	($182,643.50)	($183,165.74)	($179,377.53)	($140,132.54)	($70,646.66)
Ending Balance #191SM Over/(Under) Refund	($385,460.03)	($235,358.35)	$110,209.48	$348,599.14	$541,346.14	$590,509.67	$466,583.57	$303,700.41	$121,056.91	($62,108.83)	($241,486.36)	($381,618.90)	($381,618.90)
RS, GS, MVS, LVS Mcf's	179,259	447,430	680,828	552,851	498,351	334,829	128,151	81,634	58,039	57,415	61,939	108,800	3,189,526
Margin Sharing Credit Per Mcf	$0.84	$0.84	$0.84	$0.84	$0.84	$0.84	$0.84	$0.84	$0.84	$0.84	$0.84	$0.84	

Chesapeake Utilities Corporation
Delaware Division
Development of Gas Sales Service Rates Effective November 1, 2017

Based on Total Firm Gas Costs Recoverable through GSR effective November 1, 2017

Description	Allocator	Total System Costs	Volume (Ccf)	Cost / Ccf
Fixed Gas Costs	Peak Day Capacity Entitlements	$29,223,381	880,370	$33.19
Variable Gas Costs	Annual Volume	$15,625,043	41,474,993	$0.377
Total Firm Gas Costs	Annual Volume	$44,848,424	41,474,993	$1.081

Development of High Load Factor Service Rates per CCF (50% Load Factor)

Description		Peak Day Cap. Method	System Average Cost	HLFS Average Rate
Demand Rate	($33.19 / 317)	$0.105		
Commodity Rate		$0.377		
Total Gas Sales Service Rate		**$0.482**	**$1.081**	**$0.782**

Total High Load Factor Dollars

Projected Sales	Rate	Total Cost
3,079,690	**$0.782**	**$2,408,318**

Development of Gas Lighting Rate per CCF (100% Load Factor)

Description		Peak Day Cap. Method
Demand Rate	($33.19 / 365)	$0.091
Commodity Rate		$0.377
Total Gas Sales Service Rate		**$0.468**

Total Gas Cooling and Gas Lighting Dollars

Projected Sales	Rate	Total Cost
0	**$0.468**	**$0**

Development of RS1,RS2, GS, MVS, and LVS Rate per CCF

Description	Firm Gas Cost	Volume (CCF)	Rate per CCF	Margin Sharing Rate per CCF	Final Rate per CCF
Total System Gas Cost	$44,848,424	41,474,993			
Less : Allocated to HLFS & SFS	$2,408,318	3,079,690			
Less : Allocated to GL, GC	$0	0			
Total Remaining System	$42,440,106	38,395,303	**$1.105**	**($0.082)**	**$1.023**

Based on Total Firm Gas Costs Recoverable through GSR effective November 1, 2016

Description	Allocator	Total System Costs	Volume (Ccf)	Cost / Ccf
Fixed Gas Costs	Peak Day Capacity Entitlements	$22,658,005	851,380	$26.61
Variable Gas Costs	Annual Volume	$10,950,111	38,087,756	$0.287
Total Firm Gas Costs	Annual Volume	$33,608,116	38,087,756	$0.882

Development of High Load Factor Service Rates per CCF (50% Load Factor)

Description		Peak Day Cap. Method	System Average Cost	HLFS Average Rate
Demand Rate	($26.64/307)	$0.087		
Commodity Rate		$0.287		
Total Gas Sales Service Rate		**$0.374**	**$0.882**	**$0.628**

Total High Load Factor Dollars

Projected Sales	Rate	Total Cost
2,773,761	**$0.628**	**$1,741,922**

Development of Gas Lighting Rate per CCF (100% Load Factor)

Description		Peak Day Cap. Method
Demand Rate	($26.64/365)	$0.073
Commodity Rate		$0.287
Total Gas Sales Service Rate		**$0.360**

Total Gas Cooling and Gas Lighting Dollars

Projected Sales	Rate	Total Cost
770	**$0.360**	**$277**

Development of RS1,RS2, GS, MVS, and LVS Rate per CCF

Description	Firm Gas Cost	Volume (CCF)	Rate per CCF	Margin Sharing Rate per CCF	Final Rate per CCF
Total System Gas Cost	$33,608,116	38,087,756			
Less : Allocated to HLFS & SFS	$1,741,922	2,773,761			
Less : Allocated to GL, GC	$277	770			
Total Remaining System	$31,865,917	35,313,225	**$0.902**	**($0.084)**	**$0.818**

Change in Total Firm Gas Costs Recoverable through GSR

Description	Costs	Cost / Ccf
Fixed Gas Costs	$6,565,376	$6.580
Variable Gas Costs	$4,674,932	$0.090
Total Firm Gas Costs	$11,240,308	$0.199

Change in HLFS Rate

Description	HLFS Cost / Ccf
Demand Rate	
Commodity Rate	
Total Gas Sales Service Rate	**$0.154**

Change in Gas Lighting Rate

Description	GL Cost / Ccf
Demand Rate	
Commodity Rate	
Total Gas Sales Service Rate	**$0.108**

Change in RS1, RS2, GS, MVS, and LVS Rate

Description	Rate per CCF	Margin Sharing Rate per CCF	Final Rate per CCF
Total System Gas Cost			
Less : Allocated to HLFS			
Less : Allocated to GL, GC			
Total Remaining System	**$0.203**	**$0.002**	**$0.205**

Schedule F

Chesapeake Utililties Corporation
Delaware Division
Firm Cost of Gas Comparison

Description	Projection Inherent In November 1, 2017 GSR Filing Projected 12 Months Ending Oct-17	Average Cost Per MCF	12 Months Ending Oct-16	Average Cost Per MCF	12 Months Ended Oct-16	Average Cost Per MCF	12 Months Ended Oct-15	Average Cost Per MCF	12 Months Ended Oct-14	Average Cost Per MCF
Firm Fixed Gas Costs										
ESNG FT Reservation[1]	$17,698,237	$4.2672	$11,284,000	$3.2449	$11,367,101	$3.6143	$11,563,874	$2.9309	$11,391,303	$2.9803
Columbia FT Reservation	$853,433	$0.2058	$814,501	$0.2342	$818,778	$0.2603	$797,478	$0.2021	$822,685	$0.2152
Transco FT Reservation	$3,939,697	$0.9499	$3,941,307	$1.1334	$3,957,183	$1.2582	$3,951,032	$1.0014	$4,026,470	$1.0534
Texas Eastern FT Reservation	$6,294,765	$1.5177	$6,294,818	$1.8102	$6,294,765	$2.0015	$6,294,765	$1.5954	$6,294,811	$1.6469
Storage Demand and Capacity & Peaking	$2,068,757	$0.4988	$2,101,859	$0.6044	$1,295,500	$0.4119	$1,021,278	$0.2588	$1,048,626	$0.2743
Total Firm Fixed Gas Costs	**$30,854,889**	**$7.4394**	**$24,436,484**	**$7.0270**	**$23,733,326**	**$7.5464**	**$23,628,426**	**$5.9888**	**$23,583,895**	**$6.1702**
Firm Variable Gas Costs										
Flowing Commodity	$10,800,033	$2.6040	$8,467,264	$2.4349	$6,563,848	$2.0871	$11,568,935	$2.9322	$17,237,821	$4.5099
ESNG FT Commodity	$66,565	$0.0160	$19,133	$0.0055	$159,330	$0.0507	$66,553	$0.0169	($72,209)	($0.0189)
CNG for Vehicular Use	($1,103)	($0.0003)	($1,103)	($0.0003)	($661)	($0.0002)	($839)	($0.0002)	($1,603)	($0.0004)
Storage Injection/Withdrawal & Commodity	$1,527,188	$0.3682	$1,381,458	$0.3973	$1,438,299	$0.4573	$2,424,023	$0.6144	$2,522,818	$0.6600
Propane	$0	$0.0000	$25,432	$0.0073	$43,397	$0.0138	$93,731	$0.0238	$73,078	$0.0191
Total Firm Variable Gas Costs	**$12,392,684**	**$2.9880**	**$9,892,184**	**$2.8446**	**$8,204,214**	**$2.6086**	**$14,152,403**	**$3.5870**	**$19,759,905**	**$5.1697**
Total Firm Gas Costs	**$43,247,572**	**$10.4274**	**$34,328,669**	**$9.8716**	**$31,937,540**	**$10.1550**	**$37,780,829**	**$9.5758**	**$43,343,799**	**$11.3399**
Total Firm Mcf Sales	**4,147,499**		**3,477,506**		**3,145,006**		**3,945,448**		**3,822,237**	

[1] Includes Capacity Release revenue received

Reconciliation of Total Firm Gas Costs (Schedule F) to Cost Recoverable through GSR (Schedule B):

