KANSAS GAS SERVICE, A DIVISION OF ONE GAS, INC.
General Public Notification
Test Year Ended December 31, 2015

THIS SECTION SHOULD CONTAIN GENERAL INFORMATION ABOUT HOW COMPANY LET THE GENERAL PUBLIC WHICH IS AFFECTED BY THE FILING KNOW ABOUT THE FILING. IT SHALL INCLUDE GENERAL INFORMATION ABOUT THE FILING WHICH WILL BE OF INTEREST TO THE PUBLIC AND SUITABLE FOR PUBLICATION. INFORMATION SHALL INCLUDE:

i)	**ANNUAL REVENUE INCREASE PROPOSED IN THE FILING,**	Schedule 1, Col 6, Row 13
ii)	**AFFECTED COMMUNITIES**	Schedule 2
iii)	**NUMBER AND CLASSES OF CUSTOMERS AFFECTED,**	Schedule 1, Col 1 and Col 2
iv)	**AVERAGE MONTHLY INCREASE PER CUSTOMER,**	Schedule 1, Col 7
v)	**SUMMARY OF THE REASONS FOR THE FILING**	Schedule 3
vi)	**OTHER INFORMATION COMPANY WANTS OR KCC MAY REQUIRE, AND**	None
vii)	**COPIES OF PRESS RELEASES ISSUED PRIOR TO OR AT THE FILING DATE.**	Schedule 4

KANSAS GAS SERVICE, A DIVISION OF ONE GAS, INC.
General Public Notification
Test Year Ended December 31, 2015

Line No.	Col. 1	Annualized Average Number of Customers Col. 2	Proforma MCF Col. 3	Base Revenues Col. 4	Proposed Revenues Col. 5	Proposed Revenue Increase Col. 6	Proposed Average Monthly Base Rate Increase Per Customer Col. 7
1	Residential	579,541	42,284,167	$196,678,857	$232,125,604	$35,446,747	$5.10
2	General Service Sales - Small	36,849	3,804,594	$20,760,708	$20,758,806	($1,902)	$0.00
3	General Service Sales - Large	11,904	6,275,606	$15,698,681	$15,698,681	$0	$0.00
4	General Service Sales - Transport Eligible	566	1,423,217	$2,484,991	$2,484,991	$0	$0.00
5	Small Generator Sales Service	649	9,936	$413,030	$413,030	$0	$0.00
6	Irrigation Sales	225	146,375	$343,320	$343,320	$0	$0.00
7	KGSSD	1	31,337	$31,379	$31,379	$0	$0.00
8	Sales for Resale	7	62,689	$86,147	$86,147	$0	$0.00
9	Small Transportation	4,483	7,472,350	$14,936,970	$14,936,970	$0	$0.00
10	Compressed Natural Gas Transportation	3	148,327	$124,122	$124,122	$0	$0.00
11	Irrigation Transportation	521	848,324	$1,651,952	$1,651,952	$0	$0.00
12	Large Volume Transport	548	16,271,990	$18,464,566	$18,464,566	$0	$0.00
13	Wholesale Transport	27	1,027,222	$1,311,435	$1,311,435	$0	$0.00
14		635,324	79,806,134	$272,986,158	$308,431,003	$35,444,845	$4.65
15	Other Operating Revenue			$14,945,255	$14,945,255		
16				$287,931,413	$323,376,258		

The difference between the $5.10 shown in Col. 7, line 1 in this Schedule as the monthly increase to a typical residential customer and the $4.34 shown in the press release in Section 2 of the Application is due to the fact that the $5.10 amount includes the Gas System Reliability Surcharge of $0.76 that is being placed into base rates and is already being paid for by the residential customer. Since those customers are already paying for that surcharge, they were not included in the annual increase shown in the press release.

	Community		Community		Community		Community		Community
1	Abilene	51	Carbondale	101	Esbon	151	Industry	201	Madison
2	Alden	52	Carlyle	102	Everest	152	Inman	202	Mahaska
3	Alma	53	Carona	103	Fairview	153	Iola Rural	203	Manhattan
4	Alta Vista	54	Cawker City	104	Fairway	154	Isabel	204	Mankato
5	Ames	55	Centralia	105	Formoso	155	Iuka	205	Marquette
6	Andover	56	Chapman	106	Fort Scott	156	Jamestown	206	Marysville
7	Arkansas City	57	Chase	107	Frankfort	157	Jewell City	207	McPherson
8	Arlington	58	Cheney	108	Franklin	158	Johnson County	208	Mecca Acres
9	Arma	59	Cherokee	109	Frederick	159	Junction City	209	Medicine Lodge
10	Ashland	60	Cherryvale	110	Frontenac	160	Kanopolis	210	Medora
11	Assaria	61	Chicopee	111	Galena	161	Kansas City	211	Melvern
12	Atchison	62	Circleville	112	Galva	162	Kingman	212	Mentor
13	Atlanta	63	Claflin	113	Garden Plain	163	Kingman	213	Meridan
14	Atmos Energy	64	Clay Center	114	Gardner	164	Kingsdown	214	Merriam
15	Aubry	65	Clearwater	115	Garfield	165	Kinsley	215	Michigan Valley
16	Augusta	66	Clifton	116	Gas City	166	Kiowa	216	Midwest Energy, Inc.
17	Aurora	67	Clyde	117	Geneseo	167	Kirkwood	217	Miltonvale
18	Axtell	68	Coldwater	118	Girard	168	Kiro	218	Minneapolis
19	Baileyville	69	Colony	119	Glasco	169	Kismet	219	Minneola
20	Baldwin	70	Columbus	120	Glen Elder	170	La Harpe	220	Mission
21	Barnard	71	Colwich	121	Goddard	171	LaCrosse	221	Mission Hills
22	Barnes	72	Concordia	122	Goessel	172	Lake Quivira	222	Mission Woods
23	Baxter Springs	73	Conway Springs	123	Gorham	173	Lake Waltana	223	Monticello
24	Beattie	74	Courtland	124	Grandview Plaza	174	Lancaster	224	Montrose
25	Bel Aire	75	Crestline	125	Grantville	175	Lane	225	Moran
26	Belle Plaine	76	Cuba	126	Great Bend	176	Langdon	226	Morganville
27	Belleville	77	Cullison	127	Greeley	177	Langdon Lane	227	Morrill
28	Beloit	78	Cunningham	128	Greenleaf	178	Lansing	228	Morrowville
29	Belpre	79	Delphos	129	Greensburg	179	Larned	229	Mount Hope
30	Belvue	80	Dennis	130	Grenola	180	Leavenworth	230	Mount Vernon
31	Bentley	81	Derby	131	Gypsum	181	Leawood	231	Mullinville
32	Benton	82	Detroit	132	Haddam	182	Lebanon	232	Mulvane
33	Berryton	83	Dexter	133	Hamlin	183	Lecompton	233	Munden
34	Beverly	84	Douglass	134	Hanover	184	Lehigh	234	Muscotah
35	Bison	85	Downs	135	Harper	185	LeLoup	235	Narka
36	Black Hills Energy	86	Dwight	136	Hartford	186	Lenexa	236	Nashville
37	Blaine	87	Eastborough	137	Haven	187	Leon	237	Netawaka
38	Bloom	88	Easter's Addition	138	Haviland	188	Lewis	238	New Ozawkie
39	Blue Mound	89	Edgerton	139	Haysville	189	Lincoln Center	239	New Salem
40	Blue Rapids	90	Effingham	140	Hiawatha	190	Lindsborg	240	Newton
41	Bronson	91	El Dorado	141	Highland	191	Linn	241	North Newton
42	Bucklin	92	Elbing	142	Hoisington	192	Longford	242	Nortonville
43	Buhler	93	Ellinwood	143	Holton	193	Loretta	243	Obeeville
44	Burden	94	Ellsworth	144	Holyrood	194	Lorraine	244	Ogden
45	Burns	95	Elmont	145	Home City	195	Louisville	245	Olmitz
46	Burr Oak	96	Elwood	146	Hope	196	Lowell	246	Olpe
47	Bushton	97	Emporia	147	Horton	197	Lucas	247	Onaga
48	Cambridge	98	Englewood	148	Hudson	198	Luray	248	Osawatomie
49	Canton	99	Enterprise	149	Huron	199	Lyndon	249	Osborne
50	Capaldo	100	Erie	150	Hutchinson	200	Macksville	250	Oskaloosa

	Community
251	Oswego
252	Otis
253	Ottawa
254	Overbrook
255	Overland Park
256	Oxford
257	Ozawkie
258	Palmer
259	Paola
260	Park City
261	Parkerfield
262	Parsons
263	Partridge
264	Pauline
265	Perry
266	Petrolia
267	Pfeiffer
268	Piqua
269	Pittsburg
270	Pomona
271	Potwin
272	Prairie Village
273	Pratt
274	Preston
275	Pretty Prairie
276	Princeton
277	Protection
278	Quenemo
279	Rantoul
280	Raymond
281	Reserve
282	Richmond
283	Riverton
284	Robinson
285	Roeland Park
286	Rose Hill
287	Roseland
288	Rossville
289	Roxbury
290	Rozel
291	Russell
292	Sabetha
293	Salina
294	Scammon
295	Scandia
296	Scipio
297	Scranton
298	Sedgwick
299	Seneca
300	Shawnee
301	Shawnee Heights

	Community
302	Silver Lake
303	Smith Center
304	Smolan
305	Solomon
306	Somerset
307	South Hutchinson
308	South Mound
309	St. Benedict
310	St. George
311	St. John
312	St. Marys
313	St. Paul
314	Stafford
315	Stanley
316	Stilwell
317	Sylvan Grove
318	Tecumseh
319	Tescott
320	Thayer
321	Timkin
322	Tonganoxie
323	Topeka
324	Towanda
325	Town & County Est.
326	Troy
327	Turon
328	Udall
329	Valley Center
330	Valley Falls
331	Vermillion
332	Vesper
333	Victoria
334	Vining
335	Vliets
336	Wakefield
337	Walker
338	Walnut
339	Wamego
340	Washington
341	Waterville
342	Wathena
343	Waverly
344	Weir
345	Welda
346	Wellington
347	Wellsville
348	West Mineral
349	Westmoreland
350	Westwood
351	Westwood Hills
352	Wheaton

	Community
353	Whitewater
354	Whiting
355	Wichita
356	Williamsburg
357	Willis
358	Willowbrook Addition
359	Winchester
360	Zarah

KANSAS GAS SERVICE, A DIVISION OF ONE GAS, INC.

Summary of Reasons for Filing this Application

Kansas Gas Service, a Division of ONE Gas, Inc. ("Company") files this rate application to give the Company an opportunity to earn its authorized rate of return. The Company's current base rates were last changed in January 2013 and were based upon a twelve month test-year ending December 31, 2011.

Since our 2012 rate case filing, the Company has continued to devote capital to its operations resulting in increases in plant in service and depreciation expense. Although the Company has implemented measures to control costs and maximize efficiency in operations, it has experienced increases in labor, health care and other Operating and Maintenance costs. During this same period, the Company has seen a decline in per capita residential consumption of natural gas because of more efficient gas usage by customers. As a result, the Company does not have a reasonable opportunity to earn its authorized rate of return without an increase in its base rates.

Kansas Gas Service is also filing this rate application to reset its Gas System Reliability Surcharge to zero.. Additionally, the Company's Application seeks permission to implement an annual Cost of Service Adjustment mechanism designed to adjust rates annually to reflect the most recent costs of the provision of natural gas utility services to our customers.

Kansas Gas Service is also revising its Electronic Flow Measurement (EFM) Rider which may affect transportation customers with EFM meters. KGS proposes to reduce installation costs for standard EFM meters while providing a cellular data and solar power option for EFM transportation customers with limited landline or power connections necessary to report periodic consumption amounts.

ONE Gas

News

May 2, 2016

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918-947-7163
Media Contact: Dawn Ewing
913-319-8642

Kansas Gas Service Requests Recovery of Investments and Costs for Providing Service

OVERLAND PARK, Kan. – May 2, 2016 – ONE Gas, Inc. (NYSE: OGS) announced today that its Kansas Gas Service division filed a request with the Kansas Corporation Commission (KCC) for an increase in base rates, reflecting system investments and operating costs necessary to maintain the safety and reliability of its natural gas distribution system.

Kansas Gas Service is the state's largest natural gas utility, serving approximately 635,000 customers across two-thirds of the state of Kansas.

Kansas Gas Service's request, if approved, represents a net base rate increase of $28 million. Kansas Gas Service is already recovering $7.4 million from customers through the Gas System Reliability Surcharge (GSRS), resulting in a total base rate increase of $35.4 million. This request would increase the average residential customer's natural gas bill by $4.34 per month.

"Our number one priority is safety. In order to continue to provide a safe, reliable energy choice to our customers, we continually reinvest in our infrastructure and upgrade our technology to maintain the integrity of our system," said Pierce H. Norton II, ONE Gas president and chief executive officer.

"We understand the impact rate increases can have on our customers as we manage expenses to keep energy costs at reasonable levels," said Norton. The company will continue to assist customers through offerings such as the *Average Payment Plan* and *Share The Warmth*, the company's heating assistance fund, which is administered through The Salvation Army. Customers may also visit www.kansasgasservice.com for energy-saving information and helpful tools.

The company's filing also includes a proposed Cost of Service Adjustment (COSA) mechanism that would reset rates annually, based on a review of the previous year's financial results. The proposed rate mechanism is intended to reduce the need to file full rate cases, thereby saving costs associated with these traditional rate cases.

-more-

In accordance with Kansas law, the KCC has 240 days to consider Kansas Gas Service's filing.

Kansas Gas Service provides clean, reliable natural gas to approximately 635,000 customers in 360 communities in Kansas. It is a division of ONE Gas, Inc. (NYSE: OGS), a natural gas distribution company and the successor to the company founded in 1906 as Oklahoma Natural Gas Company.

ONE Gas provides natural gas distribution services to more than 2 million customers in Oklahoma, Kansas and Texas. ONE Gas is one of the largest publicly traded, 100 percent regulated, natural gas utilities in the United States.

ONE Gas trades on the New York Stock Exchange under the symbol "OGS," and is included in the S&P MidCap 400 Index.

For more information, visit the websites at www.kansasgasservice.com or www.onegas.com.

For the latest news about Kansas Gas Service, follow us on Twitter @KansasGas.

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KANSAS GAS SERVICE, A DIVISION OF ONE GAS, INC.
Summary of Pro Forma Rate Base and Operating Income
Test Year Ended December 31, 2015

Line No.	Description Col. 1	Schedule Reference Col. 2	Pro Forma Adjusted Total Col. 3
	Rate Base		
1	Gas plant in service	3-B	$1,770,498,662
2	Less: Accumulated provision for depreciation and amortization	3-B	604,139,074
3	Net gas plant in service		$1,166,359,588
4	Working capital	3-B	(263,391,856)
5	Rate Base		$902,967,732
	Revenues and Expenses		
6	Total revenues	3-B	$287,931,412
7	Total expenses	3-B	243,624,677
8	Operating income		$44,306,736
	Rate of Return		
9	Return on present rates (Line 8 / Line 5)		4.9068%
10	Required return on rate base	7-A	7.2798%
11	Operating income requirement (Line 5 X Line 10)		$65,734,245
	Revenue Requirement to Earn Required Rate of Return		
12	Additional operating income (Line 11 - Line 8)		$21,427,509
13	Associated income taxes		14,019,156
14	Revenue increase required		$35,446,665
	Portion of Base Rate Increase Surcharges		
15	Gas System Reliability Surcharge (1)		$7,461,497
16	Net rate increase required		$27,985,168

(1) As approved in Docket 16-KGSG-104-TAR.

KANSAS GAS SERVICE, A DIVISION OF ONE GAS, INC.
Summary of Pro Forma Rate Base and Operating Income
Test Year Ended December 31, 2015

Line No.	Description	Schedule Reference	Amount Per Books	Pro Forma Adjustments	Pro Forma Adjusted Total
	Col. 1	Col. 2	Col. 3	Col. 4	Col. 5
	Rate Base				
1	Gas plant in service	4-A	$1,702,040,331	$68,458,331	$1,770,498,662
2	Less: Accumulated provision for depreciation and amortization	5-A	591,732,290	12,406,783	604,139,074
3	Net gas plant in service		$1,110,308,041	$56,051,548	$1,166,359,588
4	Working capital	6-A	(291,293,090)	27,901,234	(263,391,856)
5	Rate Base		$819,014,951	$83,952,782	$902,967,732
	Revenues and Expenses				
6	Total revenues	9-A	$533,449,344	($245,517,932)	$287,931,412
7	Total expenses	9-A	490,167,830	(246,543,153)	243,624,677
8	Operating income		$43,281,514	$1,025,222	$44,306,736

KANSAS GAS SERVICE, A DIVISION OF ONE GAS, INC.
Summary of Pro Forma Rate Base and Operating Income
Test Year Ended December 31, 2015

Line No.	Description Col. 1	Schedule Reference Col. 2	Amount Per Books Col. 3	PLT 1 CWIP Adjustment Col. 4	PLT 2 Asset Retirement Adjustment Col. 5	PLT 3 Corporate Assets Adjustment Col. 6
	Rate Base					
1	Gas plant in service	4-A	$1,702,040,331	$13,048,927	($2,281,551)	$61,525,376
2	Less: Accumulated provision for depreciation and amortization	5-A	591,732,290	0	0	0
3	Net gas plant in service		$1,110,308,041	$13,048,927	($2,281,551)	$61,525,376
4	Working capital	6-A	(291,293,090)	0	0	0
5	Rate Base		$819,014,951	$13,048,927	($2,281,551)	$61,525,376
	Revenues and Expenses					
6	Total revenues	9-A	$533,449,344	$0	$0	$0
7	Total expenses	9-A	490,167,830	0	0	0
8	Operating income		$43,281,514	$0	$0	$0

Line No.	Description	Schedule Reference	PLT 4 Not Used & Useful Plant Adjustment	PLT 5 CNG Adjustment	PLT 6 3rd Party Reimbursements Adjustment	ADA-1 Asset Retirement Adjustment
	Col. 1	Col. 2	Col. 3	Col. 4	Col. 4	Col. 5
	Rate Base					
1	Gas plant in service	4-A	($4,453,250)	($599,134)	$1,217,964	$0
2	Less: Accumulated provision for depreciation and amortization	5-A	0	0	0	(2,281,551)
3	Net gas plant in service		($4,453,250)	($599,134)	$1,217,964	$2,281,551
4	Working capital	6-A	0	0	0	0
5	Rate Base		($4,453,250)	($599,134)	$1,217,964	$2,281,551
	Revenues and Expenses					
6	Total revenues	9-A	$0	$0	$0	$0
7	Total expenses	9-A	0	0	0	0
8	Operating income		$0	$0	$0	$0

KANSAS GAS SERVICE, A DIVISION OF ONE GAS, INC.
Summary of Pro Forma Rate Base and Operating Income
Test Year Ended December 31, 2015

Line No.	Description	Schedule Reference	ADA-2 Corporate Assets Adjustment	ADA-3 Not Used & Useful Plant Adjustment	ADA-4 CNG Adjustment	ADA-5 3rd Party Reimbursements Adjustment
	Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 3
	Rate Base					
1	Gas plant in service	4-A	$0	$0	$0	$0
2	Less: Accumulated provision for depreciation and amortization	5-A	16,693,239	(3,164,425)	(58,444)	1,217,964
3	Net gas plant in service		($16,693,239)	$3,164,425	$58,444	($1,217,964)
4	Working capital	6-A	0	0	0	0
5	Rate Base		($16,693,239)	$3,164,425	$58,444	($1,217,964)
	Revenues and Expenses					
6	Total revenues	9-A	$0	$0	$0	$0
7	Total expenses	9-A	0	0	0	0
8	Operating income		$0	$0	$0	$0

KANSAS GAS SERVICE, A DIVISION OF ONE GAS, INC.
Summary of Pro Forma Rate Base and Operating Income
Test Year Ended December 31, 2015

Line No.	Description	Schedule Reference	WC 1 Prepayments	WC 2 Long-Term Prepayments	WC 3 Pension/OPEB Funding ADIT	WC 4 2015 Operations ADIT
	Col. 1	Col. 2	Col. 5	Col. 6	Col. 3	Col. 4
	Rate Base					
1	Gas plant in service	4-A	$0	$0	$0	$0
2	Less: Accumulated provision for depreciation and amortization	5-A	0	0	0	0
3	Net gas plant in service		$0	$0	$0	$0
4	Working capital	6-A	3,759,835	618,099	51,778,325	(25,612,745)
5	Rate Base		$3,759,835	$618,099	$51,778,325	($25,612,745)
	Revenues and Expenses					
6	Total revenues	9-A	$0	$0	$0	$0
7	Total expenses	9-A	0	0	0	0
8	Operating income		$0	$0	$0	$0

KANSAS GAS SERVICE, A DIVISION OF ONE GAS, INC.
Summary of Pro Forma Rate Base and Operating Income
Test Year Ended December 31, 2015

Line No.	Description	Schedule Reference	WC 5 COGR Over/Under ADIT	WC 6 Corporate ADIT	IS 1 Eliminate Accrued and Unbilled Revenues and Expenses Adjustment	IS 2 Eliminate Deferred WNA Revenues Adjustment
	Col. 1	Col. 2	Col. 5	Col. 6	Col. 3	Col. 4
	Rate Base					
1	Gas plant in service	4-A	$0	$0	$0	$0
2	Less: Accumulated provision for depreciation and amortization	5-A	0	0	0	0
3	Net gas plant in service		$0	$0	$0	$0
4	Working capital	6-A	5,274,550	(7,916,831)	0	0
5	Rate Base		$5,274,550	($7,916,831)	$0	$0
	Revenues and Expenses					
6	Total revenues	9-A	$0	$0	$12,511,032	($7,892,181)
7	Total expenses	9-A	0	0	12,749,784	0
8	Operating income		$0	$0	($238,752)	($7,892,181)

KANSAS GAS SERVICE, A DIVISION OF ONE GAS, INC.
Summary of Pro Forma Rate Base and Operating Income
Test Year Ended December 31, 2015

Line No.	Description	Schedule Reference	IS 3 Eliminate COGR Revenues and Expenses Adjustment	IS 4 Eliminate the ATSR Revenue and Adjust the Ad Valorem Expenses Adjustment	IS 5 Eliminate GSRS Revenue Adjustment	IS 6 Test Year Revenue Adjustment
	Col. 1	Col. 2	Col. 5	Col. 6	Col. 3	Col. 4
	Rate Base					
1	Gas plant in service	4-A	$0	$0	$0	$0
2	Less: Accumulated provision for depreciation and amortization	5-A	0	0	0	0
3	Net gas plant in service		$0	$0	$0	$0
4	Working capital	6-A	0	0	0	0
5	Rate Base		$0	$0	$0	$0
	Revenues and Expenses					
6	Total revenues	9-A	($258,081,151)	$2,573,703	($5,171,257)	($93,127)
7	Total expenses	9-A	(258,081,151)	1,172,077	0	0
8	Operating income		$0	$1,401,626	($5,171,257)	($93,127)

KANSAS GAS SERVICE, A DIVISION OF ONE GAS, INC.
Summary of Pro Forma Rate Base and Operating Income
Test Year Ended December 31, 2015

Line No.	Description	Schedule Reference	IS 7 Normalize Test Year Revenues Adjustment	IS 8 Annualize Test Year Customers, Sales and Revenues Adjustment	IS 9 Eliminate CNG Revenue Adjustment	IS 10 Non-Gas Portion of Uncollectible Adjustment
	Col. 1	Col. 2	Col. 5	Col. 6	Col. 3	Col. 4
	Rate Base					
1	Gas plant in service	4-A	$0	$0	$0	$0
2	Less: Accumulated provision for depreciation and amortization	5-A	0	0	0	0
3	Net gas plant in service		$0	$0	$0	$0
4	Working capital	6-A	0	0	0	0
5	Rate Base		$0	$0	$0	$0
	Revenues and Expenses					
6	Total revenues	9-A	$10,146,344	$501,372	($12,667)	$0
7	Total expenses	9-A	0	0	0	1,280,165
8	Operating income		$10,146,344	$501,372	($12,667)	($1,280,165)

KANSAS GAS SERVICE, A DIVISION OF ONE GAS, INC.
Summary of Pro Forma Rate Base and Operating Income
Test Year Ended December 31, 2015

Line No.	Description	Schedule Reference	IS 11 Annualize Depreciation on Pro-Forma Plant Adjustment	IS 12 Annualization Depreciation at Proposed Rates Adjustment	IS 13 Eliminate Royalty Fee Adjustment	IS 14 Eliminate Transaction Credit Adjustment
	Col. 1	Col. 2	Col. 5	Col. 6	Col. 3	Col. 4
	Rate Base					
1	Gas plant in service	4-A	$0	$0	$0	$0
2	Less: Accumulated provision for depreciation and amortization	5-A	0	0	0	0
3	Net gas plant in service		$0	$0	$0	$0
4	Working capital	6-A	0	0	0	0
5	Rate Base		$0	$0	$0	$0
	Revenues and Expenses					
6	Total revenues	9-A	$0	$0	$0	$0
7	Total expenses	9-A	828,709	3,657,749	(8,607,018)	(3,423,957)
8	Operating income		($828,709)	($3,657,749)	$8,607,018	$3,423,957

Line No.	Description	Schedule Reference	IS 15 Include Certain Donations from Account 426 and Eliminate Certain Dues and Donations Adjustment	IS 16 Shared Services Contract Changes Adjustment	IS 17 Eliminate O&M costs related to plant Adjustment	IS 18 Fleet and Stores Clearing Account Adjustment
	Col. 1	Col. 2	Col. 5	Col. 6	Col. 3	Col. 4
	Rate Base					
1	Gas plant in service	4-A	$0	$0	$0	$0
2	Less: Accumulated provision for depreciation and amortization	5-A	0	0	0	0
3	Net gas plant in service		$0	$0	$0	$0
4	Working capital	6-A	0	0	0	0
5	Rate Base		$0	$0	$0	$0
	Revenues and Expenses					
6	Total revenues	9-A	$0	$0	$0	$0
7	Total expenses	9-A	13,314	87,002	(45,989)	20,760
8	Operating income		($13,314)	($87,002)	$45,989	($20,760)

KANSAS GAS SERVICE, A DIVISION OF ONE GAS, INC.
Summary of Pro Forma Rate Base and Operating Income
Test Year Ended December 31, 2015

Line No.	Description	Schedule Reference	IS 19 Reclassify Interest on Customer Deposits Adjustment	IS 20 GTI Expense Adjustment	IS 21 Insurance Adjustment	IS 22 Workers Compensation Adjustment
	Col. 1	Col. 2	Col. 5	Col. 6	Col. 3	Col. 4
	Rate Base					
1	Gas plant in service	4-A	$0	$0	$0	$0
2	Less: Accumulated provision for depreciation and amortization	5-A	0	0	0	0
3	Net gas plant in service		$0	$0	$0	$0
4	Working capital	6-A	0	0	0	0
5	Rate Base		$0	$0	$0	$0
	Revenues and Expenses					
6	Total revenues	9-A	$0	$0	$0	$0
7	Total expenses	9-A	102,624	314,868	(97,844)	250,531
8	Operating income		($102,624)	($314,868)	$97,844	($250,531)

KANSAS GAS SERVICE, A DIVISION OF ONE GAS, INC.
Summary of Pro Forma Rate Base and Operating Income
Test Year Ended December 31, 2015

Line No.	Description	Schedule Reference	IS 23 Payroll Adjustment	IS 24 Employee Medical Reserve Adjustment	IS 25 Pension & Benefits Adjustment	IS 26 Amortization of Deferred Pension & Benefits Adjustment
	Col. 1	Col. 2	Col. 5	Col. 6	Col. 3	Col. 4
	Rate Base					
1	Gas plant in service	4-A	$0	$0	$0	$0
2	Less: Accumulated provision for depreciation and amortization	5-A	0	0	0	0
3	Net gas plant in service		$0	$0	$0	$0
4	Working capital	6-A	0	0	0	0
5	Rate Base		$0	$0	$0	$0
	Revenues and Expenses					
6	Total revenues	9-A	$0	$0	$0	$0
7	Total expenses	9-A	2,364,771	658,707	(2,863,179)	(3,168,966)
8	Operating income		($2,364,771)	($658,707)	$2,863,179	$3,168,966

KANSAS GAS SERVICE, A DIVISION OF ONE GAS, INC.
Summary of Pro Forma Rate Base and Operating Income
Test Year Ended December 31, 2015

Line No.	Description	Schedule Reference	IS 27 Pension/OPEB Savings Sharing Adjustment	IS 28 Annualized Corporate Depreciation Adjustment	IS 29 Miscellaneous Corporate Charges Adjustment	IS 30 Change in Allocation Ratio Adjustment
	Col. 1	Col. 2	Col. 5	Col. 6	Col. 3	Col. 4
	Rate Base					
1	Gas plant in service	4-A	$0	$0	$0	$0
2	Less: Accumulated provision for depreciation and amortization	5-A	0	0	0	0
3	Net gas plant in service		$0	$0	$0	$0
4	Working capital	6-A	0	0	0	0
5	Rate Base		$0	$0	$0	$0
	Revenues and Expenses					
6	Total revenues	9-A	$0	$0	$0	$0
7	Total expenses	9-A	3,375,022	412,670	(267,310)	(336,434)
8	Operating income		($3,375,022)	($412,670)	$267,310	$336,434

Line No.	Description	Schedule Reference	IS 31 Normalized Compensation - STI Adjustment	IS 32 Corporate Payroll Adjustment	IS 33 Corporate OPEB, Pension, and Health Benefits Adjustment	IS 34 Rate Case Expense Amortization Adjustment
	Col. 1	Col. 2	Col. 5	Col. 6	Col. 3	Col. 4
	Rate Base					
1	Gas plant in service	4-A	$0	$0	$0	$0
2	Less: Accumulated provision for depreciation and amortization	5-A	0	0	0	0
3	Net gas plant in service		$0	$0	$0	$0
4	Working capital	6-A	0	0	0	0
5	Rate Base		$0	$0	$0	$0
	Revenues and Expenses					
6	Total revenues	9-A	$0	$0	$0	$0
7	Total expenses	9-A	(2,217,199)	1,198,841	(15,054)	326,216
8	Operating income		$2,217,199	($1,198,841)	$15,054	($326,216)

KANSAS GAS SERVICE, A DIVISION OF ONE GAS, INC.
Summary of Pro Forma Rate Base and Operating Income
Test Year Ended December 31, 2015

Line No.	Description Col. 1	Schedule Reference Col. 2	IS 35 Income Taxes Adjustment Col. 5	Pro Forma Adjusted Total Col. 6
	Rate Base			
1	Gas plant in service	4-A	$0	$68,458,331
2	Less: Accumulated provision for depreciation and amortization	5-A	0	12,406,783
3	Net gas plant in service		$0	$56,051,548
4	Working capital	6-A	0	27,901,234
5	Rate Base		$0	$83,952,782
	Revenues and Expenses			
6	Total revenues	9-A	$0	($245,517,932)
7	Total expenses	9-A	3,767,139	(246,543,153)
8	Operating income		($3,767,139)	$1,025,222

KANSAS GAS SERVICE, A DIVISION OF ONE GAS, INC.
Functional Classification of Plant in Service
Test Year Ended December 31, 2015

Line No.	Description Col. 1	Reference Col. 2	Amount Per Books Col. 3	Pro Forma Adjustments Col. 4	Pro Forma Adjusted Total Col. 5
1	Intangible plant	4-A	$58,580	$0	$58,580
2	Production plant	4-A	852,915	0	852,915
3	Storage plant	4-A	0	0	0
4	Transmission plant	4-A	266,333,008	(3,158,404)	263,174,604
5	Distribution plant	4-A	1,327,505,375	10,170,802	1,337,676,177
6	General plant	4-A	107,290,453	(79,442)	107,211,011
7	Corporate allocated plant	4-A	0	61,525,376	61,525,376
8	Total plant in service		$1,702,040,331	$68,458,331	$1,770,498,662

Line No.	Account Number	Description	Amount Per Books (Schedule 4-B)	Pro Forma Adjustments (Schedule 4-C)	Pro Forma Adjusted Total
		Col. 1	Col. 2	Col. 3	Col. 4
		Intangible Plant			
1	302	Franchises and consents	$6,045	$0	$6,045
2	303	Intangible-miscellaneous	52,535	0	52,535
3		Total intangible plant	$58,580	$0	$58,580
		Natural Gas Production and Gathering Plant			
4	325.4	Rights-of-way	$232,567	$0	$232,567
5	327	Field compressor station structures	3,053	0	3,053
6	328	Field meas. and reg. station structures	44,026	0	44,026
7	332	Field lines	45,302	0	45,302
8	333	Field compressor station equipment	12,877	0	12,877
9	334	Field meas. and reg. station equipment	515,090	0	515,090
10		Total production and gathering plant	$852,915	$0	$852,915
		Underground Storage Plant			
11	350.1	Land & Land rights	$0	$0	$0
12	351.1	Structures and improvements	0	0	0
13	351.2	Structures and improvements	0	0	0
14	351.3	Structures and improvements	0	0	0
15	352	Wells	0	0	0
16	352.1	Storage Lease and Rights	0	0	0
17	352.2	Reservoirs	0	0	0
18	352.3	Non-Recoverable Natural Gas	0	0	0
19	353	Storage Lines	0	0	0
20	354	Compressor station equipment	0	0	0
21	355	Measuring and regulating station equipment	0	0	0
22	356	Purification equipment	0	0	0
23	357	Other equipment	0	0	0
24		Total Storage plant	$0	$0	$0

KANSAS GAS SERVICE, A DIVISION OF ONE GAS, INC.
Functional Classification of Plant in Service
Test Year Ended December 31, 2015

Line No.	Account Number	Description	Amount Per Books (Schedule 4-B)	Pro Forma Adjustments (Schedule 4-C)	Pro Forma Adjusted Total
		Col. 1	Col. 2	Col. 3	Col. 4
		Transmission Plant			
1	365.1	Land and land rights	$826,609	$0	$826,609
2	365.2	Rights-of-way	12,240,603	78,079	12,318,682
3	366.1	Structures and imp. - compressor stations	4,615,635	11,690	4,627,325
4	366.2	Structures and imp. - meas. & reg. stations	1,208,818	0	1,208,818
5	367	Mains	205,309,358	775,568	206,084,926
6	368	Compressor station equipment	21,838,537	(3,979,995)	17,858,542
7	369	Measuring and regulating station equip.	20,241,077	(28,726)	20,212,351
8	371	Other Equipment	52,371	(15,021)	37,350
9		Total transmission plant	$266,333,008	($3,158,404)	$263,174,604
		Distribution Plant			
10	374.1	Land and land rights	$135,408	$19,479	$154,887
11	374.2	Rights-of-way	2,212,566	6,175	2,218,741
12	375.1	Structures and improvements	856,201	(652)	855,549
13	376	Mains	310,854,048	3,953,448	314,807,496
14	376.5	Mains - Metallic	267,473,174	145,903	267,619,077
15	376.9	Mains - Cathodic Protection	39,858,984	0	39,858,984
16	378	Meas. and reg. sta. equip. - general	23,511,576	101,500	23,613,076
17	379	Meas. and reg. sta. equip. - city gate	7,461,972	133,641	7,595,613
18	380	Services	399,549,568	3,137,626	402,687,194
19	380.5	Services - Metallic	31,989,411	115	31,989,526
20	381	Meters	108,714,149	1,606,348	110,320,497
21	381.5	Meters - AMR	20,289,237	0	20,289,237
22	382	Meter installations	94,402,391	317,108	94,719,499
23	383	House regulators	19,972,565	750,109	20,722,674
24	386	Other Property on Customer Premises	224,125	0	224,125
25	387	Other Equipment	0	0	0
26		Total distribution plant	$1,327,505,375	$10,170,802	$1,337,676,177

KANSAS GAS SERVICE, A DIVISION OF ONE GAS, INC.
Functional Classification of Plant in Service
Test Year Ended December 31, 2015

Line No.	Account Number	Description Col. 1	Amount Per Books (Schedule 4-B) Col. 2	Pro Forma Adjustments (Schedule 4-C) Col. 3	Pro Forma Adjusted Total Col. 4
		General Plant			
1	389.1	Land and land rights	$1,471,358	$0	$1,471,358
2	390.1	Structures and improvements - owned	35,359,439	31,784	35,391,223
3	390.2	Structures and improvements - leasehold	2,694,235	0	2,694,235
4	391.1	Office furniture and equipment - computers	4,949,181	65,315	5,014,496
5	391.9	Computers and other electronic equipment	9,571,166	0	9,571,166
6	392	Transportation equipment	26,644,792	205,143	26,849,935
7	393	Stores equipment	113,367	0	113,367
8	394	Tool, shop and garage equipment	8,974,944	(511,816)	8,463,128
9	395	Laboratory equipment	72,377	0	72,377
10	396	Power operated equipment	11,738,504	54,603	11,793,107
11	397	Communication equipment	5,340,533	75,530	5,416,063
12	398	Miscellaneous equipment	360,557	0	360,557
13		Total general plant	$107,290,453	($79,442)	$107,211,011
14		Corporate allocated plant	$0	$61,525,376	$61,525,376
15		Total gas plant in service	$1,702,040,331	$68,458,331	$1,770,498,662

KANSAS GAS SERVICE, A DIVISION OF ONE GAS, INC.
Plant in Service by Primary Account
Test Year Ended December 31, 2015
Balance as of

Line No.	Account Number	Description	December 31, 2012	December 31, 2013	December 31, 2014	December 31, 2015
		Col. 1	Col. 2	Col. 3	Col. 4	Col. 5
		Intangible Plant				
1	302	Franchises and consents	$6,045	$6,045	$6,045	$6,045
2	303	Intangible-miscellaneous	52,535	52,535	52,535	52,535
3		Total intangible plant	$58,580	$58,580	$58,580	$58,580
		Natural Gas Production and Gathering Plant				
4	325.4	Rights-of-way	$232,567	$232,567	$232,567	$232,567
5	327	Field compressor station structures	3,053	3,053	3,053	3,053
6	328	Field meas. and reg. station structures	44,026	44,026	44,026	44,026
7	332	Field lines	56,442	56,442	45,302	45,302
8	333	Field compressor station equipment	12,877	12,877	12,877	12,877
9	334	Field meas. and reg. station equipment	515,090	515,090	515,090	515,090
10		Total production and gathering plant	$864,055	$864,055	$852,915	$852,915
		Underground Storage Plant				
11	350.1	Land & Land rights	$0	$0	$0	$0
12	351.1	Structures and improvements	0	0	0	0
13	351.2	Structures and improvements	0	0	0	0
14	351.3	Structures and improvements	0	0	0	0
15	352	Wells	0	0	0	0
16	352.1	Storage Lease and Rights	0	0	0	0
17	352.2	Reservoirs	0	0	0	0
18	352.3	Non-Recoverable Natural Gas	0	0	0	0
19	353	Storage Lines	0	0	0	0
20	354	Compressor station equipment	0	0	0	0
21	355	Measuring and regulating station equipment	0	0	0	0
22	356	Purification equipment	0	0	0	0
23	357	Other equipment	0	0	0	0
24		Total Storage plant	$0	$0	$0	$0

KANSAS GAS SERVICE, A DIVISION OF ONE GAS, INC.
Plant in Service by Primary Account
Test Year Ended December 31, 2015
Balance as of

Line No.	Account Number	Description	December 31, 2012	December 31, 2013	December 31, 2014	December 31, 2015
		Col. 1	Col. 2	Col. 3	Col. 4	Col. 5
		Transmission Plant				
1	365.1	Land and land rights	$839,603	$826,470	$826,609	$826,609
2	365.2	Rights-of-way	11,853,721	11,792,994	11,771,290	12,240,603
3	366.1	Compressor Station Structure	4,083,723	4,608,678	4,562,600	4,615,635
4	366.2	Measuring Station Structure	1,137,206	1,177,780	1,177,780	1,208,818
5	367	Mains	190,467,813	195,949,249	201,828,595	205,309,358
6	368	Compressor station equipment	21,196,380	21,447,931	21,453,153	21,838,537
7	369	Measuring and regulating station equip.	15,660,914	16,616,759	18,174,489	20,241,077
8	371	Other Equipment	0	191,332	152,314	52,371
9		Total transmission plant	$245,239,360	$252,611,193	$259,946,830	$266,333,008
		Distribution Plant				
10	374.1	Land and land rights	$106,725	$117,408	$139,168	$135,408
11	374.2	Rights-of-way	1,919,554	1,923,270	2,091,719	2,212,566
12	375.1	Structures and improvements	856,200	856,201	860,118	856,201
13	376	Mains	282,372,219	287,610,109	298,705,463	310,854,048
14	376.5	Mains - Metallic	257,928,369	262,417,894	265,626,033	267,473,174
15	376.9	Mains - Cathodic Protection	30,579,471	33,325,334	36,110,955	39,858,984
16	378	Meas. and reg. sta. equip. - general	21,876,051	21,907,531	22,968,382	23,511,576
17	379	Meas. and reg. sta. equip. - city gate	6,754,877	6,849,825	7,254,590	7,461,972
18	380	Services	348,943,642	368,495,799	387,326,062	399,549,568
19	380.5	Services - Metallic	31,502,171	31,483,718	31,832,216	31,989,411
20	381	Meters	92,239,695	96,863,987	100,824,725	108,714,149
21	381.5	Meters - AMR	11,301,463	15,128,066	18,694,746	20,289,237
22	382	Meter installations	90,295,697	91,061,440	92,383,341	94,402,391
23	383	House regulators	14,847,342	15,200,856	15,447,408	19,972,565
24	386	Other Property on Customers Premises	224,125	224,125	224,125	224,125
25	387	Other Equipment	0	0	0	0
26		Total distribution plant	$1,191,747,602	$1,233,465,562	$1,280,489,051	$1,327,505,375

KANSAS GAS SERVICE, A DIVISION OF ONE GAS, INC.
Plant in Service by Primary Account
Test Year Ended December 31, 2015
Balance as of

Line No.	Account Number	Description	December 31, 2012	December 31, 2013	December 31, 2014	December 31, 2015
		Col. 1	Col. 2	Col. 3	Col. 4	Col. 5
		General Plant				
1	389.1	Land and land rights	$1,452,065	$1,471,358	$1,471,358	$1,471,358
2	390.1	Structures and improvements - owned	30,162,207	31,167,822	35,150,006	35,359,439
3	390.2	Structures and improvements - leasehold	2,613,356	2,675,387	2,679,957	2,694,235
4	391.1	Office furniture and equipment	4,999,921	4,992,936	5,153,986	4,949,181
5	391.9	Computers and other electronic equipment	7,218,377	8,810,204	9,221,315	9,571,166
6	392	Transportation equipment	23,596,980	24,419,074	25,411,736	26,644,792
7	393	Stores equipment	291,790	220,653	169,524	113,367
8	394	Tool, shop and garage equipment	9,067,737	9,553,304	9,771,922	8,974,944
9	395	Laboratory equipment	72,378	72,377	72,377	72,377
10	396	Power operated equipment	10,995,707	11,410,302	11,410,302	11,738,504
11	397	Communication equipment	8,550,020	6,369,293	6,403,333	5,340,533
12	398	Miscellaneous equipment	393,167	432,977	360,829	360,557
13		Total general plant	$99,413,705	$101,595,687	$107,276,645	$107,290,453
14		Total gas plant in service	$1,537,323,302	$1,588,595,076	$1,648,624,021	$1,702,040,331

Line No.	Description	PLT 1 Pro Forma Adjustment CWIP	PLT 2 Pro Forma Adjustment Asset Retirement	PLT 3 Pro Forma Adjustment Corporate Assets	PLT 4 Pro Forma Adjustment Not Used & Useful Plant	Subtotal Pro Forma Adjustments
	Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6
1	Intangible plant	$0	$0	$0	$0	$0
2	Production and gathering plant	0	0	0	0	$0
3	Storage Plant	0	0	0	0	$0
4	Transmission plant	1,568,382	(274,226)	0	(4,453,250)	($3,159,094)
5	Distribution plant	10,850,733	(1,897,205)	0	0	$8,953,528
6	General plant	629,813	(110,120)	0	0	$519,693
7	Corporate Allocated Plant	0	0	61,525,376	0	$61,525,376
8	Total gas plant in service	$13,048,927	($2,281,551)	$61,525,376	($4,453,250)	$67,839,502

Note:
(a) See Schedule 4-D for explanation of pro forma adjustments.

KANSAS GAS SERVICE, A DIVISION OF ONE GAS, INC.
Summary of Pro Forma Adjustments to Plant in Service (a)
Test Year Ended December 31, 2015

Line No.	Description	PLT 5 Pro Forma Adjustment CNG	PLT 6 Pro Forma Adjustment 3rd Party Reimbursements	Total Pro Forma Adjustments
	Col. 1	Col. 2	Col. 3	Col. 4
1	Intangible plant	$0	$0	$0
2	Production and gathering plant	0	0	0
3	Storage Plant	0	0	0
4	Transmission plant	0	690	(3,158,404)
5	Distribution plant	0	1,217,274	10,170,802
6	General plant	(599,134)	0	(79,442)
7	Corporate Allocated Plant	0	0	61,525,376
8		($599,134)	$1,217,964	$68,458,331

Note:
(a) See Schedule 4-D for explanation of pro forma adjustments.

Line No.	Account Number	Description	PLT 1 Pro Forma Adjustment CWIP	PLT 2 Pro Forma Adjustment Asset Retirement	PLT 3 Pro Forma Adjustment Corporate Assets	PLT 4 Pro Forma Adjustment Not Used & Useful Plant	Sub-Total Pro Forma Adjustments
		Col. 1	Col. 2	Col. 4	Col. 4	Col. 5	Col. 6
		Intangible Plant					
1	302	Franchises and consents	$0	$0	$0	$0	$0
2	303	Intangible-miscellaneous	0	0	0	0	0
3		Total intangible plant	$0	$0	$0	$0	$0
		Natural Gas Production and Gathering Plant					
4	325.4	Rights-of-way	$0	$0	$0	$0	$0
5	327	Field compressor station structures	0	0	0	0	0
6	328	Field meas. and reg. station structures	0	0	0	0	0
7	332	Field lines	0	0	0	0	0
8	333	Field compressor station equipment	0	0	0	0	0
9	334	Field meas. and reg. station equipment	0	0	0	0	0
10		Total production and gathering plant	$0	$0	$0	$0	$0
		Underground Storage Plant					
11	350.1	Land and Land Rights	$0	$0	$0	$0	$0
12	351.1	Structures and improvements	0	0	0	0	0
13	351.2	Structures and improvements	0	0	0	0	0
14	351.3	Structures and improvements	0	0	0	0	0
15	352	Wells	0	0	0	0	0
16	352.1	Storage Lease and Rights	0	0	0	0	0
17	352.2	Reservoirs	0	0	0	0	0
18	352.3	Non-Recoverable Natural Gas	0	0	0	0	0
19	353	Storage Lines	0	0	0	0	0
20	354	Compressor station equipment	0	0	0	0	0
21	355	Measuring and regulating station equipment	0	0	0	0	0
22	356	Purification equipment	0	0	0	0	0
23	357	Other equipment	0	0	0	0	0
24		Total Storage plant	$0	$0	$0	$0	$0

KANSAS GAS SERVICE, A DIVISION OF ONE GAS, INC.
Pro Forma Adjustments to Plant In Service
Test Year Ended December 31, 2015

Line No.	Account Number	Description	PLT 1 Pro Forma Adjustment CWIP	PLT 2 Pro Forma Adjustment Asset Retirement	PLT 3 Pro Forma Adjustment Corporate Assets	PLT 4 Pro Forma Adjustment Not Used & Useful Plant	Sub-Total Pro Forma Adjustments
		Col. 1	Col. 2	Col. 4	Col. 4	Col. 5	Col. 6
		Transmission Plant					
1	365.1	Land and land rights	$0	$0	$0	$0	$0
2	365.2	Rights-of-way	94,624	(16,545)	0	0	78,079
3	366.1	Structures and imp. - compressor stations	17,090	(2,988)	0	(2,412)	11,690
4	366.2	Structures and imp. - meas. & reg. stations	0	0	0	0	0
5	367	Mains	967,204	(169,112)	0	(22,524)	775,568
6	368	Compressor station equipment	87,122	(15,233)	0	(4,051,884)	(3,979,995)
7	369	Measuring and regulating station equip.	421,381	(73,677)	0	(376,430)	(28,726)
8	371	Other Equipment	(19,040)	3,329	0	0	(15,711)
9		Total transmission plant	$1,568,382	($274,226)	$0	($4,453,250)	($3,159,094)
		Distribution Plant					
10	374.1	Land and land rights	$23,607	($4,128)	$0	$0	$19,479
11	374.2	Rights-of-way	0	0	0	0	0
12	375.1	Structures and improvements	(790)	138	0	0	(652)
13	376	Mains	3,649,956	(638,179)	0	0	3,011,777
14	376.5	Mains - Metallic	0	0	0	0	0
15	376.9	Mains - Cathodic Protection	0	0	0	0	0
16	378	Meas. and reg. sta. equip. - general	113,161	(19,786)	0	0	93,375
17	379	Meas. and reg. sta. equip. - city gate	41,981	(7,340)	0	0	34,641
18	380	Services	3,782,738	(661,396)	0	0	3,121,342
19	380.5	Services - Metallic	0	0	0	0	0
20	381	Meters	1,946,725	(340,377)	0	0	1,606,348
21	381.5	Meters - AMR	0	0	0	0	0
22	382	Meter installations	384,301	(67,193)	0	0	317,108
23	383	House regulators	909,053	(158,944)	0	0	750,109
24	386	Other Property on Customer Premises	0	0	0	0	0
25	387	Other Equipment	0	0	0	0	0
26		Total distribution plant	$10,850,733	($1,897,205)	$0	$0	$8,953,528

Line No.	Account Number	Description	PLT 1 Pro Forma Adjustment CWIP	PLT 2 Pro Forma Adjustment Asset Retirement	PLT 3 Pro Forma Adjustment Corporate Assets	PLT 4 Pro Forma Adjustment Not Used & Useful Plant	Sub-Total Pro Forma Adjustments
		Col. 1	Col. 2	Col. 4	Col. 4	Col. 5	Col. 6
		General Plant					
1	389.1	Land and land rights	$0	$0	$0	$0	$0
2	390.1	Structures and improvements - owned	38,519	(6,735)	0	0	31,784
3	390.2	Structures and improvements - leasehold	0	0	0	0	0
4	391.1	Office furniture and equipment	79,155	(13,840)	0	0	65,315
5	391.9	Computers and other electronic equipment	0	0	0	0	0
6	392	Transportation equipment	248,612	(43,469)	0	0	205,143
7	393	Stores equipment	0	0	0	0	0
8	394	Tool, shop and garage equipment	105,821	(18,502)	0	0	87,319
9	395	Laboratory equipment	0	0	0	0	0
10	396	Power operated equipment	66,173	(11,570)	0	0	54,603
11	397	Communication equipment	91,534	(16,004)	0	0	75,530
12	398	Miscellaneous equipment	0	0	0	0	0
13		Total general plant	$629,813	($110,120)	$0	$0	$519,693
14		Corporate Allocated Plant	$0	$0	$61,525,376	$0	$61,525,376
15		Total gas plant in service	$13,048,927	($2,281,551)	$61,525,376	($4,453,250)	$67,839,502

KANSAS GAS SERVICE, A DIVISION OF ONE GAS, INC.
Pro Forma Adjustments to Plant In Service
Test Year Ended December 31, 2015

Line No.	Account Number	Description	PLT 5 Pro Forma Adjustment CNG	PLT 6 Pro Forma Adjustment 3rd Party Reimbursements	Total Pro Forma Adjustments
		Col. 1	Col. 2	Col. 3	Col. 4
		Intangible Plant			
1	302	Franchises and consents	$0	$0	$0
2	303	Intangible-miscellaneous	0	0	0
3		Total intangible plant	$0	$0	$0
		Natural Gas Production and Gathering Plant			
4	325.4	Rights-of-way	$0	$0	$0
5	327	Field compressor station structures	0	0	0
6	328	Field meas. and reg. station structures	0	0	0
7	332	Field lines	0	0	0
8	333	Field compressor station equipment	0	0	0
9	334	Field meas. and reg. station equipment	0	0	0
10		Total production and gathering plant	$0	$0	$0
		Underground Storage Plant			
11	350.1	Land & Land rights	0	0	0
12	351.1	Structures and improvements	0	0	0
13	351.2	Structures and improvements	0	0	0
14	351.3	Structures and improvements	0	0	0
15	352	Wells	0	0	0
16	352.1	Storage Lease and Rights	0	0	0
17	352.2	Reservoirs	0	0	0
18	352.3	Non-Recoverable Natural Gas	0	0	0
19	353	Storage Lines	0	0	0
20	354	Compressor station equipment	0	0	0
21	355	Measuring and regulating station equipment	0	0	0
22	356	Purification equipment	0	0	0
23	357	Other equipment	0	0	0
24		Total Storage plant	$0	$0	$0

KANSAS GAS SERVICE, A DIVISION OF ONE GAS, INC.
Pro Forma Adjustments to Plant In Service
Test Year Ended December 31, 2015

Line No.	Account Number	Description	PLT 5 Pro Forma Adjustment CNG	PLT 6 Pro Forma Adjustment 3rd Party Reimbursements	Total Pro Forma Adjustments
		Col. 1	Col. 2	Col. 3	Col. 4
		Transmission Plant			
1	365.1	Land and land rights	$0	$0	$0
2	365.2	Rights-of-way	0	0	78,079
3	366.1	Structures and imp. - compressor stations	0	0	11,690
4	366.2	Structures and imp. - meas. & reg. stations	0	0	0
5	367	Mains	0	0	775,568
6	368	Compressor station equipment	0	0	(3,979,995)
7	369	Measuring and regulating station equip.	0	0	(28,726)
8	371	Other Equipment	0	690	(15,021)
9		Total transmission plant	$0	$690	($3,158,404)
		Distribution Plant			
10	374.1	Land and land rights	$0	$0	$19,479
11	374.2	Rights-of-way	0	6,175	6,175
12	375.1	Structures and improvements	0	0	(652)
13	376	Mains	0	941,671	3,953,448
14	376.5	Mains - Metallic	0	145,903	145,903
15	376.9	Mains - Cathodic Protection	0	0	0
16	378	Meas. and reg. sta. equip. - general	0	8,126	101,500
17	379	Meas. and reg. sta. equip. - city gate	0	99,000	133,641
18	380	Services	0	16,284	3,137,626
19	380.5	Services - Metallic	0	115	115
20	381	Meters	0	0	1,606,348
21	381.5	Meters - AMR	0	0	0
22	382	Meter installations	0	0	317,108
23	383	House regulators	0	0	750,109
24	386	Other Property on Customer Premises	0	0	0
25	387	Other Equipment	0	0	0
26		Total distribution plant	$0	$1,217,274	$10,170,802

KANSAS GAS SERVICE, A DIVISION OF ONE GAS, INC.
Pro Forma Adjustments to Plant In Service
Test Year Ended December 31, 2015

Line No.	Account Number	Description	PLT 5 Pro Forma Adjustment CNG	PLT 6 Pro Forma Adjustment 3rd Party Reimbursements	Total Pro Forma Adjustments
		Col. 1	Col. 2	Col. 3	Col. 4
		General Plant			
1	389.1	Land and land rights	$0	$0	$0
2	390.1	Structures and improvements - owned	0	0	31,784
3	390.2	Structures and improvements - leasehold	0	0	0
4	391.1	Office furniture and equipment - computers	0	0	65,315
5	391.9	Computers and other electronic equipment	0	0	0
6	392	Transportation equipment	0	0	205,143
7	393	Stores equipment	0	0	0
8	394	Tool, shop and garage equipment	(599,134)	0	(511,816)
9	395	Laboratory equipment	0	0	0
10	396	Power operated equipment	0	0	54,603
11	397	Communication equipment	0	0	75,530
12	398	Miscellaneous equipment	0	0	0
13		Total general plant	($599,134)	$0	($79,442)
					0
14		Corporate allocated plant	$0	$0	$61,525,376
15		Total Plant in Service	($599,134)	$1,217,964	$68,458,331

KANSAS GAS SERVICE, A DIVISION OF ONE GAS, INC.
Explanation of Pro Forma Adjustments to Plant In Service
Test Year Ended December 31, 2015

Line No.	Description Col. 1	Increase Col. 2	Decrease Col. 3
	Adjustment PLT 1		
	CWIP		
1	Intangible plant	0	0
2	Production and gathering plant	0	0
3	Storage Plant	0	0
4	Transmission Plant	1,568,382	0
5	Distribution plant	10,850,733	0
6	General plant	629,813	0
7	Corporate Allocated Plant	0	0
8	Total	13,048,927	0

To include capital expenditures for projects underway at December 31, 2015 completed within one year after the end of the test year.

Line No.	Description Col. 1	Increase Col. 2	Decrease Col. 3
	Adjustment PLT 2		
	Asset Retirement		
9	Intangible plant	0	0
10	Production and gathering plant	0	0
11	Storage Plant	0	0
12	Transmission Plant	0	274,226
13	Distribution plant	0	1,897,205
14	General plant	0	110,120
15	Corporate Allocated Plant	0	0
16	Total	0	2,281,551

To remove plant retirements in CWIP that will retire subsequent to the test year.

KANSAS GAS SERVICE, A DIVISION OF ONE GAS, INC.
Explanation of Pro Forma Adjustments to Plant In Service
Test Year Ended December 31, 2015

Line No.	Description Col. 1	Increase Col. 2	Decrease Col. 3
	Adjustment PLT 3		
	Corporate Assets		
1	Intangible plant	0	0
2	Production and gathering plant	0	0
3	Storage Plant	0	0
4	Transmission Plant	0	0
5	Distribution plant	0	0
6	General plant	0	0
7	Corporate Allocated Plant	61,525,376	0
8	Total	61,525,376	0

To include Corporate assets providing service to Kansas Gas Service

Line No.	Description	Increase	Decrease
	Adjustment PLT 4		
	Not Used & Useful Plant		
9	Intangible plant	0	0
10	Production and gathering plant	0	0
11	Storage plant	0	0
12	Transmission plant	0	4,453,250
13	Distribution plant	0	0
14	General plant	0	0
15	Corporate Allocated Plant	0	0
16	Total	0	4,453,250

To remove the plant assets that are currently not used and useful.

Line No.	Description Col. 1	Increase Col. 2	Decrease Col. 3
	Adjustment PLT 5		
	CNG		
1	Intangible plant	0	0
2	Production and gathering plant	0	0
3	Storage Plant	0	0
4	Transmission Plant	0	0
5	Distribution plant	0	0
6	General plant	0	599,134
7	Corporate Allocated Plant	0	0
8	Total	0	599,134

To remove certain CNG assets used to provide CNG at public stations.

Line No.	Description	Increase	Decrease
	Adjustment PLT 6		
	Account Reclass		
1	Intangible plant	0	0
2	Production and gathering plant	0	0
3	Storage Plant	0	0
4	Transmission Plant	690	0
5	Distribution plant	1,217,274	0
6	General plant	0	0
7	Corporate Allocated Plant	0	0
8	Total	1,217,964	0

To reclass 3rd Party Reimbursements.

KANSAS GAS SERVICE, A DIVISION OF ONE GAS, INC.
Summary - Functional Classification of Accumulated Provision for Depreciation and Amortization
Test Year Ended December 31, 2015

Line No.	Description	Reference	Amount Per Books	Pro Forma Adjustments	Pro Forma Adjusted Total
	Col. 1	Col. 2	Col. 3	Col. 4	Col. 5
	Accumulated Provision For Depreciation				
1	Production and gathering plant	5-B	$628,534	$0	$628,534
2	Storage plant	5-B	0	0	0
3	Transmission plant	5-B	84,185,042	(3,437,961)	80,747,081
4	Distribution plant	5-B	461,904,954	(679,931)	461,225,023
5	General plant	5-B	42,219,518	(168,564)	42,050,954
6	Corporate allocated accumulated depreciation	5-B	0	16,693,239	16,693,239
7	Total accumulated provision for depreciation		$588,938,048	$12,406,783	$601,344,831
	Accumulated Provision For Amortization				
8	Total accumulated provision for amortization	5-B	2,794,242	0	2,794,242
9	Total accumulated provision for depreciation and amortization		$591,732,290	$12,406,783	$604,139,074

KANSAS GAS SERVICE, A DIVISION OF ONE GAS, INC.
Detail - Functional Classification of Accumulated Provision for Depreciation and Amortization
Test Year Ended December 31, 2015

Line No.	Account Number	Description	Amount Per Books	Pro Forma Adjustments	Pro Forma Adjusted Total
		Col. 1	Col. 2	Col. 3	Col. 4
		ACCUMULATED PROVISION FOR DEPRECIATION			
		Natural Gas Production and Gathering Plant			
1	325.4	Rights-of-way	$104,746	$0	$104,746
2	327	Field Compressor Station Structure	2,385	0	2,385
3	328	Field meas. and reg. station structures	55,464	0	55,464
4	332	Field lines	45,302	0	45,302
5	333	Field Compressor Station Equipment	12,877	0	12,877
6	334	Field meas. and reg. station equipment	407,760	0	407,760
7		Total production and gathering plant	$628,534	$0	$628,534
		Underground Storage Plant			
8	350.1	Land & Land rights	$0	$0	$0
9	350.2	Rights of way	0	0	0
10	351.1	Structures and improvements	0	0	0
11	351.2	Structures and improvements	0	0	0
12	351.3	Structures and improvements	0	0	0
13	352	Wells	0	0	0
14	352.1	Storage Lease and Rights	0	0	0
15	352.2	Reservoirs	0	0	0
16	352.3	Non-Recoverable Natural Gas	0	0	0
17	353	Storage Lines	0	0	0
18	354	Compressor station equipment	0	0	0
19	355	Measuring and regulating station equipment	0	0	0
20	356	Purification equipment	0	0	0
21	357	Other equipment	0	0	0
22		Total Underground storage plant	$0	$0	$0

KANSAS GAS SERVICE, A DIVISION OF ONE GAS, INC.
Detail - Functional Classification of Accumulated Provision for Depreciation and Amortization
Test Year Ended December 31, 2015

Line No.	Account Number	Description	Amount Per Books	Pro Forma Adjustments	Pro Forma Adjusted Total
		Col. 1	Col. 2	Col. 3	Col. 4
		Transmission Plant			
1	365.2	Rights-of-way	$3,309,275	($16,545)	$3,292,730
2	366.1	Structures and imp. - compressor stations	3,945,752	(4,284)	3,941,468
3	366.2	Structures and imp. - meas. & reg. stations	996,712	0	996,712
4	367	Mains	53,354,941	(170,862)	53,184,079
5	368	Compressor station equipment	16,944,243	(3,061,987)	13,882,256
6	369	Measuring and regulating station equipment	5,634,119	(188,302)	5,445,817
7	371	Other Equipment	0	4,019	4,019
8		Total transmission plant	$84,185,042	($3,437,961)	$80,747,081
		Distribution Plant			
9	374.2	Rights-of-way	$476,867	$2,047	$478,914
10	375.1	Structures and improvements	389,678	138	389,816
11	376	Mains	103,385,243	303,492	103,688,735
12	376.5	Mains - Metallic	89,335,827	145,903	89,481,730
13	376.9	Mains - Cathodic Protection	5,092,547	0	5,092,547
14	378	Meas. and reg. sta. equip. - general	10,286,200	(11,660)	10,274,540
15	379	Meas. and reg. sta. equip. - city gate	3,948,922	91,660	4,040,582
16	380	Services	172,364,955	(645,112)	171,719,843
17	380.5	Services - Metallic	12,910,589	115	12,910,704
18	381	Meters	24,211,866	(340,377)	23,871,489
19	381.5	Meters - AMR	3,912,736	0	3,912,736
20	382	Meter installations	28,352,353	(67,193)	28,285,160
21	383	House regulators	7,021,101	(158,944)	6,862,157
22	386	Other Property Customer Premise	218,684	0	218,684
23	387	Other Equipment	(2,614)	0	(2,614)
24		Total distribution plant	$461,904,954	($679,931)	$461,225,023

KANSAS GAS SERVICE, A DIVISION OF ONE GAS, INC.
Detail - Functional Classification of Accumulated Provision for Depreciation and Amortization
Test Year Ended December 31, 2015

Line No.	Account Number	Description Col. 1	Amount Per Books Col. 2	Pro Forma Adjustments Col. 3	Pro Forma Adjusted Total Col. 4
		General Plant			
1	389.1	Land	($14,378)	$0	($14,378)
2	390.1	Structures and improvements - owned	11,694,086	(6,735)	11,687,351
3	391.1	Office furniture and equipment	2,113,219	(13,840)	2,099,379
4	391.9	Computers and other electronic equipment	7,451,704	0	7,451,704
5	392	Transportation equipment	11,829,729	(43,469)	11,786,260
6	393	Stores equipment	(93,230)	0	(93,230)
7	394	Tools Shop and Garage Equipment	1,009,157	(76,946)	932,211
8	395	Laboratory equipment	(245,091)	0	(245,091)
9	396	Power operated equipment	6,192,016	(11,570)	6,180,446
10	397	Communication equipment	2,186,609	(16,004)	2,170,605
11	398	Miscellaneous equipment	95,697	0	95,697
12		Total general plant	$42,219,518	($168,564)	$42,050,954
13		Corporate Allocated	$0	$16,693,239	$16,693,239
14		Total accumulated provision for depreciation	$588,938,048	$12,406,783	$601,344,831
		ACCUMULATED PROVISION FOR AMORTIZATION			
15	302	Franchises and Consents	$0	$0	$0
16	303	Miscellaneous Intangible Plant	41,434	0	41,434
17	390.2	Structures and improvements - leasehold	2,752,808	0	2,752,808
18		Total accumulated provision for amortization	$2,794,242	$0	$2,794,242
19		Total accumulated provision for depreciation and amortization (a)	$591,732,290	$12,406,783	$604,139,074

Note:
(a) See Schedule 5-F for explanation of pro forma adjustments.

KANSAS GAS SERVICE, A DIVISION OF ONE GAS, INC.
Summary of Pro Forma Adjustments to Accumulated Provision for Depreciation and Amortization (a)
Test Year Ended December 31, 2015

Line No.	Description	ADA 1 Pro Forma Adjustment Asset Retirement	ADA 2 Pro Forma Adjustment Corporate Assets	ADA 3 Pro Forma Adjustment Not Used & Useful Plant	Subtotal Pro Forma Adjustments
	Col. 1	Col. 2	Col. 3	Col. 4	Col. 5
	Accumulated Provision for Depreciation				
1	Production and gathering plant	$0	$0	$0	$0
2	Underground storage plant	0	0	0	0
3	Transmission plant	(274,226)	0	(3,164,425)	(3,438,651)
4	Distribution plant	(1,897,205)	0	0	(1,897,205)
5	General plant	(110,120)	0	0	(110,120)
6	Corporate Allocated	0	16,693,239	0	16,693,239
7	Total accumulated provision for depreciation Pro forma	($2,281,551)	$16,693,239	($3,164,425)	$11,247,263
	Accumulated Provision for Amortization				
8	Total accumulated provision for amortization	0	0	0	0
9	Total accumulated provision for depreciation and amortization	($2,281,551)	$16,693,239	($3,164,425)	$11,247,263

Note:
(a) See Schedule 5-F for explanation of pro forma adjustments.

KANSAS GAS SERVICE, A DIVISION OF ONE GAS, INC.
Summary of Pro Forma Adjustments to Accumulated Provision for Depreciation and Amortization (a)
Test Year Ended December 31, 2015

Line No.	Description	ADA 4 Pro Forma Adjustment CNG	ADA 5 Pro Forma Adjustment 3rd Party Reimbursements	Total Pro Forma Adjustments
	Col. 1	Col. 2	Col. 3	Col. 5
	Accumulated Provision for Depreciation			
1	Production and gathering plant	$0	$0	$0
2	Underground storage plant	0	0	0
3	Transmission plant	0	690	(3,437,961)
4	Distribution plant	0	1,217,274	(679,931)
5	General plant	(58,444)	0	(168,564)
6	Corporate Allocated	0	0	16,693,239
7	Total accumulated provision for depreciation Pro forma	($58,444)	$1,217,964	$12,406,783
	Accumulated Provision for Amortization			
8	Total accumulated provision for amortization	0	0	0
9	Total accumulated provision for depreciation and amortization	($58,444)	$1,217,964	$12,406,783

Note:
(a) See Schedule 5-F for explanation of pro forma adjustments.

KANSAS GAS SERVICE, A DIVISION OF ONE GAS, INC.
Detail - Functional Classification of Adjustments to Accumulated Provision for Depreciation and Amortization
Test Year Ended December 31, 2015

Line No.	Account Number	Description	ADA 1 Pro Forma Adjustment CWIP	ADA 2 Pro Forma Adjustment Corporate Assets	ADA 3 Pro Forma Adjustment Not Used & Useful Plant	Subtotal Pro Forma Adjustments
		Col. 1	Col. 2	Col. 3	Col. 4	Col. 5
		ACCUMULATED PROVISION FOR DEPRECIATION				
		Natural Gas Production and Gathering Plant				
1	325.4	Rights-of-way	$0	$0	$0	$0
2	327	Field Compressor Station Structure	0	0	0	0
3	328	Field meas. and reg. station structures	0	0	0	0
4	332	Field lines	0	0	0	0
5	333	Field Compressor Station Equipment	0	0	0	0
6	334	Field meas. and reg. station equipment	0	0	0	0
7		Total production and gathering plant	$0	$0	$0	$0
		Underground Storage Plant				
8	350.1	Land & Land rights	$0	$0	$0	$0
9	350.2	Rights of way	0	0	0	0
10	351.1	Structures and improvements	0	0	0	0
11	351.2	Structures and improvements	0	0	0	0
12	351.3	Structures and improvements	0	0	0	0
13	352	Wells	0	0	0	0
14	352.1	Storage Lease and Rights	0	0	0	0
15	352.2	Reservoirs	0	0	0	0
16	352.3	Non-Recoverable Natural Gas	0	0	0	0
17	353	Storage Lines	0	0	0	0
18	354	Compressor station equipment	0	0	0	0
19	355	Measuring and regulating station equipment	0	0	0	0
20	356	Purification equipment	0	0	0	0
21	357	Other equipment	0	0	0	0
22		Total Underground storage plant	$0	$0	$0	$0

KANSAS GAS SERVICE, A DIVISION OF ONE GAS, INC.
Detail - Functional Classification of Adjustments to Accumulated Provision for Depreciation and Amortization
Test Year Ended December 31, 2015

Line No.	Account Number	Description	ADA 1 Pro Forma Adjustment Asset Retirement	ADA 2 Pro Forma Adjustment Corporate Assets	ADA-3 Pro Forma Adjustment Not Used & Useful Plant	Subtotal Pro Forma Adjustments
		Col. 1	Col. 2	Col. 3	Col. 4	Col. 5
		Transmission Plant				
1	365.2	Rights-of-way	($16,545)	$0	$0	($16,545)
2	366.1	Structures and imp. - compressor stations	(2,988)	0	(1,296)	(4,284)
3	366.2	Structures and imp. - meas. & reg. stations	0	0	0	0
4	367	Mains	(169,112)	0	(1,750)	(170,862)
5	368	Compressor station equipment	(15,233)	0	(3,046,754)	(3,061,987)
6	369	Measuring and regulating station equipment	(73,677)	0	(114,625)	(188,302)
7	371	Other Equipment	3,329	0	0	3,329
8		Total transmission plant	($274,226)	$0	($3,164,425)	($3,438,651)
		Distribution Plant				
9	374.2	Rights-of-way	($4,128)	$0	$0	($4,128)
10	375.1	Structures and improvements	138	0	0	138
11	376	Mains	(638,179)	0	0	(638,179)
12	376.5	Mains - Metallic	0	0	0	0
13	376.9	Mains - Cathodic Protection	0	0	0	0
14	378	Meas. and reg. sta. equip. - general	(19,786)	0	0	(19,786)
15	379	Meas. and reg. sta. equip. - city gate	(7,340)	0	0	(7,340)
16	380	Services	(661,396)	0	0	(661,396)
17	380.5	Services - Metallic	0	0	0	0
18	381	Meters	(340,377)	0	0	(340,377)
19	381.5	Meters - AMR	0	0	0	0
20	382	Meter installations	(67,193)	0	0	(67,193)
21	383	House regulators	(158,944)	0	0	(158,944)
22	386	Other Property Customer Premise	0	0	0	0
23	387	Other Equipment	0	0	0	0
24		Total distribution plant	($1,897,205)	$0	$0	($1,897,205)

KANSAS GAS SERVICE, A DIVISION OF ONE GAS, INC.
Detail - Functional Classification of Adjustments to Accumulated Provision for Depreciation and Amortization
Test Year Ended December 31, 2015

Line No.	Account Number	Description	ADA 1 Pro Forma Adjustment Asset Retirement	ADA 2 Pro Forma Adjustment Corporate Assets	ADA-3 Pro Forma Adjustment Not Used & Useful Plant	Subtotal Pro Forma Adjustments
		Col. 1	Col. 2	Col. 3	Col. 4	Col. 5
		General Plant				
1	389.1	Land	$0	$0	$0	$0
2	390.1	Structures and improvements - owned	(6,735)	0	0	(6,735)
3	391.1	Office furniture and equipment - computers	(13,840)	0	0	(13,840)
4	391.9	Computers and other electronic equipment	0	0	0	0
5	392	Transportation equipment	(43,469)	0	0	(43,469)
6	393	Stores equipment	0	0	0	0
7	394	Tool, shop and garage equipment	(18,502)	0	0	(18,502)
8	395	Laboratory equipment	0	0	0	0
9	396	Power operated equipment	(11,570)	0	0	(11,570)
10	397	Communication equipment	(16,004)	0	0	(16,004)
11	398	Miscellaneous equipment	0	0	0	0
12		Total general plant	($110,120)	$0	$0	($110,120)
13		Corporate Allocated	$0	$16,693,239	$0	$16,693,239
14		Total accumulated provision for depreciation	($2,281,551)	$16,693,239	($3,164,425)	$11,247,263
		ACCUMULATED PROVISION FOR AMORTIZATION				
15	302	Franchises and Consents	$0	$0	$0	$0
16	303	Miscellaneous Intangible Plant	0	0	0	0
17	390.2	Structures and improvements - leasehold	0	0	0	0
18		Total accumulated provision for amortization	$0	$0	$0	$0
19		Total accumulated provision for depreciation & Amortization	($2,281,551)	$16,693,239	($3,164,425)	$11,247,263

KANSAS GAS SERVICE, A DIVISION OF ONE GAS, INC.
Detail - Functional Classification of Adjustments to Accumulated Provision for Depreciation and Amortization
Test Year Ended December 31, 2015

Line No.	Account Number	Description	ADA 4 Pro Forma Adjustment CNG	ADA 5 Pro Forma Adjustment 3rd Party Reimbursements	Total Pro Forma Adjustments
		Col. 1	Col. 2	Col. 3	Col. 5
		ACCUMULATED PROVISION FOR DEPRECIATION			
		Natural Gas Production and Gathering Plant			
1	325.4	Rights-of-way	$0	$0	$0
2	327	Field Compressor Station Structure	0	0	0
3	328	Field meas. and reg. station structures	0	0	0
4	332	Field lines	0	0	0
5	333	Field Compressor Station Equipment	0	0	0
6	334	Field meas. and reg. station equipment	0	0	0
7		Total production and gathering plant	$0	$0	$0
		Underground Storage Plant			
8	350.1	Land & Land rights	$0	$0	$0
9	350.2	Rights of way	0	0	0
10	351.1	Structures and improvements	0	0	0
11	351.2	Structures and improvements	0	0	0
12	351.3	Structures and improvements	0	0	0
13	352	Wells	0	0	0
14	352.1	Storage Lease and Rights	0	0	0
15	352.2	Reservoirs	0	0	0
16	352.3	Non-Recoverable Natural Gas	0	0	0
17	353	Storage Lines	0	0	0
18	354	Compressor station equipment	0	0	0
19	355	Measuring and regulating station equipment	0	0	0
20	356	Purification equipment	0	0	0
21	357	Other equipment	0	0	0
22		Total Underground storage plant	$0	$0	$0

KANSAS GAS SERVICE, A DIVISION OF ONE GAS, INC.
Detail - Functional Classification of Adjustments to Accumulated Provision for Depreciation and Amortization
Test Year Ended December 31, 2015

Line No.	Account Number	Description	ADA 4 Pro Forma Adjustment CNG	ADA 5 Pro Forma Adjustment 3rd Party Reimbursements	Total Pro Forma Adjustments
		Col. 1	Col. 2	Col. 3	Col. 5
		Transmission Plant			
1	365.2	Rights-of-way	$0	$0	($16,545)
2	366.1	Structures and imp. - compressor stations	0	0	(4,284)
3	366.2	Structures and imp. - meas. & reg. stations	0	0	0
4	367	Mains	0	0	(170,862)
5	368	Compressor station equipment	0	0	(3,061,987)
6	369	Measuring and regulating station equipment	0	0	(188,302)
7	371	Other Equipment	0	690	4,019
8		Total transmission plant	$0	$690	($3,437,961)
		Distribution Plant			
9	374.2	Rights-of-way	$0	$6,175	$2,047
10	375.1	Structures and improvements	0	0	138
11	376	Mains	0	941,671	303,492
12	376.5	Mains - Metallic	0	145,903	145,903
13	376.9	Mains - Cathodic Protection	0	0	0
14	378	Meas. and reg. sta. equip. - general	0	8,126	(11,660)
15	379	Meas. and reg. sta. equip. - city gate	0	99,000	91,660
16	380	Services	0	16,284	(645,112)
17	380.5	Services - Metallic	0	115	115
18	381	Meters	0	0	(340,377)
19	381.5	Meters - AMR	0	0	0
20	382	Meter installations	0	0	(67,193)
21	383	House regulators	0	0	(158,944)
22	386	Other Property Customer Premise	0	0	0
23	387	Other Equipment	0	0	0
24		Total distribution plant	$0	$1,217,274	($679,931)

KANSAS GAS SERVICE, A DIVISION OF ONE GAS, INC.
Detail - Functional Classification of Adjustments to Accumulated Provision for Depreciation and Amortization
Test Year Ended December 31, 2015

Line No.	Account Number	Description Col. 1	ADA 4 Pro Forma Adjustment CNG Col. 2	ADA 5 Pro Forma Adjustment 3rd Party Reimbursements Col. 3	Total Pro Forma Adjustments Col. 5
		General Plant			
1	389.1	Land	$0	$0	$0
2	390.1	Structures and improvements - owned	0	0	(6,735)
3	391.1	Office furniture and equipment - computers	0	0	(13,840)
4	391.9	Computers and other electronic equipment	0	0	0
5	392	Transportation equipment	0	0	(43,469)
6	393	Stores equipment	0	0	0
7	394	Tool, shop and garage equipment	(58,444)	0	(76,946)
8	395	Laboratory equipment	0	0	0
9	396	Power operated equipment	0	0	(11,570)
10	397	Communication equipment	0	0	(16,004)
11	398	Miscellaneous equipment	0	0	0
12		Total general plant	($58,444)	$0	($168,564)
13		Corporate Allocated		$0	$16,693,239
14		Total accumulated provision for depreciation	($58,444)	$1,217,964	$12,406,783
		ACCUMULATED PROVISION FOR AMORTIZATION			
15	302	Franchises and Consents	$0	$0	$0
16	303	Miscellaneous Intangible Plant	0	0	0
17	390.2	Structures and improvements - leasehold	0	0	0
18		Total accumulated provision for amortization	$0	$0	$0
19		Total accumulated provision for depreciation & Amortization	($58,444)	$1,217,964	$12,406,783

KANSAS GAS SERVICE, A DIVISION OF ONE GAS, INC.
Accumulated Provision for Depreciation and Amortization by Primary Account
Test Year Ended December 31, 2015
Balance as of

Line No.	Account Number	Description	December 31, 2012	December 31, 2013	December 31, 2014	December 31, 2015
		Col. 1	Col. 2	Col. 3	Col. 4	Col. 5
		ACCUMULATED PROVISION FOR DEPRECIATION				
		Natural Gas Production and Gathering Plant				
1	325.4	Rights-of-way	$96,024	$98,931	$101,839	$104,746
2	327	Field Compressor Station Structure	2,120	2,208	2,296	2,385
3	328	Field meas. and reg. station structures	55,464	55,464	55,464	55,464
4	332	Field lines	56,442	56,442	45,302	45,302
5	333	Field Compressor Station Equipment	12,877	12,877	12,877	12,877
6	334	Field meas. and reg. station equipment	385,044	392,616	400,188	407,760
7		Total production and gathering plant	$607,971	$618,538	$617,966	$628,534
		Underground Storage Plant				
8	350.1	Land & Land Rights	$0	$0	$0	$0
9	350.2	Rights of way	0	0	0	0
10	351.1	Structures and Improvements	0	0	0	0
11	351.2	Structures and Improvements	0	0	0	0
12	351.3	Structures and Improvements	0	0	0	0
13	352	Wells	0	0	0	0
14	352.1	Storage Leaseholds and Rights	0	0	0	0
15	352.2	Reservoirs	0	0	0	0
16	352.3	Nonrecoverable Natural Gas	0	0	0	0
17	353	Storage Lines	0	0	0	0
18	354	Compressor Station Equipment	0	0	0	0
19	355	Measuring and Regulating Equipment	0	0	0	0
20	356	Purification Equipment	0	0	0	0
21	357	Other Equipment	0	0	0	0
22		Total Storage Facilities	$0	$0	$0	$0

KANSAS GAS SERVICE, A DIVISION OF ONE GAS, INC.
Accumulated Provision for Depreciation and Amortization by Primary Account
Test Year Ended December 31, 2015
Balance as of

Line No.	Account Number	Description Col. 1	December 31, 2012 Col. 2	December 31, 2013 Col. 3	December 31, 2014 Col. 4	December 31, 2015 Col. 5
		Transmission Plant				
1	365.2	Rights-of-way	$2,821,412	$2,998,726	$3,134,017	$3,309,275
2	366.1	Structures and imp. - compressor stations	3,801,500	3,931,624	3,805,602	3,945,752
3	366.2	Structures and imp. - meas. & reg. stations	923,699	954,364	971,695	996,712
4	367	Mains	46,428,768	48,752,955	51,491,481	53,354,941
5	368	Compressor station equipment	15,194,888	15,652,459	16,158,409	16,944,243
6	369	Measuring and regulating station equipment	4,295,823	4,650,553	5,093,447	5,634,119
7	371	Other Equipment	0	0	0	0
8		Total transmission plant	$73,466,090	$76,940,681	$80,654,651	$84,185,042
		Distribution Plant				
9	374.2	Rights-of-way	$401,244	$428,017	$455,083	$476,867
10	375.1	Structures and improvements	297,137	332,443	364,681	389,678
11	376	Mains	88,813,937	94,166,025	99,414,111	103,385,243
12	376.5	Mains - Metallic	92,063,516	91,336,352	89,657,870	89,335,827
13	376.9	Mains - Cathodic Protection	4,034,898	4,338,482	4,610,847	5,092,547
14	378	Meas. and reg. sta. equip. - general	9,100,590	9,481,063	9,971,353	10,286,200
15	379	Meas. and reg. sta. equip. - city gate	3,876,239	3,847,871	3,882,025	3,948,922
16	380	Services	166,507,539	170,905,759	174,116,116	172,364,955
17	380.5	Services - Metallic	27,922,296	24,721,200	15,765,928	12,910,589
18	381	Meters	17,879,452	19,688,316	22,036,814	24,211,866
19	381.5	Meters - AMR	798,664	1,675,930	2,744,319	3,912,736
20	382	Meter installations	22,497,970	24,292,517	26,212,112	28,352,353
21	383	House regulators	6,440,341	6,588,851	6,840,756	7,021,101
22	386	Other Property Customer Premise	191,807	207,917	222,410	218,684
23	387	Other Equipment	(2,655)	(2,660)	(2,658)	(2,614)
24		Total distribution plant	$440,822,975	$452,008,083	$456,291,767	$461,904,954

KANSAS GAS SERVICE, A DIVISION OF ONE GAS, INC.
Accumulated Provision for Depreciation and Amortization by Primary Account
Test Year Ended December 31, 2015
Balance as of

Line No.	Account Number	Description	December 31, 2012	December 31, 2013	December 31, 2014	December 31, 2015
		Col. 1	Col. 2	Col. 3	Col. 4	Col. 5
		General Plant				
1	389.1	Land and land rights	($14,378)	($14,378)	($14,378)	($14,378)
2	390.1	Structures and improvements - owned	10,109,279	10,604,572	11,122,364	11,694,086
3	391.1	Office furniture and equipment - computers	1,630,179	1,872,637	2,032,336	2,113,219
4	391.9	Computers and other electronic equipment	5,292,627	5,012,251	6,172,759	7,451,704
5	392	Transportation equipment	11,573,847	9,958,315	10,228,708	11,829,729
6	393	Stores equipment	55,622	(2,546)	(44,027)	(93,230)
7	394	Tool, shop and garage equipment	1,081,953	1,424,434	1,671,672	1,009,157
8	395	Laboratory equipment	(259,567)	(254,742)	(249,916)	(245,091)
9	396	Power operated equipment	4,470,770	4,765,076	5,472,715	6,192,016
10	397	Communication equipment	4,999,251	3,171,801	3,408,087	2,186,609
11	398	Miscellaneous equipment	83,713	88,830	77,935	95,697
12	399	Other Tangible Property	0	0	0	0
13		Total general plant	$39,023,296	$36,626,250	$39,878,255	$42,219,518
14		Total accumulated provision for depreciation	$553,920,336	$566,193,551	$577,442,634	$588,938,048
		ACCUMULATED PROVISION FOR AMORTIZATION				
15	302	Franchises and Consents	$0	$0	$0	$0
16	303	Miscellaneous Intangible Plant	22,062	28,629	35,196	41,434
17	390.2	Structures and improvements - leasehold	2,481,747	2,681,883	2,735,877	2,752,808
18		Total accumulated provision for amortization	$2,503,809	$2,710,512	$2,771,073	$2,794,242
19		Total accumulated provision for depreciation and amortization	$556,424,145	$568,904,063	$580,213,707	$591,732,290

KANSAS GAS SERVICE, A DIVISION OF ONE GAS, INC.
Explanation of Pro Forma Adjustments to Accumulated Provision for Depreciation and Amortization
Test Year Ended December 31, 2015

Line No.	Description Col. 1	Increase Col. 2	Decrease Col. 3
	Adjustment ADA 1		
	Asset Retirement		
1	Production and gathering plant	0	0
2	Underground storage plant	0	0
3	Transmission Plant	0	274,226
4	Distribution plant	0	1,897,205
5	General plant	0	110,120
6	Corporate Plant	0	0
7	Total	0	2,281,551

To remove accumulated depreciation related to plant retirements in CWIP that will retire subsequent to the test year.

