



August 31, 2018

Ms. Donna Nickerson, Secretary
Delaware Public Service Commission
861 Silver Lake Boulevard
Cannon Building, Suite 100
Dover, Delaware 19904

RE: Chesapeake Utilities Corporation – Delaware Division
Gas Sales Service Rates - Effective November 1, 2018

Dear Ms. Nickerson:

Enclosed for filing is an electronic copy of Chesapeake Utilities Corporation's ("Chesapeake") application for a proposed change in its Gas Sales Service Rates ("GSR") to be effective for service rendered on and after November 1, 2018.

Pursuant to the provisions of Chesapeake's GSR tariff clause, Chesapeake submits the following Gas Sales Service Rates to be effective for service rendered on and after November 1, 2018: \$0.833 per Ccf for customers served under rate schedules RS-1, ERS-1, RS-2, ERS-2, USA-R, GS, EGS, USA-G, MVS, EMVS, USA-M and LVS, \$0.362 per Ccf for customers served under rate schedules GLR and GLO, \$0.630 per Ccf for customers served under rate schedule HLFS. The Company also submits the following balancing rates to be effective for service rendered on and after November 1, 2018: \$0.133 per Ccf for transportation customers served under rate schedules GS, EGS and USA-G; \$0.158 per Ccf for transportation customers served under rate schedules MVS, EMVS and USA-M; \$0.107 per Ccf for transportation customers served under rate schedule LVS, and \$0.010 per Ccf for transportation customers served under rate schedule HLFS, and \$0.001 per Ccf for transportation customers served under rate schedule ITS.

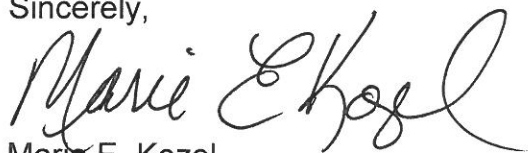
As compared to the rates in effect on November 1, 2017, an average RS-2 customer using 700 Ccf per year will experience an annual decrease of approximately 11.79% or \$11.08 per month. During the winter heating season, a typical RS-2 customer on Chesapeake's system using 110 Ccf per month will experience a decrease of approximately 13.08% or \$20.90 per winter month. An RS-2 customer using 120 Ccf per month will experience a decrease of approximately 13.27% or \$22.80 per winter month.

The basis and reasons for the proposed changes are discussed and explained in the testimony and schedules accompanying the enclosed application.

Also, enclosed is the Delaware Public Service Commission's "Filing Cover Sheet".

Should you have any questions with regard to this submission, please contact me at 302.734.6727.

Sincerely,

A handwritten signature in black ink that reads "Marie E. Kozel". The signature is written in a cursive style with a large, looping "M" and "K".

Marie E. Kozel
Regulatory Analyst III

Enclosures

CC: Andrew C. Slater, Public Advocate
Jason R. Smith

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF DELAWARE

IN THE MATTER OF THE APPLICATION OF)
CHESAPEAKE UTILITIES CORPORATION)
FOR APPROVAL OF A CHANGE IN ITS) P.S.C. DOCKET NO. 18-
GAS SALES SERVICE RATES ("GSR"))
TO BE EFFECTIVE NOVEMBER 1, 2018)

CERTIFICATE OF SERVICE

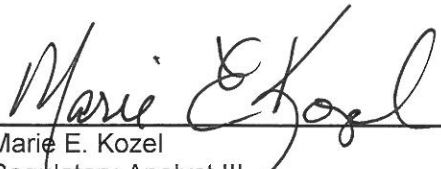
I, Marie E. Kozel, do hereby certify that on August 31, 2018, a copy of Chesapeake Utilities Corporation – Delaware Division’s application for a proposed change in its Gas Sales Service Rates to be effective for service rendered on and after November 1, 2018 was issued to the following persons in the manner indicated:

VIA ELECTRONIC DELIVERY

JASON R. SMITH
DELAWARE PUBLIC SERVICE COMMISSION
861 SILVER LAKE BLVD
SUITE 100
DOVER, DE 19904

VIA ELECTRONIC DELIVERY

ANDREW C SLATER
DIVISION OF THE PUBLIC ADVOCATE
JOHN G. TOWNSEND BUILDING
401 FEDERAL ST, STE 3 (SOS)
DOVER, DE 19904


Marie E. Kozel
Regulatory Analyst III

“DRAFT”

**BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF DELAWARE**

**IN THE MATTER OF THE APPLICATION OF)
CHESAPEAKE UTILITIES CORPORATION)
FOR APPROVAL OF A CHANGE IN ITS) PSC DOCKET NO. 18-
GAS SALES SERVICE RATES (“GSR”))
TO BE EFFECTIVE NOVEMBER 1, 2018)
(FILED August 31, 2018))**

P U B L I C N O T I C E

**TO: ALL NATURAL GAS CUSTOMERS OF CHESAPEAKE UTILITIES CORPORATION
AND OTHER INTERESTED PERSONS**

A Hearing Examiner of the Delaware Public Service Commission will conduct a public comment session concerning the above-captioned matter (as further explained below) at the following time and location:

Date

Location

TBD

Delaware Public Service Commission
Hearing Room
861 Silver Lake Blvd., Suite 100
Dover, DE 19904

Chesapeake Utilities Corporation’s Gas Sales Service Rates Application

Pursuant to 26 *Del. C.* §§303(b), 304, and 306, Chesapeake Utilities Corporation (“Chesapeake” or “the Company”) has filed an application (the “Application”) with the Delaware Public Service Commission (the “Commission”) seeking to change its Gas Sales Service (“GSR”) Rates as follows:

Rate Schedule	Present Rate	Proposed Rate
RS-1, ERS-1, RS-2, ERS-2, USA-R, GS, EGS, USA-G, MVS, EMVS, USA-M, LVS	\$1.023 per Ccf	\$0.833 per Ccf
GLR, GLO	\$0.468 per Ccf	\$0.362 per Ccf
HLFS	\$0.782 per Ccf	\$0.630 per Ccf

Compared to the rates currently in effect, an average RS-2 customer using 700 Ccf per year will

experience an annual decrease of approximately 11.79%, or \$11.08 per month. During the winter heating season, a typical RS-2 customer using 120 Ccf per winter month will experience a decrease of approximately 13.27%, or \$22.80 per winter month.

The Company has also proposed the following changes to its firm and interruptible transportation balancing rates:

Rate Schedule	Present Firm Balancing Rate	Proposed Firm Balancing Rate
GS/EGS/USA-G	\$0.093 per Ccf	\$0.133 per Ccf
MVS/EMVS/USA-M	\$0.111 per Ccf	\$0.158 per Ccf
LVS	\$0.084 per Ccf	\$0.107 per Ccf
HLFS	\$0.014 per Ccf	\$0.010 per Ccf
ITS	\$0.011 per Ccf	\$0.001 per Ccf

The Commission has permitted the proposed GSR and other rates to become effective with usage on and after November 1, 2018, subject to refund and pending the Commission's final decision after evidentiary hearings and any other proceedings that may be necessary.

The Commission will conduct evidentiary hearings, to be scheduled at a later date, concerning this Application. The Commission's final decision will be based on the evidence presented at such hearings.

If you wish to formally participate as a party in this matter, with the right to present evidence and be represented by counsel, you must file with the Commission a written petition asking for leave to intervene in accordance with the requirements of the Commission's Rules of Practice and Procedure (26 Del. Admin. C. §1001-2.9) **on or before** _____, **2018**. All such petitions should be sent to the Commission's address listed above with attention to "PSC Docket No. 18-____." Petitions filed after the deadline of _____, 2018, will not be considered except for good cause shown.

You are invited to review Chesapeake's application and supporting documents to determine how your interests may be affected by going to DelaFile

(<http://delafile.delaware.gov>), the Commission's file management system, and by searching for Docket No. 18-.

If you would like to review documents at the Commission's offices, please contact Donna Nickerson at (302) 736-7500 or by sending an email addressed to donna.nickerson@state.de.us. You may also review copies of Chesapeake's application and supporting documents at the office of the Division of the Public Advocate located at either 820 North French Street, 4th Floor, Wilmington, Delaware 19801 or 29 South State Street, Dover, Delaware 19901. Please call either (302) 577-5077 or (302) 241-2555 to arrange for a time to review the documents at either of those locations.

If you wish to request copies of documents in this matter, please submit a Freedom of Information Act Request Form. The link to this form can be found on the Commission's website, <http://depsec.delaware.gov> or by visiting this web address: <https://delafile.delaware.gov/Complaints/FOIA.aspx>. The Commission will respond to your request in accordance with the Delaware Freedom of Information Act, 29 Del. C. ch. 100.

If you have a disability and wish to participate or to review the materials in this matter, please contact the Commission to discuss any auxiliary aids or services you might need to help you. You may contact the Commission in person, by writing, by telephone (including text telephone), by Internet e-mail, or other means. If you have questions about this matter, you may call the Commission at 1-800-282-8574 (toll-free in Delaware) or (302) 736-7500 (voice and text telephone). You may also send questions regarding this matter by Internet e-mail addressed to jason.r.smith@state.de.us.

**BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF DELAWARE**

**IN THE MATTER OF THE APPLICATION OF)
CHESAPEAKE UTILITIES CORPORATION)
FOR APPROVAL OF A CHANGE IN ITS) P.S.C. DOCKET NO. 18-
GAS SALES SERVICE RATES (“GSR”))
TO BE EFFECTIVE NOVEMBER 1, 2018)**

Chesapeake Utilities Corporation (hereinafter sometimes called "Applicant") pursuant to 26 Del. C. 303(b) and 304, makes the following application for approval by the Commission of a change in its Gas Sales Service Rates (“GSR”) and balancing rates to be effective for service rendered on and after November 1, 2018:

1. Applicant is Chesapeake Utilities Corporation, 909 Silver Lake Boulevard, Dover, Delaware 19904. All communications should be addressed to the Applicant at the following address, Attention: Marie E. Kozel, Regulatory Analyst III, 500 Energy Lane, Suite 100, Dover, Delaware 19901 or at the following email address: mkoz@chpk.com. The respective phone number and fax number are 302.734.6727 and 302.744.2225.

2. Counsel for the Applicant is William F. O’Brien, Associate General Counsel Chesapeake Utilities Corporation, 114 Sandhill Drive, Suite 105, Middletown, Delaware 19709. Correspondence and other communications concerning this application should be directed to counsel at the foregoing address, or at the following e-mail address: bobrien@chpk.com. The respective phone number and fax number are 302.314.7014 and 302.744.2225.

3. Pursuant to the provisions of Applicant's Gas Sales Service Rate tariff clause, Applicant requests permission to change Applicant's current Gas Sales Service Rates from positive surcharges of \$1.023 per Ccf for customers served under rate schedules RS-1, ERS-1, RS-2, ERS-2, USA-R, GS, EGS, USA-G, MVS, EMVS, USA-M

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, to positive surcharges of \$0.833 per Ccf, \$0.362 per Ccf and \$0.630 per Ccf respectively, with said changes to be effective for service rendered on and after November 1, 2018 and thereafter until changed by further order of the Delaware Public Service Commission.

4. Applicant also requests permission to (a) increase Applicant's firm balancing rate for transportation customers served under rate schedules GS, EGS and USA-G of \$0.093 per Ccf to \$0.133; (b) increase Applicant's firm balancing rate for transportation customers served under rate schedules MVS, EMVS and USA-M from \$0.111 per Ccf to \$0.158 per Ccf; (c) increase Applicant's firm balancing rate for transportation customers served under rate schedule LVS from \$0.084 per Ccf to \$0.107 per Ccf, (d) decrease Applicant's firm balancing rate for transportation customers served under rate schedule HLFS from \$0.014 per Ccf to \$0.010 per Ccf, and (e) decrease Applicant's firm balancing rate for transportation customers served under rate schedule ITS from \$0.011 per Ccf to \$0.001 per Ccf

5. The full calculation of the proposed Gas Sales Service Rates is set forth in Schedule A.1 and the calculation of the balancing rates is set forth in Schedule J, both of which are attached to this Application. The reasons and basis for the proposed changes in Applicant's present Gas Sales Service Rates and balancing rates are more fully explained by direct testimony filed herewith.


WHEREFORE, the Applicant prays as follows:


- A. That the Commission file this Application and schedule it for hearing;
- B. That the Commission approve (i) the proposed decrease in Applicant's Gas Sales Service Rates to a positive surcharge of \$0.833 per Ccf for customers served under rate schedules RS-1, ERS-1, RS-2, ERS-2, USA-R, GS, EGS, USA-G, MVS, EMVS,

USA-M and LVS; (ii) the proposed decrease to a positive surcharge of \$0.362 per Ccf for customers served under rate schedules GLR and GLO; (iii) the proposed decrease to a positive surcharge of \$0.630 per Ccf for customers served under rate schedule HLFS; (iv) the proposed increase in Applicant's firm balancing rate for transportation customers served under rate schedules GS, EGS and USA-G of \$0.133 per Ccf; (v) the proposed increase in Applicant's firm balancing rate for transportation customers served under rate schedules MVS, EMVS and USA-M of \$0.158 per Ccf; (vi) the proposed increase in Applicant's firm balancing rate for transportation customers served under rate schedule LVS to a positive surcharge of \$0.107 per Ccf; (vii) the proposed decrease in Applicant's firm balancing rate for transportation customers served under rate schedule HLFS to a positive surcharge of \$0.010 per Ccf; (viii) the Applicant's interruptible balancing rate for transportation customers served under rate schedule ITS will decrease to a positive surcharge of \$0.001 per Ccf; with all of said changes to be effective for service rendered on and after November 1, 2018.

SIGNATURES APPEAR ON THE FOLLOWING PAGE(S)

CHESAPEAKE UTILITIES CORPORATION

BY: 
Aleida F. Socarras
Vice President, DNG

BY: 
William O'Brien
909 Silver Lake Blvd.
Dover, DE 19904
Associate General Counsel

DATED: August 31, 2018

Chesapeake Utilities Corporation
Delaware Division
Development of Gas Sales Service Rates Effective November 1, 2018

Based on Total Firm Gas Costs Recoverable through GSR effective November 1, 2018

Description	Allocator	Total System Costs	Volume (Ccf)	Cost / Ccf
Fixed Gas Costs	Peak Day Capacity Entitlements	\$27,739,448	811,130	\$34.20
Variable Gas Costs	Annual Volume	\$12,140,926	45,362,965	\$0.268
Total Firm Gas Costs	Annual Volume	\$39,880,374	45,362,965	\$0.879

Development of High Load Factor Service Rates per CCF (83.48% Load Factor)

Description	Peak Day Cap. Method	System Average Cost	HLFS Average Rate
Demand Rate (\$34.20 / 305)	\$0.112		
Commodity Rate	\$0.268		
Total Gas Sales Service Rate	\$0.380	\$0.879	\$0.630
Total High Load Factor Dollars			
	Projected Sales	Rate	Total Cost
	3,487,155	\$0.630	\$2,196,908

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

Description	Peak Day Cap. Method		
Demand Rate (\$34.20 / 365)	\$0.094		
Commodity Rate	\$0.268		
Total Gas Sales Service Rate	\$0.362		
Total Gas Lighting Dollars			
	Projected Sales	Rate	Total Cost
	350	\$0.362	\$127

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	\$39,880,374	45,362,965			
Less : Allocated to HLFS	\$2,196,908	3,487,155			
Less : Allocated to GL	\$127	350			
Total Remaining System	\$37,683,339	41,875,460	\$0.900	(\$0.067)	\$0.833

Chesapeake Utilities Corporation
Delaware Division
Cost of Fixed and Variable Gas Supply Resources
Based on Projected November 1, 2018 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	\$6.0966	\$73.1595	\$601,664
Transco					
GSS	2,655	31,860	\$3.0624	\$36.7488	\$97,568
LSS	580	6,960	\$4.5798	\$54.9577	\$31,875
WSS (includes assoc. FT)	1,503	18,036	\$7.1159	\$85.3902	\$128,342
ESS (includes assoc. FT)	3,776	45,312	\$10.8412	\$130.0947	\$491,238
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	\$24.3384	\$292.0606	\$1,878,242
MDTQ 181 Day (FSS)	8,224	49,344	\$48.6789	\$292.0732	\$2,402,010
MDTQ 151 Day (LSS, WSS)	2,083	10,415	\$58.4126	\$292.0629	\$608,367
MDTQ 90 Day (PS)	311	933	\$97.2937	\$291.8810	\$90,775
Storage Demand	17,049	204,588	\$31.0940	\$373.1285	\$6,361,467
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	\$0.0167	\$0.2008	\$5,822
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	\$0.2944	\$237,641
Storage Demand & Capacity					
Columbia					
FSS	8,224	98,688	\$7.7504	\$93.0051	\$764,874
Transco					
GSS	2,655	31,860	\$3.8601	\$46.3213	\$122,983
LSS	580	6,960	\$5.4163	\$64.9956	\$37,697
WSS	1,503	18,036	\$7.8962	\$94.7542	\$142,416
ESS	3,776	45,312	\$11.4839	\$137.8066	\$520,358
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	\$24.3384	\$292.0606	\$1,878,242
MDTQ 181 Day (FSS)	8,224	49,344	\$48.6789	\$292.0732	\$2,402,010
MDTQ 151 Day (LSS, WSS)	2,083	10,415	\$58.4126	\$292.0629	\$608,367
MDTQ 90 Day (PS)	311	933	\$97.2937	\$291.8810	\$90,775
Storage Demand & Capacity	17,049	204,588	\$32.2556	\$387.0672	\$6,599,108
Propane Peak Shaving	6,010				\$226,679
Fixed Gas Supply Resources	23,059			\$296.0192	\$6,825,787
Storage Injection & Withdrawal					
GSS	262,740	n/a	\$0.0470	n/a	\$12,344
LSS	58,000	n/a	\$0.1263	n/a	\$7,325
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	\$0.0253	n/a	\$40,883
Half of Variable Rate For Either Injection or Withdrawal			\$0.0127		

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 42.93%
@ Load Factor of	10%	37	\$296.0192	\$8.0005	
@ Load Factor of	20%	73	\$296.0192	\$4.0551	
@ Load Factor of	30%	110	\$296.0192	\$2.6911	
@ Load Factor of	40%	146	\$296.0192	\$2.0275	
@ Load Factor of	50%	183	\$296.0192	\$1.6176	
@ Load Factor of	60%	219	\$296.0192	\$1.3517	
@ Load Factor of	70%	256	\$296.0192	\$1.1563	
@ Load Factor of	80%	292	\$296.0192	\$1.0138	
@ Load Factor of	90%	329	\$296.0192	\$0.8998	
@ Load Factor of	100%	365	\$296.0192	\$0.8110	
Del. Div. Weighted Average	27.20%	99	\$296.0192	\$2.9901	\$1.2836

Variable Gas Supply Cost			Average Cost per DT	Estimated Imbalance Percentage	Variable Cost per DT
Variable Commodity Rate			\$0.0127	27.32%	\$0.0035

Development of Interruptible Balancing Service Rate			
Fixed Capacity Rate per DT		\$1.2836	
Variable Commodity Rate per DT		\$0.0035	
Balancing Service Rate per DT		\$1.2871	
Balancing Service Rate per Mcf		\$1.3322	
Capacity Release Recovery per Mcf		\$0.0000	*No dollars in current GSR
Total Balancing Service Rate per Mcf		\$1.3322	
Total Balancing Service Rate per Ccf		\$0.133	

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 45.38% Design Day
@ Load Factor of	10%	37	\$296.0192	\$8.0005	\$3.6306
@ Load Factor of	20%	73	\$296.0192	\$4.0551	\$1.8402
@ Load Factor of	30%	110	\$296.0192	\$2.6911	\$1.2212
@ Load Factor of	40%	146	\$296.0192	\$2.0275	\$0.9201
@ Load Factor of	50%	183	\$296.0192	\$1.6176	\$0.7341
@ Load Factor of	60%	219	\$296.0192	\$1.3517	\$0.6134
@ Load Factor of	70%	256	\$296.0192	\$1.1563	\$0.5247
@ Load Factor of	80%	292	\$296.0192	\$1.0138	\$0.4601
@ Load Factor of	90%	329	\$296.0192	\$0.8998	\$0.4083
@ Load Factor of	100%	365	\$296.0192	\$0.8110	\$0.3680
Del. Div. Weighted Average	24.13%	88	\$296.0192	\$3.3639	\$1.5265

Variable Gas Supply Cost			Average Cost per DT	Estimated Imbalance Percentage	Variable Cost per DT
Variable Commodity Rate			\$0.0127	33.02%	\$0.0042

Development of Firm Balancing Service Rate			
Fixed Capacity Rate per DT		\$1.5265	
Variable Commodity Rate per DT		\$0.0042	
Firm Balancing Service Rate per DT		\$1.5307	
Balancing Service Rate per Mcf		\$1.5843	
Capacity Release Recovery per Mcf		\$0.0000	*No dollars in current GSR
Total Balancing Service Rate per Mcf		\$1.5843	
Total Firm Balancing Service Rate per Ccf		\$0.158	

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 40.35% Design Day
@ Load Factor of	10%	37	\$296.0192	\$8.0005	\$3.2280
@ Load Factor of	20%	73	\$296.0192	\$4.0551	\$1.6362
@ Load Factor of	30%	110	\$296.0192	\$2.6911	\$1.0858
@ Load Factor of	40%	146	\$296.0192	\$2.0275	\$0.8181
@ Load Factor of	50%	183	\$296.0192	\$1.6176	\$0.6527
@ Load Factor of	60%	219	\$296.0192	\$1.3517	\$0.5454
@ Load Factor of	70%	256	\$296.0192	\$1.1563	\$0.4665
@ Load Factor of	80%	292	\$296.0192	\$1.0138	\$0.4090
@ Load Factor of	90%	329	\$296.0192	\$0.8998	\$0.3631
@ Load Factor of	100%	365	\$296.0192	\$0.8110	\$0.3272
Del. Div. Weighted Average	31.74%	116	\$296.0192	\$2.5519	\$1.0296

Variable Gas Supply Cost			Average Cost per DT	Estimated Imbalance Percentage	Variable Cost per DT
Variable Commodity Rate			\$0.0127	22.24%	\$0.0028

Development of Firm Balancing Service Rate			
Fixed Capacity Rate per DT		\$1.0296	
Variable Commodity Rate per DT		\$0.0028	
Firm Balancing Service Rate per DT		\$1.0324	
Balancing Service Rate per Mcf		\$1.0685	
Capacity Release Recovery per Mcf		\$0.0000	*No dollars in current GSR
Total Balancing Service Rate per Mcf		\$1.0685	
Total Firm Balancing Service Rate per Ccf		\$0.107	

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 10.18% Design Day
@ Load Factor of	10%	37	\$296.0192	\$8.0005	\$0.8145
@ Load Factor of	20%	73	\$296.0192	\$4.0551	\$0.4128
@ Load Factor of	30%	110	\$296.0192	\$2.6911	\$0.2740
@ Load Factor of	40%	146	\$296.0192	\$2.0275	\$0.2064
@ Load Factor of	50%	183	\$296.0192	\$1.6176	\$0.1647
@ Load Factor of	60%	219	\$296.0192	\$1.3517	\$0.1376
@ Load Factor of	70%	256	\$296.0192	\$1.1563	\$0.1177
@ Load Factor of	80%	292	\$296.0192	\$1.0138	\$0.1032
@ Load Factor of	90%	329	\$296.0192	\$0.8998	\$0.0916
@ Load Factor of	100%	365	\$296.0192	\$0.8110	\$0.0826
Del. Div. Weighted Average	83.48%	305	\$296.0192	\$0.9706	\$0.0988

Variable Gas Supply Cost			Average Cost per DT	Estimated Imbalance Percentage	Variable Cost per DT
Variable Commodity Rate			\$0.0127	2.17%	\$0.0003

Development of Firm Balancing Service Rate			
Fixed Capacity Rate per DT		\$0.0988	
Variable Commodity Rate per DT		\$0.0003	
Firm Balancing Service Rate per DT		\$0.0991	
Balancing Service Rate per Mcf		\$0.1026	
Capacity Release Recovery per Mcf		\$0.0000	*No dollars in current GSR
Total Balancing Service Rate per Mcf		\$0.1026	
Total Firm Balancing Service Rate per Ccf		\$0.010	

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	\$296.0192	\$8.0005	
@ Load Factor of	20%	73	\$296.0192	\$4.0551	
@ Load Factor of	30%	110	\$296.0192	\$2.6911	
@ Load Factor of	40%	146	\$296.0192	\$2.0275	
@ Load Factor of	50%	183	\$296.0192	\$1.6176	
@ Load Factor of	60%	219	\$296.0192	\$1.3517	
@ Load Factor of	70%	256	\$296.0192	\$1.1563	
@ Load Factor of	80%	292	\$296.0192	\$1.0138	
@ Load Factor of	90%	329	\$296.0192	\$0.8998	
@ Load Factor of	100%	365	\$296.0192	\$0.8110	
Interruptible @ 100% LFR	100.00%	365	\$296.0192	\$0.8110	\$0.0081

Variable Gas Supply Cost			Average Cost per DT	Estimated Imbalance Percentage	Variable Cost per DT
Variable Commodity Rate			\$0.0127	9.06%	\$0.0012


Development of Interruptible Balancing Service Rate		
Fixed Capacity Rate per DT		\$0.0081
Variable Commodity Rate per DT		\$0.0012
Balancing Service Rate per DT		\$0.0093
Balancing Service Rate per Mcf		\$0.0096
Capacity Release Recovery per Mcf		\$0.0000
Total Balancing Service Rate per Mcf		\$0.0096
Total Balancing Service Rate per Ccf		\$0.001

*No dollars in current GSR

DATED: August 31, 2018

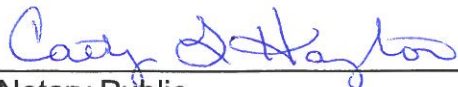
STATE OF DELAWARE)
)
COUNTY OF KENT)

BE IT REMEMBERED that on this 31st day of August, 2018, personally appeared before me, a notary public for the State and County aforesaid, Aleida F. Socarras, who being by me duly sworn, did depose and say that she is Vice President for Chesapeake Utilities Corporation, a Delaware corporation and insofar as the Application of Chesapeake Utilities Corporation states facts, said facts are true and correct, and insofar as those facts are not within his personal knowledge, he believes them to be true, and that the schedules accompanying this application and attached hereto are true and correct copies of the originals of the aforesaid schedules, and that he has executed this Application on behalf of the Company.



Aleida F. Socarras
Vice President

SWORN TO AND SUBSCRIBED before me the day and year above written.



Notary Public
My Commission Expires: 03-27-19



**RATE SCHEDULE "GS"
GENERAL SERVICE**

AVAILABILITY

This Rate Schedule is available to any Customer using gas for commercial and/or industrial purposes with an annual consumption of less than four thousand (4,000) Ccf. The Company will annually review those Customers receiving service under this Rate Schedule in order to determine the appropriate firm commercial and/or industrial Rate Schedule should their annual consumption warrant such a change. A Customer on General Service will be moved to Rate Schedule MVS with annual consumption equal to or greater than four thousand four hundred (4,400) Ccf. This annual review process will be based on the twelve (12) months ended May. Customers will not be shifted between Rate Schedules due to changes in annual consumption other than at the annual review time.

DELIVERY SERVICE RATES

The following rates for delivering gas to the Customer's location apply to all Customers served under this Rate Schedule.

Customer Charge:	\$34.00 per month
First 20 Ccf	\$0.426 per Ccf
Next 30 Ccf	\$0.257 per Ccf
Over 50 Ccf	\$0.119 per Ccf

GAS SALES SERVICE

In addition to the above Delivery Service rates, Customers purchasing their natural gas supply from the Company are subject to the gas cost rate applicable to Rate Schedule "GS" provided on Sheet No. 42.

TRANSPORTATION AND BALANCING RIDER

Transportation service is available to commercial and industrial Customers on this Rate Schedule who meet the eligibility requirements set forth in the Transportation and Balancing General Terms and Conditions provided on Sheet No. 43. In addition to the above Delivery Service rates, the Customer is subject to the following Firm Balancing Service Rate applied to all gas consumption.

Firm Balancing Service Rate:	\$0.133 per Ccf of gas consumed
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Issue Date: August 31, 2018

Effective Date: For Service Rendered on and after November 1, 2018

Authorization:

RATE SCHEDULE "EGS"

**EXPANSION AREA GENERAL SERVICE
(Continued)**

TRANSPORTATION AND BALANCING RIDER

Transportation service is available to commercial and industrial Customers on this Rate Schedule who meet the eligibility requirements set forth in the Transportation and Balancing General Terms and Conditions provided on Sheet No. 43. In addition to the above Delivery Service rates, the Customer is subject to the following Firm Balancing Service Rate applied to all gas consumption

Firm Balancing Service Rate: \$0.133 per Ccf of gas consumed

PUBLIC UTILITIES TAX

The Delivery Service, Gas Sales Service, Firm Balancing Service, and any other applicable rates or charges are subject to the Delaware Public Utilities Tax unless the Customer is exempt from such tax.

PAYMENT TERMS

Bills are due within twenty (20) days of their date.

MINIMUM BILL

The minimum monthly bill under this Rate Schedule is the Customer charge.

SPECIAL TERMS AND CONDITIONS OF SERVICE

- (1) Service under this Rate Schedule is subject to the standard terms and conditions of service as in effect from time to time under authority of the Public Service Commission of Delaware. It is also subject to the limitations stated under the "Availability" clause above.
- (2) Natural gas purchased hereunder is for the use of the Customer in one (1) location only and is not to be shared or sold to others except for retail sale as a fuel to natural gas vehicles and except for sale or transportation of CNG to third parties.

Issue Date: August 31, 2018

Effective Date: For Service Rendered on and after November 1, 2018

Authorization:

RATE SCHEDULE "USA-G"

**UNDERSERVED AREA – GENERAL SERVICE
(Continued)**

TRANSPORTATION AND BALANCING RIDER

Transportation service is available to commercial and industrial Customers on this Rate who meet the eligibility requirements set forth in the Transportation and Balancing General Terms and Conditions provided on Sheet No. 43. In addition to the above Delivery Service rates, the Customer is subject to the following Firm Balancing Service Rate applied to all gas consumption

Firm Balancing Service Rate: \$0.133 per Ccf of gas consumed

PUBLIC UTILITIES TAX

The Delivery Service, Gas Sales Service, and any other applicable rates or charges are subject to the Delaware Public Utilities Tax unless the Customer is exempt from such tax.