Total Firm Gas Costs (Schedule F)	$43,247,572
Supplier Refunds (Schedule B)	$0
Recovery of Under Collection from Transp.	$0
GSR Settlement Adjustment	$0
Balancing Rate Credit	($1,345,742)
(Over)/Under Collection (Schedule D.1)	$3,232,359
Costs Recoverable through GSR	**$45,134,189**

Schedule G

Chesapeake Utilities Corporation
Delaware Division
Unaccounted For, Company Use & Pressure Compensation Gas Volumes
Twelve Months Ended July 31, 2017

	(1)	(2)	(3)	(4)	(5) *	(6)
Month	Total Receipts (Mcf)	Total Sales and Transportation (Mcf)	Unaccounted For, Pressure Compensation and Company Use (Mcf)	Company Use (Mcf)	Pressure Compensation (Mcf)	Unaccounted For Gas (Mcf)
August-16	351,729	340,661	11,068	42	5,088	5,938
September-16	371,372	378,928	(7,558)	46	5,659	(13,263)
October-16	500,089	425,059	75,030	44	6,348	68,638
November-16	698,460	529,303	169,157	130	7,905	161,122
December-16	1,102,254	931,805	170,448	322	13,917	156,209
January-17	1,143,021	1,148,080	(5,059)	312	17,147	(22,518)
February-17	870,923	979,163	(108,239)	297	14,624	(123,160)
March-17	1,010,035	964,569	45,466	307	14,406	30,753
April-17	493,245	660,140	(166,895)	119	9,860	(176,874)
May-17	438,433	451,765	(13,332)	50	6,747	(20,129)
June-17	358,841	401,891	(43,050)	32	6,002	(49,084)
July-17	324,865	317,474	7,391	22	4,742	2,627
Total	7,663,267	7,528,838	134,427	1,722	112,445	20,260

Unaccounted For and Company Use as % of Sales (Column 3 / Column 2)	1.79%

Unaccounted For as % of Receipts (Column 6 / Column 1)	0.26%

* Represents calculation to pressurize gas delivered from the ESNG transmission pipeline to a standard pressure.

Schedule H

Chesapeake Utilities Corporation
Delaware Division
Development of Gas Sales Service Rates Effective November 1, 2017
Balancing Rate Credit for Transportation Customers

Rate Class	Projected Nov-17	Projected Dec-17	Projected Jan-18	Projected Feb-18	Projected Mar-18	Projected Apr-18	Projected May-18	Projected Jun-18	Projected Jul-18	Projected Aug-18	Projected Sep-18	Projected Oct-18	Total
General Service:													
Volumes - Mcf	793	1,184	2,042	1,851	1,899	824	607	278	185	205	264	474	10,607
Balancing Rate Revenue	$737	$1,101	$1,899	$1,721	$1,766	$766	$565	$259	$172	$191	$246	$441	$9,864
Medium Volume Service:													
Volumes - Mcf	4,921	7,947	10,304	9,465	9,633	3,985	2,592	1,325	917	808	1,024	2,083	55,004
Balancing Rate Revenue	$5,462	$8,821	$11,437	$10,506	$10,693	$4,423	$2,877	$1,471	$1,018	$897	$1,137	$2,312	$61,054
Large Volume Service:													
Volumes - Mcf	80,654	125,909	162,834	143,264	154,215	69,419	52,901	44,914	36,219	37,849	59,343	46,136	1,013,657
Balancing Rate Revenue	$67,749	$105,764	$136,781	$120,342	$129,541	$58,312	$44,437	$37,728	$30,424	$31,793	$49,848	$38,754	$851,473
High Load Factor Service:													
Volumes - Mcf	226,030	270,099	258,861	239,183	263,952	229,111	238,094	250,315	214,815	234,215	248,200	289,820	2,962,695
Balancing Rate Revenue	$31,644	$37,814	$36,241	$33,486	$36,953	$32,076	$33,333	$35,044	$30,074	$32,790	$34,748	$40,575	$414,778
Interruptible Service:													
Volumes - Mcf	6,777	5,961	3,836	2,623	3,572	3,646	5,370	10,181	9,691	10,646	6,366	9,264	77,933
Balancing Rate Revenue	$745	$656	$422	$289	$393	$401	$591	$1,120	$1,066	$1,171	$700	$1,019	$8,573
													4,119,896
Total Balancing Rate Revenue	$106,337	$154,156	$186,780	$166,344	$179,346	$95,978	$81,803	$75,622	$62,754	$66,842	$86,679	$83,101	$1,345,742

PACITY RELEASE - DEMAND

Schedule I

					30	31	31	28	31	30	31	30	31	31	30	31
Column1	Customer Name (Utilicis)	Division	DPA	Zone	Nov-17	Dec-17	Jan-18	Feb-18	Mar-18	Apr-18	May-18	Jun-18	Jul-18	Aug-18	Sep-18	Oct-18
	Customer #1	DE	8	3	233	233	233	233	233	233	233	233	233	233	233	233
	Customer #2	DE	8	3	38	38	38	38	38	38	38	38	38	38	38	38
	Customer #3	DE	8	3	0	0	0	0	0	0	0	0	0	0	0	0
	Customer #4	DE	14	3	539	539	539	539	539	539	539	539	539	539	539	539
	Customer #5	DE	14	3	7	7	7	7	7	7	7	7	7	7	7	7
	Customer #6	DE	14	3												
	Customer #7	DE	14	3	10	10	10	10	10	10	10	10	10	10	10	10
	Customer #8	DE	9	3	27	33	3	2	3	2	1	0	0	1	223	209
	Customer #9	DE	9	3	253	253	253	253	253	253	253	253	253	253	253	253
	Customer #10	DE	9	3	3	3	3	3	3	3	3	3	3	3	3	3
	Customer #11	DE	14	3	33	33	33	33	33	33	33	33	33	33	33	33
	Customer #12	DE	14	3	105	105	105	105	105	105	105	105	105	105	105	105
	Customer #13	DE	5	2	505	505	505	505	505	505	505	505	505	505	505	505
	Customer #14	DE	14	3	150	150	150	150	150	150	150	150	150	150	150	150
	Customer #15	DE	14	3	247	247	247	247	247	247	247	247				
	Customer #16	DE	15	3	27	27	27	27	27	27	27	27	27	27	27	27
	Customer #17	DE	8	3	24	24	24	24	24	24	24	24	24			
	Customer #18	DE	5	2	20	20	20	20	20	20	20	20	20	20	20	20
	Customer #19	DE	5	2	38	38	38	38	38	38	38	38	38	38	38	38
	Customer #20	DE	5	2	16	16	16	16	16	16	16	16	16	16	16	16
	Customer #21	DE	4	2	34	34	34	34	34	34	34	34	34	34	34	34
	Customer #22	DE	7	3	134	134	134	134	134	134	134	134	134	134	134	134
	Customer #23	DE	7	3	0	0	0	0	0	0	0	0	0	0	0	0
	Customer #24	DE	7	3	18	18	18	18	18	18	18	18	18	18	18	18
	Customer #25	DE	5	2	28	28	28	28	28	28	28	28	28	28	28	28
	Customer #26	DE	14	3	12	12	12	12	12	12	12	12	12	12	12	12
	Customer #27	DE	4	2	73	73	73	73	73	73	73	73	73	73	73	73
	Customer #28	DE	14	3	50	50	50	50	50	50	50	50	50	50	50	50
	Customer #29	DE	14	3	53	53	53	53	53	53	53	53	53	53	53	53
	Customer #30	DE	14	3	147	147	147	147	147	147	147	147	147	147	147	147
	Customer #31	DE	14	3	26	26	26	26	26	26	26	26	26	26	26	26
	Customer #32	DE	14	3	69	69	69	69	69	69	69	69	69	69	69	69
	Customer #33	DE	6	3	2	2	2	2	2	2	2	2	2	2	2	2
	Customer #34	DE	6	3	3	3	3	3	3	3	3	3	3	3	3	3
	Customer #35	DE	6	3	2	2	2	2	2	2	2	2	2	2	2	2
	Customer #36	DE	6	3	4	4	4	4	4	4	4	4	4	4	4	4
	Customer #37	DE	6	3	6	6	6	6	6	6	6	6	6	6	6	6
	Customer #38	DE	6	3	1428	1428	1428	1428	1428	1428	1428	1428	1428	1428	1428	1428
	Customer #39	DE	6	3	0	0	0	0	0	0	0	0	0	0	0	0
	Customer #40	DE	6	3	2	2	2	2	2	2	2	2	2	2	2	2
	Customer #41	DE	6	3	1	1	1	1	1	1	1	1	1	1	1	1
	Customer #42	DE	6	3	4	4	4	4	4	4	4	4	4	4	4	4
	Customer #43	DE	6	3	12	12	12	12	12	12	12	12	12	12	12	12
	Customer #44	DE	6	3	11	11	11	11	11	11	11	11	11	11	11	11
	Customer #45	DE	6	3	12	12	12	12	12	12	12	12	12	12	12	12
	Customer #46	DE	5	2	53	53	53	53	53	53	53	53	53	53	53	53
	Customer #47	DE	5	2	229	229	229	229	229	229	229	229	229	229	229	229
	Customer #48	DE	5	2	35	35	35	35	35	35	35	35	35	35	35	35
	Customer #49	DE	5	2	24	24	24	24	24	24	24	24	24	24	24	24
	Customer #50	DE	5	2	16	16	16	16	16	16	16	16	16	16	16	16
	Customer #51	DE	8	3	178	178	178	178	178	178	178	178	178	178	178	178
	Customer #52	DE	8	3	40	40	40	40	40	40	40	40	40	40	40	40
	Customer #53	DE	5	2	5	5	5	5	5	5	5	5	5	5	5	5
	Customer #54	DE	5	2	5	5	5	5	5	5	5	5	5	5	5	5
	Customer #55	DE	5	2	5	5	5	5	5	5	5	5	5	5	5	5
	Customer #56	DE	5	2	5	5	5	5	5	5	5	5	5	5	5	5
	Customer #57	DE	5	2	5	5	5	5	5	5	5	5	5	5	5	5
	Customer #58	DE	5	2	5	5	5	5	5	5	5	5	5	5	5	5
	Customer #59	DE	5	2	5	5	5	5	5	5	5	5	5	5	5	5
	Customer #60	DE	5	2	5	5	5	5	5	5	5	5	5	5	5	5
	Customer #61	DE	5	2	5	5	5	5	5	5	5	5	5	5	5	5
	Customer #62	DE	5	2	4	4	4	4	4	4	4	4	4	4	4	4
	Customer #63	DE	5	2	4	4	4	4	4	4	4	4	4	4	4	4
	Customer #64	DE	5	2	4	4	4	4	4	4	4	4	4	4	4	4
	Customer #65	DE	5	2	4	4	4	4	4	4	4	4	4	4	4	4
	Customer #66	DE	5	2	4	4	4	4	4	4	4	4	4	4	4	4
	Customer #67	DE	5	2	4	4	4	4	4	4	4	4	4	4	4	4
	Customer #68	DE	5	2	4	4	4	4	4	4	4	4	4	4	4	4
	Customer #69	DE	5	2	4	4	4	4	4	4	4	4	4	4	4	4
	Customer #70	DE	5	2	4	4	4	4	4	4	4	4	4	4	4	4
	Customer #71	DE	5	2	4	4	4	4	4	4	4	4	4	4	4	4
	Customer #72	DE	6	3	60	60	60	60	60	60	60	60	60	60	60	60
	Customer #73	DE	5	2	227	227	227	227	227	227	227	227	227	227	227	227
	Customer #74	DE	6	3	19	19	19	19	19	19	19	19	19	19	19	19
	Customer #75	DE	6	3	4	4	4	4	4	4	4	4	4	4	4	4
	Customer #76	DE	6	3	7	7	7	7	7	7	7	7	7	7	7	7
	Customer #77	DE	6	3	37	37	37	37	37	37	37	37	37	37	37	37
	Customer #78	DE	6	3	19	19	19	19	19	19	19	19	19	19	19	19
	Customer #79	DE	6	3	11	11	11	11	11	11	11	11	11	11	11	11
	Customer #80	DE	6	3	3	3	3	3	3	3	3	3	3	3	3	3
	Customer #81	DE	6	3	0	0	0	0	0	0	0	0	0	0	0	0
	Customer #82	DE	6	3	1	1	1	1	1	1	1	1	1	1	1	1
	Customer #83	DE	6	3	1	1	1	1	1	1	1	1	1	1	1	1
	Customer #84	DE	15	3	17	17	17	17	17	17	17	17	17			
	Customer #85	DE	5	2	253	253	253	253	253	253	253	253	253	253	253	253