Line No.	Description	Increase	Decrease
	Adjustment ADA 2		
	Corporate Assets		
8	Production and gathering plant	0	0
9	Underground storage plant	0	0
10	Transmission Plant	0	0
11	Distribution plant	0	0
12	General plant	0	0
13	Corporate Allocated Plant	16,693,239	0
14	Total	16,693,239	0

To include the accumulated depreciation reserve associated with Corporate assets providing service to Kansas Gas Service

Line No.	Description Col. 1	Increase Col. 2	Decrease Col. 3
	Adjustment ADA 3		
	Not Used & Useful Plant		
15	Production and gathering plant	0	0
16	Underground storage plant	0	0
17	Transmission Plant	0	3,164,425
18	Distribution plant	0	0
19	General plant	0	0
20	Corporate Allocated Plant	0	0
21	Total	0	3,164,425

To remove the accumulated depreciation associated with assets that are currently not used and useful.

Line No.	Description	Increase	Decrease
	Adjustment ADA 4		
	Asset Retirement		
1	Production and gathering plant	0	0
2	Underground storage plant	0	0
3	Transmission Plant	0	0
4	Distribution plant	0	0
5	General plant	0	58,444
6	Corporate Allocated Plant	0	0
7	Total	0	58,444

To remove the accumulated depreciation reserve associated with CNG assets used to provide CNG at public stations.

KANSAS GAS SERVICE, A DIVISION OF ONE GAS, INC.
Explanation of Pro Forma Adjustments to Accumulated Provision for Depreciation and Amortization
Test Year Ended December 31, 2015

Line No.	Description Col. 1	Increase Col. 2	Decrease Col. 3
	Adjustment ADA 5		
	Account Reclass		
8	Production and gathering plant	0	0
9	Underground storage plant	0	0
10	Transmission Plant	690	0
11	Distribution plant	1,217,274	0
12	General plant	0	0
13	Corporate Allocated Plant	0	0
14	Total	1,217,964	0

To reclass 3rd Party Reimbursements.

KANSAS GAS SERVICE, A DIVISION OF ONE GAS, INC.
Summary of Working Capital and Rate Base Offsets
Test Year Ended December 31, 2015

Line No.	Description	Schedule Reference	13 Month Avg. or Test Year End	Adjustment Reference	13 Month Average or TYE Per Books	Pro Forma Adjustments	Pro Forma Adjusted Average
	Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7
1	Materials and supplies (154 - 163)	6-B	Avg.		$9,054,838	$0	$9,054,838
2	Gas storage inventory (164.1)	6-B	Avg.		30,779,589	0	30,779,589
3	Prepayments (165)	6-C	Avg.	WC 1	675,146	3,759,835	4,434,981
4	Long Term Prepayments (186)	6-C	Avg.	WC 2	0	618,099	618,099
5	Accumulated Deferred Inc. Tax Liability	6-D	Year End	WC 3 - WC 5	(304,289,937)	31,440,130	(272,849,807)
6	Accumulated Deferred Inc. Tax Liab.- Corporate	6-D	Year End	WC 6	0	(7,916,831)	(7,916,831)
7	Customer Deposits (235)		Year End		(20,122,287)	0	(20,122,287)
8	Customer Advances (252)		Year End		(7,390,439)	0	(7,390,439)
9	Total Working Capital				($291,293,090)	$27,901,234	($263,391,856)

KANSAS GAS SERVICE, A DIVISION OF ONE GAS, INC.
Working Capital
Gas Storage Inventory and Materials & Supplies
Test Year Ended December 31, 2015

Line No.	Month	Gas Storage Inventory: Amount Per Book Account 164.1	Materials &Supplies: Amount Per Book Account 154	Amount Per Book Account 163	Per Book Total
	Col. 1	Col. 2	Col. 2	Col. 3	Col. 4
1	December	$47,778,181	$8,239,373	$202,912	$8,442,285
2	January	35,087,177	8,470,313	412,184	8,882,497
3	February	14,240,348	8,540,867	286,187	8,827,054
4	March	13,936,282	8,936,718	(65,510)	8,871,208
5	April	15,194,179	9,053,044	(98,753)	8,954,291
6	May	20,265,193	10,029,828	(20,701)	10,009,127
7	June	25,587,311	9,780,260	(109,760)	9,670,500
8	July	31,991,337	9,586,068	(101,382)	9,484,686
9	August	37,141,614	9,430,590	(40,868)	9,389,722
10	September	40,909,265	9,236,490	(3,030)	9,233,460
11	October	42,994,099	8,769,990	(99,216)	8,670,774
12	November	41,212,831	8,645,609	(161,363)	8,484,246
13	December	33,796,837	8,846,862	(53,824)	8,793,038
14	Total	$400,134,656	$117,566,012	$146,876	$117,712,888
15	13 month average	$30,779,589	$9,043,539	$11,298	$9,054,838

KANSAS GAS SERVICE, A DIVISION OF ONE GAS, INC.
Working Capital
Long Term Prepayments
Test Year Ended December 31, 2015

Line No.	Month	Corporate: Total Corporate Prepayments	Corporate: Kansas Gas Service Allocated @ 33.2967%	Account 165 Amount Per Book Direct 165	Per Book Average
	Col. 1	Col. 4 (Col 2 + Col. 3)	Col. 5	Col. 6	Col 7 (Col. 5 + Col. 6)
1	December	11,417,756	$3,801,736	$551,254	$4,352,990
2	January	12,571,233	4,185,806	565,603	4,751,409
3	February	13,047,607	4,344,422	527,442	4,871,865
4	March	12,403,164	4,129,844	703,270	4,833,114
5	April	10,905,685	3,631,233	674,587	4,305,820
6	May	12,713,647	4,233,225	797,558	5,030,783
7	June	11,392,910	3,793,463	748,743	4,542,207
8	July	11,162,883	3,716,872	746,738	4,463,609
9	August	9,954,111	3,314,391	720,411	4,034,801
10	September	8,814,110	2,934,808	711,474	3,646,282
11	October	7,235,350	2,409,133	664,906	3,074,039
12	November	12,275,417	4,087,309	693,236	4,780,544
13	December	12,901,029	4,295,617	671,676	4,967,292
14	Total	$146,794,901	$48,877,858	$8,776,898	$57,654,756
15	13 month average	$11,291,915	$3,759,835	$675,146	$4,434,981
16	Distrigas %	33.2967%			
17	Kansas Gas Service Allocated Portion **(WC 1)**	$3,759,835			

KANSAS GAS SERVICE, A DIVISION OF ONE GAS, INC.
Working Capital
Long Term Prepayments
Test Year Ended December 31, 2015

Line No.	Month	Corporate: Total Corporate Prepayments	Corporate: Kansas Gas Service Allocated @ 33.2967%	Account 186 Amount Per Book Direct 186	Per Book Average
	Col. 1	Col. 4 (Col 2 + Col. 3)	Col. 5	Col. 6	Col 7 (Col. 5 + Col. 6)
1	December	1,529,131	$509,150	$0	$509,150
2	January	1,478,647	492,341	0	492,341
3	February	1,441,836	480,084	0	480,084
4	March	1,396,936	465,133	0	465,133
5	April	1,960,931	652,925	0	652,925
6	May	1,993,704	663,838	0	663,838
7	June	1,911,378	636,426	0	636,426
8	July	2,062,871	686,868	0	686,868
9	August	1,968,876	655,571	0	655,571
10	September	2,323,481	773,642	0	773,642
11	October	2,167,105	721,574	0	721,574
12	November	2,013,008	670,265	0	670,265
13	December	1,884,464	627,464	0	627,464
14	Total	$24,132,367	$8,035,282	$0	$8,035,282
15	13 month average	$1,856,336	$618,099	$0	$618,099
16	Distrigas %	33.2967%			
17	Kansas Gas Service Allocated Portion **(WC 2)**	$618,099			

KANSAS GAS SERVICE, A DIVISION OF ONE GAS, INC.
Working Capital
Deferred Taxes
Test Year Ended December 31, 2015

Line No.		Description	12/31/2015 Balance	Pro Forma Adjustments	Pro Forma Balance
		Col. 1	Col. 2	Col. 3	Col. 4
	Kansas Gas Service				
1	283.0	Accumulated Deferred Taxes Current	$0		$0
2	283.0	Accumulated Deferred Federal/State Income Tax	(370,607,951)		(370,607,951)
3	283.0	Accumulated Deferred Federal/State ODC NOL	65,469,542		65,469,542
4	182.3	Regulatory Asset - Flow Through	848,472		848,472
6		ADIT associated with Pension/OPEB Funding **(WC 3)**		51,778,325	51,778,325
5		Reduction to NOL **(WC 4)**		(25,612,745)	(25,612,745)
7		ADIT associated with COGR Over/Under **(WC 5)**		5,274,550	5,274,550
8		Total Accumulated Deferred Income Taxes	($304,289,937)	$31,440,130	($272,849,807)
	ONE Gas				
7		Accumulated Deferred Income Taxes **(WC 6)**	$0	Assignment	($7,916,831)

KANSAS GAS SERVICE, A DIVISION OF ONE GAS, INC.
Test Year Ended December 31, 2015
ONE Gas Capital Structure

Consolidated Capital Structure

Line No.	Description	Schedule Reference	ONE Gas December 31, 2015 Balance	Capitalization Ratios	Adjusted [1] Capitalization Ratios	Related Costs	Cost of Capital
	Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7
1	Long term debt	7-B	$1,200,000,000	39.45%	45.0000%	3.9550%	1.7798%
2	Common equity	7-C	1,841,555,568	60.55%	55.0000%	10.0000%	5.5000%
	Total Capitalization		$3,041,555,568	100%	100%		7.2798%

(1) In Docket 14-KGSG-100-MIS, Kansas Gas Service agreed that the equity component would not exceed 55% in the subsequent base rate filing.

KANSAS GAS SERVICE, A DIVISION OF ONE GAS, INC.
Test Year Ended December 31, 2015
ONE Gas, Inc. Cost of Debt

Line No.	Issue Date	Series	Gross Amount	Original Issuance Cost	Loss on Reacquired	Net Proceeds	Coupon Rate	Annual Interest	Effective Cost	Annual Cost
		Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7	Col. 8	Col. 9
		Long-term Notes Payable								
1	27-Jan-14	2.07% 2019 $300MM	$300,000,000	$2,321,704	$0	$297,678,296	2.0700%	$ 6,210,000	2.2469%	$6,740,794
2	27-Jan-14	3.61% 2024 $300MM	300,000,000	2,471,704	0	297,528,296	3.6100%	10,830,000	3.7438%	11,231,295
3	27-Jan-14	4.658% 2044 $600MM	600,000,000	6,293,408	0	593,706,592	4.6580%	27,948,000	4.7795%	28,677,213
4		Loss on Reacquired Debt			9,731,123			0	0.0000%	810,708
5		Total debt capital	$1,200,000,000	$11,086,815	$9,731,123	$1,188,913,185		$44,988,000		$47,460,011
6							Weighed Average Cost of Debt		**3.9550%**	

KANSAS GAS SERVICE, A DIVISION OF ONE GAS, INC.
Historical Interest Coverage
12 Months Ending

Line No.	Description Col. 1	2012 Col. 2	2013 Col. 3	2014 Col. 4	2015 Col. 5
	Revenues				
1	Operating revenues	$442,947,920	$572,568,767	$596,699,653	$483,532,625
2	Non-operating revenues	45,074,494	53,333,179	53,856,995	49,916,719
3	Total	$488,022,414	$625,901,946	$650,556,648	$533,449,344
	Expenses				
4	Operating expenses	$446,680,177	$583,108,443	$607,747,440	$490,167,830
5	Miscellaneous deductions	(1,410,173)	(606,466)	(35,818)	363,574
6	Total	$445,270,004	$582,501,977	$607,711,622	$490,531,404
7	Net revenues	$42,752,410	$43,399,969	$42,845,026	$42,917,940
8	Income taxes included in line 4 above	18,142,977	16,285,928	15,869,473	16,336,241
9	Net earnings available for interest	$60,895,387	$59,685,897	$58,714,499	$59,254,181
10	Annual interest on bonds outstanding	$22,494,631	$22,520,986	$18,987,743	$18,553,001
11	Interest coverage (Line 9 / Line 10)	2.71	2.65	3.09	3.19

KANSAS GAS SERVICE, A DIVISION OF ONE GAS, INC.
Balance Sheet
Balance as of

Line No.	Account Number	Description Col. 1	December 31, 2012 Col. 2	December 31, 2013 Col. 3	December 31, 2014 Col. 4	December 31, 2015 Col. 5
		ASSETS AND OTHER DEBITS				
		Utility Plant				
1	101-106	Utility plant	$1,537,323,302	$1,588,595,077	$1,648,624,020	$1,702,040,330
2	107	Construction work in progress	9,130,018	12,556,026	5,772,346	13,048,927
3	108,111	Less: Accumulated depreciation	(556,424,145)	(568,904,063)	(580,213,707)	(591,732,290)
			990,029,174	1,032,247,040	1,074,182,659	1,123,356,967
4	114	Acquisition Adjustment	51,209,236	51,209,236	51,209,236	51,209,236
5	115	Accumulated Amortization of Acquisition	(1,270,429)	(1,270,429)	(1,270,429)	(1,270,429)
6		Net utility plant	$1,039,967,981	$1,082,185,847	$1,124,121,466	$1,173,295,774
7	117	Gas stored underground - noncurrent	$0	$0	$0	$0
8	121,122,123.1,124	Other Property and Investments	$0	$0	$0	$0
		Current and Accrued Assets				
11	131	Cash	($93,359,169)	($144,564,697)	$88,591,538	($44,625,469)
12	134	Special deposits	0	0	0	0
13	135	Working funds	0	0	0	0
14	136	Temporary cash investments	0	0	0	0
15	141-146	Receivables (Less: Provision for uncollectible accounts)	109,781,557	173,317,264	124,452,514	98,758,012
16	154	Plant material and operating supplies	4,791,201	3,829,554	8,239,373	8,846,862
17	156	Other materials and supplies	0	0	0	0
18	163	Stores expense undistributed	(38,153)	(171,572)	202,912	(53,824)
19	164.1	Gas stored underground - current	47,925,280	43,213,643	47,778,181	33,796,837
20	165	Prepayments	604,272	596,719	551,254	671,676
21	174	Miscellaneous current and accrued assets	11,496,502	0	17,920,153	1,772,582
22		Total current and accrued assets	$81,201,489	$76,220,911	$287,735,925	$99,166,676

KANSAS GAS SERVICE, A DIVISION OF ONE GAS, INC.
Balance Sheet
Balance as of

Line No.	Account Number	Description	December 31, 2012	December 31, 2013	December 31, 2014	December 31, 2015
		Col. 1	Col. 2	Col. 3	Col. 4	Col. 5
		ASSETS AND OTHER DEBITS (cont.)				
		Deferred Debits				
1	181	Unamortized debt discount and expense	$0	$0	$0	$0
2	182.1	Extraordinary property losses	0	0	0	0
3	182.3	Other regulatory assets	95,342,137	84,543,283	62,687,892	72,755,210
4	184	Clearing accounts	486,154	165,021	1,111,836	1,062,042
5	186	Miscellaneous deferred debits	1,664,218	1,052,034	1,363,182	1,430,998
6	189	Unamortized loss on reacquired debt	0	0	0	0
7	190	Accumulated deferred income taxes	0	0	0	0
8	191	Unrecovered purchased gas cost	17,209,302	12,393,519	22,056,392	13,336,409
9		Total deferred debits	$114,701,811	$98,153,856	$87,219,302	$88,584,659
10		Total assets and other debits	$1,235,871,281	$1,256,560,614	$1,499,076,693	$1,361,047,109
		LIABILITIES AND OTHER CREDITS				
		Proprietary Capital				
11	201	Common stock issued	$0	$0	$0	$0
12	204	Preferred stock issued	0	0	0	0
13	207	Premium on capital stock	0	0	0	0
14		Gain/(Loss) on reacquired stock	0	0	0	0
15	211	Other paid-in-capital	372,477,130	372,477,130	621,887,277	577,387,277
16	216	Retained earnings	102,742,452	123,621,435	11,998,635	3,363,574
17	217	Reacquired capital stock	0	0	0	0
18		Total proprietary capital	$475,219,582	$496,098,565	$633,885,912	$580,750,851
		Other Noncurrent Liabilities				
19	227	Obligations under capital leases	$0	$0	$0	$0
20		Total other noncurrent liabilities	$0	$0	$0	$0

KANSAS GAS SERVICE, A DIVISION OF ONE GAS, INC.
Balance Sheet
Balance as of

Line No.	Account Number	Description Col. 1	December 31, 2012 Col. 2	December 31, 2013 Col. 3	December 31, 2014 Col. 4	December 31, 2015 Col. 5
		LIABILITIES AND OTHER CREDITS (cont.)				
		Current and Accrued Liabilities				
1	231	Notes payable	$0	$0	$0	$0
2	232	Accounts payable	43,561,551	52,973,720	41,398,028	27,378,480
3	233	Long Term Debt	374,790,143	374,790,143	429,000,000	375,000,000
4	234	Accounts payable to associated companies	42,672,859	18,653,241	45,428,326	35,331,762
5	235	Customer deposits	17,508,256	17,940,097	19,919,337	20,122,287
6	236	Taxes accrued	11,187,479	18,254,523	10,245,354	1,118,207
7	237	Interest accrued	(1,975)	(1,960)	(1,960)	(1,938)
8	238	Dividends declared	0	0	0	0
9	239	Matured long-term debt	0	0	0	0
10	241	Tax collections payable	5,258,313	7,109,785	6,466,469	3,443,632
11	242	Miscellaneous current and accrued liabilities	4,289,083	3,357,776	5,544,232	4,809,437
12	243	Obligations under capital leases - current	0	0	0	0
13		Total current and accrued liabilities	$499,265,709	$493,077,325	$557,999,786	$467,201,867
		Deferred Credits				
14	252	Customer advances for construction	$5,200,967	$4,035,549	$5,686,065	$7,390,439
15	253	Other deferred credits	614,992	2,608	18,648,141	70,842
16	254	Other Regulatory Liabilities	0	0	0	0
17	255	Accumulated deferred investment tax credits	1,254,577	962,617	696,085	494,701
18		Total deferred credits	$7,070,535	$5,000,775	$25,030,291	$7,955,982
		Accumulated Deferred Income Taxes				
19	283	Other	$254,315,454	$262,383,950	$282,160,704	$305,138,409
20		Total accumulated deferred income taxes	$254,315,454	$262,383,950	$282,160,704	$305,138,409
21		Total liabilities and other credits	$1,235,871,281	$1,256,560,614	$1,499,076,693	$1,361,047,109

KANSAS GAS SERVICE, A DIVISION OF ONE GAS, INC.
Comparative Income Statement
Balance as of
12 Months Ending

Line No.	Account Number	Description Col. 1	December 31, 2012 Col. 2	December 31, 2013 Col. 3	December 31, 2014 Col. 4	December 31, 2015 Col. 5
1	400	Operating Revenues	$488,022,414	$625,901,946	$650,556,648	$533,449,344
		Operating Expenses				
2	401	Operation expense	$338,348,301	$457,578,325	$499,755,785	$382,219,316
3	402	Maintenance expense	21,414,716	22,727,969	22,242,770	21,204,989
4	403	Depreciation	41,721,650	39,189,777	40,847,878	44,355,253
5	404-405	Amortization and depletion	232,947	206,703	60,561	23,498
6	406	Amortization of utility plant acquisition. adj.	0	0	0	0
7	407	Other amortization	0	0	0	0
8	407.3	Regulatory debit	8,143,995	21,079,479	2,807,063	(114,456)
9	407.4	Regulatory credit	0	0	0	0
10	408.1	Taxes other than income taxes	19,022,978	26,332,222	26,430,442	26,344,373
11	409.1	Income taxes	(13,565,574)	8,405,628	6,330,303	(1,148,546)
12	410.1	Deferred income taxes (Dr.)	31,708,551	7,880,300	9,539,170	17,484,787
13	411.4	Investment tax credits, net	(347,388)	(291,960)	(266,532)	(201,384)
14		Total utility operating expenses	$446,680,177	$583,108,443	$607,747,440	$490,167,830
15		Net utility operating income	$41,342,237	$42,793,503	$42,809,208	$43,281,514
		Other Income and Deductions				
16	415	Revenues from merch., jobbing & contract	($36,416)	$25,552	($47,232)	($4,552)
17	416	(Less)Costs & expense of merch, job. & cont.	149	0	0	0
18	417 - 417.6	Revenues from non-utility operations - net	878,852	406,933	601,488	484,926
19	418	Non operating rental income	0	0	0	0
20	418.1	Equity in earnings of subsidiary companies	0	0	0	0
21	419	Interest & dividend income	0	0	14	0
22	419.1	AFUDC	0	0	0	0
23	421	Misc non-operating income	1,343,767	2,204,143	273,387	4,877
24	421.1	Gain on disposition of property	0	0	0	0
25		Total other income before tax	$2,186,054	$2,636,628	$827,657	$485,251
26	421.2	Loss on disposition of property	$0	$0	$0	$0
27	425	Miscellaneous amortization	0	0	0	0
28	426	Misc Income deductions	775,881	2,030,162	791,839	848,825
29		Total other income deductions before tax	$775,881	$2,030,162	$791,839	$848,825

KANSAS GAS SERVICE, A DIVISION OF ONE GAS, INC.
Comparative Income Statement
Balance as of
12 Months Ending

Line No.	Account Number	Description Col. 1	December 31, 2012 Col. 2	December 31, 2013 Col. 3	December 31, 2014 Col. 4	December 31, 2015 Col. 5
1	409.2	Income taxes	$0	$0	$0	$0
2	410.2	Deferred taxes	0	0	0	0
3	411.2	Provision for deferred taxes - credit	0	0	0	0
4	411.4	ITC	0	0	0	0
5	420	Less: ITC credits	0	0	0	0
6		Total taxes on other inc & deductions	$0	$0	$0	$0
7		Total other income and deductions	$1,410,173	$606,466	$35,818	($363,574)
8		Income before interest charges	$42,752,410	$43,399,969	$42,845,026	$42,917,940
		Interest Charges				
9	427	Interest on long-term debt	$0	$0	$0	$0
10	428	Amortization of debt discount and expense	370,968	370,888	30,906	0
11	429	Amortization of premium on debt (Cr.)	0	0	0	0
12	430	Interest on debt to assoc. companies	21,745,707	21,691,356	18,995,373	18,707,717
13	431	Other interest expense	622,273	659,839	149,855	28,787
14	432	Allowance for borrowed funds used during construction (Cr.)	(244,317)	(201,097)	(188,391)	(183,503)
15		Total interest charges	$22,494,631	$22,520,986	$18,987,743	$18,553,001
		Extraordinary Items				
16	434 - 435	Extraordinary income - net	$0	$0	$0	$0
17	409.3	Income taxes	0	0	0	0
18		Extraordinary Items after taxes	$0	$0	$0	$0
19		Net income	$20,257,779	$20,878,983	$23,857,283	$24,364,939

KANSAS GAS SERVICE, A DIVISION OF ONE GAS, INC.
Statement of Retained Earnings
Balance as of
12 Months Ending

Line No.	Account Number	Description	December 31, 2012	December 31, 2013	December 31, 2014	December 31, 2015
		Col. 1	Col. 2	Col. 3	Col. 4	Col. 5
		RETAINED EARNINGS				
1	216	Retained earnings, beginning balance	$82,484,673	$102,742,452	$123,621,435	$11,998,635
		Additions:				
2	433	Net income	$20,257,779	$20,878,983	$23,857,283	$24,364,939
		Less:				
3	439	Adjustments to retained earnings	$0	$0	($135,480,083)	($33,000,000)
4	437	Dividends declared -preferred stock	0	0	0	0
4	438	Dividends declared - common stock	0	0	0	0
5	131	Dividends to parent	0	0	0	
6		Total adjustment and dividends declared	$0	$0	($135,480,083)	($33,000,000)
7	216	Retained earnings, ending balance	$102,742,452	$123,621,435	$11,998,635	$3,363,574

KANSAS GAS SERVICE, A DIVISION OF ONE GAS, INC.
Operating Revenues by Primary Account
Balance as of
12 Months Ending

Line No.	Account Number	Description Col. 1	December 31, 2012 Col. 2	December 31, 2013 Col. 3	December 31, 2014 Col. 4	December 31, 2015 Col. 5
		OPERATING REVENUE				
		Gas Service Revenue				
1	480	Residential sales	$351,621,855	$458,895,992	$480,567,666	$391,147,936
2	481	Non-Residential sales	82,672,654	109,030,904	115,362,663	91,975,454
3		Total sales to ultimate customers	$434,294,509	$567,926,896	$595,930,329	$483,123,390
4	483	Sales for resale	$8,653,411	$4,641,871	$769,324	$409,235
5		Total gas service revenue	$442,947,920	$572,568,767	$596,699,653	$483,532,625
		Other Operating Revenue				
6	487	Forfeited discounts	$1,419,843	$1,901,529	$2,181,039	$1,711,257
7	488	Miscellaneous service revenues	1,537,172	1,636,415	1,650,559	1,545,271
8	489	Revenue from transmission of gas of others	41,023,800	48,811,013	49,549,125	46,452,424
9	491	Revenue from natural gas processed by others	679,057	671,305	398,481	133,766
10	493	Rent from gas property	370,184	284,523	37,395	43,812
11	495	Other gas revenue (inc. acct 412&414)	44,438	28,394	40,396	30,189
12		Total other operating revenue	$45,074,494	$53,333,179	$53,856,995	$49,916,719
13		Total gas operating revenue	$488,022,414	$625,901,946	$650,556,648	$533,449,344

KANSAS GAS SERVICE, A DIVISION OF ONE GAS, INC.
Operating Expenses by Primary Account
Balance as of
12 Months Ending

Line No.	Account Number	Description	December 31, 2012	December 31, 2013	December 31, 2014	December 31, 2015
		Col. 1	Col. 2	Col. 3	Col. 4	Col. 5
		OPERATIONS AND MAINTENANCE EXPENSES				
		Natural Gas Production and Gathering				
		Operation				
1	750	Operation supervision and engineering	$0	$0	$0	$0
2	751	Production maps and records	0	0	0	0
3	753	Field lines expense	0	0	0	0
4	754	Field compressor station expenses	0	0	0	0
5	755	Field compressor station fuel and power	0	0	0	0
6	756	Field measuring and regulating station expenses	0	0	0	0
7	757	Purification expenses	0	0	0	0
8	759	Other expenses	0	0	0	0
9	760	Rents	0	0	0	0
10		Total operation	$0	$0	$0	$0
		Maintenance				
11	761	Maintenance supervision and engineering	$0	$0	$0	$0
12	762	Maintenance of structures and improvements	0	0	0	0
13	764	Maintenance of field lines	0	0	0	0
14	765	Maintenance of field compressor station equip.	0	0	0	0
15	766	Maintenance of field meas. and reg. sta. equip.	0	0	0	0
16	767	Maintenance of purification equipment	0	0	0	0
17	769	Maintenance of other equipment	0	0	0	0
18		Total maintenance	$0	$0	$0	$0
19		Total natural gas production and gathering	$0	$0	$0	$0

KANSAS GAS SERVICE, A DIVISION OF ONE GAS, INC.
Operating Expenses by Primary Account
Balance as of
12 Months Ending

Line No.	Account Number	Description Col. 1	December 31, 2012 Col. 2	December 31, 2013 Col. 3	December 31, 2014 Col. 4	December 31, 2015 Col. 5
		Products Extraction				
		Operation				
1	776	Operations and Supplies expense	$0	$0	$0	$0
2	777	Gas processed by others	343,700	374,349	347,505	181,122
3		Total products extraction	$343,700	$374,349	$347,505	$181,122
		Other Gas Supply Expenses				
		Operation				
4	805	Other gas purchases	$219,026,815	$326,472,854	$358,059,977	$245,331,368
5		Total purchased gas	$219,026,815	$326,472,854	$358,059,977	$245,331,368
		Purchased Gas Expenses				
6	807.1	Well expenses- purchased gas	$0	$0	$0	$0
7	807.2	Operation of purchased gas measuring stations	0	0	0	0
8	807.3	Maintenance of purchased gas measuring stations	0	0	0	0
9	807.4	Purchased gas calculations expenses	31,949	36,840	18,060	0
10	807.5	Other purchased gas expenses	1,257,196	1,257,984	1,397,016	1,260,012
11		Total purchased gas expenses	$1,289,145	$1,294,824	$1,415,076	$1,260,012
		Gas Used in Utility Operations				
12	810	Gas used for compressor station fuel	($229,730)	($268,626)	($571,095)	($248,553)
13	811	Gas used for products extraction	(343,700)	(374,349)	(347,505)	(181,122)
14	812	Gas used for other utility operations	(101,673)	(22,349)	(19,083)	(10,195)
15		Total gas used in utility operations	($675,103)	($665,324)	($937,683)	($439,870)
16	813	Other gas supply expenses	$1,131,870	$1,226,764	$1,137,965	$1,224,483
17		Total other gas supply expenses	$220,772,727	$328,329,118	$359,675,335	$247,375,993
18		Total production expenses	$221,116,427	$328,703,467	$360,022,840	$247,557,115

KANSAS GAS SERVICE, A DIVISION OF ONE GAS, INC.
Operating Expenses by Primary Account
Balance as of
12 Months Ending

Line No.	Account Number	Description	December 31, 2012	December 31, 2013	December 31, 2014	December 31, 2015
		Col. 1	Col. 2	Col. 3	Col. 4	Col. 5
		Underground Storage Expenses				
		Operation				
1	814	Operation, supervision and engineering	$0	$0	$0	$0
2	815	Maps and records	0	0	0	0
3	816	Wells expenses	0	0	0	0
4	817	Lines expenses	0	0	0	0
5	818	Compressor station expenses	0	0	0	0
6	819	Compressor station fuel and power	112,790	127,414	141,492	85,509
7	820	Measuring and regulating station expenses	0	54	(11,336)	0
8	821	Purification expenses	2,171	0	373	0
9	822	Exploration and development	0	0	0	0
10	823	Gas losses	0	210	0	0
11	824	Other expenses	0	0	0	242
12	825	Storage well royalties	0	0	0	0
13	826	Rents	0	0	0	0
14		Total operation	$114,961	$127,678	$130,529	$85,751
		Maintenance				
15	830	Maintenance, supervision and engineering	$0	$0	$0	$0
16	831	Maintenance of structures and improvements	0	0	0	0
17	832	Maintenance of reservoirs and wells	0	0	0	0
18	833	Maintenance of lines	0	0	0	0
19	834	Maintenance of compressor station equipment	0	0	0	0
20	835	Maintenance of measuring & reg. station equipment	0	0	0	0
21	836	Maintenance of purification equipment	0	0	0	0
22	837	Maintenance of other equipment	0	0	0	0
23		Total maintenance	$0	$0	$0	$0
24		Total underground storage expenses	$114,961	$127,678	$130,529	$85,751

KANSAS GAS SERVICE, A DIVISION OF ONE GAS, INC.
Operating Expenses by Primary Account
Balance as of
12 Months Ending

Line No.	Account Number	Description	December 31, 2012	December 31, 2013	December 31, 2014	December 31, 2015
		Col. 1	Col. 2	Col. 3	Col. 4	Col. 5
		Transmission Expenses				
		Operation				
1	850	Operation supervision and engineering	$614,604	$519,043	$226,947	$269,399
2	851	System control and load dispatching	1,620,971	1,686,960	1,778,977	1,764,618
3	852	Communication system expense	124	0	122	0
4	853	Compressor station labor and expense	866,962	893,741	849,339	717,563
5	854	Gas for compressor station fuel	113,180	141,212	429,603	163,044
6	855	Other fuel and power for compressor stations	6,124	10,281	9,121	11,549
7	856	Mains expenses	2,920,532	3,117,256	3,694,997	3,690,705
8	857	Measuring and regulating station expenses	616,731	663,561	664,045	723,084
9	858	Transmission and compression of gas by others	0	0	0	0
10	859	Other expenses	133,836	136,506	135,356	129,060
11	860	Rents	4,017	4,229	1,023	2,078
12		Total operation	$6,897,081	$7,172,789	$7,789,530	$7,471,100
		Maintenance				
13	861	Maintenance supervision and engineering	$193,000	$179,503	$98,678	$124,406
14	862	Maintenance of structures and improvements	15,702	31,242	19,832	12,869
15	863	Maintenance of mains	762,312	806,941	558,856	579,764
16	864	Maintenance of compressor station equipment	496,205	418,291	355,580	395,081
17	865	Maintenance of meas. & regulating station equip.	441,074	480,130	456,098	459,813
18	866	Maintenance of communication equipment	0	0	0	0
19	867	Maintenance of other equipment	266	0	0	0
20		Total maintenance	$1,908,559	$1,916,107	$1,489,044	$1,571,933
21		Total transmission expenses	$8,805,640	$9,088,896	$9,278,574	$9,043,033

KANSAS GAS SERVICE, A DIVISION OF ONE GAS, INC.
Operating Expenses by Primary Account
Balance as of
12 Months Ending

Line No.	Account Number	Description	December 31, 2012	December 31, 2013	December 31, 2014	December 31, 2015
		Col. 1	Col. 2	Col. 3	Col. 4	Col. 5
		Distribution Expenses				
		Operation				
1	870	Operation supervision and engineering	$3,502,021	$3,323,804	$2,045,230	$2,459,638
2	871	Distribution load dispatching	84,674	36,297	57,753	76,425
3	874	Mains and services expense	10,879,074	11,331,160	12,723,918	13,364,339
4	875	Meas. and reg. sta. expenses - general	1,388,628	1,516,964	1,915,551	2,090,987
5	876	Meas. and reg. sta. expenses - industrial	513,329	499,783	438,854	538,153
6	877	Meas. and reg. sta. expenses - city gate	391,448	440,223	502,181	483,887
7	878	Meter and house regulator expenses	10,056,509	10,217,562	10,134,350	10,448,467
8	879	Customer installations expenses	7,138,370	7,728,818	7,604,483	7,937,785
9	880	Other expenses	6,607,572	6,062,901	4,647,398	4,314,200
10	881	Rents	567,632	586,022	586,054	617,379
11		Total operation	$41,129,257	$41,743,534	$40,655,772	$42,331,260
		Maintenance				
12	885	Maintenance, supervision and engineering	$724,330	$698,718	$522,843	$488,432
13	886	Maintenance of structures and improvements	149,224	285,315	347,077	349,221
14	887	Maintenance of mains	10,806,217	11,682,193	12,029,025	11,214,352
15	889	Maint. of meas. and reg. sta. equip. - general	1,049,309	1,064,706	911,831	870,328
16	890	Maint. of meas. and reg. sta. equip. - industrial	280,056	308,693	274,161	283,012
17	891	Maint. of meas. and reg. sta. equip. - city gate	558,758	544,553	473,291	384,509
18	892	Maintenance of services	2,673,075	2,900,429	3,211,134	2,818,682
19	893	Maintenance of meters and house regulators	2,549,070	2,611,667	2,286,409	2,509,887
20	894	Maintenance of other equipment	4,531	828	3,123	3,092
21		Total Distribution	$18,794,570	$20,097,102	$20,058,894	$18,921,515
22	932	Maintenance of General Plant	711,587	714,760	694,832	711,541
23		Total maintenance	$19,506,157	$20,811,862	$20,753,726	$19,633,056
24		Total distribution expenses	$60,635,414	$62,555,396	$61,409,498	$61,964,316

KANSAS GAS SERVICE, A DIVISION OF ONE GAS, INC.
Operating Expenses by Primary Account
Balance as of
12 Months Ending

Line No.	Account Number	Description	December 31, 2012	December 31, 2013	December 31, 2014	December 31, 2015
		Col. 1	Col. 2	Col. 3	Col. 4	Col. 5
		Customer Accounts Expense				
1	901	Supervision	$1,051,028	$957,913	$757,158	$617,758
2	902	Meter reading expenses	4,942,001	4,978,511	4,966,571	5,294,848
3	903	Customer records and collection expense	15,623,366	15,756,843	16,021,917	15,853,191
4	904	Uncollectible accounts	1,470,000	3,580,000	4,065,000	2,225,000
5	905	Miscellaneous customer accounts expense	441,503	827,107	1,234,095	1,392,656
6		Total customer accounts expenses	$23,527,898	$26,100,374	$27,044,741	$25,383,453
		Customer Service and Informational Expenses				
7	907	Supervision	$0	$486	$0	$284
8	908	Customer assistance expenses	30	48,558	139,574	257,059
9	909	Informational and instructional expenses	0	0	0	0
10	910	Misc. customer service & informational expenses	44	393	0	0
11		Total customer. service and informational expenses	$74	$49,437	$139,574	$257,343
		Sales Expense				
12	911	Supervision	$242,880	$266,198	$208,512	$0
13	912	Demonstrating and selling expenses	1,062,187	969,067	891,007	941,457
14	913	Advertising expenses	0	9,033	693	0
15	916	Miscellaneous sales expenses	0	0	0	0
16		Total sales expenses	$1,305,067	$1,244,298	$1,100,212	$941,457

KANSAS GAS SERVICE, A DIVISION OF ONE GAS, INC.
Operating Expenses by Primary Account
Balance as of
12 Months Ending

Line No.	Account Number	Description Col. 1	December 31, 2012 Col. 2	December 31, 2013 Col. 3	December 31, 2014 Col. 4	December 31, 2015 Col. 5
		Administrative and General Expenses				
		Operation				
1	920	Administrative and general salaries	$18,268,739	$18,237,374	$17,536,907	$17,114,528
2	921	Office supplies and expenses	4,501,000	4,146,611	4,305,545	3,991,055
3	922	Administrative expenses transferred	(1,765,433)	(1,327,130)	(2,004,685)	(2,162,213)
4	923	Outside services employed	2,027,825	3,386,766	1,164,551	792,982
5	924	Property insurance	0	227,631	791,139	646,379
6	925	Injuries and damages	2,461,789	693,715	1,915,480	(117,566)
7	926	Employee pensions and benefits	25,334,243	29,065,640	26,399,115	24,743,279
8	927	Franchise requirements	800	200	257	5,429
9	928	Regulatory commission expense	825,631	684,667	699,831	754,080
10	929	Duplicate expenses	(31,696,454)	(33,205,978)	(29,281,735)	(28,953,698)
11	930.1	General advertising expense	65,250	63,618	53,222	58,202
12	930.2	Miscellaneous general expenses	22,849,482	29,074,980	40,290,723	40,328,340
13	931	Rents	1,384,664	1,388,654	1,002,237	991,040
14		Total operation	$44,257,536	$52,436,748	$62,872,587	$58,191,837
15		Total administrative and general expenses	$44,257,536	$52,436,748	$62,872,587	$58,191,837
16		Total operation and maintenance expenses	$359,763,017	$480,306,294	$521,998,555	$403,424,305

KANSAS GAS SERVICE, A DIVISION OF ONE GAS, INC.
Sales Usage, Revenues, and Customer Data
Year Ending December 2012

Line No.	Description	MCF Sales	Revenue	Average Number of Customers	MCF Sales per Customer	Revenue per MCF Sold ($)
	Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6
	Residential					
1	RS - Residential Sales Service	33,878,295	$333,864,462	577,122	59	$9.8548
2	Revenue Accrual		17,757,393		N.A.	N.A.
3	Total Residential	33,878,295	$351,621,855	577,122	59	$10.3790
	Commercial					
4	GS - General Sales Service	8,661,463	$75,852,538	49,226	176	$8.7575
5	GIS - Gas Irrigation Sales Service	222,380	$1,431,987	240	927	6.4394
6	KGSSD - Kansas Gas Supply Sales Service D	61,256	358,491	1	61,256	5.8523
7	SGS-Small Generator Sales Service	4,146	384,430	575	7	92.7231
8	Revenue Accrual		4,279,219		N.A.	N.A.
9	Total commercial	8,949,245	82,306,665	50,042	179	$9.1971
	Industrial					
10	GS - General Sales Service	49,188	$356,971	67	734	$7.2573
11	Revenue Accrual		9,018		N.A.	N.A.
12	Total Industrial	49,188	$365,989	67	734	$7.4406
	Sales for Resale					
13	Sales for Resale	29,112	$180,294	16	1,820	$6.1931
14	AAGS - As-Available Gas Sales Service	3,905,240	8,473,117	14	278,946	2.1697
15	Revenue Accrual		0		N.A.	N.A.
16	Total Sales for Resale	3,934,352	$8,653,411	30	131,145	$2.1995
17	Total Sales of Gas	46,811,080	442,947,920	627,261	75	$9.4625

KANSAS GAS SERVICE, A DIVISION OF ONE GAS, INC.
Sales Usage, Revenues, and Customer Data
Year Ending December 2013

Line No.	Description	MCF Sales	Revenue	Average Number of Customers	MCF Sales per Customer	Revenue per MCF Sold ($)
	Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6
	Residential					
1	RS - Residential Sales Service	45,872,252	$465,511,538	576,989	80	$10.1480
2	Revenue Accrual		(6,615,546)		N.A.	N.A.
3	Total Residential	45,872,252	$458,895,992	576,989	80	$10.0038
	Non-Residential					
4	GSS - General Sales Service Small	3,811,960	$42,355,056	36,851	103	$11.1111
5	GSL - General Sales Service Large	6,621,068	54,397,357	11,810	561	8.2158
6	GSTE - General Sales Service Transport Eligible	1,512,632	11,400,308	553	2,735	7.5367
7	GIS - Gas Irrigation Sales Service	165,191	1,320,067	239	691	7.9912
8	KGSSD - Kansas Gas Supply Sales Service D	30,653	199,284	1	30,653	6.5013
9	SGS-Small Generator Sales Service	6,587	416,207	600	11	63.1861
10	Revenue Accrual		(1,057,376)		N.A.	N.A.
11	Total commercial	12,148,091	$109,030,903	50,054	243	$8.9751
			$0			
	Sales for Resale					
12	Sales for Resale	42,021	$290,288	16	2,626	$6.9082
13	AAGS - As-Available Gas Sales Service	1,340,563	4,351,583	2	670,282	3.2461
14	Revenue Accrual				N.A.	N.A.
15	Total Sales for Resale	1,382,584	$4,641,871	18	76,810	$3.3574
16	Total Sales of Gas	59,402,927	$572,568,766	627,062	94	$9.6387

Line No.	Description	MCF Sales	Revenue	Average Number of Customers	MCF Sales per Customer	Revenue per MCF Sold ($)
	Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6
	Residential					
1	RS - Residential Sales Service	48,032,704	$498,710,460	578,298	83	$10.3827
2	Revenue Accrual		(18,142,794)		N.A.	N.A.
3	Total residential	48,032,704	$480,567,666	578,298	83	$10.0050
	Non-Residential					
4	GSS - General Sales Service Small	4,264,375	$47,560,270	36,948	115	$11.1529
5	GSL - General Sales Service Large	6,948,864	58,685,206	11,817	588	8.4453
6	GSTE - General Sales Service Transport Eligible	1,527,698	11,863,199	541	2,824	7.7654
7	GIS - Gas Irrigation Sales Service	161,477	1,374,085	235	687	8.5095
8	KGSSD - Kansas Gas Supply Sales Service D	54,421	365,789	1	54,421	6.7215
9	SGS-Small Generator Sales Service	11,365	463,653	618	18	40.7966
10	Revenue Accrual		(4,949,539)		N.A.	N.A.
11	Total commercial	12,968,200	$115,362,663	50,160	259	$8.8958
	Sales for Resale					
12	Sales Service For Resale	104,671	$769,324	16	6,542	$7.3499
13	AAGS - As Available Gas Sales Service	0	0	0	N.A.	N.A.
14	Revenue Accrual				N.A.	N.A.
15	Total Sales for Resale	104,671	$769,324	16	6,542	$7.3499
16	Total Sales of Gas	61,105,575	$596,699,653	628,474	97	$9.7651

KANSAS GAS SERVICE, A DIVISION OF ONE GAS, INC.
Sales Usage, Revenues, and Customer Data
Year Ending December 2015

Line No.	Description	MCF Sales	Revenue	Average Number of Customers	MCF Sales per Customer	Revenue per MCF Sold ($)
	Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6
	Residential					
1	RS - Residential Sales Service	39,112,226	$386,090,494	579,151	68	$9.8714
2	Revenue Accrual		5,057,442		N.A.	N.A.
3	Total residential	39,112,226	$391,147,936	579,151	68	$10.0007
	Non-Residential					
4	GSS - General Sales Service Small	3,326,454	$36,992,453	36,857	90	$11.1207
5	GSL - General Sales Service Large	5,787,404	43,478,330	11,886	487	7.5126
6	GSTE - General Sales Service Transport Eligible	1,317,803	8,676,799	564	2,338	6.5843
7	GIS - Gas Irrigation Sales Service	147,868	1,026,683	228	650	6.9432
8	KGSSD - Kansas Gas Supply Sales Service D	30,247	198,134	1	30,247	6.5505
9	SGS-Small Generator Sales Service	9,720	464,578	640	15	47.7958
10	Revenue Accrual		1,138,477		N.A.	N.A.
11	Total commercial	10,619,497	$91,975,454	50,175	212	$8.6610
	Sales for Resale					
12	Sales Service For Resale	61,532	$409,235	16	3,846	$6.6507
13	AAGS - As Available Gas Sales Service	0	0	0	0	N.A.
14	Revenue Accrual		0		N.A.	N.A.
15	Total Sales for Resale	61,532	$409,235	16	3,846	$6.6507
16	Total sales of gas	49,793,255	$483,532,625	629,342	79	$9.7108

KANSAS GAS SERVICE, A DIVISION OF ONE GAS, INC.
Transport Usage, Revenues, and Customer Data
Year Ending December 2012

Line No.	Description	MCF Sales	Revenue	Average Number of Customers	MCF Sales per Customer	Revenue per MCF Sold ($)
	Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6
	Transmission					
1	ITt - Interruptible Gas Transportation Service	7,683,490	$819,491	21	365,880	$0.1067
2	Revenue Accrual		(21,658)		N.A.	N.A.
3	Total commercial	7,683,490	$797,833	21	365,880	$0.1038
	Distribution - Retail					
4	STk - Small Transportation Service	778,394	$1,709,645	612	1,272	$2.1964
5	STt - Small Transportation Service	232,313	530,268	185	1,256	2.2826
6	GTk - General Transportation Service	3,655,893	6,967,965	2,679	1,365	1.9060
7	GTt - General Transportation Service	1,331,023	3,063,010	895	1,487	2.3012
8	GITt - Gas Irrigation Transportation Service	1,089,971	1,946,552	471	2,314	1.7859
9	CNGk - Compressed Natural Gas General Transp. Service	21,558	18,735	2	10,779	0.8691
10	LVTk - Large Volume Transportation Service	16,517,718	11,452,320	494	33,437	0.6933
11	LVTt - Large Volume Transportation Service	26,323,366	13,194,775	147	179,071	0.5013
12	Revenue Accrual		230,307		N.A.	N.A.
13	Total distribution - retail	49,950,236	$39,113,577	5,485	9,107	$0.7831
	Distribution - Sales for Resale					
14	WTt - Wholesale Transportation Service	2,351,948	$1,273,295	29	81,102	$0.5414
15	Revenue Accrual		(160,905)		N.A.	N.A.
16	Total distribution - sales for resale	2,351,948	$1,112,390	29	81,102	$0.4730
17	Total gas transport	59,985,674	$41,023,800	5,535	10,838	$0.6839

Line No.	Description	MCF Sales	Revenue	Average Number of Customers	MCF Sales per Customer	Revenue per MCF Sold ($)
	Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6
	Transmission					
1	ITt - Interruptible Gas Transportation Service	8,035,156	$916,685	19	422,903	$0.1141
2	Revenue Accrual		34,000		N.A.	N.A.
3	Total commercial	8,035,156	$950,685	19	422,903	$0.1183
	Distribution - Retail					
4	STk - Small Transportation Service	5,610,948	$11,187,056	3,314	1,693	$1.9938
5	STt - Small Transportation Service	1,882,284	4,549,790	1,091	1,725	2.4172
6	CNGk - Compressed Natural Gas General Transp. Service	21,458	20,783	1	21,458	0.9685
7	GITt - Gas Irrigation Transportation Service	978,512	1,941,203	490	1,997	1.9838
8	LVTk - Large Volume Transportation Service Tier 1	3,023,339	3,273,523	276	10,954	1.0828
9	LVTk - Large Volume Transportation Service Tier 2	1,286,100	1,512,777	84	15,311	1.1763
10	LVTk - Large Volume Transportation Service Tier 3	2,003,341	1,794,891	53	37,799	0.8959
11	LVTk - Large Volume Transportation Service Tier 4	11,105,514	6,826,851	80	138,819	0.6147
12	LVTt - Large Volume Transportation Service Tier 1	4,427,039	2,408,036	48	92,230	0.5439
13	LVTt - Large Volume Transportation Service Tier 2	386,225	654,506	20	19,311	1.6946
14	LVTt - Large Volume Transportation Service Tier 3	388,345	582,621	29	13,391	1.5003
15	LVTt - Large Volume Transportation Service Tier 4	21,805,318	10,431,705	43	507,100	0.4784
16	Revenue Accrual		749,822		N.A.	N.A.
17	Total distribution - retail	52,918,423	$45,933,564	5,529	9,571	$0.8680
	Distribution - Sales for Resale					
18	WTt - Wholesale Transportation Service	2,769,610	$1,730,267	27	102,578	$0.6247
	Revenue Accrual		$196,496		N.A.	N.A.
19	Total distribution - sales for resale	2,769,610	1,926,763	27	102,578	$0.6957
20	Total gas transport	63,723,189	$48,811,013	5,576	11,428	$0.7660
			$0			

KANSAS GAS SERVICE, A DIVISION OF ONE GAS, INC.
Transport Usage, Revenues, and Customer Data
Year Ending December 2014

Line No.	Description	MCF Sales	Revenue	Average Number of Customers	MCF Sales per Customer	Revenue per MCF Sold ($)
	Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6
	Transmission					
1	ITt - Interruptible Gas Transportation Service	7,246,038	$1,050,757	18	402,558	$0.1450
2	Revenue Accrual		(5,309)		N.A.	N.A.
3	Total commercial	7,246,038	$1,045,448	18	402,558	$0.1443
	Distribution - Retail					
4	STk - Small Transportation Service	6,340,384	$11,897,605	3,389	1,871	$1.8765
5	STt - Small Transportation Service	1,975,546	4,653,381	1,101	1,794	2.3555
6	CNGk - Compressed Natural Gas General Transp. Service	73,811	62,453	3	24,604	0.8461
7	GITt - Gas Irrigation Transportation Service	965,299	1,856,415	506	1,908	1.9232
8	LVTk - Large Volume Transportation Service Tier 1	1,144,957	1,838,397	198	5,783	1.6056
9	LVTk - Large Volume Transportation Service Tier 2	1,668,299	1,844,499	110	15,166	1.1056
10	LVTk - Large Volume Transportation Service Tier 3	1,985,307	1,955,942	67	29,631	0.9852
11	LVTk - Large Volume Transportation Service Tier 4	13,587,048	7,825,316	88	154,398	0.5759
12	LVTt - Large Volume Transportation Service Tier 1	2,306,254	1,075,448	35	65,893	0.4663
13	LVTt - Large Volume Transportation Service Tier 2	642,217	1,003,843	34	18,889	1.5631
14	LVTt - Large Volume Transportation Service Tier 3	943,399	1,254,045	22	42,882	1.3293
15	LVTt - Large Volume Transportation Service Tier 4	24,088,056	11,761,668	53	454,492	0.4883
16	Revenue Accrual		(285,273)		N.A.	N.A.
17	Total distribution - retail	55,720,577	$46,743,739	5,606	9,939	$0.8389
	Distribution - Sales for Resale					
18	WTt - Wholesale Transportation Service	3,004,426	$1,800,024	28	107,301	$0.5991
19	Revenue Accrual		($40,085)		N.A.	N.A.
20	Total distribution - sales for resale	3,004,426	$1,759,939	28	107,301	$0.5858
21	Total gas transport	65,971,041	$49,549,125	5,652	11,672	$0.7511

Line No.	Description	MCF Sales	Revenue	Average Number of Customers	MCF Sales per Customer	Revenue per MCF Sold ($)
	Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6
	Transmission					
1	ITt - Interruptible Gas Transportation Service	5,968,385	$1,045,071	20	303,477	$0.1751
2	Revenue Accrual		(12,551)		N.A.	N.A.
3	Total commercial	5,968,385	$1,032,520	20	303,477	$0.1730
	Distribution - Retail					
4	STk - Small Transportation Service	5,401,229	$10,362,679	3,351	1,612	$1.9186
5	STt - Small Transportation Service	1,589,849	3,891,123	1,110	1,432	2.4475
6	CNGk - Compressed Natural Gas General Transp. Service	131,290	106,105	3	42,581	0.8082
7	GITt - Gas Irrigation Transportation Service	839,690	1,645,891	513	1,636	1.9601
8	LVTk - Large Volume Transportation Service Tier 1	881,574	1,676,784	207	4,259	1.9020
9	LVTk - Large Volume Transportation Service Tier 2	1,530,768	1,680,292	108	14,174	1.0977
10	LVTk - Large Volume Transportation Service Tier 3	2,023,956	1,854,332	67	30,208	0.9162
11	LVTk - Large Volume Transportation Service Tier 4	13,794,672	7,653,055	82	168,228	0.5548
12	LVTt - Large Volume Transportation Service Tier 1	196,799	397,321	38	5,179	2.0189
13	LVTt - Large Volume Transportation Service Tier 2	499,036	824,490	35	14,258	1.6522
14	LVTt - Large Volume Transportation Service Tier 3	832,068	1,207,252	23	36,177	1.4509
15	LVTt - Large Volume Transportation Service Tier 4	24,512,499	12,642,269	50	490,250	0.5157
16	Revenue Accrual		49,183		N.A.	N.A.
17	Total distribution - retail	52,233,431	$43,990,775	5,587	9,348	$0.8422
	Distribution - Sales for Resale					
18	WTt - Wholesale Transportation Service	2,796,872	$1,458,532	28	99,888	$0.5215
19	Revenue Accrual		(29,402)		N.A.	N.A.
20	Total distribution - sales for resale	2,796,872	$1,429,130	28	99,888	$0.5110
21	Total gas transport	60,998,688	$46,452,424	5,635	10,825	$0.7615

Line No.	Account Number	Description Col. 1	December 31, 2012 Col. 2	December 31, 2013 Col. 3	December 31, 2014 Col. 4	December 31, 2015 Col. 5
		Utility Plant Related Payroll				
1	106-107	Construction work in progress	$5,386,855	$4,914,376	$5,512,655	$6,204,471
2	108	Plant removal	2,329,697	2,084,017	2,025,136	2,348,574
3	154	Materials	15,280	25,355	11,161	0
4	163	Stores Expense	1,238,711	1,268,203	1,246,496	1,287,429
5	184	Clearing Accounts	8,749,079	9,835,660	11,214,517	12,634,378
6		Other	(1,124)	672	32,251	25,056
7		Total utility plant related payroll	$17,718,498	$18,128,283	$20,042,216	$22,499,908
		Operation and Maintenance Related Payroll Expenses				
		Natural Gas Production and Gathering Operation				
8	750	Operation, supervision and engineering	$0	$0	$0	$0
9	751	Maps and records	0	0	0	0
10	753	Field lines expense	0	0	0	0
11	754	Field compressor station expenses	0	0	0	0
12	755	Field compressor station expenses	0	0	0	0
13	756	Field measuring and regulating station expenses	0	0	0	0
14	757	Purification expense	0	0	0	0
15	759	Other expenses	0	0	0	0
16	760	Rents	0	0	0	0
17		Total operation	$0	$0	$0	$0

Line No.	Account Number	Description Col. 1	December 31, 2012 Col. 2	December 31, 2013 Col. 3	December 31, 2014 Col. 4	December 31, 2015 Col. 5
		Natural Gas Production and Gathering (cont.)				
		Maintenance				
1	761	Maintenance, supervision and engineering	$0	$0	$0	$0
2	762	Maintenance of structures and improvements	0	0	0	0
3	764	Maintenance of field lines	0	0	0	0
4	765	Maintenance of field compressor station equipment	0	0	0	0
5	766	Maintenance of field measuring and regulating station equipment	0	0	0	0
6	767	Maintenance of purification equipment	0	0	0	0
7	769	Maintenance of other equipment	0	0	0	0
8		Total maintenance	$0	$0	$0	$0
9		Total natural gas production and gathering	$0	$0	$0	$0
		Other Gas Supply Expenses				
10	805.1	Other gas purchases-special contracts	$0	$0	$0	$0
11	807.1	Well expenses- purchased gas	0	0	0	0
12	807.2	Operation of purchased gas measuring stations	0	0	0	0
13	807.3	Maintenance of purchased gas measuring stations	0	0	0	0
14	807.4	Purchased gas calculations expenses	18,570	21,386	11,125	0
15	807.5	Other purchased gas expenses	0	0	0	0
16	810	Gas used for compressor station fuel- credit	0	0	0	0
17	813	Other gas supply expense	657,685	711,104	698,987	755,113
18		Total other gas supply expenses	$676,255	$732,490	$710,112	$755,113
19		Total production expenses	$676,255	$732,490	$710,112	$755,113

Line No.	Account Number	Description	December 31, 2012	December 31, 2013	December 31, 2014	December 31, 2015
		Col. 1	Col. 2	Col. 3	Col. 4	Col. 5
		Underground Storage Expenses				
		Operation				
1	814	Operation, supervision and engineering	$0	$0	$0	$0
2	815	Maps and records	0	0	0	0
3	816	Wells expenses	0	0	0	0
4	817	Lines expenses	0	0	0	0
5	818	Compressor station expenses	0	0	0	0
6	819	Compressor station fuel and power	0	0	0	0
7	820	Measuring and regulating station expenses	0	0	0	0
8	821	Purification expenses	0	0	0	0
9	822	Exploration and Development	0	0	0	0
10	823	Gas losses	0	0	0	0
11	824	Other expenses	0	0	0	147
12		Total operation	$0	$0	$0	$147
		Maintenance				
13	830	Maintenance, supervision and engineering	$0	$0	$0	$0
14	831	Maintenance of structures and improvements	0	0	0	0
15	832	Maintenance of reservoirs and wells	0	0	0	0
16	833	Maintenance of lines	0	0	0	0
17	834	Maintenance of compressor station equipment	0	0	0	0
18	835	Maintenance of measuring and regulating station equipment	0	0	0	0
19	836	Maintenance of purification equipment	0	0	0	0
20	837	Maintenance of other equipment	0	0	0	0
21		Total maintenance	$0	$0	$0	$0
22		Total underground storage expenses	$0	$0	$0	$147

Line No.	Account Number	Description Col. 1	December 31, 2012 Col. 2	December 31, 2013 Col. 3	December 31, 2014 Col. 4	December 31, 2015 Col. 5
		Transmission Expenses				
		Operation				
1	850	Operation, supervision and engineering	$342,111	$290,288	$129,655	$152,285
2	851	System control and load dispatching	931,800	972,477	1,086,715	1,079,729
3	852	Communication system expense	73	0	0	0
4	853	Compressor station labor and expense	317,967	375,340	335,334	308,577
5	854	Gas for Compressor Station Fuel	0	0	0	0
6	855	Other fuel and power for compressor stations	0	0	0	0
7	856	Mains expenses	1,015,167	1,151,867	1,422,521	1,380,191
8	857	Measuring and regulating station expenses	267,200	262,934	302,049	355,266
9	859	Other expenses	19,811	20,664	31,140	46,859
10	860	Rents	0	0	0	0
11		Total operation	$2,894,130	$3,073,569	$3,307,414	$3,322,906
		Maintenance				
12	861	Maintenance, supervision and engineering	$109,124	$102,240	$59,684	$76,645
13	862	Maintenance of structures and improvements	1,228	4,393	6,856	4,663
14	863	Maintenance of mains	331,021	348,844	253,978	245,112
15	864	Maintenance of compressor station equipment	197,338	159,282	152,221	187,912
16	865	Maintenance of measuring and regulating station equipment	171,180	185,226	190,766	201,750
17	866	Maintenance of communication equipment	0	0	0	0
18	867	Maintenance of other equipment	139	0	0	0
19		Total maintenance	$810,031	$799,984	$663,505	$716,082
20		Total transmission expenses	$3,704,161	$3,873,553	$3,970,919	$4,038,988

KANSAS GAS SERVICE, A DIVISION OF ONE GAS, INC.
Payroll Data
12 Months Ending

Line No.	Account Number	Description	December 31, 2012	December 31, 2013	December 31, 2014	December 31, 2015
		Col. 1	Col. 2	Col. 3	Col. 4	Col. 5
		Distribution Expenses				
		Operation				
1	870	Operation, supervision and engineering	$1,966,014	$1,875,489	$1,242,615	$1,507,539
2	871	Distribution load dispatching	557	0	853	26,380
3	874	Mains and services expense	3,221,258	3,556,496	3,823,509	4,030,287
4	875	Measuring and regulating station expenses - general	540,877	614,309	856,295	965,964
5	876	Measuring and regulating station expenses - industrial	238,861	243,287	225,283	283,069
6	877	Measuring and regulating station expenses - city gate check station	190,579	215,615	249,638	236,973
7	878	Meter and house regulator expenses	4,457,739	4,763,061	5,007,154	5,268,599
8	879	Customer installations expenses	3,805,767	4,182,092	4,275,847	4,502,163
9	880	Other expenses	1,778,250	1,507,609	1,024,991	1,051,787
10	881	Rents	0	0	0	0
11		Total operation	$16,199,901	$16,957,959	$16,706,187	$17,872,760
		Maintenance				
12	885	Maintenance, supervision and engineering	$393,786	$388,238	$322,121	$305,346
13	886	Maintenance of structures and improvements	14,744	39,750	29,614	39,322
14	887	Maintenance of mains	4,117,791	4,767,490	5,185,359	4,829,432
15	889	Maintenance of measuring and regulating station expenses - general	350,344	385,083	375,196	412,800
16	890	Maintenance of measuring and regulating station expenses - industrial	133,683	143,844	119,847	126,000
17	891	Maintenance of measuring and regulating station expenses-city gate check	224,344	233,438	214,681	198,665
18	892	Maintenance of services	1,199,505	1,362,436	1,689,447	1,458,949
19	893	Maintenance of meters and house regulators	1,290,431	1,271,584	1,235,037	1,351,625
20	894	Maintenance of other equipment	0	0	0	0
21		Total maintenance	$7,724,627	$8,591,861	$9,171,303	$8,722,138
22		Total distribution expenses	$23,924,529	$25,549,820	$25,877,490	$26,594,898

KANSAS GAS SERVICE, A DIVISION OF ONE GAS, INC.
Payroll Data
12 Months Ending

Line No.	Account Number	Description	December 31, 2012	December 31, 2013	December 31, 2014	December 31, 2015
		Col. 1	Col. 2	Col. 3	Col. 4	Col. 5
		Customer Accounts Expense				
1	901	Supervision	$603,049	$542,200	$461,907	$376,708
2	902	Meter reading expenses	1,311,338	1,374,529	1,401,663	1,372,829
3	903	Customer records and collection expense	6,087,404	5,842,522	6,112,794	6,213,560
4	905	Miscellaneous customer accounts expense	80,411	330,442	666,092	650,796
5		Total customer accounts expenses	$8,082,201	$8,089,692	$8,642,456	$8,613,892
		Customer Service and Informational Expenses				
6	907	Supervision	$0	$0	$0	$0
7	908	Customer assistance expenses	0	45,595	73,010	140,440
8	909	Informational and instructional expenses	0	0	0	0
9	910	Miscellaneous customer service and informational expenses	0	0	0	0
10		Total customer service and informational expenses	$0	$45,595	$73,010	$140,440
		Sales Expense				
11	911	Supervision	$141,165	$154,513	$128,138	$0
12	912	Demonstrating and selling expenses	497,509	455,179	477,234	469,188
13	913	Advertising expenses	0	0	0	0
14	916	Miscellaneous sales expenses	0	0	0	0
15		Total sales expenses	$638,674	$609,692	$605,372	$469,188

KANSAS GAS SERVICE, A DIVISION OF ONE GAS, INC.
Payroll Data
12 Months Ending

Line No.	Account Number	Description Col. 1	December 31, 2012 Col. 2	December 31, 2013 Col. 3	December 31, 2014 Col. 4	December 31, 2015 Col. 5
		Administrative and General Expenses				
		Operation				
1	920	Administrative and general salaries	$8,028,090	$8,737,509	$8,708,688	$8,988,880
2	921	Office supplies and expenses	0	0	0	0
3	922	Administrative Expenses Transferred - Credit	0	0	0	0
4	923	Outside services employed	0	0	0	0
5	925	Injuries and damages	0	0	0	0
6	926	Employee pensions and benefits	0	0	0	0
7	927	Franchise requirements	0	0	0	0
8	930	Miscellaneous general expenses	0	0	0	0
9	931	Rents	0	0	0	0
10		Total operation	$8,028,090	$8,737,509	$8,708,688	$8,988,880
		Maintenance				
11	935	Maintenance of general plant	$0	$0	$0	$0
12		Total administrative and general expenses	$8,028,090	$8,737,509	$8,708,688	$8,988,880
13		Total O & M payroll expenses	$45,053,910	$47,638,351	$48,588,047	$49,601,546
14	417	Miscellaneous Non-Operating Income	$0	$7,137	$8,782	$7,125
15	426	Miscellaneous Income Deduction	$61,955	$77,456	$113,664	$116,863
16		Kansas gas operations payroll	$62,834,363	$65,851,227	$68,752,709	$72,225,443

KANSAS GAS SERVICE, A DIVISION OF ONE GAS, INC.
Pro Forma Operating Income Statement
Test Year Ended December 31, 2015

Line No.	Description	Schedule Reference	Amount Per Books	Pro Forma Adjustments	Pro Forma Adjusted
	Col. 1	Col. 2	Col. 3	Col. 4	Col. 5
	Operating Revenue				
1	Gas revenue	8-D, 9-B	$483,532,625	($247,035,513)	$236,497,112
2	Service and other	8-D, 9-B	49,916,719	1,517,581	51,434,300
3	Total revenue		$533,449,344	($245,517,932)	$287,931,412
	Operating Expenses				
4	Production	8-E, 9-B	$247,557,115	($245,297,072)	$2,260,043
5	Underground storage	8-E, 9-B	85,751	11	85,762
6	Transmission	8-E, 9-B	9,043,033	198,221	9,241,254
7	Distribution	8-E, 9-B	61,252,775	1,760,359	63,013,134
8	Customer accounts	8-E, 9-B	25,383,453	1,437,767	26,821,220
9	Customer service and information	8-E, 9-B	257,343	6,958	264,301
10	Sales	8-E, 9-B	941,457	35,476	976,933
11	Administrative and general	8-E, 9-B	58,903,378	(11,868,786)	47,034,592
12	Total operating expenses	8-E, 9-B	$403,424,305	($253,727,066)	$149,697,239
13	Depreciation and amortization	8-B, 9-B	$44,264,295	$4,745,635	$49,009,930
14	Taxes other than income taxes	8-B, 9-B	26,344,373	(1,328,861)	25,015,512
15	Income taxes-current	8-B, 9-B	(1,148,546)	4,005,596	2,857,050
16	Income taxes-deferred	8-B, 9-B	17,484,787	(238,457)	17,246,330
17	Investment Tax Credits	8-B, 9-B	(201,384)	0	(201,384)
18	Total expenses	8-B, 9-B	$490,167,830	($246,543,153)	$243,624,677
19	Operating Income		$43,281,514	$1,025,222	$44,306,736

KANSAS GAS SERVICE, A DIVISION OF ONE GAS, INC.
Summary of Pro Forma Adjustments to Operating Revenues and Expenses
Test Year Ended December 31, 2015

Line No.	Description	IS 1 Eliminate Accrued and Unbilled Revenues and Expenses	IS 2 Eliminate Deferred WNA Revenues	IS 3 Eliminate COGR Revenues and Expenses	IS 4 Eliminate the ATSR Revenue and Adjust the Ad Valorem Expenses
	Col. 1	Col. 3	Col. 4	Col. 5	Col. 2
	Operating Revenue				
1	Gas revenue	$12,518,263	($7,892,181)	($257,900,033)	$1,795,210
2	Service and other	(7,230)	0	(181,118)	778,493
3	Total revenue	$12,511,032	($7,892,181)	($258,081,151)	$2,573,703
	Operating Expenses				
4	Production	$12,749,784	$0	($258,081,151)	$0
5	Underground storage	0	0	0	0
6	Transmission	0	0	0	0
7	Distribution	0	0	0	0
8	Customer accounts	0	0	0	0
9	Customer service and information	0	0	0	0
10	Sales	0	0	0	0
11	Administrative and general	0	0	0	0
12	Total operating expenses	$12,749,784	$0	($258,081,151)	$0
13	Depreciation and amortization	$0	$0	$0	$2,689,257
14	Taxes other than income taxes	0	0	0	(1,517,180)
15	Income taxes-current	0	0	0	0
16	Income taxes-deferred	0	0	0	0
17	Investment Tax Credits	0	0	0	0
18	Total expenses	$12,749,784	$0	($258,081,151)	$1,172,077
19	Operating Income	($238,752)	($7,892,181)	$0	$1,401,626

Line No.	Description	IS 5 Eliminate GSRS Revenue	IS 6 Test Year Revenue	IS 7 Normalize Test Year Revenues	IS 8 Annualize Test Year Customers, Sales and Revenues
	Col. 1	Col. 3	Col. 3	Col. 4	Col. 5
	Operating Revenue				
1	Gas revenue	($4,377,811)	$0	$8,628,390	$192,650
2	Service and other	(793,445)	(93,127)	1,517,953	308,723
3	Total revenue	($5,171,257)	($93,127)	$10,146,344	$501,372
	Operating Expenses				
4	Production	$0	$0	$0	$0
5	Underground storage	0	0	0	0
6	Transmission	0	0	0	0
7	Distribution	0	0	0	0
8	Customer accounts	0	0	0	0
9	Customer service and information	0	0	0	0
10	Sales	0	0	0	0
11	Administrative and general	0	0	0	0
12	Total operating expenses	$0	$0	$0	$0
13	Depreciation and amortization	$0	$0	$0	$0
14	Taxes other than income taxes	0	0	0	0
15	Income taxes-current	0	0	0	0
16	Income taxes-deferred	0	0	0	0
17	Investment Tax Credits	0	0	0	0
18	Total expenses	$0	$0	$0	$0
19	Operating Income	($5,171,257)	($93,127)	$10,146,344	$501,372

KANSAS GAS SERVICE, A DIVISION OF ONE GAS, INC.
Summary of Pro Forma Adjustments to Operating Revenues and Expenses
Test Year Ended December 31, 2015

Line No.	Description	IS 9 Eliminate CNG Revenue	IS 10 Non-Gas Portion of Uncollectible	IS 11 Annualize Depreciation on Pro-Forma Plant	IS 12 Annualization Depreciation at Proposed Rates
	Col. 1	Col. 2	Col. 3	Col. 3	Col. 4
	Operating Revenue				
1	Gas revenue	$0	$0	$0	$0
2	Service and other	(12,667)	0	0	0
3	Total revenue	($12,667)	$0	$0	$0
	Operating Expenses				
4	Production	$0	$0	$0	$0
5	Underground storage	0	0	0	0
6	Transmission	0	0	0	0
7	Distribution	0	0	0	0
8	Customer accounts	0	1,280,165	0	0
9	Customer service and information	0	0	0	0
10	Sales	0	0	0	0
11	Administrative and general	0	0	0	0
12	Total operating expenses	$0	$1,280,165	$0	$0
13	Depreciation and amortization	$0	$0	$828,709	$3,657,749
14	Taxes other than income taxes	0	0	0	0
15	Income taxes-current	0	0	0	0
16	Income taxes-deferred	0	0	0	0
17	Investment Tax Credits	0	0	0	0
18	Total expenses	$0	$1,280,165	$828,709	$3,657,749
19	Operating Income	($12,667)	($1,280,165)	($828,709)	($3,657,749)

KANSAS GAS SERVICE, A DIVISION OF ONE GAS, INC.
Summary of Pro Forma Adjustments to Operating Revenues and Expenses
Test Year Ended December 31, 2015

Line No.	Description	IS 13 Eliminate Royalty Fee	IS 14 Eliminate Transaction Credit	IS 15 Donations from Account 426 and Eliminate Certain Dues and	IS 16 Shared Services Contract Changes
	Col. 1	Col. 5	Col. 2	Col. 3	Col. 4
	Operating Revenue				
1	Gas revenue	$0	$0	$0	$0
2	Service and other	$0	0	0	0
3	Total revenue	$0	$0	$0	$0
	Operating Expenses				
4	Production	$0	$0	$0	$0
5	Underground storage	0	0	0	0
6	Transmission	0	0	(284)	0
7	Distribution	0	0	(344)	0
8	Customer accounts	0	0	0	87,002
9	Customer service and information	0	0	0	0
10	Sales	0	0	(251)	0
11	Administrative and general	(8,607,018)	(3,423,957)	14,193	0
12	Total operating expenses	($8,607,018)	($3,423,957)	$13,314	$87,002
13	Depreciation and amortization	$0	$0	$0	$0
14	Taxes other than income taxes	0	0	0	0
15	Income taxes-current	0	0	0	0
16	Income taxes-deferred	0	0	0	0
17	Investment Tax Credits	0	0	0	0
18	Total expenses	($8,607,018)	($3,423,957)	$13,314	$87,002
19	Operating Income	$8,607,018	$3,423,957	($13,314)	($87,002)

KANSAS GAS SERVICE, A DIVISION OF ONE GAS, INC.
Summary of Pro Forma Adjustments to Operating Revenues and Expenses
Test Year Ended December 31, 2015

Line No.	Description	IS 17 Eliminate O&M costs related to plant	IS 18 Fleet and Stores Clearing Account	IS 19 Reclassify Interest on Customer Deposits	IS 20 GTI Expense
	Col. 1	Col. 5	Col. 2	Col. 4	Col. 5
	Operating Revenue				
1	Gas revenue	$0	$0	$0	$0
2	Service and other	0	0	0	0
3	Total revenue	$0	$0	$0	$0
	Operating Expenses				
4	Production	$0	$0	$0	$0
5	Underground storage	0	0	0	0
6	Transmission	(45,989)	2,764	0	0
7	Distribution	0	17,996	0	314,868
8	Customer accounts	0	0	0	0
9	Customer service and information	0	0	0	0
10	Sales	0	0	0	0
11	Administrative and general	0	0	102,624	0
12	Total operating expenses	($45,989)	$20,760	$102,624	$314,868
13	Depreciation and amortization	$0	$0	$0	$0
14	Taxes other than income taxes	0	0	0	0
15	Income taxes-current	0	0	0	0
16	Income taxes-deferred	0	0	0	0
17	Investment Tax Credits	0	0	0	0
18	Total expenses	($45,989)	$20,760	$102,624	$314,868
19	Operating Income	$45,989	($20,760)	($102,624)	($314,868)

Line No.	Description	IS 21 Insurance	IS 22 Workers Compensation	IS 23 Payroll	IS 24 Employee Medical Reserve
	Col. 1	Col. 2	Col. 3	Col. 4	Col. 5
	Operating Revenue				
1	Gas revenue	$0	$0	$0	$0
2	Service and other	0	0	0	0
3	Total revenue	$0	$0	$0	$0
	Operating Expenses				
4	Production	$0	$0	$34,295	$0
5	Underground storage	0	0	11	0
6	Transmission	0	0	258,533	0
7	Distribution	0	0	1,401,715	0
8	Customer accounts	0	0	69,677	0
9	Customer service and information	0	0	11,110	0
10	Sales	0	0	35,727	0
11	Administrative and general	(97,844)	250,531	396,017	658,707
12	Total operating expenses	($97,844)	$250,531	$2,207,086	$658,707
13	Depreciation and amortization	$0	$0	$0	$0
14	Taxes other than income taxes	0	0	157,686	0
15	Income taxes-current	0	0	0	0
16	Income taxes-deferred	0	0	0	0
17	Investment Tax Credits	0	0	0	0
18	Total expenses	($97,844)	$250,531	$2,364,771	$658,707
19	Operating Income	$97,844	($250,531)	($2,364,771)	($658,707)

KANSAS GAS SERVICE, A DIVISION OF ONE GAS, INC.
Summary of Pro Forma Adjustments to Operating Revenues and Expenses
Test Year Ended December 31, 2015

Line No.	Description	IS 25 Pension & Benefits	IS 26 Amortization of Deferred Pension & Benefits	IS 27 Pension/OPEB Savings Sharing	IS 28 Annualized Corporate Depreciation
	Col. 1	Col. 2	Col. 3	Col. 4	Col. 5
	Operating Revenue				
1	Gas revenue	$0	$0	$0	$0
2	Service and other	0	0	0	0
3	Total revenue	$0	$0	$0	$0
	Operating Expenses				
4	Production	$0	$0	$0	$0
5	Underground storage	0	0	0	0
6	Transmission	0	0	0	0
7	Distribution	0	0	0	0
8	Customer accounts	0	0	0	0
9	Customer service and information	0	0	0	0
10	Sales	0	0	0	0
11	Administrative and general	(2,863,179)	0	3,375,022	0
12	Total operating expenses	($2,863,179)	$0	$3,375,022	$0
13	Depreciation and amortization	$0	($3,168,966)	$0	$412,670
14	Taxes other than income taxes	0	0	0	0
15	Income taxes-current	0	0	0	0
16	Income taxes-deferred	0	0	0	0
17	Investment Tax Credits	0	0	0	0
18	Total expenses	($2,863,179)	($3,168,966)	$3,375,022	$412,670
19	Operating Income	$2,863,179	$3,168,966	($3,375,022)	($412,670)

KANSAS GAS SERVICE, A DIVISION OF ONE GAS, INC.
Summary of Pro Forma Adjustments to Operating Revenues and Expenses
Test Year Ended December 31, 2015

Line No.	Description	IS 29 Miscellaneous Corporate Charges	IS 30 Change in Allocation Ratio	IS 31 Normalized Compensation - STI	IS 32 Corporate Payroll
	Col. 1	Col. 2	Col. 3	Col. 4	Col. 5
	Operating Revenue				
1	Gas revenue	$0	$0	$0	$0
2	Service and other	0	0	0	0
3	Total revenue	$0	$0	$0	$0
	Operating Expenses				
4	Production	$0	$0	$0	$0
5	Underground storage	0	0	0	0
6	Transmission	0	0	0	(16,802)
7	Distribution	0	0	0	26,124
8	Customer accounts	0	0	0	923
9	Customer service and information	0	0	0	(4,152)
10	Sales	0	0	0	0
11	Administrative and general	(267,310)	(335,925)	(2,171,178)	1,115,584
12	Total operating expenses	($267,310)	($335,925)	($2,171,178)	$1,121,678
13	Depreciation and amortization	$0	$0	$0	$0
14	Taxes other than income taxes	0	(509)	(46,021)	77,164
15	Income taxes-current	0	0	0	0
16	Income taxes-deferred	0	0	0	0
17	Investment Tax Credits	0	0	0	0
18	Total expenses	($267,310)	($336,434)	($2,217,199)	$1,198,841
19	Operating Income	$267,310	$336,434	$2,217,199	($1,198,841)

KANSAS GAS SERVICE, A DIVISION OF ONE GAS, INC.
Summary of Pro Forma Adjustments to Operating Revenues and Expenses
Test Year Ended December 31, 2015

Line No.	Description	IS 33 Corporate OPEB, Pension, and Health Benefits	IS 34 Rate Case Expense Amortization	IS 35 Income Taxes	Total Adjustments
	Col. 1	Col. 2	Col. 3	Col. 4	Col. 2
	Operating Revenue				
1	Gas revenue	$0	$0	$0	($247,035,513)
2	Service and other	0	0	0	1,517,581
3	Total revenue	$0	$0	$0	($245,517,932)
	Operating Expenses				
4	Production	$0	$0	$0	($245,297,072)
5	Underground storage	0	0	0	11
6	Transmission	0	0	0	198,221
7	Distribution	0	0	0	1,760,359
8	Customer accounts	0	0	0	1,437,767
9	Customer service and information	0	0	0	6,958
10	Sales	0	0	0	35,476
11	Administrative and general	(15,054)	0	0	(11,868,786)
12	Total operating expenses	($15,054)	$0	$0	($253,727,066)
13	Depreciation and amortization	$0	$326,216	$0	$4,745,635
14	Taxes other than income taxes	0	0	0	(1,328,861)
15	Income taxes-current	0	0	4,005,596	4,005,596
16	Income taxes-deferred	0	0	(238,457)	(238,457)
17	Investment Tax Credits	0	0	0	0
18	Total expenses	($15,054)	$326,216	$3,767,139	($246,543,153)
19	Operating Income	$15,054	($326,216)	($3,767,139)	$1,025,222

Line No.	Adj. No.	Description Col. 1	Increase Col. 2	Decrease Col. 3
	IS 1	Eliminate Accrued and Unbilled Revenues and Expenses		
1		Operating Revenue	$12,511,032	$0
2		Production Expenses	12,749,784	0
3		Underground Storage Expenses	0	0
4		Transmission Expenses	0	0
5		Distribution Expenses	0	0
6		Customer Accounts Expenses	0	0
7		Cust. Service and Information Exp.	0	0
8		Sales and Advertising Expenses	0	0
9		Administration and General Expense	0	0
10		Depreciation and Amortization	0	0
11		Taxes Other Than Income Taxes	0	0
12		Income Taxes, Deferred Tax, Investment tax credit	0	0
		To eliminate accrued and unbilled revenues and gas costs from test year operating results.		
	IS 2	Eliminate Deferred WNA Revenues		
13		Operating Revenue	$0	$7,892,181
14		Production Expenses	0	0
15		Underground Storage Expenses	0	0
16		Transmission Expenses	0	0
17		Distribution Expenses	0	0
18		Customer Accounts Expenses	0	0
19		Cust. Service and Information Exp.	0	0
20		Sales and Advertising Expenses	0	0
21		Administration and General Expense	0	0
22		Depreciation and Amortization	0	0
23		Taxes Other Than Income Taxes	0	0
24		Income Taxes, Deferred Tax, Investment tax credit	0	0
		To eliminate deferred WNA revenues		

Line No.	Adj. No.	Description Col. 1	Increase Col. 2	Decrease Col. 3
	IS 3	Eliminate COGR Revenues and Expenses		
1		Operating Revenue	$0	$258,081,151
2		Production Expenses	0	258,081,151
3		Underground Storage Expenses	0	0
4		Transmission Expenses	0	0
5		Distribution Expenses	0	0
6		Customer Accounts Expenses	0	0
7		Cust. Service and Information Exp.	0	0
8		Sales and Advertising Expenses	0	0
9		Administration and General Expense	0	0
10		Depreciation and Amortization	0	0
11		Taxes Other Than Income Taxes	0	0
12		Income Taxes, Deferred Tax, Investment tax credit	0	0
		This adjustment eliminates the COGR revenues and the cost of gas expense to determine base rates.		
	IS 4	Eliminate the ATSR Revenue and Adjust the Ad Valorem Expenses		
13				
14		Operating Revenue	$2,573,703	$0
15		Production Expenses	0	0
16		Underground Storage Expenses	0	0
17		Transmission Expenses	0	0
18		Distribution Expenses	0	0
19		Customer Accounts Expenses	0	0
20		Cust. Service and Information Exp.	0	0
21		Sales and Advertising Expenses	0	0
22		Administration and General Expense	0	0
23		Depreciation and Amortization	2,689,257	0
24		Taxes Other Than Income Taxes	0	1,517,180
		Income Taxes, Deferred Tax, Investment tax credit	0	0
		To eliminate Ad Valorem Tax Surcharge Revenues and annualize ad valorem expenses.		