PAYMENT TERMS

Bills are due within twenty (20) days of their date.

MINIMUM BILL

The minimum monthly bill under this Rate Schedule is the Customer charge.

SPECIAL TERMS AND CONDITIONS OF SERVICE

- (1) Service under this Rate Schedule is subject to the standard terms and conditions of service as in effect from time to time under authority of the Public Service Commission of Delaware. It is also subject to the limitations stated under the "Availability" clause above.
- (2) Natural gas purchased hereunder is for the use of the Customer in one (1) location only and is not to be shared or sold to others except for retail sale as a fuel to natural gas vehicles and except for sale or transportation of CNG to third parties.

Issue Date: **August 31, 2018**

Effective Date: **For Service Rendered on and after November 1, 2018**

Authorization:

RATE SCHEDULE "USA-G"

UNDERSERVED AREA – GENERAL SERVICE

SPECIAL TERMS AND CONDITIONS OF SERVICE (Continued)

- (3) A firm Customer that transfers from Gas Sales Service to Transportation and Balancing Service, as authorized under the Company's Tariff, may be required to pay a transition charge in the future to prevent the remaining firm Gas Sales Service Customers from having to absorb stranded fixed gas supply costs which would otherwise be collected from the firm Gas Sales Service Customers switching to Transportation and Balancing Service.
- (4) A firm Customer that transfers from Gas Sales Service to Transportation and Balancing Service or Interruptible Sales Service, as authorized under the Company's Tariff, will be billed for or receive credit for any under or over collection of gas costs from prior periods.
- (5) In addition to the above Delivery Service rates, Customers served under this Rate Schedule may be subject to one (1) or more riders containing additional charges applicable to the service received, such as ER and any applicable franchise fees.

Issue Date: August 31, 2018

Effective Date: For Service Rendered on and after November 1, 2018

Authorization

**RATE SCHEDULE "MVS"
MEDIUM VOLUME SERVICE**

AVAILABILITY

This Rate Schedule is available to any Customer using gas for commercial and/or industrial purposes with an annual consumption generally equal to or greater than four thousand (4,000) Ccf and less than fifteen thousand (15,000) Ccf. The Company will annually review those Customers receiving service under this Rate Schedule in order to determine the appropriate firm commercial and/or industrial Rate Schedule should their annual consumption warrant such a change. A Customer on General Service will be moved to this Rate Schedule with annual consumption equal to or greater than four thousand four hundred (4,400) Ccf. A Customer on this Rate Schedule will be moved to General Service with annual consumption less than three thousand six hundred (3,600) Ccf. The annual review process will be based on the twelve (12) months ended May. Customers will not be shifted between Rate Schedules due to changes in annual consumption other than at the annual review time.

DELIVERY SERVICE RATES

The following rates for delivering gas to the Customer's location apply to all Customers served under this Rate Schedule.

Customer Charge:	\$80.00 per month
First 200 Ccf	\$0.242 per Ccf
Over 200 Ccf	\$0.130 per Ccf

GAS SALES SERVICE

In addition to the above Delivery Service rates, Customers purchasing their natural gas supply from the Company are subject to the gas cost rate applicable to Rate Schedule "MVS" provided on Sheet No. 42.

TRANSPORTATION AND BALANCING RIDER

Transportation service is available to commercial and industrial Customers on this Rate who meet the eligibility requirements set forth in the Transportation and Balancing General Terms and Conditions provided on Sheet No. 43. In addition to the above Delivery Service rates, the customer is subject to the following Firm Balancing Service Rate applied to all gas consumption

Firm Balancing Service Rate:	\$0.158 per Ccf of gas consumed
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Issue Date: August 31, 2018

Effective Date: For Service Rendered on and after November 1, 2018

Authorization:

RATE SCHEDULE "EMVS"

**EXPANSION AREA MEDIUM VOLUME SERVICE
(Continued)**

TRANSPORTATION AND BALANCING RIDER

Transportation service is available to commercial and industrial Customers on this Rate who meet the eligibility requirements set forth in the Transportation and Balancing General Terms and Conditions provided on Sheet No. 43. In addition to the above Delivery Service rates, the Customer is subject to the following Firm Balancing Service Rate applied to all gas consumption

Firm Balancing Service Rate: \$0.158 per Ccf of gas consumed

PUBLIC UTILITIES TAX

The Delivery Service, Gas Sales Service, and any other applicable rates or charges are subject to the Delaware Public Utilities Tax unless the Customer is exempt from such tax.

PAYMENT TERMS

Bills are due within twenty (20) days of their date.

MINIMUM BILL

The minimum monthly bill under this Rate Schedule is the Customer charge.

SPECIAL TERMS AND CONDITIONS OF SERVICE

- (1) Service under this Rate Schedule is subject to the standard terms and conditions of service as in effect from time to time under authority of the Public Service Commission of Delaware. It is also subject to the limitations stated under the "Availability" clause above.
- (2) Natural gas purchased hereunder is for the use of the Customer in one (1) location only and is not to be shared or sold to others except for retail sale as a fuel to natural gas vehicles and except for sale or transportation of CNG to third parties.

Issue Date: August 31, 2018

Effective Date: For Service Rendered on and after November 1, 2018

Authorization:

RATE SCHEDULE "USA-M"

**UNDERSERVED AREA – MEDIUM VOLUME SERVICE
(Continued)**

TRANSPORTATION AND BALANCING RIDER

Transportation service is available to commercial and industrial Customers on this Rate who meet the eligibility requirements set forth in the Transportation and Balancing General Terms and Conditions provided on Sheet No. 43. In addition to the above Delivery Service rates, the Customer is subject to the following Firm Balancing Service Rate applied to all gas consumption

Firm Balancing Service Rate: \$0.158 per Ccf of gas consumed

PUBLIC UTILITIES TAX

The Delivery Service, Gas Sales Service, and any other applicable rates or charges are subject to the Delaware Public Utilities Tax unless the Customer is exempt from such tax.

PAYMENT TERMS

Bills are due within twenty (20) days of their date.

MINIMUM BILL

The minimum monthly bill under this Rate Schedule is the Customer charge.

SPECIAL TERMS AND CONDITIONS OF SERVICE

- (3) Service under this Rate Schedule is subject to the standard terms and conditions of service as in effect from time to time under authority of the Public Service Commission of Delaware. It is also subject to the limitations stated under the "Availability" clause above.
- (4) Natural gas purchased hereunder is for the use of the Customer in one (1) location only and is not to be shared or sold to others except for retail sale as a fuel to natural gas vehicles and except for sale or transportation of CNG to third parties.

Issue Date: **August 31, 2018**

Effective Date: **For Services Rendered on and after November 1, 2018**

Authorization:

RATE SCHEDULE "USA-M"

UNDERSERVED AREA – MEDIUM VOLUME SERVICE

SPECIAL TERMS AND CONDITIONS OF SERVICE (Continued)

- (6) A firm Customer that transfers from Gas Sales Service to Transportation and Balancing Service, as authorized under the Company's Tariff, may be required to pay a transition charge in the future to prevent the remaining firm Gas Sales Service Customers from having to absorb stranded fixed gas supply costs which would otherwise be collected from the firm Gas Sales Service Customers switching to Transportation and Balancing Service.
- (7) A firm Customer that transfers from Gas Sales Service to Transportation and Balancing Service or Interruptible Sales Service, as authorized under the Company's Tariff, will be billed for or receive credit for any under or over collection of gas costs from prior periods.
- (8) In addition to the above Delivery Service rates, Customers served under this Rate Schedule may be subject to one (1) or more riders containing additional charges applicable to the service received, such as ER and any applicable franchise fees.

Issue Date: August 31, 2018

Effective Date: For Services rendered on and after November 1, 2018

Authorization

RATE SCHEDULE "LVS"

**LARGE VOLUME SERVICE
(Continued)**

TRANSPORTATION AND BALANCING SERVICE

Transportation service is available to commercial and industrial Customers on this Rate Schedule who meet the eligibility requirements set forth in the Transportation and Balancing General Terms and Conditions provided on Sheet No. 43. In addition to the above Delivery Service rates, the Customer is subject to the following Firm Balancing Service rate applied to all gas consumption.

Firm Balancing Service Rate: \$0.107 per Ccf of gas consumed

PUBLIC UTILITIES TAX

The Delivery Service, Gas Sales Service, Firm Balancing Service, and any other applicable rates or charges are subject to the Delaware Public Utilities Tax unless the Customer is exempt from such tax.

PAYMENT TERMS

Bills are due within twenty (20) days of their date.

MINIMUM BILL

The minimum monthly bill under this Rate Schedule is the Customer charge.

SPECIAL TERMS AND CONDITIONS OF SERVICE

- (1) Service under this Rate Schedule is subject to the standard terms and conditions of service as in effect from time to time under authority of the Public Service Commission of Delaware. It is also subject to the limitations stated under the "Availability" clause above.
- (2) Natural gas purchased hereunder is for the use of the Customer in one (1) location only and is not to be shared or sold to others except for retail sale as a fuel to natural gas vehicles and except for sale or transportation of CNG to third parties.

Issue Date: August 31, 2018

Effective Date: For Service Rendered on and after November 1, 2018

Authorization:

**RATE SCHEDULE "HLFS"
HIGH LOAD FACTOR SERVICE
(Continued)**

TRANSPORTATION AND BALANCING SERVICE

Transportation service is available to commercial and industrial Customers on this Rate who meet the eligibility requirements set forth in the Transportation and Balancing General Terms and Conditions provided on Sheet No. 43. In addition to the above Delivery Service rates, the Customer is subject to the following Firm Balancing Service rate applied to all gas consumption

Firm Balancing Service Rate: \$0.010 per Ccf of gas consumed

PUBLIC UTILITIES TAX

The Delivery Service, Gas Sales Service, Firm Balancing Service, and any other applicable rates or charges are subject to the Delaware Public Utilities Tax unless the Customer is exempt from such tax.

PAYMENT TERMS

Bills are due within twenty (20) days of their date.

MINIMUM BILL

The minimum monthly bill under this Rate Schedule is the Customer charge.

SPECIAL TERMS AND CONDITIONS OF SERVICE

- (1) Service under this Rate Schedule is subject to the standard terms and conditions of service as in effect from time to time under authority of the Public Service Commission of Delaware. It is also subject to the limitations stated under the "Availability" clause above.
- (2) Natural gas purchased hereunder is for the use of the Customer in one (1) location only and is not to be shared or sold to others except for retail sale as a fuel to natural gas vehicles and except for sale or transportation of CNG to third parties.

Issue Date: August 31, 2018

Effective Date: For Service Rendered on and after November 1, 2018

Authorization:

RATE SCHEDULE "NCR"

**NEGOTIATED CONTRACT RATE
(Continued)**

SPECIAL TERMS AND PROVISIONS (Continued)

- (2) The contract shall be considered a confidential document between the Company and the Customer. By signing the contract, the Customer and the Company agree not to share the contract or information contained within the contract with anyone except the parties to the contract, the Public Service Commission of Delaware and the Office of the Public Advocate, unless given written consent from the other party. Violations by the Customer of the confidentiality agreement shall permit the Company to immediately terminate the contract with the Customer and serve the Customer under another rate schedule for which the Customer qualifies. The Customer shall also be responsible for the penalty provision described below and additional damages or prejudices to any other existing or potential contracts resulting from the breach of confidentiality.
- (3) The contract between the Company and the Customer shall include penalty provisions for early contract cancellation. If at any time prior to the end of the contract term the Customer elects to terminate the contractual agreement with the Company without exercising a re-contracting option for continuing service, the Customer shall be obligated to the terms for cancellation as specified within the contract.
- (4) The Company may offer value-added services in conjunction with the contract. All service attributes agreed to between the Company and the Customer shall be included in the contract.
- (5) The Company shall file all required information with the Public Service Commission of Delaware within thirty (30) days of the executed Contract.

Issue Date: December 20, 2016

Effective Date: January 1, 2017

Authorization: Order No. 8982 dated December 20, 2016 in Docket No. 15-1734

RATE SCHEDULE "GSR"

GAS SALES SERVICE RATES

FIRM SALES RATE SCHEDULES

The Gas Sales Service Rates applicable to the respective firm Rate Schedules, as listed below, will be applied to all Customers served on that schedule based on a volumetric charge per Ccf (100 cubic feet). The Gas Sales Service Rates only apply to the respective firm Rate Schedules listed below and do not apply to the Interruptible Transportation Service, Transportation Service, Negotiated Contract Rate, and Interruptible Best Efforts Sales Service. The Gas Sales Service Rates will be calculated to the nearest tenth of a cent (.1¢).

The following lists the applicable Gas Sales Service Rates for the respective firm Rate Schedules as defined in this Tariff:

<u>RATE SCHEDULE</u>	<u>GAS SALES SERVICE RATES</u>
RS, ERS, USA-R, GS, EGS, USA-G, MVS, EMVS USA-M, LVS	\$0.833 per Ccf
HLFS	\$0.630 per Ccf
GLR and GLO	\$0.362 per Ccf

These rates are subject to change based on actual and estimated gas costs. The Company will file with the Commission a copy of these Gas Sales Service Rates at least sixty (60) days prior to the regularly scheduled adjustment date, which shall be each November 1.

The November 1 rates will be based on a projected twelve-month period of November through October (projected period). 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). The twelve-month period used for the calculation of the over/under period will be based on the actual nine months ended July 31 of each year and the projected three months ended October 31 of each year. If it appears that the use of these rates for the twelve-month over/under period will result in an over or under collection exceeding these limits, the Company shall apply to the Commission for revised rates to be effective until the next annual adjustment in the rates. If the Company's estimated over or under collection exceeds 3%, but is below the 6% under or 4.5% over collection estimate thresholds as noted above, then the Company has the option of applying to the Commission for revised rates to be effective until the next annual adjustment in rates.

Issue Date: August 31, 2018

Effective Date: For Service Rendered on and after November 1, 2018

Authorization:

RATE SCHEDULE "GSR"

**GAS SALES SERVICE RATES
(Continued)**

OVERALL METHODOLOGY (Continued)

A Demand Rate will be determined by dividing the total firm fixed cost components by the firm peak day capacity requirements. A Commodity Rate will be determined by dividing the total firm commodity cost components by total firm consumption for the respective determination period.

ALLOCATION TO RESPECTIVE FIRM RATE SCHEDULES

Rate Schedule HLFS – High Load Factor Service will be charged a single gas cost rate per Ccf based on the combination of a weighted average Demand and Commodity Rate developed on 83.48% load factor for the customer class with the overall system weighted average gas cost rate. The purchased gas costs will be allocated to this Rate Schedule based on its annual consumption for the projected period.

Rate Schedule GLO, GLR – The Gas Lighting Services will be charged the weighted average Demand and Commodity Rates through a single gas cost rate per Ccf based on a one hundred percent (100%) load factor. The purchased gas costs will be allocated to this Rate Schedule based on its annual consumption for the projected period.

Rate Schedule RS-1, ERS-1, RS-2, ERS-2, USA-R, GS, EGS, USA-G, MVS, EMVS, USA-M, LVS – These rate schedules will be assigned the remaining firm purchased gas costs after the firm purchased gas costs have been allocated to the above mentioned Rate Schedules less the portion of any shared margins resulting from capacity release, or off-system sales. These Rate Schedules will be charged a single gas cost rate per Ccf. This rate will reflect the sum of the projected demand and commodity costs for these classes divided by the sum of their annual consumption for the projected period.

MARGIN SHARING

Margins as used herein for off system sales means revenues less: (a) associated gas costs and (b) any applicable taxes based on gross receipts. Margins as used herein for capacity release means revenues less any applicable taxes based on gross receipts. As used in this Tariff, the term "Shared Margins" means off system sales margins, and upstream capacity release margins.

Issue Date: August 31, 2018

Effective Date: For Service Rendered on and after November 1, 2018

Authorization:

**RATE SCHEDULE "GS"
GENERAL SERVICE**

AVAILABILITY

This Rate Schedule is available to any Customer using gas for commercial and/or industrial purposes with an annual consumption of less than four thousand (4,000) Ccf. The Company will annually review those Customers receiving service under this Rate Schedule in order to determine the appropriate firm commercial and/or industrial Rate Schedule should their annual consumption warrant such a change. A Customer on General Service will be moved to Rate Schedule MVS with annual consumption equal to or greater than four thousand four hundred (4,400) Ccf. This annual review process will be based on the twelve (12) months ended May. Customers will not be shifted between Rate Schedules due to changes in annual consumption other than at the annual review time.

DELIVERY SERVICE RATES

The following rates for delivering gas to the Customer's location apply to all Customers served under this Rate Schedule.

Customer Charge:	\$34.00 per month
First 20 Ccf	\$0.426 per Ccf
Next 30 Ccf	\$0.257 per Ccf
Over 50 Ccf	\$0.119 per Ccf

GAS SALES SERVICE

In addition to the above Delivery Service rates, Customers purchasing their natural gas supply from the Company are subject to the gas cost rate applicable to Rate Schedule "GS" provided on Sheet No. 42.

TRANSPORTATION AND BALANCING RIDER

Transportation service is available to commercial and industrial Customers on this Rate Schedule who meet the eligibility requirements set forth in the Transportation and Balancing General Terms and Conditions provided on Sheet No. 43. In addition to the above Delivery Service rates, the Customer is subject to the following Firm Balancing Service Rate applied to all gas consumption.

Firm Balancing Service Rate: ~~\$0.0930~~0.133 per Ccf of gas consumed

Issue Date: ~~September 1, 2017~~August 31, 2018

Effective Date: For Service Rendered on and after November 1, 20178

Authorization: ~~Order No. 9218 dated May 22, 2018 in Docket No. 17-1021~~

RATE SCHEDULE "EGS"

**EXPANSION AREA GENERAL SERVICE
(Continued)**

TRANSPORTATION AND BALANCING RIDER

Transportation service is available to commercial and industrial Customers on this Rate Schedule who meet the eligibility requirements set forth in the Transportation and Balancing General Terms and Conditions provided on Sheet No. 43. In addition to the above Delivery Service rates, the Customer is subject to the following Firm Balancing Service Rate applied to all gas consumption

Firm Balancing Service Rate: ~~\$0.093~~0.133 per Ccf of gas consumed

PUBLIC UTILITIES TAX

The Delivery Service, Gas Sales Service, Firm Balancing Service, and any other applicable rates or charges are subject to the Delaware Public Utilities Tax unless the Customer is exempt from such tax.

PAYMENT TERMS

Bills are due within twenty (20) days of their date.

MINIMUM BILL

The minimum monthly bill under this Rate Schedule is the Customer charge.

SPECIAL TERMS AND CONDITIONS OF SERVICE

- (1) Service under this Rate Schedule is subject to the standard terms and conditions of service as in effect from time to time under authority of the Public Service Commission of Delaware. It is also subject to the limitations stated under the "Availability" clause above.
- (2) Natural gas purchased hereunder is for the use of the Customer in one (1) location only and is not to be shared or sold to others except for retail sale as a fuel to natural gas vehicles and except for sale or transportation of CNG to third parties.

Issue Date: ~~September 1, 2017~~August 31, 2018

Effective Date: For Service Rendered on and after November 1, ~~2017~~2018

Authorization: ~~Order No. 9218 dated May 22, 2018 in Docket No. 17-1021~~

RATE SCHEDULE "USA-G"

UNDERSERVED AREA – GENERAL SERVICE
(Continued)

TRANSPORTATION AND BALANCING RIDER

Transportation service is available to commercial and industrial Customers on this Rate who meet the eligibility requirements set forth in the Transportation and Balancing General Terms and Conditions provided on Sheet No. 43. In addition to the above Delivery Service rates, the Customer is subject to the following Firm Balancing Service Rate applied to all gas consumption

Firm Balancing Service Rate: \$0.133 per Ccf of gas consumed

PUBLIC UTILITIES TAX

The Delivery Service, Gas Sales Service, and any other applicable rates or charges are subject to the Delaware Public Utilities Tax unless the Customer is exempt from such tax.

PAYMENT TERMS

Bills are due within twenty (20) days of their date.

MINIMUM BILL

The minimum monthly bill under this Rate Schedule is the Customer charge.

SPECIAL TERMS AND CONDITIONS OF SERVICE

- (1) Service under this Rate Schedule is subject to the standard terms and conditions of service as in effect from time to time under authority of the Public Service Commission of Delaware. It is also subject to the limitations stated under the "Availability" clause above.
- (2) Natural gas purchased hereunder is for the use of the Customer in one (1) location only and is not to be shared or sold to others except for retail sale as a fuel to natural gas vehicles and except for sale or transportation of CNG to third parties.

Issue Date: **August 31, 2018**

Effective Date: **For Service Rendered on and after November 1, 2018**

Authorization:

RATE SCHEDULE "USA-G"

UNDERSERVED AREA - GENERAL SERVICE

SPECIAL TERMS AND CONDITIONS OF SERVICE (Continued)

- (3) A firm Customer that transfers from Gas Sales Service to Transportation and Balancing Service, as authorized under the Company's Tariff, may be required to pay a transition charge in the future to prevent the remaining firm Gas Sales Service Customers from having to absorb stranded fixed gas supply costs which would otherwise be collected from the firm Gas Sales Service Customers switching to Transportation and Balancing Service.**
- (4) A firm Customer that transfers from Gas Sales Service to Transportation and Balancing Service or Interruptible Sales Service, as authorized under the Company's Tariff, will be billed for or receive credit for any under or over collection of gas costs from prior periods.**
- (5) In addition to the above Delivery Service rates, Customers served under this Rate Schedule may be subject to one (1) or more riders containing additional charges applicable to the service received, such as ER and any applicable franchise fees.**

Issue Date: August 31, 2018

Effective Date: For Service Rendered on and after November 1, 2018

Authorization

**RATE SCHEDULE "MVS"
MEDIUM VOLUME SERVICE**

AVAILABILITY

This Rate Schedule is available to any Customer using gas for commercial and/or industrial purposes with an annual consumption generally equal to or greater than four thousand (4,000) Ccf and less than fifteen thousand (15,000) Ccf. The Company will annually review those Customers receiving service under this Rate Schedule in order to determine the appropriate firm commercial and/or industrial Rate Schedule should their annual consumption warrant such a change. A Customer on General Service will be moved to this Rate Schedule with annual consumption equal to or greater than four thousand four hundred (4,400) Ccf. A Customer on this Rate Schedule will be moved to General Service with annual consumption less than three thousand six hundred (3,600) Ccf. The annual review process will be based on the twelve (12) months ended May. Customers will not be shifted between Rate Schedules due to changes in annual consumption other than at the annual review time.

DELIVERY SERVICE RATES

The following rates for delivering gas to the Customer's location apply to all Customers served under this Rate Schedule.

Customer Charge:	\$80.00 per month
First 200 Ccf	\$0.242 per Ccf
Over 200 Ccf	\$0.130 per Ccf

GAS SALES SERVICE

In addition to the above Delivery Service rates, Customers purchasing their natural gas supply from the Company are subject to the gas cost rate applicable to Rate Schedule "MVS" provided on Sheet No. 42.

TRANSPORTATION AND BALANCING RIDER

Transportation service is available to commercial and industrial Customers on this Rate who meet the eligibility requirements set forth in the Transportation and Balancing General Terms and Conditions provided on Sheet No. 43. In addition to the above Delivery Service rates, the customer is subject to the following Firm Balancing Service Rate applied to all gas consumption

Firm Balancing Service Rate:	\$0.111 <u>0.158</u> per Ccf of gas consumed
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Issue Date: ~~September 1, 2017~~August 31, 2018
Effective Date: For Service Rendered on and after November 1, ~~2017~~2018
Authorization: ~~Order No. 9218 dated May 22, 2018 in Docket No. 17-1021~~

RATE SCHEDULE "EMVS"

**EXPANSION AREA MEDIUM VOLUME SERVICE
(Continued)**

TRANSPORTATION AND BALANCING RIDER

Transportation service is available to commercial and industrial Customers on this Rate who meet the eligibility requirements set forth in the Transportation and Balancing General Terms and Conditions provided on Sheet No. 43. In addition to the above Delivery Service rates, the Customer is subject to the following Firm Balancing Service Rate applied to all gas consumption

Firm Balancing Service Rate: ~~\$0.111~~0.158 per Ccf of gas consumed

PUBLIC UTILITIES TAX

The Delivery Service, Gas Sales Service, and any other applicable rates or charges are subject to the Delaware Public Utilities Tax unless the Customer is exempt from such tax.

PAYMENT TERMS

Bills are due within twenty (20) days of their date.

MINIMUM BILL

The minimum monthly bill under this Rate Schedule is the Customer charge.

SPECIAL TERMS AND CONDITIONS OF SERVICE

(1) Service under this Rate Schedule is subject to the standard terms and conditions of service as in effect from time to time under authority of the Public Service Commission of Delaware. It is also subject to the limitations stated under the "Availability" clause above.

~~(1)~~(2) Natural gas purchased hereunder is for the use of the Customer in one (1) location only and is not to be shared or sold to others except for retail sale as a fuel to natural gas vehicles and except for sale or transportation of CNG to third parties.

Issue Date: ~~September 1, 2017~~August 31, 2018

Effective Date: For Service Rendered on and after November 1, ~~2017~~2018

Authorization: ~~Order No. 9218 dated May 22, 2018 in Docket No. 17-1021~~

RATE SCHEDULE "USA-M"

UNDERSERVED AREA – MEDIUM VOLUME SERVICE
(Continued)

TRANSPORTATION AND BALANCING RIDER

Transportation service is available to commercial and industrial Customers on this Rate who meet the eligibility requirements set forth in the Transportation and Balancing General Terms and Conditions provided on Sheet No. 43. In addition to the above Delivery Service rates, the Customer is subject to the following Firm Balancing Service Rate applied to all gas consumption

Firm Balancing Service Rate: \$0.158 per Ccf of gas consumed

PUBLIC UTILITIES TAX

The Delivery Service, Gas Sales Service, and any other applicable rates or charges are subject to the Delaware Public Utilities Tax unless the Customer is exempt from such tax.

PAYMENT TERMS

Bills are due within twenty (20) days of their date.

MINIMUM BILL

The minimum monthly bill under this Rate Schedule is the Customer charge.

SPECIAL TERMS AND CONDITIONS OF SERVICE

- (3) Service under this Rate Schedule is subject to the standard terms and conditions of service as in effect from time to time under authority of the Public Service Commission of Delaware. It is also subject to the limitations stated under the "Availability" clause above.
- (4) Natural gas purchased hereunder is for the use of the Customer in one (1) location only and is not to be shared or sold to others except for retail sale as a fuel to natural gas vehicles and except for sale or transportation of CNG to third parties.

Issue Date: **August 31, 2018**

Effective Date: **For Services Rendered on and after November 1, 2018**

Authorization:

RATE SCHEDULE "USA-M"

UNDERSERVED AREA – MEDIUM VOLUME SERVICE

SPECIAL TERMS AND CONDITIONS OF SERVICE (Continued)

- (6) A firm Customer that transfers from Gas Sales Service to Transportation and Balancing Service, as authorized under the Company's Tariff, may be required to pay a transition charge in the future to prevent the remaining firm Gas Sales Service Customers from having to absorb stranded fixed gas supply costs which would otherwise be collected from the firm Gas Sales Service Customers switching to Transportation and Balancing Service.**
- (7) A firm Customer that transfers from Gas Sales Service to Transportation and Balancing Service or Interruptible Sales Service, as authorized under the Company's Tariff, will be billed for or receive credit for any under or over collection of gas costs from prior periods.**
- (8) In addition to the above Delivery Service rates, Customers served under this Rate Schedule may be subject to one (1) or more riders containing additional charges applicable to the service received, such as ER and any applicable franchise fees.**

Issue Date: August 31, 2018

Effective Date: For Services rendered on and after November 1, 2018

Authorization

RATE SCHEDULE "LVS"

**LARGE VOLUME SERVICE
(Continued)**

TRANSPORTATION AND BALANCING SERVICE

Transportation service is available to commercial and industrial Customers on this Rate Schedule who meet the eligibility requirements set forth in the Transportation and Balancing General Terms and Conditions provided on Sheet No. 43. In addition to the above Delivery Service rates, the Customer is subject to the following Firm Balancing Service rate applied to all gas consumption.

Firm Balancing Service Rate: ~~\$0.0840~~.107 per Ccf of gas consumed

PUBLIC UTILITIES TAX

The Delivery Service, Gas Sales Service, Firm Balancing Service, and any other applicable rates or charges are subject to the Delaware Public Utilities Tax unless the Customer is exempt from such tax.

PAYMENT TERMS

Bills are due within twenty (20) days of their date.

MINIMUM BILL

The minimum monthly bill under this Rate Schedule is the Customer charge.

SPECIAL TERMS AND CONDITIONS OF SERVICE

- (1) Service under this Rate Schedule is subject to the standard terms and conditions of service as in effect from time to time under authority of the Public Service Commission of Delaware. It is also subject to the limitations stated under the "Availability" clause above.
- (2) Natural gas purchased hereunder is for the use of the Customer in one (1) location only and is not to be shared or sold to others except for retail sale as a fuel to natural gas vehicles and except for sale or transportation of CNG to third parties.

Issue Date: ~~September 1, 2017~~August 31, 2018

Effective Date: For Service Rendered on and after November 1, ~~2017~~2018

Authorization: ~~Order No. 9218 dated May 22, 2018 in Docket No. 17-1021~~

**RATE SCHEDULE "HLFS"
HIGH LOAD FACTOR SERVICE
(Continued)**

TRANSPORTATION AND BALANCING SERVICE

Transportation service is available to commercial and industrial Customers on this Rate who meet the eligibility requirements set forth in the Transportation and Balancing General Terms and Conditions provided on Sheet No. 43. In addition to the above Delivery Service rates, the Customer is subject to the following Firm Balancing Service rate applied to all gas consumption

Firm Balancing Service Rate: ~~\$0.014~~0.010 per Ccf of gas consumed

PUBLIC UTILITIES TAX

The Delivery Service, Gas Sales Service, Firm Balancing Service, and any other applicable rates or charges are subject to the Delaware Public Utilities Tax unless the Customer is exempt from such tax.

PAYMENT TERMS

Bills are due within twenty (20) days of their date.

MINIMUM BILL

The minimum monthly bill under this Rate Schedule is the Customer charge.