PACITY RELEASE - DEMAND

Schedule I

					30	31	31	28	31	30	31	30	31	31	30	31
Column1	Customer Name (Utilicis)	Division	DPA	Zone	Nov-17	Dec-17	Jan-18	Feb-18	Mar-18	Apr-18	May-18	Jun-18	Jul-18	Aug-18	Sep-18	Oct-18
	Customer #86	DE	6	3	92	62	6	0	25	112	77	126	120	174	114	136
	Customer #87	DE	14	3	226	35	0	0	69	144	174	226	226	226	226	226
	Customer #88	DE	15	3	159	159	159	159	159	159	159	159	159	159	159	159
	Customer #89	DE	8	3	850	850	850	850	850	850	850	850	850	850	850	850
	Customer #90	DE	15	3	42	42	42	42	42	42	42	42	42	42	42	42
	Customer #91	DE	7	3	123	123	123	123	123	123	123	123	123	123	123	123
	Customer #92	DE	11	3	11	11	11	11	11	11	11	11	11	11	11	11
	Customer #93	DE	4	2	410	410	410	410	410	410	410	410	410	410	410	410
	Customer #94	DE	4	2	315	315	315	315	315	315	315	315	315	315	315	315
	Customer #95	DE	14	3	153	153	153	153	153	153	153	153	153	153	153	153
	Customer #96	DE	14	3	0	4	3	1	1	1	0	0	0	0	0	0
	Customer #97	DE	14	3	0	1	2	4	4	3	1	1	1	1	1	1
	Customer #98	DE	5	2	461	461	461	461	461	461	461	461	461	461	461	461
	Customer #99	DE	5	2												
	Customer #100	DE	9	3	0	0	0	0	0	0	0	0	0			
	Customer #101	DE	4	2	30	30	30	30	30	30	30	30	30	30	30	30
	Customer #102	DE	5	2	69	69	69	69	69	69	69	69	69	69	69	69
	Customer #103	DE	8	3	63	63	63	63	63	63	63	63	63	63	63	63
	Customer #104	DE	8	3	6	6	6	6	6	6	6	6	6	6	6	6
	Customer #105	DE	8	3	6	6	6	6	6	6	6	6	6	6	6	6
	Customer #106	DE	8	3	3	3	3	3	3	3	3	3	3	3	3	3
	Customer #107	DE	8	3	3	3	3	3	3	3	3	3	3	3	3	3
	Customer #108	DE	5	2	3	3	3	3	3	3	3	3	3	3	3	3
	Customer #109	DE	5	2	4	4	4	4	4	4	4	4	4	4	4	4
	Customer #110	DE	5	2	3	3	3	3	3	3	3	3	3	3	3	3
	Customer #111	DE	5	2	3	3	3	3	3	3	3	3	3	3	3	3
	Customer #112	DE	5	2	4	4	4	4	4	4	4	4	4	4	4	4
	Customer #113	DE	5	2	4	4	4	4	4	4	4	4	4	4	4	4
	Customer #114	DE	5	2	3	3	3	3	3	3	3	3	3	3	3	3
	Customer #115	DE	5	2	3	3	3	3	3	3	3	3	3	3	3	3
	Customer #116	DE	6	3	9	0	0	0	0	0	0	0	0	5	35	110
	Customer #117	DE	5	2	25	25	25	25	25	25	25	25	25	25	25	25
	Customer #118	DE	5	2	1	1	1	1	1	1	1	1	1	1	1	1
	Customer #119	DE	15	3	268	268	268	268	268	268	268	268	268	268	364	345
	Customer #120	DE	15	3	77	77	77	77	77	77	102	77	77	77	77	77
	Customer #121	DE	15	3												
	Customer #122	DE	15	3												
	Customer #123	DE	15	3	1872	1872	1872	1872	1872	1872	1872	1872	1872	1872	1872	1872
	Customer #124	DE	15	3	486	486	486	486	486	486	486	486	486	486	486	486
	Customer #125	DE	4	2	0	0	0	0	0	0	0	0	0	0	0	0
	Customer #126	DE	8	3	132	132	132	132	132	132	132	132	132	132	132	132
	Customer #127	DE	8	3	2	2	2	2	2	2	2	2	2	2	2	2
	Customer #128	DE	8	3	7	7	7	7	7	7	7	7	7	7	7	7
	Customer #129	DE	5	2	10	10	10	10	10	10	10	10	10	10	10	10
	Customer #130	DE	8	3	161	161	161	161	161	161	161	161	161	161	161	161
	Customer #131	DE	14	3	10	10	10	10	10	10	10	10	10	10		
	Customer #132	DE	8	3	0	0	0	0	0	0	0	0	0	0	0	0
	Customer #133	DE	15	3	395	395	395	395	395	395	395	395	395	395	395	395
	Customer #134	DE	11	3	374	374	374	374	374	374	374	374	374	374	374	374
	Customer #135	DE	14	3	376	376	376	376	376	376	376	376	376	376	376	376
	Customer #136	DE	14	3	178	14	0	0	0	0	0	0	0	13	380	401
	Customer #137	DE	11	3	29	29	29	29	29	29	29	87	29	33	67	67
	Customer #138	DE	5	2												
	Customer #139	DE	5	2	136	136	136	136	136	136	136	136	136	136	136	136
	Customer #140	DE	5	2	55	55	55	55	55	55	55	55	55	55	55	55
	Customer #141	DE	5	2	51	51	51	51	51	51	51	51	51	51	51	51
	Customer #142	DE	11	3	44	44	44	44	44	44	44	44	44	44	44	44
	Customer #143	DE	5	2	11	11	11	11	11	11	11	11	11	11	11	11
	Customer #144	DE	15	3	23	129	43	38	0	63	59	47	46	46	60	46
	Customer #145	DE	9	3	17	86	0	19	0	100	138	143	112	108	135	134
	Customer #146	DE	9	3	113	0	0	0	0	16	15	17	15	15	16	14
	Customer #147	DE	15	3	46	46	46	46	46	46	46	46	46	46	46	46
	Customer #148	DE	6	3	20	23	18	20	18	17	15	18	28	12	208	191
	Customer #149	DE	14	3	384	384	384	384	384	384	384	384	384	384	384	384
	Customer #150	DE	5	2	15	15	15	15	15	15	15	15	15	15	15	15
	Customer #151	DE	5	2	12	12	12	12	12	12	12	12	12	12	12	12
	Customer #152	DE	5	2	8	8	8	8	8	8	8	8	8	8	8	8
	Customer #153	DE	5	2	13	13	13	13	13	13	13	13	13	13	13	13
	Customer #154	DE	14	3	238	238	238	238	238	238	238	238	238	238	238	238
	Customer #155	DE	4	2	148	148	148	148	148	148	148	148	148	148	148	148
	Customer #156	DE	4	2	12	12	12	12	12	12	12	12	12	12	12	12
	Customer #157	DE	4	2	1	1	1	1	1	1	1	1	1	1	1	1
	Customer #158	DE	4	2	4	4	4	4	4	4	4	4	4	4	4	4
	Customer #159	DE	4	2	1	1	1	1	1	1	1	1	1	1	1	1
	Customer #160	DE	4	2	24	24	24	24	24	24	24	24	24	24	24	24
	Customer #161	DE	4	2	4	4	4	4	4	4	4	4	4	4	4	4
	Customer #162	DE	4	2	6	6	6	6	6	6	6	6	6	6	6	6
	Customer #163	DE	4	2	5	5	5	5	5	5	5	5	5	5	5	5
	Customer #164	DE	4	2	0	0	0	0	0	0	0	0	0	0	0	0
	Customer #165	DE	4	2	0	0	0	0	0	0	0	0	0	0	0	0
	Customer #166	DE	4	2	5	5	5	5	5	5	5	5	5	5	5	5
	Customer #167	DE	4	2	0	0	0	0	0	0	0	0	0	0	0	0
	Customer #168	DE	4	2	18	18	18	18	18	18	18	18	18	18	18	18