Line No.	Adj. No.	Description Col. 1	Increase Col. 2	Decrease Col. 3
	IS 5	Eliminate GSRS Revenue		
1		Operating Revenue	$0	$5,171,257
2		Production Expenses	0	0
3		Underground Storage Expenses	0	0
4		Transmission Expenses	0	0
5		Distribution Expenses	0	0
6		Customer Accounts Expenses	0	0
7		Cust. Service and Information Exp.	0	0
8		Sales and Advertising Expenses	0	0
9		Administration and General Expense	0	0
10		Depreciation and Amortization	0	0
11		Taxes Other Than Income Taxes	0	0
12		Income Taxes, Deferred Tax, Investment tax credit	0	0
		To eliminate GSRS Revenues from test year revenues to determine base rate revenues.		
	IS 6	Test Year Revenue		
13		Operating Revenue	$0	$93,127
14		Production Expenses	0	0
15		Underground Storage Expenses	0	0
16		Transmission Expenses	0	0
17		Distribution Expenses	0	0
18		Customer Accounts Expenses	0	0
19		Cust. Service and Information Exp.	0	0
20		Sales and Advertising Expenses	0	0
21		Administration and General Expense	0	0
22		Depreciation and Amortization	0	0
23		Taxes Other Than Income Taxes	0	0
24		Income Taxes, Deferred Tax, Investment tax credit	0	0
		To normalize test year revenues and expenses for prior period adjustments, contract minimum quantities, and discounted rate annualization.		

Line No.	Adj. No.	Description Col. 1	Increase Col. 2	Decrease Col. 3
	IS 7	Normalize Test Year Revenues		
1		Operating Revenue	$10,146,344	$0
2		Production Expenses	0	0
3		Underground Storage Expenses	0	0
4		Transmission Expenses	0	0
5		Distribution Expenses	0	0
6		Customer Accounts Expenses	0	0
7		Cust. Service and Information Exp.	0	0
8		Sales and Advertising Expenses	0	0
9		Administration and General Expense	0	0
10		Depreciation and Amortization	0	0
11		Taxes Other Than Income Taxes	0	0
12		Income Taxes, Deferred Tax, Investment tax credit	0	0
		Adjusts test year revenue had the weather been normal during the test year.		
	IS 8	Annualize Test Year Customers, Sales and Revenues		
13		Operating Revenue	$501,372	$0
14		Production Expenses	0	0
15		Underground Storage Expenses	0	0
16		Transmission Expenses	0	0
17		Distribution Expenses	0	0
18		Customer Accounts Expenses	0	0
19		Cust. Service and Information Exp.	0	0
20		Sales and Advertising Expenses	0	0
21		Administration and General Expense	0	0
22		Depreciation and Amortization	0	0
23		Taxes Other Than Income Taxes	0	0
24		Income Taxes, Deferred Tax, Investment tax credit	0	0
		Adjustment annualizes sales to recognize change in customer count.		

Line No.	Adj. No.	Description	Increase	Decrease
		Col. 1	Col. 2	Col. 3
	IS 9	Eliminate CNG Revenue		
1		Operating Revenue	$0	$12,667
2		Production Expenses	0	0
3		Underground Storage Expenses	0	0
4		Transmission Expenses	0	0
5		Distribution Expenses	0	0
6		Customer Accounts Expenses	0	0
7		Cust. Service and Information Exp.	0	0
8		Sales and Advertising Expenses	0	0
9		Administration and General Expense	0	0
10		Depreciation and Amortization	0	0
11		Taxes Other Than Income Taxes	0	0
12		Income Taxes, Deferred Tax, Investment tax credit	0	0
		This adjustment is to remove revenue associated with the public sale of CNG.		
	IS 10	Non-Gas Portion of Uncollectible		
13		Operating Revenue	$0	$0
14		Production Expenses	0	0
15		Underground Storage Expenses	0	0
16		Transmission Expenses	0	0
17		Distribution Expenses	0	0
18		Customer Accounts Expenses	1,280,165	0
19		Cust. Service and Information Exp.	0	0
20		Sales and Advertising Expenses	0	0
21		Administration and General Expense	0	0
22		Depreciation and Amortization	0	0
23		Taxes Other Than Income Taxes	0	0
24		Income Taxes, Deferred Tax, Investment tax credit	0	0
		This adjustment is to true up the bad debt expense for base rates.		

Line No.	Adj. No.	Description Col. 1	Increase Col. 2	Decrease Col. 3
	IS 11	Annualize Depreciation on Pro-Forma Plant		
1		Operating Revenue	$0	$0
2		Production Expenses	0	0
3		Underground Storage Expenses	0	0
4		Transmission Expenses	0	0
5		Distribution Expenses	0	0
6		Customer Accounts Expenses	0	0
7		Cust. Service and Information Exp.	0	0
8		Sales and Advertising Expenses	0	0
9		Administration and General Expense	0	0
10		Depreciation and Amortization	828,709	0
11		Taxes Other Than Income Taxes	0	0
12		Income Taxes, Deferred Tax, Investment tax credit	0	0
		To annualize the change depreciation expense on the pro-forma plant in service.		
	IS 12	Annualization Depreciation at Proposed Rates		
13		Operating Revenue	$0	$0
14		Production Expenses	0	0
15		Underground Storage Expenses	0	0
16		Transmission Expenses	0	0
17		Distribution Expenses	0	0
18		Customer Accounts Expenses	0	0
19		Cust. Service and Information Exp.	0	0
20		Sales and Advertising Expenses	0	0
21		Administration and General Expense	0	0
22		Depreciation and Amortization	3,657,749	0
23		Taxes Other Than Income Taxes	0	0
24		Income Taxes, Deferred Tax, Investment tax credit	0	0
		To annualize the change in depreciation rates on the pro-forma plant in service as a result of the depreciation study.		

Line No.	Adj. No.	Description Col. 1	Increase Col. 2	Decrease Col. 3
	IS 13	Eliminate Royalty Fee		
1		Operating Revenue	$0	$0
2		Production Expenses	0	0
3		Underground Storage Expenses	0	0
4		Transmission Expenses	0	0
5		Distribution Expenses	0	0
6		Customer Accounts Expenses	0	0
7		Cust. Service and Information Exp.	0	0
8		Sales and Advertising Expenses	0	0
9		Administration and General Expense	0	8,607,018
10		Depreciation and Amortization	0	0
11		Taxes Other Than Income Taxes	0	0
12		Income Taxes, Deferred Tax, Investment tax credit	0	0
		Eliminate the Royalty Fees from the test period.		
	IS 14	Eliminate Transaction Credit		
13		Operating Revenue	$0	$0
14		Production Expenses	0	0
15		Underground Storage Expenses	0	0
16		Transmission Expenses	0	0
17		Distribution Expenses	0	0
18		Customer Accounts Expenses	0	0
19		Cust. Service and Information Exp.	0	0
20		Sales and Advertising Expenses	0	0
21		Administration and General Expense	0	3,423,957
22		Depreciation and Amortization	0	0
23		Taxes Other Than Income Taxes	0	0
24		Income Taxes, Deferred Tax, Investment tax credit	0	0
		To adjust the expense related to the Customer Credit in Docket 14-KGSG-100-MIS.		

Line No.	Adj. No.	Description Col. 1	Increase Col. 2	Decrease Col. 3
	IS 15	Include Certain Donations from Account 426 and Eliminate Certain Dues and Donations		
1		Operating Revenue	$0	$0
2		Production Expenses	0	0
3		Underground Storage Expenses	0	0
4		Transmission Expenses	0	284
5		Distribution Expenses	0	344
6		Customer Accounts Expenses	0	0
7		Cust. Service and Information Exp.	0	0
8		Sales and Advertising Expenses	0	251
9		Administration and General Expense	14,193	0
10		Depreciation and Amortization	0	0
11		Taxes Other Than Income Taxes	0	0
12		Income Taxes, Deferred Tax, Investment tax credit	0	0
		To eliminate certain Dues, Donations and Membership Expenses by Account.		
	IS 16	Shared Services Contract Changes		
13		Operating Revenue	$0	$0
14		Production Expenses	0	0
15		Underground Storage Expenses	0	0
16		Transmission Expenses	0	0
17		Distribution Expenses	0	0
18		Customer Accounts Expenses	87,002	0
19		Cust. Service and Information Exp.	0	0
20		Sales and Advertising Expenses	0	0
21		Administration and General Expense	0	0
22		Depreciation and Amortization	0	0
23		Taxes Other Than Income Taxes	0	0
24		Income Taxes, Deferred Tax, Investment tax credit	0	0
		To adjust for the changes in the Shared Services contract between Westar Energy and Kansas Gas Service.		

Line No.	Adj. No.	Description Col. 1	Increase Col. 2	Decrease Col. 3
	IS 17	Eliminate O&M costs related to plant		
1		Operating Revenue	$0	$0
2		Production Expenses	0	0
3		Underground Storage Expenses	0	0
4		Transmission Expenses	0	45,989
5		Distribution Expenses	0	0
6		Customer Accounts Expenses	0	0
7		Cust. Service and Information Exp.	0	0
8		Sales and Advertising Expenses	0	0
9		Administration and General Expense	0	0
10		Depreciation and Amortization	0	0
11		Taxes Other Than Income Taxes	0	0
12		Income Taxes, Deferred Tax, Investment tax credit	0	0
		To remove the operation and maintenance costs associated with plant assets that are not currently used and useful.		
	IS 18	Fleet and Stores Clearing Account		
13		Operating Revenue	$0	$0
14		Production Expenses	0	0
15		Underground Storage Expenses	0	0
16		Transmission Expenses	2,764	0
17		Distribution Expenses	17,996	0
18		Customer Accounts Expenses	0	0
19		Cust. Service and Information Exp.	0	0
20		Sales and Advertising Expenses	0	0
21		Administration and General Expense	0	0
22		Depreciation and Amortization	0	0
23		Taxes Other Than Income Taxes	0	0
24		Income Taxes, Deferred Tax, Investment tax credit	0	0
		To normalize test year clearing charges		

Line No.	Adj. No.	Description	Increase	Decrease
		Col. 1	Col. 2	Col. 3
	IS 19	Reclassify Interest on Customer Deposits		
1		Operating Revenue	$0	$0
2		Production Expenses	0	0
3		Underground Storage Expenses	0	0
4		Transmission Expenses	0	0
5		Distribution Expenses	0	0
6		Customer Accounts Expenses	0	0
7		Cust. Service and Information Exp.	0	0
8		Sales and Advertising Expenses	0	0
9		Administration and General Expense	102,624	0
10		Depreciation and Amortization	0	0
11		Taxes Other Than Income Taxes	0	0
12		Income Taxes, Deferred Tax, Investment tax credit	0	0
		To reclassify interest on customer deposits as an operating expense.		
	IS 20	GTI Expense		
13		Operating Revenue	$0	$0
14		Production Expenses	0	0
15		Underground Storage Expenses	0	0
16		Transmission Expenses	0	0
17		Distribution Expenses	314,868	0
18		Customer Accounts Expenses	0	0
19		Cust. Service and Information Exp.	0	0
20		Sales and Advertising Expenses	0	0
21		Administration and General Expense	0	0
22		Depreciation and Amortization	0	0
23		Taxes Other Than Income Taxes	0	0
24		Income Taxes, Deferred Tax, Investment tax credit	0	0
		Adjust the test year expenses to include funding of the Operations Technology Development Program (OTD).		

Line No.	Adj. No.	Description Col. 1	Increase Col. 2	Decrease Col. 3
	IS 21	Insurance		
1		Operating Revenue	$0	$0
2		Production Expenses	0	0
3		Underground Storage Expenses	0	0
4		Transmission Expenses	0	0
5		Distribution Expenses	0	0
6		Customer Accounts Expenses	0	0
7		Cust. Service and Information Exp.	0	0
8		Sales and Advertising Expenses	0	0
9		Administration and General Expense	0	97,844
10		Depreciation and Amortization	0	0
11		Taxes Other Than Income Taxes	0	0
12		Income Taxes, Deferred Tax, Investment tax credit	0	0
		This adjustment is to recognize the change in property insurance from the test year.		
	IS 22	Workers Compensation		
13		Operating Revenue	$0	$0
14		Production Expenses	0	0
15		Underground Storage Expenses	0	0
16		Transmission Expenses	0	0
17		Distribution Expenses	0	0
18		Customer Accounts Expenses	0	0
19		Cust. Service and Information Exp.	0	0
20		Sales and Advertising Expenses	0	0
21		Administration and General Expense	250,531	0
22		Depreciation and Amortization	0	0
23		Taxes Other Than Income Taxes	0	0
24		Income Taxes, Deferred Tax, Investment tax credit	0	0
		This adjustment normalizes the workers compensation expense.		

Line No.	Adj. No.	Description Col. 1	Increase Col. 2	Decrease Col. 3
	IS 23	Payroll		
1		Operating Revenue	$0	$0
2		Production Expenses	34,295	0
3		Underground Storage Expenses	11	0
4		Transmission Expenses	258,533	0
5		Distribution Expenses	1,401,715	0
6		Customer Accounts Expenses	69,677	0
7		Cust. Service and Information Exp.	11,110	0
8		Sales and Advertising Expenses	35,727	0
9		Administration and General Expense	396,017	0
10		Depreciation and Amortization	0	0
11		Taxes Other Than Income Taxes	157,686	0
12		Income Taxes, Deferred Tax, Investment tax credit	0	0
		To annualize known changes to payroll expenses.		
	IS 24	Employee Medical Reserve		
13		Operating Revenue	$0	$0
14		Production Expenses	0	0
15		Underground Storage Expenses	0	0
16		Transmission Expenses	0	0
17		Distribution Expenses	0	0
18		Customer Accounts Expenses	0	0
19		Cust. Service and Information Exp.	0	0
20		Sales and Advertising Expenses	0	0
21		Administration and General Expense	658,707	0
22		Depreciation and Amortization	0	0
23		Taxes Other Than Income Taxes	0	0
24		Income Taxes, Deferred Tax, Investment tax credit	0	0
		To adjust expenses for the increase in Medical Expenses.		

Line No.	Adj. No.	Description Col. 1	Increase Col. 2	Decrease Col. 3
	IS 25	Pension & Benefits		
1		Operating Revenue	$0	$0
2		Production Expenses	0	0
3		Underground Storage Expenses	0	0
4		Transmission Expenses	0	0
5		Distribution Expenses	0	0
6		Customer Accounts Expenses	0	0
7		Cust. Service and Information Exp.	0	0
8		Sales and Advertising Expenses	0	0
9		Administration and General Expense	0	2,863,179
10		Depreciation and Amortization	0	0
11		Taxes Other Than Income Taxes	0	0
12		Income Taxes, Deferred Tax, Investment tax credit	0	0
		To adjust expenses for the change in Pension and OPEB costs.		
	IS 26	Amortization of Deferred Pension & Benefits		
13		Operating Revenue	$0	$0
14		Production Expenses	0	0
15		Underground Storage Expenses	0	0
16		Transmission Expenses	0	0
17		Distribution Expenses	0	0
18		Customer Accounts Expenses	0	0
19		Cust. Service and Information Exp.	0	0
20		Sales and Advertising Expenses	0	0
21		Administration and General Expense	0	0
22		Depreciation and Amortization	0	3,168,966
23		Taxes Other Than Income Taxes	0	0
24		Income Taxes, Deferred Tax, Investment tax credit	0	0
		To amortize over 3 years the deferred Pension and OPEB expenses.		

Line No.	Adj. No.	Description Col. 1	Increase Col. 2	Decrease Col. 3
	IS 27	Pension/OPEB Savings Sharing		
1		Operating Revenue	$0	$0
2		Production Expenses	0	0
3		Underground Storage Expenses	0	0
4		Transmission Expenses	0	0
5		Distribution Expenses	0	0
6		Customer Accounts Expenses	0	0
7		Cust. Service and Information Exp.	0	0
8		Sales and Advertising Expenses	0	0
9		Administration and General Expense	3,375,022	0
10		Depreciation and Amortization	0	0
11		Taxes Other Than Income Taxes	0	0
12		Income Taxes, Deferred Tax, Investment tax credit	0	0
		To adjust expenses to reflect the sharing between customers and rate payers the benefit of excess funding of pension and OPEB.		
	IS 28	Annualized Corporate Depreciation		
13		Operating Revenue	$0	$0
14		Production Expenses	0	0
15		Underground Storage Expenses	0	0
16		Transmission Expenses	0	0
17		Distribution Expenses	0	0
18		Customer Accounts Expenses	0	0
19		Cust. Service and Information Exp.	0	0
20		Sales and Advertising Expenses	0	0
21		Administration and General Expense	0	0
22		Depreciation and Amortization	412,670	0
23		Taxes Other Than Income Taxes	0	0
24		Income Taxes, Deferred Tax, Investment tax credit	0	0
		To annualize the corporate depreciation expense.		

Line No.	Adj. No.	Description Col. 1	Increase Col. 2	Decrease Col. 3
	IS 29	Miscellaneous Corporate Charges		
1		Operating Revenue	$0	$0
2		Production Expenses	0	0
3		Underground Storage Expenses	0	0
4		Transmission Expenses	0	0
5		Distribution Expenses	0	0
6		Customer Accounts Expenses	0	0
7		Cust. Service and Information Exp.	0	0
8		Sales and Advertising Expenses	0	0
9		Administration and General Expense	0	267,310
10		Depreciation and Amortization	0	0
11		Taxes Other Than Income Taxes	0	0
12		Income Taxes, Deferred Tax, Investment tax credit	0	0
		Adjustment for certain expenses allocated through OGS Distrigas.		
	IS 30	Change in Allocation Ratio		
13		Operating Revenue	$0	$0
14		Production Expenses	0	0
15		Underground Storage Expenses	0	0
16		Transmission Expenses	0	0
17		Distribution Expenses	0	0
18		Customer Accounts Expenses	0	0
19		Cust. Service and Information Exp.	0	0
20		Sales and Advertising Expenses	0	0
21		Administration and General Expense	0	335,925
22		Depreciation and Amortization	0	0
23		Taxes Other Than Income Taxes	0	509
24		Income Taxes, Deferred Tax, Investment tax credit	0	0
		To adjust for the change in the percent of the OGS Distrigas Allocation Ratio.		

Line No.	Adj. No.	Description Col. 1	Increase Col. 2	Decrease Col. 3
	IS 31	Normalized Compensation - STI		
1		Operating Revenue	$0	$0
2		Production Expenses	0	0
3		Underground Storage Expenses	0	0
4		Transmission Expenses	0	0
5		Distribution Expenses	0	0
6		Customer Accounts Expenses	0	0
7		Cust. Service and Information Exp.	0	0
8		Sales and Advertising Expenses	0	0
9		Administration and General Expense	0	2,171,178
10		Depreciation and Amortization	0	0
11		Taxes Other Than Income Taxes	0	46,021
12		Income Taxes, Deferred Tax, Investment tax credit	0	0
		To normalize the compensation that was recorded during the test year.		
	IS 32	Corporate Payroll		
13		Operating Revenue	$0	$0
14		Production Expenses	0	0
15		Underground Storage Expenses	0	0
16		Transmission Expenses	0	16,802
17		Distribution Expenses	26,124	0
18		Customer Accounts Expenses	923	0
19		Cust. Service and Information Exp.	0	4,152
20		Sales and Advertising Expenses	0	0
21		Administration and General Expense	1,115,584	0
22		Depreciation and Amortization	0	0
23		Taxes Other Than Income Taxes	77,164	0
24		Income Taxes, Deferred Tax, Investment tax credit	0	0
		To annualize known changes to allocated payroll expenses.		

Line No.	Adj. No.	Description	Increase	Decrease
		Col. 1	Col. 2	Col. 3
	IS 33	Corporate OPEB, Pension, and Health Benefits		
1		Operating Revenue	$0	$0
2		Production Expenses	0	0
3		Underground Storage Expenses	0	0
4		Transmission Expenses	0	0
5		Distribution Expenses	0	0
6		Customer Accounts Expenses	0	0
7		Cust. Service and Information Exp.	0	0
8		Sales and Advertising Expenses	0	0
9		Administration and General Expense	0	15,054
10		Depreciation and Amortization	0	0
11		Taxes Other Than Income Taxes	0	0
12		Income Taxes, Deferred Tax, Investment tax credit	0	0
		To decreases expense by the increase of OPEB, Pension, and Health Benefits that are allocated through the Distrigas Methodology.		
	IS 34	Rate Case Expense Amortization		
13		Operating Revenue	$0	$0
14		Production Expenses	0	0
15		Underground Storage Expenses	0	0
16		Transmission Expenses	0	0
17		Distribution Expenses	0	0
18		Customer Accounts Expenses	0	0
19		Cust. Service and Information Exp.	0	0
20		Sales and Advertising Expenses	0	0
21		Administration and General Expense	0	0
22		Depreciation and Amortization	326,216	0
23		Taxes Other Than Income Taxes	0	0
24		Income Taxes, Deferred Tax, Investment tax credit	0	0
		This adjustment is for the amortization of the rate case costs in the current case.		

Line No.	Adj. No.	Description Col. 1	Increase Col. 2	Decrease Col. 3
	IS 35	Income Taxes		
1		Operating Revenue	$0	$0
2		Production Expenses	0	0
3		Underground Storage Expenses	0	0
4		Transmission Expenses	0	0
5		Distribution Expenses	0	0
6		Customer Accounts Expenses	0	0
7		Cust. Service and Information Exp.	0	0
8		Sales and Advertising Expenses	0	0
9		Administration and General Expense	0	0
10		Depreciation and Amortization	0	0
11		Taxes Other Than Income Taxes	0	0
12		Income Taxes, Deferred Tax, Investment tax credit	3,767,139	0

To adjust for the change in income taxes associated pro-forma changes to the test year.

KANSAS GAS SERVICE, A DIVISION OF ONE GAS, INC.
Pro Forma Depreciation and Amortization Expense
Test Year Ended December 31, 2015

Line No.	Description Col. 1	Amount Per Books (Schedule 10-B) Col. 2	Pro Forma Adjustments (Schedule 10-C) Col. 3	Pro Forma Total Col. 4
	Depreciation Expense			
1	Intangible plant	$0	$1,592	$1,592
2	Production and gathering	13,138	(2,078)	11,060
3	Underground storage	0	0	0
4	Transmission plant	5,576,494	(331,393)	5,245,101
5	Distribution plant	33,445,915	2,714,891	36,160,806
6	General plant	843,024	2,103,446	2,946,470
7	Corporate Allocated	4,476,682	412,670	4,889,352
8	Total depreciation expense	$44,355,253	$4,899,128	$49,254,381
	Amortization Expense			
9	Intangible plant	$23,498	$0	$23,498
10	Distribution plant	0	0	0
11	General plant	0	0	0
12	Utility plant acquisition premium	0	0	0
13	Regulatory debit	(114,456)	(153,493)	(267,949)
14	Total amortization expense	($90,958)	($153,493)	($244,451)
15	Total depreciation and amortization expense	$44,264,295	$4,745,635	$49,009,930

KANSAS GAS SERVICE, A DIVISION OF ONE GAS, INC.
Functional Classification Detail
Test Year Ended December 31, 2015

Line No.	Description	Depreciation Charged to Operating Expense	Depreciation Charged to Clearing Accounts	Total Expense
	Col. 1	Col. 2	Col. 3	Col. 4
	Depreciation Expense			
1	Intangible plant	$0	$0	$0
2	Production and gathering	13,138	0	13,138
3	Underground storage	0	0	0
4	Transmission plant	5,576,494	0	5,576,494
5	Distribution plant	33,445,915	0	33,445,915
6	General plant	2,861,701	(2,018,677)	843,024
7	Corporate Allocated	4,476,682	0	4,476,682
8	Total depreciation expense	$46,373,930	($2,018,677)	$44,355,253
	Amortization Expense			
9	Intangible plant	$23,498	$0	$23,498
10	Distribution plant	0	0	0
11	General plant	0	0	0
12	Utility plant acquisition premium	0	0	0
13	Regulatory debit	(114,456)	0	(114,456)
14	Total amortization expense	($90,958)	$0	($90,958)
15	Total depreciation and amortization expense	$46,282,972	($2,018,677)	$44,264,295

KANSAS GAS SERVICE, A DIVISION OF ONE GAS, INC.
Summary of Pro Forma Adjustments to Depreciation and Amortization Expense (a)
Test Year Ended December 31, 2015

Line No.	Description	IS 4 Eliminate the ATSR Revenue and Adjust the Ad Valorem Expenses	IS 11 Annualize Depreciation on Pro-Forma Plant	IS 12 Annualization Depreciation at Proposed Rates	Sub Total Pro Forma Adjustments
	Col. 1	Col. 2	Col. 3	Col. 4	Col. 5
	Depreciation Expense				
1	Intangible plant	$0	$1,592	$0	$1,592
2	Production and gathering	0	(2,078)	0	(2,078)
3	Underground storage	0	0	0	0
4	Transmission plant	0	(340,681)	9,288	(331,393)
5	Distribution plant	0	(965,422)	3,680,313	2,714,891
6	General plant	0	2,135,298	(31,852)	2,103,446
7	Corporate Allocated	0	0	0	0
8	Total depreciation expense	$0	$828,709	$3,657,749	$4,486,457
	Amortization Expense				
9	Intangible plant	$0	$0	$0	$0
10	Distribution plant	0	0	0	0
11	General plant	0	0	0	0
12	Utility plant acquisition premium	0	0	0	0
13	Regulatory debit	2,689,257	0	0	2,689,257
14	Total amortization expense	$2,689,257	$0	$0	$2,689,257
15	Total expense	$2,689,257	$828,709	$3,657,749	$7,175,714

Note:
(a) See Schedule 9-C for explanation of pro forma adjustments.

KANSAS GAS SERVICE, A DIVISION OF ONE GAS, INC.
Summary of Pro Forma Adjustments to Depreciation and Amortization Expense (a)
Test Year Ended December 31, 2015

Line No.	Description	IS 26 Amortization of Deferred Pension & Benefits	IS 28 Annualized Corporate Depreciation	IS 34 Rate Case Expense Amortization	Total Pro Forma Adjustments
	Col. 1	Col. 2	Col. 3	Col. 4	Col. 5
	Depreciation Expense				
1	Intangible plant	$0	$0	$0	$1,592
2	Production and gathering	0	0	0	(2,078)
3	Underground storage	0	0	0	0
4	Transmission plant	0	0	0	(331,393)
5	Distribution plant	0	0	0	2,714,891
6	General plant	0	0	0	2,103,446
7	Corporate Allocated	0	412,670	0	412,670
8	Total depreciation expense	$0	$412,670	$0	$4,899,128
	Amortization Expense				
9	Intangible plant	$0	$0	$0	$0
10	Distribution plant	0	0	0	0
11	General plant	0	0	0	0
12	Utility plant acquisition premium	0	0	0	0
13	Regulatory debit	(3,168,966)	0	326,216	(153,493)
14	Total amortization expense	($3,168,966)	$0	$326,216	($153,493)
15	Total expense	($3,168,966)	$412,670	$326,216	$4,745,635

Note:
(a) See Schedule 9-C for explanation of pro forma adjustments.

KANSAS GAS SERVICE, A DIVISION OF ONE GAS, INC.
Summary of Depreciation Rates
Test Year Ended December 31, 2015

Line No.	Account Number	Description	Depreciation Rates Current Rates	Proposed Rates
		Col. 1	Col. 2	Col. 3
		Intangible Plant		
1	302	Franchise and Consents	0.00%	0.00%
2	303	Miscellaneous Intangible Plant	3.03%	3.03%
3		Total Intangible Plant		
		Production and gathering plant		
4	325.4	Rights of way	1.25%	1.25%
5	327	Field compressor station structures	2.89%	2.89%
6	328	Field measuring and regulating station	0.00%	0.00%
7	332	Field lines	0.80%	0.80%
8	333	Field compressor station equipment	1.01%	1.01%
9	334	Field measuring and regulating station equipment	1.47%	1.47%
10		Total Production and gathering plant		
		Underground storage plant		
11	350.1	Land & Land rights	0.00%	0.00%
12	351.1	Structures and improvements	0.00%	0.00%
13	351.2	Structures and improvements	0.00%	0.00%
14	351.3	Structures and improvements	0.00%	0.00%
15	352	Wells	0.00%	0.00%
16	352.1	Storage Lease and Rights	0.00%	0.00%
17	352.2	Reservoirs	0.00%	0.00%
18	352.3	Non-Recoverable Natural Gas	0.00%	0.00%
19	353	Storage Lines	0.00%	0.00%
20	354	Compressor station equipment	0.00%	0.00%
21	355	Measuring and regulating station equipment	0.00%	0.00%
22	356	Purification equipment	0.00%	0.00%
23	357	Other equipment	0.00%	0.00%
24		Total Underground storage plant	0.00%	0.00%

Line No.	Account Number	Description	Depreciation Rates Current Rates	Depreciation Rates Proposed Rates
		Col. 1	Col. 2	Col. 3
		Transmission plant		
1	365.1	Land & Land rights	0.00%	0.00%
2	365.2	Rights of way	1.33%	1.31%
3	366.1	Structures and improvements	2.55%	2.50%
4	366.2	Measuring and regulating station equipment	1.98%	1.94%
5	367	Mains	1.82%	1.85%
6	368	Compressor station equipment	3.31%	3.00%
7	369	Measuring and regulating station equipment	2.91%	2.95%
8		Total Transmission plant		
		Distribution plant		
9	374.1	Land & Land rights	0.00%	0.00%
10	374.2	Rights of way	1.39%	1.39%
11	375.1	Structures	3.72%	3.64%
12	376	Mains	2.23%	2.29%
13	376.5	Mains - Metallic	1.53%	1.69%
14	376.9	Mains - Cathodic Protection	1.53%	5.91%
15	378	M&R station equipment - general	2.37%	2.38%
16	379	M&R station equipment - city gate	1.88%	1.96%
17	380	Services - Metallic	2.92%	3.15%
18	380.5	Services - Plastic	2.55%	3.66%
19	381	Meters	2.53%	2.52%
20	381.5	Meters - AMR	6.67%	6.67%
21	382	Meter installations	3.02%	3.06%
22	383	House regulators	1.91%	1.97%
23	386	Other Property on Customer Premises	7.07%	2.21%
24	387	Other equipment	0.00%	0.00%
25		Total Distribution plant		

KANSAS GAS SERVICE, A DIVISION OF ONE GAS, INC.
Summary of Depreciation Rates
Test Year Ended December 31, 2015

Line No.	Account Number	Description Col. 1	Depreciation Rates Current Rates Col. 2	Depreciation Rates Proposed Rates Col. 3
		General Plant		
1	389.1	Land & Land rights	0.00%	0.00%
2	390.1	Structures	1.61%	1.52%
3	390.2	Leasehold Improvements (1)	0.00%	0.00%
4	391.1	Office furniture and equipment	5.00%	5.00%
5	391.25	Computers and other electronic equipment	12.75%	12.75%
6	392	Transportation equipment	5.03%	4.73%
7	393	Stores equipment	5.00%	5.00%
8	394	Tools, shop and garage equipment	6.51%	6.51%
9	395	Laboratory equipment	6.67%	6.67%
10	396	Power operated equipment	6.20%	4.45%
11	397	Communications equipment	6.61%	6.61%
12	398	Miscellaneous equipment	5.00%	5.00%
13		Total General Plant		

(1) Included in amortization expense

KANSAS GAS SERVICE, A DIVISION OF ONE GAS, INC.
Calculation of Pro-Forma Depreciation Expense - Existing Rates
Test Year Ended December 31, 2015

Line No.	Account Number	Description Col. 1	Pro-Forma Plant in Service Col. 2	Depreciation Rate Col. 3	Pro-Forma Depreciation Col. 4
		Intangible Plant			
1	302	Franchise and Consents	$6,045	0.00%	$0
2	303	Miscellaneous Intangible Plant	52,535	3.03%	1,592
3		Total Intangible Plant	$58,580		$1,592
		Production and gathering plant			
4	325.4	Rights of way	$232,567	1.25%	$2,907
5	327	Field compressor station structures	3,053	2.89%	88
6	328	Field measuring and regulating station	44,026	0.00%	0
7	332	Field lines	45,302	0.80%	362
8	333	Field compressor station equipment	12,877	1.01%	130
9	334	Field measuring and regulating station equipment	515,090	1.47%	7,572
10		Total Production and gathering plant	$852,915		$11,060
		Underground storage plant			
11	350.1	Land & Land rights	$0	0.00%	$0
12	351.1	Structures and improvements	0	0.00%	0
13	351.2	Structures and improvements	0	0.00%	0
14	351.3	Structures and improvements	0	0.00%	0
15	352	Wells	0	0.00%	0
16	352.1	Storage Lease and Rights	0	0.00%	0
17	352.2	Reservoirs	0	0.00%	0
18	352.3	Non-Recoverable Natural Gas	0	0.00%	0
19	353	Storage Lines	0	0.00%	0
20	354	Compressor station equipment	0	0.00%	0
21	355	Measuring and regulating station equipment	0	0.00%	0
22	356	Purification equipment	0	0.00%	0
23	357	Other equipment	0	0.00%	0
24		Total Underground storage plant	$0		$0

Line No.	Account Number	Description Col. 1	Pro-Forma Plant in Service Col. 2	Depreciation Rate Col. 3	Pro-Forma Depreciation Col. 4
		Transmission plant			
1	365.1	Land & Land rights	$826,609	0.00%	$0
2	365.2	Rights of way	12,318,682	1.33%	163,838
3	366.1	Structures and improvements	4,627,325	2.55%	117,997
4	366.2	Measuring and regulating station equipment	1,208,818	1.98%	23,935
5	367	Mains	206,084,926	1.82%	3,750,746
6	368	Compressor station equipment	17,858,542	3.31%	591,118
7	369	Measuring and regulating station equipment	20,212,351	2.91%	588,179
8	371	Other Equipment	37,350	0.00%	0
9		Total Transmission plant	$263,174,604		$5,235,813
		Distribution plant			
10	374.1	Land & Land rights	$154,887	0.00%	$0
11	374.2	Rights of way	2,218,741	1.39%	30,840
12	375.1	Structures	855,549	3.72%	31,826
13	376	Mains	314,807,496	2.23%	7,020,207
14	376.5	Mains - Metallic	267,619,077	1.53%	4,094,572
15	376.9	Mains - Cathodic Protection	39,858,984	1.53%	609,842
16	378	M&R station equipment - general	23,613,076	2.37%	559,630
17	379	M&R station equipment - city gate	7,595,613	1.88%	142,798
18	380	Services - Plastic	402,687,194	2.92%	11,758,466
19	380.5	Services - Metallic	31,989,526	2.55%	815,733
20	381	Meters	110,320,497	2.53%	2,791,109
21	381.5	Meters-AMR	20,289,237	6.67%	1,353,292
22	382	Meter installations	94,719,499	3.02%	2,860,529
23	383	House regulators	20,722,674	1.91%	395,803
24	386	Other Property on Customer Premises	224,125	7.07%	15,846
25	387	Other equipment	0	0.00%	0
26		Total Distribution plant	$1,337,676,177		$32,480,493

Line No.	Account Number	Description Col. 1	Pro-Forma Plant in Service Col. 2	Depreciation Rate Col. 3	Pro-Forma Depreciation Col. 4
		General Plant			
1	389.1	Land & Land rights	$1,471,358	0.00%	$0
2	390.1	Structures	35,391,223	1.61%	569,799
3	390.2	Leasehold Improvements (1)	2,694,235	0.00%	0
4	391.1	Office furniture and equipment	5,014,496	5.00%	250,725
5	391.9	Computers and other electronic equipment	9,571,166	12.75%	1,220,324
6	392	Transportation equipment	26,849,935	5.03%	1,350,552
7	393	Stores equipment	113,367	5.00%	5,668
8	394	Tools, shop and garage equipment	8,463,128	6.51%	550,950
9	395	Laboratory equipment	72,377	6.67%	4,828
10	396	Power operated equipment	11,793,107	6.20%	731,173
11	397	Communications equipment	5,416,063	6.61%	358,002
12	398	Miscellaneous equipment	360,557	5.00%	18,028
13		Total General Plant	$107,211,011		$5,060,047
14		Subtotal	$1,708,973,287		$42,789,004
		Less: Capitalized Depreciation			
15		392 Transportation Equipment			(1,350,552)
16		396 Power Operated Equipment			(731,173)
17		Pro-Forma Depreciation Expense			$40,707,280
18		Test Period Depreciation - Kansas Gas Service			39,878,571
19		Pro-Forma Depreciation Adjustment at Current Rates			$828,709

(1) Included in amortization expense

Line No.	Account Number	Description	Pro-Forma Plant in Service	Depreciation Rate	Pro-Forma Depreciation
		Col. 1	Col. 2	Col. 3	Col. 4
		Intangible Plant			
1	302	Franchise and Consents	$6,045	0.00%	$0
2	303	Miscellaneous Intangible Plant	52,535	3.03%	1,592
3		Total Intangible Plant	$58,580		$1,592
4		Production and gathering plant			
5	325.4	Rights of way	$232,567	1.25%	$2,907
6	327	Field compressor station structures	3,053	2.89%	88
7	328	Field measuring and regulating station	44,026	0.00%	0
8	332	Field lines	45,302	0.80%	362
9	333	Field compressor station equipment	12,877	1.01%	130
10	334	Field measuring and regulating station equipment	515,090	1.47%	7,572
		Total Production and gathering plant	$852,915		$11,060
		Underground storage plant			
11	350.1	Land & Land rights	$0	0.00%	$0
12	351.1	Structures and improvements	0	0.00%	0
13	351.2	Structures and improvements	0	0.00%	0
14	351.3	Structures and improvements	0	0.00%	0
15	352	Wells	0	0.00%	0
16	352.1	Storage Lease and Rights	0	0.00%	0
17	352.2	Reservoirs	0	0.00%	0
18	352.3	Non-Recoverable Natural Gas	0	0.00%	0
19	353	Storage Lines	0	0.00%	0
20	354	Compressor station equipment	0	0.00%	0
21	355	Measuring and regulating station equipment	0	0.00%	0
22	356	Purification equipment	0	0.00%	0
23	357	Other equipment	0	0.00%	0
24		Total Underground storage plant	$0		$0

Line No.	Account Number	Description Col. 1	Pro-Forma Plant in Service Col. 2	Depreciation Rate Col. 3	Pro-Forma Depreciation Col. 4
		Transmission plant			
1	365.1	Land & Land rights	$826,609	0.00%	$0
2	365.2	Rights of way	12,318,682	1.31%	161,375
3	366.1	Structures and improvements	4,627,325	2.50%	115,683
4	366.2	Measuring and regulating station equipment	1,208,818	1.94%	23,451
5	367	Mains	206,084,926	1.85%	3,812,571
6	368	Compressor station equipment	17,858,542	3.00%	535,756
7	369	Measuring and regulating station equipment	20,212,351	2.95%	596,264
8	371	Other Equipment	37,350	0.00%	0
9		Total Transmission plant	$263,174,604		$5,245,101
		Distribution plant			
10	374.1	Land & Land rights	$154,887	0.00%	$0
11	374.2	Rights of way	2,218,741	1.39%	30,840
12	375.1	Structures	855,549	3.64%	31,142
13	376	Mains	314,807,496	2.29%	7,209,092
14	376.5	Mains - Metallic	267,619,077	1.69%	4,522,762
15	376.9	Mains - Cathodic Protection	39,858,984	5.91%	2,355,666
16	378	M&R station equipment - general	23,613,076	2.38%	561,991
17	379	M&R station equipment - city gate	7,595,613	1.96%	148,874
18	380	Services	402,687,194	3.15%	12,684,647
19	380.5	Services - Metallic	31,989,526	3.66%	1,170,817
20	381	Meters	110,320,497	2.52%	2,780,077
21	381.5	Meters - AMR	20,289,237	6.67%	1,353,292
22	382	Meter installations	94,719,499	3.06%	2,898,417
23	383	House regulators	20,722,674	1.97%	408,237
24	386	Other Property on Customer Premises	224,125	2.21%	4,953
25	387	Other equipment	0	0.00%	0
26		Total Distribution plant	1,337,676,177		36,160,806

KANSAS GAS SERVICE, A DIVISION OF ONE GAS, INC.
Pro Forma Depreciation and Amortization Expense - Proposed Rates
Test Year Ended December 31, 2015

Line No.	Account Number	Description Col. 1		Pro-Forma Plant in Service Col. 2	Depreciation Rate Col. 3	Pro-Forma Depreciation Col. 4
		General Plant				
1	389.1	Land & Land rights		$1,471,358	0.00%	$0
2	390.1	Structures		35,391,223	1.52%	537,947
3	390.2	Leasehold Improvements (1)		2,694,235	0.00%	0
4	391.1	Office furniture and equipment		5,014,496	5.00%	250,725
5	391.9	Computers and other electronic equipment		9,571,166	12.75%	1,220,324
6	392	Transportation equipment		26,849,935	4.73%	1,270,002
7	393	Stores equipment		113,367	5.00%	5,668
8	394	Tools, shop and garage equipment		8,463,128	6.51%	550,950
9	395	Laboratory equipment		72,377	6.67%	4,828
10	396	Power operated equipment		11,793,107	4.45%	524,793
11	397	Communications equipment		5,416,063	6.61%	358,002
12	398	Miscellaneous equipment		360,557	5.00%	18,028
13		Total General Plant		$107,211,011		$4,741,265
14		Subtotal		$1,708,973,287		$46,159,824
		Less: Capitalized Depreciation				
15		392	Transportation Equipment			(1,270,002)
16		396	Power Operated Equipment			(524,793)
17		Pro-Forma Depreciation Expense				$44,365,028
18		Less: Annualized Depreciation - Present Rates 10-E				40,707,280
19		Pro-Forma Depreciation Adjustment at Proposed Rates				$3,657,749

(1) Included in amortization expense

KANSAS GAS SERVICE, A DIVISION OF ONE GAS, INC.
Pro Forma Taxes Chargeable to Operations
Test Year Ended December 31, 2015

Line No.	Description	Schedule References	Amount Per Books	Pro Forma Adjustments	Pro Forma Adjusted Total
	Col. 1	Col. 2	Col. 3	Col. 4	Col. 5
	Taxes other than income taxes:				
1	Payroll taxes	11-B	$3,654,337	$188,319	$3,842,656
2	Real estate and personal property taxes	11-B	22,471,188	(1,517,180)	20,954,008
3	Total other taxes	11-B	218,847	0	218,847
4	Total taxes other than income taxes		$26,344,373	($1,328,861)	$25,015,511
	Income taxes:				
5	Income taxes - current	11-C	($1,148,546)	$4,005,596	$2,857,050
6	Income taxes - deferred	11-E	$17,484,787	(238,457)	$17,246,330
7	Income taxes - amortization of ITC	11-E	($201,384)	$0	($201,384)
8	Total income taxes		$16,134,857	$3,767,139	$19,901,996
9	Total taxes chargeable to operations		$42,479,230	$2,438,278	$44,917,507

KANSAS GAS SERVICE, A DIVISION OF ONE GAS, INC.
Pro Forma Taxes Other Than Income Taxes
Test Year Ended December 31, 2015

Line No.	Description Col. 1	Amount Per Books Col. 2	Pro Forma Adjustments (Schedule 9-B) Col. 3	Pro Forma Adjusted Total Col. 4
	Payroll taxes:			
1	Federal payroll taxes	$5,295,357	$188,319	$5,483,676
2	Federal unemployment (FUTA)	45,391	0	45,391
3	State unemployment (SUTA)	203,631	0	203,631
4	Capitalized payroll	(1,890,041)	0	(1,890,041)
5	Total payroll taxes	$3,654,337	$188,319	$3,842,656
6	General Tax Expense	$217,388	$0	$217,388
7	General Tax Sales Tax Allowance	1,459	0	1,459
8	Real estate and personal property taxes	22,471,188	(1,517,180)	20,954,008
	Total non-payroll taxes	$22,690,035	($1,517,180)	$21,172,855
9	Total taxes other than income taxes	$26,344,373	($1,328,861)	$25,015,511

KANSAS GAS SERVICE, A DIVISION OF ONE GAS, INC.
Pro Forma Current Income Taxes
Test Year Ended December 31, 2015

Line No.	Description	Schedule Reference	Amount Per Books	Pro Forma Adjustments	Pro Forma Adjusted Total
	Col. 1	Col. 2	Col. 3	Col. 4	Col. 5
	Provision for Kansas Income Tax:				
1	Taxable income	11-D	$451,806	$7,205,001	$7,656,807
2	Kansas income tax		$1,322	$504,350	$505,672
3	Adjustments [Provision-to-Return,Temp/Perm]		(204,605)	204,605	0
4	Kansas current income tax		($203,283)	$708,955	$505,672
	Provision for Federal Income Tax:				
5	Taxable income		$451,806	$7,205,001	$7,656,807
6	Less: Provision for Kansas income tax (Line 2)		1,322	504,350	505,672
7	Federal taxable income		$450,484	$6,700,651	$7,151,134
8	Federal income tax		$6,149	$2,345,228	$2,351,377
9	Adjustments [Provision-to-Return,Temp/Perm]		(951,413)	951,413	0
10	Federal current income tax		($945,264)	$3,296,641	$2,351,377
	Summary of Current Income Taxes				
11	Kansas income tax (Line 4)		($203,283)	$708,955	$505,672
12	Federal income tax (Line 10)		(945,264)	3,296,641	2,351,377
13	Total current income taxes		($1,148,547)	$4,005,596	$2,857,050

KANSAS GAS SERVICE, A DIVISION OF ONE GAS, INC.
Pro Forma Taxable Income
Test Year Ended December 31, 2015

Line No.	Description	Schedule References	Amount Per Books	Pro Forma Adjustments	Pro Forma Adjusted Total
	Col. 1	Col. 2	Col. 3	Col. 4	Col. 5
1	Operating revenues	9-A	$533,449,344	($245,517,932)	$287,931,412
2	Less: Operating expenses (accts. 431 and 432 included)	9-A	403,424,305	(253,727,066)	149,697,239
3	Depreciation and amortization	9-A	44,264,295	4,745,635	49,009,930
4	Taxes other than income taxes	9-A	26,344,373	(1,328,861)	25,015,512
5	Interest Expense	8-B	18,553,001	(2,481,981)	16,071,020
6	Other income & deductions	8-B	363,574	(363,574)	0
7	Total expenses before income taxes		$492,949,548	($253,155,847)	$239,793,701
8	Operating income before income taxes		$40,499,796	$7,637,916	$48,137,712
	Increases/(decreases):				
9	Reverse Book Depreciation		$41,961,088	$0	$41,961,088
10	Other CIAC to Income		2,252,862	0	2,252,862
11	Workmen's Comp Settlement		(275,916)	0	(275,916)
12	Bad Debts		(246,103)	0	(246,103)
13	Amortizations		10,195	0	10,195
14	OPEB Cash Payments		(12,373,837)	0	(12,373,837)
15	Contingencies/Reserves		(13,000)	0	(13,000)
16	Pension: Book Accrual		11,273,659	0	11,273,659
17	OPEB: Book Accrual		8,753,603	0	8,753,603
18	Book Reg Assets - Net		(19,691,682)	0	(19,691,682)
19	Purchased Gas Adjustment		8,719,983	0	8,719,983
20	Tax Depreciation		(80,851,757)	0	(80,851,757)
21	Other (Eliminate below the line other income)		0	0	0
22	Total Temporary Differences increases/(decreases):		($40,480,905)	$0	($40,480,905)
23	Meal Disallowance - 50%		$179,419	($179,419)	$0
24	Lobbying Expenses		187,526	(187,526)	0
	Civic Disallowance - 50%		47,868	(47,868)	0
25	Club Memberships		902	(902)	0
26	Penalty		17,200	(17,200)	0
27	Permanent Differences		$432,915	($432,915)	$0
28	Taxable Income (Loss)		$451,806	$7,205,001	$7,656,807

Line No.	Description	Schedule Reference	Amount Per Books	Pro Forma Adjustments	Pro Forma Adjusted Total
	Col. 1	Col. 2	Col. 3	Col. 4	Col. 5
	Provision for Deferred Income Taxes :				
1	Reverse Book Depreciation		($16,595,610)	$0	($16,595,610)
2	Other CIAC to Income		($891,007)	0	(891,007)
3	Workmen's Comp Settlement		$109,125	0	109,125
4	Bad Debts		$97,334	0	97,334
5	Amortizations		($4,032)	0	(4,032)
6	OPEB Cash Payments		$4,893,853	0	4,893,853
7	Contingencies/Reserves		$5,142	0	5,142
8	Pension: Book Accrual		($4,458,732)	0	(4,458,732)
9	OPEB: Book Accrual		($3,462,050)	0	(3,462,050)
10	Book Reg Assets - Net		$7,788,060	0	7,788,060
11	Purchased Gas Adjustment		($3,448,753)	0	(3,448,753)
12	Tax Depreciation		$31,976,870	0	31,976,870
13	Other (Eliminate below the line other income)		$0	0	0
14	Sub-total Provision for deferred income taxes		$16,010,198	$0	$16,010,198
15	2014 FAS 109		$81,533	($81,533)	$0
16	2014 Provision to Return		1,156,020	0	1,156,020
17	Flow-Thru Adjustment		156,924	(156,924)	0
18	Other		0	0	0
19	Sub-total Provision for deferred income taxes		$17,404,675	($238,457)	$17,166,218
20	Amortization of Deferred ITC		($201,384)	$0	($201,384)
21	Deferred Tax Turnaround on Def ITC		80,112	0	80,112
22	Investment tax credit - net		($121,272)	$0	($121,272)
23	Total deferred income taxes		$17,283,403	($238,457)	$17,044,946

KANSAS GAS SERVICE, A DIVISION OF ONE GAS, INC.
Description of Increases/Decreases to
Operating Income Before Income Taxes
Test Year Ended December 31, 2015

Line No.	Description Col. 1	Increase Col. 2	Decrease Col. 3
1	**Book depreciation** Depreciable plant in service is depreciated through account 403 for book purposes. Tax will reverse out the book depreciation expense.	41,961,088	0
2	**Contributions in Aid (CIAC)** Advance payments for a reimbursable construction job after 1986 are treated as contributions to capital for book purposes but are includible as taxable income for tax purposes.	2,252,862	0
3	**Workmen's Compensation Settlement** Tax reverses the book estimate of workmen's compensation, then records a tax deduction for the actual payments made.	0	275,916
4	**Bad Debts** Tax reverses the book estimate of bad debt expense, then records a tax deduction for the actual net charge-offs/recoveries.	0	246,103
5	**Amortization-Leasehold Improvements** Cost associated with remodeling company facilities are being amortized for income tax purposes.	10,195	0

KANSAS GAS SERVICE, A DIVISION OF ONE GAS, INC.
Description of Increases/Decreases to
Operating Income Before Income Taxes
Test Year Ended December 31, 2015

Line No.	Description Col. 1	Increase Col. 2	Decrease Col. 3
1	**Non-Pension Cash Payments (FAS 106)** Cash benefits paid for other than pension employees medical benefits are deducted for tax when paid.	0	12,373,837
2	**Contingencies/Reserves** A general liability and damage claims expense is recorded for book purposes. Tax reverses this accrual and deducts actual cash payments.	0	13,000
3	**Pension - Book Accrual (FAS 87)** FAS 87 establishes standards for "pension benefits" to employees. The book accrual for pension benefits is reversed for tax purposes.	11,273,659	0
4	**Non-Pension - Book Accrual (Fas 106)** FAS 106 establishes standards for "postretirement benefits" other than pensions to employees. The book accrual for postretirement benefits is reversed for tax purposes.	8,753,603	0
5	**Regulatory Asset** These are regulatory assets set up and amortized for book purposes. For tax purposes these expenses are deductible when incurred. The book amortization is then reversed for tax purposes in the following years.	0	19,691,682
6	**Purchased Gas Adjustment** A public utility that uses the accrual method of accounting is authorized to include fuel charges in its customers' bills for natural gas. The charges may be adjusted monthly and are trued up annually. These estimates are reversed for tax purposes.	8,719,983	0

KANSAS GAS SERVICE, A DIVISION OF ONE GAS, INC.
Description of Increases/Decreases to
Operating Income Before Income Taxes
Test Year Ended December 31, 2015

Line No.	Description Col. 1	Increase Col. 2	Decrease Col. 3
1	**Tax Depreciation** The IRS allows depreciable plant in service to be depreciated for tax purposes at an accelerated rate. Therefore, tax depreciation as computed under IRS guidelines is recognized as a deduction for tax purposes.	0	80,851,757
2	**Other** Other miscellaneous deductions to eliminate below the line other income.	0	0
3	**50% Disallowed Meals** Book recognizes meals and entertainment expenses for GAAP purposes. disallow 50% of such expenses are disallowed per IRS guidelines.	179,419	0
4	**Lobbying Expenses** Book recognizes lobbying expenses for GAAP purposes. Lobbying expenses are disallowed per IRS guidelines; therefore, the book entry is reversed out for tax purposes.	187,526	0
5	**Civic Disallowance- 50%** Civic expenses are treated as such for book purposes, but only 50% of those expenses can be recognized as expense for tax purposes.	47,868	0
6	**Club Memberships** Employee costs related memberships in certain social clubs are not deductible for income tax purposes. Any expenses related to these items on the books are reversed for tax and not deductible.	902	0

KANSAS GAS SERVICE, A DIVISION OF ONE GAS, INC.
Description of Increases/Decreases to
Operating Income Before Income Taxes
Test Year Ended December 31, 2015

Line No.	Description Col. 1	Increase Col. 2	Decrease Col. 3
1	**Tax Penalty** Penalties accrued determined to be non-deductible for tax purposes. The impact on income tax expense for this item has been eliminated.	17,200	0
		73,404,305	113,452,295

KANSAS GAS SERVICE, A DIVISION OF ONE GAS, INC.
Composite Tax Rate
Test Year Ended December 31, 2015

Line No.	Description		Tax Rates
	Col. 1		Col. 2
1	State Income Tax Rate		7.0000%
2	Federal Income Tax Rate		35.0000%
3	Less: State Tax Deductible for Federal (35.00%*7.00%)		-2.4500%
4	Effective Federal Income Tax Rate		32.5500%
5	Composite Income Tax Rate		39.5500%
6	Inverse Tax Rate (1- 39.5500%)		60.4500%
7	Reciprocal Tax Rate (tax / 1- tax)		65.4260%
8	Tax Gross-up		1.654260
9	Interest expense computation of synchronization:		
10	Rate Base	(Schedule 3A)	$902,967,732
11	Weighted Cost of Debt	(Schedule 7A)	1.7798%
12	Interest Expense		$16,071,020

Line No.	Year Col. 1	Income Taxes Deferred Col. 2	Credited to Income Col. 3	Adjustments Col. 4	Cumulative Balance Col. 5
1	1997	$104,786,340	($4,802,035)	$4,939,865	$104,924,170
2	1998	1,237,460	(4,227,624)	(2,720,972)	99,213,034
3	1999	(4,275,619)	(376,006)	4,932,767	99,494,176
4	2000	7,343,120	13,303,552	(4,334,787)	115,806,061
5	2001	5,805,215	7,224,635	(6,371,877)	122,464,034
6	2002	18,800,446	15,594,814	(14,345,950)	142,513,344
7	2003	6,564,788	(8,831,752)	(4,323,130)	135,923,250
8	2004	5,779,043	15,460,658	(11,101,266)	146,061,685
9	2005	$5,864,481	$12,675,978	($8,428,449)	$156,173,695

KANSAS GAS SERVICE, A DIVISION OF ONE GAS, INC.
Accumulated Deferred Income Taxes
Accrual Charges and Credits to Account 283

Line No.	Year	Income Taxes Deferred	Credited to Income	Adjustments	Cumulative Balance
	Col. 1	Col. 2	Col. 3	Col. 4	Col. 5
1	2006	$17,646,429	($1,683,508)	($942,000)	$171,194,616
2	2007	7,448,708	(1,743,302)	1,261,054	178,161,076
3	2008	17,521,108	(7,086,508)	(1,110,556)	187,485,120
4	2009	20,682,151	(10,172,617)	36,528,301	234,522,954
5	2010	13,673,583	(4,870,182)	14,161,853	257,488,209
6	2011	35,072,154	(1,793,891)	14,681,666	305,448,137
7	2012	26,658,221	(272,363)	4,955,029	336,789,024
8	2013	22,902,177	(14,741,659)	(538,311)	344,411,231
9	2014	27,903,600	(18,619,684)	(285,451)	353,409,696
10	2015	24,965,789	(8,901,517)	1,133,983	370,607,951

Line No.	Year Col. 1	Beginning Balance Col. 2	Investment Credits Deferred Col. 3	Credited to Income Col. 4	Adjustments Col. 5	Ending Balance Col. 6
1	1997	$8,083,139	$0	($39,125)	$0	$8,044,014
2	1998	8,044,014	0	(307,981)	0	7,736,033
3	1999	7,736,033	0	(611,742)	0	7,124,291
4	1999SY	7,124,291	0	(180,656)	0	6,943,635
5	2000	6,943,635	0	(536,034)	0	6,407,601
6	2001	6,407,601	0	(501,120)	(247,755)	5,658,726
7	2002	5,658,726	0	(505,388)	457,650	5,610,988
8	2003	5,610,988	0	(444,807)	0	5,166,181
9	2004	5,166,181	0	(514,644)	0	4,651,537
10	2005	$4,651,537	$0	($499,464)	$0	$4,152,073

KANSAS GAS SERVICE, A DIVISION OF ONE GAS, INC.
Accumulated Deferred Investment Tax Credit
Accrual Charges and Credits to Account 255

Line No.	Year	Beginning Balance	Investment Credits Deferred	Credited to Income	Adjustments	Ending Balance
	Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6
1	2006	$4,152,073	$0	($484,224)	$0	$3,667,849
2	2007	3,667,849	0	(454,044)	0	3,213,805
3	2008	3,213,805	0	(417,516)	0	2,796,289
4	2009	2,796,289	0	(395,244)	0	2,401,045
5	2010	2,401,045	0	(414,792)	0	1,986,253
6	2011	1,986,253	0	(384,288)	0	1,601,965
7	2012	1,601,965	0	(347,388)	0	1,254,577
8	2013	1,254,577	0	(291,960)	0	962,617
9	2014	962,617	0	(266,532)	0	696,085
10	2015	696,085	0	(201,384)	0	494,701

Line No.	Description Col. 1	Kansas Gas Service Col. 2	Total Company ONE Gas, Inc. Col. 3	Kansas Gas Service Percentage Col. 4
	1st Quarter 2015 - based on 12 months Ended December 2014			
1	Gross Plant and Investment	$1,683,348,847	$4,779,327,247	35.22%
2	Operating Income	$67,769,565	$225,298,071	30.08%
3	Labor Expense	$48,566,168	$130,221,884	37.29%
4	Average Percentage			34.20%

		Kansas Gas Service	Total Company ONE Gas, Inc.	Kansas Gas Service Percentage
	2nd Quarter 2015 - based on 12 months Ended March 2015			
1	Gross Plant and Investment	$1,666,470,686	$4,727,169,056	35.25%
2	Operating Income	$65,916,964	$224,949,684	29.30%
3	Labor Expense	$48,131,092	$129,855,180	37.07%
4	Average Percentage			33.87%

Line No.	Description Col. 1	Kansas Gas Service Col. 2	Total Company ONE Gas, Inc. Col. 3	Kansas Gas Service Percentage Col. 4
	3rd Quarter 2015 - based on 12 months Ended June 2015			
1	Gross Plant and Investment	$1,679,981,681	$4,783,281,110	35.12%
2	Operating Income	$65,190,022	$229,404,179	28.42%
3	Labor Expense	$47,772,005	$129,606,051	36.86%
4	Average Percentage			33.47%

		Kansas Gas Service	Total Company ONE Gas, Inc.	Kansas Gas Service Percentage
	4th Quarter 2015 - based on 12 months Ended September 2015			
1	Gross Plant and Investment	$1,690,785,037	$4,847,718,554	34.88%
2	Operating Income	$67,537,869	$235,235,388	28.71%
3	Labor Expense	$49,765,705	$136,034,809	36.58%
4	Average Percentage			33.39%

KANSAS GAS SERVICE, A DIVISION OF ONE GAS, INC.
Allocation Ratios
Test Year Ended December 31, 2015

Line No.	Description	Kansas Gas Service	Total Company ONE Gas, Inc.	Kansas Gas Service Percentage
	Col. 1	Col. 2	Col. 3	Col. 4
	1st Quarter 2016 - based on 12 months Ended December 2015			
1	Gross Plant and Investment	$1,715,089,257	$4,932,077,669	34.77%
2	Operating Income	$68,508,314	$239,129,301	28.65%
3	Labor Expense	$49,607,681	$136,018,632	36.47%
4	Average Percentage			33.30%

Causal Allocation Percentages for 2015

Line No.	Description Col. 1	Allocation Basis Col. 2	Kansas Gas Service Col. 3	Total Company ONE Gas, Inc. Col. 2	Kansas Gas Service Percentage Col. 4
1	Accounts Payable, Ariba (A/P software)	Invoice Count in 2014	24,010	88,578	27.11%
2	OGS Human Resources, Concur (credit card software)	Employee headcount at year end 2014	1,019	3,303	31.00%
3	Power Plant, Property Accounting	Gross PP&E year end 2014	1,683,348,847	4,779,327,247	35.22%
4	Power Plant	Gross PP&E end of 1st quarter 2015 (1)	1,666,470,686	4,727,169,055	35.25%
5	Administrative Cost for SERP	KGS's percent of total budgeted cost related to SERP for 2015	22,520	75,000	30.03%
6	Administrative Cost for OPEB	KGS's percent of total budgeted cost related to OPEB for 2015	5,431	17,520	31.00%
7	Administrative Cost for Profit Share	KGS's percent of total budgeted cost related to Profit Share for 2015	56,102	263,004	21.33%
8	Administrative Cost for Pension	KGS's percent of total budgeted cost related to Pension for 2015	170,670	437,064	39.05%
9	Maximo	User Count at year end 2014	194	969	20.00%
10	Billing Control, Banner (customer billing software)	Customer Count at year end 2014	634,128	2,127,501	29.81%

(1) An additional Gross PP&E allocation factor was calculated for 2015 based on 1st quarter 2015 gross PP&E because the company reclassified the PowerPlant Software depreciation into its own account during the 2nd quarter of 2015.

Causal Allocation Percentages for 2016

Line No.	Description Col. 1	Allocation Basis	Kansas Gas Service Col. 2	Total Company ONE Gas, Inc. Col. 3	Kansas Gas Service Percentage Col. 4
1	Accounts Payable, Ariba (A/P software)	Invoice Count in 2015	25,333	141,578	17.89%
2	OGS Human Resources, Concur (credit card software)	Employee headcount at year end 2015	1,002	3,375	29.69%
3	Power Plant, Property Accounting	Gross PP&E year end 2015	1,715,089,257	4,932,077,669	34.77%
4	Administrative Cost for SERP	KGS's percent of total budgeted cost related to SERP for 2016	16,090	56,933	28.26%
5	Administrative Cost for OPEB	KGS's percent of total budgeted cost related to OPEB for 2016	4,632	15,601	29.69%
6	Administrative Cost for Profit Share	KGS's percent of total budgeted cost related to Profit Share for 2016	37,169	169,801	21.89%
7	Administrative Cost for Pension	KGS's percent of total budgeted cost related to Pension for 2016	73,359	196,400	37.35%
8	Maximo	Miles of Pipe at year end 2015	12,000	40,400	30.00%
9	Billing Control, Banner (customer billing software)	Customer Count at year end 2015	634,977	2,139,936	29.67%

KANSAS GAS SERVICE, A DIVISION OF ONE GAS, INC.
Labor Capitalization Ratio
Test Year Ended December 31, 2015

Line No.	Labor Capitalization Ratio for KGS	Labor	Labor % to Total
	Col. 1	Col. 2	Col. 3
1	Labor Expensed	$53,297,066	70.57%
2	Labor Capitalized	$22,229,886	29.43%
3	Total KGS	$75,526,952	

THIS SECTION CONTAINS THE 2015 ANNUAL REPORT

ONE Gas

A BETTER TOMORROW

• STARTS TODAY •

ONE Gas 2015 Annual Report

ONE Gas, Inc. is a 100-percent regulated natural gas utility, and trades on the New York Stock Exchange under the symbol "OGS." ONE Gas is included in the S&P MidCap 400 Index, and is one of the largest natural gas utilities in the United States.

ONE Gas

Investing for a Better Tomorrow

- *ONE Gas provides natural gas distribution services to more than 2 million customers in Oklahoma, Kansas and Texas.*
- *ONE Gas is headquartered in Tulsa, Okla.*
- *Our divisions include:*
  - *Oklahoma Natural Gas, the largest natural gas distributor in Oklahoma;*
  - *Kansas Gas Service, the largest in Kansas; and*
  - *Texas Gas Service, the third largest in Texas, in terms of customers.*
- *Our largest natural gas distribution markets by customer count are Oklahoma City and Tulsa, Okla.; Kansas City, Wichita and Topeka, Kan.; and Austin and El Paso, Texas.*
- *We serve residential, commercial, industrial, transportation and wholesale customers in all three states.*

Mission – Why We Exist

We deliver natural gas for a better tomorrow.

Vision – What We Want to Be

To be a premier natural gas distribution company creating exceptional value for our stakeholders.

Core Values

Safety: We are committed to operating safely and in an environmentally responsible manner.

Inclusion and Diversity: We embrace and promote diversity and collaboration; every employee makes a difference and contributes to our success.

Ethics: We are accountable to the highest ethical standards; honesty, trust and integrity matter.

Service: We provide exceptional service and make continuous improvements in our pursuit of excellence.

Value: We create value for all stakeholders, including our employees, customers, investors and communities.

Visit us: www.ONEGas.com

Like us on Facebook: facebook.com/onegasincorporated

Follow us on Twitter: @ONEGasInc

2015 HIGHLIGHTS

Our second year as a company was another year filled with accomplishments, thanks to the hard work and dedication of our employees.

We delivered a total shareholder return of approximately 25 percent in 2015, outperforming our peer group and the S&P MidCap Utilities Index. Shareholder returns reflect solid operating and financial results, and the continued investments in our assets.

We expect net income and earnings per share to increase by an average of 5 to 8 percent annually between 2015 and 2020.

We increased the quarterly dividend by 5 cents per share to 35 cents per share, effective for the first quarter 2016, resulting in an annualized dividend of $1.40 per share.

We expect an average annual dividend increase of 8 to 10 percent between 2015 and 2020, while maintaining a 55 to 65 percent dividend payout ratio.

SHAREHOLDER LETTER

To Our Fellow Shareholders:

This time last year, we were wrapping up our first full year as a new, stand-alone publicly traded company. We spent a lot of time during year one laying out plans and goals for the future success of our company. Our mission is straightforward and simple. *We deliver natural gas for a better tomorrow.* In year two, we were able to put our strategic plan into action – working toward our goals and measuring our success. We are extremely proud of our employees and all that they've accomplished.

Last year, we challenged ourselves to focus on the five key themes that would make the greatest impact on our company – *safety, high-performing workforce, leveraging technology, growth and regulatory.* We are pleased to say we've made great strides in executing on the objectives and initiatives supporting these five key themes.

When it comes to **safety**, our results continue to improve and reflect our emphasis on keeping our employees, customers and communities safe. Compared with 2014, we achieved a 10 percent reduction in our Total Recordable Injury Rate and a 7 percent reduction in our Preventable Vehicle Incident Rate. As a company, we've committed to focusing on processes, policies and guidelines that result in driving toward "zero harm" and "zero injuries" every day.

In 2015, employees in leadership roles participated in our Leadership Development Program. This program provided them the opportunity to learn and grow in their leadership skills. In a continued effort to cultivate a **high-performing workforce**, we will introduce an ongoing Aspiring Leader Program this year, which will focus on developing the future leaders of our company. It will also provide them with a unique opportunity to develop skills that are necessary for sustaining and growing our company for years to come.

After a demanding year of rolling out new technology to two-thirds of our field workforce, we are beginning to see the benefits of that hard work. New technology for operations is increasing our efficiency and productivity in the field, as employees become more familiar with new equipment and processes. Additionally, new mobile apps have been released to our customers, making it easier for customers to manage their own accounts by tracking usage and paying their bill, among other things. We are pleased with the progress toward our **leveraging technology** objective, and eager to see its continued impact on the work that we do.

Growth remains a top priority, and we made great progress in 2015. One way we grow is by investing in our existing systems. We invested $294 million in capital expenditures in 2015, of which more than 70 percent went toward system integrity and replacement projects. Another way we grow is by adding customers. We averaged 13,000 more customers in 2015 compared with 2014.

We continue to execute on our **regulatory strategy** through collaborative relationships with regulators and finding opportunities that allow us to provide the most cost-effective, safe and reliable service to our customers. Rate activity across all three of our states – Oklahoma, Kansas and Texas – resulted in a base revenue increase of $27.5 million, compared with 2014. Rate adjustments allow us to continue serving our customers with safe and reliable natural gas service.

We believe that natural gas remains well positioned to be competitive against other energy options and is among the best carbon fuels for maintaining limited emissions.

We remain diligent at being good stewards of our product. This includes focusing on reducing emissions and finding innovative ways to use natural gas. Natural gas goes *beyond* the four touchpoints in our homes – the natural gas furnace, clothes dryer, stove top and water heater. It provides even more – reliability, warmth, comfort and convenience.

We look forward to the year ahead – and while we're always looking forward to our future, we know that **a better tomorrow starts today.**

John W. Gibson
Chairman
ONE Gas, Inc.
April 1, 2016

Pierce H. Norton II
President and Chief Executive Officer
ONE Gas, Inc.
April 1, 2016

FINANCIAL OVERVIEW

2015 Summary

We reported full-year 2015 net income of $119.0 million, or $2.24 per diluted share, compared with $109.8 million, or $2.07 per diluted share, in 2014; and full-year 2015 capital expenditures of $294.3 million, compared with $297.1 million in 2014.

Our operating income was $239.1 million, compared with $225.3 million in 2014, as net margin increased by $14.7 million compared with last year.

Net margin increases in 2015 primarily reflected new rates in Oklahoma and Texas along with an increase in our average residential customer count in these states.

We lowered operating costs in 2015, which were $469.6 million, compared with $476.0 million in 2014, which primarily reflects decreases in information technology costs associated with our separation in 2014 from ONEOK, Inc. We also benefited from a decrease in outside services expenses, bad debt and fleet-related expenses.

On January 19, 2016, the ONE Gas Board of Directors increased the quarterly dividend by 5 cents per share to 35 cents per share, effective in the first quarter 2016, resulting in an annualized dividend of $1.40 per share. Our average annual dividend growth rate is expected to increase 8 to 10 percent between 2015 and 2020, with a targeted dividend payout ratio of 55 to 65 percent of net income, all subject to board of directors' approval.

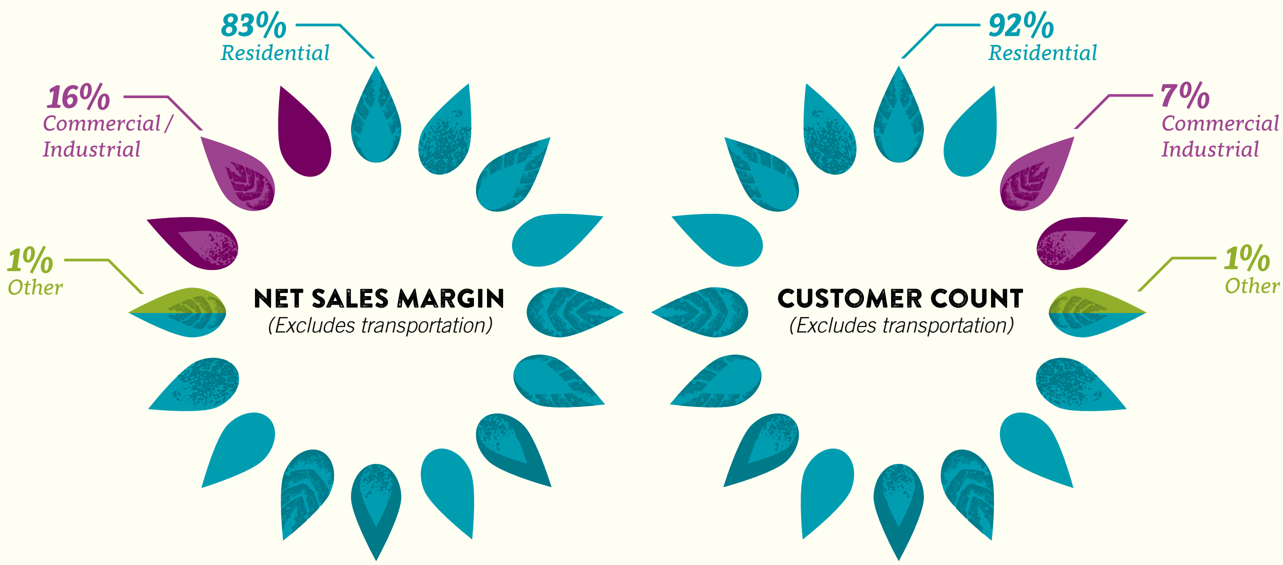
Highlights

	2015	2014	2013
Earnings and Dividends			
Net Income (thousands)	$ 119,030	$ 109,790	$ 99,195
Earnings Per Share of Common Stock			
Basic	$ 2.26	$ 2.10	$ 1.90*
Diluted	$ 2.24	$ 2.07	$ 1.90*
Dividends Per Share	$ 1.20	$ 0.84	$ –
Margin, Volumes and Weather			
Net Margin (thousands)	$ 841,733	$ 826,957	$ 813,008
Total Volumes Sold (Bcf)	154.0	166.3	164.2
Total Volumes Delivered (Bcf)	358.8	379.8	370.1
Actual Heating Degree Days	9,114	10,615	11,036
Normal Heating Degree Days	9,962	9,965	9,970
Customers and Employees			
Average Number of Customers (thousands)	2,140	2,127	2,114
Total Employees	3,400	3,300	–
Common Stock			
Market Value Per Share – Year-End Closing Price	$ 50.17	$ 41.22	–
Average Shares of Common Stock, Outstanding (thousands)			
Basic	52,578	52,364	52,319*
Diluted	53,254	52,946	52,319*

** Prior to 2014, historical basic and diluted earnings per share for the periods presented were calculated based on the number of shares distributed to ONEOK shareholders on separation plus any shares associated with fully vested stock awards that had not been issued and considered outstanding as of the beginning of each period prior to the separation.*

Significant Scale

High Percentage of Residential Customers



	Oklahoma	*Kansas*	*Texas*	*Average Total:*
2015 Fixed Charges *Sales Customers**	87%	55%	72%	73%
Average Annual Heating Degree Days – *Normal*	3,317	4,860	1,785	–
Weather Normalization**	100%	100%	62%	89%

** Fixed percentage of total net margin on natural gas sales*
*** Percent of customers who are in jurisdictions with weather normalization adjustment mechanisms*



NATURAL GAS





Beyond the Touchpoints

Natural gas touches every part of our daily lives. It is the better source of energy for heat, hot water and cooking in homes and businesses in the U.S. In addition to its efficiency, natural gas provides a greater quality of life.

Natural gas not only fuels your home, it fuels your family by providing clean clothes, hot showers and a warm home. In your kitchen, in your laundry room or on your back patio, natural gas delivers heat and energy that fuels your family's needs.

Using natural gas to fuel your home provides a sense of comfort, knowing you have chosen one of the most efficient energy options.

GROWTH

Expanding Services to Fuel Tomorrow

As a 100-percent regulated natural gas utility, we are committed to growth that aligns with our long-term strategy. Our growth opportunities are a result of capital investments related to the safety and reliability of our existing system, and system growth related to the economic and population growth in our service territories.

As a result of our commitment to enhance the safety, integrity and reliability of our existing infrastructure, we are making significant investments in our system, which we expect to further grow our rate base.

Many service territories continue to experience economic growth, allowing us opportunities to invest in new service lines and main line extensions, predominately in the major metropolitan areas.

We believe the competitiveness of natural gas is increasing relative to other energy alternatives, creating new market opportunities for natural gas as an energy source within our existing service territories.

This past year, we invested in growth in several areas, including:

The Stillwater Energy Center

Oklahoma Natural Gas installed a five-mile, 12-inch pipeline to tie the new high-efficiency, natural gas-fired power plant to an existing midstream transmission pipeline, ultimately powering the 56-megawatt energy center, which when in service in 2016 will provide electricity for the Stillwater, Okla., community.

Pipeline Upgrades in Kansas

In 2015, Kansas Gas Service completed a new main extension in Overland Park that will support future growth in southern Johnson County, bringing much-needed volume capacity to the area.

UTMB

Texas Gas Service completed construction on a new four-mile, 8-inch natural gas distribution pipeline to the University of Texas Medical Branch at Galveston (UTMB). The project allowed the company to provide additional natural gas service and energy capacity to UTMB, Galveston's largest employer.

Oklahoma Natural Gas completed a pipeline project to supply the Stillwater Energy Center with efficient natural gas.

SYSTEM INTEGRITY

A better tomorrow started companywide in 2015 with an enhanced system integrity strategy to make us even more efficient and proactive in ensuring safe and reliable natural gas service.

Our System Integrity department is benefiting from leadership focused on more efficient and effective processes. Implementation of enterprise-wide technology has enabled us to evaluate assets and projects using a consistent risk management framework – a game changer for the way we plan for work and capital expenditures.

In 2015, we were able to:

- Create clear visibility within our organizational structure by merging asset management and engineering to form a new System Integrity department;
- Verify alignment of asset management processes and integrity management programs;
- Focus on an enterprise-wide, risk-based approach to asset replacement; and
- Continue to improve asset records and long-term plans for system integrity improvements.

Employees near Sapulpa, Okla. insert a "pig" as part of procedures to inspect a pipeline. Pigs are used to perform various maintenance tasks and inspections on certain pipelines.

ONE Gas drivers log more than 30 million miles annually, so defensive driving is a must.

10% percent reduction from the previous year in the Total Recordable Injury Rate.

8,800 peer-to-peer observations through our Behavior-Based Safety program.

7% reduction in the Preventable Vehicle Incident Rate.

52% reduction in sprain and strain injuries.

COMMITMENT TO ZERO

Even a single accident is one too many.

Our "Zero Is Possible" perspective guides us when it comes to safety. Zero injuries and incidents is our target each and every day.

To work toward this goal in 2015, we continued to focus on three particular safety initiatives that brought meaningful results: *Employees achieved a 10 percent reduction from the previous year in the Total Recordable Injury Rate AND a 7 percent reduction in the Preventable Vehicle Incident Rate.*

1. Since incorporating **MoveSMART®** into their day-to-day work three years ago, employees have achieved an overall reduction of 52 percent in sprain and strain injuries.

- By learning this method of body mechanics and body positioning, employees can achieve maximum strength and balance to avoid injury.

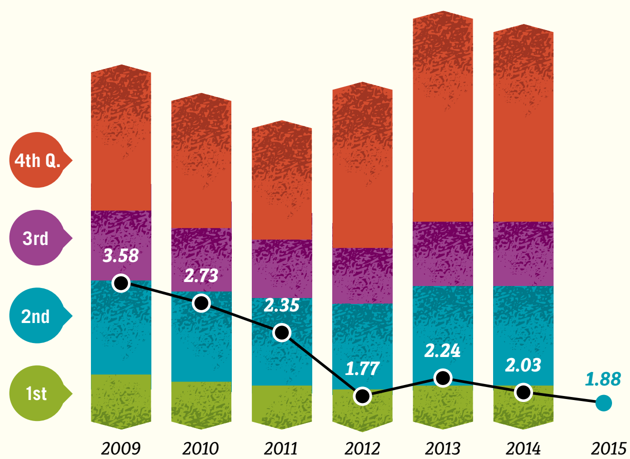
2. In 2015, employees performed more than 8,800 peer-to-peer observations through our **Behavior-Based Safety** program.

- Trained employees voluntarily go to field locations to observe other employees performing their job duties. The result is constructive feedback on how employees were working safely or how they may have been putting themselves or others at risk.
- The observers and the observed discuss ways to replace at-risk behavior with safe behavior.

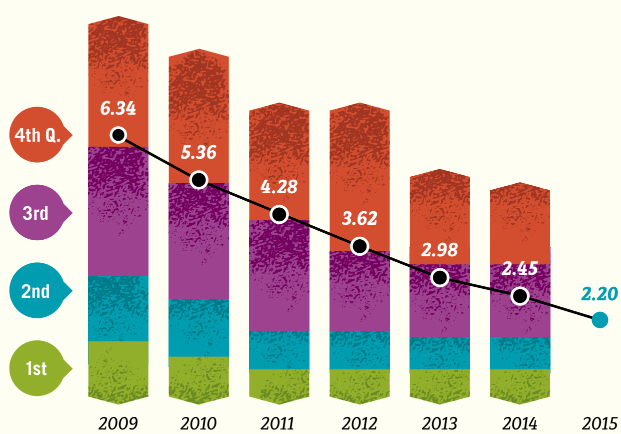
3. Implementation of the **Smith System®** driving program has been instrumental in reducing motor vehicle accidents companywide.

- The Smith System is one of the best established and most widely used defensive driving programs for fleet operations.
- It keeps drivers engaged in their surroundings and focused on the task at hand, which is safe driving.

Preventable Vehicle Incident Rate (PVIR) was 1.88 incidents per million miles driven.
American Gas Association PVIR Quartile Data



Total Recordable Incident Rate (TRIR) was 2.20 incidents per 200,000 work hours.
American Gas Association TRIR Quartile Data



The American Gas Association represents local energy companies that deliver clean natural gas throughout the U.S.

COMMUNITY INVESTMENT

ONE Gas recognizes that our employees, retirees and board of directors support community organizations in the areas where we live, work and operate, which underscores the ONE Gas Foundation's guiding principles:

Optimize Impact

Give Hope

Strengthen Communities

As a company, we believe that better tomorrows require a commitment to making communities better today through charitable giving and volunteerism.

In 2015, through our ONE Gas Foundation, civic and corporate contributions, we invested more than

$2.2 MILLION

in communities where we serve.

47

approved requests for grants by the ONE Gas Foundation.

$40,000

to Habitat for Humanity.

199 Matching Grants awarded totaling more than

$114,000.

2,026 employees, retirees and directors pledged $743,000 to United Way agencies in 2015, all matched dollar for dollar totaling more than

$1.4 MILLION.

26

public school foundation grants.