SPECIAL TERMS AND CONDITIONS OF SERVICE

- (1) Service under this Rate Schedule is subject to the standard terms and conditions of service as in effect from time to time under authority of the Public Service Commission of Delaware. It is also subject to the limitations stated under the "Availability" clause above.
- (2) Natural gas purchased hereunder is for the use of the Customer in one (1) location only and is not to be shared or sold to others except for retail sale as a fuel to natural gas vehicles and except for sale or transportation of CNG to third parties.

Issue Date: ~~September 1, 2017~~August 31, 2018
Effective Date: For Service Rendered on and after November 1, ~~2017~~2018
Authorization: ~~Order No. 9218 dated May 22, 2018 in Docket No. 17-1021~~

RATE SCHEDULE "ITS"

INTERRUPTIBLE TRANSPORTATION SERVICE

AVAILABILITY

This Rate Schedule is available to any non-residential Customer with annual consumption of at least one hundred thousand (100,000) Ccf with facilities in operating condition capable of utilizing an alternative fuel due to the fact gas service provided is subject to complete interruption at any time during the year at the Company's option. The definition of an alternative fuel under this rate schedule shall be propane, fuel oil, or electricity. When applying for service under this Rate Schedule, the Customer is required to provide the Company, in writing, with the type and specific grade of alternative fuel utilized by the Customer. The Customer shall submit, within thirty (30) days of any change in operations, written notification when such change affects its alternate fuel capability. The Customer must also purchase all of its gas from or through a qualified supplier of natural gas as set forth in Rate Schedule SUP.

DELIVERY SERVICE RATE

Customer charge: \$935.00 per month

The rate per Ccf of consumption shall be determined on an individual Customer basis according to the nature of the interruptible service to be provided. This rate can be adjusted upon one (1) days' notice to the Customer.

TRANSPORTATION AND BALANCING SERVICE

Customers must have the natural gas delivered to the Company's city gate in accordance with the Transportation and Balancing Rider General Terms and Conditions provided on Sheet No. 43. In addition to the above Delivery Service rate, the Customer is subject to the following Interruptible Balancing Service rate applied to all gas consumption.

Interruptible Balancing Service Rate: ~~\$0.0110.001~~ per Ccf of gas consumed

Issue Date: ~~September 1, 2017~~ August 31, 2018

Effective Date: For Service Rendered on and after November 1, ~~2017~~ 2018

Authorization: ~~Order No. 9218 dated May 22, 2018 in Docket No. 17-1021~~

RATE SCHEDULE "GSR"

GAS SALES SERVICE RATES

FIRM SALES RATE SCHEDULES

The Gas Sales Service Rates applicable to the respective firm Rate Schedules, as listed below, will be applied to all Customers served on that schedule based on a volumetric charge per Ccf (100 cubic feet). The Gas Sales Service Rates only apply to the respective firm Rate Schedules listed below and do not apply to the Interruptible Transportation Service, Transportation Service, Negotiated Contract Rate, and Interruptible Best Efforts Sales Service. The Gas Sales Service Rates will be calculated to the nearest tenth of a cent (.1¢).

The following lists the applicable Gas Sales Service Rates for the respective firm Rate Schedules as defined in this Tariff:

<u>RATE SCHEDULE</u>	<u>GAS SALES SERVICE RATES</u>
RS, ERS, <u>USA-R</u> , GS, EGS, <u>USA-G</u> , MVS, EMVS, <u>USA-M</u> , LVS Ccf	\$1.023 <u>0.833</u> per
HLFS Ccf	\$0.782 <u>0.630</u> per
GLR and GLO Ccf	\$0.468 <u>0.362</u> per

These rates are subject to change based on actual and estimated gas costs. The Company will file with the Commission a copy of these Gas Sales Service Rates at least sixty (60) days prior to the regularly scheduled adjustment date, which shall be each November 1.

The November 1 rates will be based on a projected twelve-month period of November through October (projected period). 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). The twelve-month period used for the calculation of the over/under period will be based on the actual nine months ended July 31 of each year and the projected three months ended October 31 of each year. If it appears that the use of these rates for the twelve-month over/under period will result in an over or under collection exceeding these limits, the Company shall apply to the Commission for revised rates to be effective until the next annual adjustment in the rates. If the Company's estimated over or under collection exceeds 3%, but is below the 6% under or 4.5% over collection estimate thresholds as noted above, then the Company has the option of applying to the Commission for revised rates to be effective until the next annual adjustment in rates.

Effective Date: For Service Rendered on and after November 1, ~~2017~~2018

Authorization: ~~Order No. 9218 dated May 22, 2018 in Docket No. 17-1021~~

RATE SCHEDULE "GSR"**GAS SALES SERVICE RATES
(Continued)****OVERALL METHODOLOGY (Continued)**

A Demand Rate will be determined by dividing the total firm fixed cost components by the firm peak day capacity requirements. A Commodity Rate will be determined by dividing the total firm commodity cost components by total firm consumption for the respective determination period.

ALLOCATION TO RESPECTIVE FIRM RATE SCHEDULES

Rate Schedule HLFS – High Load Factor Service will be charged a single gas cost rate per Ccf based on the combination of a weighted average Demand and Commodity Rate developed on ~~86.8183.48~~ % load factor for the customer class with the overall system weighted average gas cost rate. The purchased gas costs will be allocated to this Rate Schedule based on its annual consumption for the projected period.

Rate Schedule GLO, GLR – The Gas Lighting Services will be charged the weighted average Demand and Commodity Rates through a single gas cost rate per Ccf based on a one hundred percent (100%) load factor. The purchased gas costs will be allocated to this Rate Schedule based on its annual consumption for the projected period.

Rate Schedule RS-1, ERS-1, RS-2, ERS-2, USA-R, GS, EGS, USA-G, MVS, EMVS, USA-M, LVS – These rate schedules will be assigned the remaining firm purchased gas costs after the firm purchased gas costs have been allocated to the above mentioned Rate Schedules less the portion of any shared margins resulting from capacity release, or off-system sales. These Rate Schedules will be charged a single gas cost rate per Ccf. This rate will reflect the sum of the projected demand and commodity costs for these classes divided by the sum of their annual consumption for the projected period.

MARGIN SHARING

Margins as used herein for off system sales means revenues less: (a) associated gas costs and (b) any applicable taxes based on gross receipts. Margins as used herein for capacity release means revenues less any applicable taxes based on gross receipts. As used in this Tariff, the term "Shared Margins" means off system sales margins, and upstream capacity release margins.

Issue Date: ~~August 31, 2018~~ ~~September 1, 2017~~

Effective Date: For Service Rendered on and after November 1, 2017~~8~~

Authorization: ~~Order No. 9218 dated May 22, 2018 in Docket No. 17-1021~~

BEFORE THE DELAWARE PUBLIC SERVICE COMMISSION

IN THE MATTER OF THE APPLICATION OF)
CHESAPEAKE UTILITIES CORPORATION)
FOR APPROVAL OF A CHANGE IN ITS) P.S.C. DOCKET NO. 18-
GAS SALES SERVICE RATES ("GSR"))
TO BE EFFECTIVE NOVEMBER 1, 2018)

DIRECT TESTIMONY OF MARIE E. KOZEL

On Behalf of Chesapeake Utilities Corporation

Delaware Division

Submitted for filing: August 31, 2018

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

3 A. My name is Marie E. Kozel and I am a Regulatory Analyst III with
4 Chesapeake Utilities Corporation. My business address is 500 Energy
5 Lane, Suite 200, Dover, Delaware 19901.

6

7 Q. BRIEFLY DESCRIBE YOUR EDUCATION AND RELEVANT
8 PROFESSIONAL BACKGROUND.

9 A. I received a Bachelor of Science Degree in Finance with a minor in English
10 from La Salle University in Philadelphia, Pennsylvania and a Masters of
11 Business Administration from Wilmington University in Wilmington
12 Delaware. I was hired by Chesapeake Utilities Corporation in November
13 2007. As a Regulatory Analyst III, my responsibilities include gas cost
14 recovery, rate of return analysis, rate case preparation, and budgeting for
15 Chesapeake Utilities – Natural Gas Distribution Delaware Division. Prior to
16 my role as a Regulatory Analyst III, I was a Financial Business Analyst
17 responsible for the consolidation and preparation of the annual budget,
18 strategic plan and monthly forecast including Senior Management and
19 Board of Directors reporting. Prior to that I was a Gas Supply Analyst II
20 responsible for all matters associated with gas supply and its procurement
21 for Chesapeake Utilities Corporation – Delmarva Natural Gas. Immediately
22 prior to joining Chesapeake, I was employed by ING Financial Services in
23 West Chester, PA as Senior Financial Analyst in Operational Risk

1 Management for the Retail Life Division, where I performed audits for the
2 purpose of compliance with the Sarbanes Oxley Act of 2002. My
3 responsibilities also included the implementation of operational risk
4 management objectives, exposure analysis and awareness education for
5 divisional staff. I have also held positions with JP Morgan Chase and
6 Radian Guaranty Inc., where I was responsible for revenue and expense
7 analysis, budget preparation and staff management.

8
9 Q. WHAT IS THE PURPOSE OF YOUR DIRECT TESTIMONY IN THIS
10 PROCEEDING?

11 A. The purpose of my testimony is to discuss the mechanics of the three GSR
12 charges, explain the development of the firm and interruptible sales
13 volumes and total system requirements, and discuss the development of
14 the unaccounted for gas volumes. In addition, my testimony will support the
15 overall calculation of the Delaware Division's three proposed GSR charges
16 to be effective with service rendered on and after November 1, 2018, as
17 well as the mechanics of the Delaware Division's proposed balancing rates
18 for transportation service under the General Service ("GS"), Expansion
19 Area General Service ("EGS"), Medium Volume Service ("MVS"),
20 Expansion Area Medium Volume Service ("EMVS"), Large Volume Service
21 ("LVS"), High Load Factor Service ("HLFS") and Interruptible Service ("ITS")
22 rate schedules. I will be illustrating the impact of the proposed GSR charges
23 on an average residential customer's bill and ensuring compliance with the

1 gas cost provisions outlined in previous Commission Orders. Additionally,
2 my testimony will support a request to add tariff language which gives the
3 Company the option of filing for new GSR rates should the projected over
4 under balance fall outside of 3% of actual firm gas costs incurred plus
5 projected firm gas costs over the remainder of the over/under collection
6 period.

7

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

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

16

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

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

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

3 A. The three Gas Sales Service Rates proposed to be effective with service
4 rendered on and after November 1, 2018 have been developed in
5 accordance with the approved gas cost recovery mechanism as contained
6 in the Delaware Division's natural gas tariff, specifically Sheet Nos. 42
7 through 42.3.

8

9 Q. WHAT GAS SALES SERVICE RATE LEVELS ARE YOU PROPOSING IN
10 THIS PROCEEDING TO BE EFFECTIVE WITH SERVICE RENDERED ON
11 AND AFTER NOVEMBER 1, 2018?

12 A. The Company proposes the following Gas Sales Service Rates to be
13 effective for service rendered on and after November 1, 2018: \$0.833 per
14 Ccf for customers served under rate schedules RS-1, ERS-1, RS-2, ERS-
15 2, USA-R, GS, EGS, USA-G, MVS, EMVS, USA-M, and LVS, \$0.362 per
16 Ccf for customers served under rate schedules GLR and GLO, and \$0.630
17 per Ccf for customers served under rate schedule HLFS. Chesapeake is
18 also proposing the following balancing rates to be effective for service
19 rendered on and after November 1, 2018: \$0.133 per Ccf for transportation
20 customers served under rate schedules GS, EGS and USA-G \$0.158 per
21 Ccf for transportation customers served under rate schedules MVS, EMVS,
22 and USA-M \$0.107 per Ccf for transportation customers served under rate
23 schedule LVS, \$0.010 per Ccf for transportation customers served under

1 rate schedule HLFS, and \$0.001 per Ccf for transportation customers
2 served under rate schedule ITS.

3

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

6 A. As compared to the rates that were in effect November 1, 2017, an average
7 RS-2 customer using 700 Ccf per year will experience an annual decrease
8 of approximately 11.79% or \$11.08 per month. During the winter heating
9 season, a typical RS-2 customer on Chesapeake's system using 110 Ccf
10 per month will experience a decrease of approximately 13.08% or \$20.90
11 per winter month. A typical RS-2 customer using 120 Ccf per winter month
12 will experience a decrease of approximately 13.27% or \$22.80 per winter
13 month.

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

17 A. The rates were calculated based on the estimated purchased gas costs and
18 estimated sales volumes for the twelve months ending October 31, 2019
19 and are summarized on Schedule A.1. As shown on Schedule A.1, total
20 projected firm gas costs recoverable through the gas cost recovery
21 mechanism are \$39,880,374. This total is comprised of \$27,729,448 of
22 fixed costs and \$12,140,926 of variable costs. The three gas cost rates

1 shown at the top of Schedule A.1, which include a fixed rate (used to
2 calculate separate demand rates), a variable / commodity rate, and a total
3 rate or system average rate, are the key components for calculating
4 separate Gas Sales Service Rates for different services.

5

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

9 A. The analysis of the change in gas costs and Gas Sales Service Rates from
10 the Company's last gas cost recovery filing is summarized on Schedule E.
11 As shown on this schedule, variable or commodity gas costs are anticipated
12 to decrease by \$3,484,117 since the last GSR filing. The variable costs
13 contained in this filing are decreasing primarily due to the shift of
14 (\$4,129,648) in the Company's position of its over/under-collection balance
15 from the previous year. The Company is including a projected over
16 collection of \$897,289 in this GSR filing.

17 As shown on this schedule, fixed costs are anticipated to decrease by
18 \$1,483,933 since the last GSR filing. The decrease in fixed gas costs is
19 attributable to LNG peaking costs which are no longer needed and the
20 settlement of the Eastern Shore Natural Gas "ESNG" rate case. The above
21 mentioned factors result in a decrease to the system average cost per Ccf
22 of \$0.879 per Ccf in this filing versus \$1.081 in the November 1, 2017 filing.

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

5 A. Schedule A.1 is a summary of the calculation of the three proposed GSR
6 levels. The calculations of the proposed GSR levels have been made in
7 accordance with the provisions set forth in the Delaware Division's GSR
8 tariff clause. The process to determine the GSR charges consists of three
9 major steps:

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

15 Step 3 is summarized on Schedule A.1. Initially, three gas cost rates must
16 be established to calculate the three separate GSR charges: a fixed rate, a
17 commodity rate and a system average rate. Based on total firm gas costs
18 recoverable through the gas cost recovery mechanism for the GSR levels
19 to be effective November 1, 2018, the three gas cost rates are calculated
20 as follows:

1 Fixed Rate - \$34.20/ Ccf (Total fixed costs of \$27,739,448
2 divided by the firm peak day
3 capacity requirements of 811,130
4 Ccf)

5 Commodity Rate - \$0.268 / Ccf (Total firm commodity costs of
6 \$12,140,926 divided by firm sales
7 volumes of 45,362,965 Ccf for the
8 period November 2018 through
9 October 2019)

10 System Average Rate -\$0.879 / Ccf (Divide total firm gas costs of
11 \$39,880,374 by the firm sales
12 volume of 45,362,965 Ccf)

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

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

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

4 Rate Schedule HLFS

5 This GSR charge, applicable to any customer qualifying for High Load
6 Factor Service (HLFS), is calculated based on the combination of a
7 weighted average demand and commodity rate developed on an overall
8 83.48% load factor for the customer class and the overall system weighted
9 average cost rate. The 83.48% load factor is included on Schedule J. This
10 means that the fixed gas cost rate of \$34.20 per Ccf, as previously
11 described, is divided by 305 days (83.48% of 365 days in a year) to calculate
12 a demand rate of \$0.112 per Ccf. This rate is then added to the commodity
13 rate, as previously described, of \$0.268 per Ccf to calculate a volumetric
14 rate of \$0.380 per Ccf. The arithmetic average of this volumetric rate
15 (\$0.380 per Ccf) and the system average rate (\$0.879 per Ccf) is \$0.630
16 per Ccf, which equals the GSR charge for HLFS customers. Total costs
17 associated with HLFS (\$2,196,908) are projected by multiplying the GSR
18 charge \$0.630 per Ccf) by the projected sales volumes for HLFS (3,487,155
19 Ccf).

20 Rate Schedules GLO and GLR

21 All customers served under these Gas Lighting rate schedules will be
22 subject to the same GSR charge. This rate is calculated using weighted
23 average demand and commodity rates through a single gas cost rate per

1 Ccf, based on a 100% load factor. The demand rate of \$0.094 per Ccf
2 (\$34.20 / 365) plus the commodity rate of \$0.268 per Ccf, produces a GSR
3 charge of \$0.362 per Ccf. Total costs associated with Gas Lighting Services
4 of \$350 are a result of multiplying the \$0.362 per Ccf GSR charge by the
5 annual sales volumes for these services of 350 Ccf.

6 Rate Schedules RS-1, ERS-1, RS-2, ERS-2, USA-R, GS, EGS, USA-G,
7 MVS, EMVS, USA-M and LVS

8 These rate schedules are assigned the remaining firm purchased gas costs
9 after the firm purchased gas costs have been calculated for the above
10 mentioned rate schedules (\$39,880,374 - \$2,196,908 - \$127 =
11 \$27,683,339). Associated costs are divided by the remaining volume
12 (45,362,965 – 3,487,155 – 350 = 41,875,460) to develop a rate of \$0.900
13 per Ccf, less the portion of any shared margins (\$0.067 per Ccf) as shown
14 on Schedule A.2. All customers served under rate schedules RS-1, ERS-
15 1, RS-2, ERS-2, USA-R, GS, EGS, USA-G, MVS, EMVS, USA-M and LVS
16 will be charged \$0.833 per Ccf for service rendered on and after November
17 1, 2018.

18

19 Q. PLEASE DEFINE THE TERM “SHARED MARGINS”.

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

1

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

5 A. Pursuant to the settlement agreement reached in PSC Docket 12-450F, the
6 Company will retain 7.5% of all capacity release credits received from the
7 Company's Asset Manager and credit 92.5% to the firm ratepayers. Also,
8 as outlined in the settlement agreement reached in PSC Docket No. 09-
9 398F, the Company is permitted to retain 100% of all interruptible
10 transportation margins up to \$675,000 per year and 10% of all interruptible
11 transportation margins over \$675,000 per year. As shown on Schedule A.2,
12 the Company is not projected to reach the sharing threshold for interruptible
13 transportation margins in this twelve month determination period. Schedule
14 A.2 does show the calculation of the \$0.674 per Mcf margin sharing rate,
15 proposed to be effective November 1, 2018, as a result of the sharing of the
16 capacity valuation credit from the Asset Manager. The Company is not
17 projecting any off system sales for this determination period.

18

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

1 A. Yes. The Company believes, as stated in prior GSR filings, that crediting
2 100% of the revenue received from capacity released to the Delaware
3 Division's transportation customers to the firm sales customers is
4 appropriate due to the market on Eastern Shore for this capacity. The
5 Company has estimated this capacity release value to be \$5,522,029 for
6 the twelve-month period ending October 2019 as calculated on Schedule I
7 and shown as a reduction to fixed demand costs on Schedule B.

8

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

14 A. A forecast of purchased gas costs must start with a forecast of demand or
15 sales volumes for the Company's distribution system. Based on meeting
16 the sales forecast, the Company develops a forecast of the associated
17 purchases or supply requirements. For the purpose of this proceeding, the
18 sales forecast began with an analysis of the major variables that affect sales
19 volumes. These variables include such items as the number of customers
20 to be served, the rate schedule classification of those customers (i.e. large
21 volume, high load factor, etc.), temperature, and the larger individual
22 commercial and industrial customer sales volumes or demands. Sales

1 volumes are normalized based on a ten-year average of degree days for
2 the months of July 2008 through June 2018.

3

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

7 A. Yes. Schedule C.1 shows Chesapeake's projected sales volumes by
8 customer class for the determination period of the twelve months ending
9 October 31, 2019.

10

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

13 A. Forecasted sales were used for the entire twelve-month period of November
14 2018 through October 2019. Forecasted sales were developed based upon
15 the actual sales volumes billed to each customer class during each month
16 for the prior year with adjustments to reflect average temperature, customer
17 growth and customers switching among rate classes.

18

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

21 A. For the twelve month period ending October 31, 2019, the Company has
22 projected an increase of approximately 3,603 RS-2 customers over the
23 current GSR determination period, with the a large portion of the increase

1 representing growth in new customers and customer conversions in
2 southeastern Sussex County, Delaware. For the twelve month period
3 ending October 31, 2019, the Company has projected a decrease of
4 approximately 192 RS-1 customers from the current GSR determination
5 period. This reduction primarily due to RS-1 customers being re-classed to
6 RS-2.

7

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

10 A. With respect to the Commercial and Industrial customers, the Company
11 projects an overall increase of approximately 153 customers over the
12 previous twelve-month period.

13

14 Q. DOES THE COMPANY HAVE ANY PROJECTIONS FOR THE NUMBER
15 OF FIRM COMMERCIAL AND INDUSTRIAL CUSTOMERS THAT MAY
16 CHOOSE TO TRANSPORT ON ITS DISTRIBUTION SYSTEM AND THE
17 VOLUMES ASSOCIATED WITH THESE CUSTOMERS FOR THIS
18 PERIOD?

19 A. Yes. The Company has not included in its projections any firm commercial
20 or industrial customers switching from sales service to transportation
21 service during the determination period. This filing includes projections for
22 gas to be transported on the Company's distribution system for those
23 customers who are currently receiving transportation service based on the

1 Company's current eligibility requirements, as well as new natural gas
2 customers that the Company anticipates will choose transportation service.
3 There are 377 firm commercial / industrial customers and two (2)
4 interruptible commercial / industrial customers who will be transporting their
5 own gas on the Delaware Division's distribution system. The Company has
6 estimated the firm commercial / industrial transportation volumes to be
7 approximately 4,400,641 Mcf and the interruptible commercial / industrial
8 transportation volumes to be approximately 93,700 Mcf during this period.
9 The estimated firm commercial / industrial transportation volume is an
10 increase over the projection from the previous GSR filing.

11

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

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

20

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

1 A. All sales volume projections included in this GSR filing are associated with
2 a respective billing month while the Delaware Division's purchases are
3 recorded on a calendar month basis. Chesapeake includes a cycle billing
4 adjustment in its calculation of the GSR charges for the purpose of
5 accounting for the difference between a billing month and a calendar month.
6 The cycle billing adjustment is calculated by first dividing the projected,
7 normalized firm sales volumes for each month into a base load and a
8 heating load. The heating load is then multiplied by the difference between
9 the normal calendar month degree days and the normal billing month
10 degree days to calculate the cycle billing adjustment.

11

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

14 A. Company Use Gas is projected to be 1,708 Mcf for this determination
15 period. This projection is approximately the same level of volume
16 experienced by the Company during the actual twelve months ended June
17 30, 2018.

18

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

21 A. An unaccounted for gas volume of 22,627 Mcf has been projected for the
22 twelve months ending October 31, 2019. Unaccounted for gas is calculated
23 by multiplying the respective sales volumes for each month by 2.03% and

1 subtracting the estimated Company Use and Pressure Compensation for
2 the month. The 2.03% utilized in this GSR calculation includes volumes
3 attributed to metering pressure differential and is representative of five-year
4 history of unaccounted for gas volumes. The use of a five year history of
5 unaccounted for gas volumes was approved by the Public Service
6 Commission by Order No. 4189 in PSC Docket No. 95-206.

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

10 A. The pressure compensation projection of 67,753 Mcf is calculated by
11 multiplying the total projected Mcf sales by the factor 0.0149355. This factor
12 represents the calculation used to pressurize gas received from Eastern
13 Shore to a standard pressure of 14.73 PSI for delivery on the Company's
14 distribution system.

15
16 Q. PLEASE EXPLAIN HOW YOU CALCULATED THE PROJECTED COST
17 OF FIRM SALES FOR THE TWELVE-MONTH PERIOD ENDING
18 OCTOBER 31, 2019.

19 A. The projected cost of firm sales is detailed on a monthly basis throughout
20 the seven pages of Schedule C.2. In calculating the proposed cost of gas
21 for the period November 1, 2018 through October 31, 2019, the total
22 projected supply requirements were allocated between the different

1 categories of gas (commodity and storage) available to meet the projected
2 demand. Pages 1 and 2 of Schedule C.2 primarily calculate the fixed costs
3 of firm transportation on Columbia Gas Transmission (“Columbia”),
4 Columbia Gulf Transmission (“Columbia Gulf”), Transcontinental Gas Pipe
5 Line (“Transco”), Eastern Shore Natural Gas (“ESNG”), and Texas Eastern
6 Transmission (“TETCO”).

7 A summary of storage demand and capacity charges is also included on
8 these two pages. Pages 3, 4 and 5 calculate the gas commodity costs
9 associated with firm transportation service. As summarized on Page 4 of
10 Schedule C.2, the projected cost of storage gas commodity for withdrawals
11 during this period has been calculated using the actual purchases and costs
12 for the months of April 2018 through July 2018 and projected purchases
13 and costs for August 2018 through October 2018. The twelve-month period
14 ending March 2019 is used for the calculation of the storage gas demand
15 cost to properly reflect the amounts to be expensed during the
16 determination year. The rates used in the commodity gas purchase
17 projections for flowing commodity gas for November 2018 through October
18 2019 are based on natural gas commodity futures market prices during the
19 second week of August 2018, as well as any gas that had been previously
20 purchased under the Company’s “Natural Gas Commodity Procurement
21 Plan” for this determination period.

1 Q. PLEASE EXPLAIN THE CHANGE IN THE PROJECTED FIRM COST OF
2 GAS FOR THE TWELVE MONTHS ENDING OCTOBER 31, 2019 AS
3 SHOWN ON SCHEDULE F COMPARED TO NINE MONTHS OF ACTUAL
4 COSTS AND THREE MONTHS OF PROJECTED COSTS FOR THE
5 TWELVE-MONTH PERIOD ENDING OCTOBER 31, 2018.

6 A. Schedule F compares the projected firm cost of gas for the twelve months
7 ending October 31, 2019 utilized in this proceeding to the nine months of
8 actual gas costs and three months of projected gas costs for the twelve-
9 month period ending October 31, 2018. In addition, for informational
10 purposes, the actual firm cost of gas for the three prior determination
11 periods ended October 2017, 2016, and 2015 are shown. Chesapeake
12 anticipates a decrease in firm gas costs per Mcf from \$10.0232 per Mcf to
13 \$9.3994 per Mcf from the twelve months ending October 31, 2018.

14

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

16 A. Schedule D.1 sets forth the calculation of the purchased gas over/under
17 collection by month for the twelve-month period ending October 31, 2018.
18 The projected over collection balance at October 31, 2018 that is carried
19 forward into this annual filing is \$897,289.

20 Schedule D.2 reflects the shared margins over/under refund for the twelve-
21 month determination period ending October 31, 2018. Based on this
22 twelve-month determination period, the Company's under refunded shared

1 margins are \$45,763. This amount is also included in the shared margin
2 calculation on Schedule A.2.

3

4 Q. PURSUANT TO THE PROVISIONS OF THE TARIFF CONCERNING THE
5 UNACCOUNTED FOR GAS INCENTIVE MECHANISM APPROVED BY
6 ORDER NO. 3648, THE COMPANY AS PART OF ITS ANNUAL GSR
7 FILING IS REQUIRED TO PROVIDE THE COMMISSION STAFF WITH
8 ACTUAL UNACCOUNTED FOR GAS VOLUMES FOR THE PRECEDING
9 TWELVE MONTH PERIOD ENDED JULY 31. HAS THE COMPANY
10 INCLUDED A SCHEDULE SHOWING THE REQUIRED INFORMATION?

11 A. Yes. Schedule G represents the actual unaccounted for gas volumes for
12 the twelve months ended July 31, 2018.

13

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

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

23

1 Q. WHAT WAS THE ACTUAL LEVEL OF UNACCOUNTED FOR GAS
2 VOLUMES FOR THE TWELVE MONTHS ENDED JULY 31, 2018
3 COMPARED TO THE INCENTIVE MECHANISM TARGETS?

4 A. The actual unaccounted for gas percentage, as established by the approved
5 guidelines in PSC Docket No. 92-87F, for the twelve months ended July 31,
6 2018, was 0.19% of total gas requirements. This percentage is under the
7 targeted percentage of 3.20% and is also under the dead band range of
8 2.70% to 3.70%.

9

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

16 A. Chesapeake's firm transportation balancing rates are calculated in
17 accordance with the methodology approved in PSC Docket No. 95-73,
18 Phase II, by Order No. 4400, modified in PSC Docket No. 13-383, by Order
19 No. 8752, and further modified in PSC Docket No. 17-1021, by Order No.
20 9218 and are based on Chesapeake's annual purchased gas costs. As a
21 result of Order No. 4400, Chesapeake is required to update its balancing
22 rates for Rate Schedules LVS and HLFS on an annual basis at the time of
23 its annual Gas Sales Service Rate application. Chesapeake also agreed to

1 update its balancing rate for ITS during its annual Gas Sales Service
2 application as a result of Order No. 7434 issued on September 2, 2008 in
3 PSC Docket No. 07-186. Also as a result of Order No. 8752 in PSC Docket
4 No. 13-383, the Company now calculates balancing rates for transportation
5 customers served under rate schedules GS, EGS, USA-G, MVS, EMVS and
6 USA-M; these rates are also to be updated on an annual basis at the time
7 of the Company's annual Gas Sales Service Rate application.

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

12 Please note that in conjunction with the balancing rates proposed in this
13 Docket, the Company is including new tariff sheets 30.6, 30.7, 31.6, and
14 31.7. These sheets spell out the balancing rates and terms for the approved
15 "USA-G" and "USA-M" rate classes. In the tariff sheets filed with the USA-
16 G and USA-M approval, balancing rates were inadvertently excluded. The
17 Company has included proposed tariff sheets with this filing where the USA-
18 G balancing rates and terms are consistent with those for rate classes GS
19 and EGS, and the USA-M rates and terms are consistent with those for rate
20 classes MVS and EMVS.

21

1 Q. PREVIOUSLY YOU MENTIONED CHANGES TO THE BALANCING
2 RATE AS A RESULT OF ORDER NO. 9218 IN PSC DOCKET No. 17-
3 1021. COULD YOU PLEASE ELABORATE ON THOSE CHANGES?