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					30	31	31	28	31	30	31	30	31	31	30	31
Column1	Customer Name (Utilicis)	Division	DPA	Zone	Nov-17	Dec-17	Jan-18	Feb-18	Mar-18	Apr-18	May-18	Jun-18	Jul-18	Aug-18	Sep-18	Oct-18
	Customer #169	DE	6	3	38	38	38	38	38	38	38	38	38	38	38	38
	Customer #170	DE	6	3	26	26	26	26	26	26	26	26	26	26	26	26
	Customer #171	DE	6	3	40	40	40	40	40	40	40	40	40	40	40	40
	Customer #172	DE	14	3	11	11	11	11	11	11	11	11	11	11	11	11
	Customer #173	DE	14	3	45	45	45	45	45	45	45	45	45	45	45	45
	Customer #174	DE	14	3	0	0	0	0	0	0	0	0	0	0	0	0
	Customer #175	DE	14	3	11	11	11	11	11	11	11	11	11	11	11	11
	Customer #176	DE	14	3	0	0	0	0	0	0	0	0	0	0	0	0
	Customer #177	DE	5	2	16	16	16	16	16	16	16	16	16	16	16	16
	Customer #178	DE	5	2	21	21	21	21	21	21	21	21	21	21	21	21
	Customer #179	DE	5	2	44	44	44	44	44	44	44	44	44	44	44	44
	Customer #180	DE	5	2	4	4	4	4	4	4	4	4	4	4	4	4
	Customer #181	DE	5	2	7	7	7	7	7	7	7	7	7	7	7	7
	Customer #182	DE	5	2	440	440	440	440	440	440	440	440	440	440	440	440
	Customer #183	DE	5	2	16	16	16	16	16	16	16	16	16	16	16	16
	Customer #184	DE	5	2	29	29	29	29	29	29	29	29	29	29	29	29
	Customer #185	DE	5	2	2	2	2	2	2	2	2	2	2	2	2	2
	Customer #186	DE	5	2	35	35	35	35	35	35	35	35	35	35	35	35
	Customer #187	DE	5	2	16	16	16	16	16	16	16	16	16	16	16	16
	Customer #188	DE	5	2	16	16	16	16	16	16	16	16	16	16	16	16
	Customer #189	DE	5	2	6	6	6	6	6	6	6	6	6	6	6	6
	Customer #190	DE	5	2	7	7	7	7	7	7	7	7	7	7	7	7
	Customer #191	DE	5	2	9	9	9	9	9	9	9	9	9	9	9	9
	Customer #192	DE	5	2	18	18	18	18	18	18	18	18	18	18	18	18
	Customer #193	DE	5	2	4	4	4	4	4	4	4	4	4	4	4	4
	Customer #194	DE	5	2	9	9	9	9	9	9	9	9	9	9	9	9
	Customer #195	DE	5	2	19	19	19	19	19	19	19	19	19	19	19	19
	Customer #196	DE	5	2	5	5	5	5	5	5	5	5	5	5	5	5
	Customer #197	DE	5	2	8	8	8	8	8	8	8	8	8	8	8	8
	Customer #198	DE	5	2	21	21	21	21	21	21	21	21	21	21	21	21
	Customer #199	DE	5	2	7	7	7	7	7	7	7	7	7	7	7	7
	Customer #200	DE	5	2	8	8	8	8	8	8	8	8	8	8	8	8
	Customer #201	DE	5	2	37	37	37	37	37	37	37	37	37	37	37	37
	Customer #202	DE	5	2	10	10	10	10	10	10	10	10	10	10	10	10
	Customer #203	DE	5	2	19	19	19	19	19	19	19	19	19	19	19	19
	Customer #204	DE	5	2	15	15	15	15	15	15	15	15	15	15	15	15
	Customer #205	DE	5	2	33	33	33	33	33	33	33	33	33	33	33	33
	Customer #206	DE	5	2	6	6	6	6	6	6	6	6	6	6	6	6
	Customer #207	DE	5	2	33	33	33	33	33	33	33	33	33	33	33	33
	Customer #208	DE	5	2	18	18	18	18	18	18	18	18	18	18	18	18
	Customer #209	DE	5	2	39	39	39	39	39	39	39	39	39	39	39	39
	Customer #210	DE	5	2	15	15	15	15	15	15	15	15	15	15	15	15
	Customer #211	DE	5	2	21	21	21	21	21	21	21	21	21	21	21	21
	Customer #212	DE	5	2	3	3	3	3	3	3	3	3	3	3	3	3
	Customer #213	DE	5	2	9	9	9	9	9	9	9	9	9	9	9	9
	Customer #214	DE	5	2	5	5	5	5	5	5	5	5	5	5	5	5
	Customer #215	DE	5	2	5	5	5	5	5	5	5	5	5	5	5	5
	Customer #216	DE	14	3	58	58	58	58	58	58	58	58	58	58	58	58
	Customer #217	DE	15	3	33	33	33	33	33	33	33	33	33	33	33	33
	Customer #218	DE	15	3	10	10	10	10	10	10	10	10	10	10	10	10
	Customer #219	DE	15	3	5	5	5	5	5	5	5	5	5	5	5	5
	Customer #220	DE	15	3	2	2	2	2	2	2	2	2	2	2	2	2
	Customer #221	DE	15	3	1	1	1	1	1	1	1	1	1	1	1	1
	Customer #222	DE	15	3	7	7	7	7	7	7	7	7	7	7	7	7
	Customer #223	DE	15	3	0	0	0	0	0	0	0	0	0	0	0	0
	Customer #224	DE	15	3	5	5	5	5	5	5	5	5	5	5	5	5
	Customer #225	DE	15	3	15	15	15	15	15	15	15	15	15	15	15	15
	Customer #226	DE	5	2	19	19	19	19	19	19	19	19	19	19	19	19
	Customer #227	DE	5	2	3	3	3	3	3	3	3	3	3	3	3	3
	Customer #228	DE	5	2	3	3	3	3	3	3	3	3	3	3	3	3
	Customer #229	DE	5	2	7	7	7	7	7	7	7	7	7	7	7	7
	Customer #230	DE	5	2	3	3	3	3	3	3	3	3	3	3	3	3
	Customer #231	DE	5	2	13	13	13	13	13	13	13	13	13	13	13	13
	Customer #232	DE	5	2	1	1	1	1	1	1	1	1	1	1	1	1
	Customer #233	DE	5	2	1	1	1	1	1	1	1	1	1	1	1	1
	Customer #234	DE	5	2	3	3	3	3	3	3	3	3	3	3	3	3
	Customer #235	DE	5	2	13	13	13	13	13	13	13	13	13	13	13	13
	Customer #236	DE	5	2	27	27	27	27	27	27	27	27	27	27	27	27
	Customer #237	DE	5	2	23	23	23	23	23	23	23	23	23	23	23	23
	Customer #238	DE	5	2	27	27	27	27	27	27	27	27	27	27	27	27
	Customer #239	DE	5	2	206	206	206	206	206	206	206	206	206	206	206	206
	Customer #240	DE	5	2	12	12	12	12	12	12	12	12	12	12	12	12
	Customer #241	DE	5	2	35	35	35	35	35	35	35	35	35	35	35	35
	Customer #242	DE	5	2	11	11	11	11	11	11	11	11	11	11	11	11
	Customer #243	DE	5	2	24	24	24	24	24	24	24	24	24	24	24	24
	Customer #244	DE	5	2	60	60	60	60	60	60	60	60	60	60	60	60
	Customer #245	DE	15	3	13	13	13	13	13	13	13	13	13	13	13	13
	Customer #246	DE	15	3	6	6	6	6	6	6	6	6	6	6	6	6
	Customer #247	DE	15	3	36	36	36	36	36	36	36	36	36	36	36	36
	Customer #248	DE	14	3	28	28	28	28	28	28	28	28	28	28	28	28
	Customer #249	DE	6	3	2	2	2	2	2	2	2	2	2	2	2	2
	Customer #250	DE	6	3	34	34	34	34	34	34	34	34	34	34	34	34
	Customer #251	DE	6	3	13	13	13	13	13	13	13	13	13	13	13	13