6,118

Employee Volunteer Hours

Habitat for Humanity • Local Food Banks • Meals on Wheels • Special Olympics • Boys & Girls Club

A CLEANER, MORE EFFICIENT FUEL

A Better Tomorrow for All

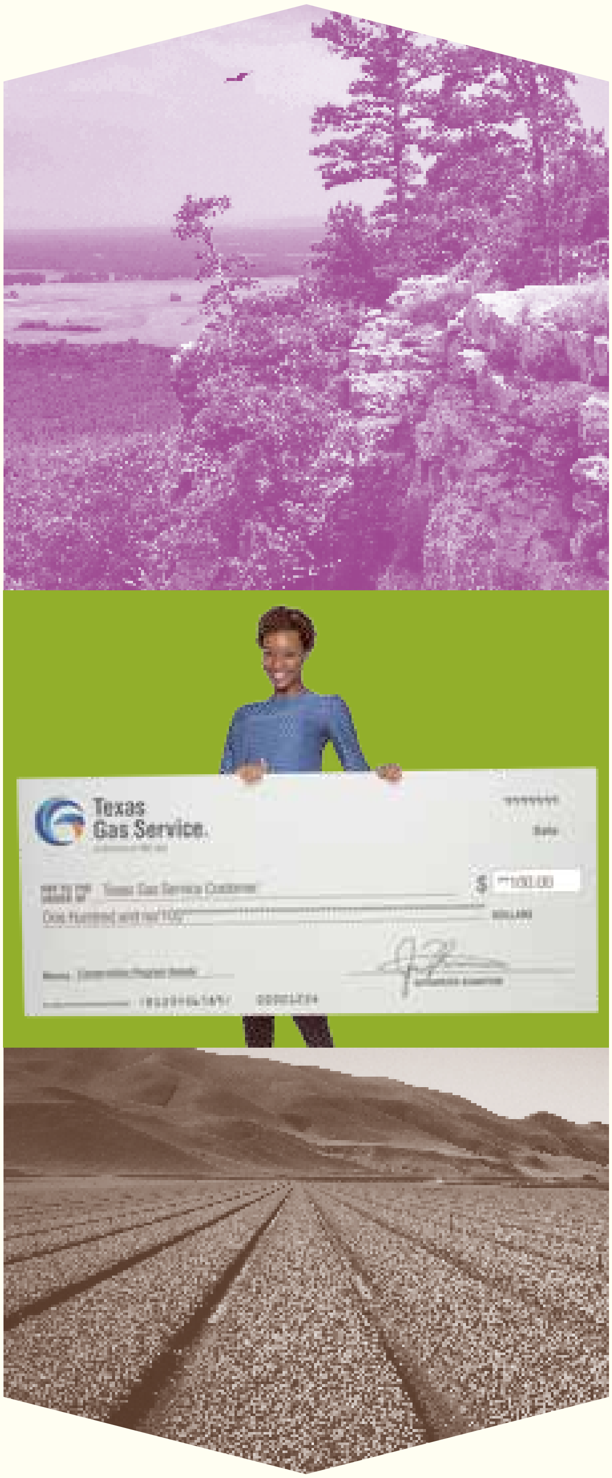
We understand we have a responsibility to all of our stakeholders to operate safely, efficiently and environmentally responsibly. We plan to meet this expectation by focusing on our mission while keeping our values intact.

According to the American Gas Association, a study published in *Environmental Science & Technology* led by a team from Washington State University found that emission estimates from local natural gas distribution systems in cities and towns throughout the U.S. have decreased in the past 20 years to levels 36 to 70 percent lower than the 2011 U.S. Environmental Protection Agency inventory.

The study concludes that as little as 0.1 percent of the natural gas delivered nationwide is emitted from local distribution systems.

ONE Gas is committed to operating in an environmentally responsible manner. We are accountable for providing services that are aligned with efforts to reduce emissions.

In 2015, we retired or replaced approximately 425 miles of distribution and transmission facilities, which will result in decreased emissions of methane.



Commitment to the Methane Challenge Program

In 2015, ONE Gas actively participated in the development of the U.S. Environmental Protection Agency (EPA) Natural Gas STAR Methane Challenge Program to voluntarily reduce greenhouse gas emissions.

The program is a flexible, voluntary partnership with natural gas companies and the EPA to promote and track the reduction of methane emissions beyond what is federally required.

The program requires a signed commitment to reduce emissions through a Best Management Practice Commitment, a companywide implementation of best practices focused on reducing emissions from key sources.

Energy Efficiency

In 2015, our Energy Efficiency Program in Oklahoma and the Austin Conservation Program in Texas issued more than 67,800 rebates combined – totaling approximately $11.15 million in energy-efficiency customer rebates on natural gas appliances and energy-efficient home improvements.

Wildlife and Endangered Species Preservation

We are committed to working to resolve any potential issues with endangered species, migratory birds, cultural or historical assets and government agency permitting requirements. We not only follow the regulations but also work with our subcontractors and consultants to do the same.

BOARD OF DIRECTORS

From left to right:

Douglas H. Yaeger
Retired Chairman, President and Chief Executive Officer, Laclede Gas Company

John W. Gibson
Chairman, ONE Gas, Inc.

Eduardo A. Rodriguez
President, Strategic Communications Consulting Group

Robert B. Evans
Retired President and Chief Executive Officer, Duke Energy Americas

Pattye L. Moore
Chairman, Red Robin Gourmet Burgers

Pierce H. Norton II
President and Chief Executive Officer, ONE Gas, Inc.

Michael G. Hutchinson
Retired Partner, Deloitte & Touche

EXECUTIVE TEAM

Pierce H. Norton II, 56
President and Chief Executive Officer

Curtis L. Dinan, 48
Senior Vice President, Chief Financial Officer and Treasurer

Joseph L. McCormick, 56
Senior Vice President, General Counsel and Assistant Secretary

Caron A. Lawhorn, 55
Senior Vice President, Commercial

Robert S. McAnnally, 52
Senior Vice President, Operations

Mark A. Bender, 51
Senior Vice President, Administration, Chief Information Officer

Andrew J. Ziola, 46
Vice President, Investor Relations and Public Affairs

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, D.C. 20549

FORM 10-K

X ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the fiscal year ended December 31, 2015.
OR
__ TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the transition period from __________ to __________.

Commission file number 001-36108

ONE Gas, Inc.

(Exact name of registrant as specified in its charter)

Oklahoma	**46-3561936**
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)
15 East Fifth Street, Tulsa, OK	**74103**
(Address of principal executive offices)	(Zip Code)

Registrant's telephone number, including area code (918) 947-7000

Securities registered pursuant to Section 12(b) of the Act:

Common stock, par value of $0.01	**New York Stock Exchange**
(Title of each class)	(Name of each exchange on which registered)

Securities registered pursuant to Section 12(g) of the Act: None

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes X No__

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act. Yes __ No X

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes X No __

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate website, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§ 232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes X No _

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Registration S-K (§229.405 of this chapter) is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. X

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See the definitions of "large accelerated filer," "accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act. (Check one) Large accelerated filer X Accelerated filer __ Non-accelerated filer __ Smaller reporting company __

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Act). Yes__ No X

The aggregate market value of the equity securities held by nonaffiliates based on the closing trade price of the registrant on June 30, 2015, was $2.1 billion.

On February 5, 2016, we had 52,292,154 shares of common stock outstanding.

DOCUMENTS INCORPORATED BY REFERENCE:

Portions of the definitive proxy statement to be delivered to shareholders in connection with the Annual Meeting of Shareholders to be held May 26, 2016, are incorporated by reference in Part III.

ONE Gas, Inc.
2015 ANNUAL REPORT

As used in this Annual Report, references to "we," "our," "us" or the "company" refer to ONE Gas, Inc., an Oklahoma corporation, and its predecessors and subsidiary, unless the context indicates otherwise.

GLOSSARY

The abbreviations, acronyms and industry terminology used in this Annual Report are defined as follows:

ACA	Annual Cost Adjustment
AFUDC	Allowance for funds used during construction
Annual Report	Annual Report on Form 10-K for the year ended December 31, 2015
ATSR	Ad Valorem Tax Surcharge Rider
Bcf	Billion cubic feet
Bcf/d	Billion cubic feet per day
CERCLA	Federal Comprehensive Environmental Response, Compensation and Liability Act of 1980, as amended
CFTC	Commodities Futures Trading Commission
Clean Air Act	Federal Clean Air Act, as amended
Clean Water Act	Federal Water Pollution Control Amendments of 1972, as amended
Code	Internal Revenue Code of 1986, as amended
COG	Cost of gas
COGR	Cost of gas rider
COSA	Cost-of-Service Adjustment
DOT	United States Department of Transportation
Dth	Dekatherm
EPA	United States Environmental Protection Agency
EPARR	El Paso Annual Rate Review
EPS	Earnings per share
EPSA	El Paso Service Area
Exchange Act	Securities Exchange Act of 1934, as amended
FERC	Federal Energy Regulatory Commission
GAAP	Accounting principles generally accepted in the United States of America
GRIP	Texas Gas Reliability Infrastructure Program
GSRS	Gas System Reliability Surcharge
Heating Degree Day or HDD	A measure designed to reflect the demand for energy needed for heating based on the extent to which the daily average temperature falls below a reference temperature for which no heating is required, usually 65 degrees Fahrenheit
IFRS	International Financial Reporting Standards
IRS	U.S. Internal Revenue Service
IRS Ruling	Private Letter Ruling from IRS
KCC	Kansas Corporation Commission
KDHE	Kansas Department of Health and Environment
LDCs	Local distribution companies
LIBOR	London Interbank Offered Rate
Moody's	Moody's Investors Service, Inc.
MMcf	Million cubic feet
NYSE	New York Stock Exchange
OCC	Oklahoma Corporation Commission
ONE Gas	ONE Gas, Inc.
ONE Gas Credit Agreement	ONE Gas' $700 million revolving credit agreement, which expires in January 2019
ONE Gas Predecessor	ONE Gas' predecessor for accounting purposes that consists of the business attributable to ONEOK's natural gas distribution segment that was transferred to ONE Gas in connection with its separation from ONEOK
ONEOK	ONEOK, Inc. and its subsidiaries
ONEOK Partners	ONEOK Partners, L.P. and its subsidiaries
OSHA	Occupational Safety and Health Administration
PBRC	Performance-Based Rate Change
PGA	Purchased Gas Adjustment

PHMSA	United States Department of Transportation Pipeline and Hazardous Materials Safety Administration
Pipeline Safety Improvement Act	Pipeline Safety Improvement Act of 2002, as amended
Pipeline Safety, Regulatory Certainty and Job Creation Act	Pipeline Safety, Regulatory Certainty and Job Creation Act of 2011, as amended
ROE	Return on equity calculated consistent with utility ratemaking principles in each jurisdiction in which we operate
RRC	Railroad Commission of Texas
S&P	Standard and Poor's Rating Services
SEC	Securities and Exchange Commission
Securities Act	Securities Act of 1933, as amended
Separation and Distribution Agreement	Separation and Distribution Agreement dated January 14, 2014, between ONEOK and ONE Gas
TAC	Temperature Adjustment Clause
Tax Matters Agreement	Tax Matters Agreement dated January 14, 2014, between ONEOK and ONE Gas
Transition Services Agreement	Transition Services Agreement dated January 14, 2014, between ONEOK and ONE Gas
WNA	Weather normalization adjustments
XBRL	eXtensible Business Reporting Language

The statements in this Annual Report that are not historical information, including statements concerning plans and objectives of management for future operations, economic performance or related assumptions, are forward-looking statements. Forward-looking statements may include words such as "anticipate," "estimate," "expect," "project," "intend," "plan," "believe," "should," "goal," "forecast," "guidance," "could," "may," "continue," "might," "potential," "scheduled" and other words and terms of similar meaning. Although we believe that our expectations regarding future events are based on reasonable assumptions, we can give no assurance that such expectations and assumptions will be achieved. Important factors that could cause actual results to differ materially from those in the forward-looking statements are described under Part I, Item 1A, "Risk Factors," and Part II, Item 7, Management's Discussion and Analysis of Financial Condition and Results of Operation and "Forward-Looking Statements," in this Annual Report.

PART I

ITEM 1. BUSINESS

SEPARATION FROM ONEOK, INC.

On January 8, 2014, ONEOK's board of directors approved the distribution of all the shares of our common stock to holders of ONEOK common stock.

In order for ONEOK to effect the distribution, we requested, and the SEC declared effective, our Registration Statement on Form 10 on January 10, 2014. ONEOK transferred all of the assets and liabilities primarily related to its natural gas distribution business to us. Assets and liabilities included accounts receivable and payable, natural gas in storage, regulatory assets and liabilities, pipeline and other natural gas distribution facilities, customer deposits, employee-related assets and liabilities, including amounts attributable to pension and other postemployment benefits, tax-related assets and liabilities and other assets and liabilities primarily associated with providing natural gas distribution service in Oklahoma, Kansas and Texas. Cash and certain corporate assets, such as office space in the corporate headquarters and certain IT hardware and software, were not transferred to us; however, the Transition Services Agreement between ONEOK and us provided temporary access to such corporate assets as necessary to operate our business prior to obtaining applicable corporate assets on our own.

Immediately prior to the contribution of the natural gas distribution business to us, ONEOK contributed to the capital of the natural gas distribution business all of the amounts outstanding on the natural gas distribution business's short-term note payable to and long-term line of credit with ONEOK. We received approximately $1.19 billion of cash from a private placement of senior notes (which were later exchanged for registered notes), then used a portion of those proceeds to fund a cash payment of approximately $1.13 billion to ONEOK. On January 31, 2014, ONEOK distributed one share of our common stock for every four shares of ONEOK common stock held by ONEOK shareholders of record as of the close of business on January 21, 2014, the record date of the distribution. At the close of business on January 31, 2014, ONE Gas became an independent, publicly traded company as a result of the distribution. Our common stock began trading "regular-way" under the ticker symbol "OGS" on the NYSE on February 3, 2014. ONEOK did not retain any ownership interest in our company.

OUR BUSINESS

We are an independent, publicly traded, 100 percent regulated natural gas distribution utility. We are one of the largest natural gas utilities in the United States. We are an Oklahoma corporation and are the successor to the company founded in 1906 as Oklahoma Natural Gas Company. We are the largest natural gas distributor in Oklahoma and Kansas and the third largest in Texas, providing service as a regulated public utility. We serve residential, commercial and industrial, transportation and wholesale and public authority customers in all three states. Our largest natural gas distribution markets in terms of customers are Oklahoma City and Tulsa, Oklahoma; Kansas City, Wichita and Topeka, Kansas; and Austin and El Paso, Texas. Our three divisions, Oklahoma Natural Gas, Kansas Gas Service and Texas Gas Service, distribute natural gas as public utilities to approximately 88 percent, 72 percent and 14 percent of the natural gas distribution customers in Oklahoma, Kansas and Texas, respectively.

Prior to our separation from ONEOK, our financial statements were derived from ONEOK's financial statements, which included its natural gas distribution business as if we, for accounting purposes, had been a separate company for all periods presented. The assets and liabilities in the financial statements have been reflected on a historical basis. The financial statements for periods prior to the separation also include expense allocations for certain corporate functions historically performed by ONEOK, including allocations of general corporate expenses related to executive oversight, accounting, treasury, tax, legal, information technology and other services. We believe our assumptions underlying the financial statements, including the assumptions regarding the allocation of general corporate expenses from ONEOK, are reasonable. However, the financial statements may not include all of the actual expenses that would have been incurred by us and may not reflect our results of operations, financial position and cash flows had we been a separate publicly traded company during the periods presented prior to the separation.

OUR STRATEGY

Our business strategy is focused on operating our systems in a safe, reliable and environmentally responsible manner, growing our business strategically, while delivering quality customer service to our customers. Over time, we believe this will enable us to generate a competitive total return for our shareholders and maintain our financial stability, leading to our strategic goals of zero harm and a fair return. We intend to accomplish our objectives by executing on the strategies listed below:

- <u>Focus on Safety, Reliability and Compliance</u> - We are committed to pursuing a zero-incident safety and compliance culture through programs, procedures, policies, guidelines and other internal controls designed to mitigate risk and incidents that may harm our employees, contractors, customers, the public or the environment. In addition, a significant portion of our capital spending is focused on the safety, reliability and efficiency of our natural gas distribution system. We are committed to compliance with all federal, state and local laws and regulations.

- <u>High-performing Workforce</u> - The foundation of our company consists of our employees. We are committed to attracting, retaining and developing a high-performing workforce where every employee understands that they can and do make a difference. We embrace and promote inclusion, diversity and collaboration. We expect a high standard of performance from our employees. We encourage our workforce to measure their productivity and be accountable for the best work possible. Each day that we do our best to safely and efficiently meet the needs of our customers is a day that leads to individual success and, ultimately, the success of the company.

- <u>Increase Our Achieved ROE</u> - We continually seek to improve our achieved ROE through improved operational performance and regulatory mechanisms. The difference between our achieved and allowed ROE is related primarily to regulatory lag. We make investments that increase our rate base and we incur increases in our costs that are above the amounts reflected in the rates we charge for our service.

  We have several initiatives underway to improve our operational performance. These initiatives include leveraging and implementing technology that is expected to result in increased efficiency, thereby helping reduce the rate of increase in operating expenses.

  Our focus on our credit metrics and maintaining a balanced approach to capital management are significant objectives in providing reasonable rates to customers while also providing a fair return to shareholders. We believe that maintaining an investment-grade credit rating is prudent for our business as we seek to access the capital markets to finance capital investments. As a 100 percent regulated utility, we intend to maintain strong credit metrics while we pursue a balanced approach to capital investment and a return of capital to shareholders via a dividend that we believe will be competitive with our peer group.

- <u>Advocate Constructive Relationships with Key Stakeholders</u> - We plan to continue our constructive, transparent relationships with our key stakeholders, which include our customers, employees, investors and regulators. Our strategy includes seeking outcomes in future rate proceedings that provide a fair return on our infrastructure investments, while also meeting the needs of our customers through safe, reliable and efficient service.

- <u>Identify and Pursue Growth Opportunities</u> - Our growth opportunities are a result of capital investments related to safety and reliability of our existing system, and system growth related to the economic and population growth in our service territories. As a result of our commitment to enhance the integrity, reliability and safety of our existing infrastructure, we are making significant investments in our existing system, which we expect to further grow our rate base. In addition, as our service territories continue to experience economic growth, we expect to grow our rate base through capital investments in new service lines and main line extensions, predominately in the major metropolitan areas.

  We believe that the competitiveness of natural gas is increasing, creating new market opportunities for natural gas as an energy source within our existing service territories.

  We remain committed to maintaining our status as a 100 percent regulated company, but will evaluate strategic acquisition opportunities that fall within that guideline based on our disciplined financial and operating approach, while weighing these alternatives against future investment opportunities with respect to our existing rate base.

REGULATORY OVERVIEW

We are subject to the regulations and oversight of the state and local regulatory authorities of the territories in which we operate. Rates and charges for natural gas distribution services are established by the OCC for Oklahoma Natural Gas and by the KCC for Kansas Gas Service. Texas Gas Service is subject to regulatory oversight by the various municipalities that it serves, which have primary jurisdiction in their respective areas. Rates in unincorporated areas of Texas and all appellate matters are subject to regulatory oversight by the RRC. These regulatory authorities have the responsibility of ensuring that the utilities in their jurisdictions provide safe and reliable service at a reasonable cost, while providing utility companies the opportunity to earn a fair and reasonable return on their investments.

Generally, our rates and charges are established in rate case proceedings. Regulatory authorities may also approve mechanisms that allow for adjustments for specific costs or investments made between rate cases. Due to the nature of the regulatory process, there is an inherent lag between the time that we make investments or incur additional costs and the setting of new rates and/or charges to recover those investments or costs. Additionally, we are not allowed recovery of certain costs we incur. The delay between the time investments are made or increases in costs are incurred and the time that our rates are adjusted to reflect these investments and costs is referred to as regulatory lag.

The following provides additional detail on the regulatory mechanisms in the jurisdictions we serve.

Oklahoma - Oklahoma Natural Gas currently operates under a PBRC mechanism, which provides for streamlined annual rate reviews between rate cases and includes adjustments for incremental capital investment and allowed expenses. Under this mechanism, we have an allowed ROE of between 9 percent and 10 percent. If our achieved ROE is below 9 percent, our base rates are increased upon OCC approval to an amount necessary to restore the ROE to 9.5 percent. If our achieved ROE exceeds 10 percent, the portion of the earnings above 10 percent is shared with our customers, who receive the benefit of 75 percent of the earnings above 10 percent. We receive the benefit of the remaining 25 percent. Oklahoma Natural Gas is required to file a rate case on or before June 20, 2021, based on a test year consisting of the twelve months ending December 31, 2020. Other regulatory mechanisms in Oklahoma include the following:

- PGA Clause - Oklahoma Natural Gas' commodity, transportation, storage and gas purchase operations and maintenance costs are passed through to its sales customers without markup via the PGA. Any costs associated with natural gas that is lost, used or unaccounted for in operations and the fuel-related portion of bad debts are also recovered through the PGA.
- TAC - The TAC is designed to reduce the delivery charge component of customers' bills for the additional volumes used when the actual heating degree days exceed the normalized heating degree days and to increase the delivery charge component of customers' bills for volumes not used when actual heating degree days are less than the normal heating degree days. The TAC is in effect from November through April.
- Energy Efficiency Programs - Oklahoma Natural Gas has an Energy-Efficiency Program, available to all of its sales customers. The costs associated with these programs and an incentive to offer these programs are recovered through a monthly surcharge on customer bills. Oklahoma Natural Gas collects approximately $11.5 million each year from sales customers to fund the program, which provides appliance rebates, education and heating system check-ups to promote energy efficiency.
- Rate Design for Residential Customers - Oklahoma Natural Gas is authorized to utilize a rate structure with two choices. Rate Choice "A" is designed for customers whose annual normalized volume is less than 50 Dth. The tariff for these customers contains both a fixed monthly service charge and a per Dth delivery fee. Although a portion of the net margin for customers in Rate Choice "A" is dependent on usage, these customers use relatively small quantities of natural gas and therefore the net margin that is dependent on usage is not significant. The fixed monthly residential customer charge for Oklahoma Natural Gas is $16.43, with a delivery fee of $4.1143 per Dth for Rate Choice "A" customers. Rate Choice "B" is designed for customers whose annual normalized volume is 50 Dth or greater. The tariff for these customers contains only a fixed monthly service charge of $33.57. At December 31, 2015, 71 percent of Oklahoma Natural Gas' residential customers are on Rate Choice "B."
- Rate Design for Commercial and Industrial Customers - Oklahoma Natural Gas is authorized to utilize a rate structure with two different rate choices for its Small Commercial and Industrial, or SCI, customers. Rate Choice "A" is designed for SCI customers whose annual normalized volume is less than 40 Dth. The tariff for these customers contains both a fixed monthly service charge of $20.55 and a delivery fee of $4.5599 per Dth. Rate Choice "B" is designed for SCI customers whose annual normalized volume is 40 Dth or greater but less than 150 Dth. The tariff for these customers contains only a fixed monthly service charge of $35.75. All of Oklahoma Natural Gas' Large Commercial and Industrial, or LCI, customers, whose annual volume is 150 Dth or greater, but less than 5,000 Dth, are on a fixed monthly service charge of $93.22. At December 31, 2015, 75 percent of Oklahoma Natural Gas' commercial and industrial customers are on either SCI Rate Choice "B" or LCI.

- Compressed Natural Gas Rebate Program - The CNG Rebate Program is designed to promote and support the CNG market in the state of Oklahoma by offering rebates to Oklahoma residents who purchase dedicated and bi-fueled natural gas vehicles or install residential CNG fueling stations. The rebates are funded by a $0.25 per gasoline gallon equivalent surcharge that Oklahoma Natural Gas is authorized to collect on fuel purchased from a CNG dispenser owned by Oklahoma Natural Gas. Collections from the surcharge to fund the program were not material in 2015.

For the year ended December 31, 2015, approximately 87 percent of Oklahoma Natural Gas' net margin from its sales customers was recovered from fixed charges.

Kansas - Kansas Gas Service operates under a traditional regulatory framework, whereby periodic rate cases are filed with the KCC as needed to increase base rates to give Kansas Gas Service the opportunity to earn its authorized ROE. Other regulatory mechanisms in Kansas include the following:

- COGR and ACA - These mechanisms allow Kansas Gas Service to recover the actual cost of the natural gas it sells to its customers. The COGR includes a monthly estimate of the cost Kansas Gas Service incurs in transporting, storing and purchasing natural gas supply for its sales customers, the ACA and other charges and credits. The ACA is an annual component of the COGR that compares the cost of gas recovered through the COGR for the preceding year with the actual natural gas supply costs and the fuel-related portion of bad debts for the same period. Any over- or under-recovery is reflected in the subsequent year's COGR.
- WNA Clause - This mechanism allows Kansas Gas Service to accrue the variation in net margin due to abnormal weather occurring from November through March. WNA is designed to reduce the delivery charge component of customers' bills for the additional volumes used when the actual heating degree days exceed the normalized heating degree days and to increase the delivery charge component of customers' bills for the reduction in volumes used when actual heating degrees days are less than the normal heating degree days. Once a year, the amount of the adjustment is determined and is then applied to customers' bills over the subsequent 12-month period.
- ATSR - This rider allows Kansas Gas Service to recover the difference each year between the property tax costs included in its base rates and its actual property tax costs incurred without having to file a rate case. The amount of the adjustment is determined annually and recovered over the subsequent 12 months as a change in the delivery-charge component of customers' bills.
- Pension and Other Postemployment Benefits Trackers - These trackers allow Kansas Gas Service to track and defer for recovery in its next rate case the difference between the pension and other postemployment benefit costs included in base rates and actual expense as determined in accordance with GAAP.
- GSRS - This surcharge allows Kansas Gas Service to file for a rate adjustment providing a recovery of and return on qualifying infrastructure investments, such as expenditures necessary to meet state and federal pipeline safety requirements and government-required relocation projects incurred, each year between rate case filings. However, rate adjustment filings cannot increase a monthly charge more than $0.40 per residential customer over the most recent GSRS filing. After five annual filings, Kansas Gas Service is required to file a rate case or cease collection of the surcharge.

The fixed monthly residential customer charge for Kansas Gas Service is $15.35. For the year ended December 31, 2015, approximately 55 percent of Kansas Gas Service's net margin from its sales customers was recovered from fixed charges. Kansas experiences the highest heating degree days of all of our service territories, which brings a level of stability to net margin even though a significant portion is based on usage.

Texas - Texas Gas Service has grouped its customers into 10 service areas. These service areas are further divided into the incorporated cities and the unincorporated areas, referred to as the environs. The incorporated cities in the service areas have original jurisdiction, with the RRC having appellate authority, and the RRC has original jurisdiction for the environs. Periodic rate cases are filed with the cities or the RRC, as needed, to give Texas Gas Service the opportunity to earn its authorized ROE. Other regulatory mechanisms and constructs in Texas include the following:

- GRIP Statute - For the incorporated cities in three service areas and the environs for four service areas, comprising 44 percent of Texas Gas Service's customers, Texas Gas Service makes an annual filing under the GRIP statute, which allows it to recover taxes and depreciation and to earn a return on the annual net increase in investment for the service area. After five annual GRIP filings, Texas Gas Service is required to file a full rate case. A full rate case may be filed at shorter intervals if desired by either Texas Gas Service or the regulator.
- COSA Filings - In six service areas, comprising 17 percent of its customers, Texas Gas Service makes an annual COSA filing for the incorporated cities. COSA tariffs permit Texas Gas Service to recover return, taxes and depreciation on the annual increases in net investment, as well as annual increases or decreases in certain expenses and

revenues. Five of the COSAs have a cap of 3.5 percent to 5 percent on all or a portion of the increase. A full rate case may be filed when desired by Texas Gas Service or the regulator, but is not required.

- EPARR Filings - In the EPSA, comprising 35 percent of its customers, Texas Gas Service makes an annual rate review filing for the incorporated cities. The annual rate review tariff permits Texas Gas Service to recover return, taxes and depreciation on the annual increases in net investment, as well as annual increases or decreases in certain expenses and revenues. There is no cap on the amount of the increase, but the request is subject to review and possible adjustment by the regulator. Upon notice, a full rate case may be filed by Texas Gas Service or the regulator, but is not required. In November 2015, Texas Gas Service notified the cities in the EPSA that it would be filing a full rate case in 2016.
- WNA Clause - Texas Gas Service employs WNA clauses in eight of its service areas, comprising 62 percent of its customers. In one of the service areas without WNA, which comprises 38 percent of its customers, Texas Gas Service recovers 88 percent of its delivery charge from fixed charges, making revenues in this service area less weather sensitive. WNA is designed to reduce the delivery charge component of customers' bills for the additional volumes used when the actual heating degree days exceed the normalized heating degree days and to increase the margin component of customers' bills for the reduction in volumes used when actual heating degree days are less than the normal heating degree days. The WNA is in effect from September through May.
- COG Clause - In all service areas, Texas Gas Service recovers 100 percent of its gas costs, including interest on natural gas in storage and the natural gas cost component of bad debts, via a COG mechanism, subject to a limitation of 5 percent on lost-and-unaccounted-for natural gas. The COG is reconciled annually to compare the gas costs recovered through the COG with the actual natural gas supply costs. Any over- or under-recovery is refunded or recovered, as applicable, in the subsequent year.
- Pension and Other Postemployment Benefits - Texas Gas Service is authorized by statute to defer pension and other postemployment benefit costs that exceed the amount recovered in base rates, and to seek recovery of the deferred costs in a future rate case.
- Pipeline-Integrity Testing Riders - Texas Gas Service recovers approximately 90 percent of its pipeline-integrity testing expenses via riders, COSAs and the EPARR filing, with the remainder included in base rates.
- Safety-Related Plant Replacements - Texas Gas Service is authorized by RRC rule to defer interest cost, taxes and depreciation expense on safety-related plant replacements from the time the replacements are in service until the plant is reflected in base rates, and to seek recovery of those accrued amounts in a future rate proceeding.
- Energy Conservation Program - Texas Gas Service has an Energy Conservation Program in its Central Texas service area, comprising 34 percent of total customers. Texas Gas Service collects approximately $3 million per year from customers to fund the program, which provides energy audits, weatherization and appliance rebates to promote energy conservation.

The average fixed monthly residential customer charge for Texas Gas Service is $15.41, and for the year ended December 31, 2015, approximately 72 percent of Texas Gas Service's net margin from its sales customers was recovered from fixed charges.

MARKET CONDITIONS AND SEASONALITY

Supply - We purchased 157 Bcf and 180 Bcf of natural gas supply in 2015 and 2014, respectively. The decrease in 2015 resulted primarily from lower supply requirements due to warmer temperatures as compared with 2014. Our natural gas supply portfolio consists of long-term, seasonal and short-term contracts from a diverse group of suppliers. We award these contracts through competitive-bidding processes to ensure reliable and competitively priced natural gas supply. We acquire our natural gas supply from natural gas processors, marketers and producers.

An objective of our supply-sourcing strategy is to provide value to our customers through reliable, competitively priced and flexible natural gas supply and transportation from multiple production areas and suppliers. This strategy is designed to mitigate the impact on our supply from physical interruption, financial difficulties of a single supplier, natural disasters and other unforeseen force majeure events, as well as to ensure these resources are reliable and flexible to meet the variations of customer demands.

We do not anticipate problems with securing natural gas supply to satisfy customer demand; however, if supply shortages were to occur, we have curtailment tariff provisions in place that allow us to reduce or discontinue natural gas service to large industrial users and to request that residential and commercial customers reduce their natural gas requirements to an amount essential for public health and safety. In addition, during times of critical supply disruptions, curtailments of deliveries to customers with firm contracts may be made in accordance with guidelines established by appropriate federal, state and local regulatory agencies.

Natural gas supply requirements are affected by weather conditions. In addition, economic conditions impact the requirements of our commercial and industrial customers. Natural gas usage per residential customer may decline as customers change their consumption patterns in response to a variety of factors, including:

- more volatile and higher natural gas prices;
- customers' improving the energy efficiency of existing homes by replacing doors and windows, adding insulation, and replacing appliances with more efficient appliances;
- more energy-efficient construction; and
- fuel switching from natural gas to electricity.

In each jurisdiction in which we operate, changes in customer-usage profiles are considered in the periodic redesign of our rates.

As of December 31, 2015, we had 50.4 Bcf of natural gas storage capacity under lease with remaining terms ranging from one to ten years and maximum allowable daily withdrawal capacity of approximately 1.3 Bcf. This storage capacity allows us to purchase natural gas during the off-peak season and store it for use in the winter periods. This storage is also needed to assure the reliability of gas deliveries during peak demands for natural gas. Approximately 25 percent of our winter natural gas supply needs for our sales customers is expected to be supplied from storage.

In managing our natural gas supply portfolios, we partially mitigate price volatility using a combination of financial derivatives and natural gas in storage. We have natural gas financial hedging programs that have been authorized by the regulatory authorities in each state in which we do business. We do not utilize financial derivatives for speculative purposes, nor do we have trading operations associated with our business.

Demand - See discussion below under "Seasonality," "Competition" and "Compressed Natural Gas" for factors affecting demand for our services.

Seasonality - Natural gas sales to residential and commercial customers are seasonal, as a substantial portion of their natural gas requirements are for heating. Accordingly, the volume of natural gas sales is higher normally during the months of November through March than in other months of the year. The impact on our margins resulting from weather temperatures that are above or below normal is offset partially through our TAC and WNA mechanisms. See discussion above under "Regulatory Overview."

Competition - We encounter competition based on customers' preference for natural gas, compared with other energy alternatives and their comparative prices. We compete to supply energy for space and water heating, cooking, clothes drying and other general energy needs. Significant energy usage competition occurs between natural gas and electricity in the residential and small commercial markets. Customers and builders typically make the decision on the type of equipment, and therefore the energy source, at initial installation, generally locking in the chosen energy source for the life of the equipment. Changes in the competitive position of natural gas relative to electricity and other energy alternatives have the potential to cause a decline in consumption of natural gas or in the number of natural gas customers.

The Department of Energy issued a statement of policy that it will use full fuel-cycle measures of energy use and emissions when evaluating energy-conservation standards for appliances. In addition, the EPA has determined that source energy is the most equitable unit for evaluating energy consumption. Assessing energy efficiency in terms of a full fuel-cycle or source-energy analysis, which takes all energy use into account, including transmission, delivery and production losses, in addition to energy consumed at the site, highlights the high overall efficiency of natural gas in residential and commercial uses compared with electricity.

The below table contains data related to the cost of our delivered gas relative to electricity based on current market conditions:

Natural Gas vs. Electricity	Oklahoma	Kansas	Texas
Average retail price of electricity / kWh(1)	10.09¢	12.31¢	11.67¢
Natural gas price equivalent of electricity / Dth(1)	$ 29.57	$ 36.08	$ 34.20
ONE Gas delivered cost of natural gas / Dth(2)	$ 9.29	$ 9.98	$ 10.39
Natural gas advantage ratio(3)	3.2x	3.6x	3.3x

(1) Source: United States Energy Information Agency, www.eia.gov, for the eleven-month period ended November 30, 2015.
(2) Represents the average delivered cost of natural gas to a residential customer, including the cost of the natural gas supplied, fixed customer charge, delivery charges and charges for riders, surcharges and other regulatory mechanisms associated with the services we provide, for the year ended December 31, 2015.
(3) Calculated as the ratio of the natural gas price equivalent per dekatherm of the average retail price of electricity per kilowatt hour to the ONE Gas delivered average cost of natural gas per dekatherm.

We are subject to competition from other pipelines for our large industrial and commercial customers, and this competition has and may continue to impact margins. Under our transportation tariffs, qualifying industrial and commercial customers are able to purchase their natural gas needs from the supplier of their choice and have us transport it for a fee. A portion of the transportation services that we provide are at negotiated rates that are below the maximum approved transportation tariff rates. Reduced-rate transportation service may be negotiated when a competitive pipeline is in close proximity or another viable energy option is available to the customer. Increased competition could potentially lower these rates.

Compressed Natural Gas (CNG) - In meeting increased interest in CNG for motor vehicle transportation, particularly from fleet operators, we have been developing an incremental source of transportation revenue by supplying natural gas to CNG fueling stations. The benefits of these programs are increased natural gas load, which could help mitigate future residential rate increases, enhanced competitive position and increased customer satisfaction. As of December 31, 2015, we supply 129 fueling stations, 30 of which we operate. Of the 99 remaining stations, we provide supply to 56 retail and 43 private CNG stations. We transported 2.3 million Dth to CNG stations in 2015, which represents an increase of 14 percent compared with 2014.

We will continue to support industry efforts to encourage development of more vehicle options by car and truck manufacturers, to support third-party investment in CNG fueling stations and to continue tax incentives for CNG. We continue to deploy a minimum amount of capital to connect CNG stations and allow the free market to build and operate the stations.

ENVIRONMENTAL AND SAFETY MATTERS

See Note 14 of the Notes to Financial Statements and Management's Discussion and Analysis of Financial Condition and Results of Operations in this Annual Report for information regarding environmental and safety matters.

EMPLOYEES

We employed approximately 3,400 people at January 29, 2016, including approximately 700 people at Kansas Gas Service who are subject to collective bargaining agreements. The following table sets forth our contracts with collective bargaining units at February 1, 2016:

Union	Approximate Employees	Contract Expires
The United Steelworkers	400	October 28, 2016
International Brotherhood of Electrical Workers (IBEW)	300	June 30, 2017

EXECUTIVE OFFICERS OF THE REGISTRANT

All executive officers are elected annually by our Board of Directors and each serves until such person resigns, is removed or is otherwise disqualified to serve or until such officer's successor is duly elected. Our executive officers listed below include the officers who have been designated by our Board of Directors as our Section 16 executive officers.

Name	Age*		Business Experience in Past Five Years
Pierce H. Norton II	55	2014 to present	President, Chief Executive Officer and Director
		2013 to 2014	Executive Vice President, Commercial, ONEOK and ONEOK Partners
		2012	Executive Vice President and Chief Operating Officer, ONEOK and ONEOK Partners
		2011	Chief Operating Officer, ONEOK
		2009 to 2011	President, ONEOK Distribution Companies, ONEOK
Curtis L. Dinan	48	2014 to present	Senior Vice President, Chief Financial Officer and Treasurer
		2011 to 2014	Senior Vice President, Natural Gas, ONEOK Partners
		2007 to 2011	Senior Vice President, Chief Financial Officer and Treasurer, ONEOK and ONEOK Partners
		2007 to 2011	Board of Directors, ONEOK Partners
Joseph L. McCormick	56	2014 to present	Senior Vice President, General Counsel and Assistant Secretary
		2008 to 2014	Vice President and Associate General Counsel, ONEOK and ONEOK Partners
Caron A. Lawhorn	54	2014 to present	Senior Vice President, Commercial
		2013 to 2014	Senior Vice President, Commercial, Natural Gas Distribution, ONEOK
		2011 to 2012	President, ONEOK Distribution Companies, ONEOK
		2009 to 2011	Senior Vice President, Corporate Planning and Development, ONEOK and ONEOK Partners
Robert S. McAnnally	52	2015 to present	Senior Vice President, Operations
		2012 to 2015	Senior Vice President, Marketing and Customer Service, Alabama Gas Corporation, a subsidiary of The Laclede Group, Inc.
		2009 to 2012	Vice President, External Affairs, Energen Corporation
Mark A. Bender	51	2015 to present	Senior Vice President, Administration and Chief Information Officer
		2014 to 2015	Vice President and Chief Information Officer
		2012 to 2014	Vice President of Information Technology Operations, Chesapeake Energy Corporation
		2010 to 2012	Chief Information Officer, Oral Roberts University

* As of January 1, 2016

No family relationship exists between any of the executive officers, nor is there any arrangement or understanding between any executive officer and any other person pursuant to which the officer was selected.

INFORMATION AVAILABLE ON OUR WEBSITE

We make available, free of charge, on our website (www.onegas.com) copies of our Annual Report, Quarterly Reports on Form 10-Q, Current Reports on Form 8-K, amendments to those reports filed or furnished to the SEC pursuant to Section 13(a) or 15

(d) of the Exchange Act and reports of holdings of our securities filed by our officers and directors under Section 16 of the Exchange Act as soon as reasonably practicable after filing such material electronically or otherwise furnishing it to the SEC. Copies of our Code of Business Conduct and Ethics, Corporate Governance Guidelines, Certificate of Incorporation, bylaws and the written charters of our Audit Committee, Executive Compensation Committee, Corporate Governance Committee and Executive Committee are also available on our website, and we will provide copies of these documents upon request. Our website and any contents thereof are not incorporated by reference into this report.

We also make available on our website the Interactive Data Files required to be submitted and posted pursuant to Rule 405 of Regulation S-T.

ITEM 1A. RISK FACTORS

Our investors should consider the following risks that could affect us and our business. Although we have tried to discuss key factors, our investors need to be aware that other risks may prove to be important in the future. New risks may emerge at any time, and we cannot predict such risks or estimate the extent to which they may affect our financial performance. Investors should carefully consider the following discussion of risks and the other information included or incorporated by reference in this Annual Report, including "Forward-Looking Statements," which are included in Item 7, "Management's Discussion and Analysis of Financial Condition and Results of Operations."

RISK FACTORS INHERENT IN OUR BUSINESS

Regulatory actions could impact our ability to earn a reasonable rate of return on our invested capital and to recover fully our operating costs.

In addition to regulation by other governmental authorities, we are subject to regulation by the OCC, KCC, RRC and various municipalities in Texas. These authorities set the rates that we charge our customers for our services. There can be no assurance that we will be able to obtain rate increases or that our authorized rates of return will continue at the current levels. We monitor and compare the rates of return we achieve with our allowed rates of return and initiate general and specific rate proceedings as needed. If a regulatory agency were to prohibit us from setting rates that allow for the timely recovery of our costs and a reasonable return by significantly lowering our allowed return or adversely altering our cost allocation, rate design or other tariff provisions, modifying or eliminating cost trackers, prohibiting recovery of regulatory assets or disallowing portions of our expenses, then our earnings could be impacted adversely. Regulatory proceedings also involve a risk of rate reduction, because once a proceeding has been filed, it is subject to challenge by various interveners.

Further, accounting principles that govern our company permit certain assets that result from the regulatory process to be recorded on our Balance Sheets that could not be recorded under GAAP for nonregulated entities. We consider factors such as rate orders from regulators, previous rate orders for substantially similar costs, written approval from the regulators and analysis of recoverability by internal and external legal counsel to determine the probability of future recovery of these assets. If we determine future recovery is no longer probable, we would be required to write off the regulatory assets at that time, which would also adversely affect our results of operations and cash flows. Regulatory authorities also review whether our natural gas costs are prudent and can adjust the amount of our natural gas costs that we pass through to our customers. If any of our natural gas costs were disallowed, our results of operations and cash flows would also be affected adversely.

In the normal course of business in the regulatory environment, assets are placed in service before regulatory action is taken, such as filing a rate case or for interim recovery under a capital tracking mechanism that could result in an adjustment of our returns. Once we make a regulatory filing, regulatory bodies have the authority to suspend implementation of the new rates while studying the filing. Because of this process, we may suffer the negative financial effects of having placed in service assets that do not initially earn our authorized rate of return or may not be allowed recovery on such expenditures at all.

The profitability of our operations is dependent on our ability to recover timely the costs related to providing natural gas service to our customers. However, we are unable to predict the impact that new regulatory requirements will have on our operating expenses or the level of capital expenditures and we cannot assure you that our regulators will continue to allow recovery of such expenditures in the future. Changes in the regulatory environment applicable to our business could impair our ability to recover costs absorbed historically by our customers, and impact adversely our results of operations, financial condition and cash flows.

We are subject to comprehensive energy regulation by governmental agencies, and the recovery of our costs is dependent on regulatory action.

We are subject to comprehensive regulation by several state and municipal utility regulatory agencies, which significantly influences our operating environment and our ability to recover our costs from utility customers. The utility regulatory authorities in Oklahoma, Kansas and Texas regulate many aspects of our utility operations, including organization, safety, financing, affiliate transactions, customer service and the terms of service to customers, including the rates that we can charge customers. The profitability of our operations is dependent on our ability to pass through costs related to providing natural gas to our customers by filing periodic rate cases. The regulatory environment applicable to our operations could impair our ability to recover costs historically absorbed by our customers.

We are unable to predict the impact that the future regulatory activities of these agencies will have on our operations. Changes in regulations or the imposition of additional regulations could have an adverse impact on our business, financial condition and results of operations. Further, the results of our operations could be impacted adversely if our authorized cost-recovery mechanisms do not function as anticipated.

We are involved in legal or administrative proceedings before various courts and governmental bodies that could adversely affect our financial condition, results of operations and cash flows.

In the normal course of business, we are involved in legal or administrative proceedings before various courts and governmental bodies with respect to general claims, rates, environmental issues, gas cost prudence reviews and other matters. Adverse decisions regarding these matters, to the extent they require us to make payments in excess of amounts provided for in our financial statements, or to the extent they are not covered by insurance, could adversely affect our financial condition, results of operations and cash flows.

Unfavorable economic and market conditions could adversely affect our earnings.

Weakening economic activity in our markets could result in a loss of existing customers, fewer new customers, especially in newly constructed homes and other buildings, or a decline in energy consumption, any of which could adversely affect our revenues or restrict our future growth. It may become more difficult for customers to pay their natural gas bills, leading to slow collections and higher-than-normal levels of accounts receivable, which in turn could increase our financing requirements and bad debt expense. The foregoing could adversely affect our business, financial condition, results of operations and cash flows.

Increases in the wholesale price of natural gas could reduce our earnings, increase our working capital requirements and impact adversely our customer base.

The supply and demand balance in natural gas markets could cause an increase in the price of natural gas. Recently, the increased production in the U.S. of natural gas from shale formations has put downward pressure on the wholesale cost of natural gas; however, restrictions or regulations on shale natural gas production, increased demand from natural gas fueled electric power generation or natural gas exports could cause natural gas prices to increase. Additionally, the CFTC under the 2010 Dodd-Frank Wall Street Reform and Consumer Protection Act has regulatory authority of the over-the-counter derivatives markets. Regulations affecting derivatives could increase the price of our natural gas supply.

An increase in the price of natural gas could cause us to experience a significant increase in short-term debt because we must pay suppliers for natural gas when purchased, and can be significantly in advance of when such costs may be recovered through the collection of customer bills, which could adversely affect our financial condition and cash flows.

Further, the volatility of natural gas prices may impact adversely our customers' perception of natural gas. Natural gas costs are passed through to the customers of our LDCs based on the actual cost of the natural gas purchased by the particular LDC. Substantial fluctuations in natural gas prices can occur from year to year and sustained periods of high natural gas prices or of pronounced natural gas price volatility may lead to customers selecting other energy alternatives, such as electricity, and to increased scrutiny of the prudency of our natural gas procurement strategies and practices by our regulators. It may also cause new home developers, builders and new customers to select alternative sources of energy. Additionally, high natural gas prices may cause customers to conserve more and may also impact adversely our accounts receivable collections, resulting in higher bad debt expense. The occurrence of any of the foregoing could adversely affect our business, financial condition, results of operations and cash flows, as well as our future growth opportunities.

In addition, customer demand for natural gas may decrease due to technological advancements that increase the efficiency of and decrease energy consumption of appliances and equipment powered by natural gas.

Our risk-management policies and procedures may not be effective, and employees may violate our risk-management policies.

We have implemented a set of policies and procedures that involve both our senior management and the Audit Committee of our Board of Directors to assist us in managing risks associated with our business. These risk-management policies and procedures are intended to align strategies, processes, people, information technology and business knowledge so that risk is managed throughout the organization. However, as conditions change and become more complex, current risk measures may fail to assess adequately the relevant risk due to changes in the market and the presence of risks previously unknown to us. Additionally, if employees fail to adhere to our policies and procedures or if our policies and procedures are not effective, potentially because of future conditions or risks outside of our control, we may be exposed to greater risk than we had intended. Ineffective risk-management policies and procedures or violation of risk-management policies and procedures could have an adverse effect on our earnings, financial condition and cash flows.

Our business is subject to competition that could adversely affect our results of operations.

The natural gas distribution business is competitive, and we face competition from other companies that supply energy, including electric companies, propane dealers, renewable energy providers and coal companies in relation to sources of energy for electric power plants, as well as nuclear energy. Significant competitive factors include efficiency, quality and reliability of the services we provide and price.

The most significant product competition occurs between natural gas and electricity in the residential and small commercial markets. Natural gas competes with electricity for water and space heating, cooking, clothes drying and other general energy needs. Increases in the price of natural gas or decreases in the price of other energy sources could impact adversely our competitive position by decreasing the price benefits of natural gas to the consumer. Customers and builders typically make the decision on the type of equipment at initial installation and use the chosen energy source for the life of the equipment. Changes in the competitive position of natural gas relative to electricity and other energy products have the potential to cause a decline in consumption or in the number of natural gas customers.

Consumer or government-mandated conservation efforts, higher natural gas costs or decreases in the price of other energy sources also may encourage decreases in natural gas consumption and allow competition from alternative energy sources for applications that have traditionally used natural gas, encouraging some customers to move away from natural gas-fired equipment to equipment fueled by other energy sources. Competition between natural gas and other forms of energy is also based on efficiency, performance, reliability, safety and other nonprice factors. Technological improvements in other energy sources and events that impair the public perception of the nonprice attributes of natural gas could erode our competitive advantage. These factors in turn could decrease the demand for natural gas, impair our ability to attract new customers, and cause existing customers to switch to other forms of energy or to bypass our systems in favor of alternative competitive sources. This could result in slow or no customer growth and could cause customers to reduce or cease using our product, thereby reducing our ability to make capital expenditures and otherwise grow our business and affecting adversely our financial condition, results of operations and cash flows.

Our business activities are concentrated in three states.

We provide natural gas distribution services to customers in Oklahoma, Kansas and Texas. Changes in the regional economies, politics, regulations and weather patterns of these states could impact adversely the growth opportunities available to us and the usage patterns and financial condition of our customers. This could adversely affect our financial condition, results of operations and cash flows.

The availability of adequate natural gas pipeline transportation and storage capacity and natural gas supply may decrease and impair our ability to meet customers' natural gas requirements and reduce our earnings.

In order to meet customers' natural gas demands, we must obtain sufficient natural gas supplies, pipeline transportation and storage capacity from third parties. If we are unable to obtain these, our ability to meet our customers' natural gas requirements could be impaired and our financial condition and results of operations may be impacted adversely. A significant disruption to or reduction in natural gas supply, pipeline capacity or storage capacity due to events including, but not limited to, operational failures or disruptions, hurricanes, tornadoes, floods, freeze off of natural gas wells, terrorist or cyber-attacks or other acts of war, or legislative or regulatory actions, could reduce our normal supply of natural gas and thereby reduce our earnings.

A downgrade in our credit ratings could adversely affect our cost of and ability to access capital.

Our ability to obtain adequate and cost-effective financing depends in part on our credit ratings. A reduction in our ratings by our rating agencies could adversely affect our costs of borrowing and/or access to sources of liquidity and capital. Such a downgrade could further limit our access to public and private credit markets and increase the costs of borrowing under available credit lines. Should our credit ratings be downgraded, it could limit our ability to obtain additional financing in the future for working capital, capital expenditures and acquisitions. An increase in borrowing costs without the ability to recover these higher costs in the rates charged to our customers could adversely affect our results of operations and cash flows by limiting our ability to earn our allowed rate of return.

We are subject to new and existing laws and regulations that may require significant expenditures or significant increases in operating costs or result in significant fines or penalties for noncompliance.

Our business and operations are subject to regulation by a number of federal agencies, including FERC, DOT, OSHA, EPA, CFTC and various regulatory agencies in Oklahoma, Kansas and Texas, and we are subject to numerous federal and state laws and regulations. Future changes to laws, regulations and policies may impair our ability to compete for business or to recover costs and may increase the cost of our operations. Furthermore, because the language in some laws and regulations is not prescriptive, there is a risk that our interpretation of these laws and regulations may not be consistent with expectations of regulators. Any compliance failure related to these laws and regulations may result in fines, penalties or injunctive measures affecting our operating assets. For example, under the Energy Policy Act of 2005, the FERC has civil penalty authority under the Natural Gas Act of 1938, as amended, to impose penalties for current violations of up to $1 million per day for each violation. In addition, as the regulatory environment for our industry increases in complexity, the risk of inadvertent noncompliance could also increase. Our failure to comply with applicable regulations could result in a material adverse effect on our business, financial condition, results of operations and cash flows.

We are subject to strict regulations at many of our facilities regarding employee safety, and failure to comply with these regulations could adversely affect our financial results.

The workplaces associated with our facilities are subject to the requirements of DOT and OSHA, and comparable state statutes that regulate the protection of the health and safety of workers. The failure to comply with DOT, OSHA and state requirements or general industry standards, including keeping adequate records or preventing occupational exposure to regulated substances, could expose us to civil or criminal liability, enforcement actions, and regulatory fines and penalties and could have a material adverse effect on our business, financial condition, results of operations and cash flows.

We are subject to environmental regulations, which could adversely affect our operations or financial results.

We are subject to laws, regulations and other legal requirements enacted or adopted by federal, state and local governmental authorities relating to environmental and health and safety matters, including those legal requirements that govern discharges of substances into the air and water, the management and disposal of hazardous substances and waste, the clean-up of contaminated sites, groundwater quality and availability, plant and wildlife protection, as well as work practices related to employee health and safety. Environmental legislation also requires that our facilities, sites and other properties associated with our operations be operated, maintained, abandoned and reclaimed to the satisfaction of applicable regulatory authorities. The failure to comply with these laws, regulations and other requirements, or the discovery of presently unknown environmental conditions, could expose us to civil or criminal liability, enforcement actions and regulatory fines and penalties and could have a material adverse effect on our business, financial condition, results of operations and cash flows.

We also own or retain liability for certain environmental conditions at 12 former manufactured natural gas sites in Kansas, and expenses related to these sites could adversely affect our business, results of operations and cash flows. A number of environmental issues may exist with respect to manufactured gas plants. With the trend toward stricter standards, greater regulation and more extensive permit requirements for the types of assets operated by us that are subject to environmental regulation, our environmental expenditures could increase in the future, and such expenditures may not be fully covered by insurance or recoverable in rates from our customers, which could adversely affect our financial condition, results of operations and cash flows.

We are subject to pipeline safety and system integrity laws and regulations that may require significant expenditures, significant increases in operating costs or, in the case of noncompliance, substantial fines.

We are subject to the Pipeline Safety Improvement Act, which requires companies like us that operate high-pressure pipelines to perform integrity assessments on pipeline segments that pass through densely populated areas or near specifically designated high-consequence areas. Further, the Pipeline Safety, Regulatory Certainty and Job Creation Act increased the maximum penalties for violating federal pipeline safety regulations and directed the DOT and Secretary of Transportation to conduct further review or studies on issues that may or may not be material to us. Compliance with existing or new laws and regulations may result in increased capital, operating and other costs which may not be recoverable in rates from our customers or may impact materially our competitive position relative to other energy providers. Failure to comply with such laws and regulations may result in fines, penalties or injunctive measures that would not be recoverable from customers in rates and could result in a material adverse effect on our financial condition, results of operations and cash flows. The failure to comply with these laws, regulations and other requirements could expose us to civil or criminal liability, enforcement actions, and regulatory fines and penalties and could have a material adverse effect on our business, financial condition, results of operations and cash flows.

Climate change, carbon neutral or energy-efficiency legislation or regulations could increase our operating costs or restrict our market opportunities, affecting adversely our growth, cash flows and results of operations.

The federal and/or state governments may enact legislation or regulations that attempt to control or limit the causes of climate change, including greenhouse gas emissions, such as carbon dioxide. Such laws or regulations could impose costs tied to carbon emissions, operational requirements or restrictions, or additional charges to fund energy efficiency activities. They could also provide a cost advantage to alternative energy sources, impose costs or restrictions on end users of natural gas, or result in other costs or requirements, such as costs associated with the adoption of new infrastructure and technology to respond to new mandates. The focus on climate change could impact adversely the reputation of fossil fuel products or services. The occurrence of the foregoing events could put upward pressure on the cost of natural gas relative to other energy sources, increase our costs and the prices we charge to customers, reduce the demand for natural gas or cause fuel switching to other energy sources, and impact the competitive position of natural gas and the ability to serve new or existing customers, affecting adversely our business, results of operations and cash flows.

We are subject to physical and financial risks associated with climate change.

There is a growing belief that emissions of greenhouse gases may be linked to global climate change. Climate change creates physical and financial risk. Our customers' energy needs vary with weather conditions, primarily temperature and humidity. For residential customers, heating and cooling represent their largest energy use. To the extent weather conditions may be affected by climate change, customers' energy use could increase or decrease depending on the duration and magnitude of any changes. A decrease in energy use due to weather changes may affect our financial condition through decreased revenues and cash flows. Extreme weather conditions in general require more system backup, adding to costs, and can contribute to increased system stresses, including service interruptions. Weather conditions outside of our operating territory could also have an impact on our revenues and cash flows by affecting natural gas prices. Severe weather impacts our operating territories primarily through thunderstorms, tornados and snow or ice storms. To the extent the frequency of extreme weather events increases, this could increase our cost of providing service. We may not be able to pass on the higher costs to our customers or recover all the costs related to mitigating these physical risks. To the extent financial markets view climate change and emissions of greenhouse gases as a financial risk, this could adversely affect our ability to access capital markets or cause us to receive less favorable terms and conditions in future financings. Our business could be affected by the potential for lawsuits related to or against greenhouse gas emitters based on the claimed connection between greenhouse gas emissions and climate change, which could impact adversely our business, results of operations and cash flows.

Demand for natural gas is highly weather sensitive and seasonal, and weather conditions may cause our earnings to vary from year to year.

Our earnings can vary from year to year, depending in part on weather conditions, which directly influence the volume of natural gas delivered to customers. Natural gas sales to residential and commercial customers are seasonal, as a substantial portion of their natural gas requirements are for heating during the winter months. Warmer-than-normal weather can reduce our utility margins as customer consumption declines. We have implemented weather normalization mechanisms for our sales to customers in Oklahoma, Kansas and portions of Texas, which are designed to limit our earnings sensitivity to weather. Weather normalization mechanisms allow us to increase customer billings to offset lower natural gas usage when weather is warmer than normal and decrease customer billings to offset higher natural gas usage when weather is colder than normal. If our rates and tariffs are modified to curtail such weather protection programs, then we would be exposed to additional risk associated with weather. As a result of occurrences of the foregoing, our results of operations and cash flows could vary and be impacted adversely.

We may not be able to complete necessary or desirable expansion or infrastructure development projects, which may delay or prevent us from serving our customers or expanding our business.

In order to serve new customers or expand our service to existing customers, we may need to maintain, expand or upgrade our distribution and/or transmission infrastructure, including laying new distribution lines. Various factors may prevent or delay us from completing such projects or make completion more costly, such as the inability to obtain required approval from local, state and/or federal regulatory and governmental bodies, public opposition to the project, inability to obtain adequate financing, competition for labor and materials, construction delays, cost overruns, and inability to negotiate acceptable agreements relating to construction or other material components of an infrastructure development project. As a result, we may not be able to serve adequately existing customers or support customer growth, which would impact adversely our business, stakeholder perception, financial condition, results of operations and cash flows.

We may pursue acquisitions, divestitures and other strategic opportunities, the success of which may impact adversely our results of operations, cash flows and financial condition.

As part of our strategic objectives, we may pursue acquisitions to complement or expand our business, as well as divestures and other strategic opportunities. We may not be able to successfully negotiate, finance or receive regulatory approval for future acquisitions or integrate the acquired businesses with our existing business and services. These efforts may also distract our management and employees from day-to-day operations and require substantial commitments of time and resources. Future acquisitions could result in potentially dilutive issuances of equity securities, a decrease in our liquidity as a result of our using a significant portion of our available cash or borrowing capacity to finance the acquisition, the incurrence of debt, contingent liabilities and amortization expenses and substantial goodwill. The effects of these strategic decisions may have long-term implications that are not likely to be known to us in the short-term. Changing political climates and public attitudes may adversely affect the ongoing acceptability of strategic decisions that have been made (and, in some cases, previously approved by regulators) to the detriment of the company. We may be affected materially and adversely if we are unable to integrate successfully businesses that we acquire.

An impairment of goodwill and long-lived assets could reduce our earnings.

At December 31, 2015, we had approximately $158 million of goodwill recorded on our balance sheet. Goodwill is recorded when the purchase price of a business exceeds the fair market value of the tangible and separately measurable intangible net assets. GAAP requires us to test goodwill for impairment on an annual basis or when events or circumstances occur indicating that goodwill might be impaired. Long-lived assets with finite useful lives are reviewed for impairment whenever events or changes in circumstances indicate that the carrying amount may not be recoverable. If we determine that impairment is indicated, we would be required to take an immediate noncash charge to earnings with a correlative effect on our equity and balance sheet leverage as measured by debt to total capitalization, which could impact adversely our financial condition and results of operations.

We may be unable to access capital or our cost of capital may increase significantly.

Our ability to obtain adequate and cost-effective financing is dependent upon the liquidity of the financial markets, in addition to our financial condition and credit ratings. Disruptions in the capital and credit markets could adversely affect our ability to access short-term and long-term capital. Access to funds under our ONE Gas Credit Agreement will be dependent on the ability of the participating banks to meet their funding commitments. Those banks may not be able to meet their funding commitments if they experience shortages of capital and liquidity. Disruptions and volatility in the global credit markets could cause the interest rate we pay on our ONE Gas Credit Agreement, which is based on LIBOR, to increase. This could result in higher interest rates on future financings, and could impact the liquidity of the lenders under our ONE Gas Credit Agreement, potentially impairing their ability to meet their funding commitments to us. Disruptions in the capital and credit markets as a result of uncertainty, changing or increased regulation or failures of significant financial institutions could adversely affect our access to capital needed for our business. The inability to access adequate capital or an increase in the cost of capital may require us to conserve cash, prevent or delay us from making capital expenditures, and require us to reduce or eliminate our dividend or other discretionary uses of cash. A significant reduction in our liquidity could cause a negative change in our ratings outlook or even a reduction in our credit ratings. This could in turn further limit our access to credit markets and increase our costs of borrowing.

Changes in federal and state fiscal, tax and monetary policy could increase significantly our costs or decrease our cash flows.

Changes in federal and state fiscal, tax and monetary policy may result in increased taxes, interest rates, and inflationary pressures on the costs of goods, services and labor. This could increase our expenses and capital spending and decrease our cash flows if we are not able to recover or recover timely such increased costs from our customers. This series of events may increase our rates to customers and thus may impact adversely customer billings and customer growth. Changes in tax rules could adversely affect our cash flows. Any of these events may cause us to increase debt, conserve cash, adversely affect our ability to make capital expenditures to grow the business or other discretionary uses of cash, and could adversely affect our cash flows.

Federal, state and local jurisdictions may challenge our tax return positions.

The preparation of our federal and state tax return filings may require significant judgments, use of estimates and the interpretation and application of complex tax laws. Significant judgment also is required in assessing the timing and amounts of deductible and taxable items. Despite management's expectation that our tax return positions will be fully supportable, certain positions may be challenged successfully by federal, state and local jurisdictions.

As a result of cross-default provisions in our borrowing arrangements, we may be unable to satisfy all of our outstanding obligations in the event of a default on our part.

The terms of our debt agreements contain cross-default provisions, which provide that we will be in default under such agreements in the event of certain defaults under other debt agreements. Accordingly, should an event of default occur under any of those agreements, we would face the prospect of being in default under all of our debt agreements, obliged in such instance to satisfy all of our outstanding indebtedness simultaneously. In such an event, we may not be able to obtain alternative financing or, if we are able to obtain such financing, we may not be able to obtain it on terms acceptable to us, which would adversely affect our ability to implement our business plan, have flexibility in planning for, or reacting to, changes in our business, make capital expenditures and finance our operations.

The cost of providing pension and other postemployment health care benefits to eligible employees and qualified retirees is subject to changes in pension fund values and changing demographics and may increase. In addition, the passage of the Patient Protection and Affordable Care Act in 2010 could increase the cost of health care benefits for our employees. Further, the costs to us of providing such benefits and related funding requirements are subject to the continued and timely recovery of such costs through our rates.

We have defined benefit pension plans and other postemployment welfare plans for certain employees. Our defined benefit and other postemployment welfare plans are closed to new participants. Our other postemployment welfare plans only subsidize costs for providing postemployment medical benefits. The cost of providing these benefits to eligible current and former employees is subject to changes in the market value of our pension and other postemployment benefit plan assets, changing demographics, including longer life expectancy of plan participants and their beneficiaries, and changes in health care costs.

Any sustained declines in equity markets and reductions in bond values may have a material adverse effect on the value of our pension and other postemployment benefit plan assets. In these circumstances, additional cash contributions to our pension and other postemployment benefit plans may be required, which could have a material adverse impact on our financial condition and cash flows.

In addition, the costs of providing health care benefits to our employees could increase over the next five to ten years due in large part to the Patient Protection and Affordable Care Act of 2010. The future costs of compliance with its provisions are difficult to measure at this time. Also, our costs of providing such benefits and related funding requirements could also increase materially in the future, depending on the timing of the recovery, if any, of such costs through our rates, which could impact adversely our financial condition and cash flows.

Our business is subject to operational hazards and unforeseen interruptions that could affect materially and adversely our business and for which we may not be insured adequately.

We are subject to all of the risks and hazards typically associated with the natural gas distribution business. Operating risks include, but are not limited to, leaks, pipeline ruptures and the breakdown or failure of equipment or processes. Other operational hazards and unforeseen interruptions include adverse weather conditions, accidents, explosions, fires, the collision of equipment with our pipeline facilities (for example, this may occur if a third-party were to perform excavation or construction work near our facilities) and catastrophic events, such as tornados, hurricanes, earthquakes, floods or other similar events beyond our control. It is also possible that our facilities could be direct targets or indirect casualties of an act of terrorism, including cyber attacks. A casualty occurrence might result in injury or loss of life, extensive property damage or environmental damage caused to or by employees, customers, contractors, vendors and other third parties. The location of pipeline facilities near populated areas, including residential areas, commercial business centers and industrial gathering places, could increase the level of damages resulting from these risks. Liabilities incurred and interruptions to the operations of our pipelines or other facilities caused by such an event could reduce revenues generated by us and increase expenses, which could have a material adverse effect on our financial condition, results of operations and cash flows. Additionally, our regulators may not allow us to recover part or all of the increased cost related to the foregoing events from our customers, which would adversely affect our earnings and cash flows.

Unanticipated events or a combination of events, failure in resources needed to respond to events, or slow or inadequate response to events may have an adverse impact on our financial condition, results of operations and cash flows.

While we have general liability and property insurance currently in place in amounts that we consider appropriate based on our assessment of business risk and best practices in our industry and in general business, such policies are subject to certain limits and deductibles. Further, we are not fully insured against all risks inherent in our business. As a result of market conditions, premiums and deductibles for certain insurance policies can increase substantially, and, in some instances, certain insurance may become unavailable or available only for reduced amounts of coverage. Consequently, we may not be able to renew existing insurance policies or purchase other desirable insurance on commercially reasonable terms, if at all.

The insurance proceeds received for any loss of, or any damage to, any of our facilities or to third parties may not be sufficient to restore the total loss or damage. Further, the proceeds of any such insurance may not be paid in a timely manner. The occurrence of any of the foregoing could have a material adverse effect on our financial condition, results of operations and cash flows.

A failure in our operational systems or cyber security attacks on any of our facilities, or those of third parties, may adversely affect our financial results.

Our business is dependent upon our operational systems to process a large amount of data and complex transactions. If any of our financial, operational or other data processing systems fail or have other significant shortcomings, our financial results could be affected adversely. Our financial results could also be affected adversely if an employee causes our operational systems to fail, either as a result of inadvertent error or by deliberately tampering with or manipulating our operational systems. In addition, dependence upon automated systems may further increase the risk that operational system flaws, employee tampering or manipulation of those systems will result in losses that are difficult to detect.

Due to increased technology advances, we have become more reliant on technology to help increase efficiency in our business. We use computer programs to help run our financial and operations organizations, including an enterprise resource planning system that integrates data and reporting activities across our company. The use of technological programs, systems and tools may subject our business to increased risks. Any future cyber security attacks that affect our distribution facilities, our customers, our suppliers and third party service providers or any financial data could have a material adverse effect on our businesses. In addition, cyber attacks on our company, customer and employee data may result in a financial loss and may impact adversely our reputation. Third-party systems on which we rely could also suffer operational system failure.

The foregoing events could adversely affect our business reputation, diminish customer confidence, disrupt operations, subject us to financial liability or increased regulation, increase our costs and expose us to material legal claims and liability, and our business, financial condition and results of operations could be affected adversely.

Our business could be affected adversely by strikes or work stoppages by our unionized employees.

At February 1, 2016, approximately 700 of our estimated 3,400 employees were represented by collective-bargaining units under collective-bargaining agreements. We are involved periodically in discussions with collective-bargaining units representing some of our employees to negotiate or renegotiate labor agreements. We cannot predict the results of these negotiations, including whether any failure to reach new agreements will have a negative effect on our business, financial condition and results of operations or whether we will be able to reach any agreement with the collective-bargaining units. Any failure to reach agreement on new labor contracts might result in a work stoppage. Any future work stoppage could, depending on the operations and the length of the work stoppage, have a material adverse effect on our financial condition and results of operations.

A shortage of skilled labor may make it difficult for us to maintain labor productivity and competitive costs, which could adversely affect operations and cash flows. Further, we may be unable to attract and retain professional and technical employees, which could impact adversely our earnings.

Our operations require skilled and experienced workers with proficiency in multiple tasks. In recent years, a shortage of workers trained in various skills associated with the natural gas distribution business has caused us to conduct certain operations without full staff, thus hiring outside resources, which may decrease productivity and increase costs. This shortage of trained workers is the result of experienced workers reaching retirement age and increased competition for workers in certain areas, combined with the difficulty of attracting new workers to the natural gas distribution industry. This shortage of skilled labor could continue over an extended period. If the shortage of experienced labor continues or worsens, it could have an adverse impact on labor productivity and costs and our ability to meet the needs of our customers in the event there is an increase in the demand for our products and services, which could adversely affect our business and cash flows.

Our ability to implement our business strategy and serve our customers is dependent upon our ability to employ talented professionals and attract and retain a skilled, high-performing workforce. We are subject to the risk that we will not be able to effectively replace or transfer the knowledge and expertise of retiring employees. Without a skilled workforce, our ability to provide quality service to our customers and meet our regulatory requirements will be challenged, and this could impact adversely our business, financial condition, results of operations and cash flows.

Changes in accounting standards may impact adversely our financial condition and results of operations.

The SEC is considering whether issuers in the United States should be required to prepare financial statements in accordance with IFRS instead of the current GAAP. IFRS is a comprehensive set of accounting standards promulgated by the International Accounting Standards Board, which are currently in effect for most other countries in the world. Unlike GAAP, IFRS does not provide currently an industry accounting standard for rate-regulated activities. As such, if IFRS were adopted in its current state, we may be precluded from applying certain regulatory accounting principles, including the recognition of certain regulatory assets and regulatory liabilities. The potential issues associated with rate-regulated accounting, along with other potential changes associated with the adoption of IFRS, may impact adversely our reported financial condition and results of operations should adoption of IFRS be required.

Additionally, we are subject to additional changes in GAAP, SEC regulations and other interpretations of financial reporting requirements for public utilities. We neither have control over the impact these changes may have on our financial condition or results of operations nor the timing of such changes.

Our financing arrangements subject us to various restrictions that could limit our operating flexibility.

The covenants in the indenture governing our Senior Notes and our ONE Gas Credit Agreement restrict our ability to create or permit certain liens, to consolidate or merge or to convey, transfer or lease substantially all of our properties and assets.

The ONE Gas Credit Agreement includes a requirement that our debt to total capital ratio may not exceed 70 percent as of the end of any calendar quarter. Events beyond our control could impair our ability to satisfy this requirement. As long as our indebtedness remains outstanding, these restrictive covenants could impair our ability to expand or pursue our growth strategy. In addition, the breach of any covenants or any payment obligations in any of these debt agreements will result in an event of default under the applicable debt instrument. If there were an event of default under one of our debt agreements, the holders of the defaulted debt may have the ability to cause all amounts outstanding with respect to that debt to be due and payable, subject to applicable grace periods. This could trigger cross-defaults under our other debt agreements, including our Senior Notes. Forced repayment of some or all of our indebtedness would reduce our available cash and have an adverse impact on our financial condition and results of operations.

Some of our debt, including borrowings under our ONE Gas Credit Agreement and our commercial paper program, is based on variable rates of interest, which could result in higher interest expenses in the event of an increase in interest rates.

In the future, we could be exposed to fluctuations in variable interest rates. This increases our exposure to fluctuations in market interest rates. Amounts borrowed under the ONE Gas Credit Agreement and commercial paper program are based on variable rates of interest. If these rates rise, the interest rate on this debt will also increase. Therefore, an increase in these rates may increase our interest payment obligations and have a negative effect on our cash flows and financial position.

RISKS RELATING TO THE SEPARATION

We are responsible for certain contingent and other liabilities related to the historical natural gas distribution business of ONEOK, as well as a portion of any contingent corporate liabilities of ONEOK that do not relate to either the natural gas distribution business or ONEOK's remaining businesses.

Under the Separation and Distribution Agreement between us and ONEOK, we assumed and are responsible for certain contingent and other corporate liabilities related to the historical natural gas distribution business of ONEOK (including associated costs and expenses, whether arising prior to, at, or after our separation). In addition, under the Separation and Distribution Agreement we are also responsible for a portion of any contingent corporate liabilities of ONEOK that do not relate to either our business or the business of ONEOK following the separation (for example, liabilities associated with certain corporate activities not specifically attributable to either business). If we are required to indemnify ONEOK or are otherwise liable for these liabilities, they may have a material adverse effect on our financial condition, results of operations and cash flows.

Third parties may seek to hold us responsible for liabilities of ONEOK that we did not assume in our agreements.

Third parties may seek to hold us responsible for retained liabilities of ONEOK. Under our agreements with ONEOK, ONEOK has agreed to indemnify us for claims and losses relating to these retained liabilities. However, if those liabilities are significant and we are ultimately held liable for them, we cannot assure that we will be able to recover the full amount of our losses from ONEOK.

Our prior and continuing relationship with ONEOK exposes us to risks attributable to businesses of ONEOK.

ONEOK is obligated to indemnify us for losses that a party may seek to impose upon us or our affiliates for liabilities relating to the business of ONEOK. Any claims made against us that are properly attributable to ONEOK in accordance with these arrangements require us to exercise our rights under our agreements with ONEOK to obtain payment from ONEOK. We are exposed to the risk that, in these circumstances, ONEOK cannot, or will not, make the required payment.

If the distribution, together with certain related transactions, were to fail to qualify as a tax-free transaction for U.S. federal income tax purposes under Sections 355, 368(a)(1)(D) and other related provisions of the Code, then ONEOK and/or its shareholders could incur significant U.S. federal income tax liabilities, and we could incur significant indemnity obligations.

ONEOK received an IRS Ruling to the effect that the distribution, together with certain related transactions, qualified as tax-free to ONEOK, us and the ONEOK shareholders under Sections 355, 368(a)(1)(D) and other related provisions of the Code. ONEOK also received an opinion of Skadden, Arps, Slate, Meagher & Flom LLP, tax counsel to ONEOK, which opinion relies on the continued validity of the IRS Ruling, with respect to certain issues relating to the tax-free nature of the transactions that were not addressed in or covered by the IRS Ruling.

The IRS Ruling and the tax opinion rely upon certain assumptions, as well as statements, representations and certain undertakings made by our officers and the officers of ONEOK regarding the past and future conduct of the companies' respective businesses and other matters. If any of those statements, representations or assumptions are incorrect or untrue in any material respect or any of those undertakings are not complied with, the conclusions reached in the IRS Ruling or the opinion could be affected adversely, and ONEOK and/or its shareholders could be subject to significant tax liabilities. Notwithstanding the IRS Ruling and opinion of tax counsel, the IRS could determine on audit that the distribution, together with certain related transactions, was taxable if it determines that any of these statements, representations, assumptions, or undertakings were not correct or have been violated or if it disagrees with the conclusions in the opinion that were not covered by the IRS Ruling, or for other reasons, including as a result of certain significant changes in the stock ownership of ONEOK or us after the distribution.

If the distribution were subsequently determined, for whatever reason, not to qualify as a transaction that is tax-free for U.S. federal income tax purposes under Sections 355, 368(a)(1)(D), and other related provisions of the Code, ONEOK and/or the holders of ONEOK common stock immediately prior to the distribution could incur significant tax liabilities, and, in certain circumstances as described further under "Certain Relationships and Related Transactions, and Director Independence - Tax Matters Agreement," we will be required to indemnify ONEOK, its subsidiaries, and certain related persons for taxes and related expenses resulting from the distribution, which could be material. Any such indemnity obligation could have a materially adverse impact on our financial condition.

To preserve the tax-free treatment to ONEOK and/or its shareholders of the distribution and certain related transactions, we may not be able to engage in certain transactions.

To preserve the tax-free treatment to ONEOK and/or its shareholders of the distribution and certain related transactions, we are restricted, under the Tax Matters Agreement between us and ONEOK, from taking any action that prevents such transactions from being tax-free for U.S. federal, state and local income tax purposes. These restrictions may limit our ability to pursue certain strategic transactions or engage in other transactions, including using our common stock to make acquisitions and in connection with equity capital market transactions that might increase the value of our business.

RISKS RELATING TO OUR COMMON STOCK

Provisions in our certificate of incorporation, our bylaws, Oklahoma law and certain of the agreements into which we have entered as part of the separation may prevent or delay an acquisition of our company, which could decrease the trading price of our common stock.

Our certificate of incorporation, bylaws and Oklahoma law contain provisions that are intended to deter coercive takeover practices and inadequate takeover bids by making such practices or bids unacceptably expensive to the raider and to encourage prospective acquirers to negotiate with our board of directors rather than to attempt a hostile takeover. These provisions include, among others:

- a board of directors that is divided into three classes with staggered terms;
- rules regarding how shareholders may present proposals or nominate directors for election at shareholder meetings;
- the right of our board of directors to issue preferred stock without shareholder approval; and
- limitations on the right of shareholders to remove directors.

Oklahoma law also imposes some restrictions on mergers and other business combinations between us and any holder of 15 percent or more of our outstanding common stock.

We believe these provisions protect our shareholders from coercive or otherwise potentially unfair takeover tactics by requiring potential acquirers to negotiate with our board of directors and by providing our board of directors with more time to assess any acquisition proposal. These provisions are not intended to make our company immune from takeovers. However, these provisions apply even if the offer may be considered beneficial by some shareholders and could delay or prevent an acquisition that our board of directors determines is not in the best interests of our company and our shareholders.

Our ability to pay dividends on our common stock will depend on our ability to generate sufficient positive earnings and cash flows.

Our ability to pay dividends in the future will depend upon, among other things, our future earnings, cash flows and restrictive covenants, if any, under future credit agreements to which we may be a party. Our cash available for dividends will principally be generated from our operations. Because the cash we generate from operations will fluctuate from quarter to quarter, we may not be able to maintain future dividends at the levels we expect or at all. Our ability to pay dividends depends primarily on cash flows, including cash flows from changes in working capital, and not solely on profitability, which is affected by noncash items. As a result, we may pay dividends during periods when we record net losses and may be unable to pay cash dividends during periods when we record net income.

ITEM 1B. UNRESOLVED STAFF COMMENTS

None.

ITEM 2. PROPERTIES

The following table sets forth the approximate number of service lines, pipeline and other natural gas distribution properties as of December 31, 2015:

Properties (miles)	OK	KS	TX	Total
Distribution	**18,300**	**12,000**	**10,100**	**40,400**
Transmission	**700**	**1,500**	**800**	**3,000**
Total properties	**19,000**	**13,500**	**10,900**	**43,400**

We lease approximately 0.5 million square feet of office space and other facilities for our operations. In addition, we have 50.4 Bcf of natural gas storage capacity under lease, with maximum allowable daily withdrawal capacity of approximately 1.3 Bcf/d.

ITEM 3. LEGAL PROCEEDINGS

See Note 14 of the Notes to Financial Statements in this Annual Report for information regarding legal proceedings.

ITEM 4. MINE SAFETY DISCLOSURES

Not applicable.

PART II

ITEM 5. MARKET FOR REGISTRANT'S COMMON EQUITY, RELATED STOCKHOLDER MATTERS AND ISSUER PURCHASES OF EQUITY SECURITIES

MARKET INFORMATION, HOLDERS AND DIVIDENDS

Our common stock is listed on the NYSE under the trading symbol "OGS." The following table sets forth the high and low closing prices of our common stock for the period indicated:

	Year Ended December 31, 2015		
	High	Low	Dividends
First Quarter	$ 46.11	$ 39.38	$ 0.30
Second Quarter	$ 44.33	$ 41.41	$ 0.30
Third Quarter	$ 45.56	$ 41.70	$ 0.30
Fourth Quarter	$ 51.34	$ 45.18	$ 0.30

	Year Ended December 31, 2014*		
	High	Low	Dividends
First Quarter	$ 35.80	$ 31.53	$ —
Second Quarter	$ 37.98	$ 34.25	$ 0.28
Third Quarter	$ 37.77	$ 34.00	$ 0.28
Fourth Quarter	$ 44.19	$ 34.03	$ 0.28

**Our common stock began regular-way trading on February 3, 2014.*

At February 5, 2016, there were 14,944 registered shareholders of the Company's common stock.

In January 2016, we declared a dividend of $0.35 per share ($1.40 per share on an annualized basis), payable on March 11, 2016, to shareholders of record as of February 26, 2016.

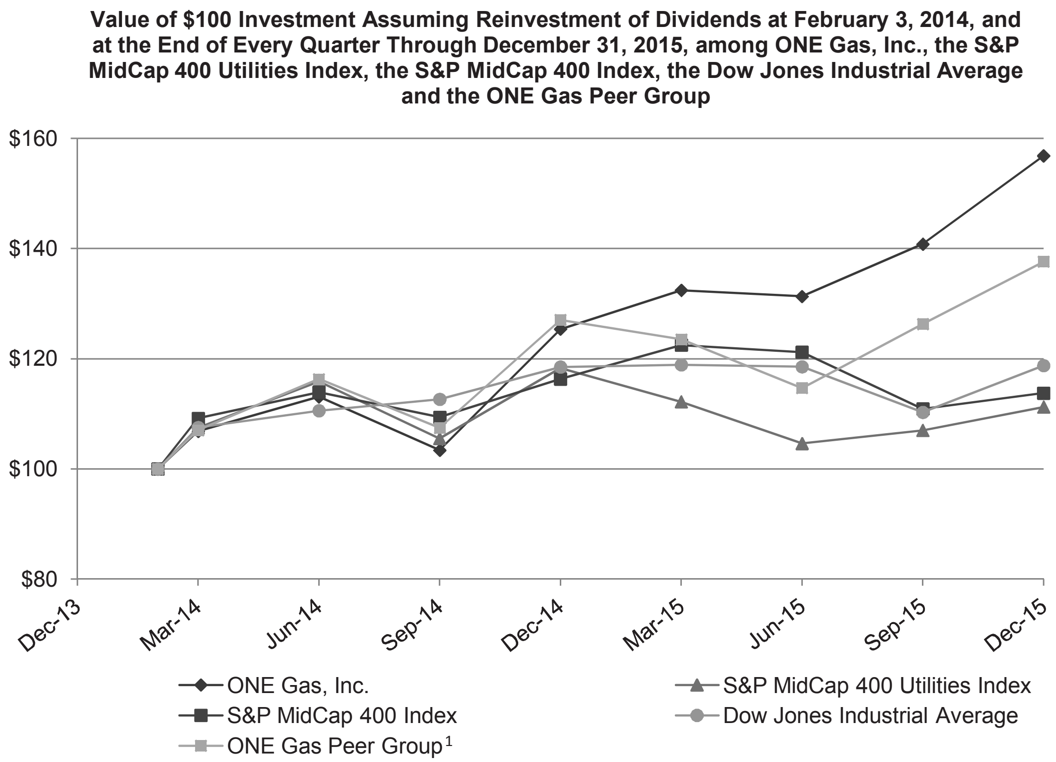
Employee Stock Award Program

Under the Employee Stock Award Program, we have issued, for no monetary consideration, one share of our common stock to all eligible employees when the per-share closing price of our common stock on the NYSE closes for the first time at or above each $1.00 increment above $34. Shares issued to employees under this program during 2015 totaled 23,506, and compensation expense related to the Employee Stock Award Program was $1.1 million.

The total number of shares of our common stock authorized for issuance under this program is 125,000. The shares issued under this program have not been registered under the Securities Act, in reliance upon the position taken by the SEC (see Release No. 6188, dated February 1, 1980) that the issuance of shares to employees pursuant to a program of this kind does not require registration under the Securities Act. See Note 11 of the Notes to Financial Statements in this Annual Report for additional information.