4
5 A. Pursuant to Order No. 9218 in PSC Docket No. 17-1021, the Company has
6 made some revisions to its balancing rate calculation methodology based
7 on recommendations by Staff and DPA Witness Mierzwa in his Direct
8 Testimony filed in the above referenced docket. The Company now
9 includes a full twelve (12) months of costs associated with ESNG capacity
10 costs related to the upstream storage assets used for balancing. In
11 addition, the Company agreed to include actual liquefied natural gas
12 (“LNG”) peaking service and propane costs in the calculation of its
13 balancing rates. While the Company did include propane costs in the
14 development of the balancing rates, the use of the LNG peaking facility has
15 been discontinued. The Company also now excludes upstream non-storage
16 related pipeline transportation capacity from the development of balancing
17 rates.

18
19 Q. PLEASE STATE THE BALANCING RATES THAT ARE BEING
20 PROPOSED IN THIS FILING.

21 A. Chesapeake is proposing the following changes to its balancing rates, to be
22 effective for service rendered on and after November 1, 2018, in this
23 application: (a) increase in the current firm balancing rate for transportation

1 customers served under rate schedules GS, EGS and USA-G of \$0.093 per
2 Ccf to \$0.133; (b) increase to the current firm balancing rate for
3 transportation customers served under rate schedules MVS, EMVS USA-M
4 from \$0.111 per Ccf to \$0.158 per Ccf; (c) decrease to the current firm
5 balancing rate for transportation customers served under rate schedule
6 "LVS" from \$0.084 per Ccf to \$0.107 per Ccf, (d) increase to the current firm
7 balancing rate for transportation customers served under rate schedule
8 "HLFS" from \$0.014 per Ccf to \$0.010 per Ccf, and (e) decrease to the
9 current interruptible balancing rate for transportation customers served
10 under rate schedule "ITS" from \$0.011 per Ccf to \$0.001 per Ccf.

11

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

14 A. As described above, the Company no longer includes any upstream firm
15 transportation costs in the determination of its transportation balancing
16 rates.

17 Previously, the Company also included a component related to upstream
18 capacity cost recovery when calculating final balancing rates for its
19 transportation customers. However, the Company's current Asset
20 Management Agreement ("AMA") is structured such that all of
21 Chesapeake's upstream capacity is released to its Asset Manager.
22 Therefore, the Company is no longer releasing upstream capacity outside
23 of the confines of its AMA. However, firm sales customers can still benefit

1 from the potential of an increased capacity valuation credit should the Asset
2 Manager earn additional revenues on this capacity. Ninety-two and one-
3 half percent (92.5%) of the Company's capacity valuation credit is credited
4 back to firm sales customers through the GSR. Therefore, the Company no
5 longer includes an addition to the balancing rate due to upstream capacity
6 cost recovery.

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

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

15
16 Q. PLEASE BRIEFLY EXPLAIN HOW THE OVERALL COSTS OF THE GAS
17 SUPPLY RESOURCES WERE DEVELOPED ON SCHEDULE J.

18 A. The Delaware Division's gas costs associated with the gas supply
19 resources for balancing services are based on the same costs contained in
20 the development of the GSR charges. The gas supply resources and their
21 costs are separated into fixed gas supply resources and variable gas supply
22 resources. The Delaware Division's storage demand and capacity, firm
23 transportation capacity reserved for balancing, and propane peak shaving

1 facilities are related to the fixed gas supply resources, while storage
2 injection and withdrawal volumes are related to the variable gas supply
3 resources.

4

5 Q. HOW WAS THE AVERAGE ANNUAL RATE OF APPROXIMATELY
6 \$240.8715 PER DT FOR THE FIXED GAS SUPPLY RESOURCES
7 DETERMINED ON SCHEDULE J, PAGE 1 OF 4?

8 A. The gas costs were determined for each of the fixed gas supply resources
9 to be used by the Company in performing this balancing service. The total
10 annualized gas supply costs of \$6,825,787 were divided by the daily
11 entitlements of 23,059 Dts to derive the annual amount of \$296.0192 per Dt
12 for these fixed gas supply resources in the balancing service.

13

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

16 A. The overall variable rate of \$0.0127 per Dt was determined based on the
17 current storage injection and withdrawal capacities of the Delaware
18 Division's storage resources. This rate was cut in half to arrive at separate
19 rates for injections and withdrawals. This is important because a
20 transportation customer on any given day will either over deliver (the
21 Company would inject the excess gas into storage) or under deliver (the
22 Company would withdraw from storage to meet the demand) the customer-
23 owned gas into the system on the customer's behalf. The resulting rate

1 used for the variable gas supply component of the balancing services is
2 \$0.0127 per Dt.

3

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

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

17

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

20 A. Schedule J, Page 2 of 6 shows the development of the firm balancing
21 service rate for this specific transportation customer class. The Delaware
22 Division developed an average cost from the fixed rate of \$296.0192 per Dt
23 based on the General Service load factor of 27.20%. This load factor

1 resulted in an average cost of \$2.9901 per Dt. Since the Company's
2 analysis determined that the DCQ method would provide approximately
3 57.07% of the peak day requirements, the Company would need to supply
4 the remaining 42.93% with its gas supply resources. In other words, these
5 firm customers would pay for 42.93% of peak day requirements through the
6 balancing service rate. The resulting rate for the fixed capacity based on
7 this 42.93% would be approximately \$1.2836 per Dt applicable to all
8 consumption. The variable commodity rate of \$0.0127 per Dt was multiplied
9 by the estimated imbalance volume percentage of 27.32% to derive the
10 variable rate of \$0.0035 per Dt. The fixed capacity rate was added to the
11 variable commodity rate to develop a balancing rate per Dt of \$1.2871,
12 which was then converted to a per Mcf rate of \$1.3322, or \$0.133 per Ccf
13 for transportation customers served under Rate Schedules GS and EGS,
14 as shown on Schedule J, page 2 of 6.

15

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

19 A. Schedule J, Page 3 of 6 shows the development of the firm balancing
20 service rate for this specific transportation customer class. The Delaware
21 Division developed an average cost from the fixed rate of \$296.0192 per Dt
22 based on the Medium Volume Service load factor of 24.13%. This load
23 factor resulted in an average cost of \$3.3639 per Dt. Since the Company's

1 analysis determined that the DCQ method would provide approximately
2 54.62% of the peak day requirements, the Company would need to supply
3 the remaining 45.38% with its gas supply resources. In other words, these
4 firm customers would pay for 45.38% of peak day requirements through the
5 balancing service rate. The resulting rate for the fixed capacity based on
6 this 45.38% would be approximately \$1.5265 per Dt applicable to all
7 consumption. The variable commodity rate of \$0.0127 per Dt was multiplied
8 by the estimated imbalance volume percentage of 33.02% to derive the
9 variable rate of \$0.0042 per Dt. The fixed capacity rate was added to the
10 variable commodity rate to develop a balancing rate per Dt of \$1.5307,
11 which was then converted to a per Mcf rate of \$1.5843. The total balancing
12 rate is \$1.5843 per Mcf, or \$0.158 per Ccf for transportation customers
13 served under Rate Schedules MVS and EMVS, as shown on Schedule J,
14 page 3 of 6.

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

17 A. Schedule J, Page 4 of 6 shows the development of the firm balancing
18 service rate for this specific transportation customer class. The Delaware
19 Division developed an average cost from the fixed rate of \$296.0192 per Dt
20 based on the Large Volume Service load factor of 31.74%. This load factor
21 resulted in an average cost of \$2.5519 per Dt. Since the Company's
22 analysis determined that the DCQ method would provide approximately
23 59.65% of the peak day requirements, the Company would need to supply

1 the remaining 40.35% with its gas supply resources. In other words, these
2 firm customers would pay for 40.35% of peak day requirements through the
3 balancing service rate. The resulting rate for the fixed capacity based on
4 this 40.35% would be approximately \$1.0296 per Dt applicable to all
5 consumption. The variable commodity rate of \$0.0127 per Dt was multiplied
6 by the estimated imbalance volume percentage of 22.24% to derive the
7 variable rate of \$0.0028 per Dt. The fixed capacity rate was added to the
8 variable commodity rate to develop a balancing rate per Dt of \$1.0324,
9 which was then converted to a per Mcf rate of \$1.0685, or \$0.107 per Ccf
10 for transportation customers served under Rate Schedule LVS, as shown
11 on Schedule J, page 4 of 6.

12

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

15 A. Schedule J, Page 5 of 6 shows the development of the firm balancing
16 service rate for this specific transportation customer class. The Delaware
17 Division developed an average cost from the fixed rate of \$296.0192 per Dt
18 based on the High Load Factor Service load factor of 83.48%. This load
19 factor resulted in an average cost of \$0.9706 per Dt. Since the Company's
20 analysis determined that the DCQ method would provide approximately
21 89.82% of the peak day requirements, the Company would need to supply
22 the remaining 10.18% with its gas supply resources. In other words, these
23 firm customers would pay for 10.18% of peak day requirements through the

1 balancing service rate. The resulting rate for the fixed capacity based on
2 this 10.18% would be approximately \$0.0988 per Dt applicable to all
3 consumption. The variable commodity rate of \$0.0127 per Dt was multiplied
4 by the estimated imbalance volume percentage of 2.17% to derive the
5 variable rate of \$0.0003 per Dt. The fixed capacity rate was added to the
6 variable commodity rate to develop a balancing rate per Dt of \$0.0991,
7 which was then converted to a per Mcf rate of \$0.1026, or \$0.010 per Ccf
8 for transportation customers served under Rate Schedule HLFS, as shown
9 on Schedule J, page 5 of 6.

10

11 Q. WHAT ABOUT THE BALANCING RATE FOR INTERRUPTIBLE
12 CUSTOMERS?

13 A. Schedule J, Page 6 of 6 shows the development of the balancing service
14 rate for this specific transportation customer class. The Delaware Division
15 developed an average cost from the fixed rate of \$296.0192 per Dt based
16 on the Interruptible Transportation Service load factor of 100%. This load
17 factor resulted in an average cost of \$0.8110 per Dt. The rate for the fixed
18 capacity based on average cost at 1.00% would be approximately \$0.0081
19 per Dt applicable to all consumption. The variable commodity rate of
20 \$0.0127 per Dt was multiplied by the estimated imbalance volume
21 percentage of 9.06% to derive the variable rate of \$0.0012 per Dt. The fixed
22 capacity rate was added to the variable commodity rate to develop a
23 balancing rate per Dt of \$0.0093, which was then converted to a per Mcf

1 rate of \$0.0096. The total balancing rate of \$0.0096 per Mcf, or \$0.001 per
2 Ccf for transportation customers served under Rate Schedule ITS, as
3 shown on Schedule J, page 6 of 6.

4

5 Q. DOES THIS CONCLUDE YOUR TESTIMONY?

6 A. Yes, it does.

DATED: August 31, 2018

STATE OF DELAWARE)
)
COUNTY OF KENT)

AFFIDAVIT OF MARIE E. KOZEL

MARIE E. KOZEL, 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 Marie E. Kozel"; 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.


Marie E. Kozel

Then personally appeared this 31st day of August 2018 the above-named Marie E. Kozel and acknowledged the foregoing Testimony to be his free act and deed. Before me,


Notary Public
My Commission Expires: 8/15/19

LYNN H. LLOYD
NOTARY PUBLIC
STATE OF DELAWARE
My Commission Expires August 15, 2019

Chesapeake Utilities Corporation
Delaware Division
Development of Gas Sales Service Rates Effective November 1, 2018

Based on Total Firm Gas Costs Recoverable through GSR effective November 1, 2018

Description	Allocator	Total System Costs	Volume (Ccf)	Cost / Ccf
Fixed Gas Costs	Peak Day Capacity Entitlements	\$27,739,448	811,130	\$34.20
Variable Gas Costs	Annual Volume	\$12,140,926	45,362,965	\$0.268
Total Firm Gas Costs	Annual Volume	\$39,880,374	45,362,965	\$0.879

Development of High Load Factor Service Rates per CCF (83.48% Load Factor)

Description	Peak Day Cap. Method	System Average Cost	HLFS Average Rate
Demand Rate (\$34.20 / 305)	\$0.112		
Commodity Rate	\$0.268		
Total Gas Sales Service Rate	\$0.380	\$0.879	\$0.630
Total High Load Factor Dollars			
	Projected Sales	Rate	Total Cost
	3,487,155	\$0.630	\$2,196,908

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

Description	Peak Day Cap. Method		
Demand Rate (\$34.20 / 365)	\$0.094		
Commodity Rate	\$0.268		
Total Gas Sales Service Rate	\$0.362		
Total Gas Lighting Dollars			
	Projected Sales	Rate	Total Cost
	350	\$0.362	\$127

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	\$39,880,374	45,362,965			
Less : Allocated to HLFS	\$2,196,908	3,487,155			
Less : Allocated to GL	\$127	350			
Total Remaining System	\$37,683,339	41,875,460	\$0.900	(\$0.067)	\$0.833

**Chesapeake Utilities Corporation
Delaware Division
Development of Gas Sales Service Rates Effective November 1, 2018**

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	2018 November Projected	2018 December Projected	2019 January Projected	2019 February Projected	2019 March Projected	2019 April Projected	2019 May Projected	2019 June Projected	2019 July Projected	2019 August Projected	2019 September Projected	2019 October Projected	Total
Interruptible Transportation	\$14,099	\$14,645	\$12,024	\$10,683	\$12,296	\$11,692	\$12,729	\$21,604	\$23,772	\$26,280	\$17,222	\$21,431	\$198,476
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	\$264,099	\$264,645	\$262,024	\$260,683	\$262,296	\$261,692	\$262,729	\$271,604	\$273,772	\$276,280	\$267,222	\$271,431	\$3,198,476

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	\$198,476	0%	\$0
Interruptible Transportation over \$675,000	\$0	90%	\$0
Capacity Valuation	\$3,000,000	92.5%	\$2,775,000
Total	\$3,198,476		\$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-18	297,938	(4)	(22,908)	275,027
Dec-18	542,309	(4)	(28,052)	514,253
Jan-19	900,268	(4)	(37,064)	863,200
Feb-19	845,561	(2)	(34,420)	811,139
Mar-19	670,474	(3)	(32,755)	637,715
Apr-19	444,694	(3)	(29,943)	414,748
May-19	217,793	(3)	(26,317)	191,473
Jun-19	129,053	0	(28,624)	100,429
Jul-19	96,176	0	(24,612)	71,564
Aug-19	91,894	(4)	(23,967)	67,923
Sep-19	112,815	(4)	(26,176)	86,636
Oct-19	187,322	(4)	(33,878)	153,439
Total	4,536,296	(35)	(348,715)	4,187,546

Customer Sharing (\$)	Prior Period Under Refund (Nov 17 - Oct 18)	Refund through Nov. 1, 2018 GSR	RS,GS,MVS, & LVS Sales In Mcf	Margin Sharing Rate Per Mcf	Margin Sharing Rate Per Ccf
(\$2,775,000)	(\$45,763)	(\$2,820,763)	4,187,546	(\$0.674)	(\$0.067)

Chesapeake Utilities Corporation
 Delaware Division
 Current Firm Gas Costs
 Effective November 1, 2018

				November 1, 2017			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
<u>Demand Rate:</u>		81,113			88,037			(6,924)	
Columbia FT Reservation	\$826,866		\$10.194	\$853,433		\$9.69	(\$26,567)		\$0.50
Transco FT Reservation	\$3,935,032		\$48.513	\$3,939,697		\$44.75	(\$4,665)		\$3.76
Texas Eastern FT Reservation	\$6,294,765		\$77.605	\$6,294,765		\$71.50	\$0		\$6.10
Storage Demand & Capacity & Peaking	\$1,035,317		\$12.764	\$2,068,757		\$23.50	(\$1,033,440)		(\$10.73)
ESNG FT Reservation	\$18,043,003		\$222.443	\$19,703,213		\$223.81	(\$1,660,210)		(\$1.36)
ESNG 2017 Expansion FT Reservation	\$4,987,522		\$61.489	\$3,037,339		\$34.50	\$1,950,183		\$26.99
ESNG Capacity Release for Transp.	(\$5,522,029)		(\$68.078)	(\$5,042,314)		(\$57.27)	(\$479,715)		(\$10.80)
Balancing Rate Credit	(\$1,861,027)		(\$22.944)	(\$1,345,742)		(\$15.29)	(\$515,285)		(\$7.66)
GSR Settlement Adjustment	\$0		\$0.000	\$0		\$0.00	\$0		\$0.00
Upstream Capacity Release	\$0		\$0.000	(\$285,766)		(\$3.25)	\$285,766		\$3.25
Total Firm Fixed Gas Costs	\$27,739,448		\$341.99	\$29,223,381		\$331.94	(\$1,483,933)		\$10.04
Peak Day Capacity (Mcf)	81,113			88,037			(6,924)		
Annual Fixed Cost per Mcf	\$341.99			\$331.94			\$10.05		
Annual Fixed Cost per Ccf	\$34.20			\$33.19			\$1.01		
Monthly Fixed Cost per Mcf	\$28.50			\$27.66			\$0.84		
Monthly Fixed Cost per Ccf	\$2.850			\$2.766			\$0.084		
<u>Commodity Rate:</u>		4,536,296			4,147,499			388,797	
Flowing Commodity	\$11,200,896		\$2.469	\$10,800,033		\$2.60	\$400,863		(\$0.13)
Storage I/W & Commodity	\$1,690,661		\$0.373	\$1,527,188		\$0.37	\$163,473		\$0.00
ESNG FT Commodity	\$147,810		\$0.033	\$66,565		\$0.02	\$81,245		\$0.02
CNG for Vehicular Use	(\$1,153)		(\$0.000)	(\$1,103)		(\$0.00)	(\$50)		\$0.00
(Over)/Under Collection	(\$937,299)		(\$0.198)	\$3,232,359		\$0.78	(\$4,129,648)		(\$0.98)
Total Firm Variable Gas Costs	\$12,140,926		\$2.68	\$15,625,043		\$3.77	(\$3,484,117)		(\$1.09)
Total Firm Sales Volumes (Mcf)	4,536,296			4,147,499			388,797		
Total Firm Sales Volumes (Ccf)	45,362,965			41,474,993			3,887,972		
Commodity Rate per Mcf	\$2.68			\$3.77			(\$1.09)		
Commodity Rate per Ccf	\$0.268			\$0.377			(\$0.11)		
<u>System Average Rate:</u>									
Total Firm Fixed Gas Costs	\$27,739,448			\$29,223,381			(\$1,483,933)		
Total Firm Variable Gas Costs	\$12,140,926			\$15,625,043			(\$3,484,117)		
Total Firm Gas Costs	\$39,880,374	4,536,296	\$8.79	\$44,848,424	4,147,499	\$10.81	(\$4,968,050)		(\$2.02)

Chesapeake Utilities Corporation
Projected Sales and Requirements Summary
November 1, 2018 - October 31, 2019

	Projected Nov-18	Projected Dec-18	Projected Jan-19	Projected Feb-19	Projected Mar-19	Projected Apr-19	Projected May-19	Projected Jun-19	Projected Jul-19	Projected Aug-19	Projected Sep-19	Projected Oct-19	Total
Mcf Sales													
Firm													
Residential Service - 1	4,507	12,817	23,022	20,957	15,471	9,811	4,184	2,305	1,747	1,574	1,821	3,283	101,500
Residential Service - 2	212,185	393,308	647,049	619,634	487,471	323,635	148,528	75,571	53,631	49,541	59,714	111,855	3,182,123
General Service	16,892	33,493	75,512	70,594	50,952	33,608	13,804	6,822	4,856	4,532	5,779	10,958	327,801
Medium Volume Service	20,107	38,426	68,773	61,046	51,190	30,191	15,130	7,773	5,860	5,788	7,523	13,224	325,032
Large Volume Service	21,336	36,209	48,843	38,908	32,632	17,502	9,827	7,959	5,470	6,487	11,799	14,119	251,090
High Load Factor Service	22,908	28,052	37,064	34,420	32,755	29,943	26,317	28,624	24,612	23,967	26,176	33,878	348,715
Gas Lighting	4	4	4	2	3	3	3	0	0	4	4	4	35
Total Firm Mcf Sales	297,938	542,309	900,268	845,561	670,474	444,694	217,793	129,053	96,176	91,894	112,815	187,322	4,536,296
Natural Gas Vehicles	8	5	10	9	9	6	8	8	17	4	8	4	96
Total Mcf Sales	297,946	542,314	900,278	845,570	670,483	444,700	217,801	129,061	96,193	91,898	112,823	187,326	4,536,392
Mcf Requirements													
Mcf Sales	297,946	542,314	900,278	845,570	670,483	444,700	217,801	129,061	96,193	91,898	112,823	187,326	4,536,392
Adjusted Mcf Sales	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Mcf Sales	297,946	542,314	900,278	845,570	670,483	444,700	217,801	129,061	96,193	91,898	112,823	187,326	4,536,392
Cycle Billing Adjustment	74,339	81,861	88,267	(86,344)	(50,914)	(118,124)	(60,259)	(23,933)	(1,207)	0	21,299	75,015	0
Subtotal	372,285	624,175	988,545	759,226	619,569	326,576	157,542	105,128	94,986	91,898	134,122	262,341	4,536,392
Company Use	137	232	408	269	275	123	64	44	25	39	46	43	1,708
Unaccounted For	2,970	4,339	6,212	2,514	2,288	(136)	(119)	163	466	454	992	2,485	22,627
Pressure Compensation	4,450	8,100	13,446	12,629	10,014	6,642	3,253	1,928	1,437	1,373	1,685	2,798	67,753
Total Mcf Requirements	379,842	636,846	1,008,612	774,638	632,146	333,205	160,740	107,262	96,914	93,764	136,845	267,667	4,628,479
Dt Requirements													
Total Dt Requirements	393,138	659,136	1,043,914	801,751	654,271	344,868	166,366	111,017	100,306	97,045	141,635	277,035	4,790,482
Eastern Shore Fuel (0.0)	0	0	0	0	0	0	0	0	0	0	0	0	0
Requirements Upstream of ESNG (Dt)	393,138	659,136	1,043,914	801,751	654,271	344,868	166,366	111,017	100,306	97,045	141,635	277,035	4,790,482

Chesapeake Utilities Corporation
Delaware Division

Schedule C.2

	Projected November-18 30	Projected December-18 31	Projected January-19 31	Projected February-19 28	Projected March-19 31	Projected April-19 30	Projected May-19 31	Projected June-19 30	Projected July-19 31	Projected August-19 31	Projected September-19 30	Projected October-19 31	Total	365
FIXED COSTS														
Columbia Gas Transmission FT														
FTS Firm Transportation Service														
Reservation Rates	\$6,2870	\$6,2870	\$6,2870	\$6,2870	\$6,2870	\$6,2870	\$6,2870	\$6,2870	\$6,2870	\$6,2870	\$6,2870	\$6,2870	\$6,2870	
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	10,960	
Reservation Costs	\$68,905.52	\$68,905.52	\$68,905.52	\$68,905.52	\$68,905.52	\$68,905.52	\$68,905.52	\$68,905.52	\$68,905.52	\$68,905.52	\$68,905.52	\$68,905.52	\$68,905.52	\$826,866.24
Columbia Reservation Costs	\$68,905.52	\$68,905.52	\$68,905.52	\$68,905.52	\$68,905.52	\$68,905.52	\$68,905.52	\$68,905.52	\$68,905.52	\$68,905.52	\$68,905.52	\$68,905.52	\$68,905.52	\$826,866.24
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	\$0.50064	
Electric Power Rate	\$0.00305	\$0.00305	\$0.00305	\$0.00305	\$0.00305	\$0.00305	\$0.00305	\$0.00305	\$0.00305	\$0.00305	\$0.00305	\$0.00305	\$0.00305	
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	\$0.48538	
Electric Power Rate	\$0.00295	\$0.00295	\$0.00295	\$0.00295	\$0.00295	\$0.00295	\$0.00295	\$0.00295	\$0.00295	\$0.00295	\$0.00295	\$0.00295	\$0.00295	
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	\$0.45641	
Electric Power Rate	\$0.00273	\$0.00273	\$0.00273	\$0.00273	\$0.00273	\$0.00273	\$0.00273	\$0.00273	\$0.00273	\$0.00273	\$0.00273	\$0.00273	\$0.00273	
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	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	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	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	11,112	
Reservation Costs:														
Transco Zone 1 (Sta 30)														
	\$28,544.10	\$29,495.57	\$29,495.57	\$26,641.16	\$29,495.57	\$28,544.10	\$29,495.57	\$28,544.10	\$29,495.57	\$29,495.57	\$28,544.10	\$29,495.57	\$29,495.57	\$347,286.55
Transco Zone 2 (Sta 45)														
	\$40,697.70	\$42,054.29	\$42,054.29	\$37,984.52	\$42,054.29	\$40,697.70	\$42,054.29	\$40,697.70	\$42,054.29	\$42,054.29	\$40,697.70	\$42,054.29	\$42,054.29	\$495,155.35
Transco Zone 3 (Sta 50 and 62)														
	\$88,774.50	\$91,733.65	\$91,733.65	\$82,856.20	\$91,733.65	\$88,774.50	\$91,733.65	\$88,774.50	\$91,733.65	\$91,733.65	\$88,774.50	\$91,733.65	\$91,733.65	\$1,080,089.75
Transco	\$158,016.30	\$163,283.51	\$163,283.51	\$147,481.88	\$163,283.51	\$158,016.30	\$163,283.51	\$158,016.30	\$163,283.51	\$163,283.51	\$158,016.30	\$163,283.51	\$163,283.51	\$1,922,531.65
Transco Zone 5 (Cove Point)														
Reservation Rates	\$0.55137	\$0.55137	\$0.55137	\$0.55137	\$0.55137	\$0.55137	\$0.55137	\$0.55137	\$0.55137	\$0.55137	\$0.55137	\$0.55137	\$0.55137	
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	10,000	
Reservation Costs	\$165,411.00	\$170,924.70	\$170,924.70	\$154,383.60	\$170,924.70	\$165,411.00	\$170,924.70	\$165,411.00	\$170,924.70	\$170,924.70	\$165,411.00	\$170,924.70	\$170,924.70	\$2,012,500.50
Transco Reservation Costs	\$323,427.30	\$334,208.21	\$334,208.21	\$301,865.48	\$334,208.21	\$323,427.30	\$334,208.21	\$323,427.30	\$334,208.21	\$334,208.21	\$323,427.30	\$334,208.21	\$334,208.21	\$3,935,032.15
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	\$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	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	\$524,563.71	\$6,294,764.52