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					30	31	31	28	31	30	31	30	31	31	30	31
Column1	Customer Name (Utilicis)	Division	DPA	Zone	Nov-17	Dec-17	Jan-18	Feb-18	Mar-18	Apr-18	May-18	Jun-18	Jul-18	Aug-18	Sep-18	Oct-18
	Customer #252	DE	6	3	15	15	15	15	15	15	15	15	15	15	15	15
	Customer #253	DE	6	3	2	2	2	2	2	2	2	2	2	2	2	2
	Customer #254	DE	6	3	24	24	24	24	24	24	24	24	24	24	24	24
	Customer #255	DE	6	3	0	0	0	0	0	0	0	0	0	0	0	0
	Customer #256	DE	6	3	1	1	1	1	1	1	1	1	1	1	1	1
	Customer #257	DE	15	3	14	14	14	14	14	14	14	14	14	14	14	14
	Customer #258	DE	15	3	11	11	11	11	11	11	11	11	11	11	11	11
	Customer #259	DE	14	3	0	0	0	0	0	0	0	0	0	0	0	0
	Customer #260	DE	14	3	1	1	1	1	1	1	1	1	1	1	1	1
	Customer #261	DE	14	3	3	3	3	3	3	3	3	3	3	3	3	3
	Customer #262	DE	14	3	40	40	40	40	40	40	40	40	40	40	40	40
	Customer #263	DE	14	3	21	21	21	21	21	21	21	21	21	21	21	21
	Customer #264	DE	5	2	18	18	18	18	18	18	18	18	18	18	18	18
	Customer #265	DE	5	2	29	29	29	29	29	29	29	29	29	29	29	29
	Customer #266	DE	6	3	76	76	76	76	76	76	76	76	76	76	76	76
	Customer #267	DE	8	3	1	1	1	1	1	1	1	1	1	1	1	1
	Customer #268	DE	8	3	15	15	15	15	15	15	15	15	15	15	15	15
	Customer #269	DE	8	3	2	2	2	2	2	2	2	2	2	2	2	2
	Customer #270	DE	8	3	40	40	40	40	40	40	40	40	40	40	40	40
	Customer #271	DE	8	3	2	2	2	2	2	2	2	2	2	2	2	2
	Customer #272	DE	8	3	28	28	28	28	28	28	28	28	28	28	28	28
	Customer #273	DE	8	3	1	1	1	1	1	1	1	1	1	1	1	1
	Customer #274	DE	8	3	1	1	1	1	1	1	1	1	1	1	1	1
	Customer #275	DE	5	2	87	87	87	87	87	87	87	87	87	87	87	87
	Customer #276	DE	5	2	4	4	4	4	4	4	4	4	4	4	4	4
	Customer #277	DE	5	2	0	0	0	0	0	0	0	0	0	0	0	0
	Customer #278	DE	5	2	1	1	1	1	1	1	1	1	1	1	1	1
	Customer #279	DE	5	2	4	4	4	4	4	4	4	4	4	4	4	4
	Customer #280	DE	5	2												
	Customer #281	DE	5	2	14	14	14	14	14	14	14	14	14	14	14	14
	Customer #282	DE	5	2	10	10	10	10	10	10	10	10	10	10	10	10
	Customer #283	DE	15	3	3	3	3	3	3	3	3	3	3	3	3	3
	Customer #284	DE	15	3												
	Customer #285	DE	15	3	3	3	3	3	3	3	3	3	3	3	3	3
	Customer #286	DE	15	3	35	35	35	35	35	35	35	35	35	35	35	35
	Customer #287	DE	15	3	2	2	2	2	2	2	2	2	2	2	2	2
	Customer #288	DE	15	3	73	73	73	73	73	73	73	73	73	73	73	73
	Customer #289	DE	15	3	4	4	4	4	4	4	4	4	4	4	4	4
	Customer #290	DE	15	3	4	4	4	4	4	4	4	4	4	4	4	4
	Customer #291	DE	15	3	3	3	3	3	3	3	3	3	3	3	3	3
	Customer #292	DE	15	3	0	0	0	0	0	0	0	0	0	0	0	0
	Customer #293	DE	15	3	16	16	16	16	16	16	16	16	16	16	16	16
	Customer #294	DE	15	3	0	0	0	0	0	0	0	0	0	0	0	0
	Customer #295	DE	15	3	0	0	0	0	0	0	0	0	0	0	0	0
	Customer #296	DE	15	3	1	1	1	1	1	1	1	1	1	1	1	1
	Customer #297	DE	15	3	0	0	0	0	0	0	0	0	0	0	0	0
	Customer #298	DE	15	3	18	18	18	18	18	18	18	18	18	18	18	18
	Customer #299	DE	15	3	18	18	18	18	18	18	18	18	18	18	18	18
	Customer #300	DE	15	3	20	20	20	20	20	20	20	20	20	20	20	20
	Customer #301	DE	15	3	20	20	20	20	20	20	20	20	20	20	20	20
	Customer #302	DE	15	3	0	0	0	0	0	0	0	0	0	0	0	0
	Customer #303	DE	15	3	2	2	2	2	2	2	2	2	2	2	2	2
	Customer #304	DE	15	3	11	11	11	11	11	11	11	11	11	11	11	11
	Customer #305	DE	15	3	10	10	10	10	10	10	10	10	10	10	10	10
	Customer #306	DE	15	3	40	40	40	40	40	40	40	40	40	40	40	40
	Customer #307	DE	15	3	0	0	0	0	0	0	0	0	0	0	0	0
	Customer #308	DE	15	3	46	46	46	46	46	46	46	46	46	46	46	46
	Customer #309	DE	15	3	0	0	0	0	0	0	0	0	0	0	0	0
	Customer #310	DE	15	3	0	0	0	0	0	0	0	0	0	0	0	0
	Customer #311	DE	15	3	14	14	14	14	14	14	14	14	14	14	14	14
	Customer #312	DE	15	3	0	0	0	0	0	0	0	0	0	0	0	0
	Customer #313	DE	15	3	20	20	20	20	20	20	20	20	20	20	20	20
	Customer #314	DE	7	3	24	24	24	24	24	24	24	24	24	24	24	24
	Customer #315	DE	11	3	36	36	36	36	36	36	36	36	36	36	36	36
	Customer #316	DE	11	3	2	2	2	2	2	2	2	2	2	2	2	2
	Customer #317	DE	11	3	2	2	2	2	2	2	2	2	2	2	2	2
	Customer #318	DE	11	3	32	32	32	32	32	32	32	32	32	32	32	32
	Customer #319	DE	6	3	13	13	13	13	13	13	13	13	13	13	13	13
	Customer #320	DE	8	3	18	18	18	18	18	18	18	18	18	18	18	18
	Customer #321	DE	6	3	31	0	0	6	85	65	108	71	25	243	243	147
	Customer #322	DE	6	3	35	22	1	13	31	29	24	17	4	18	35	27
	Customer #323	DE	5	2	4	4	4	4	4	4	4	4	4	4	4	4
	Customer #324	DE	5	2	4	4	4	4	4	4	4	4	4	4	4	4
	Customer #325	DE	5	2	5	5	5	5	5	5	5	5	5	5	5	5
	Customer #326	DE	5	2	4	4	4	4	4	4	4	4	4	4	4	4
	Customer #327	DE	5	2	4	4	4	4	4	4	4	4	4	4	4	4
	Customer #328	DE	5	2	5	5	5	5	5	5	5	5	5	5	5	5
	Customer #329	DE	5	2	4	4	4	4	4	4	4	4	4	4	4	4
	Customer #330	DE	5	2	7	7	7	7	7	7	7	7	7	7	7	7
	Customer #331	DE	5	2	47	47	47	47	47	47	47	47	47	47	47	47
	Customer #332	DE	5	2	46	46	46	46	46	46	46	46	46	46	46	46
	Customer #333	DE	14	3	54	54	54	54	54	54	54	54	54	54	54	54
	Customer #334	DE	8	3	35	35	35	35	35	35	35	35	35	35	35	35
	Customer #335	DE	6	3	62	62	62	62	62	62	62	62	62	62	62	62