Performance Graph

The following performance graph compares the performance of our common stock with the S&P MidCap 400 Index, the Dow Jones Industrial Average and a ONE Gas Peer Group during the period beginning February 3, 2014, and ending on December 31, 2015. February 3, 2014 was the first day of "regular way" trading for ONE Gas on the NYSE. This graph assumes a $100 investment in our common stock and in each of the indices at the beginning of the period and a reinvestment of dividends paid on such investments throughout the period.



	Cumulative Total Return As of Each Quarter Ending							
	3/31/2014	6/30/2014	9/30/2014	12/31/2014	3/31/2015	6/30/2015	9/30/2015	12/31/2015
ONE Gas, Inc.	$ 106.84	$ 113.12	$ 103.41	$ 125.39	$ 132.43	$ 131.32	$ 140.81	$ 156.83
S&P MidCap 400 Utilities Index	$ 107.49	$ 115.89	$ 105.54	$ 118.29	$ 112.20	$ 104.63	$ 107.00	$ 111.26
S&P MidCap 400 Index	$ 109.21	$ 113.93	$ 109.38	$ 116.32	$ 122.50	$ 121.19	$ 110.89	$ 113.78
Dow Jones Industrial Average	$ 107.54	$ 110.59	$ 112.66	$ 118.52	$ 118.91	$ 118.56	$ 110.28	$ 118.77
ONE Gas Peer Group[1]	$ 107.04	$ 116.31	$ 107.44	$ 127.05	$ 123.53	$ 114.69	$ 126.30	$ 137.63

[1] The ONE Gas peer group used in this graph is the same peer group that will be used in determining our level of performance under our 2015 performance units at the end of the three-year performance period and is comprised of the following companies: AGL Resources Inc.; Atmos Energy Corporation; Avista Corporation; The Laclede Group, Inc.; New Jersey Resources Corporation; Northwest Natural Gas Company; Piedmont Natural Gas Company, Inc.; Questar Corporation; South Jersey Industries, Inc.; Southwest Gas Corp.; Vectren Corporation and WGL Holdings, Inc.

ITEM 6. SELECTED FINANCIAL DATA

The following table sets forth our selected financial data for each of the periods indicated:

	Years Ended December 31,				
	2015	**2014**	**2013**	**2012**	**2011**
	(Millions of dollars except per share data)				
Revenues	**$ 1,547.7**	$ 1,818.9	$ 1,690.0	$ 1,376.6	$ 1,621.3
Net margin	**$ 841.7**	$ 827.0	$ 813.0	$ 756.4	$ 751.8
Operating income	**$ 239.1**	$ 225.3	$ 220.3	$ 215.7	$ 199.7
Net income	**$ 119.0**	$ 109.8	$ 99.2	$ 96.5	$ 86.8
Total assets	**$ 4,644.4**	$ 4,649.2	$ 3,846.5	$ 3,491.3	$ 3,285.5
Long-term line of credit with ONEOK	**$ —**	$ —	$ 1,027.6	$ 1,027.6	$ 912.4
Long-term debt, including current maturities	**$ 1,201.3**	$ 1,201.3	$ 1.3	$ 1.5	$ 1.9
Basic earnings per share	**$ 2.26**	$ 2.10	$ 1.90	$ 1.84	$ 1.66
Diluted earnings per share	**$ 2.24**	$ 2.07	$ 1.90	$ 1.84	$ 1.66
Dividends declared per common share	**$ 1.20**	$ 0.84	—	—	—

Prior to 2014, historical basic and diluted earnings per share for the periods presented were calculated based on the number of shares distributed to ONEOK shareholders on separation plus any shares associated with fully vested stock awards that had not been issued and considered outstanding as of the beginning of each period prior to the separation. See Note 1 of the Notes to Financial Statements in this Annual Report for additional information on earnings per share.

ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

The following discussion and analysis should be read in conjunction with our audited financial statements and Notes to Financial Statements in this Annual Report.

EXECUTIVE SUMMARY

We are a 100 percent regulated natural gas distribution company. As such, our regulators determine the rates we are allowed to charge for our service based on our revenue requirements needed to achieve our authorized rates of return. We earn revenues from the delivery of natural gas, but do not earn a profit on the natural gas that we deliver, as those costs are passed through to our customers at cost. The primary components of our revenue requirements are the amount of capital invested in our business, which is also known as rate base, our allowed rate of return on our capital investments and our recoverable operating expenses, including depreciation and income taxes. Our rates have both a fixed and a variable component, with approximately 73 percent and 71 percent of our natural gas sales net margin in 2015 and 2014, respectively, derived from fixed monthly charges to our customers. The variable component of our rates is dependent on the consumption of natural gas, which is impacted primarily by the weather and, to a lesser extent, economic activity. While we have weather normalization mechanisms in most jurisdictions that adjust customers' bills when the actual heating degree days differ from normalized heating degree days, these mechanisms are in place for only a portion of the year and do not offset all fluctuations in usage resulting from weather variability. Accordingly, the weather can have either a positive or negative impact on our financial performance.

Our financial performance, therefore, is contingent on a number of factors, including: (1) regulatory outcomes, which determine the returns we are authorized to earn and the rates we are allowed to charge for our service; (2) the consumption of natural gas, which impacts the amount of our net margin derived from the variable component of our rates; (3) our operating performance, which impacts our operating expenses; and (4) the perceived value of natural gas relative to other energy sources, particularly electricity, which influences our customers' choice of natural gas to provide a portion of their energy needs.

We are subject to regulatory requirements for pipeline integrity and environmental compliance. These requirements impact our operating expenses and the level of capital expenditures required for compliance. Historically, our regulators have allowed recovery of these expenditures. However, because integrity and environmental regulation is changing constantly, our capital and operating expenditures to comply will change, as well. Although we believe our regulators will continue to allow recovery of such expenditures in the future, we will continue to make these expenditures with no assurance about if, or over what period, we will be permitted to recover them.

RECENT DEVELOPMENTS

In January 2016, a dividend of $0.35 per share ($1.40 per share on an annualized basis) was declared for shareholders of record on February 26, 2016, payable March 11, 2016.

REGULATORY ACTIVITIES

Oklahoma - In July 2015, Oklahoma Natural Gas filed a request with the OCC for an increase in base rates, reflecting system investments and operating costs necessary to maintain the safety and reliability of its natural gas distribution system. In January 2016, the OCC approved a joint stipulation and settlement agreement reached in November 2015 to allow an increase in revenue of $29,995,000. We also recorded a regulatory asset of $2.4 million to recover certain information technology costs incurred as a result of our separation from ONEOK in 2014, which will be recovered over four years. The agreement set Oklahoma Natural Gas' authorized return on equity at 9.5 percent, which represents the midpoint of the allowed range of 9.0 to 10.0 percent and a rate base of approximately $1.2 billion. The agreement includes the continuation, with certain modifications, of the Performance Based Rate Change tariff that was established in 2009.

In March 2015, Oklahoma Natural Gas filed its energy-efficiency program true-up application for its 2014 program year, requesting a utility incentive of $1.2 million. In July 2015, the Public Utility Division of the OCC and all other parties entered into a joint stipulation approving the filing. A hearing on merits was held in July 2015, with the Administrative Law Judge recommending the approval of the joint stipulation. The joint stipulation was approved by the OCC in December 2015.

Oklahoma Natural Gas filed a PBRC application in March 2014. In June 2014, a joint stipulation and settlement agreement associated with our PBRC filing was reached and contained an increase in base rates of approximately $13.7 million, and an energy-efficiency program true-up and a utility incentive adjustment of $0.9 million. In August 2014, the settlement was approved by the OCC.

Kansas - Kansas Gas Service is expected to file a rate case in 2016 based on a 2015 test year, with new rates effective January 2017.

In August 2015, Kansas Gas Service submitted an application to the KCC requesting an increase of approximately $2.4 million related to its GSRS. GSRS is a capital-recovery mechanism that allows for rate adjustment, providing recovery of and a return on incremental safety-related and government-mandated capital investments made between rate cases. In November 2015, the KCC approved the $2.4 million increase effective December 2015.

In August 2014, Kansas Gas Service submitted an application to the KCC requesting an increase in rates of approximately $3.5 million related to its GSRS. In November 2014, the KCC approved an increase of $3.5 million, which became effective on December 2014.

In December 2013, the KCC approved a settlement agreement between ONEOK, the staff of the KCC, and the Citizens' Utility Ratepayer Board for the separation from ONEOK of our Kansas Gas Service natural gas distribution business. Among other things, the terms of the settlement agreement include the following:

- Kansas Gas Service shall not change its base rates prior to January 1, 2017. The time limitation on filing a general rate case to change base rates does not preclude Kansas Gas Service from changing rates or tariffs to recover appropriate costs under its current approved riders and tariffs, including its COGR, ACA, WNA, ATSR and GSRS tariffs;
- Kansas Gas Service agreed to expense certain costs associated with ONEOK's acquisition of Kansas Gas Service in 1997 that were previously recorded as a regulatory asset and were being amortized and recovered in rates over a 40-year period. As such, we recorded a noncash charge to income of approximately $10.2 million in the fourth quarter of 2013;
- The level of pension and other postemployment benefit costs used to calculate Kansas Gas Service's Pension and Other Postemployment Benefit Trackers was adjusted to $13.6 million from $16.6 million, with a corresponding reduction to revenues; and
- A one-time contribution to 501(c)(3) organizations of $1.2 million to provide financial assistance for weatherization of housing for low income natural gas customers of Kansas Gas Service that was accrued in the fourth quarter of 2013.

The agreement authorized the transfer of ONEOK's existing Kansas natural gas distribution assets, certificates of convenience and necessity, franchises and tariffs to us.

Texas - In December 2015, Texas Gas Service filed a rate case requesting an increase in revenues of $3.1 million for its Galveston and South Jefferson County service areas. Texas Gas Service filed this rate case directly with the incorporated cities, and the RRC for the unincorporated areas. If approved by the cities and the RRC, the new rates will become effective in June 2016.

In March 2014, Texas Gas Service and the City of El Paso agreed to enter into an annual rate review mechanism called the EPARR. The EPARR provides for a streamlined review of Texas Gas Service's revenue requirement on an annual basis, and is in lieu of a filing under the GRIP statute. Texas Gas Service continued to file under the GRIP statute for other incorporated cities in the EPSA until early 2015, when the other incorporated cities in the EPSA adopted the EPARR mechanism. GRIP is a capital-recovery mechanism that allows for a rate adjustment providing recovery of and a return on incremental capital investments made between rate cases.

In March 2015, Texas Gas Service filed under the EPARR, requesting an increase in revenues of $9.4 million in the City of El Paso and surrounding incorporated cities in the EPSA. The filing included a request to include a payroll adjustment which would increase revenues by an additional $1.8 million, for a total increase in revenues of $11.2 million. In August 2015, Texas Gas Service and the incorporated cities in the EPSA reached an agreement on a rate increase of $8.0 million to take effect in August 2015. In April 2015, Texas Gas Service filed with the RRC under the GRIP statute, requesting an increase of $0.4 million in revenues for the unincorporated areas of the EPSA. The RRC approved the filing in July 2015. In November 2015, Texas Gas Service notified the EPSA that it would be filing a full rate case in lieu of the EPARR in 2016.

Texas Gas Service filed requests for interim rate relief under the GRIP statute with the City of Austin, Texas, and surrounding communities in February 2014 for approximately $5.2 million. The city councils approved the requested increase effective May 2014. Texas Gas Service received approval for rate relief under the GRIP statute with the City of Austin, Texas, and surrounding communities in May 2015, for approximately $3.7 million. The new rates became effective in June 2015.

Texas Gas Service filed requests for interim rate relief under the GRIP statute with the cities of Austin, Texas, and surrounding communities in February 2013 and with El Paso, Texas, in April 2013 for approximately $4.1 million and $4.9 million, respectively. In May 2013, the City of Austin approved the requested increase. In July 2013, the City of El Paso denied Texas Gas Service's GRIP request, which Texas Gas Service appealed to the RRC. In September 2013, the RRC approved Texas Gas Service's requested increase.

In the normal course of business, Texas Gas Service has filed rate cases and sought GRIP and cost-of-service adjustments in various other Texas jurisdictions to address investments in rate base and changes in expense. Annual rate increases totaling $4.8 million, $4.0 million and $4.2 million associated with these filings were approved in 2015, 2014 and 2013, respectively.

Texas Gas Service expects to file a rate case in the Central Texas jurisdiction, which includes the city of Austin, in 2016.

General - Certain costs to be recovered through the ratemaking process have been capitalized as regulatory assets. Should recovery cease due to regulatory actions, certain of these assets may no longer meet the criteria for recognition and accordingly, a writeoff of regulatory assets and stranded costs may be required. In 2013, as part of the KCC settlement for the separation of our Kansas Gas Service assets from ONEOK, we expensed $10.2 million for the remaining balance of certain costs associated with ONEOK's acquisition of Kansas Gas Service in 1997. There were no writeoffs of regulatory assets resulting from the failure to meet the criteria for capitalization during 2015 and 2014.

Selected Financial Results - The following table sets forth certain selected financial results for our operations for the periods indicated:

Financial Results	Years Ended December 31, 2015	2014	2013	Variances 2015 vs. 2014 Increase (Decrease)		Variances 2014 vs. 2013 Increase (Decrease)	
	(Millions of dollars, except percentages)						
Natural gas sales	**$ 1,417.9**	$ 1,680.1	$ 1,558.5	**$ (262.2)**	**(16)%**	$ 121.6	8 %
Transportation revenues	**98.8**	102.3	98.7	**(3.5)**	**(3)%**	3.6	4 %
Cost of natural gas	**706.0**	991.9	876.9	**(285.9)**	**(29)%**	115.0	13 %
Net margin, excluding other revenues	**810.7**	790.5	780.3	**20.2**	**3 %**	10.2	1 %
Other revenues	**31.0**	36.5	32.7	**(5.5)**	**(15)%**	3.8	12 %
Net margin	**841.7**	827.0	813.0	**14.7**	**2 %**	14.0	2 %
Operating costs	**469.6**	476.0	447.9	**(6.4)**	**(1)%**	28.1	6 %
Depreciation and amortization	**133.0**	125.7	144.8	**7.3**	**6 %**	(19.1)	(13)%
Operating income	**$ 239.1**	$ 225.3	$ 220.3	**$ 13.8**	**6 %**	$ 5.0	2 %
Capital expenditures	**$ 294.3**	$ 297.1	$ 292.1	**$ (2.8)**	**(1)%**	$ 5.0	2 %

The following table sets forth our net margin, excluding other revenues, by type of customer, for the periods indicated:

Net Margin, Excluding Other Revenues	Years Ended December 31, 2015	2014	2013	Variances 2015 vs. 2014 Increase (Decrease)		Variances 2014 vs. 2013 Increase (Decrease)	
Natural gas sales	(Millions of dollars, except percentages)						
Residential	**$ 589.8**	$ 569.7	$ 564.5	**$ 20.1**	**4 %**	$ 5.2	1%
Commercial and industrial	**115.6**	112.9	111.5	**2.7**	**2 %**	1.4	1%
Wholesale and public authority	**6.5**	5.6	5.6	**0.9**	**16 %**	—	—%
Net margin on natural gas sales	**711.9**	688.2	681.6	**23.7**	**3 %**	6.6	1%
Transportation revenues	**98.8**	102.3	98.7	**(3.5)**	**(3)%**	3.6	4%
Net margin, excluding other revenues	**$ 810.7**	$ 790.5	$ 780.3	**$ 20.2**	**3 %**	$ 10.2	1%

Our net margin on natural gas sales is comprised of two components, fixed and variable margin. Fixed margin reflects the portion of our net margin attributable to the monthly fixed customer charge component of our rates, which does not fluctuate based on customer usage in each period. Variable margin reflects the portion of our net margin that fluctuates with the volumes delivered and billed. We believe that the combination of the significant residential component of our customer base, the fixed charge component of our sales margin and our regulatory rate mechanisms in place result in a stable cash flow profile. The following table sets forth our net margin on natural gas sales by revenue type for the periods indicated:

Net Margin on Natural Gas Sales	Years Ended December 31, 2015	2014	2013	Variances 2015 vs. 2014 Increase (Decrease)		Variances 2014 vs. 2013 Increase (Decrease)	
Net margin on natural gas sales	(Millions of dollars, except percentages)						
Fixed margin	**$ 519.2**	$ 490.4	$ 470.6	**$ 28.8**	**6 %**	$ 19.8	4 %
Variable margin	**192.7**	197.8	211.0	**(5.1)**	**(3)%**	(13.2)	(6)%
Net margin on natural gas sales	**$ 711.9**	$ 688.2	$ 681.6	**$ 23.7**	**3 %**	$ 6.6	1 %

2015 vs. 2014 - Net margin increased $14.7 million due primarily to the following:

- an increase of $27.5 million from new rates, primarily in Texas and Oklahoma; and
- an increase of $4.8 million in residential sales due primarily to customer growth in Oklahoma and Texas; offset partially by
- a decrease of $6.0 million due to lower line extension revenue, from commercial and industrial customers, and other revenues;
- a decrease of $4.8 million due to lower sales volumes, net of weather normalization, primarily due to warmer weather in 2015;

- a decrease of $3.7 million in rider and surcharge recoveries due to a lower ad-valorem surcharge in Kansas and the expiration of the rider associated with the recovery of take-or-pay settlements in Oklahoma, both of which are offset by lower regulatory amortization in depreciation and amortization expense; and
- a decrease of $3.1 million due primarily to lower transportation volumes from weather-sensitive customers primarily in Kansas.

Operating costs decreased $6.4 million due primarily to the following:

- a decrease of $6.8 million in information technology services associated with our separation from ONEOK;
- a decrease of $6.0 million in outside services costs due primarily to operational efficiencies;
- a decrease of $4.1 million in legal and worker's compensation expense;
- a decrease of $2.7 million in bad debt expense primarily due to warmer weather in Kansas;
- a decrease of $1.4 million in fleet-related expenses due primarily to lower fuel costs; and
- a decrease of $0.9 million in ad valorem taxes; offset partially by
- an increase of $16.3 million in employee-related costs due primarily to increases of $9.3 million in higher labor costs due to an increase in our number of employees and $7.0 million in benefit costs, which includes the impact of the changes in our discount rate for pension and other postemployment benefit costs compared with the prior year.

Depreciation and amortization expense increased $7.3 million due primarily to an increase in depreciation of $12.1 million from capital expenditures being placed in service, offset partially by a decrease in the amortization of the ad valorem surcharge in Kansas and the take-or-pay rider in Oklahoma of $3.6 million.

2014 vs. 2013 - Net margin increased $14.0 million due primarily to the following:

- an increase of $16.8 million from new rates, primarily in Texas and Oklahoma;
- an increase of $5.6 million in residential sales due primarily to customer growth;
- an increase of $4.7 million from higher volumes due primarily to weather-sensitive transportation customers; and
- an increase of $2.8 million in CNG revenue and higher line extension revenue from commercial and industrial customers in Oklahoma; offset partially by
- a decrease of $12.8 million in rider and surcharge recoveries due to a lower ad-valorem surcharge in Kansas and the expiration of the rider associated with the recovery of take-or-pay settlements in Oklahoma, both of which are offset by lower regulatory amortization in depreciation and amortization expense; and
- a decrease of $3.7 million due primarily to warmer weather in all three states compared with colder-than-normal weather in 2013, net of weather normalization.

Operating costs increased $28.1 million due primarily to the following:

- an increase of $13.0 million in outside service costs related primarily to $6.8 million of costs associated with our separation from ONEOK and $3.7 million in pipeline maintenance activities;
- an increase of $12.6 million in insurance, information technology and rent expenses;
- an increase of $11.0 million in employee-related expenses resulting from higher labor and compensation costs; and
- an increase of $1.7 million in bad debt expense; offset partially by
- a decrease of $8.0 million in benefit costs related primarily to lower pension and other postemployment benefit costs resulting from an annual change in the estimated discount rate.

Depreciation and amortization expense increased due primarily to the settlement agreement approved by the KCC authorizing the separation of the Kansas Gas Service assets from ONEOK to us, whereby Kansas Gas Service agreed to expense a $10.2 million regulatory asset related to a transaction cost recovery and an increase in the amortization of amounts previously deferred for ad valorem taxes, which is offset in net margin.

Capital Expenditures - Our capital expenditures program includes expenditures for pipeline integrity, automated meter reading, extending service to new areas, modifications to customer service lines, increasing system capabilities, pipeline replacements, government-mandated relocation of pipelines, fleet and facilities, and information technology hardware and software. It is our practice to maintain and upgrade our infrastructure, facilities and systems to ensure safe, reliable and efficient operations.

Capital expenditures decreased $2.8 million for 2015, compared with 2014, due primarily to reduced spending on information technology hardware and software in 2014 related to our separation from ONEOK. Capital expenditures increased $5.0 million for 2014, compared with 2013, primarily as a result of an increase in spending on information technology hardware and software related to our separation from ONEOK. Our capital expenditures are expected to be approximately $305.0 million for 2016.

Selected Operating Information - The following tables set forth certain selected operating information for the periods indicated:

	Years Ended December 31,								Variances 2015 vs. 2014			
(in thousands)	2015				2014				Increase (Decrease)			
Average Number of Customers	**OK**	**KS**	**TX**	**Total**	**OK**	**KS**	**TX**	**Total**	**OK**	**KS**	**TX**	**Total**
Residential	**783**	**579**	**606**	**1,968**	776	578	601	1,955	**7**	**1**	**5**	**13**
Commercial and industrial	**73**	**50**	**34**	**157**	72	50	34	156	**1**	**—**	**—**	**1**
Wholesale and public authority	**—**	**—**	**3**	**3**	—	—	4	4	**—**	**—**	**(1)**	**(1)**
Transportation	**5**	**6**	**1**	**12**	5	6	1	12	**—**	**—**	**—**	**—**
Total customers	**861**	**635**	**644**	**2,140**	853	634	640	2,127	**8**	**1**	**4**	**13**

	Years Ended December 31,								Variances 2014 vs. 2013			
(in thousands)	2014				2013				Increase (Decrease)			
Average Number of Customers	**OK**	**KS**	**TX**	**Total**	**OK**	**KS**	**TX**	**Total**	**OK**	**KS**	**TX**	**Total**
Residential	776	578	601	1,955	770	577	597	1,944	6	1	4	11
Commercial and industrial	72	50	34	156	72	50	33	155	—	—	1	1
Wholesale and public authority	—	—	4	4	—	—	3	3	—	—	1	1
Transportation	5	6	1	12	5	6	1	12	—	—	—	—
Total customers	853	634	640	2,127	847	633	634	2,114	6	1	6	13

	Years Ended December 31,		
Volumes *(MMcf)*	**2015**	**2014**	**2013**
Natural gas sales			
Residential	**115,477**	125,337	122,855
Commercial and industrial	**35,943**	38,555	36,956
Wholesale and public authority	**2,615**	2,454	4,403
Total volumes sold	**154,035**	166,346	164,214
Transportation	**204,763**	213,456	205,915
Total volumes delivered	**358,798**	379,802	370,129

Total volumes delivered decreased for 2015, compared with 2014, due primarily to warmer temperatures in 2015. Residential and commercial and industrial natural gas sales volumes increased for 2014, compared with 2013, due primarily to colder temperatures in the first quarter of 2014. The impacts on margins for the periods presented were mitigated largely by weather-normalization mechanisms.

Wholesale sales represent contracted natural gas volumes that exceed the needs of our residential, commercial and industrial customer base and are available for sale to other parties. The impact to net margin from changes in volumes associated with these customers is minimal.

Heating Degree Days	2015 Actual	2015 Normal	2014 Actual	2014 Normal	2015 vs 2014 Actual Variance	2015 Actual as a percent of Normal	2014 Actual as a percent of Normal
Oklahoma	**3,135**	**3,317**	3,720	3,317	**(16)%**	**95%**	112%
Kansas	**4,264**	**4,860**	5,179	4,860	**(18)%**	**88%**	107%
Texas	**1,715**	**1,785**	1,716	1,788	**— %**	**96%**	96%

Years Ended December 31,

Heating Degree Days	2014 Actual	2014 Normal	2013 Actual	2013 Normal	2014 vs 2013 Actual Variance	2014 Actual as a percent of Normal	2013 Actual as a percent of Normal
Oklahoma	3,720	3,317	3,848	3,317	(3)%	112%	116%
Kansas	5,179	4,860	5,246	4,860	(1)%	107%	108%
Texas	1,716	1,788	1,942	1,793	(12)%	96%	108%

Normal HDDs are established through rate proceedings in each of our rate jurisdictions for use primarily in weather normalization billing calculations. Normal HDDs disclosed above are based on:

- 10-year weighted average HDDs as of December 31, 2014, for years 2005-2014, as calculated using 11 weather stations across Oklahoma and weighted on average customer count for Oklahoma;
- 30-year average for years 1981-2010 published by the National Oceanic and Atmospheric Administration, as calculated using 13 weather stations across Kansas and weighted on HDDs by weather station and customers for Kansas; and
- a rolling 10-year average of actual natural gas distribution sales volumes by service area for Texas.

Actual HDDs are based on quarter-to-date and year-to-date, weighted average of:

- 11 weather stations and customers by month for Oklahoma;
- 13 weather stations and customers by month for Kansas; and
- 9 weather stations and natural gas distribution sales volumes by service area for Texas.

CONTINGENCIES

We are a party to various litigation matters and claims that have arisen in the normal course of our operations. While the results of litigation and claims cannot be predicted with certainty, we believe the reasonably possible losses from such matters, individually and in the aggregate, are not material. Additionally, we believe the probable final outcome of such matters will not have a material adverse effect on our results of operations, financial position or cash flows. See Note 14 of the Notes to Financial Statements in this Annual Report for information with respect to legal proceedings.

LIQUIDITY AND CAPITAL RESOURCES

General - From the date of the separation, we have funded operating expenses, working capital requirements, including purchases of natural gas and capital expenditures primarily with operating cash flows and commercial paper. Prior to the separation, we relied primarily on operating cash flow and participation in ONEOK's cash management program for our liquidity and capital resource requirements.

We believe that the combination of the significant residential component of our customer base, the fixed-charge component of our natural gas sales net margin and our regulatory rate mechanisms that we have in place result in a stable cash flow profile. Because the energy consumption of residential customers is less volatile compared with commercial and industrial customers, our business historically has generated stable and predictable net margin and cash flows. Additionally, we have several regulatory rate mechanisms in place to reduce the lag in earning a return on our capital expenditures. We anticipate that our cash flow generated from operations and our expected short- and long-term financing arrangements will enable us to maintain our current and planned level of operations and provide us flexibility to finance our infrastructure investments.

Our ability to access capital markets for debt and equity financing under reasonable terms depends on market conditions and our financial condition and credit ratings. We believe that stronger credit ratings will provide a significant advantage to our business. By maintaining a conservative financial profile and stable revenue base, we believe that we will be able to maintain an investment-grade credit rating, which we believe will provide us access to diverse sources of capital at more favorable rates in order to finance our infrastructure investments. Credit rating agencies perform independent analyses when assigning credit ratings.

Short-term Financing - The ONE Gas Credit Agreement, which is scheduled to expire in January 2019, contains certain financial, operational and legal covenants. Among other things, these covenants include maintaining ONE Gas' total debt-to-capital ratio of no more than 70 percent at the end of any calendar quarter. The ONE Gas Credit Agreement also contains customary affirmative and negative covenants, including covenants relating to liens, indebtedness of subsidiaries, investments, changes in the nature of business, fundamental changes, transactions with affiliates, burdensome agreements, and use of proceeds. In the event of a breach of certain covenants by ONE Gas, amounts outstanding under the ONE Gas Credit Agreement may become due and payable immediately. At December 31, 2015, our total debt-to-capital ratio was 40 percent, and we were in compliance with all covenants under the ONE Gas Credit Agreement.

The ONE Gas Credit Agreement includes a $50 million sublimit for the issuance of standby letters of credit and also features an option to request an increase in the size of the facility to an aggregate of $1.2 billion from $700 million, upon satisfaction of customary conditions, including receipt of commitments from new lenders or increased commitments from existing lenders. Borrowings made under the facility are available for general corporate purposes. The ONE Gas Credit Agreement contains provisions for an applicable margin rate and an annual facility fee, both of which adjust with changes in our credit rating. Based on our current credit ratings, borrowings, if any, will accrue interest at LIBOR plus 79.5 basis points, and the annual facility fee is 8 basis points.

We may reduce the unutilized portion of the ONE Gas Credit Agreement in whole or in part without premium or penalty. The ONE Gas Credit Agreement contains customary events of default. Upon the occurrence of certain events of default, the obligations under the ONE Gas Credit Agreement may be accelerated and the commitments may be terminated.

We have a commercial paper program under which we may issue unsecured commercial paper up to a maximum amount of $700 million to fund short-term borrowing needs. The maturities of the commercial paper notes may vary but may not exceed 270 days from the date of issue. The commercial paper notes are generally sold at par less a discount representing an interest factor.

The ONE Gas Credit Agreement is available to repay the commercial paper notes, if necessary. Amounts outstanding under the commercial paper program reduce the borrowing capacity under the ONE Gas Credit Agreement.

At December 31, 2015, we had issued $12.5 million in the form of commercial paper, $1.0 million in letters of credit outstanding and had approximately $2.4 million of cash and cash equivalents. At December 31, 2015, we had no borrowings and $686.5 million of credit available under the ONE Gas Credit Agreement. The weighted-average interest rate on our commercial paper was 0.7 percent at December 31, 2015.

Debt Issuance - In January 2014, we issued senior notes, consisting of $300 million of 2.07 percent senior notes due 2019, $300 million of 3.61 percent senior notes due 2024 and $600 million of 4.658 percent senior notes due 2044 (collectively, our "Senior Notes"). The net proceeds were approximately $1.19 billion and were used to fund a one-time cash payment to ONEOK of approximately $1.13 billion as part of the separation. The remaining portion of the net proceeds was retained in order to provide sufficient financial flexibility and to support working capital requirements and capital expenditures.

The indenture governing our Senior Notes includes an event of default upon the acceleration of other indebtedness of $100 million or more. Such events of default would entitle the trustee or the holders of 25 percent in aggregate principal amount of the outstanding Senior Notes to declare those Senior Notes immediately due and payable in full.

We may redeem our Senior Notes at par, plus accrued and unpaid interest to the redemption date, starting one month, three months, and six months, respectively, before their maturity dates. Prior to these dates, we may redeem these Senior Notes, in whole or in part, at a redemption price equal to the principal amount, plus accrued and unpaid interest and a make-whole premium. The redemption price will never be less than 100 percent of the principal amount of the respective Senior Notes plus accrued and unpaid interest to the redemption date. Our Senior Notes are senior unsecured obligations, ranking equally in right of payment with all of our existing and future unsecured senior indebtedness.

Credit Ratings - Our credit ratings as of January 31, 2016 were:

Rating Agency	Rating	Outlook
Moody’s	A2	Stable
S&P	A-	Stable

Our commercial paper is currently rated Prime-1 by Moody’s and A-2 by S&P. We intend to maintain strong credit metrics while we pursue a balanced approach to capital investment and a return of capital to shareholders via a dividend that we believe will be competitive with our peer group.

Capitalization structure - As of December 31, 2015, our total capitalization structure was 40 percent debt to 60 percent equity.

Pension and Other Postemployment Benefit Plans - Information about our pension and other postemployment benefits plans, including anticipated contributions, is included under Note 12 of the Notes to Financial Statements in this Annual Report.

CASH FLOW ANALYSIS

Prior to the separation, we utilized ONEOK’s centralized cash management program that concentrated the cash assets of its operating divisions and subsidiaries in joint accounts for the purpose of providing financial flexibility and lowering the cost of borrowing, transaction costs and bank fees. Under this cash management program, depending on whether we had a short-term cash surplus or cash requirement, we provided cash to ONEOK or ONEOK provided cash to us when necessary. Subsequent to the separation, we maintain separate cash accounts from ONEOK, and our interest expense is related only to our borrowings.

We use the indirect method to prepare our Statements of Cash Flows. Under this method, we reconcile net income to cash flows provided by operating activities by adjusting net income for those items that impact net income but may not result in actual cash receipts or payments and changes in our assets and liabilities not classified as investing or financing activities during the period. Items that impact net income but may not result in actual cash receipts or payments include, but are not limited to, depreciation and amortization, deferred income taxes, share-based compensation expense and provision for doubtful accounts.

The following table sets forth the changes in cash flows by operating, investing and financing activities for the periods indicated:

	Years Ended December 31,			Variances 2015 vs. 2014	Variances 2014 vs. 2013
	2015	**2014**	**2013**	**Increase (Decrease)**	**Increase (Decrease)**
			(Millions of dollars)		
Total cash provided by (used in):					
Operating activities	**$ 394.2**	**$ 246.6**	$ 154.2	**$ 147.6**	$ 92.4
Investing activities	**(294.3)**	**(297.1)**	(290.7)	**2.8**	(6.4)
Financing activities	**(109.4)**	**59.2**	135.7	**(168.6)**	(76.5)
Change in cash and cash equivalents	**(9.5)**	**8.7**	(0.8)	**(18.2)**	9.5
Cash and cash equivalents at beginning of period	**11.9**	**3.2**	4.0	**8.7**	(0.8)
Cash and cash equivalents at end of period	**$ 2.4**	**$ 11.9**	$ 3.2	**$ (9.5)**	$ 8.7

Operating Cash Flows - Changes in cash flows from operating activities, before changes in operating assets and liabilities, are due primarily to changes in net margin and operating expenses discussed in Financial Results and Operating Information. Changes in natural gas prices and demand for our services or natural gas, whether because of general economic conditions, changes in supply or increased competition from other service providers, could affect our earnings and operating cash flows. Typically, our cash flows from operations are greater in the first half of the year compared with the second half of the year.

2015 vs. 2014 - Cash flows from operating assets and liabilities in our operating activities increased in 2015, compared to 2014, due primarily to the collection of trade receivables, tax receivables, payment of trade payables and the recovery of natural gas purchase costs, including natural gas in storage, through our purchased-gas cost adjustment mechanisms, which were impacted by warmer weather and lower natural gas costs. The timing of cash collections from customers and payments to vendors and suppliers vary from period to period in the normal course of business and directly impact our cash flows from operations. In addition, our changes in income taxes receivable were impacted by an extension of the IRS rules for bonus depreciation.

2014 vs. 2013 - Cash flows from operating assets and liabilities in our operating activities increased in 2014, compared to 2013, due primarily to the collection of trade receivables, payment of trade payables and the recovery of natural gas purchase costs through our purchased-gas cost adjustment mechanisms. The timing of cash collections from customers and payments to vendors and suppliers vary from period to period in the normal course of business and directly impact our cash flows from operations.

Investing Cash Flows - 2015 vs. 2014 - Cash used in investing activities decreased for 2015, compared to 2014, due primarily to capital expenditures for information technology hardware and software associated with our separation from ONEOK.

2014 vs. 2013 - Cash used in investing activities increased for 2014, compared to 2013, due primarily to capital expenditures for information technology hardware and software associated with our separation from ONEOK.

Financing Cash Flows - 2015 vs. 2014 - Cash used in financing activities increased for 2015, compared with 2014, due primarily to an increase in the dividend rate of two cents, an additional quarter of dividends paid in 2015, a decrease in our outstanding notes payable, and purchases of treasury stock used to offset shares issued under our equity compensation and employee stock purchase plans.

2014 vs. 2013 - Cash used in financing activities decreased for 2014, compared with 2013 due primarily to the $1.19 billion debt issuance and $1.13 billion cash payment to ONEOK in connection with our separation from ONEOK in 2014, compared with our participation in ONEOK’s cash management program and our distributions to ONEOK in 2013.

ENVIRONMENTAL, SAFETY AND REGULATORY MATTERS

Environmental Matters - We are subject to multiple historical, wildlife preservation and environmental laws and/or regulations that affect many aspects of our present and future operations. Regulated activities include, but are not limited to, those involving air emissions, storm water and wastewater discharges, handling and disposal of solid and hazardous wastes, wetland preservation, hazardous materials transportation, and pipeline and facility construction. These laws and regulations require us to obtain and/or comply with a wide variety of environmental clearances, registrations, licenses, permits and other approvals. Failure to comply with these laws, regulations, licenses and permits may expose us to fines, penalties and/or interruptions in our operations that could be material to our results of operations. In addition, emission controls and/or other regulatory or permitting mandates under the Clean Air Act and other similar federal and state laws could require unexpected capital expenditures. We cannot assure that existing environmental statutes and regulations will not be revised or that new regulations will not be adopted or become applicable to us. Revised or additional statutes or regulations that result in increased compliance costs or additional operating restrictions could have a material adverse effect on our business, financial condition, results of operations and cash flows.

We own or retain legal responsibility for the environmental conditions at 12 former manufactured natural gas sites in Kansas. These sites contain potentially harmful materials that are subject to control or remediation under various environmental laws and regulations. A consent agreement with the KDHE governs all work at these sites. The terms of the consent agreement allow us to investigate these sites and set remediation activities based upon the results of the investigations and risk analysis. Remediation involves typically the management of contaminated soils and may involve removal of structures and monitoring and/or remediation of groundwater.

We have completed or addressed removal of the source of soil contamination at 11 of the 12 sites according to plans approved by KDHE. Regulatory closure has been achieved at three of the sites. We have begun site assessment at the remaining site where no active remediation has occurred.

Our expenditures for environmental evaluation, mitigation, remediation and compliance to date have not been significant in relation to our financial position, results of operations or cash flows, and our expenditures related to environmental matters had no material effects on earnings or cash flows during 2015, 2014 and 2013. A number of environmental issues may exist with respect to manufactured gas plants. With the trend toward stricter standards, greater regulation and more extensive permit requirements for the types of assets operated by us that are subject to environmental regulation, our environmental expenditures could increase in the future, and such expenditures may not be fully covered by insurance or recoverable in rates from our customers, and those costs may adversely affect our financial condition, results of operations and cash flows.

Pipeline Safety - We are subject to PHMSA regulations, including integrity-management regulations. PHMSA regulations require pipeline companies operating high-pressure transmission pipelines to perform integrity assessments on pipeline segments that pass through densely populated areas or near specifically designated high-consequence areas. In January 2012, the Pipeline Safety, Regulatory Certainty and Job Creation Act was signed into law. The law increased maximum penalties for violating federal pipeline safety regulations and directs the DOT and the Secretary of Transportation to conduct further review or studies on issues that may or may not be material to us. These issues include, but are not limited to, the following:

- an evaluation of whether natural gas pipeline integrity-management requirements should be expanded beyond current high-consequence areas;
- a verification of records for pipelines in class 3 and 4 locations and high-consequence areas to confirm maximum allowable operating pressures; and
- a requirement to test previously untested pipelines operating above 30 percent yield strength in high-consequence areas.

The potential capital and operating expenditures related to this legislation, the associated regulations or other new pipeline safety regulations are unknown.

Air and Water Emissions - The Clean Air Act, the Clean Water Act, analogous state laws and/or regulations promulgated thereunder, impose restrictions and controls regarding the discharge of pollutants into the air and water in the United States. Under the Clean Air Act, a federally enforceable operating permit is required for sources of significant air emissions. We may be required to incur certain capital expenditures for air-pollution-control equipment in connection with obtaining or maintaining permits and approvals for sources of air emissions. We do not expect that these expenditures will have a material impact on our respective results of operations, financial position or cash flows. The Clean Water Act imposes substantial potential liability for the removal of pollutants discharged to waters of the United States and remediation of waters affected by such discharge.

Federal, state and regional initiatives to measure and regulate greenhouse gas emissions are underway. We monitor relevant federal and state legislation to assess the potential impact on our operations. The EPA's Mandatory Greenhouse Gas Reporting Rule requires annual greenhouse gas emissions reporting as carbon dioxide equivalents from affected facilities and for the natural gas delivered by us to our natural gas distribution customers who are not otherwise required to report their own emissions. The additional cost to gather and report this emission data did not have, and we do not expect it to have, a material impact on our results of operations, financial position or cash flows. In addition, Congress has considered, and may consider in the future, legislation to reduce greenhouse gas emissions, including carbon dioxide and methane. Likewise, the EPA may institute additional regulatory rulemaking associated with greenhouse gas emissions. At this time, no rule or legislation has been enacted that assesses any costs, fees or expenses on any of these emissions.

CERCLA - The federal CERCLA, also commonly known as Superfund, imposes strict, joint and several liability, without regard to fault or the legality of the original act, on certain classes of "persons" (defined under CERCLA) that caused and/or contributed to the release of a hazardous substance into the environment. These persons include, but are not limited to, the owner or operator of a facility where the release occurred and/or companies that disposed or arranged for the disposal of the hazardous substances found at the facility. Under CERCLA, these persons may be liable for the costs of cleaning up the hazardous substances released into the environment, damages to natural resources and the costs of certain health studies. We do not expect that our responsibilities under CERCLA will have a material impact on our respective results of operations, financial position or cash flows.

Pipeline Security - The United States Department of Homeland Security's Transportation Security Administration issued updated pipeline security guidelines in April 2012. Our pipeline facilities have been reviewed according to the current guidelines and no material changes have been required to date.

Environmental Footprint - Our environmental and climate change strategy focuses on taking steps to minimize the impact of our operations on the environment. These strategies include: (1) developing and maintaining an accurate greenhouse gas emissions inventory according to current rules issued by the EPA; (2) improving the efficiency of our various pipelines; (3) following developing technologies for emission control; and (4) utilizing practices to reduce the loss of methane from our facilities such as vintage pipe replacement which not only improves system integrity but also helps lower emissions.

We participate in the EPA's Natural Gas STAR Program to voluntarily reduce methane emissions. We continue to focus on maintaining low rates of lost-and-unaccounted-for natural gas through expanded implementation of best practices to limit the release of natural gas during pipeline and facility maintenance and operations. Additionally, the EPA is currently developing a methane emissions partnership program expected to be finalized in 2016.

Regulatory - Several regulatory initiatives impacted the earnings and future earnings potential of our business. See additional information regarding our regulatory initiatives in Management's Discussion and Analysis of Financial Condition and Results of Operations.

Additional information about our environmental matters is included in the section entitled "Environmental Matters" in Note 14 of the Notes to Financial Statements in this Annual Report. We cannot assure that existing environmental statutes and regulations will not be revised or that new regulations will not be adopted or become applicable to us. Revised or additional regulations that result in increased compliance costs or additional operating restrictions could have a material adverse effect on our business, financial condition and results of operations. Our expenditures for environmental evaluation, mitigation, remediation and compliance to date have not been significant in relation to our financial position, results of operations or cash flows, and our expenditures related to environmental matters had no material effects on earnings or cash flows during 2015, 2014 and 2013. We do not expect to incur material expenditures for these matters in the future.

IMPACT OF NEW ACCOUNTING STANDARDS

Information about the impact of new accounting standards is included in Note 1 of the Notes to Financial Statements in this Annual Report.

ESTIMATES AND CRITICAL ACCOUNTING POLICIES

The preparation of our financial statements and related disclosures in accordance with GAAP requires us to make estimates and assumptions with respect to values or conditions that cannot be known with certainty that affect the reported amounts of assets and liabilities and the disclosure of contingent assets and liabilities at the date of the financial statements. These estimates and assumptions also affect the reported amounts of revenue and expenses during the reporting period. Although we believe these estimates and assumptions are reasonable, actual results could differ from our estimates. See our Risk Factors and/or Forward-Looking Statements for factors which could impact our estimates.

The following summary sets forth what we consider to be our most critical estimates and accounting policies. Our critical accounting policies are defined as those estimates and policies most important to the portrayal of our financial condition and results of operations and that require management's most difficult, subjective or complex judgment, particularly because of the need to make estimates concerning the impact of inherently uncertain matters.

Regulation - Our operations are subject to regulation with respect to rates, service, maintenance of accounting records and various other matters by the respective regulatory authorities in the states in which we operate. We account for the financial effects of the ratemaking and accounting practices and policies of the various regulatory commissions in our financial statements. We record regulatory assets for costs that have been deferred for which future recovery through customer rates is considered probable and regulatory liabilities when it is probable that revenues will be reduced for amounts that will be credited to customers through the ratemaking process. As a result, certain costs that would normally be expensed under GAAP are capitalized or deferred on the balance sheet because it is probable they can be recovered through rates. Discontinuing the application of this method of accounting for regulatory assets and liabilities could significantly increase our operating expenses, as fewer costs would likely be capitalized or deferred on the balance sheet, which could reduce our net income. Further, regulation may impact the period in which revenues or expenses are recognized. The amounts to be recovered or recognized are based upon historical experience and our understanding of the regulations. The impact of regulation on our operations may be affected by decisions of the regulatory authorities or the issuance of new regulations.

For further discussion of regulatory assets and liabilities, see Note 9 of the Notes to Financial Statements in this Annual Report.

Impairment of Goodwill - We assess our goodwill for impairment at least annually as of July 1. Our goodwill impairment analysis performed in 2015 and 2014, utilized a qualitative assessment and did not result in any impairment indicators. Subsequent to July 1, 2015, no event has occurred indicating that the fair value is less than the carrying value.

As part of our goodwill impairment test, we first assess qualitative factors (including macroeconomic conditions, industry and market considerations, cost factors and overall financial performance) to determine whether it is more likely than not that our fair value is less than our carrying amount. If further testing is necessary, we perform a two-step impairment test for goodwill. In the first step, an initial assessment is made by comparing our fair value with our book value, including goodwill. If the fair value is less than the book value, an impairment is indicated, and we must perform a second test to measure the amount of the impairment. In the second test, we calculate the implied fair value of the goodwill by deducting the fair value of all tangible and intangible net assets from the fair value determined in step one of the assessment. If the carrying value of the goodwill exceeds the implied fair value of the goodwill, we will record an impairment charge.

To estimate our fair value, we use two generally accepted valuation approaches, an income approach and a market approach, using assumptions consistent with a market participant's perspective. Under the income approach, we use anticipated cash flows over a period of years plus a terminal value and discount these amounts to their present value using appropriate discount rates. Under the market approach, we apply acquisition multiples to forecasted cash flows. The acquisition multiples used are consistent with historical asset transactions. The forecasted cash flows are based on average forecasted cash flows over a period of years.

Our impairment tests require the use of assumptions and estimates, such as industry economic factors and the profitability of future business strategies. If actual results are not consistent with our assumptions and estimates or our assumptions and estimates change due to new information, we may be exposed to future impairment charges.

See Note 1 of the Notes to Financial Statements in this Annual Report for further discussion of goodwill.

Pension and Other Postemployment Benefits - We have defined benefit retirement plans covering eligible full-time employees. We also sponsor welfare plans that provide other postemployment medical and life insurance benefits to eligible employees who retire with at least five years of service. In connection with the separation from ONEOK, we entered into an Employee Matters Agreement with ONEOK, which provides that our employees no longer participate in benefit plans sponsored or maintained by ONEOK as of the separation date. Effective January 1, 2014, the ONEOK defined benefit pension plans and other postemployment benefit plans transferred assets and obligations related to those employees transferring to ONE Gas and vested participants who are no longer employees to the new ONE Gas plans. As a result, we recorded sponsored pension and other postemployment plan obligations of approximately $1.1 billion, and sponsored pension and other postemployment plan assets of approximately $1.0 billion. Additionally, as a result of the transfer of unrecognized losses from ONEOK, our regulatory assets and deferred income taxes increased $331 million and $86 million, respectively.

Prior to the separation, eligible employees participated in similar defined benefit pension plans and other postemployment health and welfare plans (the Plans) sponsored by ONEOK. We accounted for these plans as multiemployer benefit plans. Accordingly, we did not record an asset or liability to recognize the funded status of the Plans. We recognized a liability only for any required contributions to the Plans that were accrued and unpaid at the balance sheet date. The related pension and other postemployment expenses were allocated to us based on plan participants who directly supported our operations. These pension and other postemployment benefit costs included amounts associated with vested participants who are no longer employees. As described in Note 2 of the Notes to Financial Statements in this Annual Report, prior to 2014, ONEOK also charged us for the allocated cost of certain employees of ONEOK who provided general and administrative services on our behalf. ONEOK included an allocation of the benefit costs associated with these ONEOK employees based upon its allocation methodology, not necessarily specific to the employees providing general and administrative services on our behalf. See Note 2 of the Notes to Financial Statements in this Annual Report for discussion of ONEOK's allocation methodology.

To calculate the expense and liabilities related to our plans, we utilize an outside actuarial consultant, which uses statistical and other factors to anticipate future events. These factors include assumptions about the discount rate, expected return on plan assets, rate of future compensation increases, age and employment periods. In determining the projected benefit costs, assumptions can change from period to period and may result in material changes in the costs we recognize.

In October 2015, plan amendments were approved to merge our frozen cash-balance defined benefit pension plan covering certain Texas Gas Service employees with our defined benefit pension plan covering certain eligible employees. In addition, we announced to eligible pre-65 participants in our postemployment medical plan a change from a self-insured postemployment medical plan to a plan providing participants an annual benefit that will allow them to select coverage on a healthcare exchange. As a result, we remeasured the respective plan assets and benefit obligations, effective October 1, 2015, which resulted in a reduction in benefit obligations of our postemployment benefit plan of $11.9 million at December 31, 2015. Net periodic benefit cost for the plans in 2015 was reduced by $3.4 million. See Note 12 of the Notes to Financial Statements in this Annual Report for additional information.

During 2015, we recorded net periodic benefit costs of $38.0 million and $5.0 million related to our pension plans and other postemployment benefit plans, respectively, prior to regulatory deferrals. We estimate that in 2016, we will record $32.0 million and $1.7 million related to pension plans and other postemployment benefit plans, respectively, prior to regulatory deferrals.

The following table sets forth the weighted-average assumptions used to determine our estimated 2016 net periodic benefit cost related to our defined pension and other postemployment benefit plans, and sensitivity to changes with respect to these assumptions:

	Rate Used	Cost Sensitivity (a)	Obligation Sensitivity (b)
		(*Millions of dollars*)	
Discount rate	**4.75%**	$ **3.7**	$ **37.3**
Expected long-term return on plan assets (c)	**7.75%/8.0%**	$ **2.3**	$ **—**

(a) Approximate impact a quarter percentage point decrease in the assumed rate would have on net periodic pension costs.
(b) Approximate impact a quarter percentage point decrease in the assumed rate would have on defined benefit pension obligation.
(c) Expected long-term rate of return on plan assets for pension and other postemployment benefits are 7.75 percent and 8.0 percent, respectively.

Assumed health care cost-trend rates have a significant effect on the amounts reported for our other postemployment benefit plans. A one percentage point change in assumed health care cost trend rates would have the following effects:

	One Percentage Point Increase	One Percentage Point Decrease
	(*Millions of dollars*)	
Effect on total of service and interest cost	$ **0.8**	$ **(0.7)**
Effect on other postemployment benefit obligation	$ **3.6**	$ **(3.8)**

During 2015, we contributed approximately $14.1 million to our other postemployment benefit plans. In 2016, we expect to contribute approximately $0.9 million and approximately $5.8 million to our defined benefit pension plan and other postemployment benefit plans, respectively.

Revenue Recognition - For regulated deliveries of natural gas, we read meters and bill customers on a monthly cycle. We recognize revenues upon the delivery of natural gas commodity or services rendered to customers. Revenues are accrued for natural gas delivered and services rendered to customers, but not yet billed, based on estimates from the last meter-reading date to month end (accrued unbilled revenue). The billing cycles for customers do not necessarily coincide with the accounting periods used for financial reporting purposes. We accrue unbilled revenues for natural gas that has been delivered but not yet billed at the end of an accounting period. Accrued unbilled revenue is based on a percentage estimate of amounts unbilled each month, which is dependent upon a number of factors, some of which require management's judgment. These factors include customer consumption patterns and the impact of weather on usage.

Contingencies - Our accounting for contingencies covers a variety of business activities, including contingencies for legal and environmental exposures. We accrue these contingencies when our assessments indicate that it is probable that a liability has been incurred or an asset will not be recovered and an amount can be reasonably estimated. We expense legal fees as incurred and base our legal liability estimates on currently available facts and our assessments of the ultimate outcome or resolution. Accruals for estimated losses from environmental remediation obligations generally are recognized no later than the completion of a remediation feasibility study. Recoveries of environmental remediation costs from other parties are recorded as assets when their receipt is deemed probable. Our expenditures for environmental evaluation, mitigation, remediation and compliance to date have not been significant in relation to our financial position or results of operations, and our expenditures related to environmental matters had no material effect on earnings or cash flows for 2015, 2014 and 2013. Actual results may differ from our estimates resulting in an impact, positive or negative, on earnings.

See Note 14 of the Notes to Financial Statements in this Annual Report for additional discussion of contingencies.

CONTRACTUAL OBLIGATIONS

The following table sets forth our contractual obligations at December 31, 2015:

	Contractual Obligations						
	(*Millions of dollars*)						
	2016	2017	2018	2019	2020	Thereafter	Total
Commercial paper	$ 12.5	$ —	$ —	$ —	$ —	$ —	$ 12.5
Long-term debt, including current maturities	—	—	—	300.0	—	901.3	1,201.3
Interest payments on debt	45.1	45.1	45.1	39.4	38.9	649.2	862.8
Firm transportation and storage capacity contracts	178.2	148.0	109.4	61.3	58.2	54.2	609.3
Natural gas purchase commitments	158.1	5.0	2.0	1.5	0.9	1.5	169.0
Employee benefit plans	6.7	4.4	4.5	25.5	37.5	—	78.6
Operating leases	4.6	4.5	4.2	3.5	3.3	7.0	27.1
Total	$ 405.2	$ 207.0	$ 165.2	$ 431.2	$ 138.8	$ 1,613.2	$ 2,960.6

Commercial paper - Commercial paper includes short-term notes payable with maturities that may vary but may not exceed 270 days from the date of issue.

Long-term debt and interest payments on debt - Long-term debt includes our three debt issuances at their due dates. Interest payments on debt are calculated by multiplying our long-term debt by the respective coupon rates.

Firm transportation and storage contracts - We are party to fixed-price contracts providing us with firm transportation and storage capacity. The commitments associated with these contracts are recoverable through our purchased-gas cost mechanisms as allowed by the applicable regulatory authority.

Natural gas purchase commitments - We are party to fixed-price and variable-price contracts for the purchase of natural gas. Future variable-price natural gas purchase commitments are estimated based on market price information. Actual future variable-price purchase commitments may vary depending on market prices at the time of delivery. As market information changes daily and is potentially volatile, these values may change significantly. The commitments associated with these contracts are recoverable through our purchased-gas cost mechanisms as allowed by the applicable regulatory authority.

Employee benefit plans - Employee benefit plans include our anticipated contribution to maintain the minimum required funding level for our pension and other postemployment benefit plans. See Note 12 of the Notes to Financial Statements in this Annual Report for discussion of employee benefit plans.

Operating leases - Our operating leases include leases for office space, facilities and information technology hardware and software.

FORWARD-LOOKING STATEMENTS

Some of the statements contained and incorporated in this Annual Report are forward-looking statements within the meaning of Section 27A of the Securities Act and Section 21E of the Exchange Act. The forward-looking statements relate to our anticipated financial performance, liquidity, management's plans and objectives for our future operations, our business prospects, the outcome of regulatory and legal proceedings, market conditions and other matters. We make these forward-looking statements in reliance on the safe harbor protections provided under the Private Securities Litigation Reform Act of 1995. The following discussion is intended to identify important factors that could cause future outcomes to differ materially from those set forth in the forward-looking statements.

Forward-looking statements include the items identified in the preceding paragraph, the information concerning possible or assumed future results of our operations and other statements contained or incorporated in this Annual Report identified by words such as "anticipate," "estimate," "expect," "project," "intend," "plan," "believe," "should," "goal," "forecast," "guidance," "could," "may," "continue," "might," "potential," "scheduled," and other words and terms of similar meaning.

One should not place undue reliance on forward-looking statements, which are applicable only as of the date of this Annual Report. Known and unknown risks, uncertainties and other factors may cause our actual results, performance or achievements to be materially different from any future results, performance or achievements expressed or implied by forward-looking statements. Those factors may affect our operations, markets, products, services and prices. In addition to any assumptions and other factors referred to specifically in connection with the forward-looking statements, factors that could cause our actual results to differ materially from those contemplated in any forward-looking statement include, among others, the following:

- our ability to recover operating costs and amounts equivalent to income taxes, costs of property, plant and equipment and regulatory assets in our regulated rates;
- our ability to manage our operations and maintenance costs;
- changes in regulation, including the application of market rates by state and local agencies;
- the economic climate and, particularly, its effect on the natural gas requirements of our residential and commercial industrial customers;
- competition from alternative forms of energy, including, but not limited to, solar power, wind power, geothermal energy and biofuels;
- conservation efforts of our customers;
- variations in weather, including seasonal effects on demand, the occurrence of storms and disasters, and climate change;
- indebtedness could make us more vulnerable to general adverse economic and industry conditions, limit our ability to borrow additional funds and/or place us at competitive disadvantage compared with competitors;
- our ability to secure reliable, competitively priced and flexible natural gas transportation and supply, including decisions by natural gas producers to reduce production or shut-in producing natural gas wells and expiration of existing supply and transportation arrangements that are not replaced with contracts with similar terms and pricing;
- the mechanical integrity of facilities operated;
- operational hazards and unforeseen operational interruptions;
- adverse labor relations;
- the effectiveness of our strategies to reduce earnings lag, margin protection strategies and risk mitigation strategies;
- our ability to generate sufficient cash flows to meet all of our cash needs;
- changes in the financial markets during the periods covered by the forward-looking statements, particularly those affecting the availability of capital and our ability to refinance existing debt and fund investments and acquisitions;
- actions of rating agencies, including the ratings of debt, general corporate ratings and changes in the rating agencies' ratings criteria;
- changes in inflation and interest rates;
- our ability to purchase and sell assets at attractive prices and on other attractive terms;
- our ability to recover the costs of natural gas purchased for our customers;
- impact of potential impairment charges;
- volatility and changes in markets for natural gas;
- possible loss of LDC franchises or other adverse effects caused by the actions of municipalities;
- payment and performance by counterparties and customers as contracted and when due;
- changes in regulation of natural gas distribution services, particularly those in Oklahoma, Kansas and Texas;
- changes in law resulting from new federal or state energy legislation;
- changes in environmental, safety, tax and other laws to which we and our subsidiaries are subject;
- advances in technology;
- population growth rates and changes in the demographic patterns of the markets we serve;
- acts of nature and the potential effects of threatened or actual terrorism, including cyber attacks or breaches of technology systems and war;
- the sufficiency of insurance coverage to cover losses;
- the effects of our strategies to reduce tax payments;
- the effects of litigation and regulatory investigations, proceedings, including our rate cases, or inquiries;
- changes in accounting standards and corporate governance;
- discovery of material weaknesses in our internal controls;
- our ability to attract and retain talented management and directors;
- the results of financing efforts, including our ability to obtain financing on favorable terms, which can be affected by various factors, including our credit ratings and general economic conditions;
- declines in the market prices of debt and equity securities and resulting funding requirements for our defined benefit pension plans;
- the ability to successfully complete merger, acquisition or divestiture plans, regulatory or other limitations imposed as a result of a merger, acquisition or divestiture, and the success of the business following a merger, acquisition or divestiture;

- the final resolutions or outcomes with respect to our contingent and other corporate liabilities related to the natural gas distribution business and any related actions for indemnification made pursuant to the Separation and Distribution Agreement; and
- the costs associated with increased regulation and enhanced disclosure and corporate governance requirements pursuant to the Dodd-Frank Wall Street Reform and Consumer Protection Act of 2010.

These factors are not necessarily all of the important factors that could cause actual results to differ materially from those expressed in any of our forward-looking statements. Other factors could also have material adverse effects on our future results. These and other risks are described in greater detail in Item 1A, Risk Factors, in this Annual Report. All forward-looking statements attributable to us or persons acting on our behalf are expressly qualified in their entirety by these factors. Other than as required under securities laws, we undertake no obligation to update publicly any forward-looking statement whether as a result of new information, subsequent events or change in circumstances, expectations or otherwise.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

Our exposure to market risk discussed below includes forward-looking statements. Our views on market risk are not necessarily indicative of actual results that may occur and do not represent the maximum possible gains and losses that may occur since actual gains and losses will differ from those estimated based on actual fluctuations in commodity prices or interest rates and the timing of transactions.

Commodity Price Risk

Our commodity price risk, driven primarily by fluctuations in the price of natural gas, is mitigated by our purchased-gas cost adjustment mechanisms. We use derivative instruments to economically hedge the cost of anticipated natural gas purchases during the winter heating months to protect our customers from upward market price volatility of natural gas. Additionally, we inject natural gas into storage during the summer months and withdraw the natural gas during the winter heating season. Gains or losses associated with these derivative instruments and storage activities are included in, and recoverable through our purchased-gas cost adjustment mechanisms, which are subject to review by regulatory authorities.

Interest-Rate Risk

We are exposed to interest-rate risk primarily associated with new debt financing needed to fund capital requirements, including future contractual obligations and maturities of long-term and short-term debt. We expect to manage interest-rate risk on future borrowings through the use of fixed-rate debt, floating-rate debt and, at times, interest-rate swaps. Fixed-rate swaps may be used to reduce our risk of increased interest costs during periods of rising interest rates. Floating-rate swaps may be used to convert the fixed rates of long-term borrowings into short-term variable rates.

Counterparty Credit Risk

We assess the creditworthiness of our customers. Those customers who do not meet minimum standards are required to provide security, including deposits and other forms of collateral, when appropriate. With more than 2 million customers across three states, we are not exposed materially to a concentration of credit risk. We maintain a provision for doubtful accounts based upon factors surrounding the credit risk of customers, historical trends, consideration of the current credit environment and other information. In most jurisdictions, we are able to recover natural gas costs related to uncollectible accounts through our purchased-gas cost adjustment mechanisms.

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ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

Report of Independent Registered Public Accounting Firm

To the Board of Directors and Shareholders of ONE Gas, Inc.:

In our opinion, the accompanying balance sheets and the related statements of income, comprehensive income, equity and cash flows present fairly in all material respects, the financial position of ONE Gas, Inc. (the Company) at December 31, 2015 and 2014, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2015 in conformity with accounting principles generally accepted in the United States of America. Also in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2015, based on criteria established in *Internal Control - Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). The Company's management is responsible for these financial statements, for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in Management's Report on Internal Control Over Financial Reporting appearing under Item 9A. Our responsibility is to express opinions on these financial statements and on the Company's internal control over financial reporting based on our audits (which were integrated audits in 2015 and 2014). We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the financial statements are free of material misstatement and whether effective internal control over financial reporting was maintained in all material respects. Our audits of the financial statements included examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (ii) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (iii) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

/s/ PricewaterhouseCoopers LLP

Tulsa, Oklahoma
February 18, 2016

ONE Gas, Inc.
STATEMENTS OF INCOME

	Years Ended December 31,		
	2015	**2014**	**2013**
	(*Thousands of dollars, except per share amounts*)		
Revenues	**$ 1,547,692**	$ 1,818,906	$ 1,689,952
Cost of natural gas	**705,959**	991,949	876,944
Net margin	**841,733**	826,957	813,008
Operating expenses			
Operations and maintenance	**414,476**	420,686	393,072
Depreciation and amortization	**133,023**	125,722	144,758
General taxes	**55,105**	55,255	54,830
Total operating expenses	**602,604**	601,663	592,660
Operating income	**239,129**	225,294	220,348
Other income	**263**	1,625	6,165
Other expense	**(2,813)**	(2,949)	(3,680)
Interest expense	**(44,570)**	(45,842)	(61,366)
Income before income taxes	**192,009**	178,128	161,467
Income taxes	**(72,979)**	(68,338)	(62,272)
Net income	**$ 119,030**	$ 109,790	$ 99,195
Earnings per share			
Basic	**$ 2.26**	$ 2.10	$ 1.90
Diluted	**$ 2.24**	$ 2.07	$ 1.90
Average shares (*thousands*)			
Basic	**52,578**	52,364	52,319
Diluted	**53,254**	52,946	52,319
Dividends declared per share of stock	**$ 1.20**	$ 0.84	$ —

See accompanying Notes to Financial Statements.

ONE Gas, Inc.
STATEMENTS OF COMPREHENSIVE INCOME

	Years Ended December 31,		
	2015	**2014**	**2013**
	(*Thousands of dollars*)		
Net income	**$ 119,030**	$ 109,790	$ 99,195
Other comprehensive income (loss), net of tax			
Change in pension and other postemployment benefit plans liability, net of tax of $(483), $1,244, and $0, respectively	**773**	(1,781)	—
Total other comprehensive income (loss), net of tax	**773**	(1,781)	—
Comprehensive income	**$ 119,803**	$ 108,009	$ 99,195

See accompanying Notes to Financial Statements.

ONE Gas, Inc.
BALANCE SHEETS

		December 31, 2015		December 31, 2014
Assets		(*Thousands of dollars*)		
Property, plant and equipment				
Property, plant and equipment	**$**	**5,132,682**	$	4,850,201
Accumulated depreciation and amortization		**1,620,771**		1,556,481
Net property, plant and equipment		**3,511,911**		3,293,720
Current assets				
Cash and cash equivalents		**2,433**		11,943
Accounts receivable, net		**216,343**		326,749
Materials and supplies		**33,325**		27,511
Income tax receivable		**38,877**		43,800
Natural gas in storage		**142,153**		185,300
Regulatory assets		**32,925**		50,193
Other current assets		**16,789**		22,005
Total current assets		**482,845**		667,501
Goodwill and other assets				
Regulatory assets		**435,863**		478,723
Goodwill		**157,953**		157,953
Other assets		**55,838**		51,313
Total goodwill and other assets		**649,654**		687,989
Total assets	**$**	**4,644,410**	$	4,649,210

See accompanying Notes to Financial Statements.

ONE Gas, Inc.
BALANCE SHEETS
(Continued)

		December 31, 2015		December 31, 2014
Equity and Liabilities		*(Thousands of dollars)*		
Equity and long-term debt				
Common stock, $0.01 par value: authorized 250,000,000 shares; issued 52,598,005 shares and outstanding 52,259,224 shares at December 31, 2015; authorized 250,000,000 shares, issued and outstanding 52,083,859 shares at December 31, 2014	**$**	**526**	$	521
Paid-in capital		**1,764,875**		1,758,796
Retained earnings		**95,046**		39,894
Accumulated other comprehensive income (loss)		**(4,401)**		(5,174)
Treasury stock, at cost: 338,781 shares at December 31, 2015 and no shares at December 31, 2014		**(14,491)**		—
Total equity		**1,841,555**		1,794,037
Long-term debt, excluding current maturities		**1,201,305**		1,201,311
Total equity and long-term debt		**3,042,860**		2,995,348
Current liabilities				
Current maturities of long-term debt		**7**		6
Notes payable		**12,500**		42,000
Accounts payable		**107,482**		159,064
Accrued interest		**18,873**		18,872
Accrued taxes other than income		**37,249**		44,742
Accrued liabilities		**31,470**		26,019
Customer deposits		**60,325**		60,003
Regulatory liabilities		**24,615**		32,467
Other current liabilities		**11,700**		9,260
Total current liabilities		**304,221**		392,433
Deferred credits and other liabilities				
Deferred income taxes		**951,785**		894,585
Employee benefit obligations		**272,309**		287,779
Other deferred credits		**73,235**		79,065
Total deferred credits and other liabilities		**1,297,329**		1,261,429
Commitments and contingencies				
Total liabilities and equity	**$**	**4,644,410**	$	4,649,210

See accompanying Notes to Financial Statements.

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ONE Gas, Inc.
STATEMENTS OF CASH FLOWS

	Years Ended December 31,		
	2015	**2014**	**2013**
	(Thousands of dollars)		
Operating activities			
Net income	**$ 119,030**	$ 109,790	$ 99,195
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation and amortization	**133,023**	125,722	144,758
Deferred income taxes	**63,789**	49,935	62,205
Share-based compensation expense	**9,187**	7,613	—
Provision for doubtful accounts	**4,520**	7,195	5,460
Changes in assets and liabilities:			
Accounts receivable	**105,886**	23,044	(102,142)
Materials and supplies	**(5,814)**	10,868	(1,668)
Income tax receivable	**4,923**	(43,800)	—
Natural gas in storage	**43,147**	(19,172)	(63,139)
Asset removal costs	**(51,608)**	(47,125)	(46,567)
Affiliate payable	**—**	—	(8,140)
Accounts payable	**(59,635)**	(6,881)	37,241
Accrued interest	**1**	18,743	(1)
Accrued taxes other than income	**(7,493)**	12,316	2,449
Accrued liabilities	**5,451**	21,228	(5,443)
Customer deposits	**322**	2,643	(727)
Regulatory assets and liabilities	**50,658**	30,067	29,436
Employee benefit obligation	**(15,033)**	(10,102)	—
Other assets and liabilities	**(6,147)**	(45,421)	1,291
Cash provided by operating activities	**394,207**	246,663	154,208
Investing activities			
Capital expenditures	**(294,320)**	(297,103)	(292,080)
Proceeds from sale of assets	**—**	—	1,327
Cash used in investing activities	**(294,320)**	(297,103)	(290,753)
Financing activities			
Settlement of short-term notes payable to ONEOK, net	**—**	—	150,851
Borrowings on notes payable, net	**(29,500)**	42,000	—
Repurchase of common stock	**(24,122)**	—	—
Issuance of debt, net of discounts	**—**	1,199,994	—
Long-term debt financing costs	**—**	(11,087)	—
Cash payment to ONEOK upon separation	**—**	(1,130,000)	—
Issuance of common stock	**7,051**	2,001	—
Dividends paid	**(62,826)**	(43,696)	—
Repayment of long-term debt	**—**	—	(206)
Distributions to ONEOK	**—**	—	(14,969)
Cash provided by (used in) financing activities	**(109,397)**	59,212	135,676
Change in cash and cash equivalents	**(9,510)**	8,772	(869)
Cash and cash equivalents at beginning of period	**11,943**	3,171	4,040
Cash and cash equivalents at end of period	**$ 2,433**	$ 11,943	$ 3,171
Supplemental cash flow information:			
Cash paid for interest, net of amounts capitalized	**$ 42,980**	$ 21,066	$ —
Cash paid to ONEOK for interest, net of amounts capitalized	**$ —**	$ —	$ 61,366
Cash (received) paid for income taxes, net	**$ (5,423)**	$ 44,603	$ —
Cash paid to ONEOK for income taxes	**$ —**	$ —	$ 67

See accompanying Notes to Financial Statements.

ONE Gas, Inc.
STATEMENTS OF EQUITY

	Common Stock Issued	Common Stock	Paid-in Capital	Retained Earnings
	(Shares)	*(Thousands of dollars)*		
January 1, 2013	—	$ —	$ —	$ —
Net income	—	—	—	—
Distributions to ONEOK	—	—	—	—
Common stock issued	100	—	—	—
December 31, 2013	100	—	—	—
Net income	—	—	—	84,214
Other comprehensive loss	—	—	—	—
Net transfers from ONEOK	—	—	—	—
Reclassification of Owner's net investment to paid-in capital	—	—	1,749,078	—
Issuance of common stock at the separation	51,941,136	520	(520)	—
Common stock issued	142,623	1	9,614	—
Common stock dividends - $0.84 per share	—	—	624	(44,320)
December 31, 2014	52,083,859	521	1,758,796	39,894
Net income	**—**	**—**	**—**	**119,030**
Other comprehensive income	**—**	**—**	**—**	**—**
Repurchase of common stock	**—**	**—**	**—**	**—**
Common stock issued	**514,146**	**5**	**5,027**	**—**
Common stock dividends - $1.20 per share	**—**	**—**	**1,052**	**(63,878)**
December 31, 2015	**52,598,005**	**$ 526**	**$ 1,764,875**	**$ 95,046**

See accompanying Notes to Financial Statements.

ONE Gas, Inc.
STATEMENTS OF EQUITY
(Continued)

	Treasury Stock	Owner's Net Investment	Accumulated Other Comprehensive Income (Loss)	Total Equity
			(Thousands of dollars)	
January 1, 2013	$ —	$ 1,154,797	$ —	$ 1,154,797
Net income	—	99,195	—	99,195
Distributions to ONEOK	—	(14,969)	—	(14,969)
Common stock issued	—	—	—	—
December 31, 2013	—	1,239,023	—	1,239,023
Net income	—	25,576	—	109,790
Other comprehensive loss	—	—	(1,781)	(1,781)
Net transfers from ONEOK	—	484,479	(3,393)	481,086
Reclassification of Owner's net investment to paid-in capital	—	(1,749,078)	—	—
Issuance of common stock at the separation	—	—	—	—
Common stock issued	—	—	—	9,615
Common stock dividends - $0.84 per share	—	—	—	(43,696)
December 31, 2014	—	—	(5,174)	1,794,037
Net income	—	—	—	**119,030**
Other comprehensive income	—	—	**773**	**773**
Repurchase of common stock	**(24,122)**	—	—	**(24,122)**
Common stock issued	**9,631**	—	—	**14,663**
Common stock dividends - $1.20 per share	—	—	—	**(62,826)**
December 31, 2015	**$ (14,491)**	$ —	**$ (4,401)**	**$ 1,841,555**

See accompanying Notes to Financial Statements.

ONE Gas, Inc.
NOTES TO FINANCIAL STATEMENTS

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Organization and Nature of Operations - Prior to January 31, 2014, ONE Gas was a wholly owned subsidiary of ONEOK and comprised its former natural gas distribution business. On January 8, 2014, ONEOK's board of directors approved the distribution of all the shares of our common stock to holders of ONEOK common stock. On January 31, 2014, we became an independent, publicly traded company as a result of a distribution by ONEOK of our common stock to ONEOK's shareholders. Our common stock began trading "regular-way" under the ticker symbol "OGS" on the NYSE on February 3, 2014.

We provide natural gas distribution services to more than 2 million customers through our divisions in Oklahoma, Kansas and Texas through Oklahoma Natural Gas, Kansas Gas Service and Texas Gas Service, respectively. We serve residential, commercial, industrial and transportation customers in all three states. In addition, we also provide natural gas distribution services to wholesale and public authority customers.

Basis of Presentation - Prior to our separation from ONEOK, our financial statements were derived from ONEOK's financial statements, which included its natural gas distribution business as if we, for accounting purposes, had been a separate company for all periods presented. The assets and liabilities in the financial statements have been reflected on a historical basis. The financial statements for periods prior to the separation also include expense allocations for certain corporate functions historically performed by ONEOK, including allocations of general corporate expenses related to executive oversight, accounting, treasury, tax, legal, information technology and other services. We believe our assumptions underlying the financial statements, including the assumptions regarding the allocation of general corporate expenses from ONEOK, are reasonable. However, the financial statements may not include all of the actual expenses that would have been incurred by us and may not reflect our results of operations, financial position and cash flows had we been a separate publicly traded company during the periods presented prior to the separation.

Because the operations of the natural gas distribution business within ONEOK were conducted through separate divisions, ONEOK's net investment in us, excluding the long-term line of credit with ONEOK, is shown as owner's net investment in lieu of equity in the financial statements prior to the separation. Transactions between ONEOK and us that were not part of the long-term line of credit with ONEOK or the short-term note payable to ONEOK have been identified in the Statements of Equity as a net transfer from ONEOK.

All financial information presented after the separation represents the results of operations, financial position and cash flows of ONE Gas. Accordingly:

- Our Statements of Income and Comprehensive Income for the year ended December 31, 2014, consist of the results of ONE Gas for the eleven months ended December 31, 2014, and the results of ONE Gas Predecessor for the one month ended January 31, 2014. Our Statements of Income and Comprehensive Income for the year ended December 31, 2013, consist entirely of the results of ONE Gas Predecessor. Our net income for the period prior to January 31, 2014, was recorded to owner's net investment.
- Our Statement of Cash Flows for the year ended December 31, 2014, consists of the results of ONE Gas for the eleven months ended December 31, 2014, and the results of ONE Gas Predecessor for the one month ended January 31, 2014. Our Statement of Cash Flows for the year ended December 31, 2013, consists entirely of the results of ONE Gas Predecessor.
- Our Statement of Equity for the year ended December 31, 2014, consists of both the activity for ONE Gas Predecessor prior to January 31, 2014, and the activity for ONE Gas completed in connection with, and subsequent to, the separation on January 31, 2014. Our Statement of Equity for the year ended December 31, 2013, consists entirely of the results of ONE Gas Predecessor.

The financial statements include the accounts of the natural gas distribution business as set forth in "Organization and Nature of Operations" above. All significant balances and transactions between our divisions have been eliminated.

Use of Estimates - The preparation of our financial statements and related disclosures in accordance with GAAP requires us to make estimates and assumptions with respect to values or conditions that cannot be known with certainty that affect the reported amount of assets and liabilities, and the disclosure of contingent assets and liabilities at the date of the financial statements. These estimates and assumptions also affect the reported amounts of revenue and expenses during the reporting period. Items that may be estimated include, but are not limited to, the economic useful life of assets, fair value of assets and liabilities, provisions for doubtful accounts receivable, unbilled revenues for natural gas delivered but for which meters have not been read, natural gas purchased but for which no invoice has been received, provision for income taxes, including any deferred tax valuation allowances, the results of litigation and various other recorded or disclosed amounts.

We evaluate these estimates on an ongoing basis using historical experience and other methods we consider reasonable based on the particular circumstances. Nevertheless, actual results may differ significantly from the estimates. Any effects on our financial position or results of operations from revisions to these estimates are recorded in the period when the facts that give rise to the revision become known.

Fair Value Measurements - We define fair value as the price that would be received from the sale of an asset or the transfer of a liability in an orderly transaction between market participants at the measurement date. We use the market and income approaches to determine the fair value of our assets and liabilities and consider the markets in which the transactions are executed. We measure the fair value of a group of financial assets and liabilities consistent with how a market participant would price the net risk exposure at the measurement date.

Fair Value Hierarchy - At each balance sheet date, we utilize a fair value hierarchy to classify fair value amounts recognized or disclosed in our financial statements based on the observability of inputs used to estimate such fair value. The levels of the hierarchy are described below:

- Level 1 - Unadjusted quoted prices in active markets for identical assets or liabilities;
- Level 2 - Significant observable pricing inputs other than quoted prices included within Level 1 that are, either directly or indirectly, observable as of the reporting date. Essentially, this represents inputs that are derived principally from or corroborated by observable market data; and
- Level 3 - May include one or more unobservable inputs that are significant in establishing a fair value estimate. These unobservable inputs are developed based on the best information available and may include our own internal data.

We recognize transfers into and out of the levels as of the end of each reporting period.

Determining the appropriate classification of our fair value measurements within the fair value hierarchy requires management's judgment regarding the degree to which market data is observable or corroborated by observable market data. We categorize derivatives for which fair value is determined using multiple inputs within a single level, based on the lowest level input that is significant to the fair value measurement in its entirety. See Note 8 for additional information regarding our fair value measurements.

Cash and Cash Equivalents - Cash equivalents consist of highly liquid investments, which are readily convertible into cash and have original maturities of three months or less.

Revenue Recognition - For regulated deliveries of natural gas, we read meters and bill customers on a monthly cycle. We recognize revenues upon the delivery of the natural gas commodity or services rendered to customers. The billing cycles for customers do not necessarily coincide with the accounting periods used for financial reporting purposes. Revenues are accrued for natural gas delivered and services rendered to customers, but not yet billed. Accrued unbilled revenue is based on a percentage estimate of amounts unbilled each month, which is dependent upon a number of factors, some of which require management's judgment. These factors include customer consumption patterns and the impact of weather on usage. The amounts of accrued unbilled natural gas sales revenues at December 31, 2015 and 2014, were $109.6 million and $141.7 million, respectively.

Accounts Receivable - Accounts receivable represent valid claims against nonaffiliated customers for natural gas sold or services rendered, net of allowances for doubtful accounts. We assess the creditworthiness of our customers. Those customers who do not meet minimum standards are required to provide security, including deposits and other forms of collateral, when appropriate. With more than 2 million customers across three states, we are not exposed materially to a concentration of credit risk. We maintain an allowance for doubtful accounts based upon factors surrounding the credit risk of customers, historical trends, consideration of the current credit environment and other information. In Oklahoma, Kansas and most jurisdictions we serve in Texas, we are able to recover natural gas costs related to doubtful accounts through purchased-gas cost adjustment mechanisms. At December 31, 2015 and 2014, our allowance for doubtful accounts was $3.5 million and $4.0 million, respectively.

Inventories - Natural gas in storage is maintained on the basis of weighted-average cost. Natural gas inventories that are injected into storage are recorded in inventory based on actual purchase costs, including storage and transportation costs. Natural gas inventories that are withdrawn from storage are accounted for in our purchased-gas cost adjustment mechanisms at the weighted-average inventory cost.

Materials and supplies inventories, which are included in other current assets on our Balance Sheets, are stated at the lower of weighted-average cost or net realizable value. Our materials and supplies inventories totaled $33.3 million and $27.5 million at December 31, 2015 and 2014, respectively.

Derivatives and Risk Management Activities - We record all derivative instruments at fair value, with the exception of normal purchases and normal sales that are expected to result in physical delivery. The accounting for changes in the fair value of a derivative instrument depends on whether it has been designated and qualifies as part of a hedging relationship and, if so, the reason for holding it, or if regulatory rulings require a different accounting treatment.

If certain conditions are met, we may elect to designate a derivative instrument as a hedge of exposure to changes in fair values or cash flows.

The table below summarizes the various ways in which we account for our derivative instruments and the impact on our financial statements:

	Recognition and Measurement	
Accounting Treatment	**Balance Sheet**	**Income Statement**
Normal purchases and normal sales	- Fair value not recorded	- Change in fair value not recognized in earnings
Mark-to-market	- Recorded at fair value	- Change in fair value recognized in, and recoverable through, the purchased-gas cost adjustment mechanisms

We have not elected to designate any of our derivative instruments as hedges. Gains or losses associated with the fair value of commodity derivative instruments entered into by us are included in, and recoverable through, the purchased-gas cost adjustment mechanisms.

See Note 8 for additional information regarding our fair value measurements and hedging activities using derivatives.

Property, Plant and Equipment - Our properties are stated at cost, which includes direct construction costs such as direct labor, materials, burden and AFUDC. Generally, the cost of our property retired or sold, plus removal costs, less salvage, is charged to accumulated depreciation. Gains and losses from sales or retirement of an entire operating unit or system of our properties are recognized in income. Maintenance and repairs are charged directly to expense.

AFUDC represents the cost of borrowed funds used to finance construction activities. We capitalize interest costs during the construction or upgrade of qualifying assets. Capitalized interest is recorded as a reduction to interest expense.

Our properties are depreciated using the straight-line method over their estimated useful lives. Generally, we apply composite depreciation rates to functional groups of property having similar economic circumstances. We periodically conduct depreciation studies to assess the economic lives of our assets. These depreciation studies are completed as a part of our rate proceedings, and the changes in economic lives, if applicable, are implemented prospectively when the new rates are effective. Changes in the estimated economic lives of our property, plant and equipment could have a material effect on our financial position, results of operations or cash flows.

Property, plant and equipment on our Balance Sheets includes construction work in process for capital projects that have not yet been placed in service and therefore are not being depreciated. Assets are transferred out of construction work in process when they are substantially complete and ready for their intended use.

See Note 10 for additional information regarding our property, plant and equipment.

Impairment of Goodwill and Long-Lived Assets - We assess our goodwill for impairment at least annually as of July 1. Total goodwill was $158.0 million at December 31, 2015 and 2014, respectively. Our goodwill impairment analysis performed in 2015, 2014 and 2013, utilized a qualitative assessment and did not result in any impairment indicators. Subsequent to July 1, 2015, no event has occurred indicating that it is more likely that not that our fair value is less than our carrying value of our net assets.

As part of our goodwill impairment test, we first assess qualitative factors (including macroeconomic conditions, industry and market considerations, cost factors and overall financial performance) to determine whether it is more likely than not that our fair value is less than our carrying amount. If further testing is necessary, we perform a two-step impairment test for goodwill. In the first step, an initial assessment is made by comparing our fair value with our book value, including goodwill. If the fair value is less than the book value, an impairment is indicated, and we must perform a second test to measure the amount of the impairment. In the second test, we calculate the implied fair value of the goodwill by deducting the fair value of all tangible and intangible net assets from the fair value determined in step one of the assessment. If the carrying value of the goodwill exceeds the implied fair value of the goodwill, we will record an impairment charge.