**Chesapeake Utilities Corporation
Delaware Division**

Schedule C.2

		Projected November-18	Projected December-18	Projected January-19	Projected February-19	Projected March-19	Projected April-19	Projected May-19	Projected June-19	Projected July-19	Projected August-19	Projected September-19	Projected October-19	Total
Eastern Shore Natural Gas														
FT	Firm Transportation - Receipt Zone 1													
	Reservation Rates:													
	Reservation - FT	\$1,587.8	\$1,587.8	\$1,587.8	\$1,587.8	\$1,587.8	\$1,587.8	\$1,587.8	\$1,587.8	\$1,587.8	\$1,587.8	\$1,587.8	\$1,587.8	
	Billing Units (MDTQ):													
	Reservation - FT	35,150	35,150	35,150	35,150	35,150	35,150	35,150	35,150	35,150	35,150	35,150	35,150	
	Reservation Costs:													
	Reservation - FT	\$55,811.17	\$55,811.17	\$55,811.17	\$55,811.17	\$55,811.17	\$55,811.17	\$55,811.17	\$55,811.17	\$55,811.17	\$55,811.17	\$55,811.17	\$55,811.17	\$669,734.04
	Reservation Costs - Receipt Zone 1	\$55,811.17	\$55,811.17	\$55,811.17	\$55,811.17	\$55,811.17	\$55,811.17	\$55,811.17	\$55,811.17	\$55,811.17	\$55,811.17	\$55,811.17	\$55,811.17	\$669,734.04
FT/ST	Firm Transportation - Receipt Zone 2													
	Reservation Rates:													
	Reservation - FT	\$4,629.4	\$4,629.4	\$4,629.4	\$4,629.4	\$4,629.4	\$4,629.4	\$4,629.4	\$4,629.4	\$4,629.4	\$4,629.4	\$4,629.4	\$4,629.4	
	Billing Units (MDTQ):													
	Reservation - FT	65,726	66,948	66,948	66,948	65,726	65,726	59,885	59,885	59,885	59,885	59,885	59,885	
	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	
	Reservation - ST	69,707	70,929	70,929	70,929	69,707	69,707	60,631	60,631	60,631	60,631	60,631	60,631	
	Reservation Costs:													
	Reservation - FT	\$304,271.94	\$309,929.07	\$309,929.07	\$309,929.07	\$304,271.94	\$304,271.94	\$277,231.62	\$277,231.62	\$277,231.62	\$277,231.62	\$277,231.62	\$277,231.62	\$3,505,992.75
	Reservation - ST	\$23,521.98	\$23,521.98	\$23,521.98	\$23,521.98	\$23,521.98	\$23,521.98	\$8,545.87	\$8,545.87	\$8,545.87	\$8,545.87	\$8,545.87	\$8,545.87	\$192,407.10
	Reservation Costs - Receipt Zone 2	\$327,793.92	\$333,451.05	\$333,451.05	\$333,451.05	\$327,793.92	\$327,793.92	\$285,777.49	\$285,777.49	\$285,777.49	\$285,777.49	\$285,777.49	\$285,777.49	\$3,698,399.85
FT	Firm Transportation - Delivery Zone 1													
	Reservation Rates:													
	Reservation - FT	\$6,640.0	\$6,640.0	\$6,640.0	\$6,640.0	\$6,640.0	\$6,640.0	\$6,640.0	\$6,640.0	\$6,640.0	\$6,640.0	\$6,640.0	\$6,640.0	
	Billing Units (MDTQ):													
	Reservation - FT	16,339	16,437	16,437	16,437	16,339	16,339	15,879	15,879	15,879	15,879	15,879	15,879	
	Reservation - ST	400	400	400	400	400	400	145	145	145	145	145	145	
	Reservation Costs:													
	Reservation - FT	\$108,490.96	\$109,141.68	\$109,141.68	\$109,141.68	\$108,490.96	\$108,490.96	\$105,436.56	\$105,436.56	\$105,436.56	\$105,436.56	\$105,436.56	\$105,436.56	\$1,285,517.28
	Reservation - ST	\$2,656.00	\$2,656.00	\$2,656.00	\$2,656.00	\$2,656.00	\$2,656.00	\$962.80	\$962.80	\$962.80	\$962.80	\$962.80	\$962.80	\$21,712.80
	Reservation Costs - Delivery Zone 1	\$111,146.96	\$111,797.68	\$111,797.68	\$111,797.68	\$111,146.96	\$111,146.96	\$106,399.36	\$106,399.36	\$106,399.36	\$106,399.36	\$106,399.36	\$106,399.36	\$1,307,230.08
FT	Firm Transportation - Delivery Zone 2													
	Reservation Rates:													
	Reservation - FT	\$20,543.5	\$20,543.5	\$20,543.5	\$20,543.5	\$20,543.5	\$20,543.5	\$20,543.5	\$20,543.5	\$20,543.5	\$20,543.5	\$20,543.5	\$20,543.5	
	Billing Units (MDTQ):													
	Reservation - FT	49,367	50,511	50,511	50,511	49,367	49,367	44,006	44,006	44,006	44,006	44,006	44,006	
	Reservation - ST	4,681	4,681	4,681	4,681	4,681	4,681	1,701	1,701	1,701	1,701	1,701	1,701	
	Reservation Costs:													
	Reservation - FT	\$1,014,581.83	\$1,037,672.73	\$1,037,672.73	\$1,037,672.73	\$1,014,581.83	\$1,014,581.83	\$904,037.26	\$904,037.26	\$904,037.26	\$904,037.26	\$904,037.26	\$904,037.26	\$11,580,987.24
	Reservation - ST	\$96,164.12	\$96,164.12	\$96,164.12	\$96,164.12	\$96,164.12	\$96,164.12	\$34,944.49	\$34,944.49	\$34,944.49	\$34,944.49	\$34,944.49	\$34,944.49	\$786,651.66
	Reservation Costs - Delivery Zone 2	\$1,110,745.95	\$1,133,836.85	\$1,133,836.85	\$1,133,836.85	\$1,110,745.95	\$1,110,745.95	\$938,981.75	\$938,981.75	\$938,981.75	\$938,981.75	\$938,981.75	\$938,981.75	\$12,367,638.90
2017	2017 Expansion													
	Reservation Rates:													
	Reservation - FT	\$26,044.5	\$26,044.5	\$26,044.5	\$26,044.5	\$26,044.5	\$26,044.5	\$26,044.5	\$26,044.5	\$26,044.5	\$26,044.5	\$26,044.5	\$26,044.5	
	Billing Units (MDTQ):													
	Reservation - FT	10,000	16,500	16,500	16,500	16,500	16,500	16,500	16,500	16,500	16,500	16,500	16,500	
	Reservation Costs:													
	Reservation - FT	\$260,445.00	\$429,734.25	\$429,734.25	\$429,734.25	\$429,734.25	\$429,734.25	\$429,734.25	\$429,734.25	\$429,734.25	\$429,734.25	\$429,734.25	\$429,734.25	\$4,987,521.75
	Reservation Costs - 2017 Expansion	\$260,445.00	\$429,734.25	\$429,734.25	\$429,734.25	\$429,734.25	\$429,734.25	\$429,734.25	\$429,734.25	\$429,734.25	\$429,734.25	\$429,734.25	\$429,734.25	\$4,987,521.75
Eastern Shore Reservation Costs		\$1,865,943.00	\$2,064,631.00	\$2,064,631.00	\$2,064,631.00	\$2,035,232.25	\$2,035,232.25	\$1,816,704.02	\$1,816,704.02	\$1,816,704.02	\$1,816,704.02	\$1,816,704.02	\$1,816,704.02	\$23,030,524.62
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		\$ (462,865.63)	\$ (470,769.24)	\$ (467,802.20)	\$ (455,254.37)	\$ (456,609.79)	\$ (456,219.68)	\$ (447,139.28)	\$ (447,887.36)	\$ (449,171.81)	\$ (454,189.51)	\$ (472,724.39)	\$ (481,596.16)	\$ (5,522,029.42)
Storage Demand & Capacity														
Reservation Costs:														
Columbia:														
	FSS Firm Storage Service	\$152,974.61	\$152,974.61	\$152,974.60	\$152,974.61	\$152,974.60								\$764,873.03
Transco:														
	GSS General Storage Service	\$24,596.41	\$24,596.41	\$24,596.41	\$24,596.42	\$24,596.41								\$122,982.06
	LSS Leidy Storage Service	\$7,540.06	\$7,540.06	\$7,540.06	\$7,540.05	\$7,540.06								\$37,700.29
	WSS Washington Storage Service	\$5,620.31	\$5,620.31	\$5,620.30	\$5,620.31	\$5,620.30								\$28,101.53
	ESS Eminence Storage Service	\$11,637.65	\$11,637.66	\$11,637.65	\$11,637.66	\$11,637.65								\$58,188.27
	PS Peaking Service	\$4,694.37	\$4,694.37	\$4,694.37	\$4,694.37	\$4,694.36								\$23,471.84
	Total Transco	\$54,088.80	\$54,088.81	\$54,088.79	\$54,088.81	\$54,088.78								\$270,443.99
Total Storage Demand & Capacity Costs		\$207,063.41	\$207,063.42	\$207,063.39	\$207,063.42	\$207,063.38								\$1,035,317.02
LNG Peaking Facility		\$0.00	\$0.00	\$0.00	\$0.00	\$0.00								\$0.00
TOTAL FIXED COSTS		\$2,527,037.31	\$2,728,602.62	\$2,731,769.63	\$2,711,774.76	\$2,713,363.28	\$2,495,909.10	\$2,297,242.18	\$2,285,713.20	\$2,295,209.65	\$2,290,191.95	\$2,260,876.16	\$2,262,785.30	\$29,600,475.13

**Chesapeake Utilities Corporation
Delaware Division**

Schedule C.2

COMMODITY COSTS

Columbia Gas Transmission FT

Swing Purchases - TCO (FTS)

	Projected November-18	Projected December-18	Projected January-19	Projected February-19	Projected March-19	Projected April-19	Projected May-19	Projected June-19	Projected July-19	Projected August-19	Projected September-19	Projected October-19	Total
Commodity Rate	\$2,8224	\$2,9155	\$3,0003	\$2,9754	\$2,8192	\$2,4915	\$2,4089	\$2,4158	\$2,3783	\$2,3510	\$2,3152	\$2,3423	
Commodity in DT	25,751	35,802	58,216	43,729	40,074	24,348	11,745	7,838	7,082	6,851	9,997	19,558	290,990
Commodity Cost	\$72,679.07	\$104,379.72	\$174,664.44	\$130,112.47	\$112,976.65	\$60,662.25	\$28,293.25	\$18,934.73	\$16,842.18	\$16,106.76	\$23,145.29	\$45,811.45	\$804,608.26

Columbia - TCO 1278

Commodity Rate	\$3,0400	\$3,1367	\$3,2259	\$3,1908	\$3,0869	\$2,7754	\$2,7406	\$2,7700	\$2,8024	\$2,8077	\$2,7897	\$2,8066	
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	25,751	35,802	58,216	43,729	40,074	24,348	11,745	7,838	7,082	6,851	9,997	19,558	290,990
Total FTS Commodity Costs	\$72,679.07	\$104,379.72	\$174,664.44	\$130,112.47	\$112,976.65	\$60,662.25	\$28,293.25	\$18,934.73	\$16,842.18	\$16,106.76	\$23,145.29	\$45,811.45	\$804,608.26

TCO Pool through SST to ESNG

Commodity Rate	\$3,0400	\$3,1367	\$3,2259	\$3,1908	\$3,0869	\$2,7754	\$2,7406	\$2,7700	\$2,8024	\$2,8077	\$2,7897	\$2,8066	
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	\$2,8224	\$2,9155	\$3,0003	\$2,9754	\$2,8192	\$2,4915	\$2,4089	\$2,4158	\$2,3783	\$2,3510	\$2,3152	\$2,3423	
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 Volume	25,751	35,802	58,216	43,729	40,074	24,348	11,745	7,838	7,082	6,851	9,997	19,558	290,990
Commodity Costs	\$72,679.07	\$104,379.72	\$174,664.44	\$130,112.47	\$112,976.65	\$60,662.25	\$28,293.25	\$18,934.73	\$16,842.18	\$16,106.76	\$23,145.29	\$45,811.45	\$804,608.26

Transco FT

FT Zone 1 to Zone 6 - (Sta 30)

Commodity Rate	\$3,0897	\$3,1796	\$3,2483	\$3,1995	\$3,1060	\$2,8328	\$2,8039	\$2,8462	\$2,8701	\$2,8811	\$2,8575	\$2,8748	
Commodity in DT	14,444	20,081	32,454	24,528	22,478	13,697	6,586	4,396	3,872	3,843	3,807	10,979	163,218
Commodity Cost	\$44,626.99	\$63,830.67	\$106,068.50	\$78,477.68	\$69,815.97	\$38,686.91	\$18,472.13	\$12,512.79	\$11,400.37	\$11,071.44	\$16,023.26	\$31,537.67	\$502,524.38

FT Zone 2 to Zone 6 - (Sta 45)

Commodity Rate	\$3,0654	\$3,1631	\$3,2496	\$3,2099	\$3,1101	\$2,8130	\$2,7829	\$2,8237	\$2,8554	\$2,8664	\$2,8440	\$2,8601	
Commodity in DT	21,264	29,264	48,075	36,111	33,092	20,106	9,689	6,472	5,848	5,857	8,255	16,151	240,294
Commodity Cost	\$65,184.12	\$93,514.69	\$156,218.90	\$115,912.14	\$102,920.29	\$56,557.63	\$26,991.41	\$18,275.97	\$16,692.92	\$16,216.46	\$23,478.35	\$46,193.04	\$738,160.92

FT Zone 3 to Zone 6 - (Sta 65)

Commodity Rate	\$3,0350	\$3,1415	\$3,2432	\$3,2139	\$3,1080	\$2,7874	\$2,7562	\$2,7955	\$2,8348	\$2,8458	\$2,8248	\$2,8395	
Commodity in DT	49,350	68,611	111,586	83,804	76,739	46,661	22,509	15,021	13,571	13,130	19,159	37,462	557,663
Commodity Cost	\$149,776.12	\$215,542.65	\$361,831.72	\$269,338.85	\$238,691.48	\$130,061.87	\$62,039.44	\$41,990.47	\$38,472.21	\$37,363.97	\$54,119.64	\$106,430.59	\$1,705,659.01

Total FT Commodity Volume	85,058	118,257	192,293	144,443	132,369	80,423	38,796	25,889	23,391	22,630	33,022	64,603	961,175
Total FT Commodity Costs	\$259,587.23	\$372,888.01	\$624,119.12	\$463,728.67	\$411,427.74	\$225,306.41	\$107,502.98	\$72,779.23	\$66,570.50	\$64,651.87	\$93,621.25	\$184,161.30	\$2,946,344.31

FT Zone 5 to Zone 6 - (Cove Point)

Commodity Rate	\$3,0396	\$3,1363	\$3,2254	\$3,1903	\$3,0864	\$2,7750	\$2,7403	\$2,7696	\$2,8020	\$2,8073	\$2,7893	\$2,8062	
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	\$2,9958	\$3,0911	\$3,1790	\$3,1444	\$3,0420	\$2,7350	\$2,7008	\$2,7297	\$2,7617	\$2,7669	\$2,7491	\$2,7658	
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	\$3,0519	\$3,1532	\$3,2457	\$3,2105	\$3,1082	\$2,8015	\$2,7710	\$2,8112	\$2,8459	\$2,8569	\$2,8352	\$2,8506	
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	85,058	118,257	192,293	144,443	132,369	80,423	38,796	25,889	23,391	22,630	33,022	64,603	961,175
Commodity Costs	\$259,587.23	\$372,888.01	\$624,119.12	\$463,728.67	\$411,427.74	\$225,306.41	\$107,502.98	\$72,779.23	\$66,570.50	\$64,651.87	\$93,621.25	\$184,161.30	\$2,946,344.31

TETCO FT

Commodity Rate	\$2,6148	\$2,7380	\$2,8427	\$2,8104	\$2,7179	\$2,3155	\$2,1826	\$2,2147	\$2,2001	\$2,1957	\$2,0993	\$2,1389	
Commodity in DT	253,937	353,048	574,063	431,220	395,175	240,097	115,825	77,290	69,833	67,564	98,616	192,873	2,869,541
Commodity Cost	\$663,993.30	\$966,645.11	\$1,631,887.92	\$1,211,900.54	\$1,074,047.29	\$555,944.84	\$252,798.81	\$171,173.57	\$153,639.67	\$148,350.82	\$207,025.22	\$412,536.67	\$7,449,943.76

TETCO FT

Commodity Volume	253,937	353,048	574,063	431,220	395,175	240,097	115,825	77,290	69,833	67,564	98,616	192,873	2,869,540.81
Commodity Costs	\$663,993.30	\$966,645.11	\$1,631,887.92	\$1,211,900.54	\$1,074,047.29	\$555,944.84	\$252,798.81	\$171,173.57	\$153,639.67	\$148,350.82	\$207,025.22	\$412,536.67	\$7,449,943.76

**Chesapeake Utilities Corporation
Delaware Division**

Schedule C.2

	Projected November-18	Projected December-18	Projected January-19	Projected February-19	Projected March-19	Projected April-19	Projected May-19	Projected June-19	Projected July-19	Projected August-19	Projected September-19	Projected October-19	Total
Eastern Shore Natural Gas													
Total Upstream Volume	393,138	659,136	1,043,914	801,751	654,271	344,868	166,366	111,017	100,306	97,045	141,635	277,035	4,790,482
Eastern Shore Fuel	0	0	0	0	0	0	0	0	0	0	0	0	0
Eastern Shore Volume	393,138	659,136	1,043,914	801,751	654,271	344,868	166,366	111,017	100,306	97,045	141,635	277,035	4,790,482
Delivery Zone 1													
Commodity Rate	\$0.0187	\$0.0187	\$0.0187	\$0.0187	\$0.0187	\$0.0187	\$0.0187	\$0.0187	\$0.0187	\$0.0187	\$0.0187	\$0.0187	\$0.0187
Commodity in DT	137,598	230,698	365,370	280,613	228,995	120,704	58,228	38,856	35,107	33,966	49,572	96,962	
Commodity Cost	\$2,573.09	\$4,314.05	\$6,832.42	\$5,247.46	\$4,282.20	\$2,257.16	\$1,088.87	\$726.61	\$656.50	\$635.16	\$927.00	\$1,813.19	\$31,353.71
Interruptible Commodity Rate	\$0.3911	\$0.3911	\$0.3911	\$0.3911	\$0.3911	\$0.3911	\$0.3911	\$0.3911	\$0.3911	\$0.3911	\$0.3911	\$0.3911	\$0.3911
Interruptible Commodity in DT	0	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	2,124,210	2,232,899	2,232,899	2,016,812	2,195,017	2,124,210	1,913,661	1,851,930	1,913,661	1,913,661	1,851,930	1,913,661	
Delivery Zone 2													
Commodity Rate	\$0.0374	\$0.0374	\$0.0374	\$0.0374	\$0.0374	\$0.0374	\$0.0374	\$0.0374	\$0.0374	\$0.0374	\$0.0374	\$0.0374	\$0.0374
Commodity in DT	255,540	428,438	678,544	521,138	425,276	224,164	108,138	72,161	65,199	63,079	92,063	180,073	
Commodity Cost	\$9,557.18	\$16,023.60	\$25,377.55	\$19,490.57	\$15,905.33	\$8,383.74	\$4,044.36	\$2,698.82	\$2,438.44	\$2,359.16	\$3,443.15	\$6,734.72	\$116,456.62
Interruptible Commodity Rate	\$0.9035	\$0.9035	\$0.9035	\$0.9035	\$0.9035	\$0.9035	\$0.9035	\$0.9035	\$0.9035	\$0.9035	\$0.9035	\$0.9035	\$0.9035
Interruptible Commodity in DT	0	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	\$12,130.27	\$20,337.65	\$32,209.97	\$24,738.03	\$20,187.53	\$10,640.90	\$5,133.23	\$3,425.43	\$3,094.94	\$2,994.32	\$4,370.15	\$8,547.91	\$147,810.33
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	\$12,130.27	\$20,337.65	\$32,209.97	\$24,738.03	\$20,187.53	\$10,640.90	\$5,133.23	\$3,425.43	\$3,094.94	\$2,994.32	\$4,370.15	\$8,547.91	\$147,810.33
TOTAL COMMODITY COSTS	\$1,080,735.12	\$1,849,001.11	\$3,018,188.75	\$2,291,059.64	\$1,836,317.20	\$852,554.40	\$393,728.27	\$266,312.96	\$240,147.29	\$232,103.77	\$328,161.91	\$651,057.33	\$13,039,367.75

**Chesapeake Utilities Corporation
Delaware Division**

Schedule C.2

Pipeline Summary

Columbia Gas Transmission

Columbia/Columbia Gulf FT Costs

	Projected November-18	Projected December-18	Projected January-19	Projected February-19	Projected March-19	Projected April-19	Projected May-19	Projected June-19	Projected July-19	Projected August-19	Projected September-19	Projected October-19	Total
Fixed Costs	\$68,905.52	\$68,905.52	\$68,905.52	\$68,905.52	\$68,905.52	\$68,905.52	\$68,905.52	\$68,905.52	\$68,905.52	\$68,905.52	\$68,905.52	\$68,905.52	\$826,866.24
Commodity Costs	\$72,679.07	\$104,379.72	\$174,864.44	\$130,112.47	\$112,976.65	\$60,662.25	\$28,293.25	\$18,934.73	\$16,842.18	\$16,106.76	\$23,145.29	\$45,811.45	\$804,608.26
Total Costs	\$141,584.59	\$173,285.24	\$243,569.96	\$199,017.99	\$181,882.17	\$129,567.77	\$97,198.77	\$87,840.25	\$85,747.70	\$85,012.28	\$92,050.81	\$114,716.97	\$1,631,474.50

Columbia/Columbia Gulf Storage Costs

Fixed Costs	\$152,974.61	\$152,974.61	\$152,974.60	\$152,974.61	\$152,974.60	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$764,873.03
Commodity Costs	\$53,784.78	\$215,139.16	\$322,708.73	\$268,923.94	\$107,569.58	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$968,126.19
Total Costs	\$206,759.39	\$368,113.77	\$475,683.33	\$421,898.55	\$260,544.18	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$1,732,999.22

Columbia/Columbia Gulf Total Costs

Fixed Costs	\$221,880.13	\$221,880.13	\$221,880.12	\$221,880.13	\$221,880.12	\$68,905.52	\$68,905.52	\$68,905.52	\$68,905.52	\$68,905.52	\$68,905.52	\$68,905.52	\$1,591,739.27
Commodity Costs	\$126,463.85	\$319,518.88	\$497,373.17	\$399,036.41	\$220,546.23	\$60,662.25	\$28,293.25	\$18,934.73	\$16,842.18	\$16,106.76	\$23,145.29	\$45,811.45	\$1,772,734.45
Total Costs	\$348,343.98	\$541,399.01	\$719,253.29	\$620,916.54	\$442,426.35	\$129,567.77	\$97,198.77	\$87,840.25	\$85,747.70	\$85,012.28	\$92,050.81	\$114,716.97	\$3,364,473.72

Columbia FT Volume

	25,751	35,802	58,216	43,729	40,074	24,348	11,745	7,838	7,082	6,851	9,997	19,558	290,990
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Columbia Storage Volume

	21,251	85,005	127,508	106,256	42,503	0	0	0	0	0	0	0	382,523
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Columbia Total Volume

	47,002	120,807	185,723	149,986	82,577	24,348	11,745	7,838	7,082	6,851	9,997	19,558	673,513
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Transco

Transco FT Costs

Fixed Costs	\$323,427.30	\$334,208.21	\$334,208.21	\$301,865.48	\$334,208.21	\$323,427.30	\$334,208.21	\$323,427.30	\$334,208.21	\$334,208.21	\$323,427.30	\$334,208.21	\$3,935,032.15
Commodity Costs	\$259,587.23	\$372,888.01	\$624,119.12	\$463,728.67	\$411,427.74	\$225,306.41	\$107,502.98	\$72,779.23	\$66,570.50	\$64,651.87	\$93,621.25	\$184,161.30	\$2,946,344.31
Total Costs	\$583,014.53	\$707,096.22	\$958,327.33	\$765,594.15	\$745,635.95	\$548,733.71	\$441,711.19	\$396,206.53	\$400,778.71	\$398,860.08	\$417,048.55	\$518,369.51	\$6,881,376.46

Transco Storage Costs

Fixed Costs	\$54,088.80	\$54,088.81	\$54,088.79	\$54,088.81	\$54,088.78	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$270,443.99
Commodity Costs	\$18,560.47	\$169,611.46	\$232,598.57	\$191,655.99	\$110,108.41	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$722,534.90
Total Costs	\$72,649.27	\$223,700.27	\$286,687.36	\$245,744.80	\$164,197.19	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$992,978.89

Transco Total Costs

Fixed Costs	\$377,516.10	\$388,297.02	\$388,297.00	\$355,954.29	\$388,296.99	\$323,427.30	\$334,208.21	\$323,427.30	\$334,208.21	\$334,208.21	\$323,427.30	\$334,208.21	\$4,205,476.14
Commodity Costs	\$278,147.70	\$542,499.47	\$856,717.69	\$655,384.66	\$521,536.15	\$225,306.41	\$107,502.98	\$72,779.23	\$66,570.50	\$64,651.87	\$93,621.25	\$184,161.30	\$3,688,879.21
Total Costs	\$655,663.80	\$930,796.49	\$1,245,014.69	\$1,011,338.95	\$909,833.14	\$548,733.71	\$441,711.19	\$396,206.53	\$400,778.71	\$398,860.08	\$417,048.55	\$518,369.51	\$7,894,355.35

Transco FT Volume

	85,058	118,257	192,293	144,443	132,369	80,423	38,796	25,889	23,391	22,630	33,022	64,603	961,175
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Transco Storage Volume

	7,142	67,024	91,835	76,102	44,150	0	0	0	0	0	0	0	286,253
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Transco Total Volume

	92,199	185,281	284,128	220,545	176,519	80,423	38,796	25,889	23,391	22,630	33,022	64,603	1,247,428
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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	\$663,993.30	\$966,645.11	\$1,631,887.92	\$1,211,900.54	\$1,074,047.29	\$555,944.84	\$252,798.81	\$171,173.57	\$153,639.67	\$148,350.82	\$207,025.22	\$412,536.67	\$7,449,943.76
Total Costs	\$1,188,557.01	\$1,491,208.82	\$2,156,451.63	\$1,736,464.25	\$1,598,611.00	\$1,080,508.55	\$777,362.52	\$695,737.28	\$678,203.38	\$672,914.53	\$731,588.93	\$937,100.38	\$13,744,708.28

Eastern Shore Natural Gas

ESNG FT

Fixed Costs	\$1,865,943.00	\$2,064,631.00	\$2,064,631.00	\$2,064,631.00	\$2,035,232.25	\$2,035,232.25	\$1,816,704.02	\$1,816,704.02	\$1,816,704.02	\$1,816,704.02	\$1,816,704.02	\$1,816,704.02	\$23,030,524.62
Commodity Costs	\$12,130.27	\$20,337.65	\$32,209.97	\$24,738.03	\$20,187.53	\$10,640.90	\$5,133.23	\$3,425.43	\$3,094.94	\$2,994.32	\$4,370.15	\$9,547.91	\$147,810.33
Total Costs	\$1,878,073.27	\$2,084,968.65	\$2,096,840.97	\$2,089,369.03	\$2,055,419.78	\$2,045,873.15	\$1,821,837.25	\$1,820,129.45	\$1,819,798.96	\$1,819,698.34	\$1,821,074.17	\$1,825,251.93	\$23,178,334.95

Total Commodity Volume

	364,745	507,107	824,571	619,393	567,619	344,868	166,366	111,017	100,306	97,045	141,635	277,035	4,121,706
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Total Storage Volume

	28,393	152,029	219,343	152,358	86,652	0	0	0	0	0	0	0	668,776
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Total Volume

	393,138	659,136	1,043,914	801,751	654,271	344,868	166,366	111,017	100,306	97,045	141,635	277,035	4,790,482
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Chesapeake Utilities Corporation
Delaware Division

Schedule C.2

	Projected November-18 1,035	Projected December-18 1,035	Projected January-19 1,035	Projected February-19 1,035	Projected March-19 1,035	Projected April-19 1,035	Projected May-19 1,035	Projected June-19 1,035	Projected July-19 1,035	Projected August-19 1,035	Projected September-19 1,035	Projected October-19 1,035	Total 1,035
Flowing Commodity WACOG													
Transco Station 30	\$44,626.99	\$63,830.67	\$106,068.50	\$78,477.68	\$69,815.97	\$38,686.91	\$18,472.13	\$12,512.79	\$11,400.37	\$11,071.44	\$16,023.26	\$31,537.67	\$502,524.38
Transco Station 45	\$65,184.12	\$93,514.69	\$156,218.90	\$115,912.14	\$102,920.29	\$56,557.63	\$26,991.41	\$18,275.97	\$16,697.92	\$16,216.46	\$23,478.35	\$46,193.04	\$738,160.92
Transco Station 65	\$149,776.12	\$215,542.65	\$361,831.72	\$269,338.85	\$238,691.48	\$130,061.87	\$62,039.44	\$41,990.47	\$38,472.21	\$37,363.97	\$54,119.64	\$106,430.59	\$1,705,659.01
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	\$72,679.07	\$104,379.72	\$174,664.44	\$130,112.47	\$112,976.65	\$60,662.25	\$28,293.25	\$18,934.73	\$16,842.18	\$16,106.76	\$23,145.29	\$45,811.45	\$804,608.26
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	\$663,993.30	\$966,645.11	\$1,631,887.92	\$1,211,900.54	\$1,074,047.29	\$555,944.84	\$252,798.81	\$171,173.57	\$153,639.67	\$148,350.82	\$207,025.22	\$412,536.67	\$7,449,943.76
ESNG Commodity	\$12,130.27	\$20,337.65	\$32,209.97	\$24,738.03	\$20,187.53	\$10,640.90	\$5,133.23	\$3,425.43	\$3,094.94	\$2,994.32	\$4,370.15	\$8,547.91	\$147,810.33
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
	\$1,008,389.87	\$1,464,250.49	\$2,462,881.45	\$1,830,479.71	\$1,618,639.21	\$852,554.40	\$393,728.27	\$266,312.96	\$240,147.29	\$232,103.77	\$328,161.91	\$651,057.33	\$11,348,706.66
Dt	364,745	507,107	824,571	619,393	597,819	344,868	186,366	111,017	100,306	97,045	141,635	277,035	4,121,707
Unit Cost per Dt	\$2,7314	\$2,8474	\$2,9478	\$2,9153	\$2,8161	\$2,4413	\$2,3358	\$2,3680	\$2,3633	\$2,3609	\$2,2861	\$2,3192	\$2,7175
Unit Cost per Dt w/ESN Com	\$2,7646	\$2,8875	\$2,9869	\$2,9553	\$2,8516	\$2,4721	\$2,3666	\$2,3988	\$2,3941	\$2,3917	\$2,3170	\$2,3501	\$2,7594
Unit Cost per Mcf w/ESN Com	\$2,8614	\$2,9896	\$3,0914	\$3,0587	\$2,9514	\$2,5586	\$2,4494	\$2,4828	\$2,4779	\$2,4754	\$2,3981	\$2,4324	\$2,8498
Unit Cost per Mcf w/ESN Com + UFG	\$2,9195	\$3,0493	\$3,1542	\$3,1208	\$3,0113	\$2,6105	\$2,4991	\$2,5332	\$2,5282	\$2,5267	\$2,4468	\$2,4818	\$2,9072
TOTAL COSTS													
Fixed Costs													
Other Pipeline FT Reservation	\$916,896.53	\$927,677.44	\$927,677.44	\$895,334.71	\$927,677.44	\$916,896.53	\$927,677.44	\$916,896.53	\$927,677.44	\$927,677.44	\$916,896.53	\$927,677.44	\$11,056,662.91
Storage Demand & Capacity	\$207,063.41	\$207,063.42	\$207,063.39	\$207,063.42	\$207,063.38	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$1,035,317.02
LNG Peaking Facility	\$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
ESNG FT Reservation	\$1,865,943.00	\$2,064,631.00	\$2,064,631.00	\$2,064,631.00	\$2,035,232.25	\$2,035,232.25	\$1,816,704.02	\$1,816,704.02	\$1,816,704.02	\$1,816,704.02	\$1,816,704.02	\$1,816,704.02	\$23,030,524.62
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	(\$462,865.63)	(\$470,769.24)	(\$467,602.20)	(\$455,254.37)	(\$456,609.79)	(\$456,219.68)	(\$447,139.28)	(\$447,887.36)	(\$449,171.81)	(\$454,189.51)	(\$472,724.39)	(\$481,596.16)	(\$5,522,029.42)
Fixed Costs	\$2,527,037.31	\$2,728,602.62	\$2,731,769.63	\$2,711,774.76	\$2,713,363.28	\$2,495,909.10	\$2,297,242.18	\$2,285,713.20	\$2,295,209.65	\$2,290,191.95	\$2,260,876.16	\$2,262,785.30	\$29,600,475.13
Commodity Costs													
Flowing Commodity	\$986,259.60	\$1,443,912.84	\$2,430,671.48	\$1,805,741.68	\$1,598,451.68	\$841,913.50	\$388,585.04	\$262,887.53	\$237,052.35	\$229,109.45	\$323,791.76	\$642,509.42	\$11,200,896.33
Storage I/W & Commodity	\$72,345.25	\$384,750.62	\$555,307.30	\$460,579.93	\$217,677.99	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$1,690,661.09
ESNG FT Commodity	\$12,130.27	\$20,337.65	\$32,209.97	\$24,738.03	\$20,187.53	\$10,640.90	\$5,133.23	\$3,425.43	\$3,094.94	\$2,994.32	\$4,370.15	\$8,547.91	\$147,810.33
Commodity Costs	\$1,080,735.12	\$1,849,001.11	\$3,018,188.75	\$2,291,059.64	\$1,836,317.20	\$852,554.40	\$393,728.27	\$266,312.96	\$240,147.29	\$232,103.77	\$328,161.91	\$651,057.33	\$13,039,367.75
Less: CNG Use	(\$131.27)	(\$108.63)	(\$81.39)	(\$133.18)	(\$133.43)	(\$80.84)	(\$104.21)	(\$94.36)	(\$87.28)	(\$95.48)	(\$116.28)	(\$93.18)	(\$1,152.68)
Total Firm Cost of Gas	\$3,607,641.21	\$4,577,493.89	\$5,749,878.00	\$5,002,701.24	\$4,549,547.05	\$3,348,372.55	\$2,690,866.24	\$2,551,931.80	\$2,535,299.73	\$2,522,247.23	\$2,588,921.80	\$2,913,789.45	\$42,638,690.20