PACITY RELEASE - DEMAND

Schedule I

						30	31	31	28	31	30	31	30	31	31	30	31	
	Column1	Customer Name (Utilicis)	Division	DPA	Zone	Nov-17	Dec-17	Jan-18	Feb-18	Mar-18	Apr-18	May-18	Jun-18	Jul-18	Aug-18	Sep-18	Oct-18	
		Customer #336	DE	4	2	59	59	59	59	59	59	59	59	59	59	59	59	
		Customer #337	DE	5	2	272	272	272	272	272	272	272	272	272	272	272	272	
		Customer #338	DE	5	2	3	3	3	3	3	3	3	3	3	3	3	3	
		Customer #339	DE	5	2	6	6	6	6	6	6	6	6	6	6	6	6	
		Customer #340	DE	5	2	5	5	5	5	5	5	5	5	5	5	5	5	
		Customer #341	DE	5	2	2	2	2	2	2	2	2	2	2	2	2	2	
		Customer #342	DE	5	2	23	23	23	23	23	23	23	23	23	23	23	23	
		Customer #343	DE	5	2	12	12	12	12	12	12	12	12	12	12	12	12	
		Customer #344	DE	5	2	8	8	8	8	8	8	8	8	8	8	8	8	
		Customer #345	DE	5	2	90	90	90	90	90	90	90	90	90	90	90	90	
		Customer #346	DE	5	2	10	10	10	10	10	10	10	10	10	10	10	10	
		Customer #347	DE	5	2	8	8	8	8	8	8	8	8	8	8	8	8	
		Customer #348	DE	5	2	7	7	7	7	7	7	7	7	7	7	7	7	
		Customer #349	DE	5	2	7	7	7	7	7	7	7	7	7	7	7	7	
		Customer #350	DE	5	2	8	8	8	8	8	8	8	8	8	8	8	8	
		Customer #351	DE	5	2	8	8	8	8	8	8	8	8	8	8	8	8	
		Customer #352	DE	5	2	8	8	8	8	8	8	8	8	8	8	8	8	
		Customer #353	DE	5	2	29	29	29	29	29	29	29	29	29	29	29	29	
			DE			18,432	18,070	17,737	17,764	17,897	18,213	18,298	18,385	17,991	18,239	19,173	19,120	
			Zone		2	5,901	5,901	5,901	5,901	5,901	5,901	5,901	5,901	5,901	5,901	5,901	5,901	
			Zone		3	12,531	12,169	11,836	11,863	11,996	12,312	12,397	12,484	12,090	12,338	13,272	13,219	
DE						**18,432**	**18,070**	**17,737**	**17,764**	**17,897**	**18,213**	**18,298**	**18,385**	**17,991**	**18,239**	**19,173**	**19,120**	
DE																		
DE		**ESNG Max Rate**		Z2	$ 0.4720	$ 83,558.16	$ 83,558.16	$ 83,558.16	$ 83,558.16	$ 83,558.16	$ 83,558.16	$ 83,558.16	$ 83,558.16	$ 83,558.16	$ 83,558.16	$ 83,558.16	$ 83,558.16	
DE				Z3	$ 0.6440	$ 242,098.92	$ 235,105.08	$ 228,671.52	$ 229,193.16	$ 231,762.72	$ 237,867.84	$ 239,510.04	$ 241,190.88	$ 233,578.80	$ 238,370.16	$ 256,415.04	$ 255,391.08	
DE		**TOTAL ESNG Capacity Credits**				**$ 325,657.08**	**$ 318,663.24**	**$ 312,229.68**	**$ 312,751.32**	**$ 315,320.88**	**$ 321,426.00**	**$ 323,068.20**	**$ 324,749.04**	**$ 317,136.96**	**$ 321,928.32**	**$ 339,973.20**	**$ 338,949.24**	**$ 3,871,853.16**
DE																		
DE						3,349	4,312	4,784	4,941	4,093	2,835	1,859	1,528	1,338	1,503	1,584	2,052	
DE						9,446	9,957	10,782	10,993	10,154	9,111	7,823	7,256	6,827	6,953	9,064	8,637	
DE						**12,795**	**14,269**	**15,566**	**15,934**	**14,247**	**11,946**	**9,682**	**8,784**	**8,165**	**8,456**	**10,648**	**10,689**	
				Z2	$ 0.0118	$ 1,185.55	$ 1,577.33	$ 1,749.99	$ 1,632.51	$ 1,497.22	$ 1,003.59	$ 680.02	$ 540.91	$ 489.44	$ 549.80	$ 560.74	$ 750.62	
				Z3	$ 0.0170	$ 4,817.46	$ 5,247.34	$ 5,682.11	$ 5,232.67	$ 5,351.16	$ 4,646.61	$ 4,122.72	$ 3,700.56	$ 3,597.83	$ 3,664.23	$ 4,622.64	$ 4,551.70	
		TOTAL ESNG Comodity Credits				**$ 6,003.01**	**$ 6,824.67**	**$ 7,432.10**	**$ 6,865.17**	**$ 6,848.38**	**$ 5,650.20**	**$ 4,802.74**	**$ 4,241.47**	**$ 4,087.27**	**$ 4,214.03**	**$ 5,183.38**	**$ 5,302.32**	**$ 67,454.74**
		TOTAL ESNG CREDIT * Original Rates				**$ 331,660.09**	**$ 325,487.91**	**$ 319,661.78**	**$ 319,616.49**	**$ 322,169.26**	**$ 327,076.20**	**$ 327,870.94**	**$ 328,990.51**	**$ 321,224.23**	**$ 326,142.35**	**$ 345,156.58**	**$ 344,251.56**	**$ 3,939,307.90**
		TOTAL ESNG CREDIT * Midpoint Rate Case Increase				$ 424,524.91	$ 416,624.52	$ 409,167.08	$ 409,109.11	$ 412,376.65	$ 418,657.54	$ 419,674.81	$ 421,107.86	$ 411,167.01	$ 417,462.21	$ 441,800.42	$ 440,642.00	**$ 5,042,314.11**

Chesapeake Utilities Corporation
Delaware Division
Cost of Fixed and Variable Gas Supply Resources
Based on Projected November 1, 2017 Gas Costs
Transportation Balancing Services