To estimate our fair value, we use two generally accepted valuation approaches, an income approach and a market approach, using assumptions consistent with a market participant's perspective. Under the income approach, we use anticipated cash flows over a period of years plus a terminal value and discount these amounts to their present value using appropriate discount rates. Under the market approach, we apply acquisition multiples to forecasted cash flows. The acquisition multiples used are consistent with historical asset transactions. The forecasted cash flows are based on average forecasted cash flows over a period of years.

We assess our long-lived assets for impairment whenever events or changes in circumstances indicate that an asset's carrying amount may not be recoverable. An impairment is indicated if the carrying amount of a long-lived asset exceeds the sum of the undiscounted future cash flows expected to result from the use and eventual disposition of the asset. If an impairment is indicated, we record an impairment loss equal to the difference between the carrying value and the fair value of the long-lived asset. We determined that there were no asset impairments in 2015, 2014 or 2013.

Regulation - We are subject to the rate regulation and accounting requirements of the OCC, KCC, RRC and various municipalities in Texas. We follow the accounting and reporting guidance for regulated operations. During the ratemaking process, regulatory authorities set the framework for what we can charge customers for our services and establish the manner that our costs are accounted for, including allowing us to defer recognition of certain costs and permitting recovery of the amounts through rates over time, as opposed to expensing such costs as incurred. Examples include weather normalization, unrecovered purchased-gas costs, pension and postemployment benefit costs and ad valorem taxes. This allows us to stabilize rates over time rather than passing such costs on to the customer for immediate recovery. Actions by regulatory authorities could have an effect on the amount recovered from rate payers. Any difference in the amount recoverable and the amount deferred is recorded as income or expense at the time of the regulatory action. A write-off of regulatory assets and costs not recovered may be required if all or a portion of the regulated operations have rates that are no longer:

- established by independent regulators;
- designed to recover the specific entity's costs of providing regulated services; and
- set at levels that will recover our costs when considering the demand and competition for our services.

See Note 9 for additional information regarding our regulatory assets and liabilities disclosures.

Pension and Other Postemployment Employee Benefits - We have defined benefit retirement plans covering eligible employees. We also sponsor welfare plans that provide other postemployment medical and life insurance benefits to eligible employees who retire with at least five years of service. To calculate the costs and liabilities related to our plans, we utilize an outside actuarial consultant, which uses statistical and other factors to anticipate future events. These factors include assumptions about the discount rate, expected return on plan assets, rate of future compensation increases, age and mortality and employment periods. In determining the projected benefit obligations and costs, assumptions can change from period to period and may result in material changes in the cost and liabilities we recognize.

Prior to the separation, certain employees participated in pension and other postemployment employee benefit plans sponsored by ONEOK. We accounted for these plans as multiemployer benefit plans. Accordingly, we did not record an asset or liability to recognize the funded status of these plans. We recognized a liability only for any required contributions to those plans that were accrued and unpaid at the balance sheet date. The related pension and other postemployment expenses were allocated to us based on plan participants who directly supported our operations. These pension and other postemployment benefit costs included amounts associated with vested participants who are no longer employees.

Prior to the separation, certain benefit costs associated with employees who directly supported our operations were determined based on a specific employee basis. We were also allocated benefit costs associated with employees of ONEOK that provided general corporate services. These amounts were charged to us by ONEOK as described in Note 2. Prior to the separation, we were not the plan sponsor for the ONEOK pension and other postemployment benefit plans. Accordingly, our balance sheets prior to the separation do not reflect any assets or liabilities related to these plans. See Note 12 for additional information regarding pension and other postemployment employee benefit plans.

Income Taxes - Deferred income taxes are recorded for the difference between the financial statement and income tax basis of assets and liabilities and carryforward items, based on income tax laws and rates existing at the time the temporary differences are expected to reverse. The effect on deferred taxes of a change in tax rates is deferred and amortized for operations regulated by the OCC, KCC, RRC and various municipalities in Texas, if, as a result of an action by a regulator, it is probable that the effect of the change in tax rates will be recovered from or returned to customers through future rates. We continue to amortize previously deferred investment tax credits for ratemaking purposes over the periods prescribed by our regulators.

A valuation allowance for deferred tax assets is recognized when it is more likely than not that some or all of the benefit from the deferred tax asset will not be realized. To assess that likelihood, we use estimates and judgment regarding our future taxable income, as well as the jurisdiction in which such taxable income is generated, to determine whether a valuation allowance is required. Such evidence can include our current financial position, our results of operations, both actual and forecasted, the reversal of deferred tax liabilities, as well as the current and forecasted business economics of our industry. We had no valuation allowance at December 31, 2015 and 2014.

We utilize a more-likely-than-not recognition threshold and measurement attribute for the financial statement recognition and measurement of a tax position that is taken or expected to be taken in a tax return. We reflect penalties and interest as part of income tax expense as they become applicable for tax provisions that do not meet the more-likely-than-not recognition threshold and measurement attribute. There were no material uncertain tax positions at December 31, 2015 and 2014.

See Note 13 for additional information regarding income taxes.

Asset Retirement Obligations - Asset retirement obligations represent legal obligations associated with the retirement of long-lived assets that result from the acquisition, construction, development and/or normal use of the asset. Certain long-lived assets that comprise our natural gas distribution systems, primarily our pipeline assets, are subject to agreements or regulations that give rise to an asset retirement obligation for removal or other disposition costs associated with retiring the assets in place upon the discontinued use of the natural gas distribution system. We recognize the fair value of a liability for an asset retirement obligation in the period when it is incurred if a reasonable estimate of the fair value can be made. We are not able to estimate reasonably the fair value of the asset retirement obligations for portions of our assets because the settlement dates are indeterminable given our expected continued use of the assets with proper maintenance. We expect our natural gas distribution systems will continue in operation as long as natural gas supply and demand for natural gas distribution service exists. Based on the widespread use of natural gas for heating and cooking activities by residential and commercial customers in our service areas, management expects supply and demand to exist for the foreseeable future.

In accordance with long-standing regulatory treatment, we collect through rates the estimated costs of removal on certain regulated properties through depreciation expense, with a corresponding credit to accumulated depreciation and amortization. These removal costs collected through our rates include costs attributable to legal and nonlegal removal obligations; however, the amounts collected that are in excess of these nonlegal asset-removal costs incurred are accounted for as a regulatory liability for financial reporting purposes. Historically, with the exception of the regulatory authority in Kansas, the regulatory authorities that have jurisdiction over our regulated operations have not required us to quantify or disclose this amount; rather, these costs are addressed prospectively in depreciation rates and are set in each general rate order. We have made an estimate of our regulatory liability using current rates since the last general rate order in each of our jurisdictions; however, for financial reporting purposes, significant uncertainty exists regarding the future disposition of this regulatory liability, pending, among other issues, clarification of regulatory intent. We continue to monitor the regulatory requirements, and the liability may be adjusted as more information is obtained. We record the estimated asset removal obligation in noncurrent liabilities in other deferred credits on our Balance Sheets. To the extent this estimated liability is adjusted, such amounts will be reclassified between accumulated depreciation and amortization and other deferred credits and therefore will not have an impact on earnings.

Contingencies - Our accounting for contingencies covers a variety of business activities, including contingencies for legal and environmental exposures. We accrue these contingencies when our assessments indicate that it is probable that a liability has been incurred or an asset will not be recovered and an amount can be estimated reasonably. We expense legal fees as incurred and base our legal liability estimates on currently available facts and our estimates of the ultimate outcome or resolution. Accruals for estimated losses from environmental remediation obligations generally are recognized no later than the completion of a remediation feasibility study. Recoveries of environmental remediation costs from other parties are recorded as assets when their receipt is deemed probable. Actual results may differ from our estimates resulting in an impact, positive or negative, on earnings. See Note 14 for additional information regarding contingencies.

Share-Based Payments - We expense the fair value of share-based payments net of estimated forfeitures. We estimate forfeiture rates based on historical forfeitures under our share-based payment plans.

Prior to the separation, ONEOK charged us for compensation expense related to stock-based compensation awards granted to our employees that directly supported our operations. Share-based compensation was also a component of allocated amounts charged to us by ONEOK for general and administrative personnel providing services on our behalf.

Earnings per share - Basic EPS is based on net income and is calculated based upon the daily weighted-average number of common shares outstanding during the periods presented. Also, this calculation includes fully vested stock awards that have not yet been issued as common stock. Diluted EPS includes the above, plus unvested stock awards granted under our compensation plans, but only to the extent these instruments dilute earnings per share.

Segments - We operate in one reportable business segment: regulated public utilities that deliver natural gas to residential, commercial, industrial and transportation customers. We define reportable business segments as components of an organization for which discrete financial information is available and operating results are evaluated on a regular basis by the chief operating decision maker (CODM) in order to assess performance and allocate resources. Our CODM is our Chief Executive Officer (CEO). Characteristics of our organization that were relied upon in making this determination include the similar nature of services we provide, the functional alignment of our organizational structure, and the reports that are regularly reviewed by the CODM for the purpose of assessing performance and allocating resources. Our management is functionally aligned and centralized, with performance evaluated based upon results of the entire distribution business. Capital allocation decisions are driven by asset integrity management and operating efficiency, not geographic location.

We evaluate performance based principally on operating income. Affiliate sales are recorded on the same basis as sales to unaffiliated customers and are discussed in further detail in Note 2. Net margin is comprised of total revenues less cost of natural gas. Cost of natural gas includes commodity purchases, fuel, storage and transportation costs and does not include an allocation of general operating costs or depreciation and amortization.

In 2015, 2014 and 2013, we had no single external customer from which we received 10 percent or more of our gross revenues.

Treasury Stock - We record treasury stock purchases at cost, which includes incremental direct transaction costs. Amounts are recorded as reductions in equity in our Balance Sheets. We record the reissuance of treasury stock at our weighted average cost of treasury shares recorded in equity in our Balance Sheets.

Recently Issued Accounting Standards Update - In October 2015, the FASB issued ASU 2015-17, “Balance Sheet Classification of Deferred Taxes,” to simplify reporting of deferred taxes. The new guidance requires all deferred tax assets and liabilities, along with any related valuation allowance, be classified as noncurrent on the balance sheet. This guidance is required to be adopted for our interim and annual reports for periods beginning after December 15, 2016, but early adoption is permitted. We have adopted this guidance early to simplify our financial reporting process, have applied it prospectively for the period beginning October 1, 2015, and it did not have a material impact on our financial statements. Prior periods were not retrospectively adjusted.

In August 2015, the FASB issued ASU 2015-15, “Interest-Imputation of Interest (Subtopic 835-30),” which specifically addresses the presentation and subsequent measurement of debt issuance costs associated with line of credit arrangements. We do not expect this issued guidance, which will be adopted concurrently with ASU 2015-03, to have a material impact on our financial statements.

In April 2015, the FASB issued ASU 2015-03, “Interest-Imputation of Interest,” which requires that debt issuance costs related to a recognized debt liability be presented in the balance sheet as a direct deduction from the carrying amount of that debt liability. We do not expect this issued guidance, which is required to be adopted for our interim and annual reports for periods beginning after December 15, 2015, to have a material impact on our financial statements.

In April 2015, the FASB issued ASU 2015-05, “Intangibles-Goodwill and Other-Internal-Use Software,” which helps entities evaluate the accounting for fees paid by a customer in a cloud computing arrangement. We do not expect this issued guidance, which is required to be adopted for our interim and annual reports for periods beginning after December 15, 2015, to have a material impact on our financial statements.

In May 2014, the FASB issued ASU 2014-09, “Revenue from Contracts with Customers,” which clarifies and converges the revenue recognition principles under GAAP and IFRS. In July 2015, FASB delayed the effective date of ASU 2014-09 for one year. We are evaluating the impact of this recently issued guidance, which is required to be adopted for our interim and annual reports beginning with the first quarter 2018.

2. SEPARATION & RELATED-PARTY TRANSACTIONS

Distribution - On January 8, 2014, ONEOK's board of directors approved the distribution of our common stock to holders of ONEOK common stock.

In order for ONEOK to effect the distribution, we requested, and the SEC declared effective, our Registration Statement on Form 10 on January 10, 2014. ONEOK transferred all of the assets and liabilities primarily related to its natural gas distribution business to us. Assets and liabilities included accounts receivable and payable, natural gas in storage, regulatory assets and liabilities, pipeline and other natural gas distribution facilities, customer deposits, employee-related assets and liabilities, including amounts attributable to pension and other postemployment benefits, tax-related assets and liabilities and other assets and liabilities primarily associated with providing natural gas distribution service in Oklahoma, Kansas and Texas. Cash and certain corporate assets, such as office space in the corporate headquarters and certain IT hardware and software, were not transferred to us; however, a Transition Services Agreement between ONEOK and us provided access to such corporate assets as necessary to operate our business for a period of time to enable us to obtain the applicable corporate assets.

Immediately prior to the contribution of the natural gas distribution business to us, ONEOK contributed to the capital of the natural gas distribution business all of the amounts outstanding on the natural gas distribution business' short-term note payable to and long-term line of credit with ONEOK. We received approximately $1.19 billion of cash from a private placement of senior notes, which were later exchanged for registered notes, then used a portion of those proceeds to fund a cash payment of approximately $1.13 billion to ONEOK. Effective January 31, 2014, the number of our authorized shares increased to 250 million shares of common stock and 50 million of preferred stock. On January 31, 2014, ONEOK distributed one share of our common stock for every four shares of ONEOK common stock held by ONEOK shareholders of record as of the close of business on January 21, 2014, the record date of the distribution. At the close of business on January 31, 2014, we became an independent, publicly traded company as a result of the distribution.

Reorganization Adjustments - We entered into the Separation and Distribution Agreement and several other agreements with ONEOK to effect the separation and provide a framework for our relationships with ONEOK after the distribution. These agreements govern the relationship between ONEOK and us subsequent to the completion of the distribution, and provide for the allocation among ONEOK and us of the assets, liabilities and obligations (including employee benefits and tax-related assets and liabilities) relating to the natural gas distribution business attributable to periods prior to, at and after the distribution. In accordance with the terms of the Separation and Distribution Agreement, ONEOK contributed the assets and liabilities of its natural gas distribution business to us. The noncash contributions below represent ONEOK assets and liabilities attributable to pension and other postemployment employee benefits, general corporate assets and liabilities and related deferred taxes not included previously in the ONE Gas Predecessor balance sheet, but the costs for which were included in ONE Gas Predecessor's results of operations. The table below also includes the contribution of the short-term note payable to and long-term line of credit with ONEOK previously included in ONE Gas Predecessor balance sheets. The assets and liabilities below were recorded at historical cost as the reorganization was among entities under common control. Net transfers from ONEOK included:

(Thousands of dollars)		
Property, plant and equipment, net	**$**	**21,459**
Regulatory assets, pension and other postemployment benefits		**331,148**
Other assets		**80,700**
Long-term line of credit with ONEOK		**1,027,631**
Short-term note payable to ONEOK		**397,857**
Pension and other postemployment benefits - liabilities		**(123,800)**
Other liabilities		**(34,404)**
Deferred taxes		**(86,112)**
Accumulated other comprehensive loss		**(3,393)**
Net contribution of assets (liabilities)	**$**	**1,611,086**
Less: Cash paid to ONEOK		**1,130,000**
Net transfers from ONEOK	**$**	**481,086**

Affiliate Transactions - Prior to our separation, we had certain transactions with ONEOK and its subsidiaries. We purchased a portion of our natural gas supply and natural gas transportation and storage services from ONEOK and its affiliates. These contracts were awarded through a competitive-bidding process, and the costs were recoverable through our purchased-gas cost adjustment mechanisms.

Prior to our separation, the Statements of Income included expense allocations for certain corporate functions historically performed by ONEOK and allocated to its natural gas distribution business, including allocations of general corporate expenses related to executive oversight, accounting, treasury, tax, legal, information technology and facilities maintenance. Where costs were incurred specifically on our behalf, the costs were billed directly to us by ONEOK. In other situations, the costs were allocated to us through a variety of methods, depending upon the nature of the expenses. For example, a service that applied equally to all employees of ONEOK was allocated based upon the number of employees in each ONEOK affiliate. An expense benefiting us but having no direct basis for allocation was allocated by the modified Distrigas method, a method using a combination of ratios that include gross plant and investment, operating income and payroll expense. It is not practicable to determine what these general overhead costs would be on a stand-alone basis. These allocations included the following costs:

Corporate Services - These represent costs for certain employees of ONEOK who provided general and administrative services on our behalf. These charges were either directly identifiable or allocated based upon usage factors for our operations. In addition, we received other allocated costs for our share of general corporate expenses of ONEOK, which were determined based on our relative use of the service or, if there was no direct basis for allocation, were allocated by the modified Distrigas method. All of these costs are reflected in operations and maintenance and depreciation expense in the Statements of Income.

Benefit Plans and Incentives - These represent benefit costs and other incentives, including group health and welfare benefits, pension plans, other postemployment benefit plans and employee stock-based compensation plans. Costs associated with incentive and stock-based compensation plans were determined on a specific identification basis for certain employees who directly supported our operations. All other employee benefit costs historically were allocated using a percentage factor derived from a ratio of benefit costs to salary costs for ONEOK's employees. These expenses are included in operations and maintenance expenses in the Statements of Income.

Total compensation cost, which included costs for both employees who directly supported our operations and allocations for corporate services, charged to us by ONEOK related to share-based payment plans was $15.5 million during 2013. Compensation costs charged to us by ONEOK in 2014 were not material. See Note 11 for additional information regarding share-based payments. Total cost charged to us by ONEOK related to pension and other postemployment health and welfare plans was $52.1 million during 2013, which is net of amounts deferred through regulatory mechanisms of $1.8 million during 2013. Cost related to pension and other postemployment health and welfare plans which was charged to us by ONEOK in 2014 was not material. See Note 12 for additional information regarding employee benefit plans.

Interest Expense - ONEOK utilized a centralized approach to cash management and the financing of its businesses. Cash receipts and cash expenditures for costs and expenses from our operations were transferred to or from ONEOK on a regular basis and recorded as increases or decreases in the balance due in short-term note payable to ONEOK under an unsecured promissory note we had in place with ONEOK. The amounts outstanding under the long-term line of credit with ONEOK and the short-term note payable to ONEOK accrued interest based on ONEOK's weighted-average cost of long-term and short-term debt, respectively.

The weighted average interest rate on amounts outstanding under the long-term line of credit with ONEOK was 5.79 percent in 2013. The interest rate on the revolver was reset each year based on ONEOK's outstanding debt plus an adjustment of 50 basis points for ONEOK's cost to administer the program.

The weighted-average interest rate for the short-term notes payable to ONEOK was 0.92 percent for 2013. Principal under these notes payable beared interest based on ONEOK's weighted-average cost of short-term debt, plus a utilization fee of 50 basis points, calculated monthly.

The following table shows ONEOK's and its subsidiaries' transactions with us included in the Statements of Income for the periods indicated:

	Year Ended December 31, 2013
	(Thousands of dollars)
Cost of natural gas	$ 226,582
Operations and maintenance	
Direct employee labor and benefit costs	177,526
Allocated employee labor and benefit costs	29,955
Charges for general and administrative services	36,078
Depreciation and amortization	6,940
Other (income)/expense, net	(5,073)
Interest expense	60,930
Total	$ 532,938

Employee labor and benefit costs capitalized totaled $49.3 million for 2013. In addition, we recorded regulated utility revenue from ONEOK and its subsidiaries. This amount was immaterial for the period presented.

The remaining related party transactions prior to the separation were not material in 2014.

3. CREDIT FACILITY AND SHORT-TERM NOTES PAYABLE

ONE Gas Credit Agreement - The ONE Gas Credit Agreement contains certain financial, operational and legal covenants. Among other things, these covenants include maintaining ONE Gas' total debt-to-capital ratio of no more than 70 percent at the end of any calendar quarter. The ONE Gas Credit Agreement also contains customary affirmative and negative covenants, including covenants relating to liens, indebtedness of subsidiaries, investments, changes in the nature of business, fundamental changes, transactions with affiliates, burdensome agreements, and use of proceeds. In the event of a breach of certain covenants by ONE Gas, amounts outstanding under the ONE Gas Credit Agreement may become due and payable immediately. At December 31, 2015, our total debt-to-capital ratio was 40 percent and we were in compliance with all covenants under the ONE Gas Credit Agreement.

The ONE Gas Credit Agreement includes a $50 million sublimit for the issuance of standby letters of credit and also features an option to request an increase in the size of the facility to an aggregate of $1.2 billion from $700 million by either commitments from new lenders or increased commitments from existing lenders. Borrowings made under the facility are available for general corporate purposes. The ONE Gas Credit Agreement contains provisions for an applicable margin rate and an annual facility fee, both of which adjust with changes in our credit rating. Based on our current credit ratings, borrowings, if any, will accrue interest at LIBOR plus 79.5 basis points, and the annual facility fee is 8 basis points.

We have a commercial paper program under which we may issue unsecured commercial paper up to a maximum amount of $700 million to fund short-term borrowing needs. The maturities of the commercial paper notes may vary but may not exceed 270 days from the date of issue. The commercial paper notes are sold generally at par less a discount representing an interest factor.

The ONE Gas Credit Agreement is available to repay the commercial paper notes, if necessary. Amounts outstanding under the commercial paper program reduce the borrowing capacity under the ONE Gas Credit Agreement. At December 31, 2015, we had $12.5 million of commercial paper and $1.0 million in letters of credit issued under the ONE Gas Credit Agreement, with no borrowings and $686.5 million of remaining credit available under the ONE Gas Credit Agreement. The weighted-average interest rate on our commercial paper was 0.70 percent and 0.32 percent at December 31, 2015 and 2014, respectively.

4. LONG-TERM DEBT

Senior notes issuance - In January 2014, we issued senior notes, consisting of $300 million of 2.07 percent senior notes due 2019, $300 million of 3.61 percent senior notes due 2024 and $600 million of 4.658 percent senior notes due 2044 (collectively, our "Senior Notes"). The net proceeds were approximately $1.19 billion and were used to fund a one-time cash payment to ONEOK of approximately $1.13 billion as part of the separation. The remaining portion of the net proceeds was retained in order to provide sufficient financial flexibility and to support working capital requirements and capital expenditures.

The indenture governing our Senior Notes includes an event of default upon the acceleration of other indebtedness of $100 million or more. Such events of default would entitle the trustee or the holders of 25 percent in the aggregate principal amount of the outstanding Senior Notes to declare those senior notes immediately due and payable in full.

We may redeem our Senior Notes at par, plus accrued and unpaid interest to the redemption date, starting one month, three months, and six months, respectively, before their maturity dates. Prior to these dates, we may redeem these Senior Notes, in whole or in part, at a redemption price equal to the principal amount, plus accrued and unpaid interest and a make-whole premium. The redemption price will never be less than 100 percent of the principal amount of the respective note plus accrued and unpaid interest to the redemption date. Our Senior Notes are senior unsecured obligations, ranking equally in right of payment with all of our existing and future unsecured senior indebtedness.

5. EQUITY

Preferred Stock - At December 31, 2015, we have 50 million, $0.01 par value, authorized shares of preferred stock available. We have not issued or established any classes or series of shares of preferred stock.

Common Stock - At December 31, 2015, we had approximately 197.4 million shares of authorized common stock available for issuance.

Treasury Shares - We purchase treasury shares to be used to offset shares issued under our employee and non-employee director equity compensation and employee stock purchase plans. Our Board of Directors established an annual limit of $20 million of treasury stock purchases, exclusive of funds received through the dividend reinvestment and employee stock purchase plans. Stock purchases may be made in the open market or in private transactions at times, and in amounts that we deem appropriate. There is no guarantee as to the exact number of shares that we purchase, and we can terminate or limit the program at any time. We hold the purchased shares as treasury shares and account for them using the cost method.

Dividends Declared - In January 2016, a dividend of $0.35 per share ($1.40 per share on an annualized basis) was declared for shareholders of record on February 26, 2016, payable March 11, 2016.

6. ACCUMULATED OTHER COMPREHENSIVE INCOME (LOSS)

The following table sets forth the balance in accumulated other comprehensive income (loss) for the period indicated:

	Accumulated Other Comprehensive Income (Loss)
	(Thousands of dollars)
January 1, 2014	$ —
Transfers in upon separation	(3,393)
Pension and other postemployment benefit plans obligations	
Other comprehensive income (loss) before reclassification, net of tax of $1,442	(2,096)
Amounts reclassified from accumulated other comprehensive income (loss), net of tax of $(198)	315
Other comprehensive income (loss)	(1,781)
December 31, 2014	(5,174)
Pension and other postemployment benefit plans obligations	
Other comprehensive income (loss) before reclassification, net of tax of $(130)	**209**
Amounts reclassified from accumulated other comprehensive income (loss), net of tax of $(353)	**564**
Other comprehensive income (loss)	**773**
December 31, 2015	**$ (4,401)**

The following table sets forth the effect of reclassifications from accumulated other comprehensive income (loss) on our Statements of Income for the period indicated:

Details about Accumulated Other Comprehensive Income (Loss) Components	Year Ended December 31, 2015	2014	Affected Line Item in the Statements of Income
	(Thousands of dollars)		
Pension and other postemployment benefit plan obligations (a)			
Amortization of net loss	**$ 47,494**	$ 34,169	
Amortization of unrecognized prior service cost	**(1,962)**	(1,211)	
	45,532	32,958	
Regulatory adjustments (b)	**(44,615)**	(32,445)	
	917	513	Income before income taxes
	(353)	(198)	Income tax expense
Total reclassifications for the period	**$ 564**	$ 315	Net income

(a) These components of accumulated other comprehensive income (loss) are included in the computation of net periodic benefit cost. See Note 12 for additional information regarding our net periodic benefit cost.
(b) Regulatory adjustments represent pension and other postemployment benefit costs expected to be recovered through rates and are deferred as part of our regulatory assets. See Note 9 for additional information regarding our regulatory assets and liabilities.

7. EARNINGS PER SHARE

The following tables set forth the computation of basic and diluted EPS from continuing operations for the periods indicated:

	Year Ended December 31, 2015 Income	Shares	Per Share Amount
	(Thousands, except per share amounts)		
Basic EPS Calculation			
Net income available for common stock	**$ 119,030**	**52,578**	**$ 2.26**
Diluted EPS Calculation			
Effect of dilutive securities	—	**676**	
Net income available for common stock and common stock equivalents	**$ 119,030**	**53,254**	**$ 2.24**

	Year Ended December 31, 2014		
	Income	**Shares**	**Per Share Amount**
	(Thousands, except per share amounts)		
Basic EPS Calculation			
Net income available for common stock	$ 109,790	52,364	$ 2.10
Diluted EPS Calculation			
Effect of dilutive securities	—	582	
Net income available for common stock and common stock equivalents	$ 109,790	52,946	$ 2.07

	Year Ended December 31, 2013		
	Income	**Shares**	**Per Share Amount**
	(Thousands, except per share amounts)		
Basic EPS Calculation			
Net income available for common stock	$ 99,195	52,319	$ 1.90
Diluted EPS Calculation			
Effect of dilutive securities	—	—	
Net income available for common stock and common stock equivalents	$ 99,195	52,319	$ 1.90

On January 31, 2014, 51,941,236 shares of our common stock were distributed to ONEOK shareholders in conjunction with the separation. For comparative purposes, and to provide a more meaningful calculation of weighted-average shares outstanding, we have assumed this amount and any shares associated with fully vested stock awards that have not been issued to be outstanding as of the beginning of each period prior to the separation presented in the calculation of weighted-average shares.

8. DERIVATIVE FINANCIAL INSTRUMENTS AND FAIR VALUE MEASUREMENTS

Derivative Instruments - At December 31, 2015, we held purchased natural gas call options for the heating season ending March 2016, with total notional amounts of 17.0 Bcf, for which we paid premiums of $5.8 million, and had a fair value of $0.4 million. At December 31, 2014, we held purchased natural gas call options for the heating season ended March 2015, with total notional amounts of 16.0 Bcf, for which we paid premiums of $6.4 million, and had a fair value of $0.1 million. The premiums paid and any cash settlements received are recorded as part of our unrecovered purchased-gas costs in current regulatory assets as these contracts are included in, and recoverable through, the purchased-gas cost adjustment mechanisms. Additionally, changes in fair value associated with these contracts are deferred as part of our unrecovered purchased-gas costs in our Balance Sheets. Our natural gas call options are classified as Level 1 as fair value amounts are based on unadjusted quoted prices in active markets including NYMEX-settled prices. There were no transfers between levels for the periods presented.

Other Financial Instruments - The approximate fair value of cash and cash equivalents, accounts receivable and accounts payable is equal to book value, due to the short-term nature of these items. Our cash and cash equivalents are comprised of bank and money market accounts, and are classified as Level 1.

Short-term notes payable and commercial paper are due upon demand and, therefore, the carrying amounts approximate fair value and are classified as Level 1. The book value of our long-term debt, including current maturities, was $1.2 billion at both December 31, 2015 and 2014. The estimated fair value of our long-term debt, including current maturities, was $1.2 billion and $1.3 billion at December 31, 2015 and 2014, respectively. The estimated fair value of our Senior Notes was determined using quoted market prices, and are considered Level 2.

9. REGULATORY ASSETS AND LIABILITIES

The table below presents a summary of regulatory assets, net of amortization, and liabilities for the periods indicated:

		December 31, 2015		
	Remaining Recovery Period	Current	Noncurrent	Total
		(Thousands of dollars)		
Under-recovered purchased-gas costs	1 year	**$ 13,336**	**$ —**	**$ 13,336**
Pension and other postemployment benefit costs	See Note 12	**15,670**	**425,175**	**440,845**
Weather normalization	1 year	**2,198**	**—**	**2,198**
Reacquired debt costs	12 years	**812**	**8,919**	**9,731**
Other	1 to 23 years	**909**	**1,769**	**2,678**
Total regulatory assets, net of amortization		**32,925**	**435,863**	**468,788**
Accumulated removal costs (a)	up to 50 years	**—**	**(9,032)**	**(9,032)**
Over-recovered purchased-gas costs	1 year	**(22,884)**	**—**	**(22,884)**
Ad valorem tax	1 year	**(1,731)**	**—**	**(1,731)**
Total regulatory liabilities		**(24,615)**	**(9,032)**	**(33,647)**
Net regulatory assets and liabilities		**$ 8,310**	**$ 426,831**	**$ 435,141**

(a) Included in other deferred credits in our Balance Sheets.

		December 31, 2014		
	Remaining Recovery Period	Current	Noncurrent	Total
		(Thousands of dollars)		
Under-recovered purchased-gas costs	1 year	$ 28,712	$ —	$ 28,712
Pension and other postemployment benefit costs	See Note 12	18,108	466,684	484,792
Reacquired debt costs	13 years	812	9,730	10,542
Other	1 to 24 years	2,561	2,309	4,870
Total regulatory assets, net of amortization		50,193	478,723	528,916
Accumulated removal costs (a)	up to 50 years	—	(15,451)	(15,451)
Weather normalization	1 year	(16,516)	—	(16,516)
Over-recovered purchased-gas costs	1 year	(13,055)	—	(13,055)
Ad valorem tax	1 year	(2,896)	—	(2,896)
Total regulatory liabilities		(32,467)	(15,451)	(47,918)
Net regulatory assets and liabilities		$ 17,726	$ 463,272	$ 480,998

(a) Included in other deferred credits in our Balance Sheets.

Regulatory assets on our Balance Sheets, as authorized by the various regulatory authorities, are probable of recovery. Base rates are designed to provide a recovery of cost during the period rates are in effect but do not generally provide for a return on investment for amounts we have deferred as regulatory assets. All of our regulatory assets recoverable through base rates are subject to review by the respective regulatory authorities during future rate proceedings. We are not aware of any evidence that these costs will not be recoverable through either rate riders or base rates, and we believe that we will be able to recover such costs, consistent with our historical recoveries.

Purchased-gas costs represent the natural gas costs that have been over- or under-recovered from customers through the purchased-gas cost adjustment mechanisms, and includes natural gas utilized in our operations and premiums paid and any cash settlements received from our purchased natural gas call options.

We amortize reacquired debt costs in accordance with the accounting guidelines prescribed by the OCC and KCC.

In December 2013, the KCC approved a settlement agreement between ONEOK, the staff of the KCC, and the Citizens' Utility Ratepayer Board that authorized the transfer of ONEOK's Kansas Gas Service natural gas distribution assets to us. As a result, Kansas Gas Service expensed certain transition costs associated with ONEOK's acquisition of Kansas Gas Service in 1997 that previously had been recorded as a regulatory asset and amortized and recovered in rates over a 40-year period. As such, we recorded a noncash charge to income of approximately $10.2 million before taxes during 2013 in depreciation and amortization.

Weather normalization represents revenue over- or under-recovered through the weather normalization adjustment rider in Kansas. This amount is deferred as a regulatory asset or liability for a 12-month period. Kansas Gas Service then applies an adjustment to the customers' bills for 12 months to refund the over-collected revenue or bill the under-collected revenue.

Ad valorem tax represents an increase or decrease in Kansas Gas Service's taxes above or below the amount approved in a rate case. This amount is deferred as a regulatory asset or liability for a 12-month period. Kansas Gas Service then applies an adjustment to the customers' bills for 12 months to refund the over-collected revenue or bill the under-collected revenue.

Recovery through rates resulted in amortization of regulatory assets of approximately $1.6 million and $6.4 million for the years ended December 31, 2015 and 2014, respectively. Amortization of regulatory assets of approximately $32.0 million for the year ended December 31, 2013, included amounts recovered through rates totaling $21.8 million and $10.2 million related to certain transition costs as described above.

We collect, through our rates, the estimated costs of removal on certain regulated properties through depreciation expense, with a corresponding credit to accumulated depreciation and amortization. These removal costs are nonlegal obligations; however, the amounts collected that are in excess of these nonlegal asset-removal costs incurred are accounted for as a regulatory liability. We have made an estimate of our regulatory liability using current rates since the last general rate order in each of our jurisdictions. We record the estimated nonlegal asset removal obligation in noncurrent liabilities in other deferred credits on our Balance Sheets.

In January 2016, as a result of our rate case in Oklahoma, we recorded a regulatory asset of $2.4 million to recover certain information technology costs incurred as a result of our separation from ONEOK in 2014, which will be recovered over four years.

10. PROPERTY, PLANT AND EQUIPMENT

The following table sets forth our property, plant and equipment by property type, for the periods indicated:

	December 31, 2015	December 31, 2014
	(Thousands of dollars)	
Natural gas distribution pipelines and related equipment	**$ 4,114,090**	$ 3,909,881
Natural gas transmission pipelines and related equipment	**462,654**	450,810
General plant and other	**498,906**	418,157
Construction work in process	**57,032**	71,353
Property, plant and equipment	**5,132,682**	4,850,201
Accumulated depreciation and amortization	**(1,620,771)**	(1,556,481)
Net property, plant and equipment	**$ 3,511,911**	$ 3,293,720

We compute depreciation expense for distribution operations by applying composite, straight-line rates approved by various regulatory authorities. The average depreciation rates for our property are set forth in the following table for the periods indicated:

Years Ended December 31,		
2015	**2014**	**2013**
2.0% - 3.0%	2.0% - 3.0%	2.0% - 3.0%

We recorded capitalized interest of $2.6 million, $2.5 million and $1.3 million for the years ended December 31, 2015, 2014 and 2013, respectively. We incurred liabilities for construction work in process that had not been paid at December 31, 2015, 2014 and 2013 of $15.0 million, $7.0 million and $10.5 million, respectively. Such amounts are not included in capital expenditures on the Statements of Cash Flows.

Amounts recorded for regulatory accounting purposes that were not reflected in our financial statements were not material for the years ended December 31, 2015 and 2014.

11. SHARE-BASED PAYMENTS

The ONE Gas Equity Compensation Plan (ECP or ONE Gas Plan) provides for the granting of stock-based compensation, including incentive stock options, nonstatutory stock options, stock bonus awards, restricted stock awards, restricted stock unit awards, performance stock awards and performance unit awards to eligible employees and the granting of stock awards to nonemployee directors. We have reserved 2.8 million shares of common stock for issuance under the ECP. At December 31, 2015, we had approximately 1.4 million shares available for issuance under the ECP, which reflect shares issued and estimated shares expected to be issued upon vesting of outstanding awards granted under the plan, less forfeitures. The plan allows for the deferral of awards granted in stock or cash, in accordance with Internal Revenue Code section 409A requirements.

Prior to our separation, certain employees assigned to us in the separation participated in ONEOK's share-based awards plans (ONEOK Plans). The ONEOK Plans provided for ONEOK common stock based awards to both employees and ONEOK's nonemployee directors. The plans permitted the granting of various types of awards including, but not limited to, performance stock units and restricted stock units. Awards could be granted for no consideration other than prior and future services or based on certain financial performance targets. In connection with the separation, awards granted by ONEOK in 2012 and 2013 were cancelled and replaced with awards of ONE Gas shares. The number of restricted stock units held by a ONE Gas participant was multiplied by a ratio of 2.04 which was determined by the ONEOK volume-weighted average share price of $68.22 on January 31, 2014, and the ONE Gas volume-weighted average share price of $33.50 on February 3, 2014, rounded to the nearest whole share.

The same ratio of 2.04 was used to convert the outstanding performance stock units awarded by ONEOK prior to the separation into awards for ONE Gas shares. A pre-distribution payout factor was applied to each grant based on ONEOK's total shareholder return performance compared with its peer group for the number of days lapsed from the date of the grant to January 31, 2014, and these awards were frozen or "banked" and are not subject to an additional payout factor. The remaining units from each grant will continue to be at-risk based on our performance and the relative total shareholder return of our peer group.

No incremental cost was recorded in our financial statements upon cancellation and replacement of the 2012 and 2013 restricted stock units and performance stock units because the previous awards were cancelled and replaced pursuant to anti-dilution provisions of the ONEOK Plans and the fair value of the awards immediately following the cancellation and replacement was not higher than the fair value of the awards immediately before the cancellation and replacement.

We were charged by ONEOK for share-based compensation expense related to employees that directly supported our operations. ONEOK also charged us for the allocated costs of certain employees of ONEOK (including stock-based compensation) who provided general and administrative services on our behalf. Information included in this note is limited to share-based compensation associated with employees in 2014, and employees that directly supported our operations as part of ONEOK prior to our separation. See Note 2 for total costs charged to us by ONEOK.

Compensation cost expensed for our share-based payment plans was $5.7 million, net of tax benefits of $3.5 million, for 2015, and $7.0 million, net of tax benefits of $4.4 million for 2014. Compensation cost charged to us for employees directly supporting our operations by ONEOK for 2013 totaled $9.7 million, respectively, which is net of $6.1 million of tax benefits.

Restricted Stock Unit Awards - We have granted restricted stock unit awards to key employees that vest over a service period of generally three years and entitle the grantee to receive shares of our common stock. The awards granted that replaced awards granted by ONEOK in 2012 vested, and 2013 will vest, consistent with their original vesting dates in 2015 and 2016, respectively. Restricted stock unit awards granted in 2015 and 2014 and that replaced awards granted by ONEOK in 2013 accrue dividend equivalents in the form of additional restricted stock units prior to vesting. Restricted stock unit awards are measured at fair value as if they were vested and issued on the grant date, reduced by expected dividend payments for awards that do not accrue dividends and adjusted for estimated forfeitures. Compensation expense is recognized on a straight-line basis over the vesting period of the award. A forfeiture rate of 3 percent per year based on historical forfeitures under our share-based payment plans is used.

Performance Stock Unit Awards - We have granted performance stock unit awards to key employees. The shares of common stock underlying the performance stock units vest at the expiration of a service period of generally three years if certain performance criteria are met by us as determined by the Executive Compensation Committee of the Board of Directors. The awards granted that replaced awards granted by ONEOK in 2012 vested, and 2013 will vest, consistent with their original vesting dates in 2015 and 2016, respectively, if certain performance criteria are met by us for the at-risk portion of the awards as described above. Upon vesting, a holder of performance stock units is entitled to receive a number of shares of common stock equal to a percentage (0 percent to 200 percent) of the performance stock units granted, based on our total shareholder return over the vesting period, compared with the total shareholder return of a peer group of other utilities over the same period.

If paid, the outstanding performance stock unit awards entitle the grantee to receive shares of our common stock. The outstanding performance stock unit awards are equity awards with a market-based condition, which results in the compensation expense for these awards being recognized on a straight-line basis over the requisite service period, provided that the requisite service period is fulfilled, regardless of when, if ever, the market condition is satisfied. The new performance stock unit awards granted in 2015 and 2014 and the grants that replaced awards granted by ONEOK in 2013 accrue dividend equivalents in the form of additional performance stock units prior to vesting. The fair value of these performance stock units was estimated on the grant date based on a Monte Carlo model. The compensation expense on these awards will only be adjusted for changes in forfeitures. A forfeiture rate of 3 percent per year based on historical forfeitures under our and, prior to the separation, ONEOK's share-based payment plans was used.

Restricted Stock Unit Award Activity

As of December 31, 2015, there was $3.2 million of total unrecognized compensation costs related to the nonvested restricted stock unit awards, which is expected to be recognized over a weighted-average period of 1.8 years. The following tables set forth activity and various statistics for restricted stock unit awards outstanding under the respective plans for the period indicated:

	Number of Shares		Weighted-Average Price
Nonvested December 31, 2014	325,730	$	23.47
Granted	**75,880**	**$**	**41.40**
Vested	**(162,280)**	**$**	**18.32**
Forfeited	**(8,072)**	**$**	**34.42**
Nonvested December 31, 2015	**231,258**	**$**	**32.59**

		2015		2014		2013
Weighted-average grant date fair value (per share)	**$**	**41.40**	$	33.19	$	47.36
Fair value of shares granted (thousands of dollars)	**$**	**3,141**	$	3,149	$	1,323

Performance Stock Unit Award Activity

As of December 31, 2015, there was $4.7 million of total unrecognized compensation cost related to the nonvested performance stock unit awards, which is expected to be recognized over a weighted-average period of 1.7 years. The following tables set forth activity and various statistics related to our performance stock unit awards and the assumptions used by us, and ONEOK prior to 2014, in the valuations of the 2015, 2014 and 2013 grants at the grant date:

	Number of Units		Weighted-Average Price
Nonvested December 31, 2014	847,951	$	17.62
Granted	**100,860**	**$**	**44.48**
Vested	**(502,474)**	**$**	**14.33**
Forfeited	**(7,087)**	**$**	**30.22**
Nonvested December 31, 2015	**439,250**	**$**	**27.35**

	2015		2014		2013	
Volatility	**15.90%**	(a)	18.40%	(a)	22.27%	(b)
Dividend yield	**2.90%**		3.37%		3.04%	
Risk-free interest rate	**1.10%**		0.67%		0.42%	

(a) - Volatility based on historical volatility over three years using daily stock price observations of our peer utilities.

(b) - Volatility based on historical volatility over three years using daily ONEOK stock price observations.

	2015		2014		2013	
Weighted-average grant date fair value (per share)	**$**	**44.48**	$	35.98	$	52.30
Fair value of shares granted (thousands of dollars)	**$**	**4,486**	$	4,462	$	2,926

Employee Stock Purchase Plan

We have reserved a total of 0.7 million shares of common stock for issuance under our Employee Stock Purchase Plan (the ESPP). Subject to certain exclusions, all employees who work at least 20 hours per week are eligible to participate in the ESPP. Employees can choose to have up to 10 percent of their annual base pay withheld to purchase our common stock, subject to terms and limitations of the plan. The purchase price of the stock is 85 percent of the lower of the average market price of our common stock on the grant date or exercise date. Approximately 40 percent and 36 percent of employees participated in the plan in 2015 and 2014, respectively, and purchased 51,092 shares at $36.15 in 2015 and 51,418 shares at $32.29 in 2014. Compensation expense, before taxes, was $1.3 million and $0.4 million in 2015 and 2014, respectively. All eligible employees of ONEOK were eligible to participate in a similar ESPP plan, but enrollment of our employees in that plan was terminated upon the separation. Compensation expense, before tax, charged to us by ONEOK for employees who directly supported our operations was $2.7 million for 2013.

Employee Stock Award Program

Under the program, each time the per-share closing price of our common stock on the NYSE closed for the first time at or above each $1.00 increment above its previous historical high closing price, we issued, for no monetary consideration, one share of our common stock to all eligible employees. The total number of shares of our common stock authorized for issuance under this program is 125,000. Shares issued to employees under this program during 2015 and 2014 totaled 23,506 and 35,324, and compensation expense, before taxes, related to the Employee Stock Award Program was $1.1 million and $2.5 million for 2015 and 2014, respectively. Compensation expense, before taxes, charged to us by ONEOK related to a similar program to ours that was administered by ONEOK for employees who directly supported our operations was $4.2 million for 2013.

12. EMPLOYEE BENEFIT PLANS

Retirement and Other Postemployment Benefit Plans

Prior to separation, certain employees participated in the Plans sponsored by ONEOK. We accounted for the Plans as multiemployer benefit plans. These defined benefit pension and other postemployment benefit costs included amounts associated with vested participants who are no longer employees. As described in Note 2, prior to 2014, ONEOK also charged us for the allocated cost of certain employees of ONEOK who provided general and administrative services on our behalf. ONEOK included an allocation of the benefit costs associated with these ONEOK employees based upon its allocation methodology, not necessarily specific to the employees providing general and administrative services on our behalf.

Retirement Plans - We have a defined benefit pension plan covering nonbargaining-unit employees hired before January 1, 2005, and certain bargaining-unit employees hired before December 15, 2011. Nonbargaining unit employees hired after December 31, 2004; employees represented by Local No. 304 of the International Brotherhood of Electrical Workers (IBEW) hired on or after July 1, 2010; employees represented by the United Steelworkers hired on or after December 15, 2011; and employees who accepted a one-time opportunity to opt out of the defined benefit pension plan are covered by a profit-sharing plan. Certain employees of the Texas Gas Services division were entitled to benefits under a frozen cash-balance pension plan. In addition, we have a supplemental executive retirement plan for the benefit of certain officers. No new participants in the supplemental executive retirement plan have been approved since 2005, and it was formally closed to new participants as of January 1, 2014. We fund our defined benefit pension costs at a level needed to maintain or exceed the minimum funding levels required by the Employee Retirement Income Security Act of 1974, as amended, and the Pension Protection Act of 2006. Pension expense was $38.0 million and $27.1 million in 2015 and 2014, respectively, prior to regulatory deferrals. Pension expense charged to us by ONEOK for employees directly supporting our operations totaled $35.0 million for 2013, prior to regulatory deferrals.

Other Postemployment Benefit Plans - We sponsor health and welfare plans that provide postemployment medical and life insurance benefits to certain employees who retire with at least five years of service. The postemployment medical plan is contributory based on hire date, age and years of service, with retiree contributions adjusted periodically, and contains other cost-sharing features such as deductibles and coinsurance. Other postemployment benefit expense was $5.0 million and $5.9

million in 2015 and 2014, respectively, prior to regulatory deferrals. Other postemployment benefit expense charged to us by ONEOK for employees directly supporting our operations totaled $12.3 million for 2013, prior to regulatory deferrals.

Plan Amendments - In October 2015, plan amendments were approved to merge our frozen cash-balance defined benefit pension plan covering certain Texas Gas Service employees with our defined benefit pension plan covering certain eligible employees. In addition, we announced to eligible pre-65 participants in our postemployment medical plans a change from a self-insured postemployment medical plan to a plan providing participants an annual benefit that will allow them to select coverage on a healthcare exchange. As a result, we remeasured the respective plan assets and benefit obligations, effective October 1, 2015, which resulted in a reduction in benefit obligations of our postemployment benefit plan of $11.9 million. Net periodic benefit cost for the plans in 2015 was reduced by $3.4 million.

Actuarial Assumptions - The following table sets forth the weighted-average assumptions used to determine benefit obligations for pension and postemployment benefits for the periods indicated:

	December 31,	
	2015	**2014**
Discount rate	**4.75%**	4.25%
Compensation increase rate	**3.35% - 3.40%**	3.30% - 3.50%

The following table sets forth the weighted-average assumptions used by us, and ONEOK prior to 2014, to determine the periodic benefit costs for the periods indicated:

	Nine Months Ended September 30,	**Three Months Ended December 31,**	**Years Ended December 31,**	
	2015	**2015**	**2014**	**2013**
Discount rate - pension plans	**4.25%**	**4.75%**	5.25%	4.25%
Discount rate - other postemployment plans	**4.25%**	**4.75%**	5.00%	4.00%
Expected long-term return on plan assets	**7.75%**	**7.75%**	7.75%	8.25%
Compensation increase rate	**3.30% - 3.50%**	**3.30% - 3.50%**	3.35% - 3.50%	3.45% - 3.50%

We determine our overall expected long-term rate of return on plan assets, based on our review of historical returns and economic growth models. At December 31, 2014, we updated our assumed mortality rates to incorporate the new set of mortality tables issued by the Society of Actuaries in October 2014.

We determine our discount rates annually. We estimate our discount rate based upon a comparison of the expected cash flows associated with our future payments under our defined benefit pension and other postemployment obligations to a hypothetical bond portfolio created using high-quality bonds that closely match expected cash flows. Bond portfolios are developed by selecting a bond for each of the next 60 years based on the maturity dates of the bonds. Bonds selected to be included in the portfolios are only those rated by Moody's as AA- or better and exclude callable bonds, bonds with less than a minimum issue size, yield outliers and other filtering criteria to remove unsuitable bonds.

Regulatory Treatment - The OCC, KCC and regulatory authorities in Texas have approved the recovery of pension costs and other postemployment benefits costs through rates for Oklahoma Natural Gas, Kansas Gas Service and Texas Gas Service, respectively. The costs recovered through rates are based on current funding requirements and the net periodic benefit cost for defined benefit pension and other postemployment costs. Differences, if any, between the expense and the amount recovered through rates would be reflected in earnings, net of authorized deferrals.

We historically have recovered defined benefit pension and other postemployment benefit costs through rates. We believe it is probable that regulators will continue to include the net periodic pension and other postemployment benefit costs in our cost of service.

Obligations and Funded Status - In connection with the separation from ONEOK, we entered into an Employee Matters Agreement with ONEOK, which provides that our employees no longer participate in benefit plans sponsored or maintained by ONEOK as of the separation date. Effective January 1, 2014, the ONEOK defined benefit pension plans and other postemployment benefit plans transferred assets and obligations related to those employees transferring to ONE Gas and vested participants who are no longer employees to the new ONE Gas plans. As a result, we recorded sponsored pension and other postemployment plan obligations of approximately $1.1 billion, and sponsored defined benefit pension and other postemployment plan assets of approximately $1.0 billion, which are reflected below as our balances at the beginning of the period. Additionally, as a result of the transfer of unrecognized losses from ONEOK, our regulatory assets and deferred income taxes increased $331 million and $86 million, respectively.

The following table sets forth our defined benefit pension and other postemployment benefit plans, benefit obligations and fair value of plan assets for the periods indicated:

	Pension Benefits		Other Postemployment Benefits	
	December 31,		December 31,	
	2015	2014	2015	2014
Changes in Benefit Obligation	*(Thousands of dollars)*			
Benefit obligation, beginning of period	**$ 1,028,171**	$ 863,620	**$ 257,688**	$ 239,171
Service cost	**13,660**	11,620	**3,257**	3,468
Interest cost	**43,542**	43,791	**10,628**	11,605
Plan participants' contributions	**—**	—	**2,915**	2,642
Actuarial loss (gain)	**(47,607)**	159,275	**(19,702)**	14,998
Benefits paid	**(52,142)**	(50,135)	**(14,632)**	(14,196)
Plan amendment	**—**	—	**(11,901)**	—
Benefit obligation, end of period	**985,624**	1,028,171	**228,253**	257,688
Change in Plan Assets				
Fair value of plan assets, beginning of period	**845,396**	840,699	**151,777**	147,237
Actual return on plan assets	**(9,026)**	53,907	**1,335**	6,912
Employer contributions	**933**	925	**14,100**	9,182
Plan participants' contributions	**—**	—	**2,915**	2,642
Benefits paid	**(52,142)**	(50,135)	**(14,632)**	(14,196)
Fair value of assets, end of period	**785,161**	845,396	**155,495**	151,777
Balance at December 31	**$ (200,463)**	$ (182,775)	**$ (72,758)**	$ (105,911)
Current liabilities	**$ (912)**	$ (907)	**$ —**	$ —
Noncurrent liabilities	**(199,551)**	(181,868)	**(72,758)**	(105,911)
Balance at December 31	**$ (200,463)**	$ (182,775)	**$ (72,758)**	$ (105,911)

The accumulated benefit obligation for our defined benefit pension plans was $934.3 million and $970.7 million at December 31, 2015 and 2014, respectively.

There are no plan assets expected to be withdrawn and returned to us in 2016.

Components of Net Periodic Benefit Cost - The following table sets forth the components of net periodic benefit cost for our defined benefit pension and other postemployment benefit plans for the period indicated:

	Pension Benefits	
	Year Ended December 31,	
	2015	**2014**
	(Thousands of dollars)	
Components of net periodic benefit cost		
Service cost	**$ 13,660**	$ 11,620
Interest cost	**43,542**	43,791
Expected return on assets	**(61,769)**	(59,862)
Amortization of unrecognized prior service cost	**266**	549
Amortization of net loss	**42,226**	30,200
Settlements	**27**	773
Net periodic benefit cost	**$ 37,952**	$ 27,071

	Other Postemployment Benefits	
	Year Ended December 31,	
	2015	**2014**
	(Thousands of dollars)	
Components of net periodic benefit cost		
Service cost	**$ 3,257**	$ 3,468
Interest cost	**10,628**	11,605
Expected return on assets	**(11,892)**	(11,393)
Amortization of unrecognized prior service cost	**(2,228)**	(1,760)
Amortization of net loss	**5,268**	3,969
Net periodic benefit cost	**$ 5,033**	$ 5,889

Other Comprehensive Income (Loss) - The following table sets forth the amounts recognized in other comprehensive income (loss) related to our defined benefit pension benefits for the period indicated:

	Pension Benefits	
	Year Ended December 31,	
	2015	**2014**
	(Thousands of dollars)	
Net gain (loss) arising during the period	**$ 339**	$ (3,543)
Amortization of loss	**917**	518
Deferred income taxes	**(483)**	1,244
Total recognized in other comprehensive income (loss)	**$ 773**	$ (1,781)

There were no amounts recognized in other comprehensive income (loss) related to our other postemployment benefits for the periods presented.

The tables below sets forth the amounts in accumulated other comprehensive income (loss) that had not yet been recognized as components of net periodic benefit expense for the periods indicated:

	Pension Benefits			
	December 31,			
		2015		2014
	(Thousands of dollars)			
Prior service credit (cost)	**$**	**—**	$	(266)
Accumulated loss		**(407,798)**		(426,862)
Accumulated other comprehensive loss before regulatory assets		**(407,798)**		(427,128)
Regulatory asset for regulated entities		**400,625**		418,699
Accumulated other comprehensive loss after regulatory assets		**(7,173)**		(8,429)
Deferred income taxes		**2,772**		3,255
Accumulated other comprehensive loss, net of tax	**$**	**(4,401)**	$	(5,174)

	Other Postemployment Benefits			
	December 31,			
		2015		2014
	(Thousands of dollars)			
Prior service credit (cost)	**$**	**14,010**	$	4,337
Accumulated loss		**(50,447)**		(64,861)
Accumulated other comprehensive loss before regulatory assets		**(36,437)**		(60,524)
Regulatory asset for regulated entities		**36,437**		60,524
Accumulated other comprehensive loss after regulatory assets		**—**		—
Deferred income taxes		**—**		—
Accumulated other comprehensive loss, net of tax	**$**	**—**	$	—

The following tables set forth the amounts recognized in either accumulated comprehensive income (loss) or regulatory assets expected to be recognized as components of net periodic benefit expense in the next fiscal year:

		Pension Benefits		Other Postemployment Benefits
Amounts to be recognized in 2016	(Thousands of dollars)			
Prior service credit (cost)	$	—	$	(3,633)
Actuarial net loss	$	35,542	$	4,608

Health Care Cost Trend Rates - The following table sets forth the assumed health care cost-trend rates for the periods indicated:

	2015	2014
Health care cost-trend rate assumed for next year	**4.00% - 7.50%**	4.00% - 7.75%
Rate to which the cost-trend rate is assumed to decline (the ultimate trend rate)	**4.00% - 5.00%**	4.00% - 5.00%
Year that the rate reaches the ultimate trend rate	**2022**	2022

Assumed health care cost-trend rates have a significant effect on the amounts reported for our health care plans. A one percentage point change in assumed health care cost-trend rates would have the following effects:

	One Percentage Point Increase	One Percentage Point Decrease
	(Thousands of dollars)	
Effect on total of service and interest cost	$ **263**	$ **(266)**
Effect on other postemployment benefit obligation	$ **3,655**	$ **(3,752)**

Plan Assets - Our investment strategy is to invest plan assets in accordance with sound investment practices that emphasize long-term fundamentals. The goal of this strategy is to maximize investment returns while managing risk in order to meet the plan's current and projected financial obligations. To achieve this strategy, we have established a liability-driven investment strategy to change the allocations as the plan reaches certain funded status. The plan's investments include a diverse blend of various domestic and international equities, investment-grade debt securities which mirror the cash flows of our liability, insurance contracts and alternative investments. The current target allocation for the assets of our defined benefit pension plan is as follows:

U.S. large-cap equities	37.4%
Investment-grade bonds	30.0%
Developed foreign large-cap equities	10.6%
Alternative investments	7.7%
Mid-cap equities	5.6%
Emerging markets equities	5.0%
Small-cap equities	3.7%
Total	100%

As part of our risk management for the plans, minimums and maximums have been set for each of the asset classes listed above. All investment managers for the plan are subject to certain restrictions on the securities they purchase and, with the exception of indexing purposes, are prohibited from owning our stock.

The following tables set forth our pension benefits and other postemployment benefits plan assets by fair value category as of the measurement date:

	Pension Benefits December 31, 2015			
Asset Category	**Level 1**	**Level 2**	**Level 3**	**Total**
	(Thousands of dollars)			
Investments:				
Equity securities (a)	$ **405,935**	$ **62,150**	$ —	$ **468,085**
Government obligations	—	**44,651**	—	**44,651**
Corporate obligations (b)	—	**139,396**	—	**139,396**
Cash and money market funds (c)	**5,429**	**10,279**	—	**15,708**
Insurance contracts and group annuity contracts	—	—	**56,465**	**56,465**
Other investments (d)	**2,884**	—	**57,972**	**60,856**
Total assets	$ **414,248**	$ **256,476**	$ **114,437**	$ **785,161**

(a) - This category represents securities of the various market sectors from diverse industries.
(b) - This category represents bonds from diverse industries.
(c) - This category is primarily money market funds.
(d) - This category represents alternative investments such as hedge funds and other financial instruments.

Asset Category	Pension Benefits December 31, 2014 Level 1	Level 2	Level 3	Total
	(Thousands of dollars)			
Investments:				
Equity securities (a)	$ 439,165	$ 66,766	$ —	$ 505,931
Government obligations	—	47,769	—	47,769
Corporate obligations (b)	—	153,412	—	153,412
Cash and money market funds (c)	4,152	16,341	—	20,493
Insurance contracts and group annuity contracts	—	—	59,877	59,877
Other investments (d)	—	—	57,914	57,914
Total assets	$ 443,317	$ 284,288	$ 117,791	$ 845,396

(a) - This category represents securities of the various market sectors from diverse industries.
(b) - This category represents bonds from diverse industries.
(c) - This category is primarily money market funds.
(d) - This category represents alternative investments such as hedge funds.

Asset Category	Other Postemployment Benefits December 31, 2015 Level 1	Level 2	Level 3	Total
	(Thousands of dollars)			
Investments:				
Equity securities (a)	**$ 54,560**	**$ 7,498**	**$ —**	**$ 62,058**
Government obligations	—	**64**	—	**64**
Corporate obligations (b)	—	**200**	—	**200**
Cash and money market funds (c)	**233**	**13,322**	—	**13,555**
Insurance contracts and group annuity contracts	—	**79,531**	—	**79,531**
Other investments (d)	**4**	—	**83**	**87**
Total assets	**$ 54,797**	**$ 100,615**	**$ 83**	**$ 155,495**

(a) - This category represents securities of the various market sectors from diverse industries.
(b) - This category represents bonds from diverse industries.
(c) - This category is primarily money market funds.
(d) - This category represents alternative investments such as hedge funds.

Asset Category	Other Postemployment Benefits December 31, 2014 Level 1	Level 2	Level 3	Total
	(Thousands of dollars)			
Investments:				
Equity securities (a)	$ 49,553	$ 12,589	$ —	$ 62,142
Government obligations	—	78	—	78
Corporate obligations (b)	—	251	—	251
Cash and money market funds (c)	964	5,894	—	6,858
Insurance contracts and group annuity contracts	—	82,353	—	82,353
Other investments (d)	—	—	95	95
Total assets	$ 50,517	$ 101,165	$ 95	$ 151,777

(a) - This category represents securities of the various market sectors from diverse industries.
(b) - This category represents bonds from diverse industries.
(c) - This category is primarily money market funds.
(d) - This category represents alternative investments such as hedge funds.

The following table sets forth the reconciliation of Level 3 fair value measurements of our pension plans for the periods indicated:

	Pension Benefits Insurance Contracts	Other Investments	Total
	(Thousands of dollars)		
January 1, 2014	$ 63,454	$ 73,590	$ 137,044
Net realized and unrealized gains (losses)	3,446	(15,676)	(12,230)
Settlements	(7,023)	—	(7,023)
December 31, 2014	$ 59,877	$ 57,914	$ 117,791
Net realized and unrealized gains	**2,188**	**58**	**2,246**
Settlements	**(5,600)**	**—**	**(5,600)**
December 31, 2015	**$ 56,465**	**$ 57,972**	**$ 114,437**

Contributions - During 2015, we contributed $0.9 million to our defined benefit pension plans and we contributed $14.1 million to our other postemployment benefit plans. In 2016, we expect to contribute $0.9 million to our defined benefit pension plans and expect to contribute $5.8 million to our other postemployment benefit plans.

Pension and Other Postemployment Benefit Payments - Benefit payments for our defined benefit pension and other postemployment benefit plans for the period ended December 31, 2015 were $52.1 million and $14.6 million, respectively. The following table sets forth the pension benefits and other postemployment benefits payments expected to be paid in 2016-2025:

	Pension Benefits	Other Postemployment Benefits
Benefits to be paid in:	*(Thousands of dollars)*	
2016	$ 53,359	$ 14,116
2017	$ 54,710	$ 13,875
2018	$ 56,201	$ 14,435
2019	$ 57,238	$ 14,956
2020	$ 58,901	$ 15,406
2021 through 2025	$ 311,194	$ 81,175

The expected benefits to be paid are based on the same assumptions used to measure our benefit obligation at December 31, 2015, and include estimated future employee service.

Other Employee Benefit Plans

401(k) Plan - We have a 401(k) Plan which covers all full-time employees, and employee contributions are discretionary. We match 100 percent of each participant's eligible contribution up to 6 percent of each participant's eligible compensation, subject to certain limits. Our contributions made to the plan were $10.2 million and $9.7 million 2015 and 2014, respectively. Prior to our separation, ONEOK maintained a similar 401(k) Plan and compensation expense charged to us for employees who directly supported our operations by ONEOK totaled $8.3 million in 2013 for ONEOK's matching contributions to this plan.

Profit-Sharing Plan - We have a profit-sharing plan for all employees that do not participate in our defined benefit pension plan. We plan to make a contribution to the profit-sharing plan each quarter equal to 1 percent of each participant's eligible compensation during the quarter. Additional discretionary employer contributions may be made at the end of each year. Employee contributions are not allowed under the plan. Our contributions made to the plan were $6.5 million and $4.0 million in 2015 and 2014, respectively. ONEOK maintained a similar Profit-Sharing Plan and compensation expense associated with ONEOK's contributions made to the plan for employees who directly supported our operations prior to the separation were $1.6 million in 2013.

Employee Deferred Compensation Plan - Our Nonqualified Deferred Compensation Plan provides select employees with the option to defer portions of their compensation and provides nonqualified deferred compensation benefits that are not available due to limitations on employer and employee contributions to qualified defined contribution plans under the federal tax laws. Contributions made to the plan were not material in 2015 and 2014. ONEOK maintained a similar plan and contributions made to the plan for employees who directly supported our operations prior to the separation were not material in 2013.

13. INCOME TAXES

The following table sets forth our provision for income taxes for the periods indicated:

	Years Ended December 31,		
	2015	2014	2013
	(*Thousands of dollars*)		
Current income tax provision			
Federal	**$ 7,135**	$ 17,006	$ —
State	**2,055**	1,397	67
Total current income tax provision	**9,190**	18,403	67
Deferred income tax provision			
Federal	**56,440**	42,024	53,562
State	**7,349**	7,911	8,643
Total deferred income tax provision	**63,789**	49,935	62,205
Total provision for income taxes	**$ 72,979**	$ 68,338	$ 62,272

The following table is a reconciliation of our income tax provision for the periods indicated:

	Years Ended December 31,		
	2015	2014	2013
	(*Thousands of dollars*)		
Income before income taxes	**$ 192,009**	$ 178,128	$ 161,467
Federal statutory income tax rate	**35%**	35%	35%
Provision for federal income taxes	**67,203**	62,345	56,513
State income taxes, net of federal tax benefit	**6,114**	6,051	5,661
Other, net	**(338)**	(58)	98
Total provision for income taxes	**$ 72,979**	$ 68,338	$ 62,272

Prior to our separation from ONEOK, our operations were included in the consolidated federal and state income tax returns of ONEOK. Our income tax provision was calculated on a separate return basis. Accordingly, we recognized deferred tax assets and liabilities for the difference between the financial statement and income tax basis of assets and liabilities and carry-forward items, based on income tax laws and rates existing at the time the temporary differences are expected to reverse as if we had been a corporation for federal and state income tax purposes. In addition, ONEOK managed its tax position based upon the tax attributes of the consolidated group. Certain attributes may not be available to use if we had been operating as an independent company.

The following table sets forth the tax effects of temporary differences that gave rise to significant portions of the deferred tax assets and liabilities for the periods indicated:

	December 31,	
	2015	2014
	(*Thousands of dollars*)	
Deferred tax assets		
Employee benefits and other accrued liabilities	**$ 110,148**	$ 128,715
Net operating loss	**—**	8,144
Other	**7,848**	5,655
Total deferred tax assets	**117,996**	142,514
Deferred tax liabilities		
Excess of tax over book depreciation	**897,667**	820,853
Purchased-gas cost adjustment	**3,999**	16,177
Other regulatory assets and liabilities, net	**168,115**	193,159
Total deferred tax liabilities	**1,069,781**	1,030,189
Net deferred tax liabilities	**$ 951,785**	$ 887,675

At December 31, 2015 and 2014, we had income taxes receivable of $38.9 million and $43.8 million, respectively.

Prior to our separation from ONEOK, we were included in the ONEOK income tax returns for all applicable years. We file income tax returns in the United States federal jurisdiction as well as in the states where we have operations. In 2015, we filed our initial United States consolidated federal tax return for the period February 1, 2014 through December 31, 2014.

We have adopted ASU 2015-17, "Balance Sheet Classification of Deferred Taxes," early to simplify our financial reporting process and have applied it prospectively for the period beginning October 1, 2015. Prior periods were not retrospectively adjusted.

14. COMMITMENTS AND CONTINGENCIES

Commitments - Operating leases represent future minimum lease payments under noncancelable leases covering office space, facilities and information technology hardware and software. Rental expense was $5.0 million in each of 2015 and 2014 and $4.8 million in 2013. The following table sets forth our operating lease payments for the periods indicated:

	Operating Leases
(Millions of dollars)	
2016	$ 4.6
2017	4.5
2018	4.2
2019	3.5
2020	3.3
Thereafter	7.0
Total	$ 27.1

Environmental Matters - We are subject to multiple historical, wildlife preservation and environmental laws and/or regulations, which affect many aspects of our present and future operations. Regulated activities include, but are not limited to, those involving air emissions, storm water and wastewater discharges, handling and disposal of solid and hazardous wastes, wetland preservation, hazardous materials transportation, and pipeline and facility construction. These laws and regulations require us to obtain and/or comply with a wide variety of environmental clearances, registrations, licenses, permits and other approvals. Failure to comply with these laws, regulations, licenses and permits may expose us to fines, penalties and/or interruptions in our operations that could be material to our results of operations. In addition, emission controls and/or other regulatory or permitting mandates under the Clean Air Act and other similar federal and state laws could require unexpected capital expenditures. We cannot assure that existing environmental statutes and regulations will not be revised or that new regulations will not be adopted or become applicable to us. Revised or additional statutes or regulations that result in increased compliance costs or additional operating restrictions could have a material adverse effect on our business, financial condition, results of operations and cash flows.

We own or retain legal responsibility for the environmental conditions at 12 former manufactured natural gas sites in Kansas. These sites contain potentially harmful materials that are subject to control or remediation under various environmental laws and regulations. A consent agreement with the KDHE governs all work at these sites. The terms of the consent agreement allow us to investigate these sites and set remediation activities based upon the results of the investigations and risk analysis. Remediation involves typically the management of contaminated soils and may involve removal of structures and monitoring and/or remediation of groundwater.

We have completed or addressed removal of the source of soil contamination at 11 of the 12 sites according to plans approved by KDHE. Regulatory closure has been achieved at three of the sites. We have begun site assessment at the remaining site where no active remediation has occurred.

Our expenditures for environmental evaluation, mitigation, remediation and compliance to date have not been significant in relation to our financial position, results of operations or cash flows, and our expenditures related to environmental matters had no material effects on earnings or cash flows during 2015, 2014 and 2013. A number of environmental issues may exist with respect to manufactured gas plants. With the trend toward stricter standards, greater regulation and more extensive permit requirements for the types of assets operated by us that are subject to environmental regulation, our environmental expenditures could increase in the future, and such expenditures may not be fully covered by insurance or recoverable in rates from our customers, and those costs may adversely affect our financial condition, results of operations and cash flows.

Pipeline Safety - We are subject to PHMSA regulations, including integrity-management regulations. PHMSA regulations require pipeline companies operating high-pressure transmission pipelines to perform integrity assessments on pipeline segments that pass through densely populated areas or near specifically designated high-consequence areas. In January 2012, the Pipeline Safety, Regulatory Certainty and Job Creation Act was signed into law. The law increased maximum penalties for violating federal pipeline safety regulations and directs the DOT and Secretary of Transportation to conduct further review or studies on issues that may or may not be material to us. These issues include but are not limited to the following:

- an evaluation of whether natural gas pipeline integrity-management requirements should be expanded beyond current high-consequence areas;
- a verification of records for pipelines in class 3 and 4 locations and high-consequence areas to confirm maximum allowable operating pressures; and
- a requirement to test previously untested pipelines operating above 30 percent yield strength in high-consequence areas.

The potential capital and operating expenditures related to this legislation, the associated regulations or other new pipeline safety regulations are unknown.

Legal Proceedings - We are a party to various litigation matters and claims that have arisen in the normal course of our operations. While the results of litigation and claims cannot be predicted with certainty, we believe the reasonably possible losses from such matters, individually and in the aggregate, are not material. Additionally, we believe the probable final outcome of such matters will not have a material adverse effect on our results of operations, financial position or cash flows.

15. QUARTERLY FINANCIAL DATA (UNAUDITED)

Year Ended December 31, 2015	**First Quarter**	**Second Quarter**	**Third Quarter**	**Fourth Quarter**
		(Thousands of dollars)		
Revenues	**$ 676,531**	**$ 256,786**	**$ 225,226**	**$ 389,149**
Net margin	**$ 262,978**	**$ 176,837**	**$ 170,502**	**$ 231,416**
Operating income	**$ 109,005**	**$ 31,270**	**$ 24,951**	**$ 73,903**
Net income	**$ 60,381**	**$ 12,076**	**$ 7,371**	**$ 39,202**
Earnings per share				
Basic	**$ 1.15**	**$ 0.23**	**$ 0.14**	**$ 0.75**
Diluted	**$ 1.13**	**$ 0.23**	**$ 0.14**	**$ 0.74**

Year Ended December 31, 2014	**First Quarter**	**Second Quarter**	**Third Quarter**	**Fourth Quarter**
		(Thousands of dollars)		
Revenues	$ 766,178	$ 296,838	$ 241,522	$ 514,368
Net margin	$ 259,836	$ 176,493	$ 166,452	$ 224,176
Operating income	$ 109,353	$ 26,812	$ 19,119	$ 70,010
Net income	$ 59,076	$ 9,454	$ 4,653	$ 36,607
Earnings per share				
Basic	$ 1.13	$ 0.18	$ 0.09	$ 0.70
Diluted	$ 1.13	$ 0.18	$ 0.09	$ 0.69

ITEM 9. CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE

None.

ITEM 9A. CONTROLS AND PROCEDURES

Evaluation of Disclosure Controls and Procedures

Our Chief Executive Officer (Principal Executive Officer) and Chief Financial Officer (Principal Financial Officer) have concluded that our disclosure controls and procedures were effective as of the end of the period covered by this report based on the evaluation of the controls and procedures required by Rule 13a-15(b) of the Exchange Act.

Management's Report on Internal Control Over Financial Reporting

Our management is responsible for establishing and maintaining adequate internal control over financial reporting, as such term is defined in Exchange Act Rule 13a-15(f). Under the supervision and with the participation of our management, including our Principal Executive Officer and Principal Financial Officer, we evaluated the effectiveness of our internal control over financial reporting based on the framework in *Internal Control-Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Because of inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate. Based on our evaluation under that framework and applicable SEC rules, our management concluded that our internal control over financial reporting was effective as of December 31, 2015.

The effectiveness of our internal control over financial reporting as of December 31, 2015, has been audited by PricewaterhouseCoopers LLP, an independent registered public accounting firm, as stated in their reports which are included herein (Item 8).

Changes in Internal Control Over Financial Reporting

There have been no changes in our internal control over financial reporting during the quarter ended December 31, 2015, that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

ITEM 9B. OTHER INFORMATION

Not applicable.

PART III.

ITEM 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE

Directors of the Registrant

Information concerning our directors is set forth in our 2016 definitive Proxy Statement and is incorporated herein by this reference.

Executive Officers of the Registrant

Information concerning our executive officers is included in Part I, Item 1, Business, of this Annual Report.

Compliance with Section 16(a) of the Exchange Act

Information on compliance with Section 16(a) of the Exchange Act is set forth in our 2016 definitive Proxy Statement and is incorporated herein by this reference.

Code of Ethics

Information concerning the code of ethics, or code of business conduct, is set forth in our 2016 definitive Proxy Statement and is incorporated herein by this reference.

Nominating Procedures

Information concerning the nominating procedures is set forth in our 2016 definitive Proxy Statement and is incorporated herein by this reference.

The Audit Committee

Information concerning the Audit Committee is set forth in our 2016 definitive Proxy Statement and is incorporated herein by this reference.

The Audit Committee Financial Experts

Information concerning the Audit Committee Financial Experts is set forth in our 2016 definitive Proxy Statement and is incorporated herein by this reference.

The Executive Compensation Committee

Information concerning the Executive Compensation Committee is set forth in our 2016 definitive Proxy Statement and is incorporated herein by this reference.

The Corporate Governance Committee

Information concerning the Corporate Governance Committee is set forth in our 2016 definitive Proxy Statement and is incorporated herein by this reference.

The Executive Committee

Information concerning the Executive Committee is set forth in our 2016 definitive Proxy Statement and is incorporated herein by this reference.

Committee Charters

The full text of our Audit Committee charter, Executive Compensation Committee charter, Corporate Governance Committee charter and Executive Committee charter are published on and may be printed from our website at www.onegas.com and are also available from our corporate secretary upon request.

ITEM 11. EXECUTIVE COMPENSATION

Information on executive compensation is set forth in our 2016 definitive Proxy Statement and is incorporated herein by this reference.

ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT AND RELATED STOCKHOLDER MATTERS

Security Ownership of Certain Beneficial Owners

Information concerning the ownership of certain beneficial owners is set forth in our 2016 definitive Proxy Statement and is incorporated herein by this reference.

Security Ownership of Management

Information on security ownership of directors and officers is set forth in our 2016 definitive Proxy Statement and is incorporated herein by this reference.

Equity Compensation Plan Information

The following table sets forth certain information concerning our equity compensation plans as of December 31, 2015:

Plan Category	Number of Securities Issued Upon Exercise of Outstanding Options, Warrants and Rights (a)	Weighted-Average Exercise Price of Outstanding Options, Warrants and Rights (b)	Number of Securities Remaining Available For Future Issuance Under Equity Compensation Plans (Excluding Securities in Column (a)) (c)
Equity compensation plans approved by security holders (1)	—	$ — (3)	2,191,002
Equity compensation plans not approved by security holders (2)	—	$ —	612,410
Total	—	$ —	2,803,412

(1) Includes restricted stock incentive units and performance-unit awards granted under our Equity Compensation Plan and our Nonqualified Deferred Compensation Plan for Nonemployee Directors. For a brief description of the material features of this plan, see Note 12 of the Notes to Financial Statements in this Annual Report.
(2) Includes shares granted under our Employee Stock Purchase Plan and Employee Stock Award Program. For a brief description of the material features of these plans, see Note 11 of the Notes to Financial Statements in this Annual Report. Column (c) includes 546,234 and 66,176 shares available for future issuance under our Employee Stock Purchase Plan and Employee Stock Award Program, respectively.
(3) Compensation deferred into our common stock under our Employee Non-Qualified Deferred Compensation Plan and Deferred Compensation Plan for Nonemployee Directors is distributed to participants at fair market value on the date of distribution. The price used for these plans to calculate the weighted-average exercise price in the table is $50.17, which represents the year-end closing price of our common stock on the NYSE.

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS, AND DIRECTOR INDEPENDENCE

Information on certain relationships and related transactions and director independence is set forth in our 2016 definitive Proxy Statement and is incorporated herein by this reference.

ITEM 14. PRINCIPAL ACCOUNTING FEES AND SERVICES

Information on the principal accountant’s fees and services is set forth in our 2016 definitive Proxy Statement and is incorporated herein by this reference.

PART IV.

ITEM 15. EXHIBITS, FINANCIAL STATEMENT SCHEDULES

(2) Financial Statements Schedules

All schedules have been omitted because of the absence of conditions under which they are required.

(3) Exhibits

2.1	Separation and Distribution Agreement, dated as of January 14, 2014, by and between ONE Gas, Inc. and ONEOK, Inc. (incorporated by reference to Exhibit 2.1 to ONE Gas, Inc.'s Current Report on Form 8-K filed on January 15, 2014 (File No. 1-36108)).
3.1	Amended and Restated Certificate of Incorporation of ONE Gas, Inc., dated January 31, 2014 (incorporated by reference to Exhibit 4.5 to ONE Gas, Inc.'s Registration Statement on Form S-8 filed on January 31, 2014 (File No. 333-193690)).
3.2	Amended and Restated By-Laws of ONE Gas, Inc. (incorporated by reference to Exhibit 4.6 to ONE Gas, Inc.'s Registration Statement on Form S-8 filed on January 31, 2014 (File No. 333-193690)).
4.1	Form of Common Stock Certificate (incorporated by reference to Exhibit 4.2 to ONE Gas, Inc.'s Registration Statement on Form 10, Amendment No. 2 filed on December 23, 2013 (File No. 1-36108)).
4.2	Indenture, dated January 27, 2014, between ONE Gas, Inc. and U.S. Bank National Association, as trustee (incorporated by reference to Exhibit 10.1 to ONE Gas, Inc.'s Current Report on Form 8-K filed on January 30, 2014 (File No. 1-36108)).
4.3	Supplemental Indenture No. 1, dated January 27, 2014, between ONE Gas, Inc. and U.S. Bank National Association, as trustee (incorporated by reference to Exhibit 10.2 to ONE Gas, Inc.'s Current Report on Form 8-K filed on January 30, 2014 (File No. 1-36108)).

4.4	Registration Rights Agreement, dated January 27, 2014, among Morgan Stanley & Co. LLC, J.P. Morgan Securities LLC and RBS Securities Inc., as representatives of the several initial purchasers named therein (incorporated by reference to Exhibit 10.3 to ONE Gas, Inc.'s Current Report on Form 8-K filed on January 30, 2014 (File No. 1-36108)).
10.1	Tax Matters Agreement, dated January 14, 2014, by and between ONE Gas, Inc. and ONEOK, Inc. (incorporated by reference to Exhibit 10.1 to ONE Gas, Inc.'s Current Report on Form 8-K filed on January 15, 2014 (File No. 1-36108)).
10.2	Transition Services Agreement, dated January 14, 2014, by and between ONE Gas, Inc. and ONEOK, Inc. (incorporated by reference to Exhibit 10.2 to ONE Gas, Inc.'s Current Report on Form 8-K filed on January 15, 2014 (File No. 1-36108)).
10.3	Employee Matters Agreement, dated January 14, 2014, by and between ONE Gas, Inc. and ONEOK, Inc. (incorporated by reference to Exhibit 10.3 to ONE Gas, Inc.'s Current Report on Form 8-K filed on January 15, 2014 (File No. 1-36108)).
10.4	Form of ONE Gas, Inc. Indemnification Agreement between ONE Gas, Inc. and ONE Gas, Inc. officers and directors (incorporated by reference to Exhibit 10.5 to ONE Gas, Inc.'s Registration Statement on Form 10 filed on October 1, 2013 (File No. 1-36108)).
10.5	ONE Gas, Inc. Annual Officer Incentive Plan (incorporated by reference to Exhibit 10.6 to ONE Gas, Inc.'s Registration Statement on Form 10, Amendment No. 2 filed on December 23, 2013 (File No. 1-36108)).
10.6	ONE Gas, Inc. Pre-2005 Nonqualified Deferred Compensation Plan (incorporated by reference to Exhibit 10.7 to ONE Gas, Inc.'s Registration Statement on Form 10, Amendment No. 2 filed on December 23, 2013 (File No. 1-36108)).
10.7	ONE Gas, Inc. Employee Nonqualified Deferred Compensation Plan (incorporated by reference to Exhibit 10.8 to ONE Gas, Inc.'s Registration Statement on Form 10, Amendment No. 2 filed on December 23, 2013 (File No. 1-36108)).
10.8	ONE Gas, Inc. Pre-2005 Supplemental Executive Retirement Plan (incorporated by reference to Exhibit 10.9 to ONE Gas, Inc.'s Registration Statement on Form 10, Amendment No. 2 filed on December 23, 2013 (File No. 1-36108)).
10.9	ONE Gas, Inc. Supplemental Executive Retirement Plan (incorporated by reference to Exhibit 10.10 to ONE Gas, Inc.'s Registration Statement on Form 10, Amendment No. 2 filed on December 23, 2013 (File No. 1-36108)).
10.10	Credit Agreement, dated as of December 20, 2013, among ONE Gas, Inc., Bank of America, N.A., as administrative agent, swingline lender and a letter of credit issuer, and the other lenders and letter of credit issuers parties thereto (incorporated by reference to Exhibit 10.2 to ONEOK, Inc.'s Current Report on Form 8-K filed on December 23, 2013 (File No. 1-13643)).
10.11	ONE Gas, Inc. Officer Change in Control Severance Plan (incorporated by reference to Exhibit 10.12 to ONE Gas, Inc.'s Registration Statement filed on Form 10, Amendment No. 2 filed on December 23, 2013 (File No. 1-36108)).
10.12	ONE Gas, Inc. Equity Compensation Plan (incorporated by reference to Exhibit 10.13 to ONE Gas, Inc.'s Registration Statement on Form 10, Amendment No. 2 filed on December 23, 2013 (File No. 1-36108)).
10.13	Form of 2014 Restricted Unit Award Agreement (incorporated by reference to Exhibit 10.13 to ONE Gas, Inc.'s Annual Report on Form 10-K filed on February 25, 2014 (File No. 1-36108)).