**Chesapeake Utilities Corporation
Delaware Division
Projected Gas Cost Over/(Under) Collection
For The Twelve Months Ending October 31, 2018**

	Actual Nov-17	Actual Dec-17	Actual Jan-18	Actual Feb-18	Actual Mar-18	Actual Apr-18	Actual May-18	Actual Jun-18	Estimated Jul-18	Projected Aug-18	Projected Sep-18	Projected Oct-18	Total
Calculation of Current Over/(Under) Collections													
GSR Revenue (RS, GS, MVS, LVS)	\$2,054,889.12	\$5,164,385.46	\$9,861,808.13	\$7,542,210.97	\$6,167,979.89	\$5,196,872.81	\$1,900,602.81	\$782,894.23	\$665,952.17	\$640,557.00	\$873,978.00	\$1,343,326.00	\$42,195,456.59
GSR Revenue (HLFS, SFS)	\$179,534.36	\$222,531.83	\$322,839.37	\$274,742.42	\$269,758.64	\$288,984.17	\$203,318.45	\$196,236.68	\$192,307.04	\$154,437.00	\$156,369.00	\$210,952.00	\$2,672,010.96
GSR Revenue (GLR, GLO, GCR, GCO, NGV)	\$16.62	\$20.22	\$51.33	\$13.48	\$13.48	\$13.48	\$13.48	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$142.09
Total GSR Revenue	\$2,234,440.10	\$5,386,937.51	\$10,184,698.83	\$7,816,966.87	\$6,437,752.01	\$5,486,870.46	\$2,103,934.74	\$979,130.91	\$858,259.21	\$794,994.00	\$1,030,347.00	\$1,554,278.00	\$44,867,609.64
Less: Regulatory Assessment	\$6,703.32	\$16,160.81	\$30,554.10	\$23,450.90	\$19,313.26	\$16,457.61	\$6,311.80	\$2,937.39	\$2,574.78	\$2,384.98	\$3,091.04	\$4,662.83	\$134,602.82
Net Collections	\$2,227,736.78	\$5,370,776.70	\$10,154,144.73	\$7,793,515.97	\$6,418,438.75	\$5,469,412.85	\$2,097,622.94	\$976,193.52	\$855,684.43	\$792,609.02	\$1,027,255.96	\$1,549,615.17	\$44,733,006.82
Natural Gas Cost	\$3,819,115.83	\$5,269,048.67	\$6,339,210.00	\$4,096,446.70	\$4,592,843.62	\$3,149,639.04	\$2,181,404.72	\$2,062,878.22	\$2,237,361.03	\$2,576,864.72	\$2,617,886.06	\$2,888,592.74	\$41,831,291.34
Propane Costs	\$0.00	\$22,078.76	\$182,586.24	\$0.00	\$0.00	\$22,014.30	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$226,679.30
Cost of Interruptible Sales	(\$18.65)	(\$14.42)	(\$31.11)	(\$28.00)	(\$28.00)	(\$17.55)	(\$23.40)	(\$21.42)	(\$45.52)	(\$9.52)	(\$25.61)	(\$12.96)	(\$276.16)
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	(\$107,258.35)	\$2,648.65	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	(\$7,671.61)	\$0.00	(\$5,186.11)	(\$3,960.00)	(\$3,447.67)	(\$124,875.09)
Upstream Capacity Release Credits	\$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
Transportation Balancing Rate Credit	(\$55,418.02)	\$2,727.99	(\$131,291.81)	(\$188,811.26)	(\$205,550.54)	(\$137,632.32)	(\$83,117.28)	(\$73,057.59)	(\$69,724.40)	(\$66,842.00)	(\$86,679.00)	(\$83,101.00)	(\$1,178,497.23)
Transportation Cash In/Out Credit	(\$125,153.39)	(\$173,309.43)	(\$267,879.44)	\$93,723.87	(\$12,463.72)	(\$95,054.27)	(\$29,061.07)	\$46,680.21	(\$25,146.30)	\$0.00	\$0.00	\$0.00	(\$587,663.54)
Net Cost	\$3,531,267.42	\$5,123,180.22	\$6,122,593.88	\$4,001,331.31	\$4,374,801.36	\$2,938,949.20	\$2,069,202.97	\$2,028,807.81	\$2,142,444.81	\$2,504,827.09	\$2,527,221.45	\$2,802,031.11	\$40,166,348.62
Current (Over)/Under Collection	\$1,303,530.64	(\$247,596.48)	(\$4,031,550.85)	(\$3,792,184.67)	(\$2,043,637.39)	(\$2,530,463.65)	(\$28,419.97)	\$1,052,614.29	\$1,286,760.38	\$1,712,218.07	\$1,499,965.49	\$1,252,415.94	(\$4,566,348.20)
Calculation of Carrying Charge on Account #191													
Balance in #191 in the Beginning of Month	\$4,545,373.52	\$5,858,241.00	\$5,620,340.23	\$1,600,516.27	(\$2,188,439.17)	(\$4,236,807.49)	(\$8,304,051.07)	(\$8,350,956.84)	(\$7,316,922.32)	(\$6,051,199.05)	(\$3,637,908.18)	(\$2,145,183.39)	\$4,545,373.52
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	\$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
Adjusted Beginning Balance	\$4,545,373.52	\$5,858,241.00	\$5,620,340.23	\$1,600,516.27	(\$2,188,439.17)	(\$4,236,807.49)	(\$8,304,051.07)	(\$8,350,956.84)	(\$7,316,922.32)	(\$6,051,199.05)	(\$3,637,908.18)	(\$2,145,183.39)	\$4,545,373.52
Times Effective Tax Rate	40.655%	40.655%	40.655%	40.655%	40.655%	40.655%	40.655%	40.655%	27.873%	40.655%	40.655%	40.655%	
Deferred Income Tax	\$1,847,921.60	\$2,381,667.88	\$2,284,949.32	\$650,689.89	(\$889,709.94)	(\$1,722,474.09)	(\$3,376,011.96)	(\$3,395,081.50)	(\$2,039,445.76)	(\$2,460,114.97)	(\$1,478,991.57)	(\$872,124.31)	(\$9,068,725.41)
Balance Net of Income Tax & Capacity Amortization	\$2,697,451.92	\$3,476,573.12	\$3,335,390.91	\$949,826.38	(\$1,298,729.23)	(\$2,514,333.40)	(\$4,928,039.11)	(\$4,955,875.34)	(\$5,277,476.56)	(\$3,591,084.08)	(\$2,158,916.61)	(\$1,273,059.08)	(\$15,538,271.08)
Times 1/12 of Annual Interest Rate	0.381%	0.381%	0.354%	0.354%	0.354%	0.373%	0.373%	0.391%	0.330%	0.330%	0.330%	0.351%	
Interest (Revenue) or Expense	\$9,468.06	\$12,202.77	\$11,807.28	\$3,362.39	(\$4,597.50)	(\$9,378.46)	(\$18,381.59)	(\$18,485.42)	(\$20,634.93)	(\$11,850.58)	(\$7,124.42)	(\$4,468.44)	(\$58,080.84)
Calculation of Ending Balance in Account #191													
Balance in #191 in the Beginning of Period	\$4,545,373.52	\$5,858,241.00	\$5,620,340.23	\$1,600,516.27	(\$2,188,439.17)	(\$4,236,807.49)	(\$8,304,051.07)	(\$8,350,956.84)	(\$7,316,922.32)	(\$6,051,199.05)	(\$3,637,908.18)	(\$2,145,183.39)	\$4,545,373.52
Current (Over)/Under Collections	\$1,303,530.64	(\$247,596.48)	(\$4,031,550.85)	(\$3,792,184.67)	(\$2,043,637.39)	(\$2,530,463.65)	(\$28,419.97)	\$1,052,614.29	\$1,286,760.38	\$1,712,218.07	\$1,499,965.49	\$1,252,415.94	(\$4,566,348.20)
Supplier Refunds	\$0.00	(\$2,397.23)	\$0.00	\$0.00	\$0.00	(\$1,527,310.53)	\$0.00	\$0.00	(\$344.98)	\$712,971.87	\$10.28	\$0.00	(\$817,080.87)
CNG Vehicular Fuel	(\$131.22)	(\$109.83)	(\$80.39)	(\$133.16)	(\$133.43)	(\$90.94)	(\$104.21)	(\$94.35)	(\$57.20)	(\$48.49)	(\$16.00)	(\$53.18)	(\$1,152.68)
Interest Revenue or (Expense)	\$9,468.06	\$12,202.77	\$11,807.28	\$3,362.39	(\$4,597.50)	(\$9,378.46)	(\$18,381.59)	(\$18,485.42)	(\$20,634.93)	(\$11,850.58)	(\$7,124.42)	(\$4,468.44)	(\$58,080.84)
Ending Balance #191 (Over)/Under Collections	\$5,858,241.00	\$5,620,340.23	\$1,600,516.27	(\$2,188,439.17)	(\$4,236,807.49)	(\$8,304,051.07)	(\$8,350,956.84)	(\$7,316,922.32)	(\$6,051,199.05)	(\$3,637,908.18)	(\$2,145,183.39)	(\$897,289.07)	(\$897,289.07)
RS, GS, MVS, LVS Mcf's	203,300	473,158	902,460	682,554	558,184	470,388	172,014	70,854	60,265	57,969	79,093	121,568	3,851,807
HLFS, SFS Mcf's	25,327	28,457	41,284	35,133	34,496	36,955	26,000	25,094	24,591	19,749	19,996	26,976	344,058
GLR, GLO, GCR, GCO Mcf's	0	0	0	2	3	3	3	0	0	0	0	0	11
Total Firm Mcf's + Adjusted Sales	228,627	501,615	943,744	717,689	592,683	507,346	198,017	95,948	84,856	77,718	99,089	148,544	4,195,876
RS, GS, MVS, LVS GSR Rate	\$11.05	\$11.05	\$11.05	\$11.05	\$11.05	\$11.05	\$11.05	\$11.05	\$11.05	\$11.05	\$11.05	\$11.05	\$11.05
HLFS Rate	\$7.82	\$7.82	\$7.82	\$7.82	\$7.82	\$7.82	\$7.82	\$7.82	\$7.82	\$7.82	\$7.82	\$7.82	\$7.82
GLR, GLO Rate	\$4.68	\$4.68	\$4.68	\$4.68	\$4.68	\$4.68	\$4.68	\$4.68	\$4.68	\$4.68	\$4.68	\$4.68	\$4.68
Annual Interest Rate	4.210%	4.210%	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%	27.873%	40.655%	40.655%	40.655%	40.655%
Supplier Refunds	\$0.00	\$2,397.23	\$0.00	\$0.00	\$0.00	\$1,527,310.53	\$0.00	\$0.00	\$344.98	(\$712,971.87)	\$0.00	\$0.00	
	\$0.81	\$1.09	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	(\$3,637,908.18)	(\$2,145,183.39)	(\$897,289.07)	

Chesapeake Utilities Corporation
 Delaware Division
 Projected Shared Margins Over/(Under) Refund
 For The Twelve Months Ending October 31, 2018

	Actual Nov-17	Actual Dec-17	Actual Jan-18	Actual Feb-18	Actual Mar-18	Actual Apr-18	Actual May-18	Actual Jun-18	Estimated Jul-18	Projected Aug-18	Projected Sep-18	Projected Oct-18	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	\$166,706.00	\$387,989.56	\$740,017.20	\$559,694.28	\$457,710.88	\$385,718.16	\$141,051.48	\$58,100.28	\$49,417.30	\$47,534.58	\$64,856.26	\$99,685.76	\$3,158,481.74
Less: Regulatory Assessment	\$500.12	\$1,163.97	\$2,220.05	\$1,679.08	\$1,373.13	\$1,157.15	\$423.15	\$174.30	\$148.25	\$142.60	\$194.57	\$299.06	\$9,475.43
Net Margin Refunded Through Rate	\$166,205.88	\$386,825.59	\$737,797.15	\$558,015.20	\$456,337.75	\$384,561.01	\$140,628.33	\$57,925.98	\$49,269.05	\$47,391.98	\$64,661.69	\$99,386.70	\$3,149,006.31
Shared Margins Expensed	(\$231,250.00)	(\$231,250.00)	(\$231,250.00)	(\$231,250.00)	(\$231,250.00)	(\$231,249.06)	(\$231,250.00)	(\$231,250.00)	(\$231,250.00)	(\$231,250.00)	(\$231,250.00)	(\$231,250.00)	(\$2,774,999.06)
Current Over/(Under) Refund	(\$65,044.12)	\$155,575.59	\$506,547.15	\$326,765.20	\$225,087.75	\$153,311.95	(\$90,621.67)	(\$173,324.02)	(\$181,980.95)	(\$183,858.02)	(\$166,588.31)	(\$131,863.30)	\$374,007.25
Calculation of Ending Balance in Account #191SM													
Balance in #191SM in the Beginning of Period	(\$419,771.75)	(\$484,815.87)	(\$329,240.28)	\$177,306.87	\$504,073.70	\$729,161.45	\$882,473.40	\$791,851.73	\$618,527.71	\$436,546.76	\$252,688.74	\$86,100.43	(\$419,771.75)
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	(\$419,771.75)	(\$484,815.87)	(\$329,240.28)	\$177,306.87	\$504,073.70	\$729,161.45	\$882,473.40	\$791,851.73	\$618,527.71	\$436,546.76	\$252,688.74	\$86,100.43	(\$419,771.75)
Current Over/(Under) Refund	(\$65,044.12)	\$155,575.59	\$506,547.15	\$326,766.83	\$225,087.75	\$153,311.95	(\$90,621.67)	(\$173,324.02)	(\$181,980.95)	(\$183,858.02)	(\$166,588.31)	(\$131,863.30)	\$374,008.88
Ending Balance #191SM Over/(Under) Refund	(\$484,815.87)	(\$329,240.28)	\$177,306.87	\$504,073.70	\$729,161.45	\$882,473.40	\$791,851.73	\$618,527.71	\$436,546.76	\$252,688.74	\$86,100.43	(\$45,762.87)	(\$45,762.87)
RS, GS, MVS, LVS Mcf's Margin Sharing Credit Per Mcf	203,300 \$0.82	473,158 \$0.82	902,460 \$0.82	682,554 \$0.82	558,184 \$0.82	470,388 \$0.82	172,014 \$0.82	70,854 \$0.82	60,265 \$0.82	57,969 \$0.82	79,093 \$0.82	121,568 \$0.82	3,851,807

Chesapeake Utilities Corporation
 Delaware Division
 Development of Gas Sales Service Rates Effective November 1, 2018

Based on Total Firm Gas Costs Recoverable through GSR effective November 1, 2018

Description	Allocator	Total System Costs	Volume (Ccf)	Cost / Ccf
Fixed Gas Costs	Peak Day Capacity Entitlements	\$27,739,448	811,130	\$34.20
Variable Gas Costs	Annual Volume	\$12,140,926	45,362,965	\$0.268
Total Firm Gas Costs	Annual Volume	\$39,880,374	45,362,965	\$0.879

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	(\$34.20 / 305)	\$0.112	
Commodity Rate		\$0.268	
Total Gas Sales Service Rate		\$0.380	\$0.630
Total High Load Factor Dollars			
	Projected Sales	Rate	Total Cost
	3,487,155	\$0.630	\$2,196,908

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

Description	Peak Day Cap. Method	System Average Cost	
Demand Rate	(\$34.20 / 365)	\$0.094	
Commodity Rate		\$0.268	
Total Gas Sales Service Rate		\$0.362	
Total Gas Cooling and Gas Lighting Dollars			
	Projected Sales	Rate	Total Cost
	350	\$0.362	\$127

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	\$39,880,374	45,362,965			
Less : Allocated to HLFS & SFS	\$2,196,908	3,487,155			
Less : Allocated to GL, GC	\$127	350			
Total Remaining System	\$37,683,339	41,875,460	\$0.900	(\$0.067)	\$0.833

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	\$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	System Average Cost	
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

Change in Total Firm Gas Costs Recoverable through GSR

Description	Costs	Cost / Ccf
Fixed Gas Costs	(\$1,483,933)	\$1.010
Variable Gas Costs	(\$3,484,117)	(\$0.109)
Total Firm Gas Costs	(\$4,968,050)	(\$0.202)

Change in HLFS Rate

Description	HLFS Cost / Ccf
Demand Rate	
Commodity Rate	
Total Gas Sales Service Rate	(\$0.152)

Change in Gas Lighting Rate

Description	GL Cost / Ccf
Demand Rate	
Commodity Rate	
Total Gas Sales Service Rate	(\$0.106)

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	(\$0.205)	\$0.015	(\$0.190)

Chesapeake Utilities Corporation
Delaware Division
Firm Cost of Gas Comparison

Description	Projection Inherent In November 1, 2018 GSR Filing		Estimated 12 Months Ending Oct-18	Average Cost Per MCF	12 Months Ending Oct-17	Average Cost Per MCF	12 Months Ended Oct-16	Average Cost Per MCF	12 Months Ended Oct-15	Average Cost Per MCF
	Projected 12 Months Ending Oct-19	Average Cost Per MCF								
Firm Fixed Gas Costs										
ESNG FT Reservation ¹	\$17,508,495	\$3.8596	\$15,176,568	\$3.6169	\$12,347,817	\$3.5871	\$11,367,101	\$3.6143	\$11,563,874	\$2.9309
Columbia FT Reservation	\$826,866	\$0.1823	\$824,291	\$0.1964	\$824,332	\$0.2395	\$818,778	\$0.2603	\$797,478	\$0.2021
Transco FT Reservation	\$3,935,032	\$0.8675	\$3,936,962	\$0.9383	\$3,941,307	\$1.1450	\$3,957,183	\$1.2582	\$3,951,032	\$1.0014
Texas Eastern FT Reservation	\$6,294,765	\$1.3876	\$6,294,765	\$1.5002	\$6,278,037	\$1.8238	\$6,294,765	\$2.0015	\$6,294,765	\$1.5954
Storage Demand and Capacity & Peaking	\$1,035,317	\$0.2282	\$2,373,797	\$0.5657	\$2,101,641	\$0.6105	\$1,295,500	\$0.4119	\$1,021,278	\$0.2588
Total Firm Fixed Gas Costs	\$29,600,475	\$6.5253	\$28,606,383	\$6.8176	\$25,493,134	\$7.4059	\$23,733,326	\$7.5464	\$23,628,426	\$5.9888
Firm Variable Gas Costs										
Flowing Commodity	\$11,200,896	\$2.4692	\$11,275,314	\$2.6872	\$8,299,258	\$2.4110	\$6,563,848	\$2.0871	\$11,568,935	\$2.9322
ESNG FT Commodity	\$147,810	\$0.0326	\$234,991	\$0.0560	\$29,220	\$0.0085	\$159,330	\$0.0507	\$66,553	\$0.0169
CNG for Vehicular Use	(\$1,153)	(\$0.0003)	(\$1,153)	(\$0.0003)	(\$1,163)	(\$0.0003)	(\$661)	(\$0.0002)	(\$839)	(\$0.0002)
Storage Injection/Withdrawal & Commodity	\$1,690,661	\$0.3727	\$1,714,604	\$0.4086	\$1,405,759	\$0.4084	\$1,438,299	\$0.4573	\$2,424,023	\$0.6144
Propane	\$0	\$0.0000	\$226,679	\$0.0540	\$25,432	\$0.0074	\$43,397	\$0.0138	\$93,731	\$0.0238
Total Firm Variable Gas Costs	\$13,038,215	\$2.8742	\$13,450,435	\$3.2056	\$9,758,506	\$2.8349	\$8,204,214	\$2.6086	\$14,152,403	\$3.5870
Total Firm Gas Costs	\$42,638,690	\$9.3994	\$42,056,818	\$10.0232	\$35,251,639	\$10.2408	\$31,937,540	\$10.1550	\$37,780,829	\$9.5758
Total Firm Mcf Sales	4,536,296		4,195,965		3,442,284		3,145,006		3,945,448	

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)	\$42,638,690
Supplier Refunds (Schedule B)	\$0
Recovery of Under Collection from Transp.	\$0
GSR Settlement Adjustment	\$0
Balancing Rate Credit	(\$1,861,027)
(Over)/Under Collection (Schedule D.1)	(\$897,289)
Costs Recoverable through GSR	\$39,880,374

Chesapeake Utilities Corporation
Delaware Division
Unaccounted For, Company Use & Pressure Compensation Gas Volumes
Twelve Months Ended July 31, 2018

	(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-17	369,592	358,153	11,439	39	5,349	6,051
September-17	409,571	401,152	8,417	46	5,991	2,380
October-17	467,850	422,736	45,114	43	6,314	38,757
November-17	785,200	576,341	208,859	137	8,608	200,114
December-17	1,235,555	914,171	321,383	232	13,654	307,497
January-18	1,417,202	1,498,259	(81,057)	408	22,377	(103,842)
February-18	946,685	1,147,199	(200,513)	269	17,134	(217,916)
March-18	1,158,057	1,065,714	92,343	275	15,917	76,151
April-18	733,036	882,131	(149,095)	123	13,175	(162,393)
May-18	405,972	504,231	(98,259)	64	7,531	(105,854)
June-18	363,037	383,442	(20,405)	44	5,727	(26,176)
July-18	351,459	345,009	6,450	25	5,153	1,272
Total	8,643,216	8,498,538	144,676	1,708	126,930	16,039

Unaccounted For and Company Use as % of Sales (Column 3 / Column 2)	1.70%
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Unaccounted For as % of Receipts (Column 6 / Column 1)	0.19%
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* Represents calculation to pressurize gas delivered from the ESNG transmission pipeline to a standard pressure.

Chesapeake Utilities Corporation
Delaware Division
Development of Gas Sales Service Rates Effective November 1, 2018
Balancing Rate Credit for Transportation Customers

Rate Class	Projected Nov-18	Projected Dec-18	Projected Jan-19	Projected Feb-19	Projected Mar-19	Projected Apr-19	Projected May-19	Projected Jun-19	Projected Jul-19	Projected Aug-19	Projected Sep-19	Projected Oct-19	Total
General Service:													
Volumes - Mcf	907	1,976	3,368	2,184	2,378	1,199	600	632	475	386	347	459	14,910
Balancing Rate Revenue	\$1,208	\$2,633	\$4,487	\$2,909	\$3,168	\$1,597	\$799	\$842	\$633	\$515	\$462	\$611	\$19,864
Medium Volume Service:													
Volumes - Mcf	5,159	10,698	15,415	9,744	10,982	6,370	2,981	1,484	952	1,136	1,493	1,888	68,301
Balancing Rate Revenue	\$8,173	\$16,949	\$24,422	\$15,438	\$17,399	\$10,091	\$4,722	\$2,350	\$1,508	\$1,799	\$2,365	\$2,992	\$108,208
Large Volume Service:													
Volumes - Mcf	85,830	167,927	256,788	176,686	192,360	120,254	59,464	48,355	38,564	48,502	73,544	76,274	1,344,549
Balancing Rate Revenue	\$91,710	\$179,430	\$274,378	\$188,789	\$205,537	\$128,492	\$63,537	\$51,668	\$41,206	\$51,824	\$78,582	\$81,499	\$1,436,652
High Load Factor Service:													
Volumes - Mcf	243,866	285,185	265,923	231,587	257,206	239,686	234,306	240,792	196,262	223,679	234,895	225,794	2,879,181
Balancing Rate Revenue	\$25,021	\$29,260	\$27,284	\$23,761	\$26,389	\$24,592	\$24,040	\$24,705	\$20,136	\$22,949	\$24,100	\$23,166	\$295,403
Interruptible Service:													
Volumes - Mcf	7,862	6,152	4,153	3,525	4,259	4,809	6,463	10,298	11,204	14,823	7,910	12,242	93,700
Balancing Rate Revenue	\$75	\$59	\$40	\$34	\$41	\$46	\$62	\$99	\$108	\$142	\$76	\$118	\$900
													4,400,641
Total Balancing Rate Revenue	\$126,187	\$228,331	\$330,611	\$230,931	\$252,534	\$164,818	\$93,160	\$79,664	\$63,591	\$77,229	\$105,585	\$108,386	\$1,861,027

CAPACITY RELEASE - DEMAND

Customer Name (Utilicis)	Division	DPA	Zone	30	31	31	28	31	30	31	30	31	31	30	31	
				Nov-18	Dec-18	19-Jan	19-Feb	19-Mar	19-Apr	19-May	19-Jun	19-Jul	19-Aug	19-Sep	19-Oct	
Customer #1	DE	5	2	4	4	4	4	4	4	4	4	4	4	4	4	4
Customer #2	DE	5	2	3	3	3	3	3	3	3	3	3	3	3	3	3
Customer #3	DE	5	2	3	3	3	3	3	3	3	3	3	3	3	3	3
Customer #4	DE	5	2	4	4	4	4	4	4	4	4	4	4	4	4	4
Customer #5	DE	5	2	3	3	3	3	3	3	3	3	3	3	3	3	3
Customer #6	DE	5	2	5	5	5	5	5	5	5	5	5	5	5	5	5
Customer #7	DE	5	2	3	3	3	3	3	3	3	3	3	3	3	3	3
Customer #8	DE	5	2	4	4	4	4	4	4	4	4	4	4	4	4	4
Customer #9	DE	8	2	270	270	270	270	270	270	270	270	270	270	270	270	270
Customer #10	DE	8	2	41	41	41	41	41	41	41	41	41	41	41	41	41
Customer #11	DE	8	2	0	0	0	0	0	0	0	0	0	0	0	0	0
Customer #12	DE	14	2	417	417	417	417	417	417	417	417	417	417	417	417	417
Customer #13	DE	14	2	6	6	6	6	6	6	6	6	6	6	6	6	6
Customer #14	DE	14	2													
Customer #15	DE	14	2	9	9	9	9	9	9	9	9	9	9	9	9	9
Customer #16	DE	9	2	27	9	3	2	3	2	1	0	0	1	221	207	
Customer #17	DE	9	2	250	250	240	240	240	250	250	250	250	250	250	250	250
Customer #18	DE	9	2	3	3	3	3	3	3	3	3	3	3	3	3	3
Customer #19	DE	14	2	32	32	32	32	32	32	32	32	32	32	32	32	32
Customer #20	DE	14	2	75	75	75	75	75	75	75	75	75	75	75	75	75
Customer #21	DE	14	2	505	505	505	505	505	505	505	505	505	505	505	505	505
Customer #22	DE	5	2	150	150	150	150	150	150	150	150	150	150	150	150	150
Customer #23	DE	14	2	246	246	246	246	246	246	246	246	246	246	246	246	246
Customer #24	DE	15	2	36	36	36	36	36	36	36	36	36	36	36	36	36
Customer #25	DE	8	2	26	26	26	26	26	26	26	26	26	24	24	24	24
Customer #26	DE	5	2	21	21	21	21	21	21	21	21	21	21	21	21	21
Customer #27	DE	5	2	34	34	34	34	34	34	34	38	36	37	37	34	
Customer #28	DE	5	2	15	15	15	15	15	15	15	15	15	15	15	15	15
Customer #29	DE	4	1	27	27	27	27	27	27	27	27	27	27	27	27	27
Customer #30	DE	7	2	156	156	156	156	156	156	156	173	156	184	156	156	156
Customer #31	DE	7	2	12	12	12	12	12	12	12	13	12	14	12	12	12
Customer #32	DE	7	2	0	0	0	0	0	0	0	0	0	0	0	0	0
Customer #33	DE	5	2	21	21	21	21	21	21	21	21	21	21	21	21	21
Customer #34	DE	14	2	11	11	11	11	11	11	11	11	11	11	11	11	11
Customer #35	DE	4	1	20	20	20	20	20	20	20	20	20	20	20	20	20
Customer #36	DE	4	1	48	48	48	48	48	48	48	48	48	48	48	48	48
Customer #37	DE	4	1	66	66	66	66	66	66	66	66	66	66	66	66	66
Customer #38	DE	14	2	48	48	48	48	48	48	48	48	48	48	48	48	48
Customer #39	DE	14	2	53	53	53	53	53	53	53	53	53	53	53	53	53
Customer #40	DE	14	2	155	155	155	155	155	155	155	155	155	155	155	155	155
Customer #41	DE	14	2	9	9	9	9	9	9	9	9	9	9	9	9	9
Customer #42	DE	14	2	85	85	85	85	85	85	85	85	85	85	85	85	85
Customer #43	DE	6	2	2	2	2	2	2	2	2	2	2	2	2	2	2
Customer #44	DE	6	2	3	3	3	3	3	3	3	3	3	3	3	3	3
Customer #45	DE	6	2	2	2	2	2	2	2	2	2	2	2	2	2	2
Customer #46	DE	6	2	4	4	4	4	4	4	4	4	4	4	4	4	4
Customer #47	DE	6	2	6	6	6	6	6	6	6	6	6	6	6	6	6
Customer #48	DE	6	2	1347	1347	1347	1347	1347	1347	1347	1347	1347	1347	1347	1347	1347
Customer #49	DE	6	2	0	0	0	0	0	0	0	0	0	0	0	0	0
Customer #50	DE	6	2	2	2	2	2	2	2	2	2	2	2	2	2	2
Customer #51	DE	6	2	0	0	0	0	0	0	0	0	0	0	0	0	0
Customer #52	DE	6	2	4	4	4	4	4	4	4	4	4	4	4	4	4
Customer #53	DE	6	2	12	12	12	12	12	12	12	12	12	12	12	12	12
Customer #54	DE	6	2	11	11	11	11	11	11	11	11	11	11	11	11	11
Customer #55	DE	6	2	11	11	11	11	11	11	11	11	11	11	11	11	11
Customer #56	DE	5	2	53	53	53	53	53	53	53	53	53	53	53	53	53
Customer #57	DE	5	2	218	218	218	218	218	218	218	218	218	218	218	218	218
Customer #58	DE	5	2	34	34	34	34	34	34	34	34	34	34	34	34	34
Customer #59	DE	5	2	23	23	23	23	23	23	23	23	23	23	23	23	23
Customer #60	DE	5	2	16	16	16	16	16	16	16	16	16	16	16	16	16
Customer #61	DE	8	2	147	147	147	147	147	147	147	147	147	147	147	147	147
Customer #62	DE	8	2	137	137	137	137	137	137	137	137	137	137	137	137	137
Customer #63	DE	5	2	5	5	5	5	5	5	5	5	5	5	5	5	5
Customer #64	DE	5	2	5	5	5	5	5	5	5	5	5	5	5	5	5
Customer #65	DE	5	2	5	5	5	5	5	5	5	5	5	5	5	5	5
Customer #66	DE	5	2	5	5	5	5	5	5	5	5	5	5	5	5	5
Customer #67	DE	5	2	5	5	5	5	5	5	5	5	5	5	5	5	5
Customer #68	DE	5	2	5	5	5	5	5	5	5	5	5	5	5	5	5
Customer #69	DE	5	2	5	5	5	5	5	5	5	5	5	5	5	5	5
Customer #70	DE	5	2	5	5	5	5	5	5	5	5	5	5	5	5	5
Customer #71	DE	5	2	5	5	5	5	5	5	5	5	5	5	5	5	5
Customer #72	DE	5	2	4	4	4	4	4	4	4	4	4	4	4	4	4
Customer #73	DE	5	2	4	4	4	4	4	4	4	4	4	4	4	4	4
Customer #74	DE	5	2	4	4	4	4	4	4	4	4	4	4	4	4	4