Description	Monthly Demand in DT	Annual Demand in DT	Average Monthly Rate / DT	Average Annual Rate / DT	Current Annualized Gas Cost
Storage Demand					
Columbia					
FSS (includes assoc. SST)	8,224	98,688	$6.0164	$72.1964	$593,743
Transco					
GSS	2,655	31,860	$3.0630	$36.7557	$97,586
LSS	580	6,960	$4.6254	$55.5052	$32,193
WSS (includes assoc. FT)	1,503	18,036	$7.0774	$84.9291	$127,648
ESS (includes assoc. FT)	3,776	45,312	$10.7795	$129.3540	$488,441
PS Reservation	311	3,732	$8.4101	$100.9207	$31,386
Fuel Retention (0.0%)	0	0			
ESNG Reservation					
MDTQ (GSS 365 Day, ESS 243 Day)	6,431	77,172	$16.9321	$203.1852	$1,306,684
MDTQ 181 Day (FSS)	8,224	49,344	$21.0531	$126.3187	$1,038,845
MDTQ 151 Day (LSS, WSS)	2,083	10,415	$21.0522	$105.2612	$219,259
MDTQ 90 Day (PS)	311	933	$21.0450	$63.1350	$19,635
Storage Demand	17,049	204,588	$19.3336	$232.0031	$3,955,421
Storage Capacity					
Columbia					
FSS	472,250	5,667,000	$0.0288	$0.3456	$163,210
Transco					
GSS	131,370	1,576,440	$0.0161	$0.1935	$25,415
LSS	29,000	348,000	$0.0170	$0.2044	$5,928
WSS	142,830	1,713,960	$0.0082	$0.0985	$14,074
ESS	31,660	379,920	$0.0766	$0.9198	$29,120
Storage Capacity	807,110	9,685,320	$0.0245	$0.2946	$237,747
Storage Demand & Capacity					
Columbia					
FSS	8,224	98,688	$7.6702	$92.0420	$756,953
Transco					
GSS	2,655	31,860	$3.8607	$46.3282	$123,001
LSS	580	6,960	$5.4772	$65.7259	$38,121
WSS	1,503	18,036	$7.8578	$94.2930	$141,722
ESS	3,776	45,312	$11.4222	$137.0659	$517,561
PS Reservation	311	3,732	$8.4101	$100.9207	$31,386
Fuel Retention (0.0%)	0	0			
ESNG Reservation					
MDTQ 365 Day (GSS, ESS)	6,431	77,172	$16.9321	$203.1852	$1,306,684
MDTQ 181 Day (FSS)	8,224	49,344	$21.0531	$126.3187	$1,038,845
MDTQ 151 Day (LSS, WSS)	2,083	10,415	$21.0522	$105.2612	$219,259
MDTQ 90 Day (PS)	311	933	$21.0450	$63.1350	$19,635
Storage Demand & Capacity	17,049	204,588	$20.4957	$245.9480	$4,193,168
Propane Peak Shaving	10,176	n/a	n/a	$0.00	$0
Summary	27,225			**$154.0190**	$4,193,168
FT Capacity	16,374			**$167.5617**	$2,743,656
Fixed Gas Supply Resources	43,599			**$159.1051**	$6,936,824
Storage Injection & Withdrawal					
GSS	262,740	n/a	$0.0461	n/a	$12,125
LSS	58,000	n/a	$0.0252	n/a	$1,462
WSS	285,660	n/a	$0.0146	n/a	$4,159
ESS	63,320	n/a	$0.0411	n/a	$2,604
FSS	944,500	n/a	$0.0153	n/a	$14,451
Variable Gas Supply Resources	1,614,220	n/a	$0.0216	n/a	$34,801
Half of Variable Rate For Either Injection or Withdrawal			**$0.0108**		

Chesapeake Utilities Corporation
Delaware Division
Transportation Balancing Services
Development of Interruptible Balancing Service Rate
General Service Transportation Service

Fixed Gas Supply Cost	Annual Load Factor	Average Daily Load	Cost Per Gas Supply Entitlement	Average Cost per DT	Average Cost @ Use of 43.98%
@ Load Factor of	10%	37	$159.1051	$4.3001	
@ Load Factor of	20%	73	$159.1051	$2.1795	
@ Load Factor of	30%	110	$159.1051	$1.4464	
@ Load Factor of	40%	146	$159.1051	$1.0898	
@ Load Factor of	50%	183	$159.1051	$0.8694	
@ Load Factor of	60%	219	$159.1051	$0.7265	
@ Load Factor of	70%	256	$159.1051	$0.6215	
@ Load Factor of	80%	292	$159.1051	$0.5449	
@ Load Factor of	90%	329	$159.1051	$0.4836	
@ Load Factor of	100%	365	$159.1051	$0.4359	
Del. Div. Weighted Average	**24.08%**	**88**	**$159.1051**	**$1.8080**	**$0.7952**

Variable Gas Supply Cost			Average Cost per DT	Estimated Imbalance Percentage	Variable Cost per DT
Variable Commodity Rate			**$0.0108**	**29.94%**	**$0.0032**

Development of Interruptible Balancing Service Rate			
	Fixed Capacity Rate per DT	**$0.7952**	
	Variable Commodity Rate per DT	**$0.0032**	
	Balancing Service Rate per DT	**$0.7984**	
	Balancing Service Rate per Mcf	**$0.8263**	
	Capacity Release Recovery per Mcf	**$0.1044**	
	Total Balancing Service Rate per Mcf	**$0.9307**	
	Total Balancing Service Rate per Ccf	**$0.093**	

Chesapeake Utilities Corporation
Delaware Division
Transportation Balancing Services
Development of Firm Balancing Service Rate
Medium Volume Service

Fixed Gas Supply Cost	Annual Load Factor	Average Daily Load	Cost Per Gas Supply Entitlement	Average Cost per DT	Average Cost 46.26% Design Day
					0.5374
@ Load Factor of	10%	37	$159.1051	$4.3001	$1.9890
@ Load Factor of	20%	73	$159.1051	$2.1795	$1.0081
@ Load Factor of	30%	110	$159.1051	$1.4464	$0.6690
@ Load Factor of	40%	146	$159.1051	$1.0898	$0.5041
@ Load Factor of	50%	183	$159.1051	$0.8694	$0.4021
@ Load Factor of	60%	219	$159.1051	$0.7265	$0.3360
@ Load Factor of	70%	256	$159.1051	$0.6215	$0.2875
@ Load Factor of	80%	292	$159.1051	$0.5449	$0.2520
@ Load Factor of	90%	329	$159.1051	$0.4836	$0.2237
@ Load Factor of	100%	365	$159.1051	$0.4359	$0.2016
Del. Div. Weighted Average	**20.89%**	**76**	**$159.1051**	**$2.0935**	**$0.9684**

Variable Gas Supply Cost			Average Cost per DT	Estimated Imbalance Percentage	Variable Cost per DT
Variable Commodity Rate			**$0.0108**	**36.56%**	**$0.0039**

Development of Firm Balancing Service Rate			
	Fixed Capacity Rate per DT	**$0.9684**	
	Variable Commodity Rate per DT	**$0.0039**	
	Firm Balancing Service Rate per DT	**$0.9723**	
	Balancing Service Rate per Mcf	**$1.0063**	
	Capacity Release Recovery per Mcf	**$0.1044**	
	Total Balancing Service Rate per Mcf	**$1.1107**	
	Total Firm Balancing Service Rate per Ccf	**$0.111**	

Chesapeake Utilities Corporation
Delaware Division
Transportation Balancing Services
Development of Firm Balancing Service Rate
Large Volume Service

Fixed Gas Supply Cost	Annual Load Factor	Average Daily Load	Cost Per Gas Supply Entitlement	Average Cost per DT	Average Cost 42.51% Design Day
@ Load Factor of	10%	37	$159.1051	$4.3001	$1.8280
@ Load Factor of	20%	73	$159.1051	$2.1795	$0.9265
@ Load Factor of	30%	110	$159.1051	$1.4464	$0.6149
@ Load Factor of	40%	146	$159.1051	$1.0898	$0.4633
@ Load Factor of	50%	183	$159.1051	$0.8694	$0.3696
@ Load Factor of	60%	219	$159.1051	$0.7265	$0.3088
@ Load Factor of	70%	256	$159.1051	$0.6215	$0.2642
@ Load Factor of	80%	292	$159.1051	$0.5449	$0.2316
@ Load Factor of	90%	329	$159.1051	$0.4836	$0.2056
@ Load Factor of	100%	365	$159.1051	$0.4359	$0.1853
Del. Div. Weighted Average	**26.17%**	**96**	**$159.1051**	**$1.6573**	**$0.7045**

Variable Gas Supply Cost			Average Cost per DT	Estimated Imbalance Percentage	Variable Cost per DT
Variable Commodity Rate			**$0.0108**	**26.11%**	**$0.0028**

Development of Firm Balancing Service Rate			
	Fixed Capacity Rate per DT	**$0.7045**	
	Variable Commodity Rate per DT	**$0.0028**	
	Firm Balancing Service Rate per DT	**$0.7073**	
	Balancing Service Rate per Mcf	**$0.7321**	
	Capacity Release Recovery per Mcf	**$0.1044**	
	Total Balancing Service Rate per Mcf	**$0.8365**	
	Total Firm Balancing Service Rate per Ccf	**$0.084**	