10.14	Form of 2014 Performance Unit Award Agreement (incorporated by reference to Exhibit 10.14 to ONE Gas, Inc.'s Annual Report on Form 10-K filed on February 25, 2014 (File No. 1-36108)).
10.15	Form of 2013 Restricted Unit Award Agreement (incorporated by reference to Exhibit 10.15 to ONE Gas, Inc.'s Annual Report on Form 10-K filed on February 25, 2014 (File No. 1-36108)).
10.16	Form of 2013 Performance Unit Award Agreement (incorporated by reference to Exhibit 10.16 to ONE Gas, Inc.'s Annual Report on Form 10-K filed on February 25, 2014 (File No. 1-36108)).
10.17	ONE Gas, Inc. Equity Compensation Plan (incorporated by reference to Appendix A to ONE Gas, Inc.'s Definitive Proxy Statement on Schedule 14A filed on April 1, 2015 (File No. 1-36108)).
10.18	ONE Gas, Inc. Employee Stock Purchase Plan (incorporated by reference to Exhibit 10.16 to ONE Gas, Inc.'s Registration Statement on Form 10, Amendment No. 2 filed on December 23, 2013 (File No. 1-36108)).
10.19	ONE Gas, Inc. Deferred Compensation Plan for Non-Employee Directors (incorporated by reference to Exhibit 10.1 to ONE Gas, Inc. Current Report on Form 8-K filed on February 24, 2014 (File No. 1-36108)).
10.20	ONE Gas, Inc. 401(k) Plan of ONE Gas Employees and Former ONE Gas Employees effective as of January 1, 2014 (incorporated by reference to Exhibit 4.4 to ONE Gas, Inc.'s Registration Statement on Form S-8 filed on January 31, 2014 (File No. 333-193690)).
10.21	Form of Commercial Paper Dealer Agreement (incorporated by reference to Exhibit 10.1 to ONE Gas, Inc.'s Current Report on Form 8-K filed on September 10, 2014 (File No. 1-36108)).
10.22	Form of 2015 Performance Unit Award Agreement (incorporated by reference to Exhibit 10.2 to ONE Gas, Inc.'s Quarterly Report on Form 10-Q filed on April 30, 2015 (File 1-36108)).
10.23	Form of 2015 Restricted Unit Award Agreement (incorporated by reference to Exhibit 10.3 to ONE Gas, Inc.'s Quarterly Report on Form 10-Q filed on April 30, 2015 (File 1-36108)).
10.24	Form of 2016 Performance Unit Award Agreement.
10.25	Form of 2016 Restricted Unit Award Agreement.
12.1	Computation of Ratio of Earnings to Fixed Charges for the years ended December 31, 2015, 2014, 2013, 2012 and 2011.
21.1	Subsidiaries of ONE Gas, Inc.
23.1	Consent of Independent Registered Public Accounting Firm - PricewaterhouseCoopers LLP.
31.1	Certification of Pierce H. Norton II pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
31.2	Certification of Curtis L. Dinan pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
32.1	Certification of Pierce H. Norton II pursuant to 18 U.S.C. Section 1350 as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 (furnished only pursuant to Rule 13a-14(b)).
32.2	Certification of Curtis L. Dinan pursuant to 18 U.S.C. Section 1350 as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 (furnished only pursuant to Rule 13a-14(b)).

101.INS	XBRL Instance Document.
101.SCH	XBRL Schema Document.
101.CAL	XBRL Calculation Linkbase Document.
101.LAB	XBRL Label Linkbase Document.
101. PRE	XBRL Presentation Linkbase Document.
101.DEF	XBRL Extension Definition Linkbase Document.

Attached as Exhibit 101 to this Annual Report are the following XBRL-related documents: (i) Document and Entity Information; (ii) Statements of Income for the years ended December 31, 2015, 2014 and 2013; (iii) Statements of Comprehensive Income for the years ended December 31, 2015, 2014 and 2013; (iv) Balance Sheets for the years ended December 31, 2015 and 2014; (v) Statements of Cash Flows for the years ended December 31, 2015, 2014 and 2013; (vi) Statements of Equity for the years ended December 31, 2015, 2014 and 2013; and (vii) Notes to Financial Statements.

We also make available on our website the Interactive Data Files submitted as Exhibit 101 to this Annual Report.

Signatures

Pursuant to the requirements of Section 13 or 15(d) of the Exchange Act, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

Date: February 18, 2016	ONE Gas, Inc.
	Registrant
	By: /s/ Curtis L. Dinan
	Curtis L. Dinan
	Senior Vice President,
	Chief Financial Officer and Treasurer

Pursuant to the requirements of the Exchange Act, this report has been signed below by the following persons on behalf of the registrant and in the capacities indicated on this 18th day of February 2016.

/s/ John W. Gibson	/s/ Pierce H. Norton II
John W. Gibson	Pierce H. Norton II
Chairman of the Board	President, Chief Executive Officer and Director
/s/ Curtis L. Dinan	/s/ Robert B. Evans
Curtis L. Dinan	Robert B. Evans
Senior Vice President, Chief Financial Officer and Treasurer (Principal Accounting Officer)	Director
/s/ Michael G. Hutchinson	/s/ Pattye L. Moore
Michael G. Hutchinson	Pattye L. Moore
Director	Director
/s/ Eduardo A. Rodriguez	/s/ Douglas H. Yaeger
Eduardo A. Rodriguez	Douglas H. Yaeger
Director	Director

Forward-looking Statements

Statements contained in this annual report that include company expectations or predictions should be considered forward-looking statements that are covered by the safe harbor provisions of the Securities Act of 1933 and the Securities Exchange Act of 1934, as amended.

It is important to note that the actual results could differ materially from those projected in such forward-looking statements.

For additional information that could cause actual results to differ materially from such forward-looking statements, refer to ONE Gas' Securities and Exchange Commission filings.

Shareholder Information

Wells Fargo Shareowner Services
P.O. Box 64874
St. Paul, MN 55164-0856
P: 1-855-217-6403
P: (Outside U.S.) 1-651-450-4064
TDD number: 1-651-450-4144
www.shareowneronline.com

Direct Stock Purchase & Dividend Reinvestment Plan
ONE Gas' Direct Stock Purchase and Dividend Reinvestment Plan provides new investors and current shareholders a convenient way to purchase ONE Gas common stock without paying processing fees or service charges and to reinvest cash dividends. For more information or to enroll in the plan, call Wells Fargo at 1-855-217-6403. The Prospectus is also available at *www.onegas.com*.

Annual Meeting Details
First Place Tower
15 East Fifth Street
Tulsa, OK 74103

May 26, 2016 – 9 a.m. CDT

Auditors
PricewaterhouseCoopers LLP
Two Warren Place
6120 South Yale Avenue, Suite 1850
Tulsa, OK 74136

Corporate Headquarters
First Place Tower
15 East Fifth Street
Tulsa, OK 74103

Credit Ratings
Moody's: A2 (Stable)
Standard & Poor's: A- (Stable)

Investor Relations
ONE Gas Investor Relations Department
P.O. Box 21049
Tulsa, OK 74121
P: 1-855-496-0200
E: IR@onegas.com

Andrew Ziola, *Vice President, Investor Relations and Public Affairs*
P: 1-918-947-7163
E: andrew.ziola@onegas.com

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FINANCIAL STATEMENTS ARE PROVIDED IN SECTION 13

KANSAS GAS SERVICE, A DIVISION OF ONE Gas, INC.
Summary of Revenue by General Customer Classification
Test Year Ended December 31, 2015

Line No.	Description	Pro Forma Revenue Existing Tariffs	Revenue Increase	Pro Forma Revenue Proposed Tariffs
	Col. 1	Col. 2	Col. 3	Col. 4
	Operating Revenues			
	Sales service revenue			
1	Residential sales service	$196,678,857	$35,446,747	$232,125,604
2	General sales service small	20,760,708	(1,902)	20,758,806
3	General sales service large	15,698,681	0	15,698,681
4	General sales service transport eligible	2,484,991	0	2,484,991
5	Small generator sales service	413,030	0	413,030
6	Gas irrigation service	343,320	0	343,320
7	Kansas Gas Supply sales service D	31,379	0	31,379
8	Sales service for resale	86,147	0	86,147
9	Total sales revenue	$236,497,113	$35,444,845	$271,941,958
	Transportation service revenue			
10	Small transportation service	$14,936,970	$0	$14,936,970
11	Compressed natural gas general transportation service	124,122	0	124,122
12	Gas irrigation transportation service	1,651,952	0	1,651,952
13	Large volume transportation service	18,464,566	0	18,464,566
14	Wholesale transportation service	1,311,435	0	1,311,435
15	Total transportation revenue	$36,489,045	$0	$36,489,045
16	Other operating revenue	$14,945,255	$0	14,945,255
17	Total operating revenues	$287,931,413	$35,444,845	$323,376,258
18	Proposed target revenue			323,378,077
19	Rate design difference			($1,819)

Line No.	Description	Reference	Residential Sales Service Tariff Schedule - RS Sales	Transport
	Col. 1	Col. 2	Col. 3	Col. 4
	Customers			
1	Average number of customers per books	8-F	579,151	0
2	Pro forma adjustments		390	0
3	Pro forma average number of customers		579,541	0
	Deliveries			
4	Deliveries (Mcf) per books	8-F	39,112,226	0
5	Pro forma adjustments		3,171,941	0
6	Pro forma deliveries (Mcf)		42,284,167	0
	Revenue			
7	Base revenue		$183,598,224	$0
8	Cost of Gas		202,492,271	0
9	Total revenue per books	8-F	$386,090,494	$0
10	Pro forma revenue adjustments		(189,411,638)	0
11	Pro forma revenue		$196,678,857	$0
12	Revenue per unit (line 11 / line 6)		$4.6514	$0.0000

Line No.	Description	Reference	General Sales Service Small Tariff Schedule - GSS Sales	Transport
	Col. 1	Col. 2	Col. 3	Col. 4
	Customers			
1	Average number of customers per books	8-F	36,857	0
2	Pro forma adjustments		(8)	0
3	Pro forma average number of customers		36,849	0
	Deliveries			
4	Deliveries (Mcf) per books	8-F	3,326,454	0
5	Pro forma adjustments		478,140	0
6	Pro forma deliveries (Mcf)		3,804,594	0
	Revenue			
7	Base revenue		$19,191,449	$0
8	Cost of Gas		17,801,004	0
9	Total revenue per books	8-F	$36,992,453	$0
10	Pro forma revenue adjustments		(16,231,745)	0
11	Pro forma revenue		$20,760,708	$0
12	Revenue per unit (line 11 / line 6)		$5.4567	$0.0000

KANSAS GAS SERVICE, A DIVISION OF ONE Gas, INC.
Revenue, Sales and Customer Data - Existing Tariff Schedules
Test Year Ended December 31, 2015

Line No.	Description	Reference	General Sales Service Large Tariff Schedule - GSL Sales	Transport
	Col. 1	Col. 2	Col. 3	Col. 4
	Customers			
1	Average number of customers per books	8-F	11,886	0
2	Pro forma adjustments		19	0
3	Pro forma average number of customers		11,904	0
	Deliveries			
4	Deliveries (Mcf) per books	8-F	5,787,404	0
5	Pro forma adjustments		488,202	0
6	Pro forma deliveries (Mcf)		6,275,606	0
	Revenue			
7	Base revenue		$13,695,621	$0
8	Cost of Gas		29,782,710	0
9	Total revenue per books	8-F	$43,478,330	$0
10	Pro forma revenue adjustments		(27,779,649)	0
11	Pro forma revenue		$15,698,681	$0
12	Revenue per unit (line 11 / line 6)		$2.5015	$0.0000

Line No.	Description	Reference	General Sales Service Transport Eligible Tariff Schedule - GSTE Sales	Transport
	Col. 1	Col. 2	Col. 3	Col. 4
	Customers			
1	Average number of customers per books	8-F	564	0
2	Pro forma adjustments		2	0
3	Pro forma average number of customers		566	0
	Deliveries			
4	Deliveries (Mcf) per books	8-F	$1,317,803	$0
5	Pro forma adjustments		105,413	0
6	Pro forma deliveries (Mcf)		$1,423,217	$0
	Revenue			
7	Base revenue		$2,071,290	$0
8	Cost of Gas		6,605,508	0
9	Total revenue per books	8-F	$8,676,799	$0
10	Pro forma revenue adjustments		(6,191,807)	0
11	Pro forma revenue		$2,484,991	$0
12	Revenue per unit (line 11 / line 6)		$1.7460	$0.0000

Line No.	Description	Reference	Small Generator Sales Service Tariff Schedule - SGS: Sales	Transport
	Col. 1	Col. 2	Col. 3	Col. 4
	Customers			
1	Average number of customers per books	8-F	640	0
2	Pro forma adjustments		9	0
3	Pro forma average number of customers		649	0
	Deliveries			
4	Deliveries (Mcf) per books	8-F	9,720	0
5	Pro forma adjustments		216	0
6	Pro forma deliveries (Mcf)		9,936	0
	Revenue			
7	Base revenue		$414,484	$0
8	Cost of Gas		50,094	0
9	Total revenue per books	8-F	$464,578	$0
10	Pro forma revenue adjustments		(51,548)	0
11	Pro forma revenue		$413,030	$0
12	Revenue per unit (line 11 / line 6)		$41.5690	$0.0000

Line No.	Description	Reference	Gas Irrigation Service Tariff Schedule - GIS Sales	Transport
	Col. 1	Col. 2	Col. 3	Col. 4
	Customers			
1	Average number of customers per books	8-F	228	0
2	Pro forma adjustments		(3)	0
3	Pro forma average number of customers		225	0
	Deliveries			
4	Deliveries (Mcf) per books	8-F	147,868	0
5	Pro forma adjustments		(1,493)	0
6	Pro forma deliveries (Mcf)		146,375	0
	Revenue			
7	Base revenue		$350,491	$0
8	Cost of Gas		676,192	0
9	Total revenue per books	8-F	$1,026,683	$0
10	Pro forma revenue adjustments		(683,364)	0
11	Pro forma revenue		$343,320	$0
12	Revenue per unit (line 11 / line 6)		$2.3455	$0.0000

Line No.	Description	Reference	Kansas Gas Supply Sales Service D Tariff Schedule - KGSSD Sales	Transport
	Col. 1	Col. 2	Col. 2	Col. 3
	Customers			
1	Average number of customers per books	8-F	1	0
2	Pro forma adjustments		0	0
3	Pro forma average number of customers		1	0
	Deliveries			
4	Deliveries (Mcf) per books	8-F	30,247	0
5	Pro forma adjustments		1,090	0
6	Pro forma deliveries (Mcf)		31,337	0
	Revenue			
7	Base revenue		$30,656	$0
8	Cost of Gas		167,478	0
9	Total revenue per books	8-F	$198,134	$0
10	Pro forma revenue adjustments		(166,755)	0
11	Pro forma revenue		$31,379	$0
12	Revenue per unit (line 11 / line 6)		$1.0013	$0.0000

Line No.	Description	Reference	Sales Service for Resale Tariff Schedule - SSR Sales	Sales Service for Resale Tariff Schedule - SSR Transport
	Col. 1	Col. 2	Col. 2	Col. 3
	Customers			
1	Average number of customers per books	8-F	16	0
2	Pro forma adjustments		(9)	0
3	Pro forma average number of customers		7	0
	Deliveries			
4	Deliveries (Mcf) per books	8-F	61,532	0
5	Pro forma adjustments		1,157	0
6	Pro forma deliveries (Mcf)		62,689	0
	Revenue			
7	Base revenue		$84,460	$0
8	Cost of Gas		324,775	0
9	Total revenue per books	8-F	$409,235	$0
10	Pro forma revenue adjustments		(323,088)	0
11	Pro forma revenue		$86,147	$0
12	Revenue per unit (line 11 / line 6)		$1.3742	$0.0000

Line No.	Description	Reference	Small Transportation Service Tariff Schedule - STk: Sales	Small Transportation Service Tariff Schedule - STk: Transport
	Col. 1	Col. 2	Col. 2	Col. 3
	Customers			
1	Average number of customers per books	8-F	0	3,351
2	Pro forma adjustments		0	13
3	Pro forma average number of customers		0	3,365
	Deliveries			
4	Deliveries (Mcf) per books	8-F	0	5,401,229
5	Pro forma adjustments		0	314,744
6	Pro forma deliveries (Mcf)		0	5,715,973
	Revenue			
7	Base revenue		$0	$10,362,682
8	Cost of Gas		0	(4)
9	Total revenue per books	8-F	$0	$10,362,679
10	Pro forma revenue adjustments		0	402,469
11	Pro forma revenue		$0	$10,765,147
12	Revenue per unit (line 11 / line 6)		$0.0000	$1.8833

Line No.	Description	Reference	Small Transportation Service Tariff Schedule - STt Sales	Transport
	Col. 1	Col. 2	Col. 2	Col. 3
	Customers			
1	Average number of customers per books	8-F	0	1,110
2	Pro forma adjustments		0	8
3	Pro forma average number of customers		0	1,118
	Deliveries			
4	Deliveries (Mcf) per books	8-F	0	1,589,849
5	Pro forma adjustments		0	166,528
6	Pro forma deliveries (Mcf)		0	1,756,377
	Revenue			
7	Base revenue		$0	$3,891,123
8	Cost of Gas		0	0
9	Total revenue per books	8-F	$0	$3,891,123
10	Pro forma revenue adjustments		0	280,700
11	Pro forma revenue		$0	$4,171,823
12	Revenue per unit (line 11 / line 6)		$0.0000	$2.3752

Line No.	Description	Reference	Compressed Natural Gas General Transportation Service Tariff Schedule - CNGk Sales	Transport
	Col. 1	Col. 2	Col. 2	Col. 3
	Customers			
1	Average number of customers per books	8-F	0	3
2	Pro forma adjustments		0	0
3	Pro forma average number of customers		0	3
	Deliveries			
4	Deliveries (Mcf) per books	8-F	0	131,290
5	Pro forma adjustments		0	17,037
6	Pro forma deliveries (Mcf)		0	148,327
	Revenue			
7	Base revenue		$0	$106,105
8	Cost of Gas		0	0
9	Total revenue per books	8-F	$0	$106,105
10	Pro forma revenue adjustments		0	18,017
11	Pro forma revenue		$0	$124,122
12	Revenue per unit (line 11 / line 6)		$0.0000	$1.0577

Line No.	Description	Reference	Gas Irrigation Transportation Service Tariff Schedule - GITt Sales	Transport
	Col. 1	Col. 2	Col. 2	Col. 3
	Customers			
1	Average number of customers per books	8-F	0	513
2	Pro forma adjustments		0	8
3	Pro forma average number of customers		0	521
	Deliveries			
4	Deliveries (Mcf) per books	8-F	0	839,690
5	Pro forma adjustments		0	8,633
6	Pro forma deliveries (Mcf)		0	848,324
	Revenue			
7	Base revenue		$0	$1,645,891
8	Cost of Gas		0	0
9	Total revenue per books	8-F	$0	$1,645,891
10	Pro forma revenue adjustments		0	6,061
11	Pro forma revenue		$0	$1,651,952
12	Revenue per unit (line 11 / line 6)		$0.0000	$1.9473

Line No.	Description	Reference	Large Volume Transportation Service Tariff Schedule - LVTk Tier 1 Sales	Transport
	Col. 1	Col. 2	Col. 3	Col. 4
	Customers			
1	Average number of customers per books	8-F	0	207
2	Pro forma adjustments		0	(19)
3	Pro forma average number of customers		0	189
	Deliveries			
4	Deliveries (Mcf) per books	8-F	0	881,574
5	Pro forma adjustments		0	(2,235)
6	Pro forma deliveries (Mcf)		0	879,339
	Revenue			
7	Base revenue		$0	$1,676,784
8	Cost of Gas		0	0
9	Total revenue per books	8-F	$0	$1,676,784
10	Pro forma revenue adjustments		0	(440,059)
11	Pro forma revenue		$0	$1,236,725
12	Revenue per unit (line 11 / line 6)		$0.0000	$1.4064

Line No.	Description	Reference	Large Volume Transportation Service Tariff Schedule - LVTk Tier 2: Sales	Transport
	Col. 1	Col. 2	Col. 3	Col. 4
	Customers			
1	Average number of customers per books	8-F	0	108
2	Pro forma adjustments		0	2
3	Pro forma average number of customers		0	111
	Deliveries			
4	Deliveries (Mcf) per books	8-F	0	1,530,768
5	Pro forma adjustments		0	132,045
6	Pro forma deliveries (Mcf)		0	1,662,813
	Revenue			
7	Base revenue		$0	$1,680,292
8	Cost of Gas		0	0
9	Total revenue per books	8-F	$0	$1,680,292
10	Pro forma revenue adjustments		0	102,962
11	Pro forma revenue		$0	$1,783,254
12	Revenue per unit (line 11 / line 6)		$0.0000	$1.0724

Line No.	Description	Reference	Large Volume Transportation Service Tariff Schedule - LVTk Tier 3 Sales	Transport
	Col. 1	Col. 2	Col. 3	Col. 4
	Customers			
1	Average number of customers per books	8-F	0	67
2	Pro forma adjustments		0	(4)
3	Pro forma average number of customers		0	63
	Deliveries			
4	Deliveries (Mcf) per books	8-F	0	2,023,956
5	Pro forma adjustments		0	(198,563)
6	Pro forma deliveries (Mcf)		0	1,825,393
	Revenue			
7	Base revenue		$0	$1,854,332
8	Cost of Gas		0	0
9	Total revenue per books	8-F	$0	$1,854,332
10	Pro forma revenue adjustments		0	(40,958)
11	Pro forma revenue		$0	$1,813,374
12	Revenue per unit (line 11 / line 6)		$0.0000	$0.9934

Line No.	Description	Reference	Large Volume Transportation Service Tariff Schedule - LVTk Tier 4 Sales	Large Volume Transportation Service Tariff Schedule - LVTk Tier 4 Transport
	Col. 1	Col. 2	Col. 3	Col. 4
	Customers			
1	Average number of customers per books	8-F	0	82
2	Pro forma adjustments		0	(21)
3	Pro forma average number of customers		0	61
	Deliveries			
4	Deliveries (Mcf) per books	8-F	0	13,794,672
5	Pro forma adjustments		0	(7,220,532)
6	Pro forma deliveries (Mcf)		0	6,574,140
	Revenue			
7	Base revenue		$0	$7,653,055
8	Cost of Gas		0	0
9	Total revenue per books	8-F	$0	$7,653,055
10	Pro forma revenue adjustments		0	(1,644,811)
11	Pro forma revenue		$0	$6,008,244
12	Revenue per unit (line 11 / line 6)		$0.0000	$0.9139

Line No.	Description	Reference	Large Volume Transportation Service Tariff Schedule - LVTt Tier 1 Sales	Transport
	Col. 1	Col. 2	Col. 3	Col. 4
	Customers			
1	Average number of customers per books	8-F	0	38
2	Pro forma adjustments		0	(4)
3	Pro forma average number of customers		0	34
	Deliveries			
4	Deliveries (Mcf) per books	8-F	0	196,799
5	Pro forma adjustments		0	23,965
6	Pro forma deliveries (Mcf)		0	220,764
	Revenue			
7	Base revenue		$0	$397,321
8	Cost of Gas		0	0
9	Total revenue per books	8-F	$0	$397,321
10	Pro forma revenue adjustments		0	8,996
11	Pro forma revenue		$0	$406,316
12	Revenue per unit (line 11 / line 6)		$0.0000	$1.8405

Line No.	Description	Reference	Large Volume Transportation Service Tariff Schedule - LVTt Tier 2: Sales	Transport
	Col. 1	Col. 2	Col. 3	Col. 4
	Customers			
1	Average number of customers per books	8-F	0	35
2	Pro forma adjustments		0	2
3	Pro forma average number of customers		0	37
	Deliveries			
4	Deliveries (Mcf) per books	8-F	0	499,036
5	Pro forma adjustments		0	61,261
6	Pro forma deliveries (Mcf)		0	560,297
	Revenue			
7	Base revenue		$0	$824,490
8	Cost of Gas		0	0
9	Total revenue per books	8-F	$0	$824,490
10	Pro forma revenue adjustments		0	72,217
11	Pro forma revenue		$0	$896,707
12	Revenue per unit (line 11 / line 6)		$0.0000	$1.6004

Line No.	Description	Reference	Large Volume Transportation Service Tariff Schedule - LVTt Tier 3 Sales	Transport
	Col. 1	Col. 2	Col. 3	Col. 4
	Customers			
1	Average number of customers per books	8-F	0	23
2	Pro forma adjustments		0	1
3	Pro forma average number of customers		0	24
	Deliveries			
4	Deliveries (Mcf) per books	8-F	0	832,068
5	Pro forma adjustments		0	(21,497)
6	Pro forma deliveries (Mcf)		0	810,571
	Revenue			
7	Base revenue		$0	$1,207,252
8	Cost of Gas		0	0
9	Total revenue per books	8-F	$0	$1,207,252
10	Pro forma revenue adjustments		0	(4,348)
11	Pro forma revenue		$0	$1,202,904
12	Revenue per unit (line 11 / line 6)		$0.0000	$1.4840

Line No.	Description	Reference	Large Volume Transportation Service Tariff Schedule - LVTt Tier 4 Sales	Transport
	Col. 1	Col. 2	Col. 3	Col. 4
	Customers			
1	Average number of customers per books	8-F	0	50
2	Pro forma adjustments		0	(21)
3	Pro forma average number of customers		0	29
	Deliveries			
4	Deliveries (Mcf) per books	8-F	0	24,512,499
5	Pro forma adjustments		0	(20,773,826)
6	Pro forma deliveries (Mcf)		0	3,738,673
	Revenue			
7	Base revenue		$0	$12,642,269
8	Cost of Gas		0	0
9	Total revenue per books	8-F	$0	$12,642,269
10	Pro forma revenue adjustments		0	(7,525,227)
11	Pro forma revenue		$0	$5,117,042
12	Revenue per unit (line 11 / line 6)		$0.0000	$1.3687

Line No.	Description	Reference	Wholesale Transportation Service Tariff Schedule - WTt Sales	Wholesale Transportation Service Tariff Schedule - WTt Transport
	Col. 1	Col. 2	Col. 2	Col. 3
	Customers			
1	Average number of customers per books	8-F	0	28
2	Pro forma adjustments		0	(1)
3	Pro forma average number of customers		0	27
	Deliveries			
4	Deliveries (Mcf) per books	8-F	0	2,796,872
5	Pro forma adjustments		0	(1,769,650)
6	Pro forma deliveries (Mcf)		0	1,027,222
	Revenue			
7	Base revenue		$0	$1,458,532
8	Cost of Gas		0	0
9	Total revenue per books	8-F	$0	$1,458,532
10	Pro forma revenue adjustments		0	(147,097)
11	Pro forma revenue		$0	$1,311,435
12	Revenue per unit (line 11 / line 6)		$0.0000	$1.2767

Line No.	Description	Reference	Residential Sales Service Tariff Schedule - RS Sales	Transport
	Col. 1	Col. 2	Col. 3	Col. 4
	Customers			
1	Pro forma average number of customers	17-B	579,541	0
	Deliveries			
2	Pro forma deliveries (Mcf)	17-B	42,284,167	0
	Revenue			
3	Proposed revenue		$232,125,604	$0
4	Pro forma revenue - existing tariffs	17-B	196,678,857	0
5	Additional revenue from proposed tariffs (line 3 - line 4)		$35,446,747	$0
6	COGR revenue		$219,007,334	$0
7	Percent increase (line 5 / (line 4+6))		8.53%	0.00%
8	Revenue per unit - proposed tariffs (line 3 / line 2)		$5.4897	$0.0000

Line No.	Description	Reference	General Sales Service Small Tariff Schedule - GSS Sales	Transport
	Col. 1	Col. 2	Col. 3	Col. 4
	Customers			
1	Pro forma average number of customers	17-B	36,849	0
	Deliveries			
2	Pro forma deliveries (Mcf)	17-B	3,804,594	0
	Revenue			
3	Proposed revenue		$20,758,806	$0
4	Pro forma revenue - existing tariffs	17-B	20,760,708	0
5	Additional revenue from proposed tariffs (line 3 - line 4)		($1,902)	$0
6	COGR revenue		$19,705,580	$0
7	Percent increase (line 5 / (line 4+6))		0.00%	0.00%
8	Revenue per unit - proposed tariffs (line 3 / line 2)		$5.4562	$0.0000

Line No.	Description	Reference	General Sales Service Large Tariff Schedule - GSL Sales	Transport
	Col. 1	Col. 2	Col. 3	Col. 4
	Customers			
1	Pro forma average number of customers	17-B	11,904	0
	Deliveries			
2	Pro forma deliveries (Mcf)	17-B	6,275,606	0
	Revenue			
3	Proposed revenue		$ 15,698,681	$0
4	Pro forma revenue - existing tariffs	17-B	15,698,681	0
5	Additional revenue from proposed tariffs (line 3 - line 4)		$0	$0
6	COGR revenue		$32,503,983	$0
7	Percent increase (line 5 / (line 4+6))		0.00%	0.00%
8	Revenue per unit - proposed tariffs (line 3 / line 2)		$2.5015	$0.0000

Line No.	Description	Reference	General Sales Service Transport Eligible Tariff Schedule - GSTE Sales	Transport
	Col. 1	Col. 2	Col. 3	Col. 4
	Customers			
1	Pro forma average number of customers	17-B	566	0
	Deliveries			
2	Pro forma deliveries (Mcf)	17-B	1,423,217	0
	Revenue			
3	Proposed revenue		$ 2,484,991	$0
4	Pro forma revenue - existing tariffs	17-B	2,484,991	0
5	Additional revenue from proposed tariffs (line 3 - line 4)		$0	$0
6	COGR revenue		$7,371,433	$0
7	Percent increase (line 5 / (line 4+6))		0.00%	0.00%
8	Revenue per unit - proposed tariffs (line 3 / line 2)		$1.7460	$0.0000

Line No.	Description	Reference	Small Generator Sales Service Tariff Schedule - SGS Sales	Transport
	Col. 1	Col. 2	Col. 3	Col. 4
	Customers			
1	Pro forma average number of customers	17-B	649	0
	Deliveries			
2	Pro forma deliveries (Mcf)	17-B	9,936	0
	Revenue			
3	Proposed revenue		$413,030	$0
4	Pro forma revenue - existing tariffs	17-B	413,030	0
5	Additional revenue from proposed tariffs (line 3 - line 4)		$0	$0
6	COGR revenue		$51,463	$0
7	Percent increase (line 5 / (line 4+6))		0.00%	0.00%
8	Revenue per unit - proposed tariffs (line 3 / line 2)		$41.5690	$0.0000

Line No.	Description	Reference	Gas Irrigation Service Tariff Schedule - GIS Sales	Transport
	Col. 1	Col. 2	Col. 3	Col. 4
	Customers			
1	Pro forma average number of customers	17-B	225	0
	Deliveries			
2	Pro forma deliveries (Mcf)	17-B	146,375	0
	Revenue			
3	Proposed revenue		$343,320	$0
4	Pro forma revenue - existing tariffs	17-B	343,320	0
5	Additional revenue from proposed tariffs (line 3 - line 4)		$0	$0
6	COGR revenue		$758,137	$0
7	Percent increase (line 5 / (line 4+6))		0.00%	0.00%
8	Revenue per unit - proposed tariffs (line 3 / line 2)		$2.3455	$0.0000

Line No.	Description	Reference	Kansas Gas Supply Sales Service D Tariff Schedule - KGSSD Sales	Transport
	Col. 1	Col. 2	Col. 3	Col. 4
	Customers			
1	Pro forma average number of customers	17-B	1	0
	Deliveries			
2	Pro forma deliveries (Mcf)	17-B	31,337	0
	Revenue			
3	Proposed revenue		$31,379	$0
4	Pro forma revenue - existing tariffs	17-B	31,379	0
5	Additional revenue from proposed tariffs (line 3 - line 4)		$0	$0
6	COGR revenue (b)		$162,307	$0
7	Percent increase (line 5 / (line 4+6))		0.00%	0.00%
8	Revenue per unit - proposed tariffs (line 3 / line 2)		$1.0013	$0.0000

Line No.	Description	Reference	Sales Service for Resale Tariff Schedule - SSR Sales	Transport
	Col. 1	Col. 2	Col. 3	Col. 4
	Customers			
1	Pro forma average number of customers	17-B	7	0
	Deliveries			
2	Pro forma deliveries (Mcf)	17-B	62,689	0
	Revenue			
3	Proposed revenue		$86,147	$0
4	Pro forma revenue - existing tariffs	17-B	86,147	0
5	Additional revenue from proposed tariffs (line 3 - line 4)		$0	$0
6	COGR revenue		$324,692	$0
7	Percent increase (line 5 / (line 4+6))		0.00%	0.00%
8	Revenue per unit - proposed tariffs (line 3 / line 2)		$1.3742	$0.0000

Line No.	Description	Reference	Small Transportation Service Tariff Schedule - STk Sales	Small Transportation Service Tariff Schedule - STk Transport
	Col. 1	Col. 2	Col. 3	Col. 4
	Customers			
1	Pro forma average number of customers	17-B	0	3,365
	Deliveries			
2	Pro forma deliveries (Mcf)	17-B	0	5,715,973
	Revenue			
3	Proposed revenue		$0	$10,765,147
4	Pro forma revenue - existing tariffs	17-B	0	10,765,147
5	Additional revenue from proposed tariffs (line 3 - line 4)		$0	$0
6	COGR revenue		$0	$0
7	Percent increase (line 5 / (line 4+6))		0.00%	0.00%
8	Revenue per unit - proposed tariffs (line 3 / line 2)		$0.0000	$1.8833

Line No.	Description	Reference	Small Transportation Service Tariff Schedule - STt Sales	Small Transportation Service Tariff Schedule - STt Transport
	Col. 1	Col. 2	Col. 3	Col. 4
	Customers			
1	Pro forma average number of customers	17-B	0	1,118
	Deliveries			
2	Pro forma deliveries (Mcf)	17-B	0	1,756,377
	Revenue			
3	Proposed revenue		$0	$4,171,823
4	Pro forma revenue - existing tariffs	17-B	0	4,171,823
5	Additional revenue from proposed tariffs (line 3 - line 4)		$0	$0
6	COGR revenue		$0	$0
7	Percent increase (line 5 / (line 4+6))		0.00%	0.00%
8	Revenue per unit - proposed tariffs (line 3 / line 2)		$0.0000	$2.3752

Line No.	Description	Reference	Compressed Natural Gas General Transportation Service Tariff Schedule - CNGk Sales	Transport
	Col. 1	Col. 2	Col. 3	Col. 4
	Customers			
1	Pro forma average number of customers	17-B	0	3
	Deliveries			
2	Pro forma deliveries (Mcf)	17-B	0	148,327
	Revenue			
3	Proposed revenue		$0	$124,122
4	Pro forma revenue - existing tariffs	17-B	0	124,122
5	Additional revenue from proposed tariffs (line 3 - line 4)		$0	$0
6	COGR revenue (b)		$0	$0
7	Percent increase (line 5 / (line 4+6))		0.00%	0.00%
8	Revenue per unit - proposed tariffs (line 3 / line 2)		$0.0000	$0.8368

Line No.	Description	Reference	Gas Irrigation Transportation Service Tariff Schedule - GITt: Sales	Gas Irrigation Transportation Service Tariff Schedule - GITt: Transport
	Col. 1	Col. 2	Col. 3	Col. 4
	Customers			
1	Pro forma average number of customers	17-B	0	521
	Deliveries			
2	Pro forma deliveries (Mcf)	17-B	0	848,324
	Revenue			
3	Proposed revenue		$0	$1,651,952
4	Pro forma revenue - existing tariffs	17-B	0	1,651,952
5	Additional revenue from proposed tariffs (line 3 - line 4)		$0	$0
6	COGR revenue (b)		$0	$0
7	Percent increase (line 5 / (line 4+6))		0.00%	0.00%
8	Revenue per unit - proposed tariffs (line 3 / line 2)		$0.0000	$1.9473

Line No.	Description	Reference	Large Volume Transportation Service Tariff Schedule - LVTk Tier 1 Sales	Large Volume Transportation Service Tariff Schedule - LVTk Tier 1 Transport
	Col. 1	Col. 2	Col. 3	Col. 4
	Customers			
1	Pro forma average number of customers	17-B	0	189
	Deliveries			
2	Pro forma deliveries (Mcf)	17-B	0	879,339
	Revenue			
3	Proposed revenue		$0	$1,236,725
4	Pro forma revenue - existing tariffs	17-B	0	1,236,725
5	Additional revenue from proposed tariffs (line 3 - line 4)		$0	$0
6	COGR revenue		$0	$0
7	Percent increase (line 5 / (line 4+6))		0.00%	0.00%
8	Revenue per unit - proposed tariffs (line 3 / line 2)		$0.0000	$1.4064

Line No.	Description	Reference	Large Volume Transportation Service Tariff Schedule - LVTk Tier 2 Sales	Transport
	Col. 1	Col. 2	Col. 3	Col. 4
	Customers			
1	Pro forma average number of customers	17-B	0	111
	Deliveries			
2	Pro forma deliveries (Mcf)	17-B	0	1,662,813
	Revenue			
3	Proposed revenue		$0	$1,783,254
4	Pro forma revenue - existing tariffs	17-B	0	1,783,254
5	Additional revenue from proposed tariffs (line 3 - line 4)		$0	$0
6	COGR revenue		$0	$0
7	Percent increase (line 5 / (line 4+6))		0.00%	0.00%
8	Revenue per unit - proposed tariffs (line 3 / line 2)		$0.0000	$1.0724

Line No.	Description	Reference	Large Volume Transportation Service Tariff Schedule - LVTk Tier 3 Sales	Large Volume Transportation Service Tariff Schedule - LVTk Tier 3 Transport
	Col. 1	Col. 2	Col. 3	Col. 4
	Customers			
1	Pro forma average number of customers	17-B	0	63
	Deliveries			
2	Pro forma deliveries (Mcf)	17-B	0	1,825,393
	Revenue			
3	Proposed revenue		$0	$1,813,374
4	Pro forma revenue - existing tariffs	17-B	0	1,813,374
5	Additional revenue from proposed tariffs (line 3 - line 4)		$0	$0
6	COGR revenue		$0	$0
7	Percent increase (line 5 / (line 4+6))		0.00%	0.00%
8	Revenue per unit - proposed tariffs (line 3 / line 2)		$0.0000	$0.9934

Line No.	Description	Reference	Large Volume Transportation Service Tariff Schedule - LVTk Tier 4 Sales	Transport
	Col. 1	Col. 2	Col. 3	Col. 4
	Customers			
1	Pro forma average number of customers	17-B	0	61
	Deliveries			
2	Pro forma deliveries (Mcf)	17-B	0	6,574,140
	Revenue			
3	Proposed revenue		$0	$6,008,244
4	Pro forma revenue - existing tariffs	17-B	0	6,008,244
5	Additional revenue from proposed tariffs (line 3 - line 4)		$0	$0
6	COGR revenue		$0	$0
7	Percent increase (line 5 / (line 4+6))		0.00%	0.00%
8	Revenue per unit - proposed tariffs (line 3 / line 2)		$0.0000	$0.9139

Line No.	Description	Reference	Large Volume Transportation Service Tariff Schedule - LVTt Tier 1 Sales	Transport
	Col. 1	Col. 2	Col. 3	Col. 4
	Customers			
1	Pro forma average number of customers	17-B	0	34
	Deliveries			
2	Pro forma deliveries (Mcf)	17-B	0	220,764
	Revenue			
3	Proposed revenue		$0	$406,316
4	Pro forma revenue - existing tariffs	17-B	0	406,316
5	Additional revenue from proposed tariffs (line 3 - line 4)		$0	$0
6	COGR revenue		$0	$0
7	Percent increase (line 5 / (line 4+6))		0.00%	0.00%
8	Revenue per unit - proposed tariffs (line 3 / line 2)		$0.0000	$1.8405

Line No.	Description	Reference	Large Volume Transportation Service Tariff Schedule - LVTt Tier 2	
			Sales	Transport
	Col. 1	Col. 2	Col. 3	Col. 4
	Customers			
1	Pro forma average number of customers	17-B	0	37
	Deliveries			
2	Pro forma deliveries (Mcf)	17-B	0	560,297
	Revenue			
3	Proposed revenue		$0	$896,707
4	Pro forma revenue - existing tariffs	17-B	0	896,707
5	Additional revenue from proposed tariffs (line 3 - line 4)		$0	$0
6	COGR revenue		$0	$0
7	Percent increase (line 5 / (line 4+6))		0.00%	0.00%
8	Revenue per unit - proposed tariffs (line 3 / line 2)		$0.0000	$1.6004

Line No.	Description	Reference	Large Volume Transportation Service Tariff Schedule - LVTt Tier 3 Sales	Transport
	Col. 1	Col. 2	Col. 3	Col. 4
	Customers			
1	Pro forma average number of customers	17-B	0	24
	Deliveries			
2	Pro forma deliveries (Mcf)	17-B	0	810,571
	Revenue			
3	Proposed revenue		$0	$1,202,904
4	Pro forma revenue - existing tariffs	17-B	0	1,202,904
5	Additional revenue from proposed tariffs (line 3 - line 4)		$0	$0
6	COGR revenue		$0	$0
7	Percent increase (line 5 / (line 4+6))		0.00%	0.00%
8	Revenue per unit - proposed tariffs (line 3 / line 2)		$0.0000	$1.4840

			Large Volume Transportation Service Tariff Schedule - LVTt Tier 4	
Line No.	Description	Reference	Sales	Transport
	Col. 1	Col. 2	Col. 3	Col. 4
	Customers			
1	Pro forma average number of customers	17-B	0	29
	Deliveries			
2	Pro forma deliveries (Mcf)	17-B	0	3,738,673
	Revenue			
3	Proposed revenue		$0	$5,117,042
4	Pro forma revenue - existing tariffs	17-B	0	5,117,042
5	Additional revenue from proposed tariffs (line 3 - line 4)		$0	$0
6	COGR revenue		$0	$0
7	Percent increase (line 5 / (line 4+6))		0.00%	0.00%
8	Revenue per unit - proposed tariffs (line 3 / line 2)		$0.0000	$1.3687

Line No.	Description	Reference	Wholesale Transportation Service Tariff Schedule - WTt Sales	Transport
	Col. 1	Col. 2	Col. 3	Col. 4
	Customers			
1	Pro forma average number of customers	17-B	0	27
	Deliveries			
2	Pro forma deliveries (Mcf)	17-B	0	1,027,222
	Revenue			
3	Proposed revenue		$0	$1,311,435
4	Pro forma revenue - existing tariffs	17-B	0	1,311,435
5	Additional revenue from proposed tariffs (line 3 - line 4)		$0	$0
6	COGR revenue		$0	$0
7	Percent increase (line 5 / (line 4+6))		0.00%	0.00%
8	Revenue per unit - proposed tariffs (line 3 / line 2)		$0.0000	$1.2767

RATE SCHEDULE INDEX

INDEX #	SCHEDULE NAME	DESIGNATION
	Transportation Service Rate Schedules	
29	Small Transportation Service – ‘k’ system	STk
30	Small Transportation Service – ‘t’ system	STt
32	Large Volume Transportation Service – ‘k’ system	LVTk
33	Large Volume Transportation Service – ‘t’ system	LVTt
~~34~~	~~Wholesale Transportation Service – ‘k’ system~~	~~WTk~~
35	Wholesale Transportation Service – ‘t’ system	WTt
36	Interruptible Gas Transportation Service – ‘t’ system	ITt
37	Gas Irrigation Transportation Service – ‘t’ system	GITt
38	Compressed Natural Gas General Transportation Service	CNG
	Surcharges/Riders to Rate Schedules	
40	Cost of Gas Rider	COGR
41	Economic Development Rider—Gas	EDG
42	Electronic Flow Measurement Rider	EFMR
43	Weather Normalization Adjustment Rider	WNAR
44	Gas System Reliability Surcharge	GSRS
47	Gas Transportation for Schools Rider	GTSR
48	Ad Valorem Tax Surcharge Rider	ATSR
49	Cost of Service Adjustment Plan	COSA

COMMUNITIES INDEX (Cont.)

"k" System Communities (cont.):

Available Schedules: RS, GSS, GSL, GSTE, SGS, GIS, CNG, STk and LVTk

Wathena	Whitewater
Waverly	Whiting
Weir	Wichita
Welda	Williamsburg
Wellington	Willis
Wellsville	Willowbrook Addition
West Mineral	Winchester
Westwood	Zarah
Westwood Hills	

Communities and Gas Distribution Companies Served at Wholesale:

Available Schedule: SSR, ~~WTk and~~ WTt

Alma	Jamestown	Midwest Energy, Inc.
Aurora	Longford	Atmos Energy
Belleville	Palmer	Black Hills Energy
Hudson	Rozel	
Isabel		

	Month	Day	Year
Issued	December	10	2012
Effective	January	01	2013

By

DAVID N. DITTEMORE, Manager-Regulatory Affairs

12-KGSG-835-RTS
APPROVED
KANSAS CORPORATION COMMISSION
December 5, 2012
/S/ Patrice Petersen-Klein

GENERAL TERMS AND CONDITIONS FOR GAS SERVICE

THE STATE CORPORATION COMMISSION OF KANSAS INDEX NO 15.6

KANSAS GAS SERVICE
A DIVISION OF ONEOK, INC.
(Name of Issuing Utility)

SCHEDULE CONTENTS

ALL RATE AREAS
(Territory to which schedule is applicable)

Replacing Schedule CONTENTS Sheet 6
which was filed December 5, 2012

No supplement or separate understanding shall modify the tariff as shown hereon.

GENERAL TERMS AND CONDITIONS FOR GAS SERVICE

Issued	April	9	2013
	Month	Day	Year
Effective	July	1	2013
	Month	Day	Year

By

DAVID N. DITTEMORE, Manager-Regulatory Affairs

13-KGSG-615-TAR
Approved
KANSAS CORPORATION COMMISSION
June 26, 2013
/S/ Jackie Montfoort Paige

GENERAL TERMS AND CONDITIONS FOR GAS SERVICE

GENERAL TERMS AND CONDITIONS FOR GAS SERVICE

1.06 Commission: The State Corporation Commission of the State of Kansas or any successor of such Commission having jurisdiction over the subject matter herein.

1.07 Company: Kansas Gas Service, a division of ONE~~OK~~ Gas, Inc. or its properly designated Agent.

1.08 Confidentiality: Company's treatment of customer-specific information. This information, which shall include all billing statement information, usage data and agent information, shall not be released to any other party without the customer's consent, except that neither notice nor Customer consent shall be required when customer-specific information is released in response to a request of the Commission or its staff. This section shall not prevent Company from providing information regarding Customer status when requested by law enforcement or emergency personnel acting in an official capacity or when customer-specific information is released by court order, subpoena, or other order or requirement issued by a duly constituted authority, or when release of such information is necessary to provide service. Company shall not be required to notify the Customer or obtain the customer's consent in these instances.

1.09 Contiguous Premises: Properties, sharing at least one common point or local boundary, upon which all buildings and/or natural gas consuming devices are owned or occupied by the same Customer, and upon which all natural gas service is utilized to supply one or more connected natural gas loads which Company considers to be components of a unified operation. Streets, alleys, and other rights-of-way intersecting the customer's properties are not considered property occupied or used by others.

1.10 Curtailment: Company's complete or partial limiting of delivery services to a Customer or customers otherwise entitled to receive such services.

GENERAL TERMS AND CONDITIONS FOR GAS SERVICE

2.05 Refusal of Service After Application of Service: Company may refuse service at any time when, in Company's judgment, it is unsafe for Company personnel to perform work at customer's premises. Unsafe situations that may prevent Company personnel from performing work at customer's premises include, but are not limited to, physical and/or verbal acts of aggression, intimidation, or anything which threatens the safety of Company personnel.

2.06 Notices Between Customer and Company:

2.06.01 Written Notices: All notices given to Company shall be in writing except as provided in Section 6.03 Defective Customer Equipment, and as described herein.

(1) Oral communication directed to the appropriate Company representative shall be considered proper notice.

(2) When oral notices are taken in person or by telephone by Company's representative, a confirmation number and the employee's name shall be provided to customer as evidence of customer's contact with Company.

(3) Company shall exercise reasonable diligence in carrying out notices from customer, but shall not be responsible for error, delay or expense resulting there from, unless it shall be shown affirmatively that the error, delay or expense has been caused by willful default or negligence on the part of Company.

(4) Billing errors resulting from Company's failure to carry out customer's written notice or an oral notice for which customer has a confirmation number and employee's name, will be corrected as provided in Section ~~4.04.06~~4.05.02 Correction of Erroneous Bills.

2.06.02 Contracts: Company representatives are not authorized to contractually bind Company except by writing duly executed.

Issued	December	10	2012	12-KGSG-835-RTS Approved Kansas Corporation Commission December 5, 2012 /S/ Patrice Petersen-Klein
	Month	Day	Year	
Effective	January	1	2013	
	Month	Day	Year	
By				
	DAVID N. DITTEMORE, Manager-Regulatory Affairs			

GENERAL TERMS AND CONDITIONS FOR GAS SERVICE

(1) When estimating usage~~,~~ for missing route reads, Company shall consider the customer's historical consumption, current consumption of similar customers for whom actual meter readings were obtained and the length of the billing period.

Company shall use the following formula for calculation of estimated Mcf usage for billing purposes.

(A / B) x C = Estimated usage for a meter
Where:
A = peer group's usage this month
B = peer group's usage for same month last year
C = usage for same month last year for meter to be estimated. If meter-specific usage from last year is unavailable, the value of "B" shall be substituted for "C".

Company shall use current billing cycle information to profile the customer's peer group. Peer Groups shall be compiled from meters with like rate codes and revenue classes. Peer groups of less than minimum size may be expanded to contain not only the town, but the office the town is in, the division or up to Company level if required. More than one rate code may be included where necessary.

(2) When estimating usage in instances when missing read(s) exist for individual customers where peer group information is not available or customer has supplied information specific to their usage, Company may consider the customer's historical consumption, current and historical weather information as well as any customer-supplied information.

Company shall use the following formula for calculation of estimated Mcf usage for billing purposes for individual accounts:

(A/B) x C = Estimated usage for meter
Where:

GENERAL TERMS AND CONDITIONS FOR GAS SERVICE

A = Heating Degree Days (HDD) for month to be estimated
B = HDD for same month the prior year
C = Billed consumption for same month the prior year. Company may use other historical known usage from the premises as necessary.

4.05 Adjustments to Meter Reads and Bills:

4.05.01 Estimated Bill Adjustments: Any adjustment to a previous bill which was based on estimated usage or a meter reading by a customer will be shown on the bill. The adjustment shall be calculated for bills rendered during the period between the prior and most recent meter readings by Company. Calculation of adjustments for previously estimated bills may include customer supplied information on an individual basis as necessary. The adjusted bill shall show the credit due to the customer or the balance due and payable to Company.

(1) Any credit due to the customer may be applied as a credit to subsequent bills. However, if the amount is greater than the amount specified in Section 12.03 Credit Due Amount and customer so requests, Company shall refund the amount.

GENERAL TERMS AND CONDITIONS FOR GAS SERVICE

(2) If a balance is due and payable to Company, customer may, upon request and approval of Company, pay the amount in equal monthly installments over a period of time equal to the adjusted billing period.

(3) In no case will an adjustment to an estimated bill be made for an amount which is less than the amount specified in Section 12.09 Adjusted Bill Amount.

~~4.05.02 Calculation of Unconfirmed Usage: When the company is unable to confirm usage due to a non-registering meter, usage may be estimated by an individualized analysis based on information including, but not limited to, weather data, historical usage at the premises, and customer supplied information. No bill shall be issued to adjust a period exceeding six months due to the failure of a meter to register.~~

~~4.05.03 Allocation of Confirmed Usage: When the company is able to confirm usage registered by a meter that has not been previously billed due to reasons such as a non-reporting Automatic Meter Reading (AMR) device, confirmed usage may be allocated by an individualized analysis based on information including but not limited to, weather data, historical usage at the premises, and customer-supplied information.~~

~~When determining the adjustment period, Company may allocate known usage to the last confirmed meter reading or unsubstantiated change in usage history. If no such conditions exist, company shall not allocate known usage to periods exceeding the length of time stated in Section 4.05.04 Correction of Erroneous Bills.~~

~~4.05.04~~ 4.05.02 Correction of Erroneous Bills: In the event of an error in billing as a result of issues including, but not limited to, accounting errors, meter or meter reading equipment misprogramming or failure, Company shall issue a corrected bill. The corrected bill shall show the adjusted amount due or amount to be refunded. Any amounts paid by customer on the erroneous bill shall be shown as a credit on the corrected bill.

(1) No corrected bill for confirmed usage, as determined by the

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By				
	DAVID N. DITTEMORE, Manager-Regulatory Affairs			

GENERAL TERMS AND CONDITIONS FOR GAS SERVICE

Company, shall be issued for a period exceeding 12 months, unless the date of the error can be determined in which case the correction ~~shall~~ may be computed back to but not beyond such date. No correction for erroneous bills need be made for amounts equal to or less than that specified in Section 12.04 Bill Error Amount.

(2) When the Company is unable to confirm usage due to a non-registering meter, usage may be estimated by an individualized analysis based on information including, but not limited to, weather data, historical usage at the premises, and customer supplied information. No bill shall be issued to adjust a period exceeding six months due to the failure of a meter to register.

GENERAL TERMS AND CONDITIONS FOR GAS SERVICE

~~4.05.05~~ 4.05.03 Prorated Bills: Company shall prorate customers' bills during the billing month in which a change in rates or tariffs becomes effective, unless otherwise ordered by the Commission. Proration of gas cost shall always be Company's option.

Company shall prorate customer charges only when a change in rates or tariffs becomes effective or when the billing cycle is caused to be outside the range of 26 through 36 days by:

(1) Connection or disconnection of service, or

(2) Rerouting of meter routes, for the directly affected customers only.

~~4.05.06~~ 4.05.04 Adjustment for Taxes and Franchise Fees: When any governing body of a taxing subdivision imposes a franchise, occupation, business, sales, license, excise, privilege or similar charge of any kind on Company, these charges shall be recovered from the customers within the boundaries of the taxing subdivision. The amount of the charge shall be levied on each of the customers within the taxing subdivision in the same form in which it is imposed on Company, unless the Commission determines otherwise. All charges so imposed on Company shall be added as a separate charge to the customer's bill for gas service. Any customer exempted from the charge by a taxing subdivision in the calculation of the charge imposed on Company shall be exempt from the charge, unless the Commission determines otherwise.

GENERAL TERMS AND CONDITIONS FOR GAS SERVICE

4.06 Average Payment Plan:

4.06.01 Availability: Upon mutual agreement between a customer and Company, the Average Payment Plan (APP) shall be made available upon the request of a Residential or Small General Service customer who meets the following requirements:

(1) A residential customer may enroll in the APP during the Cold Weather Rule (CWR) Period at the same time (s)he enters into a CWR pay agreement for arrearages, pursuant to Section 4.07 Cold Weather Rule.

(2) A residential customer may enroll in the APP during the non-CWR period at the same time (s)he enters into an Extended Payment Plan pursuant to Section 4.08 Extended Payment Plan.

(3) A residential or general service customer may enroll in the APP at any time as long as the account is in current status with no arrears.

4.06.02 Calculation of Monthly Billing Amount: Company shall use available billing history to calculate the customer's monthly APP billing amount as the sum of:

(1) The current net monthly billing amount, plus the previous 11 months billing, estimated if not known, plus financial transactions that would impact a customer's monthly bill (e.g. rebate and rebills),

(2) Divided by twelve (12),

(3) plus the Periodic Review Adjustment as described in Section 4.06.04 Periodic Review.

GENERAL TERMS AND CONDITIONS FOR GAS SERVICE

(2) For piping 1 ¼ inch in diameter or less, ~~T~~the Customer receiving service shall be billed for additional Service and/or Yard Line installation or replacement at the cost of $4.54 per foot in excess of 200 feet. For piping greater than 1¼ inch in diameter, the customer receiving service shall be billed for actual construction costs.

(a) Customer shall also be billed for any construction costs including labor, overheads and material used in unusual construction conditions including but not limited to piping that is to be installed in frozen ground, rock, under paved areas or other obstructions, regardless of Service Line/Yard Line length.

(b) A copy of Company's estimate showing the costs of labor, overheads and material required to perform the work hereunder shall be furnished to customer upon request prior to construction, unless safety conditions are to be addressed and the response does not afford the opportunity to prepare an estimate.

(3) All replacements of Customer-owned Service/Yard Lines shall be performed by Company or Company-authorized personnel and shall thereafter be owned, operated and maintained by Company.

(4) Replacement of Customer-owned Service/Yard Lines will occur in accordance with Company's schedule and the requirements of regulatory authorities having jurisdiction herein.

(5) Billing and Payment Options

(a) For installations or replacements of service lines 1 ¼ inch in diameter or less where the excess costs exceed $500, Company may, after giving due consideration to the total costs and Customer's ability to make the required payment, enter into a special payment agreement with Customer to permit payment over a period of up to 36 months.

GENERAL TERMS AND CONDITIONS FOR GAS SERVICE

(b) For installations or replacements of service lines greater than 1 ¼ inch in diameter where costs exceed $500, Company will present Customer a bill which will be due and payable upon receipt.

~~(b)~~(c) For new Service Line and Yard Line Installations where costs are estimated to be $500 or less, Company will present Customer a bill for such costs, which shall be due and payable upon receipt. Upon payment, Company shall install or cause to be installed, the required lines.

~~(c)~~(d) For replacement of customer-owned lines where costs are $500 or less, Customer will be billed for such costs, which shall be due and payable upon receipt. Customer may be permitted to pay the balance in equal monthly installments over a period not to exceed 12 months.

~~(d)~~(e) Customer's failure to pay the excess costs in accordance with the pay agreement shall be sufficient cause to discontinue service to Customer upon due notice and in accordance with these General Terms and Conditions.

7.05 Company Liability: Customer shall save Company harmless from all claims for trespass, injury to persons, or damage to lawns, trees, shrubs, buildings or other property that may be caused by reason of the installation, operation, or replacement of the Service Line, Yard Line and other necessary appurtenances to serve Customer unless it shall affirmatively appear that the injury to persons or damage to property complained of has been caused by willful default or negligence on the part of Company or its accredited personnel.

Company may refuse or discontinue service if an inspection or test reveals leakage, escape or loss of gas on customer's premises. Company will not be liable for any loss, damage or injury whatsoever caused by such leakage, escape or loss of gas from Customer's Service Line, Yard Line, Ancillary Lines, house piping, appliances or other equipment.

Company shall not be liable to Customer for any damages, consequential or otherwise, caused by external forces not within the exclusive control of the Company.

GENERAL TERMS AND CONDITIONS FOR GAS SERVICE

8. EXTENSION POLICY

8.01 Extension of Distribution Mains:

8.01.01 Distribution Mains: The term "distribution mains" is used herein to designate the pipe and other related facilities of Company, excluding service lines, which are located downstream of town border stations or other points where Company determines that the primary function of such facilities is to distribute natural gas among customers as opposed to moving natural gas through transmission lines.

8.01.02 Extension Requests:

(1) A distribution main extension ~~shall~~ may normally be requested by a customer as defined in Section 1.11~~0~~ Customer or~~.~~ ~~Company may also enter main extension agreements with~~ by developers, including but not limited to area developers, construction companies, contractors and similar entities~~.~~ and ~~Developers~~ shall be subject to the customer-related provisions in this Section 8 unless otherwise ordered or approved by the Commission.

(2) Main Extension Agreement: Company and requesting party may enter into a Main Extension Agreement regarding terms mutually determined and agreed upon by both parties.

8.01.03 Economic Evaluation: Company may conduct an Ecomomic Evaluation of the project to determine whether extension is of Ordinary or Extraordinary in nature as defined below:

~~8.01.02~~(1) Ordinary Extensions: Company will make ordinary extensions of its distribution mains as and when necessary to serve prospective customers ~~and~~ located within the corporate limits of a city or suburban area adjacent thereto, or within unincorporated communities.

~~(1)~~(a) The Ordinary Extension Allowance shall be the length of

GENERAL TERMS AND CONDITIONS FOR GAS SERVICE

the actual extension up to ~~but no greater than~~ ~~75~~ 100 feet per customer served.

~~(2)~~(b) The Ordinary Extension Value shall be the Ordinary Extension Allowance times the per foot cost of the distribution main project, not including extraordinary costs due to unusual construction conditions or barriers or of special equipment or facilities.

~~8.01.03~~8.01.01 ~~Extension Requests: A distribution main extension shall normally be requested by a customer as defined in Section 1.10 Customer. Company may also enter main extension agreements with developers, including but not limited to area developers, construction companies, contractors and similar entities. Developers shall be subject to the customer-related provisions in this Section 8 unless otherwise ordered or approved by the Commission.~~

GENERAL TERMS AND CONDITIONS FOR GAS SERVICE

~~8.01.04~~(2) Extraordinary Extensions: Company may determine any distribution main extension to be of an extraordinary nature.

~~(1)~~(a) An extraordinary extension shall be one:

~~(a)~~i. From which the prospective service usage is so limited that it is doubtful whether the revenues from the extension will pay a fair return on the investment pursuant to an Economic Evaluation conducted by the Company, or

~~(b)~~ii. For which the cost of making such extension is prohibitive due to unusual construction conditions or barriers, even though the length of the extension does not exceed ~~75~~ 100 feet per applicant, or

~~(c)~~iii. Which incorporates special equipment or facilities to serve the customer's load requirements.

~~(2)~~(b) When a distribution main extension is determined to be of an extraordinary nature or exceeds the Ordinary Extension Allowance, Company shall have the right to require:

~~(a)~~i. A ~~customer~~ contruction contribution sufficient to compensate Company for the extraordinary costs ~~involved~~ above the Ordinary Extension Value, or

~~(b)~~ii. A satisfactory guarantee of revenue through adjustment of the minimum bill provisions of the applicable rate.

~~8.01.058.01.01 Determination of the Extension Route: The distance of the premises from the nearest existing distribution main having sufficient available capacity to provide adequate service to customer and to other customers connected thereto shall be measured along easements, streets, roads, highways, and alleys but not across private property.~~

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GENERAL TERMS AND CONDITIONS FOR GAS SERVICE

~~(1)~~(3) ~~In those instances where unusual conditions exist and where good engineering practices dictate that an alternative to the shortest route be selected, Company reserves the right to determine such alternate route.~~

GENERAL TERMS AND CONDITIONS FOR GAS SERVICE

~~(2)~~(1) ~~Company may refuse service to an applicant who would extend piping across another's property to circumvent payment for a main extension.~~

~~(3)~~(1) ~~Crossings of streets and alleys shall not be included in computing the total length of the extension if:~~

~~(a) the crossings are avoidable because of the added efficiency, economy or safety of other options, or~~

~~(b)~~(a) ~~the crossings are not required to provide sufficient and reliable service to the customer or development, or~~

~~(c)~~(a) ~~the crossings are installed primarily to increase reliability or capacity of Company's overall gas distribution system.~~

8.01.04 Construction Contribution: Company ~~shall~~ may require a potentially refundable advance payment of the total estimated Ordinary or Extraordinary construction costs for main installations, unless the Company determines the anticipated revenue is sufficient to prevent undue burden on existing Customers.

(1) The amount of the construction contribution required will be estimated by Company. If Company requires a construction contribution in advance of any construction or modification of Company's facilities as herein described, it shall be understood that such contribution is based on estimated costs.

~~8.01.06~~(2) Company reserves the right to modify such contribution after actual costs become known. The term "estimated cost" as used herein will be the estimated cost for materials, labor and work equipment required, plus Company's related overheads. A copy of Company's estimate showing the costs of labor, overheads and material required to perform the work hereunder will be furnished to customer upon request prior to construction.

~~Applicants requesting to be connected to a gas distribution main which was installed according to an agreement for which a construction~~

GENERAL TERMS AND CONDITIONS FOR GAS SERVICE

~~contribution was required, shall pay as a nonrefundable sum, a main tap charge if the request is made within a period of 5 years from the date of the main extension agreement. The main tap charge shall be an amount determined by dividing the total cost of the main extension by the number of potential customers reasonably expected to take service from the extension, less the Ordinary Extension Value per potential customer as determined in Section 8.01.02 Ordinary Extensions. For~~

GENERAL TERMS AND CONDITIONS FOR GAS SERVICE

~~purposes of this calculation, the number of potential customers shall be that number established by Company based on, but not limited to, information supplied by the applicant, a legal description of the area, maps, and Company's experience in similar developments.~~

~~8.01.07 Contribution Refunds: Refunds for construction contributions shall be made to the party who paid the contribution.~~

~~(1) Qualified Customer: A Qualified Customer shall be one:~~
~~(a) Which is connected directly to the extension and not to a further extension, and~~

~~(b) Which, within a period of 5 years from the date of a main extension agreement requiring a construction contribution, was connected to the extension and for which the applicable refund was requested from Company, and~~

~~(c) Which utilizes Company's natural gas service for its full space heating requirements and, for residential end uses, also for its full water heating requirements.~~

~~(2) Qualified Nonresidential Customer: A Qualified Nonresidential Customer shall be one:~~
~~(a) Which is connected directly to the extension and not to a further extension, and~~

~~(b) Which, within a period of 5 years from the date of a main extension agreement requiring a construction contribution, was connected to the extension and for which the applicable refund was requested from Company, and~~

~~(c) Which is served under any rate schedule except Company's Residential Sales Service rate schedule, and~~

~~(d)~~(a) ~~Which is not served under a negotiated, discounted or~~

GENERAL TERMS AND CONDITIONS FOR GAS SERVICE

~~special contract rate.~~

GENERAL TERMS AND CONDITIONS FOR GAS SERVICE

~~(3) Standard Refund: The refund for the connection of one Qualified Customer or one Qualified Nonresidential Customer shall be the Ordinary Extension Value described in Section 8.01.02 Ordinary Extensions, except a Usage Based Refund may be elected in lieu of the Standard Refund for connection of a Qualified Nonresidential Customer.~~

~~(4) Usage-Based Refund: Upon the request of the party who made the construction contribution, the refund for the connection of a Qualified Nonresidential Customer shall be based on usage in lieu of the Standard Refund.~~

~~(a) A Usage-Based Refund shall be calculated as:~~

$$\cancel{\frac{(A * B)}{(C * D)} * E}$$

~~Where:~~

~~A is the Qualified Nonresidential Customer's Refund Usage.~~

~~B is the Delivery Charge of the Company's rate schedule under which the Qualified Nonresidential Customer was served during the referenced billing period.~~

~~C is the Base Residential Usage, which shall be the annual Mcf required from a residential customer to achieve the return on investment accepted in the Company's most recent rate docket, as stated in Section 12.11.~~

~~D is the current Delivery Charge of the Company's Residential Sales Service tariff.~~

~~E is the Standard Refund~~

GENERAL TERMS AND CONDITIONS FOR GAS SERVICE

~~(b) There shall be five (5) consecutive Refund Calculation Periods, each composed of 12 months. The initial Refund Calculation Period shall begin on the date the applicable main extension agreement was signed and the last shall end 5 years from that date.~~

~~(c) Refund Usage shall be the Qualified Nonresidential Customer's Actual Usage minus Base Usage.~~

~~(d) Actual Usage shall be the total Mcf delivered to the Qualified Nonresidential Customer during a Refund Calculation Period. A Qualified Nonresidential Customer's usage accumulated over a lesser time period may be included in a total refund. If an account has been in delinquent status more than one time during the Refund Calculation Period, no usage from that account shall be included as Actual Usage.~~

~~(e) Base Usage shall be zero Mcf for the initial refund calculation; thereafter, Base Usage shall be the highest Actual Usage in any Refund Calculation Period.~~

~~(f) A negative Refund Usage for a Refund Calculation Period will neither generate a refund nor decrease the Base Usage. No additional construction contribution shall be required due to decreased actual usage.~~

~~(g) Usage Based Refunds shall be available only under main extension agreements dated on or after December 17, 2004.~~

~~(5) Binding Choice: A customer, having once selected either the Standard or the Usage-Based refund option for a specific project, shall not be allowed to change to the other methodology.~~

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DAVID N. DITTEMORE, Manager-Regulatory Affairs				

GENERAL TERMS AND CONDITIONS FOR GAS SERVICE

8.01.05 Contribution Refunds ~~Requests~~: The amount of refund for construction contributions shall be determined according to terms defined in the Main Extension Agreement, if applicable, for natural gas utilization as calculated in the Economic Evaluation performed by Company.

(1) Refund Requests: Refunds for construction contributions shall be made to the party who paid the contribution.

(a) It shall be the responsibility of the party who made the construction contribution to request Company to calculate and issue a refund.

(b) The requesting party shall have 60 days from the expiration of the calculation period designated in the Main Extension Agreement to request a refund.

(c) Refunds will be issued within a period of 7 years from the date of a Main Extension Agreement for active connections to the extension and not to a further extension.

~~(6)~~

~~(a) A Standard Refund may be requested after service is connected. The requestor of a Standard Refund shall identify the service address(es) of the applicable Qualified Customer(s).~~

~~(b) The requestor of a Usage Based Refund shall identify the Refund Calculation Period and provide the service addresses of the applicable Qualified Nonresidential Customers.~~

~~(7)~~(2) Total Refunds: At no time shall the aggregate refunds exceed the ~~original construction contribution less any amount attributable to unusual construction conditions or barriers.~~ advance payment.

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DAVID N. DITTEMORE, Manager-Regulatory Affairs

GENERAL TERMS AND CONDITIONS FOR GAS SERVICE

~~(8)~~(3) Unrefunded Contributions: Any portion of a construction contribution remaining after ~~5~~ 7 years from the date of the main extension agreement shall become a nonrefundable contribution in aid of construction and no additional Main Tap Charges from new applicants or extension allowances from Company will be applicable to the extension.

~~(9)~~(4) Confidential Information: Company shall maintain the confidentiality associated with a Qualified Customer's usage, pursuant to Section 1.~~07~~ 08 Confidentiality. The Qualified Customer may, at its sole discretion, provide Company with a signed affidavit permitting Company to release such information to the party who made the construction contribution, although Company shall have no responsibility to secure such affidavit from a Qualified Customer. In the absence of such authority, any disputes shall be presented to the Commission for resolution.

GENERAL TERMS AND CONDITIONS FOR GAS SERVICE

8.01.06 Customer's Guarantee: Company shall not be obligated to make any extension of its distribution system unless Customer executes a contract in writing with suitable guarantees that Customer will use the service for at least one year, or unless the owner of the property served by such extension or some other responsible person shall guarantee that the service will be used for at least one year.

8.01.07 Determination of the Extension Route: The distance of the premises from the nearest existing distribution main having sufficient available capacity to provide adequate service to customer and to other customers connected thereto shall be measured along easements, streets, roads, highways, and alleys but not across private property.

(1) In those instances where unusual conditions exist and where good engineering practices dictate that an alternative to the shortest route be selected, Company reserves the right to determine such alternate route and base construction cost estimates accordingly, as referenced in the subparts of 8.01.03 Economic Evaluation..

(2) Company may refuse service to an applicant who would extend piping across another's property to circumvent payment for a main extension.

(3) Crossings of streets and alleys shall not be included in computing the total length of the extension ~~if~~ unless:

(a) the crossings are avoidable because of the added efficiency, economy or safety of other options, or

(b) the crossings are ~~not~~ required to provide sufficient and reliable service to the customer or development, or

(c) the crossings are installed primarily to increase reliability or capacity of Company's overall gas distribution system.

~~8.01.08~~(4)

~~8.01.09~~8.01.08 Right-of-Way Limitations: Company shall not in any case be

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GENERAL TERMS AND CONDITIONS FOR GAS SERVICE

required to secure private rights-of-way for the purpose of making extensions of distribution mains or other facilities to property owned or otherwise controlled by Customer. Customer will provide or procure for Company such private rights-of-way as are satisfactory to Company for the construction, operation and maintenance by Company of its facilities necessary or incidental to the supplying of service. When necessary, Company shall endeavor to secure franchise rights from the municipality to cover extensions required, but will not make extensions on municipal streets or alleys not covered by lawful franchise grants.

~~8.01.10~~8.01.09 Extensions on Unimproved Streets and Alleys: Company shall not be required to construct any extensions of distribution mains in any street or alley for which the property lines, sidewalk lines and curb lines have not been previously established to the final grade. In cases where the street or alley is ungraded, Company shall not be required to extend its distribution mains unless the existing contour of the ground is within 12 inches of the final grade at the proposed locations of Company's mains. Free and safe access to and through such streets and alleys must be provided.

~~8.01.11~~8.01.10 Service Lines: Company's investment in Service Lines and provisions for leak surveys and maintenance are included in Subsection 7.04 Service Lines and Yard Lines.

GENERAL TERMS AND CONDITIONS FOR GAS SERVICE

~~8.01.12~~8.01.11 Extensions to be Property of Company: All extensions made under these rules shall at all times be and remain the property of Company.

~~8.01.13~~8.01.12 Other Restrictions: Distribution mains will not be extended unless Company is certificated by the Commission to provide service in the area. The character and type of the main extension and its route shall be decided by Company.

GENERAL TERMS AND CONDITIONS FOR GAS SERVICE

9.02.05 Adjustment of Bills for Meter Error: Billing adjustments shall be prepared for metering errors.

(1) Fast or Slow Registering Meters: When a billing adjustment is prepared for metering error, it shall be based on the calculated corrected meter readings for a period not exceeding six months or for the time the meter has been in service at that location if less than six months. If it can be shown that the error was due to some cause, the date of which can be fixed, the over charge or under charge shall be computed back to, but not beyond, such date.

(2) Non-registering Meters: If the meter is found not to register for any period, Company shall estimate the utility service used during this period in accordance with Section 4.05.02 ~~Calculation of Unconfirmed Usage.~~Correction of Erroneous Bills.

(3) Non-reporting Automatic Meter Reading (AMR) Devices: If AMR device is found not to have reported known usage for any period; Company shall allocate the utility service used during this period in accordance with Sections 4.04.05 Estimating Procedure and 4.05.02~~3 Allocation of Confirmed Usage~~Correction of Erroneous Bills.

(4) Payment: Company may permit payments to be made in installments over a reasonable period of time. No refund or bill less than the amount stated in Section 12.09 Adjusted Bill Amount need be issued or made.

9.02.06 Sub-Metering: When an additional meter is installed at the sole discretion of Company for use as sub-meter for the customer's convenience, a monthly charge may be made for the use of such meter, depending on its size. Sub-metering by the customer is not permitted.

THE STATE CORPORATION COMMISSION OF KANSAS

INDEX NO 12.1

KANSAS GAS SERVICE
A DIVISION OF ONEOK, INC.
(Name of Issuing Utility)

SCHEDULE GTC12

All Rate Areas
(Territory to which schedule is applicable)

Replacing Schedule GTC12 Sheet 1
which was filed December 21, 2011

No supplement or separate understanding shall modify the tariff as shown hereon.

Sheet 1 of 1 Sheets

GENERAL TERMS AND CONDITIONS FOR GAS SERVICE

12. STATEMENT OF MISCELLANEOUS CHARGES AND AMOUNTS

		Reference Section	Amount
12.01	Service Initiation Charge	2.13.01	$ 5.00
12.02	Meter Reading Charge	4.03.02 4.04.02	$ 10.00
12.03	Credit Due Amount	4.05.01	$ 10.00
12.04	Bill Error Amount	4.05.~~04~~02	$ 2.00
12.05	Collection or Disconnection Charge	5.08	$ 10.00
12.06	Reconnection Charge	5.09	$ 15.00
12.07	Insufficient Funds Check Charge	4.01.05	$ 30.00
12.08	Insufficient Funds Service Charge	4.01.05	$ 30.00
12.09	Adjusted Bill Amount	4.05.01 9.02.05	$ 2.00
12.10	Meter Test Fee	9.02.04	$ 40.00
12.11	Base Residential Usage	8.01.07(4)(a)	138 Mcf
12.12	Credit /Debit /ATM Card Fee per transaction up to and including $500	4.01.05(4)	$ 2.13
12.13	Diversion Reconnection Charge	5.09	$ 55.00

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December 5, 2012
/S/ Patrice Petersen-Klein

RESIDENTIAL SALES SERVICE

AVAILABILITY

Available in and around the communities specified in the Index to residential customers at single locations. Service is subject to the DEFINITIONS AND CONDITIONS section below.

NET MONTHLY BILL

$~~15.35~~20.45 Service Charge, plus

Applicable adjustments and charges provided in Company's Gas System Reliability Surcharge, plus

$ 2.126~~7~~2 Delivery Charge per Mcf for all gas delivered, plus

Applicable adjustments and charges provided in Company's Cost of Gas Rider, Weather Normalization Adjustment Rider and Ad Valorem Tax Surcharge Rider.

The Net Monthly Bill shall be no less than the Service Charge plus any minimum charges set forth in a customer's Service Agreement.

DEFINITIONS AND CONDITIONS

1. Sales service under this rate schedule is available to residential customers for use by the customer as provided for in Company's General Terms and Conditions for Gas Service.

2. Sales service is provided for the charge specified in the NET MONTHLY BILL when supplied from Company's existing facilities. When additional facilities are needed to serve a customer, an additional charge may be required.

3. Sales service under this rate schedule is subject to the provisions and applicable charges contained in Company's General Terms and Conditions for Gas Service, or successor documents, approved by the Commission.

4. All provisions of this rate schedule are subject to changes made by order of the Commission.

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/S/ Patrice Petersen-Klein

THE STATE CORPORATION COMMISSION OF KANSAS INDEX NO 21.1

KANSAS GAS SERVICE SCHEDULE GSS
A DIVISION OF ONEOK, INC.
(Name of Issuing Utility)

All Rate Areas
(Territory to which schedule is applicable)

Replacing Schedule GS Sheet 1
which was filed December 18, 2008

No supplement or separate understanding shall modify the tariff as shown hereon.

Sheet 1 of 2 Sheets

GENERAL SALES SERVICE SMALL

AVAILABILITY

Available in and around the communities specified in the Index to nonresidential customers at single locations. Not available for service to separately metered generators with a capacity less than 20 kilowatts. Service is subject to the DEFINITIONS AND CONDITIONS section below.

NET MONTHLY BILL

$ 28.65	Service Charge, plus
	Applicable adjustments and charges provided in Company's Gas System Reliability Surcharge Rider, plus
$ 2.126~~7~~2	Delivery Charge per Mcf for all gas delivered, plus
	Applicable adjustments and charges provided in Company's Cost of Gas Rider, Weather Normalization Adjustment Rider and Ad Valorem Tax Surcharge Rider.

The Net Monthly Bill shall be no less than the Service Charge plus any minimum charges set forth in a customer's Service Agreement.

DEFINITIONS AND CONDITIONS

1. Annual deliveries less than 200 Mcf at an individual meter during the last 12 billing periods shall qualify a customer for service under this rate schedule.

2. If a customer does not select a general service rate schedule for which it may qualify, Company may select the applicable general service rate schedule on the customer's behalf. A customer may change the general service rate schedule which the customer is being billed during the first 12 months of service under the selected rate schedule. Thereafter, the customer is prohibited from making more than one change in a 12-month period.

3. Sales service is provided for the charge specified in the NET MONTHLY BILL section when supplied from Company's existing facilities. When additional facilities are needed to serve a customer, an additional charge may be required.

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/S/ Patrice Petersen-Klein

ELECTRONIC FLOW MEASUREMENT RIDER

APPLICABILITY

Applicable to all customers served under rate schedules STk, STt, LVTk, LVTt~~, WTk~~ and WTt and located in and around the communities specified in the Index. Service is subject to the DEFINITIONS AND CONDITIONS section below.

NET MONTHLY BILL

$ 25.00 ~~per meter~~ for each meter upon which Electronic Flow Measurement equipment (EFM) is installed, plus any charge to reimburse Company for the installed cost of the EFM, plus if applicable,~~.~~

$15.00 for each meter connected to Company-maintained cellular data equipment.

DEFINITIONS AND CONDITIONS

1. EFM shall be required on all meters serving transportation accounts, except for the provisions of Definition and Condition #2 (below). Company shall install, operate, and own all EFM. Company shall provide and bill the customer the actual cost for any requested assistance beyond maintenance to Company's EFM and/or connection.

   a. The requirements of this provision shall be judged to have been met pending a customer’s sequential assignment to Company’s EFM installation schedule.

   b. Company may, at its sole discretion, waive the requirements of this provision for a customer which uses gas primarily during Company's off-peak season.

   c. A customer which declines Company’s EFM installation, or which does not provide a Contribution in Aid of Construction (CIAC), or which does not install and/or maintain an operable dedicated telephone circuit, all as required by this rider, shall be ineligible for transportation service. ~~Company shall promptly notify a customer of the need to install or maintain an operable dedicated telephone circuit and may, 45 days after such notification, disqualify such customer from transportation service.~~

   ~~c.~~d. In the event that existing customer-maintained communication facilities fail to adequately transmit meter data, Company shall promptly notify a customer of the need to install or maintain an operable dedicated telephone circuit. The customer must

ELECTRONIC FLOW MEASUREMENT RIDER

repair the phone circuit or elect to switch to Equipment Option 2 as outlined in part 3 below. If, after 60 days from initial notification, the customer fails to provide an operational dedicated phone circuit or select the applicable Equipment Option, the Company, at its sole discretion, may disqualify such customer from transportation service and place the account on the appropriate General Sales rate.

ELECTRONIC FLOW MEASUREMENT RIDER (Cont.)

2. RDQ Balancing: Notwithstanding the provisions above, according to the Required Daily Quantity (RDQ) Balancing provisions in Section 11, Pipeline System Restrictions & Priorities of Company's General Terms and Conditions for Gas Service (GTC), a customer may agree to deliver during a Period of Curtailment (POC) a predetermined RDQ of natural gas to a transportation service meter which records a peak-month usage of less than 1,500 Mcf in the most recent 12 month period ending April 30, in lieu of the Company's requirement to install EFM. However, meters upon which EFM equipment has already been installed shall not be eligible for the RDQ Balancing option and the customer shall be subject to all charges set out in the Net Monthly Bill section.

3. A customer shall reimburse Company for the installed cost of EFM which shall become the sole property of Company. This CIAC for labor, material, and overhead costs associated with the installation shall be one of the following installation options:

~~$ 1,600 per meter – if the customer's existing measurement facilities do not require the use of an electronic correction device as part of the EFM, or~~

Option 1: $ 3,400 per meter for installation of EFM equipment with an electronic correction device and modem to transmit meter and usage data via a customer-provided and maintained, dedicated landline phone circuit, or~~if the customer's existing measurement facilities include or require the use of an electronic correction device as part of the EFM.~~

Option 2: $4800 per meter for installation of EFM equipment with an electronic correction device and modem to transmit meter and usage data via a Company-provided cellular connection. Customer is required to provide and maintain AC power to the meter setting, if available. Otherwise, customer may arrange for Company-provided and maintained solar power equipment necessary to operate EFM equipment. The cellular equipment option is only available if there is reliable cellular service at the meter setting. If reliable cellular service is not available, the customer will be required to install a dedicated phone circuit under Option 1 or be ineligible for transportation service.

Customers can, at any time, select another data/power option if adequate services are available to support the selection. The cost to upgrade shall be the difference of initial installation costs listed above.

Issued	December	10	2012
	Month	Day	Year
Effective	January	1	2013
	Month	Day	Year

By

DAVID N. DITTEMORE, Manager-Regulatory Affairs

12-KGSG-835-RTS
Approved
Kansas Corporation Commission
December 5, 2012
/S/ Patrice Petersen-Klein

ELECTRONIC FLOW MEASUREMENT RIDER (Cont.)

In the event the customer elects to downgrade Equipment Options, Company is not required to refund prior installation costs.

Some cellular service installations may require a remote mounted cellular antenna, remote mounted solar panel(s), up-sized solar panel(s) or other modifications that are above and beyond basic installation. Company will promptly notify customer in such events and provide a cost estimate prior to installation. Customer will be responsible for these additional costs.

4. A customer shall make an additional CIAC sufficient to cover the cost of any non-EFM related work performed and/or equipment installed at the customer's request. All such facilities and/or equipment shall become the sole property of Company. Payment shall be due from the customer at the time equipment is installed, except that Company may permit the customer to finance the EFM over a four year period at 8% per annum.

5. ~~Company shall endeavor to coordinate the installation of all facilities required herein with a customer as soon as practicable following the effective date of this rider.~~ Company shall notify the customer of its intent to install EFM, as well as the scope and estimated cost thereof.
   a. A customer shall provide adequate space for the installation of the EFM.

   b. A customer shall provide and maintain, at its cost, a dedicated telephone circuit or a Company-accepted alternative, according to Company's EFM Standards. Company and the customer shall mutually agree upon electric power and telephone connection location.

ELECTRONIC FLOW MEASUREMENT RIDER (Cont.)

c. A customer's acceptance of Company's installation plan shall be assumed unless the customer declines in writing within 15 days of Company's notice. If customer selects equipment Option 1, ~~T~~the customer shall, within ~~45~~60 days of acceptance, complete the installation of the required telephone circuit, at the customer's own expense, after which time Company shall install EFM equipment. If customer selects Equipment Option 2, Company will perform a site evaluation to determine if adequate cellular and/or sun exposure is available.

6. ~~When an EFM installation includes an electronic correction device, and a~~At a customer's request, Company may provide a data link or contact closure meeting Company's Standards from Company's EFM to the customer at the meter site so the customer can receive data with the same type of output signal as Company. At the customer's request, Company shall inspect and evaluate the customer's connection during normal Company working hours.