CAPACITY RELEASE - DEMAND

Customer Name (Utilicis)	Division	DPA	Zone	30	31	31	28	31	30	31	30	31	31	30	31
				Nov-18	Dec-18	19-Jan	19-Feb	19-Mar	19-Apr	19-May	19-Jun	19-Jul	19-Aug	19-Sep	19-Oct
Customer #75	DE	5	2	4	4	4	4	4	4	4	4	4	4	4	4
Customer #76	DE	5	2	4	4	4	4	4	4	4	4	4	4	4	4
Customer #77	DE	5	2	4	4	4	4	4	4	4	4	4	4	4	4
Customer #78	DE	5	2	4	4	4	4	4	4	4	4	4	4	4	4
Customer #79	DE	5	2	4	4	4	4	4	4	4	4	4	4	4	4
Customer #80	DE	5	2	4	4	4	4	4	4	4	4	4	4	4	4
Customer #81	DE	5	2	4	4	4	4	4	4	4	4	4	4	4	4
Customer #82	DE	6	2	45	45	45	45	45	45	45	45	45	45	45	45
Customer #83	DE	5	2	227	227	227	227	227	227	227	227	227	227	227	227
Customer #84	DE	6	2	17	17	17	17	17	17	17	17	17	17	17	17
Customer #85	DE	6	2	3	3	3	3	3	3	3	3	3	3	3	3
Customer #86	DE	6	2	7	7	7	7	7	7	7	7	7	7	7	7
Customer #87	DE	6	2	32	32	32	32	32	32	32	32	32	32	32	32
Customer #88	DE	6	2	19	19	19	19	19	19	19	19	19	19	19	19
Customer #89	DE	6	2	9	9	9	9	9	9	9	9	9	9	9	9
Customer #90	DE	6	2	3	3	3	3	3	3	3	3	3	3	3	3
Customer #91	DE	6	2	1	1	1	1	1	1	1	1	1	1	1	1
Customer #92	DE	6	2	1	1	1	1	1	1	1	1	1	1	1	1
Customer #93	DE	6	2	1	1	1	1	1	1	1	1	1	1	1	1
Customer #94	DE	15	2	17	17	17	17	17	17	17	17	17	17	17	17
Customer #95	DE	5	2	239	239	239	239	239	239	239	239	239	239	239	239
Customer #96	DE	6	2	91	61	9	0	25	111	76	125	119	172	113	135
Customer #97	DE	14	2	36	0	0	0	34	71	69	75	69	83	71	79
Customer #98	DE	15	2	162	162	162	162	162	162	162	162	162	162	162	162
Customer #99	DE	8	2	891	891	891	891	891	891	891	891	891	891	891	891
Customer #100	DE	14	2	77	66	7	0	0	0	0	0	0	0	0	7
Customer #101	DE	15	2	42	42	42	42	42	42	42	42	42	42	42	42
Customer #102	DE	7	2	119	119	119	119	119	119	119	119	119	119	119	119
Customer #103	DE	11	2	11	11	11	11	11	11	11	11	11	11	11	11
Customer #104	DE	4	1	410	410	410	410	410	410	410	410	410	410	410	410
Customer #105	DE	4	1	315	315	315	315	315	315	315	315	315	315	315	315
Customer #106	DE	14	2	161	161	161	161	161	161	161	161	161	161	161	161
Customer #107	DE	14	2	4	4	4	4	4	4	4	4	4	4	4	4
Customer #108	DE	14	2	7	7	7	7	7	7	7	7	7	7	7	7
Customer #109	DE	14	2	2	2	2	2	2	2	2	2	2	2	2	2
Customer #110	DE	5	2	323	323	323	323	323	323	323	323	323	323	323	323
Customer #111	DE	5	2												
Customer #112	DE	9	2	9	0	0	0	0	0	0	0	0	0	0	0
Customer #113	DE	4	1												
Customer #114	DE	5	2	58	58	58	58	58	58	58	58	58	58	58	58
Customer #115	DE	8	2	58	58	58	58	58	58	58	58	58	58	58	58
Customer #116	DE	8	2	6	6	6	6	6	6	6	6	6	6	6	6
Customer #117	DE	8	2	6	6	6	6	6	6	6	6	6	6	6	6
Customer #118	DE	8	2	2	2	2	2	2	2	2	2	2	2	2	2
Customer #119	DE	8	2	4	4	4	4	4	4	4	4	4	4	4	4
Customer #120	DE	5	2	3	3	3	3	3	3	3	3	3	3	3	3
Customer #121	DE	5	2	4	4	4	4	4	4	4	4	4	4	4	4
Customer #122	DE	5	2	3	3	3	3	3	3	3	3	3	3	3	3
Customer #123	DE	5	2	3	3	3	3	3	3	3	3	3	3	3	3
Customer #124	DE	5	2	4	4	4	4	4	4	4	4	4	4	4	4
Customer #125	DE	5	2	4	4	4	4	4	4	4	4	4	4	4	4
Customer #126	DE	5	2	3	3	3	3	3	3	3	3	3	3	3	3
Customer #127	DE	5	2	3	3	3	3	3	3	3	3	3	3	3	3
Customer #128	DE	6	2	5	0	0	0	0	0	2	0	0	0	35	126
Customer #129	DE	5	2	21	21	21	21	21	21	21	21	21	21	21	21
Customer #130	DE	5	2	0	1	1	1	1	0	0	0	0	0	0	0
Customer #131	DE	4	1	398	398	398	398	398	398	398	398	398	398	398	398
Customer #132	DE	15	2	86	86	86	86	86	86	86	86	86	86	86	86
Customer #133	DE	15	2												
Customer #134	DE	15	2												
Customer #135	DE	15	2	2162	2162	2162	2162	2162	2162	2162	2162	2162	2162	2162	2162
Customer #136	DE	15	2	533	533	533	533	533	533	533	533	533	533	533	533
Customer #137	DE	15	2	10	0	0	0	0	0	0	1	1	10	76	
Customer #138	DE	8	2	132	132	132	132	132	132	132	132	132	132	132	132
Customer #139	DE	8	2	3	3	3	3	3	3	3	3	3	3	3	3
Customer #140	DE	8	2	8	8	8	8	8	8	8	8	8	8	8	8
Customer #141	DE	5	2												
Customer #142	DE	8	2	170	170	170	170	170	170	170	170	170	170	170	170
Customer #143	DE	14	2	10	10	10	10	10	10	10	10	10	10	10	10
Customer #144	DE	14	2	0	0	0	0	0	0	0	0	0	0	0	0
Customer #145	DE	8	2	395	395	395	395	395	415	415	415	415	415	415	415
Customer #146	DE	8	2	374	374	374	374	374	374	374	374	374	374	374	374
Customer #147	DE	11	2	376	376	376	376	376	376	376	376	376	376	376	376
Customer #148	DE	15	2	178	14	0	0	0	0	0	0	0	13	380	401

CAPACITY RELEASE - DEMAND

Customer Name (Utilicis)	Division	DPA	Zone	30	31	31	28	31	30	31	30	31	31	30	31	
				Nov-18	Dec-18	19-Jan	19-Feb	19-Mar	19-Apr	19-May	19-Jun	19-Jul	19-Aug	19-Sep	19-Oct	
Customer #149	DE	11	2	75	75	75	75	75	75	75	75	75	75	75	75	75
Customer #150	DE	5	2													
Customer #151	DE	5	2	51	51	51	51	51	51	51	51	51	51	51	51	51
Customer #152	DE	5	2	21	21	21	21	21	21	21	21	21	21	21	21	21
Customer #153	DE	5	2	51	51	51	51	51	51	51	51	51	51	51	51	51
Customer #154	DE	11	2	43	43	43	43	43	43	43	43	43	43	43	43	43
Customer #155	DE	5	2													
Customer #156	DE	15	2	277	277	277	277	277	277	277	277	277	277	277	277	277
Customer #157	DE	9	2	19	19	19	19	19	19	19	19	19	19	19	19	19
Customer #158	DE	9	2	155	155	155	155	155	155	155	155	155	155	155	155	155
Customer #159	DE	15	2	46	46	46	46	46	46	46	46	46	46	46	46	46
Customer #160	DE	6	2	20	23	18	20	18	17	15	18	28	12	208	191	191
Customer #161	DE	14	2	375	375	375	375	375	375	375	375	375	375	375	375	375
Customer #162	DE	5	2	24	24	24	24	24	24	24	24	24	24	24	24	24
Customer #163	DE	5	2	19	19	19	19	19	19	19	19	19	19	19	19	19
Customer #164	DE	5	2	13	13	13	13	13	13	13	13	13	13	13	13	13
Customer #165	DE	5	2	21	21	21	21	21	21	21	21	21	21	21	21	21
Customer #166	DE	14	2	233	233	233	233	233	233	233	233	233	233	233	233	233
Customer #167	DE	4	1	148	148	148	148	148	148	148	148	148	148	148	148	148
Customer #168	DE	5	2	7	7	7	7	7	7	7	7	7	7	7	7	7
Customer #169	DE	5	2	2	2	2	2	2	2	2	2	2	2	2	2	2
Customer #170	DE	5	2	4	4	4	4	4	4	4	4	4	4	4	4	4
Customer #171	DE	5	2	1	1	1	1	1	1	1	1	1	1	1	1	1
Customer #172	DE	5	2	18	18	18	18	18	18	18	18	18	18	18	18	18
Customer #173	DE	5	2	3	3	3	3	3	3	3	3	3	3	3	3	3
Customer #174	DE	5	2	7	7	7	7	7	7	7	7	7	7	7	7	7
Customer #175	DE	5	2	4	4	4	4	4	4	4	4	4	4	4	4	4
Customer #176	DE	5	2	0	0	0	0	0	0	0	0	0	0	0	0	0
Customer #177	DE	5	2	0	0	0	0	0	0	0	0	0	0	0	0	0
Customer #178	DE	5	2	3	3	3	3	3	3	3	3	3	3	3	3	3
Customer #179	DE	5	2	0	0	0	0	0	0	0	0	0	0	0	0	0
Customer #180	DE	5	2	16	16	16	16	16	16	16	16	16	16	16	16	16
Customer #181	DE	5	2	12	12	12	12	12	12	12	12	12	12	12	12	12
Customer #182	DE	5	2	35	35	35	35	35	35	35	35	35	35	35	35	35
Customer #183	DE	5	2	21	21	21	21	21	21	21	21	21	21	21	21	21
Customer #184	DE	5	2	35	35	35	35	35	35	35	35	35	35	35	35	35
Customer #185	DE	6	2	0	2	2	0	0	0	0	0	0	0	0	0	0
Customer #186	DE	6	2	0	4	4	0	0	0	0	0	0	0	0	0	0
Customer #187	DE	5	2	6	73	73	6	6	6	6	6	6	6	6	6	6
Customer #188	DE	5	2	16	172	172	16	16	16	16	16	16	16	16	16	16
Customer #189	DE	5	2	2	24	24	2	2	2	2	2	2	2	2	2	2
Customer #190	DE	5	2	15	150	150	15	15	15	15	15	15	15	15	15	15
Customer #191	DE	5	2	7	7	7	7	7	7	7	7	7	7	7	7	7
Customer #192	DE	5	2	45	45	45	0	45	45	45	45	45	45	45	45	45
Customer #193	DE	5	2	0	41	41	41	41	0	0	0	0	0	0	0	0
Customer #194	DE	5	2	13	13	13	13	13	13	13	13	13	13	13	13	13
Customer #195	DE	5	2	0	0	0	0	0	0	0	0	0	0	0	0	0
Customer #196	DE	5	2	14	14	14	14	14	14	14	14	14	14	14	14	14
Customer #197	DE	5	2	14	14	14	14	14	14	14	14	14	14	14	14	14
Customer #198	DE	5	2	31	31	31	31	31	31	31	31	31	31	31	31	31
Customer #199	DE	5	2	1	1	1	1	1	1	1	1	1	1	1	1	1
Customer #200	DE	5	2	1	1	1	1	1	1	1	1	1	1	1	1	1
Customer #201	DE	6	2	2	2	2	2	2	2	2	2	2	2	2	2	2
Customer #202	DE	6	2	3	3	3	3	3	3	3	3	3	3	3	3	3
Customer #203	DE	9	2	499	499	499	499	499	499	499	499	499	499	499	499	499
Customer #204	DE	9	2	16	16	16	16	16	16	16	16	16	16	16	16	16
Customer #205	DE	5	2	25	25	25	25	25	25	25	25	25	25	25	25	25
Customer #206	DE	5	2	2	2	2	2	2	2	2	2	2	2	2	2	2
Customer #207	DE	5	2	43	43	43	43	43	43	43	43	43	43	43	43	43
Customer #208	DE	5	2	11	11	11	11	11	11	11	11	11	11	11	11	11
Customer #209	DE	5	2	14	14	14	14	14	14	14	14	14	14	14	14	14
Customer #210	DE	5	2	3	3	3	3	3	3	3	3	3	3	3	3	3
Customer #211	DE	5	2	8	8	8	8	8	8	8	8	8	8	8	8	8
Customer #212	DE	5	2	9	9	9	9	9	9	9	9	9	9	9	9	9
Customer #213	DE	5	2	19	19	19	19	19	19	19	19	19	19	19	19	19
Customer #214	DE	5	2	5	5	5	5	5	5	5	5	5	5	5	5	5
Customer #215	DE	5	2	8	8	8	8	8	8	8	8	8	8	8	8	8
Customer #216	DE	5	2	13	13	13	13	13	13	13	13	13	13	13	13	13
Customer #217	DE	5	2	6	6	6	6	6	6	6	6	6	6	6	6	6
Customer #218	DE	5	2	6	6	6	6	6	6	6	6	6	6	6	6	6
Customer #219	DE	6	2	19	19	19	19	19	19	19	19	19	19	19	19	19
Customer #220	DE	5	2	9	9	9	9	9	9	9	9	9	9	9	9	9
Customer #221	DE	5	2	9	9	9	9	9	9	9	9	9	9	9	9	9
Customer #222	DE	5	2	23	23	23	23	23	23	23	23	23	23	23	23	23

CAPACITY RELEASE - DEMAND

Customer Name (Utilicis)	Division	DPA	Zone	30	31	31	28	31	30	31	30	31	31	30	31
				Nov-18	Dec-18	19-Jan	19-Feb	19-Mar	19-Apr	19-May	19-Jun	19-Jul	19-Aug	19-Sep	19-Oct
Customer #223	DE	5	2	9	9	9	9	9	9	9	9	9	9	9	9
Customer #224	DE	5	2	16	16	16	16	16	16	16	16	16	16	16	16
Customer #225	DE	5	2	12	12	12	12	12	12	12	12	12	12	12	12
Customer #226	DE	5	2	33	33	33	33	33	33	33	33	33	33	33	33
Customer #227	DE	6	2	5	5	5	5	5	5	5	5	5	5	5	5
Customer #228	DE	5	2	24	24	24	24	24	24	24	24	24	24	24	24
Customer #229	DE	5	2	16	16	16	16	16	16	16	16	16	16	16	16
Customer #230	DE	4	1	38	38	38	38	38	38	38	38	38	38	38	38
Customer #231	DE	4	1	10	10	10	10	10	10	10	10	10	10	10	10
Customer #232	DE	4	1	18	18	18	18	18	18	18	18	18	18	18	18
Customer #233	DE	4	1	4	4	4	4	4	4	4	4	4	4	4	4
Customer #234	DE	4	1	11	11	11	11	11	11	11	11	11	11	11	11
Customer #235	DE	5	2	6	6	6	6	6	6	6	6	6	6	6	6
Customer #236	DE	4	1	4	4	4	4	4	4	4	4	4	4	4	4
Customer #237	DE	6	2	71	71	71	71	71	71	71	71	71	71	71	71
Customer #238	DE	14	2	39	39	39	39	39	39	39	39	39	39	39	39
Customer #239	DE	14	2	10	10	10	10	10	10	10	10	10	10	10	10
Customer #240	DE	14	2	4	4	4	4	4	4	4	4	4	4	4	4
Customer #241	DE	14	2	4	4	4	4	4	4	4	4	4	4	4	4
Customer #242	DE	5	2	1	1	1	1	1	1	1	1	1	1	1	1
Customer #243	DE	14	2	6	6	6	6	6	6	6	6	6	6	6	6
Customer #244	DE	5	2	0	0	0	0	0	0	0	0	0	0	0	0
Customer #245	DE	6	2	4	4	4	4	4	4	4	4	4	4	4	4
Customer #246	DE	6	2	16	16	16	16	16	16	16	16	16	16	16	16
Customer #247	DE	6	2	0	0	0	0	0	0	0	0	0	0	0	0
Customer #248	DE	6	2	8	8	8	8	8	8	8	8	8	8	8	8
Customer #249	DE	6	2	2	2	2	2	2	2	2	2	2	2	2	2
Customer #250	DE	6	2	1	1	1	1	1	1	1	1	1	1	1	1
Customer #251	DE	6	2	12	12	12	12	12	12	12	12	12	12	12	12
Customer #252	DE	4	1	3	3	3	3	3	3	3	3	3	3	3	3
Customer #253	DE	4	1	2	2	2	2	2	2	2	2	2	2	2	2
Customer #254	DE	4	1	6	6	6	6	6	6	6	6	6	6	6	6
Customer #255	DE	4	1	2	2	2	2	2	2	2	2	2	2	2	2
Customer #256	DE	5	2	8	8	8	8	8	8	8	8	8	8	8	8
Customer #257	DE	14	2	0	0	0	0	0	0	0	0	0	0	0	0
Customer #258	DE	4	1	1	1	1	1	1	1	1	1	1	1	1	1
Customer #259	DE	5	2	2	2	2	2	2	2	2	2	2	2	2	2
Customer #260	DE	4	1	10	10	10	10	10	10	10	10	10	10	10	10
Customer #261	DE	14	2	19	19	19	19	19	19	19	19	19	19	19	19
Customer #262	DE	4	1	22	22	22	22	22	22	22	22	22	22	22	22
Customer #263	DE	5	2	22	22	22	22	22	22	22	22	22	22	22	22
Customer #264	DE	5	2	2	2	2	2	2	2	2	2	2	2	2	2
Customer #265	DE	6	2	5	5	5	5	5	5	5	5	5	5	5	5
Customer #266	DE	5	2	3	3	3	3	3	3	3	3	3	3	3	3
Customer #267	DE	5	2	0	0	0	0	0	0	0	0	0	0	0	0
Customer #268	DE	5	2	1	1	1	1	1	1	1	1	1	1	1	1
Customer #269	DE	15	2	3	3	3	3	3	3	3	3	3	3	3	3
Customer #270	DE	5	2	8	8	8	8	8	8	8	8	8	8	8	8
Customer #271	DE	5	2	21	21	21	21	21	21	21	21	21	21	21	21
Customer #272	DE	5	2	34	34	34	34	34	34	34	34	34	34	34	34
Customer #273	DE	15	2	3	3	3	3	3	3	3	3	3	3	3	3
Customer #274	DE	5	2	9	9	9	9	9	9	9	9	9	9	9	9
Customer #275	DE	5	2	6	6	6	6	6	6	6	6	6	6	6	6
Customer #276	DE	5	2	6	6	6	6	6	6	6	6	6	6	6	6
Customer #277	DE	5	2	190	190	190	190	190	190	190	190	190	190	190	190
Customer #278	DE	5	2	10	10	10	10	10	10	10	10	10	10	10	10
Customer #279	DE	5	2	33	33	33	33	33	33	33	33	33	33	33	33
Customer #280	DE	6	2	8	8	8	8	8	8	8	8	8	8	8	8
Customer #281	DE	6	2	22	22	22	22	22	22	22	22	22	22	22	22
Customer #282	DE	6	2	41	41	41	41	41	41	41	41	41	41	41	41
Customer #283	DE	5	2	12	12	12	12	12	12	12	12	12	12	12	12
Customer #284	DE	5	2	8	8	8	8	8	8	8	8	8	8	8	8
Customer #285	DE	5	2	31	31	31	31	31	31	31	31	31	31	31	31
Customer #286	DE	5	2	19	19	19	19	19	19	19	19	19	19	19	19
Customer #287	DE	5	2	3	3	3	3	3	3	3	3	3	3	3	3
Customer #288	DE	5	2	32	32	32	32	32	32	32	32	32	32	32	32
Customer #289	DE	5	2	12	12	12	12	12	12	12	12	12	12	12	12
Customer #290	DE	5	2	16	16	16	16	16	16	16	16	16	16	16	16
Customer #291	DE	15	2	2	2	2	2	2	2	2	2	2	2	2	2
Customer #292	DE	15	2	18	18	18	18	18	18	18	18	18	18	18	18
Customer #293	DE	8	2	0	0	0	0	0	0	0	0	0	0	0	0
Customer #294	DE	8	2	1	1	1	1	1	1	1	1	1	1	1	1
Customer #295	DE	8	2	16	16	16	16	16	16	16	16	16	16	16	16
Customer #296	DE	8	2	3	3	3	3	3	3	3	3	3	3	3	3

CAPACITY RELEASE - DEMAND

Customer Name (Utilicis)	Division	DPA	Zone	30	31	31	28	31	30	31	30	31	31	30	31	
				Nov-18	Dec-18	19-Jan	19-Feb	19-Mar	19-Apr	19-May	19-Jun	19-Jul	19-Aug	19-Sep	19-Oct	
Customer #297	DE	8	2	13	13	13	13	13	13	13	13	13	13	13	13	13
Customer #298	DE	8	2	1	1	1	1	1	1	1	1	1	1	1	1	1
Customer #299	DE	8	2	1	1	1	1	1	1	1	1	1	1	1	1	1
Customer #300	DE	8	2	3	3	3	3	3	3	3	3	3	3	3	3	3
Customer #301	DE	11	2	32	32	32	32	32	32	32	32	32	32	32	32	32
Customer #302	DE	7	2	17	17	17	17	17	17	17	17	17	17	17	17	17
Customer #303	DE	15	2	21	21	21	21	21	21	21	21	21	21	21	21	21
Customer #304	DE	15	2	31	31	31	31	31	31	31	31	31	31	31	31	31
Customer #305	DE	15	2	85	85	85	85	85	85	85	85	85	85	85	85	85
Customer #306	DE	15	2	1	1	1	1	1	1	1	1	1	1	1	1	1
Customer #307	DE	15	2	11	11	11	11	11	11	11	11	11	11	11	11	11
Customer #308	DE	15	2	1	1	1	1	1	1	1	1	1	1	1	1	1
Customer #309	DE	15	2	51	51	51	51	51	51	51	51	51	51	51	51	51
Customer #310	DE	15	2	2	2	2	2	2	2	2	2	2	2	2	2	2
Customer #311	DE	15	2	24	24	24	24	24	24	24	24	24	24	24	24	24
Customer #312	DE	15	2	1	1	1	1	1	1	1	1	1	1	1	1	1
Customer #313	DE	15	2	1	1	1	1	1	1	1	1	1	1	1	1	1
Customer #314	DE	15	2	2	2	2	2	2	2	2	2	2	2	2	2	2
Customer #315	DE	15	2	23	23	23	23	23	23	23	23	23	23	23	23	23
Customer #316	DE	14	2	108	108	108	108	108	108	108	108	108	108	108	108	108
Customer #317	DE	14	2	5	5	5	5	5	5	5	5	5	5	5	5	5
Customer #318	DE	14	2	3	3	3	3	3	3	3	3	3	3	3	3	3
Customer #319	DE	14	2	1	1	1	1	1	1	1	1	1	1	1	1	1
Customer #320	DE	14	2	4	4	4	4	4	4	4	4	4	4	4	4	4
Customer #321	DE	15	2	0	0	0	0	0	0	0	0	0	0	0	0	0
Customer #322	DE	15	2	16	16	16	16	16	16	16	16	16	16	16	16	16
Customer #323	DE	15	2	9	9	9	9	9	9	9	9	9	9	9	9	9
Customer #324	DE	15	2	4	4	4	4	4	4	4	4	4	4	4	4	4
Customer #325	DE	15	2													
Customer #326	DE	15	2	3	3	3	3	3	3	3	3	3	3	3	3	3
Customer #327	DE	15	2	23	23	23	23	23	23	23	23	23	23	23	23	23
Customer #328	DE	15	2	1	1	1	1	1	1	1	1	1	1	1	1	1
Customer #329	DE	15	2	58	58	58	58	58	58	58	58	58	58	58	58	58
Customer #330	DE	15	2	2	2	2	2	2	2	2	2	2	2	2	2	2
Customer #331	DE	15	2	3	3	3	3	3	3	3	3	3	3	3	3	3
Customer #332	DE	15	2	2	2	2	2	2	2	2	2	2	2	2	2	2
Customer #333	DE	15	2													
Customer #334	DE	15	2	1	1	1	1	1	1	1	1	1	1	1	1	1
Customer #335	DE	15	2	5	5	5	5	5	5	5	5	5	5	5	5	5
Customer #336	DE	15	2	0	0	0	0	0	0	0	0	0	0	0	0	0
Customer #337	DE	15	2	1	1	1	1	1	1	1	1	1	1	1	1	1
Customer #338	DE	15	2	1	1	1	1	1	1	1	1	1	1	1	1	1
Customer #339	DE	15	2	0	0	0	0	0	0	0	0	0	0	0	0	0
Customer #340	DE	15	2	7	7	7	7	7	7	7	7	7	7	7	7	7