Chesapeake Utilities Corporation
Delaware Division
Transportation Balancing Services
Development of Firm Balancing Service Rate
High Load Factor Service

Fixed Gas Supply Cost	Annual Load Factor	Average Daily Load	Cost Per Gas Supply Entitlement	Average Cost per DT	Average Cost 7.73% Design Day
					0.9227
@ Load Factor of	10%	37	$159.1051	$4.3001	$0.3325
@ Load Factor of	20%	73	$159.1051	$2.1795	$0.1685
@ Load Factor of	30%	110	$159.1051	$1.4464	$0.1118
@ Load Factor of	40%	146	$159.1051	$1.0898	$0.0843
@ Load Factor of	50%	183	$159.1051	$0.8694	$0.0672
@ Load Factor of	60%	219	$159.1051	$0.7265	$0.0562
@ Load Factor of	70%	256	$159.1051	$0.6215	$0.0481
@ Load Factor of	80%	292	$159.1051	$0.5449	$0.0421
@ Load Factor of	90%	329	$159.1051	$0.4836	$0.0374
@ Load Factor of	100%	365	$159.1051	$0.4359	$0.0337
Del. Div. Weighted Average	**86.81%**	**317**	**$159.1051**	**$0.5019**	**$0.0388**

Variable Gas Supply Cost			Average Cost per DT	Estimated Imbalance Percentage	Variable Cost per DT
Variable Commodity Rate			**$0.0108**	**1.48%**	**$0.0002**

Development of Firm Balancing Service Rate		
	Fixed Capacity Rate per DT	**$0.0388**
	Variable Commodity Rate per DT	**$0.0002**
	Firm Balancing Service Rate per DT	**$0.0390**
	Balancing Service Rate per Mcf	**$0.0404**
	Capacity Release Recovery per Mcf	**$0.1044**
	Total Balancing Service Rate per Mcf	**$0.1448**
	Total Firm Balancing Service Rate per Ccf	**$0.014**

Chesapeake Utilities Corporation
Delaware Division
Transportation Balancing Services
Development of Interruptible Balancing Service Rate
Interruptible Transportation Service

Fixed Gas Supply Cost	Annual Load Factor	Average Daily Load	Cost Per Gas Supply Entitlement	Average Cost per DT	Average Cost @ Use of 1.00%
@ Load Factor of	10%	37	$159.1051	$4.3001	
@ Load Factor of	20%	73	$159.1051	$2.1795	
@ Load Factor of	30%	110	$159.1051	$1.4464	
@ Load Factor of	40%	146	$159.1051	$1.0898	
@ Load Factor of	50%	183	$159.1051	$0.8694	
@ Load Factor of	60%	219	$159.1051	$0.7265	
@ Load Factor of	70%	256	$159.1051	$0.6215	
@ Load Factor of	80%	292	$159.1051	$0.5449	
@ Load Factor of	90%	329	$159.1051	$0.4836	
@ Load Factor of	100%	365	$159.1051	$0.4359	
Interruptible @ 100% LFR	**100.00%**	**365**	**$159.1051**	**$0.4359**	**$0.0044**

Variable Gas Supply Cost			Average Cost per DT	Estimated Imbalance Percentage	Variable Cost per DT
Variable Commodity Rate			**$0.0108**	**19.83%**	**$0.0021**

Development of Interruptible Balancing Service Rate		
Fixed Capacity Rate per DT	**$0.0044**	
Variable Commodity Rate per DT	**$0.0021**	
Balancing Service Rate per DT	**$0.0065**	
Balancing Service Rate per Mcf	**$0.0067**	
Capacity Release Recovery per Mcf	**$0.1044**	
Total Balancing Service Rate per Mcf	**$0.1111**	
Total Balancing Service Rate per Ccf	**$0.011**	

Schedule L

Chesapeake Utilities Corporation
Delaware Division
Gas Supply Resources
Demand and Capacity Entitlements effective November 2016 & November 2017
(DT)

Transcontinental Gas Pipeline Corporation			
		2016	**2017**
FT, MDQ	*	21,112	21,112
PS-1 FT, MDQ	*	311	311
GSS, MDQ **	*	2,655	2,655
LSS, MDQ **	*	580	580
LGA, MDQ **	*	-	-
GSS, Capacity		131,370	131,370
LSS, Capacity		29,000	29,000
LGA, Capacity		-	-
WSS, Demand		1,503	1,503
WSS, Capacity		142,830	142,830
ESS, Demand		3,776	3,776
ESS, Capacity		31,660	31,660

Columbia Gas Transmission Corporation			
		2016	**2017**
FTS, MDQ	*	10,960	10,960
SST, MDQ, Oct - Mar		8,224	8,224
SST, MDQ, Apr - Sep		4,113	4,113
FSS, MDQ	*	8,224	8,224
FSS, Capacity		472,250	472,250

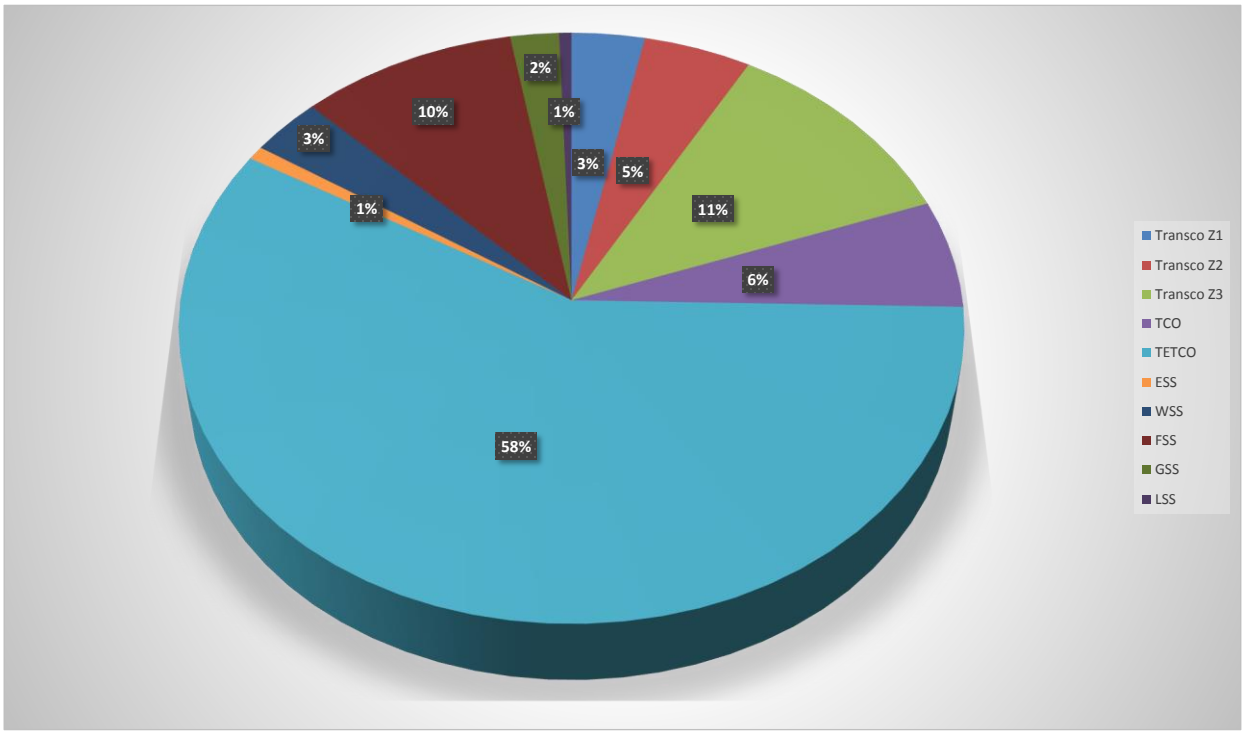
Texas Eastern Transmission Company			
		2016	**2017**
FT-1	*	34,100	34,100

Eastern Shore Natural Gas Company			
		2016	**2017**
FT, MDQ - R1		35,150	35,150
FT, MDQ - R2	*	66,948	66,948
ST, MDQ - R2	*	5,081	5,081
FT, MDQ - D2		38,611	37,636
ST, MDQ - D2		3,349	3,349
FT, MDQ - D3		28,562	29,312
ST, MDQ - D3		1,732	1,732

Chesapeake Utilities Corporation - Delaware Division			
		2016	**2017**
Propane Peak Shaving Facilities	*	10,176	10,176
Temporary LNG Peak Shaving Service		3,000	3,000

MDQ = Maximum Daily Quantity
*** Design Day Deliverability**
**** Storage Service Contracted with ESNG**

Schedule M

DELAWARE DIVISION LOAD AND SUPPLY

2017 - 2018 Forecast Year