CAPACITY RELEASE - DEMAND

Customer Name (Utilicis)	Division	DPA	Zone	30	31	31	28	31	30	31	30	31	31	30	31	
				Nov-18	Dec-18	19-Jan	19-Feb	19-Mar	19-Apr	19-May	19-Jun	19-Jul	19-Aug	19-Sep	19-Oct	
Customer #341	DE	15	2	6	6	6	6	6	6	6	6	6	6	6	6	6
Customer #342	DE	15	2	26	26	26	26	26	26	26	26	26	26	26	26	26
Customer #343	DE	5	2	11	11	11	11	11	11	11	11	11	11	11	11	11
Customer #344	DE	11	2	0	0	0	0	0	0	0	0	0	0	0	0	0
Customer #345	DE	11	2	5	5	5	5	5	5	5	5	5	5	5	5	5
Customer #346	DE	11	2	9	9	9	9	9	9	9	9	9	9	9	9	9
Customer #347	DE	15	2	10	10	10	10	10	10	10	10	10	10	10	10	10
Customer #348	DE	15	2	20	20	20	20	20	20	20	20	20	20	20	20	20
Customer #349	DE	8	2	1	1	1	1	1	1	1	1	1	1	1	1	1
Customer #350	DE	15	2	36	36	36	36	36	36	36	36	36	36	36	36	36
Customer #351	DE	15	2	1	1	1	1	1	1	1	1	1	1	1	1	1
Customer #352	DE	15	2	1	1	1	1	1	1	1	1	1	1	1	1	1
Customer #353	DE	15	2	18	18	18	18	18	18	18	18	18	18	18	18	18
Customer #354	DE	15	2	1	1	1	1	1	1	1	1	1	1	1	1	1
Customer #355	DE	15	2	14	14	14	14	14	14	14	14	14	14	14	14	14
Customer #356	DE	15	2	22	22	22	22	22	22	22	22	22	22	22	22	22
Customer #357	DE	15	2	27	27	27	27	27	27	27	27	27	27	27	27	27
Customer #358	DE	15	2	0	0	0	0	0	0	0	0	0	0	0	0	0
Customer #359	DE	15	2	1	1	1	1	1	1	1	1	1	1	1	1	1
Customer #360	DE	15	2	57	57	57	57	57	57	57	57	57	57	57	57	57
Customer #361	DE	6	2	12	12	12	12	12	12	12	12	12	12	12	12	12
Customer #362	DE	8	2	19	19	19	19	19	19	19	19	19	19	19	19	19
Customer #363	DE	6	2	273	273	273	273	273	273	25	0	105	165	146	273	273
Customer #364	DE	6	2	35	35	35	35	35	35	18	1	28	28	27	35	35
Customer #365	DE	5	2													
Customer #366	DE	5	2													
Customer #367	DE	5	2													
Customer #368	DE	5	2													
Customer #369	DE	5	2													
Customer #370	DE	5	2													
Customer #371	DE	5	2													
Customer #372	DE	5	2													
Customer #373	DE	5	2	46	46	46	46	46	46	46	46	46	46	46	46	46
Customer #374	DE	14	2	42	42	42	42	42	42	42	42	42	42	42	42	42
Customer #375	DE	6	2	47	47	47	47	47	47	47	47	47	47	47	47	47
Customer #376	DE	5	2	34	34	34	34	34	34	34	34	34	34	34	34	34
Customer #377	DE	4	1	57	57	57	57	57	57	57	57	57	57	57	57	57
Customer #378	DE	5	2	50	50	50	50	50	50	50	50	50	50	50	50	50
Customer #379	DE	8	2	236	236	236	236	236	236	236	236	236	236	236	236	236
Customer #380	DE	5	2													
Customer #381	DE	5	2	6	6	6	6	6	6	6	6	6	6	6	6	6
Customer #382	DE	5	2	4	4	4	4	4	4	4	4	4	4	4	4	4
Customer #383	DE	5	2	0	1	1	1	1	0	0	0	0	0	0	0	0
Customer #384	DE	5	2	24	24	24	24	24	24	24	24	24	24	24	24	24
Customer #385	DE	5	2	11	11	11	11	11	11	11	11	11	11	11	11	11
Customer #386	DE	5	2	7	7	7	7	7	7	7	7	7	7	7	7	7
Customer #387	DE	5	2	81	81	84	84	84	84	84	84	84	84	84	84	84
Customer #388	DE	5	2	9	9	9	9	9	9	9	9	9	9	9	9	9
Customer #389	DE	5	2	10	10	10	10	10	10	10	10	10	10	10	10	10
Customer #390	DE	5	2	14	14	14	14	14	14	14	14	14	14	14	14	14
Customer #391	DE	5	2	1	0	0	0	0	1	1	2	3	3	3	3	1
Customer #392	DE	5	2	1	0	0	0	0	1	2	3	4	4	4	3	2
Customer #393	DE	5	2	1	0	0	0	0	1	2	3	4	4	4	3	2
Customer #394	DE	5	2	7	7	7	7	7	7	7	7	7	7	7	7	7
Customer #395	DE	5	2	25	25	25	25	25	25	25	25	25	25	25	25	25
	DE			18954	19100	18957	18511	18569	18725	18422	18464	18576	18730	19434	19746	
		Zone	1	1620	1620	1620	1620	1620	1620	1620	1620	1620	1620	1620	1620	
	377	Zone	2	17334	17480	17337	16891	16949	17105	16802	16844	16956	17110	17814	18126	
				18954	19100	18957	18511	18569	18725	18422	18464	18576	18730	19434	19746	
ESNG Max Rate	Z1	\$ 0.3705		\$ 18,006.30	\$ 18,006.30	\$ 18,006.30	\$ 18,006.30	\$ 18,006.30	\$ 18,006.30	\$ 18,006.30	\$ 18,006.30	\$ 18,006.30	\$ 18,006.30	\$ 18,006.30	\$ 18,006.30	
	Z2	\$ 0.8276		\$ 430,368.55	\$ 433,993.44	\$ 430,443.04	\$ 419,369.75	\$ 420,809.77	\$ 424,682.94	\$ 417,160.06	\$ 418,202.83	\$ 420,983.57	\$ 424,807.08	\$ 442,285.99	\$ 450,032.33	
TOTAL ESNG Capacity Credits				\$ 448,374.85	\$ 451,999.74	\$ 448,449.34	\$ 437,376.05	\$ 438,816.07	\$ 442,689.24	\$ 435,166.36	\$ 436,209.13	\$ 438,989.87	\$ 442,813.38	\$ 460,292.29	\$ 468,038.63	
	Z1	DCQ		583	873	965	1,072	822	484	234	224	213	237	333	284	
	Z2	DCQ		12,180	15,194	15,466	15,945	14,407	11,404	9,859	9,943	8,377	9,360	10,536	11,154	
				12,763	16,067	16,431	17,017	15,229	11,888	10,093	10,167	8,590	9,597	10,869	11,438	
	Z1	\$ 0.0200		\$ 349.80	\$ 541.26	\$ 598.30	\$ 600.32	\$ 509.64	\$ 290.40	\$ 145.08	\$ 134.40	\$ 132.06	\$ 146.94	\$ 199.80	\$ 176.08	
	Z2	\$ 0.0387		\$ 14,140.98	\$ 18,228.24	\$ 18,554.56	\$ 17,278.00	\$ 17,284.08	\$ 13,240.04	\$ 11,827.84	\$ 11,543.82	\$ 10,049.89	\$ 11,229.19	\$ 12,232.30	\$ 13,381.45	
TOTAL ESNG Commodity Credits				\$ 14,490.78	\$ 18,769.50	\$ 19,152.86	\$ 17,878.32	\$ 17,793.72	\$ 13,530.44	\$ 11,972.92	\$ 11,678.22	\$ 10,181.95	\$ 11,376.13	\$ 12,432.10	\$ 13,557.53	
TOTAL ESNG CREDIT				\$ 462,865.63	\$ 470,769.24	\$ 467,602.20	\$ 455,254.37	\$ 456,609.79	\$ 456,219.68	\$ 447,139.28	\$ 447,887.36	\$ 449,171.81	\$ 454,189.51	\$ 472,724.39	\$ 481,596.16	

Chesapeake Utilities Corporation
Delaware Division
Cost of Fixed and Variable Gas Supply Resources
Based on Projected November 1, 2018 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	\$6.0966	\$73.1595	\$601,664
Transco					
GSS	2,655	31,860	\$3.0624	\$36.7488	\$97,568
LSS	580	6,960	\$4.5798	\$54.9577	\$31,875
WSS (includes assoc. FT)	1,503	18,036	\$7.1159	\$85.3902	\$128,342
ESS (includes assoc. FT)	3,776	45,312	\$10.8412	\$130.0947	\$491,238
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	\$24.3384	\$292.0606	\$1,878,242
MDTQ 181 Day (FSS)	8,224	49,344	\$48.6789	\$292.0732	\$2,402,010
MDTQ 151 Day (LSS, WSS)	2,083	10,415	\$58.4126	\$292.0629	\$608,367
MDTQ 90 Day (PS)	311	933	\$97.2937	\$291.8810	\$90,775
Storage Demand	17,049	204,588	\$31.0940	\$373.1285	\$6,361,467
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	\$0.0167	\$0.2008	\$5,822
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	\$0.2944	\$237,641
Storage Demand & Capacity					
Columbia					
FSS	8,224	98,688	\$7.7504	\$93.0051	\$764,874
Transco					
GSS	2,655	31,860	\$3.8601	\$46.3213	\$122,983
LSS	580	6,960	\$5.4163	\$64.9956	\$37,697
WSS	1,503	18,036	\$7.8962	\$94.7542	\$142,416
ESS	3,776	45,312	\$11.4839	\$137.8066	\$520,358
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	\$24.3384	\$292.0606	\$1,878,242
MDTQ 181 Day (FSS)	8,224	49,344	\$48.6789	\$292.0732	\$2,402,010
MDTQ 151 Day (LSS, WSS)	2,083	10,415	\$58.4126	\$292.0629	\$608,367
MDTQ 90 Day (PS)	311	933	\$97.2937	\$291.8810	\$90,775
Storage Demand & Capacity	17,049	204,588	\$32.2556	\$387.0672	\$6,599,108
Propane Peak Shaving	6,010				\$226,679
Fixed Gas Supply Resources	23,059			\$296.0192	\$6,825,787
Storage Injection & Withdrawal					
GSS	262,740	n/a	\$0.0470	n/a	\$12,344
LSS	58,000	n/a	\$0.1263	n/a	\$7,325
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	\$0.0253	n/a	\$40,883
Half of Variable Rate For Either Injection or Withdrawal			\$0.0127		

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 42.93%
@ Load Factor of	10%	37	\$296.0192	\$8.0005	
@ Load Factor of	20%	73	\$296.0192	\$4.0551	
@ Load Factor of	30%	110	\$296.0192	\$2.6911	
@ Load Factor of	40%	146	\$296.0192	\$2.0275	
@ Load Factor of	50%	183	\$296.0192	\$1.6176	
@ Load Factor of	60%	219	\$296.0192	\$1.3517	
@ Load Factor of	70%	256	\$296.0192	\$1.1563	
@ Load Factor of	80%	292	\$296.0192	\$1.0138	
@ Load Factor of	90%	329	\$296.0192	\$0.8998	
@ Load Factor of	100%	365	\$296.0192	\$0.8110	
Del. Div. Weighted Average	27.20%	99	\$296.0192	\$2.9901	\$1.2836

Variable Gas Supply Cost			Average Cost per DT	Estimated Imbalance Percentage	Variable Cost per DT
Variable Commodity Rate			\$0.0127	27.32%	\$0.0035

Development of Interruptible Balancing Service Rate			
Fixed Capacity Rate per DT		\$1.2836	
Variable Commodity Rate per DT		\$0.0035	
Balancing Service Rate per DT		\$1.2871	
Balancing Service Rate per Mcf		\$1.3322	
Capacity Release Recovery per Mcf		\$0.0000	*No dollars in current GSR
Total Balancing Service Rate per Mcf		\$1.3322	
Total Balancing Service Rate per Ccf		\$0.133	

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 45.38% Design Day
@ Load Factor of	10%	37	\$296.0192	\$8.0005	\$3.6306
@ Load Factor of	20%	73	\$296.0192	\$4.0551	\$1.8402
@ Load Factor of	30%	110	\$296.0192	\$2.6911	\$1.2212
@ Load Factor of	40%	146	\$296.0192	\$2.0275	\$0.9201
@ Load Factor of	50%	183	\$296.0192	\$1.6176	\$0.7341
@ Load Factor of	60%	219	\$296.0192	\$1.3517	\$0.6134
@ Load Factor of	70%	256	\$296.0192	\$1.1563	\$0.5247
@ Load Factor of	80%	292	\$296.0192	\$1.0138	\$0.4601
@ Load Factor of	90%	329	\$296.0192	\$0.8998	\$0.4083
@ Load Factor of	100%	365	\$296.0192	\$0.8110	\$0.3680
Del. Div. Weighted Average	24.13%	88	\$296.0192	\$3.3639	\$1.5265

Variable Gas Supply Cost			Average Cost per DT	Estimated Imbalance Percentage	Variable Cost per DT
Variable Commodity Rate			\$0.0127	33.02%	\$0.0042

Development of Firm Balancing Service Rate			
Fixed Capacity Rate per DT		\$1.5265	
Variable Commodity Rate per DT		\$0.0042	
Firm Balancing Service Rate per DT		\$1.5307	
Balancing Service Rate per Mcf		\$1.5843	
Capacity Release Recovery per Mcf		\$0.0000	*No dollars in current GSR
Total Balancing Service Rate per Mcf		\$1.5843	
Total Firm Balancing Service Rate per Ccf		\$0.158	

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 40.35% Design Day
@ Load Factor of	10%	37	\$296.0192	\$8.0005	\$3.2280
@ Load Factor of	20%	73	\$296.0192	\$4.0551	\$1.6362
@ Load Factor of	30%	110	\$296.0192	\$2.6911	\$1.0858
@ Load Factor of	40%	146	\$296.0192	\$2.0275	\$0.8181
@ Load Factor of	50%	183	\$296.0192	\$1.6176	\$0.6527
@ Load Factor of	60%	219	\$296.0192	\$1.3517	\$0.5454
@ Load Factor of	70%	256	\$296.0192	\$1.1563	\$0.4665
@ Load Factor of	80%	292	\$296.0192	\$1.0138	\$0.4090
@ Load Factor of	90%	329	\$296.0192	\$0.8998	\$0.3631
@ Load Factor of	100%	365	\$296.0192	\$0.8110	\$0.3272
Del. Div. Weighted Average	31.74%	116	\$296.0192	\$2.5519	\$1.0296

Variable Gas Supply Cost			Average Cost per DT	Estimated Imbalance Percentage	Variable Cost per DT
Variable Commodity Rate			\$0.0127	22.24%	\$0.0028

Development of Firm Balancing Service Rate			
Fixed Capacity Rate per DT		\$1.0296	
Variable Commodity Rate per DT		\$0.0028	
Firm Balancing Service Rate per DT		\$1.0324	
Balancing Service Rate per Mcf		\$1.0685	
Capacity Release Recovery per Mcf		\$0.0000	*No dollars in current GSR
Total Balancing Service Rate per Mcf		\$1.0685	
Total Firm Balancing Service Rate per Ccf		\$0.107	

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 10.18% Design Day
@ Load Factor of	10%	37	\$296.0192	\$8.0005	\$0.8145
@ Load Factor of	20%	73	\$296.0192	\$4.0551	\$0.4128
@ Load Factor of	30%	110	\$296.0192	\$2.6911	\$0.2740
@ Load Factor of	40%	146	\$296.0192	\$2.0275	\$0.2064
@ Load Factor of	50%	183	\$296.0192	\$1.6176	\$0.1647
@ Load Factor of	60%	219	\$296.0192	\$1.3517	\$0.1376
@ Load Factor of	70%	256	\$296.0192	\$1.1563	\$0.1177
@ Load Factor of	80%	292	\$296.0192	\$1.0138	\$0.1032
@ Load Factor of	90%	329	\$296.0192	\$0.8998	\$0.0916
@ Load Factor of	100%	365	\$296.0192	\$0.8110	\$0.0826
Del. Div. Weighted Average	83.48%	305	\$296.0192	\$0.9706	\$0.0988

Variable Gas Supply Cost			Average Cost per DT	Estimated Imbalance Percentage	Variable Cost per DT
Variable Commodity Rate			\$0.0127	2.17%	\$0.0003

Development of Firm Balancing Service Rate			
Fixed Capacity Rate per DT		\$0.0988	
Variable Commodity Rate per DT		\$0.0003	
Firm Balancing Service Rate per DT		\$0.0991	
Balancing Service Rate per Mcf		\$0.1026	
Capacity Release Recovery per Mcf		\$0.0000	*No dollars in current GSR
Total Balancing Service Rate per Mcf		\$0.1026	
Total Firm Balancing Service Rate per Ccf		\$0.010	

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	\$296.0192	\$8.0005	
@ Load Factor of	20%	73	\$296.0192	\$4.0551	
@ Load Factor of	30%	110	\$296.0192	\$2.6911	
@ Load Factor of	40%	146	\$296.0192	\$2.0275	
@ Load Factor of	50%	183	\$296.0192	\$1.6176	
@ Load Factor of	60%	219	\$296.0192	\$1.3517	
@ Load Factor of	70%	256	\$296.0192	\$1.1563	
@ Load Factor of	80%	292	\$296.0192	\$1.0138	
@ Load Factor of	90%	329	\$296.0192	\$0.8998	
@ Load Factor of	100%	365	\$296.0192	\$0.8110	
Interruptible @ 100% LFR	100.00%	365	\$296.0192	\$0.8110	\$0.0081

Variable Gas Supply Cost			Average Cost per DT	Estimated Imbalance Percentage	Variable Cost per DT
Variable Commodity Rate			\$0.0127	9.06%	\$0.0012

Development of Interruptible Balancing Service Rate		
Fixed Capacity Rate per DT		\$0.0081
Variable Commodity Rate per DT		\$0.0012
Balancing Service Rate per DT		\$0.0093
Balancing Service Rate per Mcf		\$0.0096
Capacity Release Recovery per Mcf		\$0.0000
Total Balancing Service Rate per Mcf		\$0.0096
Total Balancing Service Rate per Ccf		\$0.001

*No dollars in current GSR

Chesapeake Utilities Corporation			
Delaware Division			
Gas Supply Resources			
Demand and Capacity Entitlements effective November 2017 & November 2018			
(DT)			
Transcontinental Gas Pipeline Corporation			
		2017	2018
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			
		2017	2018
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			
		2017	2018
FT-1	*	34,100	34,100
Eastern Shore Natural Gas Company			
		2017	2018
FT, MDQ - R1		35,150	35,150
FT, MDQ - R2	*	66,948	83,448
ST, MDQ - R2	*	5,081	5,081
FT, MDQ - D1		-	16,437
ST, MDQ - D1		-	400
FT, MDQ - D2		38,386	67,011
ST, MDQ - D2		3,349	4,681
FT, MDQ - D3		28,562	-
ST, MDQ - D3		1,732	-
Chesapeake Utilities Corporation - Delaware Division			
		2017	2018
Propane Peak Shaving Facilities	*	10,176	6,010
Temporary LNG Peak Shaving Service		3,000	-

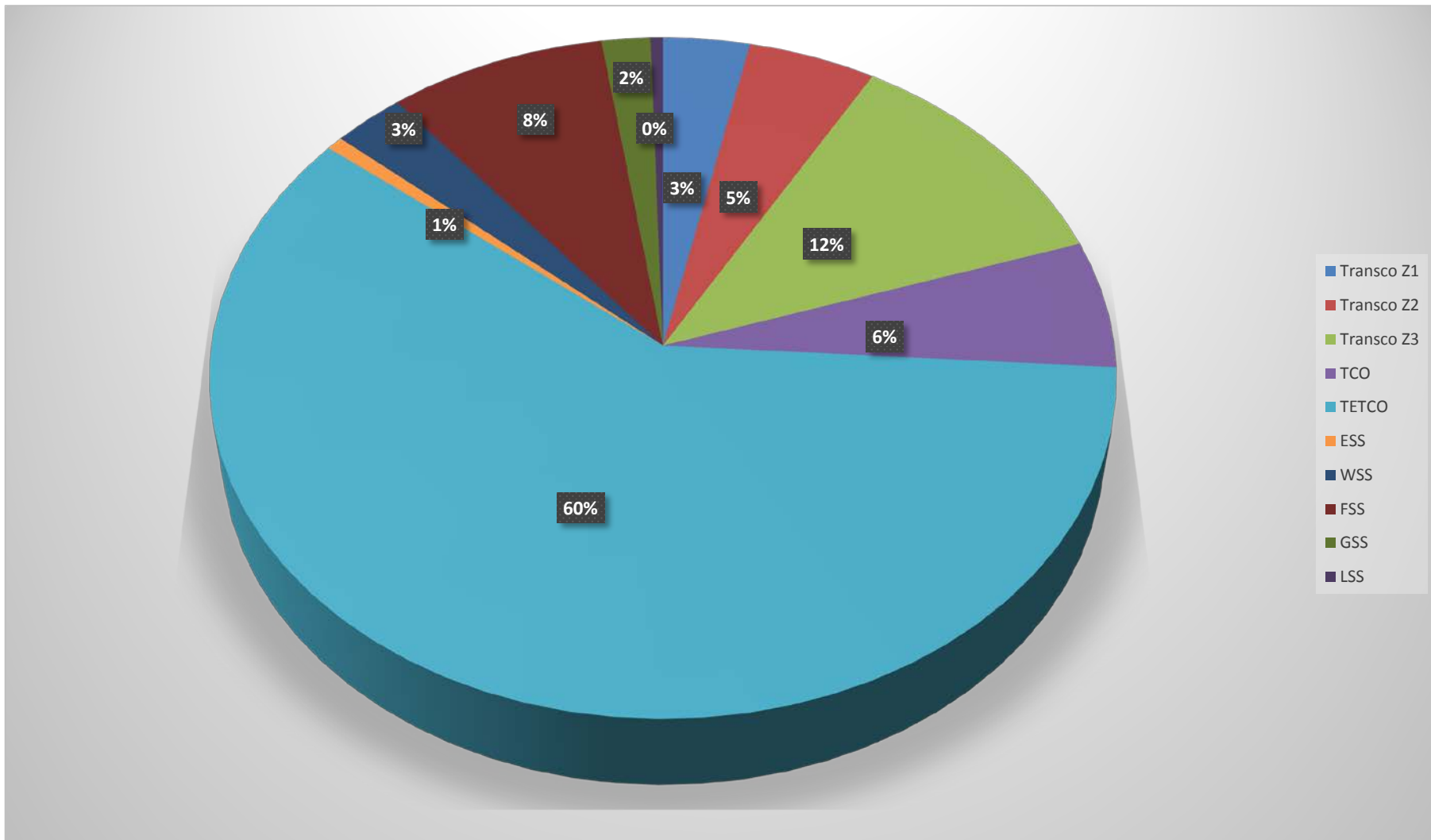
MDQ = Maximum Daily Quantity

*** Design Day Deliverability**

**** Storage Service Contracted with ESNG**

DELAWARE DIVISION LOAD AND SUPPLY

2018 - 2019 Forecast Year



BEFORE THE DELAWARE PUBLIC SERVICE COMMISSION

IN THE MATTER OF THE APPLICATION OF)
CHESAPEAKE UTILITIES CORPORATION)
FOR APPROVAL OF A CHANGE IN ITS) P.S.C. DOCKET NO. 18-
GAS SALES SERVICE RATES ("GSR"))
TO BE EFFECTIVE NOVEMBER 1, 2018)

DIRECT TESTIMONY OF WILLIAM R. KRISS

On Behalf of Chesapeake Utilities Corporation

Delaware Division

Submitted for filing: August 31, 2018

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

3 A. My name is William R. Kriss, and I am the Manager of Gas Supply and
4 Transportation Services for Chesapeake Utilities Corporation
5 ("Chesapeake" or "the Company"). My business address is 350 S. Queen
6 Street, Dover, Delaware 19904.

7

8 Q. DESCRIBE BRIEFLY YOUR EDUCATION AND RELEVANT
9 PROFESSIONAL BACKGROUND.

10 A. I received a Bachelor of Science Degree in Operations Management with a
11 minor in Economics from the University of Delaware in Newark, Delaware
12 and a Masters of Business Administration concentrated in Finance from
13 Wilmington University in Wilmington, Delaware. I was hired by Chesapeake
14 Utilities Corporation in December 2007 and have worked in various gas
15 supply roles since. My current responsibilities are inclusive of all matters
16 associated with gas supply and its procurement for Chesapeake Utilities
17 Corporation. Prior to joining Chesapeake, my experience included auditing
18 of internal controls for the purpose of Sarbanes Oxley compliance with
19 Wilmington Trust Corporation in Wilmington, Delaware, as well as
20 investment accounting with PFPC, a wholly-owned subsidiary of PNC Bank.

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

3 A. The purpose of my direct testimony in this GSR application is to provide
4 support for the gas costs used in the calculation of the Delaware Division's
5 three proposed Gas Sales Service Rates to be effective with service
6 rendered on and after November 1, 2017. My direct testimony will also
7 discuss the Company's gas supply and procurement activities as required
8 by Commission Order No. 4767 issued on April 14, 1998 in the Company's
9 Gas Sales Service Rate filing in Docket No. 97-294F.

10

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

13 A. No. In my direct testimony, I will address Schedule L, which is a summary
14 of Chesapeake's demand and capacity entitlements to be effective
15 November 2017 and Schedule M, which is a chart of the Delaware
16 Division's load and supply projections for the upcoming determination
17 period. Both schedules are attached to the direct testimony of Marie E.
18 Kozel.

19

20 Q. WHAT PIPELINE SUPPLIERS ARE CURRENTLY PROVIDING
21 SERVICES TO THE DELAWARE DIVISION?

1 A. The Delaware Division is currently receiving a mix of transportation and
2 storage services from four interstate pipeline suppliers. These four pipeline
3 suppliers are Transcontinental Gas Pipe Line Company, LLC (“Transco”),
4 Columbia Gas Transmission, LLC (“Columbia”), Texas Eastern
5 Transmission, LP (“TETCO”) and Eastern Shore Natural Gas Company
6 (“ESNG”).

7

8 Q. WHAT WERE THE DELAWARE DIVISION’S CAPACITY ENTITLEMENTS
9 ON PIPELINES UPSTREAM OF ESNG DURING THE LAST WINTER
10 SEASON?

11 A. Schedule L represents the Delaware Division’s winter season upstream
12 capacity entitlements that were effective November 1 of 2017, and 2018.
13 The maximum daily upstream entitlements were 77,942 Dts/day.

14

15 Q. HAS THE DELAWARE DIVISION CHANGED ITS CAPACITY
16 ENTITLEMENTS ON ANY PIPELINES SINCE THE LAST GSR
17 PROCEEDING?

18 A. Yes. The Company previously executed a precedent agreement in 2016,
19 and the corresponding firm service agreement in 2017 for an additional
20 16,500 dts ESNG capacity, which will be in-service for this winter season.

1 Q. PLEASE PROVIDE INFORMATION ON CHESAPEAKE'S STORAGE
2 SERVICES.

3 A. Chesapeake contracts for several different storage services, which provides
4 flexibility to meet customer needs. Currently, the Company includes three
5 storage services in the Company's Asset Management Agreement ("AMA")
6 and contracts for two storage services on ESNG. The storages included in
7 the AMA are Transco's Washington Storage Service ("WSS") and
8 Eminence Storage Service ("ESS") and Columbia's Firm Storage Service
9 ("FSS"). At the beginning of the AMA, these storage balances were
10 reconciled and transferred to the control of the Asset Manager. The
11 Company designates quantities of gas to be injected or withdrawn from
12 these storage services, however these quantities are understood to be
13 paper transactions which may differ from the actual storage activity at any
14 point in time since the AMA authorizes the Asset Manager, subject to the
15 Company's designation of storage and tariff limitations, to withdraw and
16 inject at its discretion. The Company retains the right to receive, on demand
17 at the delivery point, the quantity of gas that it has requested. On a monthly
18 basis, the paper balance for each storage service managed by the Asset
19 Manager is reconciled. Withdrawals from WSS are anticipated in the
20 monthly baseload calculation because Transco Firm Transportation ("FT")
21 capacity is utilized in order to flow WSS. The primary purpose of ESS is to
22 provide the Company a supply option during weather emergencies, such as

1 hurricanes, or other supply disruptions. It is the Company's policy to fill ESS
2 by August 1 each year in order to be in a position to mitigate supply
3 disruptions during hurricane season. As is the case with WSS, ESS
4 requires the use of FT capacity to be transported. Daily withdrawals from
5 FSS during the winter season are anticipated but are not typically
6 baseloaded. FSS is the Company's largest storage service and provides
7 greater flexibility in scheduling with regard to changes in weather and
8 unexpected fluctuations in demand. In addition FSS flows on Storage
9 Service Transportation ("SST") contracts rather than utilizing FT contracts.
10 Injections for FSS are typically baseloaded. The two ESNG storage
11 services are General Storage Service ("GSS") and Leidy Storage Service
12 ("LSS"). GSS is a year round storage service and provides the Company
13 swing capability throughout the year. LSS is a seasonal storage service,
14 meaning that injections can only be made April through October and
15 withdrawals are only available November through March. GSS and LSS
16 have transportation deliverability inherent in the services. No additional FT
17 is needed for injections or withdrawals. The Company tracks the storage
18 levels of each storage service closely, in order to comply with the provisions
19 established by each storage service Tariff and to ensure the adequacy of
20 storage supply.

1 Q. PLEASE PROVIDE A BRIEF DESCRIPTION OF THE COMPANY'S GAS
2 SUPPLY PROCUREMENT ACTIVITIES SINCE NOVEMBER 1, 2016.

3 A. The Company utilizes its Asset Manager for gas supply, procuring monthly
4 baseload and spot purchases pursuant to the terms of its AMA. It is
5 consistent with the Company's procurement practices to minimize its
6 exposure to the volatility of the daily market during the winter season;
7 therefore, most of the Company's gas supply costs during the winter months
8 are based on fixed prices that are set prior to the beginning of the delivery
9 month. The daily spot purchases referenced above are susceptible to daily
10 market volatility. However, due to the varying nature of the Company's
11 demand requirements, it is essential to have an element of spot supply to
12 ensure the Company has the flexibility to comply with pipeline tariffs and
13 operating requirements. Therefore, a mix of pricing mechanisms, including
14 commodity prices based on the published "Inside FERC" monthly index, the
15 published "Gas Daily" midpoint and "triggers" based on New York
16 Mercantile Exchange postings have been used to mitigate the impact of
17 market fluctuations on the commodity cost of gas during this period.
18 Effective July 12, 2007, the Company implemented the parameters
19 identified in the commodity procurement plan ("Plan") attached to the
20 settlement agreement in PSC Docket No. 06-287F and amended as part of
21 the settlement in Docket No. 09-398F. The parameters of the Plan dictate
22 that the Company will enter into physical transactions for natural gas for the

1 upcoming twelve-month period on the second Wednesday of each month.

2 The Company has followed the guidelines set forth in the Plan.

3

4 Q. PLEASE BRIEFLY EXPLAIN THE COMPANY'S RELATIONSHIP WITH
5 ITS ASSET MANAGER AND THE SERVICES THAT ARE PROVIDED.

6 A. As authorized by the Commission on October 6, 2016, by Order No. 8954
7 in PSC Docket No. 15-1362 the Company entered into a new Asset
8 Management Agreement for the period April 1, 2017 to March 31, 2020.
9 Chesapeake's Asset Manager provides capacity management, as well as
10 supply and dispatch scheduling on pipelines upstream of ESNG, firm and
11 interruptible gas supply, balancing of supply resources, and monthly
12 accounting and reporting of transactions. The Company's firm customers
13 benefit from the AMA, which provides the Company with access to reliable
14 and flexible supply alternatives in addition to enhanced fixed cost recovery
15 relating to the Company's transportation and storage entitlements. The cost
16 recovery achieved by the Company is reflected as a credit on the monthly
17 supply invoice that is submitted by the Asset Manager.

18

19 Q. WHAT ARE THE DELAWARE DIVISION'S PLANS REGARDING GAS
20 SUPPLY FOR THE UPCOMING WINTER SEASON OF 2018-2019?

21 A. The Company has prepared demand projections for the upcoming winter
22 season, which is visually represented by Schedule M. It expects to meet

1 those demand projections with supply purchases of baseload, daily spot,
2 and storage service as negotiated within its Asset Management Agreement.
3 Approximately 50% of the winter's expected firm sales requirements will
4 have been procured utilizing the Company's approved hedging program.
5 Details of Chesapeake's winter supply preparedness will be discussed
6 further in the annually filed "Long-Term Supply and Demand Strategic Plan".

7

8 Q. DOES THIS CONCLUDE YOUR TESTIMONY?

9 A. Yes, it does.

DATED: August 31, 2018

STATE OF DELAWARE)
)
COUNTY OF KENT)

AFFIDAVIT OF WILLIAM R. KRISS

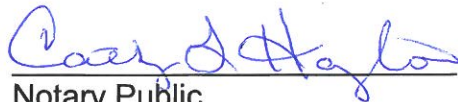
WILLIAM R. KRISS, being first duly sworn according to law, on oath deposes and says that he is the witness whose testimony appears as "Chesapeake Utilities Corporation, Delaware Division, Direct Testimony of William R. Kriss"; that, if asked the questions which appear in the text of the direct testimony, 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 31st day of August 2018 the above-named William R. Kriss and acknowledged the foregoing Testimony to be his free act and deed. Before me,





Notary Public
My Commission Expires: 03-27-19