7. Upon a customer's written request made prior to April 30 of each year, and agreement by Company given prior to May 31 of that same year and which shall not be unreasonably withheld, Company may credit 50% of assessed and paid Overrun Penalties incurred by the customer in the preceding winter heating season of November through March, to EFM. The credit shall be limited to the per meter CIAC required by Definition and Condition #2 (above). A credit for EFM is available only on new, Company-installed EFM and when Company is not assessed Overrun Penalties for a similar time period pursuant to a pipeline's authorized tariff.

8. In the event ~~the EFM should fail, uncorrected mechanical readings shall be used to establish the estimated corrected read, except for orifice meter installations where~~ of equipment failure, Company shall use uncorrected mechanical readings, historical data and/or customer supplied data ~~shall be used~~ to estimate billing data.

9. A customer shall hold Company harmless from all claims for trespass, injury to persons, or damage to lawns, trees, shrubs, buildings or other property that may be caused by reason of the installation, operation, or replacement of the EFM or customer connection and other necessary equipment to serve the customer unless it shall be affirmatively proved that the injury to persons or damage to property complained of has been caused by willful default or negligence on the part of Company or its accredited personnel.

10. Service under this rider is subject to the provisions and applicable charges contained in Company's GTC or successor documents, approved by the Commission.

11. All provisions of this rider are subject to changes made by order of the Commission.

WEATHER NORMALIZATION ADJUSTMENT RIDER

APPLICABILITY

This rider is applicable to all service provided to all customers served under sales rate schedules RS, GSS, GSL and GSTE. Service is subject to the DEFINITIONS AND CONDITIONS section below.

NET ANNUAL CHARGE

A Weather Normalization Adjustment (WNA) factor shall be applied to all monthly usage to refund revenue excesses or collect revenue deficiencies which occur as a result of deviations from normal weather. The WNA factor shall be calculated by the formula:

WNA Factor = [Revenue + Adjustment] / Volumes

Where:

Revenue = WDF * Rate * Customers for the WNA Calculation Period

WDF = Weather Deviation Factor is the per capita volume deviation due to non-normal weather.
(NHDDp – AHDDp) * HSFp + (NHDDc – AHDDc) * HSFc
Where p = prior month data and c = current month data for the given class and weather station.

NHDD = Normal Heating Degree Days for the applicable month.

AHDD = Actual Heating Degree Days for the applicable month.

HSF = Heat Sensitivity Factor is the usage per degree day calculation which is specific to the applicable weather station and Company service schedule.

Customers = Count of customers for the given class and weather station.

Rate = The applicable customer delivery charge per Mcf.

Volumes = Estimated volumes for the current WNA Collection Period.

Adjustment = Revenue from the prior year WNA Calculation Period less Recoveries.

Recoveries = WNA Factor times the monthly actual sales volumes.

WEATHER NORMALIZATION ADJUSTMENT RIDER (Cont.)

DEFINITIONS AND CONDITIONS

1. All provisions set forth in the rate schedule under which a customer takes service shall apply to the extent they are not superseded by provisions of this rider.

2. WNA factors shall be calculated to the nearest $0.0001 per Mcf.

3. The Heat Sensitivity Factors and the Heating Degree Day normals, as approved in KCC Docket No. ~~12~~16-KGSG-~~835~~__-RTS, shall be used for each rate schedule and weather station.

4. The WNA Collection Year, consisting of the twelve month period ending ~~May 31~~June 30 of each calendar year, shall define the period during which a WNA factor is collected.

5. The WNA Calculation Period, consisting of the ~~five~~ seven cycle billing months of ~~November~~ October through ~~March~~April prior to the WNA Collection Year, shall define the period over which the revenue excess or deficiency is calculated.

6. Company shall file a report with the Commission by ~~May~~ June 25 of each year, detailing the calculations deriving the WNA factors authorized by this rider to be applied during the subsequent WNA Collection Year.

Issued	April	23	2015
	Month	Day	Year
Effective	April	23	2015
	Month	Day	Year

By /S/
David N. Dittemore, Manager-Regulatory Affairs

15-KGSG-291-TAR
Approved
Kansas Corporation Commission
April 23, 2015
/S/ Amy L. Gilbert

THE STATE CORPORATION COMMISSION OF KANSAS
KANSAS GAS SERVICE
a division of ONE Gas, Inc.
(Name of Issuing Utility)

INDEX NO 44.1
SCHEDULE GSRS

All Rate Areas
(Territory to which schedule is applicable)

Replacing Schedule GSRS Sheet 1
which was filed November 25, 2014

No supplement or separate understanding shall modify the tariff as shown hereon.

Sheet 1 of 2 Sheets

GAS SYSTEM RELIABILITY SURCHARGE RIDER

AVAILABILITY

This rider is applicable to every bill for service provided under each of the Company's sales and transportation rate schedules except where not permitted under a separately negotiated contract with a customer. Not applicable to bills for As-Available Gas Sales Service or Interruptible Gas Transportation Service.

NET MONTHLY CHARGE

The Gas System Reliability Surcharge (GSRS) shall be a fixed monthly amount calculated as the applicable GSRS times the number of meters serving the customer's account, as indicated by the total number of Service Charges billed.

RS	Residential Sales Service		$ ~~0.76~~ 0.00
GSS	General Sales Service Small		$ ~~1.12~~ 0.00
GSL	General Sales Service Large		$ ~~2.76~~ 0.00
GSTE	General Sales Service Transport Eligible		$ ~~10.48~~ 0.00
SGS	Small Generator Sales Service		$ ~~1.40~~ 0.00
KGSSD	Kansas Gas Supply D		$ ~~120.27~~ 0.00
GIS	Gas Irrigation Sales Service		$ ~~4.63~~ 0.00
SSR	Sales Service Resale		$ ~~14.81~~ 0.00
STk	Small Transportation Service (k)		$ ~~6.88~~ 0.00
STt	Small Transportation Service (t)		$ ~~8.69~~ 0.00
LVTk	Large Volume Transportation Service (k)		
	Annual Use:	Below 10,000 Mcf	$ ~~13.30~~ 0.00
		10,001 Mcf – 20,000 Mcf	$ ~~40.40~~ 0.00
		20,001 Mcf – 40,000 Mcf	$ ~~87.80~~ 0.00
		Above 40,001 Mcf	$ ~~181.40~~ 0.00
LVTt	Large Volume Transportation Service (t)		
	Annual Use:	Below 10,000 Mcf	$ ~~28.00~~ 0.00
		10,001 Mcf – 20,000 Mcf	$ ~~80.00~~ 0.00
		20,001 Mcf – 40,000 Mcf	$ ~~208.00~~ 0.00
		Above 40,001 Mcf	$ ~~426.60~~ 0.00
WTt	Wholesale Transportation Service (t)		$ ~~143.07~~ 0.00
GITt	Gas Irrigation Transportation Service (t)		$ ~~10.16~~ 0.00
CNG	Compressed Natural Gas General Transportation		$ ~~25.25~~ 0.00

	Month	Day	Year
Issued	November	6	2015
Effective	December	1	2015

By /S/
David N. Dittemore, Director-Regulatory Affairs

16-KGSG-104-TAR
Approved
Kansas Corporation Commission
November 5, 2015
/S/ Amy L. Green

Kansas Gas Service™

A Division of ONE Gas

Issued: ______________________	
Effective: ______________________	
By: ______________________	
David N. Dittemore, Director – Regulatory Affairs	

Transfer Notice

Effective January 27, 2014, the natural gas distribution business of ONEOK, Inc. was transferred to ONE Gas, Inc.

Kansas Gas Service, a Division of ONE Gas, Inc. hereby states that all tariffs, schedules, general terms and conditions, rules, notices, contracts, certificates, authorities or other instruments whatsoever, filed with the Kansas Corporation Commission, by Kansas Gas Service, A Division of ONEOK, Inc. prior to January 27, 2014, are applicable to it as if the same had been originally filed under the name of Kansas Gas Service, A Division of ONE Gas, Inc.

This notice also applies to all supplements and amendments to any of the above schedules, etc. which Kansas Gas Service, A Division of ONEOK, Inc. has heretofore filed with said Commission.

Rate Schedule Index

Kansas Gas Service Company, A Division of ONE Gas, Inc. provides natural gas services to customers under the following schedules:

Issued: ____________ Effective: ____________ By: ____________ David N. Dittemore, Director – Regulatory Affairs	

Rate Schedule Index

Communities Index

"t" System Communities: Available Schedules: RS, GSS, GSL, GSTE, SGS, GIS, CNG, GITt, STt, and LVTt

Abilene
Ames
Ashland
Assaria
Axtell
Baileyville
Barnes
Beattie
Belpre
Belvue
Bison
Blaine
Blue Rapids
Buhler
Canton
Centralia
Chapman
Clay Center
Clifton
Clyde
Coldwater
Concordia
Courtland
Cuba
Cullison
Cunningham
Detroit
Ellinwood
Enterprise
Frankfort
Galva
Garfield
Gorham
Grandview Plaza
Great Bend
Greenleaf
Greensburg
Gypsum
Haddam
Hanover
Haviland
Hoisington
Home City
Hope
Hutchinson
Industry
Inman
Junction City
Kingman
Kinsley
Kiro
LaCrosse
Larned
Lehigh
Lewis
Lindsborg
Linn
Loretta
Louisville
Macksville
Mahaska
Manhattan
Marquette
Marysville
McPherson
Medora
Medicine Lodge
Mentor
Morganville
Morrowville
Munden
Narka
Nashville
Ogden
Olmitz
Onaga
Otis
Partridge
Pfeiffer
Pratt
Pretty Prairie
Protection
Rossville
Roxbury
Russell
St. Benedict
St. George
St. John
St. Marys
Salina
Scandia
Seneca
Silver Lake
Smolan
South Hutchinson
Stafford
Timkin
Vermillion
Victoria
Vining
Vliets
Wakefield
Walker
Wamego
Washington
Waterville
Westmoreland
Wheaton

Communities Index

"k" System Communities: Available Schedules: RS, GSS, GSL, GSTE, SGS, GIS, CNG, STk, and LVTk

Alden
Alta Vista
Andover
Arkansas City
Arlington
Arma
Atchison
Altanta
Aubry
Augusta
Baldwin
Barnard
Baxter Springs
Bel Aire
Belle Plaine
Beloit
Bentley
Benton
Berryton
Beverly
Bloom
Blue Mound
Bronson
Bucklin
Burden
Burns
Burr Oak
Bushton
Cambridge
Capaldo
Carbondale
Carlyle
Carona
Cawker City
Chase
Cheney
Cherokee
Cherryvale
Chicopee
Circleville
Claflin
Clearwater
Colony
Columbus
Colwich
Conway Springs
Crestline
Delphos
Dennis
Derby
Dexter
Douglass
Downs
Dwight
Eastborough
Easter's Addition
Edgerton
Effingham
Elbing
El Dorado
Ellsworth
Elmont
Elwood
Emporia
Englewood
Erie
Esbon
Everest
Fairview
Fairway
Formoso
Fort Scott
Franklin
Frederick
Frontenac
Galena
Garden Plain
Gardner
Gas City
Geneseo
Girard
Glasco
Glen Elder
Goddard
Goessel
Grantville
Greeley
Grenola
Hamlin
Harper
Hartford
Haven
Haysville
Hiawatha
Highland
Holton
Holyrood
Horton
Huron
Iola Rural
Iuka
Jewell City
Johnson County
Kanopolis
Kansas City
Kingman
Kingsdown
Kiowa
Kirkwood
Kismet
La Harpe
Lake Quivira
Lake Waltana
Lancaster
Lane
Langdon
Langdon Lane
Lansing
Leavenworth
Leawood
Lebanon
Lecompton
LeLoup
Lenexa
Leon
Lincoln Center
Lorraine
Lowell
Lucas
Luray
Lyndon
Madison
Mankato
Mecca Acres
Melvern
Meridan
Merriam
Michigan Valley
Miltonvale
Minneapolis
Minneola
Mission
Mission Hills
Mission Woods
Monticello
Montrose
Moran
Morrill

Issued: ______ Effective: ______ By: ______ David N. Dittemore, Director – Regulatory Affairs	

Communities Index

"k" System Communities: Available Schedules: RS, GSS, GSL, GSTE, SGS, GIS, CNG, STk, and LVTk

Mount Hope
Mount Vernon
Mullinville
Mulvane
Muscotah
Netawaka
New Ozawkie
New Salem
Newton
North Newton
Nortonville
Obeeville
Olpe
Osawatomie
Osborne
Oskaloosa
Oswego
Ottawa
Overbrook
Overland Park
Oxford
Ozawkie
Paola
Park City
Parkerfield
Parsons
Pauline
Perry
Petrolia
Piqua
Pittsburg
Pomona
Potwin
Prairie Village
Preston
Princeton
Quenemo
Rantoul
Raymond
Reserve
Richmond
Riverton
Robinson
Roeland Park
Rose Hill
Roseland
St. Paul
Sabetha
Scammon
Scipio
Scranton
Sedgwick
Shawnee
Shawnee Heights
Smith Center
Somerset
South Mound
Stanley
Stilwell
Sylvan Grove
Tecumseh
Tescott
Thayer
Tonganoxie
Topeka
Towanda
Town & County Est.
Troy
Turon
Udall
Valley Center
Valley Falls
Vesper
Walnut
Wathena
Waverly
Weir
Welda
Wellington
Wellsville
West Mineral
Westwood
Westwood Hills
Whitewater
Whiting
Wichita
Williamsburg
Willis
Willowbrook Addition
Winchester
Zarah

Communities and Gas Distribution Companies Served at Wholesale:
Available Schedule: SSR and WTt

Alma
Aurora
Belleville
Hudson
Isabel
Jamestown
Longford
Palmer
Midwest Energy, Inc.
Atmos Energy
Black Hills Energy

Issued: __________
Effective: __________

By: __________
David N. Dittemore, Director – Regulatory Affairs

General Terms and Conditions for Gas Service

General Terms and Conditions for Gas Service

General Terms and Conditions for Gas Service

Issued: ______ Effective: ______ By: ______ David N. Dittemore, Director – Regulatory Affairs	

General Terms and Conditions for Gas Service

Issued:	
Effective:	
By:	
David N. Dittemore, Director – Regulatory Affairs	

General Terms and Conditions for Gas Service

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General Terms and Conditions for Gas Service

Issued: ______ Effective: ______ By: ______ David N. Dittemore, Director – Regulatory Affairs	

General Terms and Conditions for Gas Service

General Terms and Conditions for Gas Service

1. **Definitions**

1.01 **Agent**: A person, partnership, public/private firm, or corporation authorized by another entity to perform services on their behalf.

1.01.01 **Company Agent**: A person or agency employed or appointed by Company to act as its representative for the purpose of providing service or otherwise exercising the authorities described in Company's Commission-approved Tariffs.

1.01.02 **Marketer Agent**: An agent authorized by the Customer to perform transportation service-related activities for the Customer. A gas marketer must meet criteria established under Section 10 Requirements for Transportation Service.

1.02 **Ancillary Line**: The exterior piping installed and owned by customer and connected to the yard line or house piping to supply fuel to any exterior appliance or apparatus.

1.03 **Arrears**: The first day of the arrearage period is the first day after the due date on the bill.

1.04 **Central Clock Time (CCT)**: Central Standard Time throughout the year, as adjusted for Central Daylight Time.

1.05 **Character of Service**: The qualities inherent in the classification and nature of service.

1.05.01 **Classification of Service**: The category of service provided to the Customer. A change in the classification of service may be marked by, but is not exclusively limited to, movement from Residential to Nonresidential service or by a change from small to large Nonresidential.

1.05.02 **Nature of Service**: The manner by which service is received. Fundamental modifications to parameters including, but not limited to, delivery pressure or the size of the meter or required distribution piping constitute a change in the nature of service.

1.06 **Commission**: The State Corporation Commission of the State of Kansas or any successor of such Commission having jurisdiction over the subject matter herein.

1.07 **Company**: Kansas Gas Service, a division of ONE Gas, Inc. or its properly designated Agent.

1.08 **Confidentiality**: Company's treatment of customer-specific information. This information, which shall include all billing statement information, usage data and agent

General Terms and Conditions for Gas Service

information, shall not be released to any other party without the customer's consent, except that neither notice nor Customer consent shall be required when customer-specific information is released in response to a request of the Commission or its staff. This section shall not prevent Company from providing information regarding Customer status when requested by law enforcement or emergency personnel acting in an official capacity or when customer-specific information is released by court order, subpoena, or other order or requirement issued by a duly constituted authority, or when release of such information is necessary to provide service. Company shall not be required to notify the Customer or obtain the customer's consent in these instances.

1.09 **Contiguous Premises**: Properties, sharing at least one common point or local boundary, upon which all buildings and/or natural gas consuming devices are owned or occupied by the same Customer, and upon which all natural gas service is utilized to supply one or more connected natural gas loads which Company considers to be components of a unified operation. Streets, alleys, and other rights-of-way intersecting the customer's properties are not considered property occupied or used by others.

1.10 **Curtailment**: Company's complete or partial limiting of delivery services to a Customer or customers otherwise entitled to receive such services.

1.11 **Customer**: An end-user of natural gas for which Company has approved an application for service supplied under Company's Tariffs.

1.11.01 **Residential**: A Customer receiving natural gas Sales Service at a Single Location, principally for the maintenance or improvement of the quality of life in a household, home, or place of dwelling having separate kitchen, sleeping and living facilities and permanent provisions for sanitation, or at a detached garage on the same premises as customer's home. The primary use of utility service shall be limited to comfort space conditioning, water heating, food preparation, and other non-profit household uses. Uses shall also include:

(1) Premises, served through one meter, that have been converted from one to no more than five single-family dwelling units, each having separate kitchen facilities, and

(2) Premises in which four or fewer sleeping rooms are rented or available for rent.

1.11.02 **Nonresidential**: A Customer served at a single location for which the primary activity cannot be defined as residential. Nonresidential customers may include, but shall not necessarily be limited to, those using service for

Issued: ______________________	
Effective: ______________________	
By: ______________________	
David N. Dittemore, Director – Regulatory Affairs	

General Terms and Conditions for Gas Service

wholesale and retail trade, professional and miscellaneous business services; hotels and other lodging places; garages located on property not contiguous to the customer's residential dwelling; clubs; single-metered apartment houses; commercial office buildings; warehouses; theaters and auditoriums; water pumping plants; laundries; greenhouses; public buildings; universities, colleges and schools; hospitals, institutions for the care or detention of persons; and airfields, military and naval posts. Nonresidential customers may also include those using service to change raw or unfinished materials into other forms or products. Meters serving the common use of multiple customers or units, whether Residential or Nonresidential, shall be considered Nonresidential.

1.12 **Customer-Owned Distribution Network**: The customer-owned lines located downstream from a Company-owned Master Meter. Such networks include, but are not limited to, institutional, educational and health care campuses, mobile home parks, military complexes, industrial facilities, commercial complexes, irrigation systems and oil and natural gas leases.

1.13 **Delivery Point**: The point on Company's system at which it delivers natural gas that is transported.

1.14 **Delivery Systems**: The areas into which Company's delivery facilities are divided.

1.14.01 **"k" System**: Company's local distribution facilities connected to interstate pipelines not affiliated with Company and providing service to customers living in and around the communities listed in the Index.

1.14.02 **"t" System**: Company's affiliated and integrated transmission and local distribution facilities providing service to customers living in and around the communities listed in the Index.

1.15 **Diversion**: The obtaining of natural gas service not authorized by Company by way of interference, redirecting, or bypass of the meter to prevent measurement. Diversion shall include, but is not limited to, installing solid pipe or flexible steel tubing, hoses or other connection in or around a gas service riser.

1.16 **Fraud**: The misrepresentation or omission of facts or the giving of false and/or misleading information, the reliance on which would result in a customer's obtaining or maintaining utility service, or avoiding payment for past, present or future service, or obtaining a refund. Fraud shall include, but is not limited to, any verbal or documentary representation by which a prospective or current customer, or the customer's agent, provides:

General Terms and Conditions for Gas Service

(1) False names or identification information not legally assigned to such person.

(2) False or altered residency, either past, present or future.

(3) False or altered ownership or lease documentation

(4) False or insufficiently funded non-cash payments, through means including but not limited to:

(a) A false and/or unauthorized electronic fund transfers.

(b) False and/or unauthorized credit card or debit card information, to include the cancellation of a prior transaction without which disconnection of service would have occurred.

1.17 **Gas Day**: A 24-hour period from 9:00 a.m. to 9:00 a.m. Central Clock Time unless stated otherwise in an agreement with a specific pipeline. The Gas Day shall be used to determine receipt and delivery of gas by Company. It shall also be the basis for projecting the customer's requirement and nominating monthly usage.

1.18 **Gas Supply**: The total natural gas volumes purchased by Company to be available to meet the needs of its Sales Service customers.

1.19 **Master Meter**: A Company-owned meter providing service to a Customer-Owned Distribution Network.

1.20 **Nomination**: A customer's request to deliver a specified amount of gas through Company's local distribution facilities. A nomination is a daily MMBtu quantity and must include a beginning and ending date.

1.21 **Operational Flow Order (OFO)**: A directive instructing customers to control their usage to avoid either Under-Deliveries or Over-Deliveries to protect the integrity of any portion of Company's system or to ensure compliance with upstream transporters' requirements.

1.22 **Over-Delivery**: The condition resulting when deliveries of natural gas to a customer are greater than the usage level authorized by Company.

1.23 **Period of Curtailment (POC)**: A period of time during which Company limits delivery service to sales and/or transportation customers.

1.24 **Point of Delivery**: For inside meter settings, point of delivery shall be a point 12 inches exterior to the point at which the service line enters the building wall. For outside meter settings, point of delivery shall be Company's meter outlet, unless Company owns and

General Terms and Conditions for Gas Service

maintains the line extending from the meter to the building in which case the point of delivery shall be a point 12 inches exterior to the building wall.

1.25 **Receipt Point**: A mutually agreeable location on Company's system where a transportation service customer provides for Company to receive gas.

1.26 **Service**

1.26.01 **Sales Service**: Gas delivery for which Company is responsible for procuring an adequate supply of gas to meet a customer's needs. Company's responsibility under sales service is conditioned by Company's Rate Schedules and these GTC, specifically Section 11 Pipeline System Restrictions & Priorities.

1.26.02 **Transportation Service**: Gas delivery for which a Customer is responsible for procuring a supply of gas adequate for the customer's needs. Company's responsibility under transportation service is conditioned by Company's Rate Schedules and these GTC, specifically Section 10, Requirements for Transportation Service and Section 11, Pipeline System Restrictions & Priorities.

1.27 **Service Line**: For outside meter settings, it is the pipe installed from Company's main to the inlet of Company's meter. For inside meter settings, the Service Line extends from Company's main to the building wall.

1.28 **Single Location**: A customer's Contiguous Premises.

1.29 **Supplier**: A person, partnership, public/private firm, or corporation which provides and delivers natural gas to a Company Receipt Point on behalf of Company, a transportation customer, or the customer's agent.

1.30 **Supply Emergency**: A system condition in which Company's available gas supply is insufficient to meet the requirements of its critical-needs Sales Service customers. A supply emergency may be caused by insufficient supply or inadequate capacity, either on Company's system or on that of any connected interstate pipeline.

1.31 **Tampering**: Obtaining natural gas service not authorized by Company by altering the service regulator or other acts which prevent meters and/or regulators from accurately measuring the amount of gas consumed, or the use of an unassigned meter to obtain unauthorized service. Tampering shall include, but is not limited to:

(1) Making a tap connection to any service, distribution or transmission line owned by Company;

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(2) Defacing, puncturing, removing, reversing or altering any meter or any connections for the purpose of securing unauthorized or unmeasured service;

(3) Preventing any such meters from properly measuring or registering; or

(4) Taking, receiving, using or converting to such person's own use any service which has not been measured.

1.32 **Tariffs**: Company documents, on file with the Commission, which define the terms and conditions under which Company provides service to customers.

1.32.01 **General Terms and Conditions for Gas Service (GTC)**: The operational practices and methods for service to customers. The GTC applies to all service agreements between Company and a Customer and to all Rate Schedules and Surcharge/Rider Schedules approved by the Commission. These GTC in no way supersede or modify any rules, regulations, and lawful orders of the Commission. If there appears to be any conflict, the rules, regulations, and/or lawful orders of the Commission shall control. These GTC are also intended to be consistent with the service agreements, Rate Schedules, and Surcharge/Rider Schedules of Company. The more specific provisions of a service agreement, Rate Schedule, or Surcharge/Rider Schedule shall control if there appears to be any inconsistency. No representative, Agent, or employee of Company shall have authority to amend, modify, alter, or waive any of these GTC except as directed by the Commission. Certain requirements of these GTC may be waived by the Commission in individual cases upon written request by Company and a showing that compliance with the requirement would not serve the interests of Company or the Customer.

1.32.02 **Rate Schedules**: Rates and specific conditions for service. Rate schedules are subject to change as provided by law.

1.32.03 **Surcharge/Rider Schedules**: Rates and/or conditions for service applicable to certain customers, but which must refer to and rely upon a rate schedule or the customer’s complete requirements.

1.33 **Under-Delivery**: The condition resulting when deliveries of natural gas to a Customer are less than those received into Company’s system on behalf of the Customer.

1.34 **Yard Line**: Used in conjunction with outside meter settings, excluding Master Meters, to designate the underground piping installed from the outlet of Company's meter to the building wall.

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2. **Application for Service and Agreements**

2.01 **Availability of Service**: Service shall be made available to customers located within Company's certificated areas in accordance with its rate schedules and General Terms and Conditions as approved by the Commission.

2.02 **Application for Service**: Completion of Company's standard application or contract forms in writing shall constitute an application for service. Verbal application for service may be accepted by Company.

2.02.01 A separate application or contract shall be made for each class of service at each separate location. Upon acceptance of an application for service, Company shall supply customer with service in accordance with the rate schedules and these General Terms and Conditions filed with and approved by the Commission.

2.02.02 New customers, from whom an application for service shall be required, are those not meeting the requirements of 2.02.03 and which are:

(1) Individuals or corporate or business entities desiring but not currently receiving service from Company, or

(2) Customers who apply for new service at a concurrent and separate metering point, residence, or location, or

(3) Residential customers who have been disconnected for over 30 days, or

(4) Nonresidential customers who have been disconnected and issued a final bill, or

(5) New owners or leaseholders of existing premises, or

(6) New owners of the corporate or business entity that is the customer, or

(7) Customers who file for bankruptcy.

2.02.03 Existing customers are:

(1) Customers for whom Company has previously approved an application for service and whose account status remains active, or

(2) Residential customers who have been disconnected and reconnected to service at the same premises within 30 days, or

(3) Nonresidential customers who have been disconnected, but not issued a final bill.

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2.02.04 The taking of utility service by customer will constitute acceptance and agreement to be bound by all such provisions of Company's standard application contract and these General Terms and Conditions.

2.02.05 Company's waiver with respect to any customer default in complying with the provisions of an application for service shall not be deemed to be a waiver with respect to any other or subsequent default by such customer.

2.03 **Positive identification**: Company may require the applicant to provide positive identification prior to initiation of service.

2.03.01 Residential Applicants shall be required to provide at least one form of positive identification.

2.03.02 Positive identification may include, but is not limited to a driver’s license, passport or other photo identification issued by a governmental authority, a social security number or a birth certificate. A social security number may be requested as one method of positive identification but shall not be required.

2.03.03 Company may request the names of each adult occupant residing at the location where residential service is being provided.

2.03.04 Nonresidential applicants may be required to provide:

(1) The name of the person(s) responsible for payment of the account and at least one form of positive identification,

(2) The name of the business,

(3) The type of business, and

(4) The employer identification number (EIN), if available, issued by the Internal Revenue Service.

2.03.05 If positive identification is not immediately available at the time of application for service, a residential customer providing a full deposit will have at least 30 days to secure positive identification, provided that said grace period does not conflict with any statutes or regulations relating to identity theft detection, prevention and mitigation.

2.03.06 If positive identification is not provided within said grace period, or such identification constitutes fraud, Company may disconnect service pursuant to Section 5 of these General Terms and Conditions.

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2.04 **Refusal of Service at Time of Application**: Company shall not be required to commence service if, at the time of application for service, the applicant has outstanding with Company, an undisputed and unpaid service account until such indebtedness is satisfied or a payment agreement covering the indebtedness is executed.

2.04.01 For purposes of this rule, Customer's indebtedness shall include undisputed and unpaid accounts that accrued within the last 5 years for service provided under a written agreement, or 3 years for service provided under an oral agreement. The requested class of service must be the same as that for which the indebtedness was incurred, either at the same or former premises and located in any area served by Company.

2.04.02 Company shall not refuse service to a customer for an outstanding debt on an account unless that customer either signed the service agreement on the account or agreed orally at the time service was established to be responsible for the account. The only exception to this rule is when the current customer and the former customer, who signed the service agreement or agreed orally at the time service was established to be responsible for the account, lived together when the debt was incurred and continue to live together. Service may be withheld until such indebtedness is satisfied or a payment agreement covering the indebtedness is executed.

2.04.03 If Company refuses service to a customer at the time of application for service in accordance with this section, it shall clearly state the reason for such refusal. Company shall not make any other representation of its reason for its refusal except the applicable portion of this section.

2.05 **Refusal of Service After Application of Service**: Company may refuse service at any time when, in Company's judgment, it is unsafe for Company personnel to perform work at customer's premises. Unsafe situations that may prevent Company personnel from performing work at customer's premises include, but are not limited to, physical and/or verbal acts of aggression, intimidation, or anything which threatens the safety of Company personnel.

2.06 **Notices Between Customer and Company**:

2.06.01 **Written Notices**: All notices given to Company shall be in writing except as provided in Section 6.03 Defective Customer Equipment, and as described herein.

(1) Oral communication directed to the appropriate Company representative shall be considered proper notice.

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(2) When oral notices are taken in person or by telephone by Company's representative, a confirmation number and the employee's name shall be provided to customer as evidence of customer's contact with Company.

(3) Company shall exercise reasonable diligence in carrying out notices from customer, but shall not be responsible for error, delay or expense resulting there from, unless it shall be shown affirmatively that the error, delay or expense has been caused by willful default or negligence on the part of Company.

(4) Billing errors resulting from Company's failure to carry out customer's written notice or an oral notice for which customer has a confirmation number and employee's name, will be corrected as provided in Section 4.05.02 Correction of Erroneous Bills.

2.06.02 **Contracts**: Company representatives are not authorized to contractually bind Company except by writing duly executed.

2.07 **Availability of Rate Schedules**: Company's rate schedules and copies of these General Terms and Conditions for Gas Service shall be made available upon the request of any interested party. Company's service shall not be sold or otherwise provided except as specified in its rate schedules, contracts and General Terms and Conditions on file with the Commission.

2.08 **Choice by Customer**: Company shall, upon customer application for service or at any time upon request, advise customer as to the rate schedules available for and best adapted to existing or anticipated service requirements as defined by customer, but Company does not assume responsibility for the selection of such rate.

2.09 **Change of Rates**: Customer, having selected an applicable rate schedule, may not change to another rate within a 12 month period unless there is a substantial change in the character or condition of customer's service. If such change occurs, Company reserves the right to reissue bills for service rendered under the rate schedule applicable thereto for the period during which such service was in effect, but such period shall not exceed 12 months.

2.10 **Compliance With Rate Schedule**: If service is used for purposes not permitted in a rate schedule, Company reserves the right to reissue bills on the applicable rate for a period not to exceed 12 months, unless the date of the infraction can be determined in which case the correction shall be computed back to but not beyond such date, and all future bills will be on the applicable rate.

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2.11 **Retail Service**: The utility service furnished under a retail rate schedule is for the sole use of customer. Customer shall not resell such service to any other party. In case utility service supplied by Company is resold, service may be disconnected as provided in Section 5.02 Conditions for Discontinuing Service.

2.12 **Service for Resale**

2.12.01 **Definition of Resale Customer**: A resale customer is a customer who, by contract between Company and customer and approved by the Commission, is permitted to purchase utility service from Company for resale outside of Company's certificated areas. Resale shall be under rates filed with the Commission and only when Company's existing facilities, as determined by Company, have adequate pressure and capacity to provide such resale service without jeopardizing service to Company's other customers.

2.12.02 **Sales to Resale Customers**: A resale customer desiring to purchase additional utility service from Company for resale to any of its consumers other than those provided for in Category 1 of Company's priority of service rules specified in Section 11 Pipeline System Restrictions & Priorities, shall advise Company in writing of the name, location, load characteristics, available standby fuel facilities, and other necessary data relating to each such consumer. Within 30 days after receiving the request, Company will notify resale customer in writing (a) whether such service can be made available, (b) the effective date of such service, (c) the appropriate priority category, and (d) the applicable rate under which such service will be rendered. A resale customer desiring to provide utility service to one consumer under different priority categories at a single address or location may do so provided the portion of consumer's load under each category is measured through a separate meter and purchased from Company under the applicable rate for such deliveries.

2.12.03 **Measurement and Reporting of Delivered Volumes**: As soon after the end of each billing month as is practical, resale customer shall report to Company the volume of gas sold under priority category at each point of delivery during the billing month. The volumes reported to Company shall be on the same measurement basis as that on which resale customer purchases gas from Company.

2.12.04 **Verification of Delivered Volumes and Curtailment**: Company shall have the right to verify the delivered volumes of gas reported by resale customer

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and also the effectiveness of any curtailment or interruption requested by Company. Verification may be accomplished by an audit of resale customer's records and/or meter readings. Company shall have the right to read the meters serving applicable consumers at any time during an ordered curtailment or interruption.

2.13 **Service Initiation Charges**

2.13.01 **Service Initiation Charges:** Upon application for and commencement of service to customer at each service location, a service initiation charge as provided for in Subsection 12.01 Service Initiation Charge, shall be due from customer.

2.13.02 **Billing of Service Initiation Charge**: Service Initiation charges shall be billed on the initial service bill for each customer service location and shall be due and payable on the date specified thereon.

2.14 **Succession and Assignment**: A service agreement shall inure to the benefit of and be binding upon customer's heirs or successors but shall not be assignable by customer without the prior written consent of Company, which consent shall not be unreasonably withheld.

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3. **Credit and Security Deposit Regulations**

3.01 **Credit Requirements**: Company may request customer to provide reasonable credit information to the Company based on internal bill payment history or payment history with another utility before service is made available.

3.02 **Security Deposits**

3.02.01 **New Customers**: At the time of application for service, Company may request an initial deposit to guarantee payment of final bills for utility service rendered if:

(1) Company establishes that customer has unsatisfactory credit or has insufficient prior credit history upon which credit may be based.

(2) Customer has outstanding, with Company or any other utility, an undisputed and unpaid service account which accrued within the last 5 years if the service was provided under a written agreement, or 3 years if service was provided under an oral agreement.

(3) Customer has, in an unauthorized manner used, interfered or tampered with, or diverted (meter bypass) the service of a utility within the last 5 years.

3.02.02 **Existing Customers**: At any time after application for service, upon 5 days written notice, Company may require from an existing customer, as defined in Section 2.02.03, a new or modified deposit to guarantee payment of bills for utility service rendered if:

(1) Customer fails to pay an undisputed bill before the bill due date for 3 consecutive billing periods, one of which is at least 30 days in arrears.

(2) The customer is a non-residential customer and has a change in the character of service.

(3) The customer was disconnected for non-payment two or more times within the most recent twelve month period.

(4) The customer has defaulted on a pay agreement two or more times within the most recent twelve month period.

(5) The customer has tendered two or more insufficient funds payments within the most recent twelve month period.

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(6) The customer has sought debt restructuring relief under federal bankruptcy laws and is therefore considered a new customer under Section 2.02.02(7). Within 60 days after the bankruptcy has been discharged, if the new deposit on file is less than the maximum security deposit requirement for the same premises, the utility may recalculate the customer's security deposit based on the most recent twelve months usage.

3.02.03 **Amount of Deposit**: For purposes of establishing deposits and estimating monthly bills, Company shall consider the length of time customer can reasonably be expected to take service, past consumption patterns, end use of the service, and consumption patterns of other similar customers.

(1) For all residential customers and small non-residential customers (whose annual natural gas requirements average no more than 50 Mcf per month), the amount of the cash deposit or surety bond required shall not exceed 2 times the amount of the projected average monthly bill for that customer.

(2) For large non-residential customers (whose annual natural gas requirements average more than 50 Mcf per month) and for all other customers, such cash deposit or surety bond shall not exceed the sum of the projected 2 largest monthly bills for that customer.

(3) For residential customers requesting service within 30 days of disconnection for nonpayment pursuant to Section 2.02.03 (2), Company may collect or retain a security deposit in an amount no greater than required on the date of disconnection. Company may assess a new deposit amount if customer has met any condition listed under Section 3.02.02.

(4) For a customer who has been documented to have diverted service through tampering or meter bypass, an additional deposit based on one month's use may be assessed.

(5) If the customer's existing security deposit is to be adjusted or modified, the customer's maximum security deposit requirement will be calculated in the same manner as an initial deposit. The entire deposit requirement will be treated as an initial deposit subject to the rules for installment payments and retention.

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3.02.04 **Payment of Deposits**: Except as provided in Section 4.07 Cold Weather Rule, customers shall be informed of and Company shall permit payment of required deposits:

(1) From all residential customers and small non-residential customers (whose annual natural gas requirements average no more than 50 Mcf per month):

(a) In equal installments over a period of at least 4 months.

(b) An additional 2 months shall be allowed to a customer required to provide a deposit due to documented tampering or diversion (meter bypass) of service.

(2) From large non-residential customers (whose natural gas requirements average more than 50 Mcf per month) any security deposit requested is due 5 days following Company's written notice.

(3) Security deposits paid to Company by any payment method approved for the payment of bills (cash, check, credit card, debit card or electronic payment, etc.) shall be considered as paid in “cash” to Company. These deposits shall accrue interest according to Section 3.06 Interest on Cash Deposits.

(4) An applicant’s full deposit provided in lieu of positive identification shall be subject to the provisions of Section 2.03.05.

(5) Disconnection for nonpayment of deposit shall be governed by Section 5.01 Notice to Customer for Discontinuing Service.

3.03 **Records of Deposit**: Company shall maintain a record of all deposits received showing customer's name, service address for which the deposit is maintained, date and amount of deposit, and the date and amount of interest paid.

3.04 **Deposit Receipts**: Whenever a security deposit is accepted, Company will issue to customer a non-assignable receipt showing the name of customer; place, date and amount of deposit; Company name, address, signature and title of Company employee receiving the deposit; current annual interest rate earned on the deposit; and a statement of the terms and conditions governing the use, retention and return of deposits.

In lieu of a receipt, Company may indicate on customer's monthly billing the amount of deposit retained by Company, provided customer is individually notified in writing of the current annual interest rate earned on deposits and that customer is provided a

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statement of the terms and conditions governing the use, retention and return of deposits. In all cases, a receipt shall be given upon customer request.

3.05 **Transfer of Deposit**: Service deposits shall not be transferable from one customer to another customer; however, upon termination of customer's service at a service address, Company may transfer the cash deposit or surety bond for service at such address to customer's new service account.

3.06 **Interest on Cash Deposits**: Company shall pay accrued simple interest on cash deposits as defined in Section 3.02.04 at a rate not less than that provided by K.S.A. 1978 Supp. 12-822 and amendments. Such interest shall be credited once a year to customer's account balance or refunded if requested.

3.07 **Return of Deposit**: Deposits and interest shall be returned by crediting to the customer's service bill or, if requested, by check. Company may require the identification of the person surrendering the deposit receipt. In case customer shall have lost the deposit receipt, Company will require that customer sign its standard release form acknowledging return of the deposit and accrued interest.

3.07.01 Upon termination of service, if the deposit is not to be transferred to a new service account, Company will return to customer the amount of cash deposit or any surety bond, less any unpaid bills (including added charges for late payment) due Company.

3.07.02 Company will return the cash deposits, together with accrued interest, of residential customers who have paid 10 of the last 12 bills on time and from whom no undisputed bill was unpaid after 30 days beyond due date.

3.07.03 Company will return the cash deposits, together with accrued interest, of small non-residential customers after the customer has paid 20 of the last 24 bills on time and no undisputed bill was unpaid after 30 days beyond due date. The month(s) of a disputed bill(s) shall be ignored in this calculation.

3.07.04 Company will retain the security deposits of or continue to require surety bond or other guarantee from large non-residential customers until termination of service.

(1) Company will recalculate deposit of large non-residential customers every three years or when the non-cash security deposit expires. Customers may request that the utility recalculate their deposit at a shorter interval.

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(2) After recalculation, the maximum deposit requirement shall be increased or decreased as appropriate for each customer. The utility and/or customer shall have 30 days to correct the deposit on file.

3.08 **Third Party Guarantees**: In lieu of a security deposit:

3.08.01 For a residential customer's service account, Company will accept the written guarantee of any current residential customer with no deposit on file, who has made 10 of the last 12 payments on time with no undisputed payment remaining unpaid after 30 days. Company may also accept the written guarantee of any responsible party or obtain a letter of credit as surety for a residential customer's service account.

3.08.02 For non-residential customers, Company may accept a surety bond, irrevocable letter of credit, or other written guarantee from a responsible individual or company that will be responsible for paying the customer's utility bill in the event of nonpayment.

3.08.03 Company shall not hold the guarantor liable for sums in excess of the maximum amount of the required deposit or for attorney or collection fees.

3.08.04 In the event customer's service is disconnected for nonpayment or for final billing and the balance due remains unpaid, the unpaid service amount not exceeding the guarantee amount will be transferred to the guarantor's account pursuant to the written agreement. The guarantor will have the same time to pay the deposit as a new customer and can be disconnected for nonpayment under conditions set out in Section 5.02 Conditions for Discontinuing Service or Section 4.07 Cold Weather Rule. Such deposit collected from the guarantor shall be used to reduce the residential customer's indebtedness.

3.08.05 The guarantor shall be released when the customer would qualify for a deposit refund under Section 3.07, Return of Deposit.

3.09 **Discrimination**: No deposit shall be required because of customer's race, sex, creed, national origin, marital status, age, number of dependents, source of income, or geographical area of residence.

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4. **Billing and Payment**

4.01 **Payment of Bills**: All bills for service are due and payable upon receipt. Normally, bills shall be sent by mail; however, the non-receipt of a bill by a customer shall not release or diminish the obligation of the customer with respect to the full payment thereof, including penalties. If the last calendar day for remittance falls on a day when Company's offices are not open to the general public, the final payment date shall be extended through the next business day.

4.01.01 **Delinquency**: A bill shall be deemed delinquent when payment is not received by Company or its authorized agent on or before the delinquency date.

(1) **Delayed Payment Charge**: If the bill becomes delinquent, a Delayed Payment Charge in an amount equal to 2 percent of the delinquent amount owed for current utility service shall be added and any collection efforts by Company shall be initiated.

(2) **Residential Customers**: Bills for service to residential customers shall become delinquent on the last date payments received can, in the normal and reasonable course of business, be credited to the customer's account in preparation of the next succeeding normal bill.

(3) **Non-Residential Customers**: Bills for service to non-residential customers shall become delinquent business 15 days after their mailing date, unless otherwise specified by contract, agreement or applicable rate schedule.

(a) Non-residential customers who are unable to make timely payment of bills before the delinquency date because of internal bill paying procedures will be given an opportunity to receive a copy of each bill at a second location at no additional cost.

(b) If a non-residential customer chooses, and also agrees to pay a 1 percent fee each month, Company will allow an extension of time in which to pay monthly bills so that they become delinquent at the same time as the bills of residential customers in the same billing cycle. This agreement will be canceled upon customer's request or upon customer's failure to pay any bill before the extended delinquency date. Once canceled, no new agreement with the same customer will be permitted.

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(4) Company shall print on the customer's bill a Due Date reflecting an allowance for return mailing.

4.01.02 **Partial Payment**: If a customer makes partial payment on the total bill, payment will be credited first to the balance outstanding for utility service beginning with the oldest service debt, then to additional utility charges such as disconnection /reconnection charges, and then to charges for special services.

4.01.03 **Combined Payment for Several Meters**: Company may agree to not assess the otherwise applicable Delayed Payment Charge to a customer responsible for payment of bills that become due on different dates during the month.

(1) The customer must notify Company in writing of:

(a) The location where such service is rendered,

(b) The respective names and account numbers of each account, and

(c) The customer's intent to make payment of all such bills on or before the delinquency date of any one of such accounts.

(2) Company shall collect Delayed Payment Charges on the basis of each single billing if payment is not made within the agreed-upon time.

(3) The agreement with the customer may be canceled after the third time it becomes necessary to assess the Delayed Payment Charge during any consecutive 12-month period.

4.01.04 **General Payment Provisions**

(1) **No Separate Fees**: The customer shall not be assessed a separate fee for using any method of payment other than that described in Section 4.01.05(4) **Credit /Debit /ATM Cards**.

(2) **Authorized Pay Agents**: Company may contract with non-utility business partners and authorize them to accept payments directly from customers on Company's behalf.

(a) Company shall require Authorized Pay Agents to operate in compliance with the Commission's rules and regulations.

(b) The payment method may be electronic, telephonic and/or in person.

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(c) Payments received by an Authorized Pay Agent shall be considered made as if received on the same date at Company's remittance processing center. A payment received by an Authorized Pay Agent shall normally be posted to the customer's account within 2 business days.

(d) The Authorized Pay Agent shall provide a receipt number to the customer making payment. It shall be the customer's responsibility, to avoid a pending disconnection, to timely confirm this receipt number to Company's customer contact center.

(3) **Unauthorized Pay Agents**: Unauthorized Pay Agents have no contractual or other requirement to operate under rules approved by the Commission. They may include but are not limited to banks and other financial institutions, retail stores with "drop boxes" and/or third-party businesses or individuals. Company's acceptance of payment from an Unauthorized Pay Agent on behalf of a customer shall not be construed as acceptance of such agent's assurance to the customer as to timeliness or accuracy.

(4) **Notification**: Company shall provide an annual notice to customers informing them of authorized bill payment options and where they can find a list of authorized payment centers. The Notice shall also advise of the potential impact of using unauthorized payment sources. Such notice shall be provided to the Commission for review at least 30 days prior to mailing.

(5) **Internet Information**: Company's Internet web site shall provide:

(a) A complete list of all authorized payment options and the amount of any transaction fees payable by customers.

(b) An up-to-date list of Authorized Pay Station (APS) locations established pursuant to Section 4.01.05(3) Authorized Pay Stations.

(c) Links to Company-Authorized Pay Agents that provide authorized credit /debit /ATM card services pursuant to Section 4.01.05(4) Credit /Debit /ATM Cards.

(6) **Delinquency**: A check returned unpaid to Company because of insufficient funds, an electronic payment transaction not completed because of insufficient funds, or a credit card payment reversed for any

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reason, may cause customer's account to be deemed delinquent as if the payment had never been tendered.

4.01.05 **Methods of Payment**

(1) **Payment By Mail**: Customers paying by mail shall place a check or money order in a clearly addressed envelope and shall post such payment to cause it to arrive at Company's remittance processing center on or before the delinquency date.

(a) A check returned to Company for insufficient funds shall incur a charge pursuant to Section 12.07 Insufficient Funds Check Charge.

(b) Company or Company's Authorized Pay Agent may convert a customer's check to an Electronic Funds Transaction (EFT) unless the customer instructs otherwise by "opting out" of the transaction. If this electronic transaction is returned unpaid due to insufficient funds, or if it is not able to be completed because of insufficient funds, Company may assess a charge pursuant to Section 12.08 Insufficient Funds Service Charge.

(2) **Electronic Payments**: Customer may request Company or an Authorized Pay Agent to process an electronic transaction on a customer's account in a U.S. financial institution for payment of the customer's bill for utility services.

(a) The decision to accept and/or process an electronic payment shall be solely that of Company.

(b) Company or its Authorized Pay Agent may accept requests for electronic payments through a live telephone representative or through automated processes such as interactive voice response (IVR) systems and the Company's internet web site.

(c) An electronic payment received by Company or its Authorized Pay Agent shall be credited to the customer's account as if payment had been received at Company's remittance center on the same business day as the customer's request.

(d) Customer shall ensure that sufficient funds are available to pay the amount of the requested electronic payment.

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i. An electronic payment transaction not completed because of insufficient funds shall incur a charge pursuant to Section 12.08 Insufficient Funds Service Charge.

ii. Company may refuse to process an electronic payment for a customer who, on one or more occasions, has tendered to Company or an Authorized Pay Agent a check which was returned unpaid because of insufficient funds and/or has requested an electronic payment transaction that was not completed because of insufficient funds.

(3) **Authorized Pay Stations (APS)**: Company may, either by itself or through a contract with an Authorized Pay Agent, establish and maintain an authorized network of non-utility businesses and other appropriate locations where customers can make payments in person.

(a) A check returned for insufficient funds shall incur a charge pursuant to Section 12.07 Insufficient Funds Check Charge.

(b) Company or its Authorized Pay Agent may convert a customer's check to an electronic transaction unless the customer instructs Company otherwise by "opting out" of the transaction. If this electronic transaction is returned unpaid due to insufficient funds, or if it is not able to be completed because of insufficient funds, Company may assess a charge pursuant to Section 12.08 Insufficient Funds Service Charge.

(c) APS locations shall provide a complete list of all available payment options and the amount of any associated fees payable by customers.

(4) **Credit /Debit /ATM Cards**: Company may contract or make other arrangements with an Authorized Pay Agent to provide credit /debit card payment options to customers paying their bill for natural gas service.

(a) The Authorized Pay Agent may charge the customer an additional fee for the use of credit /debit /ATM cards pursuant to Section 12.12 Credit /Debit /ATM Card Fee.

i. Fees for payment by credit/debit card may increase the customer's total responsibility above that of a cash payment.

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ii. The customer shall be advised, prior to providing the credit /debit /ATM card number, of the amount of any additional fee and must answer in the affirmative to proceed with the payment process.

iii. The Authorized Pay Agent shall be solely responsible for collecting the fee from the customer.

(b) A debit card or ATM card transaction not completed because of insufficient funds may incur a charge pursuant to Section 12.08 Insufficient Funds Service Charge.

(c) The determination of credit /debit /ATM card “brands” available for customers’ payments shall be at Company’s sole discretion.

(d) Company shall ensure that toll-free telephone service is provided for customers to make credit /debit /ATM card payments by phone.

(e) Company or its Authorized Pay Agent may refuse to accept credit /debit /ATM card payments from a customer for reasons including, but not limited to, reported or suspected fraudulent use of a card, reported or suspected use of a stolen card, and/or the customer’s prior use of a card to defraud Company or the card’s owner.

(5) **Automatic Bill Payment Plan**: Company may establish a program that will, upon a customer’s request, systematically withdraw the customer’s billed payments from his/her account at a bank or recognized financial institution.

Company may process an Automatic Bill Payment as an electronic transaction. If this electronic transaction is returned unpaid due to insufficient funds, or if it is not able to be completed because of insufficient funds, Company may assess a charge pursuant to Section 12.08 Insufficient Funds Service Charge.

(6) Any payment which constitutes fraud, pursuant to Section 1, Definitions, may be subject to disconnection according to Section 5 of these General Terms and Conditions.

4.02 **Customer Billing**

4.02.01 **Information on Bill**: Customer's bills shall show:

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(1) The beginning and ending meter reading for the billing period. An estimated billing shall disclose that it is based on an estimated meter reading by the inclusion of the word “Estimated” on the bill.

(2) The date of the most recent meter reading and the date of the billing.

(3) The final date by which a payment can be received before a Delayed Payment Charge is imposed.

(4) The actual or estimated utility service supplied during the billing period.

(5) The comparative energy consumption for the current billing period and the comparable period a year ago.

(6) The amount due for prompt payment and the amount due after delinquency in payment.

(7) The gas cost in dollars per unit (1,000 cubic feet or Mcf) and the total amount due. If the gas cost is prorated, each applicable cost of gas factor and the estimated usage associated with that factor shall be shown.

(8) The amount of additional charges due for past due accounts, security deposits, collection, service initiation or disconnection charges, installment payments, and other charges authorized by the Commission.

(9) The monthly amounts due for customers paying down an arrearage under the Cold Weather Rule (CWR) or other payment plans.

(10) The total amount due for the current billing period.

(11) The amount due for city franchise fee and state and local sales taxes, stated separately, unless otherwise ordered by the Commission.

(12) The address and telephone number of Company's office where a customer may make a report, inquiry or complaint concerning a disputed bill, service rendered, account delinquency or termination of service.

4.02.02 **Charges for Special Services**: Company may include on the bill charges for special services which are not authorized or specifically regulated by the Commission provided they are clearly designated and set separately from charges for utility service.

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4.03 **Determination of Usage**: Meters shall be read periodically in a range of no less than 26 days and no more than 36 days for monthly billings.

4.03.01 **Company Read Meters**: Company may adopt a cycle-billing plan for dividing its service territory into districts and for reading meters on a schedule of days throughout the month. Company may vary its regular reading of a customer's meter to recognize the effects of connection, disconnection, or rerouting of meter routes.

4.03.02 **Customer Read Meters**: Company may request customers in sparsely populated areas or customers with inaccessible meters, to read their meters at intervals approximating the billing period. The customer shall provide the requested meter reading by completing and returning a Company-provided printed form containing instructions as to the method of obtaining the reading, or by using Company's Interactive Voice Recording System.

Meter readings by a customer, though used for billing purposes, shall not be considered final. Company shall read such customer meters at least once a year and shall compare the readings obtained with the customer's readings. If there is any difference between the readings, an adjustment shall be made in accordance with Section 4.05 Adjustments to Meter Reads and Bills. In the event a customer does not furnish a meter reading pursuant to this section for 2 consecutive billing periods, Company may read the meter and charge the customer a meter reading charge as provided in Section 12.02 Meter Reading Charge for each such extra meter reading occurrence. A final bill when service is discontinued shall be based on an actual reading by Company, except as provided in Section 4.04.01 Reasons to Estimate.

4.03.03 **Meter Readings Not Combined**: Each class of service at each separate location supplied will be metered and billed separately. When more than one meter or metering facility is set at one premises for customer's convenience, or when customer has service at different premises, the readings of the separate meters will not be combined for billing purposes unless the applicable rate schedule provides otherwise.

4.04 **Estimated Bills**: Company may estimate a customer's usage for a billing period and bill accordingly. Company may render a bill based on estimated usage only if the estimating procedures employed by Company and any substantial changes in those procedures have been approved by the Commission.

4.04.01 **Reasons to Estimate**: Company may render bills based on estimated usage.

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(1) To seasonal customers, provided an appropriate rate schedule is filed with the Commission and an actual reading is obtained before each change in the seasonal cycle.

(2) When extreme weather conditions, emergencies, work stoppages, broken meters or other equipment failures or other circumstances beyond Company's control prevent actual meter readings.

(3) When Company is unable to reasonably obtain access to customer's premises for reading the meter and efforts to obtain a customer reading of the meter, such as mailing or leaving pre-addressed forms upon which customer may note the readings, are unavailing.

(4) When the customer does not furnish a meter reading as requested by Company.

(5) For final, corrected or initial bills, but only when:

(a) The customer so requests and any necessary adjustments are made to the bill upon a subsequent actual meter reading by Company.

(b) An actual meter reading would not show actual customer usage, but is used in estimating usage.

(c) An actual meter reading cannot be taken because of a broken meter or other equipment failure.

(6) When Company has sufficient reason to believe usage determined from meter readings is erroneous or incorrect.

4.04.02 **Frequency of Estimated Bills**: Company shall not render a bill based on estimated usage for more than 3 consecutive billing periods or 6 months, whichever is less, or more often than 6 billing periods per year, except in cases where:

(1) The meter is inaccessible and the customer is not available or fails to furnish a meter reading as requested by Company, or

(2) The customer is served under an approved rate schedule providing otherwise.

Company shall read these meters at least once a year and shall adjust the customer's bill as provided by this Section. If a special meter reading is

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required, Company may charge the customer a fee as provided in Section 12.02 Meter Reading Charge.

4.04.03 **Record Keeping**: When Company renders estimated bills, it shall maintain accurate records of the reasons therefore and efforts made to secure actual readings. Company shall retain these records for at least 36 months.

4.04.04 **Disclosure**: All estimated bills shall disclose the fact that they are based on estimated usage and that any appropriate adjustments will be made upon subsequent actual reading of the meter by Company.

4.04.05 **Estimating Procedure**: Before rendering an estimated bill, Company may request a customer to provide a meter reading on pre-addressed forms or through Company's Interactive Voice Recording System. Meter readers shall not make estimates of customer usage; however, meter readers may provide specific knowledge of unique customer circumstances to Company's Billing Department which may recognize that information in the estimated bill calculation.

(1) When estimating usage for missing route reads, Company shall consider the customer's historical consumption, current consumption of similar customers for whom actual meter readings were obtained and the length of the billing period.

Company shall use the following formula for calculation of estimated Mcf usage for billing purposes.

(A / B) x C = Estimated usage for a meter

Where:

A = peer group's usage this month

B = peer group's usage for same month last year

C = usage for same month last year for meter to be estimated. If meter-specific usage from last year is unavailable, the value of "B" shall be substituted for "C".

Company shall use current billing cycle information to profile the customer's peer group. Peer Groups shall be compiled from meters with like rate codes and revenue classes. Peer groups of less than minimum size may be expanded to contain not only the town, but the

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office the town is in, the division or up to Company level if required. More than one rate code may be included where necessary.

(2) When estimating usage in instances when missing read(s) exist for individual customers where peer group information is not available or customer has supplied information specific to their usage, Company may consider the customer's historical consumption, current and historical weather information as well as any customer-supplied information.

Company shall use the following formula for calculation of estimated Mcf usage for billing purposes for individual accounts:

(A/B) x C = Estimated usage for meter

Where:

A = Heating Degree Days (HDD) for month to be estimated

B = HDD for same month the prior year

C = Billed consumption for same month the prior year. Company may use other historical known usage from the premises as necessary.

4.05 **Adjustments to Meter Reads and Bills**

4.05.01 **Estimated Bill Adjustments**: Any adjustment to a previous bill which was based on estimated usage or a meter reading by a customer will be shown on the bill. The adjustment shall be calculated for bills rendered during the period between the prior and most recent meter readings by Company. Calculation of adjustments for previously estimated bills may include customer supplied information on an individual basis as necessary. The adjusted bill shall show the credit due to the customer or the balance due and payable to Company.

(1) Any credit due to the customer may be applied as a credit to subsequent bills. However, if the amount is greater than the amount specified in Section 12.03 Credit Due Amount and customer so requests, Company shall refund the amount.

(2) If a balance is due and payable to Company, customer may, upon request and approval of Company, pay the amount in equal monthly installments over a period of time equal to the adjusted billing period.

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(3) In no case will an adjustment to an estimated bill be made for an amount which is less than the amount specified in Section 12.09 Adjusted Bill Amount.

4.05.02 **Correction of Erroneous Bills**: In the event of an error in billing as a result of issues including, but not limited to, accounting errors, meter or meter reading equipment misprogramming or failure, Company shall issue a corrected bill. The corrected bill shall show the adjusted amount due or amount to be refunded. Any amounts paid by customer on the erroneous bill shall be shown as a credit on the corrected bill.

(1) No corrected bill for confirmed usage, as determined by the Company, shall be issued for a period exceeding 12 months, unless the date of the error can be determined in which case the correction may be computed back to but not beyond such date. No correction for erroneous bills need be made for amounts equal to or less than that specified in Section 12.04 Bill Error Amount.

(2) When the Company is unable to confirm usage due to a non-registering meter, usage may be estimated by an individualized analysis based on information including, but not limited to, weather data, historical usage at the premises, and other customer supplied information. No bill shall be issued to adjust a period exceeding six months due to the failure of a meter to register.

4.05.03 **Prorated Bills**: Company shall prorate customers' bills during the billing month in which a change in rates or tariffs becomes effective, unless otherwise ordered by the Commission. Proration of gas cost shall always be Company's option.

Company shall prorate customer charges only when a change in rates or tariffs becomes effective or when the billing cycle is caused to be outside the range of 26 through 36 days by

(1) Connection or disconnection of service, or

(2) Rerouting of meter routes, for the directly affected customers only.

4.05.04 **Adjustment for Taxes and Franchise Fees**: When any governing body of a taxing subdivision imposes a franchise, occupation, business, sales, license, excise, privilege or similar charge of any kind on Company, these charges shall be recovered from the customers within the boundaries of the taxing subdivision. The amount of the charge shall be levied on each of the customers within the taxing subdivision in the same form in which it is imposed on Company, unless the Commission determines otherwise. All charges so imposed on Company shall be added as a separate charge to the customer's bill for gas service. Any customer exempted from the charge by a taxing subdivision in the calculation of the charge imposed on Company shall be exempt from the charge, unless the Commission determines otherwise.

4.06 **Average Payment Plan**

4.06.01 **Availability**: Upon mutual agreement between a customer and Company, the Average Payment Plan (APP) shall be made available upon the request of a Residential or Small General Service customer who meets the following requirements:

(1) A residential customer may enroll in the APP during the Cold Weather Rule (CWR) Period at the same time (s)he enters into a CWR pay agreement for arrearages, pursuant to Section 4.07 Cold Weather Rule.

(2) A residential customer may enroll in the APP during the non-CWR period at the same time (s)he enters into an Extended Payment Plan pursuant to Section 4.08 Extended Payment Plan.

(3) A residential or general service customer may enroll in the APP at any time as long as the account is in current status with no arrears.

4.06.02 **Calculation of Monthly Billing Amount**: Company shall use available billing history to calculate the customer's monthly APP billing amount as the sum of:

(1) The current net monthly billing amount, plus the previous 11 months billing, estimated if not known, plus financial transactions that would impact a customer’s monthly bill (e.g. rebate and rebills),

(2) Divided by twelve (12),

(3) plus the Periodic Review Adjustment as described in Section 4.06.04 Periodic Review.

4.06.03 **Monthly Billings**: APP bills shall contain the information specified in Section 4.02.01 Information on Bill and shall also show the current Settlement Balance defined under Section 4.06.04 Periodic Review.

(1) Additional charges reflecting balances due under Section 4.07 Cold Weather Rule or Section 4.08 Extended Payment Plan may be

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displayed on the monthly APP bill and are understood to be separate and distinct from the APP billing amount.

(2) APP billings are due and payable as provided in Section 4.01 Payment of Bills. If such billing becomes delinquent, a charge shall be added as provided in Section 4.01.01 Delinquency.

4.06.04 **Periodic Review**: Company shall review each customer’s APP billing amount monthly and adjust it as necessary. Additional Periodic Reviews may result from, but are not limited to, a customer’s request, rate changes, edits in Company’s billing system, variations in usage or gas prices, and/or weather conditions.

(1) The Settlement Balance shall be identified at the time of a Periodic Review as the difference between the amounts billed to date and the amounts calculated under Company's normal billing procedures.

(2) The Periodic Review Adjustment shall consist of the Settlement Balance divided by twelve (12). The Periodic Review Adjustment shall be an increase or decrease, pursuant to Section 4.06.02 Calculation of Monthly Billing Amount, for a period not to exceed twelve months following the Periodic Review.

4.06.05 **Termination**: Final settlement occurs only when participation in the APP is terminated. Any amount due or owing, including the Settlement Balance, shall be included in the current bill upon termination. Termination of the APP may occur:

(1) At the request of the customer, or

(2) At the time of billing, when payment of the Amount Due on the prior month’s bill is delinquent pursuant to Section 4.01.01 Delinquency and the customer has entered into:

(a) a CWR Payment Plan pursuant to Section 4.07, or

(b) an Extended Payment Plan pursuant to Section 4.08, or

(3) At the time of billing, when payment of the Amount Due on any two consecutive monthly bills has been delinquent pursuant to Section 4.01.01 Delinquency, or

(4) Pursuant to any of the provisions in Section 5.02 Conditions for Discontinuing Service.

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4.07 **Cold Weather Rule**

4.07.01 **Availability**: The provisions of the CWR allow for special payment and disconnection procedures for any qualifying residential customer with unpaid arrearages to retain or restore utility service throughout the cold weather period, which extends from November 1 through March 31.

4.07.02 **Prohibitions on Disconnections**: Company shall not disconnect a customer's service between November 1 and March 31 when the local National Weather Service forecasts that the temperature will drop below 35 degrees or will be in the mid 30s or colder within the following 48 hour period unless:

(1) Disconnection is at the customer's request;

(2) The service is abandoned;

(3) A dangerous condition exists on the customer's premises;

(4) The customer violates any rule of the utility which adversely affects the safety of the customer or other persons, or the physical integrity of the utility's delivery system;

(5) The customer causes or permits unauthorized interference with, or diversion or use of utility service (meter bypass) situated or delivered on or about the customer's premises;

(6) The customer misrepresents his or her identity for the purpose of obtaining or retaining utility service; or

(7) The customer tenders an insufficient funds check as the initial payment or an installment payment under a CWR Payment Plan and does not cure the insufficient payment during the 10-day period after a disconnection notice is sent to the customer.

Under (1), (2), (3), and (4), Company may disconnect the service immediately.

Under (5) or (6), Company may disconnect the customer 48 hours after a disconnection notice is left on the customer's door or personal or telephone contact is made with the customer of record and the telephone number of the Commission's Consumer Protection Office is given to the customer, or 10 days after a disconnection notice is sent, whichever is quicker.

Under (7), Company may disconnect the customer 10 days after a disconnection notice is sent if the customer has not cured the insufficient payment during that 10-day period.

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Services disconnected under (3) or (4) above shall be restored as soon as possible after the physical problems defined in (c) or (d) have been corrected.

Service disconnected under (5) shall be restored as soon as possible after payment by the customer of the full value of the diverted service. The value of the diverted service shall be estimated based on the historic use of the customer or the residence.

During the CWR period the same service charges apply as pursuant to Sections 5.08 and 5.09 in these General Terms and Conditions.

4.07.03 **Customer's Responsibilities**: To qualify for the benefits of the CWR, to keep from having service disconnected when the temperature is 35 degrees or above, or to have service reconnected regardless of temperature, a customer must comply with the following provisions:

(1) Inform the utility of the customer's inability to pay the bill in full;

(2) Provide sufficient information to allow the utility to make a payment agreement;

(3) Make an initial payment of 1/12 of the arrearage amount, 1/12 of the bill for current consumption, the full amount of any disconnection or reconnection fees, plus any applicable deposit, and enter into an 11-month plan for payment of the rest of the arrearage; or enter a payment plan as negotiated with the utility for the payment of the arrearage amount; and

(4) Apply for federal, state, local or other assistance funds for which the customer is eligible.

4.07.04 **Company's Responsibilities**: Company shall:

(1) Once a year, at least 30 days prior to the CWR period, mail a written notice of the CWR to each residential customer who is currently receiving service, and to each residential customer who has been disconnected during or after the most recent cold weather period and who remains without service. Company shall file a copy of the notice with the Commission.

(2) Send one written notice, mailed first-class at least 10 days prior to disconnection. A customer shall not be disconnected until a 48-hour forecast above the activating temperature is predicted by the National Weather Service. On the day of disconnection, Company

shall receive a 24-hour forecast above the activating temperature from the National Weather Service. If the temperature is then forecast to be below the activating temperature, the disconnection shall not be carried out and the utility must wait for another 48-hour forecast above the activating temperature and follow the same procedures prior to disconnection.

During the first 24 hours, which shall be the day prior to disconnection, Company shall make at least one telephone call attempt with the customer of record and, if telephone contact on that day is not made, make one attempt at a personal contact with the customer of record on the day prior to disconnection. The telephone call attempt(s) and personal contact on the day prior to disconnection are in addition to the notice requirements in Section 5 Discontinuation of Service. On the day prior to disconnection, if the customer is not contacted by the phone call(s) or the personal contact, Company shall leave a disconnection message on the door. There will be no charge for this service.

In the telephone contact(s), the 10-day written notice, the personal contact, and the disconnection message on the door, Company shall also inform the customer of the existence of the CWR, that the customer can avoid disconnection by complying with Section 4.07.03 Customer's Responsibilities, and of the telephone number of the Commission's Consumer Protection Office.

(3) Inform the customer of, or provide a list of the requirements of Section 4.07.03 Customer's Responsibilities.

(4) Inform the customer of, or provide a list of organizations where funds are available to assist with payment of utility bills.

(5) Inform the customer of, or provide a list of all other pay arrangements for which the customer might qualify. Prior to discussing any plan for CWR payments over a period of fewer than 12 months, Company shall inform the customer of the customer's right to have a level payment plan for current and future consumption and to pay the arrearage amount through an initial payment and equal installment payments over the next 11 months.

(6) Inform the customer of the availability of Company's third-party notification plan under Section 4.09 Third Party Notification.

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4.07.05 **Security Deposits**: Deposits made in conjunction with the CWR may be amortized over the period of the payment plan, except that no security deposit shall be amortized over fewer months than authorized under Section 3.02.04 Payment of Deposits.

4.07.06 **Renegotiation**: A customer may renegotiate a CWR Payment Plan if lump sum assistance funds are received from an assistance agency or other program and are credited to the customer's account.

4.07.07 **Default**: The issuance of an insufficient funds check for the initial payment or for any installment of the payment plan, unless subsequently cured by the customer, shall constitute a default of the CWR Payment Plan.

A customer who defaults on a CWR Payment Plan shall not be eligible under Section 4.08 Extended Payment Plan unless the arrearages from the prior CWR Payment Plan are paid.

A customer who defaults on a CWR Payment Plan shall be eligible to enter into a new CWR Payment Plan upon complying with the customer responsibility provisions of Section 4.07.03 Customer's Responsibilities.

A payment plan of any length that is negotiated by the customer and Company, after the customer has been informed of the payment plans offered under the CWR, is considered to be a CWR Payment Plan. However, a customer with a payment plan of fewer than 11 months shall not be considered to be in default of the payment plan if the payments actually made are equal to or greater than the amount that would have been required under an 11-month payment plan.

4.08 **Extended Payment Plan**: An Extended Payment Plan similar to the CWR average payment plan shall be available to residential customers with arrears. A customer shall make an initial payment of 1/12 of the arrearage amount, 1/12 of the bill for current consumption, the full amount of any disconnection or reconnection fees, plus any applicable deposit, and enter into a payment plan for up to 11 months to pay the rest of the arrearage. Arrearages from a previous CWR plan or Extended Payment Plan must be paid off before entering into this plan. Customers shall be informed of this option.

Monthly billings under the Extended Payment Plan are due and payable as provided in Section 4.01 Payment of Bills. If such billing becomes delinquent, a 2 percent Delayed Payment Charge based upon such billing will be added. Failure to pay any Extended Payment Plan monthly billing on or before its due date may be cause for termination by Company of the payment plan with respect to the customer.

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Billings to customers using the Extended Payment Plan shall contain the information specified in Section 4.02.01 Information on Bill, and shall also show the overage or underage of the amounts paid to date as compared to the cumulative actual amounts used.

4.09 **Third Party Notification**: Upon mutual agreement between Company, a customer and any interested third party, Company shall notify such third party when the customer's bill becomes delinquent. The purpose of this agreement is to afford the customer all available methods to maintain the account balance on a current basis and retain utility service. Other than the notice, Company shall have no responsibility to the third party and likewise, the third party shall not be obligated to pay the delinquent bill.

4.10 **Annual Customer Notice**: Once a year, Company shall mail to each of its customers a notice apprizing them of the Commission's complaint procedure, including its role in settling complaints which have reached an impasse. The notice shall include the Commission's Consumer Protection Office's telephone number as well as a comment form concerning Company's service. Customers wishing to comment to the Commission on Company's quality of service may use this notice.

4.11 **Rate Change Notice**: Company shall provide general information explaining overall changes in rates to customers through bill inserts or direct mail when new rates are implemented due to a rate proceeding.

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4.10 **Annual Customer Notice**: Once a year, Company shall mail to each of its customers a notice apprizing them of the Commission's complaint procedure, including its role in settling complaints which have reached an impasse. The notice shall include the Commission's Consumer Protection Office's telephone number as well as a comment form concerning Company's service. Customers wishing to comment to the Commission on Company's quality of service may use this notice.

4.11 **Rate Change Notice**: Company shall provide general information explaining overall changes in rates to customers through bill inserts or direct mail when new rates are implemented due to a rate proceeding.

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5. **Discontinuation of Service**

5.01 **Notice to Customer for Discontinuing Service**

5.01.01 **Notice to Customer**: Company will give customer 10 days written notice before discontinuing service unless the discontinuance is made for any of the following reasons, in which case Company may discontinue service immediately:

(1) Upon customer request.

(2) The service is abandoned.

(3) Because of a dangerous condition.

(4) Because customer interferes with or diverts service (including meter bypass).

(5) To protect the safety of customer or other person.

(6) To maintain the integrity of Company's system.

(7) In order to comply with curtailment orders as issued by Company.

Company will restore service as soon as practicable as soon as the physical problems described in items (3) through (7) above have been corrected.

5.01.02 **Notice to Other Residents**: If Company has knowledge that persons other than customer or members of customer's family are residing at the premises where unauthorized interference, diversion, or use is taking place, Company shall give such persons a 2 day written or 24 hour oral notice prior to discontinuance, provided no dangerous conditions exist. Except as provided in Section 4.07 Cold Weather Rule, all written notices to customers for discontinuing service shall contain:

(1) The name and address of customer and the address, if different, where service is rendered.

(2) A clear and concise statement of the reason for the proposed discontinuance of service.

(3) The dates which service can be discontinued unless customer takes appropriate action.

(4) Terms under which customer may avoid discontinuance, including a statement that discontinuance may be postponed or avoided if customer can demonstrate that special circumstances prevent complete

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payment and satisfactory credit arrangements are made with Company for amounts not in dispute.

(5) The cost and conditions for reconnection.

Disconnection notices will also contain a statement to apprise customer of the administrative procedure which may be used in the event of a bona fide dispute or under other circumstances, such as provided in Section 5.04 Discontinuing Service - Special Circumstances. Such notices will include the telephone number, address and office of Company at which customer may meet with a designated Company employee to present reasons for disputing a bill or Company's reasons for discontinuance, request credit arrangements or request a postponement of discontinuance.

Disconnection notices will be mailed separately from customer's regular monthly bill to the normal mailing address and to the service address, if different, and will be considered as having been served as of the date of mailing, as indicated by Company's records. Company will maintain a record of the date of mailing and the effective dates of the notice. The disconnect shall become effective 10 days following the date of mailing and shall remain in effect for one month during which time Company may disconnect service. A telephone contact with customer will be attempted at least 2 days prior to date of disconnection advising customer of pending disconnection.

In situations where Company's records show that the service account proposed to be disconnected serves more than one residential dwelling unit, Company shall also post a Notice of Disconnection in an area common to the dwelling units at least 5 days prior to the discontinuance date specified therein.

When Company has evidence documenting that customer is receiving service through false identity, it may disconnect customer upon 48 hours notice given by personal or telephone contact and the telephone number of the Commission's Consumer Protection Office is provided to customer. Company will also mail its normal 10 day disconnect notice immediately; so that if contact is not made, service may be disconnected at the end of the 10 day period.

5.02 **Conditions for Discontinuing Service**: Company may discontinue or refuse service for any of the following reasons:

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(1) Upon customer request.

(2) When a dangerous condition exists on customer's premises.

(3) When a service bill becomes delinquent, as provided in Section 4.01 Payment of Bills, and after proper notice, as provided in Section 5.01 Notice to Customer for Discontinuing Service.

(4) When customer defaults under the Cold Weather Rule pursuant to Section 4.07 Cold Weather Rule or Section 4.08 Extended Payment Plan.

(5) When customer causes or permits unauthorized use, interference, tampering or diversion of service (meter bypass) on or about customer's premises.

(6) When service supplied by Company is used or misapplied by customer causing an unsatisfactory condition affecting the quality, safety or continuity of service to other customers.

(7) When service is resold or shared by customer or customers without written consent of Company.

(8) When customer fails to provide credit information or a security deposit or guarantee as may be required by Section 3.01 Credit Requirements or Section 3.02 Security Deposits.

(9) When customer has a previous undisputed and unpaid separate account for Company's service which accrued within the last 5 years, if the service was provided under a written agreement, or 3 years if service was provided under an oral agreement.

(10) When customer fails to comply with Company's General Terms and Conditions, or with an executed contract for service or applicable rate schedule as approved by the Commission.

(11) When customer fails to comply with curtailment orders as issued by Company.

(12) When customer's identity is misrepresented for the purpose of obtaining or retaining service or when any other means of fraud, as defined in Section 1, Definitions, is committed.

(13) When customer refuses to grant Company personnel access, during normal working hours, to Company facilities installed upon the premises of customer for the purpose of inspection, meter reading, maintenance or replacement.

(14) When customer abandons service.

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(15) When customer tenders an insufficient funds check as the initial payment or an installment payment under a Cold Weather Rule Payment Plan pursuant to Section 4.07 Cold Weather Rule and does not cure the insufficient payment during the 10-day period after a disconnection notice is sent to the customer.

When conditions listed in (2), (5) and (6) above are discovered by Company, Company may disconnect service immediately. However, when the Cold Weather Rule is in effect, service must be reconnected as soon as practicable after the physical problem described in (2), (5) and (6) above has been corrected.

5.03 **Conditions Insufficient to Cause Discontinuation of Service**: Company shall not disconnect or refuse service for any of the following reasons:

(1) The failure of customer to pay for charges other than those specifically identified in Company's approved tariffs and terms and conditions.

(2) The failure of customer to pay for service received at a concurrent and separate metering point, residence or location.

(3) The failure of customer to pay for a different class of service received at the same location. The placing of more than one meter at the same location for the purpose of billing the usage of specific devices under optional rate schedules or provisions is not considered as a separate class of service for purposes of this rule.

(4) The failure of customer to pay a bill which is in dispute; provided, however, that customer pays that portion of the bill not in dispute.

(5) Undisputed and unpaid accounts which have accrued that are more than 5 years old for service provided under a written agreement or more than 3 years old for service provided under an oral agreement.

5.04 **Discontinuing Service - Special Circumstances**: In addition to the provisions of Section 4.07 Cold Weather Rule, Company will either allow payment in reasonable installments or postpone discontinuing service for at least 21 days so that a residential customer may make arrangements for payment of service bill either in full or by reasonable installment payments, if the customer notifies Company and establishes that:

(1) Discontinuing service would be especially dangerous to the health of customer, resident member of customer's family or other permanent resident of the premises where service is rendered, and that

(2) Customer is unable to pay for such service in accordance with Company's billing or is able to pay for such service only in installments.

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In determining whether discontinuing service would be especially dangerous to health, consideration shall be given to the weather, customer's or other resident's medical condition, age or disability.

5.05 **Procedures for Discontinuing Service**: Except as provided in Section 4.07 Cold Weather Rule, Company's employee who is to disconnect service will make a reasonable effort to contact and establish identity with customer or other responsible person then upon the premises, announce the purpose of Company employee's presence, identify and record the name of the person contacted, accept payment of all amounts tendered which are necessary to avoid disconnection, record any statements disputing the accuracy of the delinquent bills, the cause of discontinuance, or concerning the medical condition of any permanent resident of the premises. Company may refuse to accept cash payments at the customer's premises pursuant to the Commission's order in Docket No. 11-KGSG-503-MIS.

If contact with customer or other responsible individual is not made, Company's employee shall leave notice upon the premises in a manner conspicuous to customer stating the date and time of discontinuing service and the address and telephone number of Company where customer may arrange to have service restored.

Except for discontinuing service pursuant to Section 5.02 Conditions for Discontinuing Service, Parts (1), (2), (5), (6) and (10) Company shall discontinue service only when, at the time of the proposed discontinuance, Company's office or personnel identified in the notices given pursuant to Section 5.01 Notice to Customer for Discontinuing Service, are open or available to customer for one hour after discontinuance and on the full working day following discontinuance to enable customer to obtain reconnection. Company personnel with authority to approve reasonable pay arrangements shall be available during this period.

5.06 **Restoration of Service**: Upon customer request, Company will restore service promptly when the cause of discontinuing service has been eliminated, applicable charges paid, and/or if required, satisfactory credit arrangements have been made. Every effort will be made to restore service to existing customers defined under Section 2.02.03 on the day requested but in no event shall restoration be later than the next normal business day following the day requested by customer.

5.07 **Disputed Bills**: When customer advises Company in any reasonable manner such as written notice, in person, or by telephone call directed to the appropriate personnel prior to the date of proposed discontinuance of service that all or any part of a bill rendered is in dispute or that Company's reasons for discontinuing service are factually invalid, Company shall record the date, time and place that customer notice of a dispute is given, and postpone discontinuing service until a prompt and full investigation is completed.

Company and customer shall attempt to informally resolve the dispute to the mutual satisfaction of both Company and customer. In the event the dispute is not resolved Company shall advise customer of informal and formal procedures available before the Commission and shall then discontinue service if proper notice has been given to customer.

5.08 **Collection or Disconnection Charge**: When it is necessary for Company to make a service call for the purpose of collection or disconnection of service because of non-payment, a service charge as specified in Section 12.05 Collection or Disconnection Charge, will be collected from customer by Company.

5.09 **Reconnection Charge**: When a customer has been disconnected for conditions in Section 5.02 Conditions for Discontinuing Service, Company may require a service charge as specified in Section 12.06 Reconnection Charge, for reconnecting service. In addition, Company may require a security deposit, as specified in Section 3.01 Credit Requirements and Section 3.02 Security Deposits, before service is reestablished. In the event a customer orders a disconnection and a reconnection at the same premises within a period of 12 months, Company will collect, as a reconnection charge, the sum of such minimum bills as would have occurred during the period of disconnection, but in no event less than the reconnection charge provided for in Section 12.06 Reconnection Charge. If service has been discontinued because of unauthorized use, interference, tampering or diversion of service (meter bypass), customer shall pay Company an amount estimated by Company to be a reasonable payment for the unauthorized service used and the reconnection charge pursuant to Section 12.13 Diversion Reconnection Charge.

Company shall not charge both a reconnection fee as specified in Section 12.06 Reconnection Charge, and a reconnection charge as specified in Section 12.13 Diversion Reconnection Charge for the same reconnect.

5.10 **Transfer of Account Balances**: In the event of discontinuance or termination of service at customer's metering point, residence or other location, Company may transfer any unpaid balance to another concurrent active account of customer only with customer's written consent. In the event of the failure of customer to pay a final bill at a metering point, residence or other location, Company may transfer such unpaid balance to any successive service account opened by customer for the same class of service, and may discontinue service, upon proper notice at such successive metering point, residence or location for non-payment of such transferred amount.

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6. Customer's Service Obligations

6.01 Customer's Appliances and Piping

6.01.01 **Customer's Piping**: The term "customer's piping" is used to designate all piping, fixtures, valves, appliances and apparatus of any kind or nature on customer's side of the point of delivery. All piping shall be installed and maintained by customer at customer's expense in conformity with these General Terms and Conditions, Orders and Rules and Regulations prescribed by the Commission and state and local governmental standards and/or requirements. Where Company's rate schedules provide for different classes of service, customer's piping, at customer's expense, shall be so arranged that each class of service can be metered separately. If customer's piping cannot be so arranged, Company shall reserve the right to assign rate schedules and priority to customer's total requirement.

6.01.02 **Multi-Metering Installations**: Where building or premises are occupied by more than one customer, Company will set as many meters as there are separate applications for service. Customer piping shall be so arranged as to permit the installation of Company's meters adjacent to each other and shall not be interconnected. Customer piping shall be clearly and permanently marked to indicate the particular customer supplied by it.

6.02 Standards and Approvals of Customer's Facilities

6.02.01 **Compliance with Safety Requirements**: All piping, appliances and appurtenances installed by customer shall be of types certified by the American Gas Association and/or listed by the Underwriters Laboratories. These installations shall also meet the standards of the National Fire Protection Association and shall comply with federal, state and municipal codes insofar as they apply and all reasonable requirements of Company, and shall be maintained by customer in a good, safe and serviceable condition.

6.02.02 **Inspection and Testing of Customer's Facilities**: Prior to the original connection of service to any specific location, customer's piping, appliances and appurtenances shall be inspected and approved by a city inspector or other such authorized person for the proper receipt and use of utility service. If a certificate of approval is required by local authorities, it shall be obtained by customer at customer's expense. In the absence of an authorized person representing a governmental agency, the facilities will be inspected by a representative of Company. Such Company inspection shall not impose on Company any responsibility or liability for the safe condition of the facilities.

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After the commencement of service, Company will not be obligated to inspect customer's facilities, although at its discretion, Company shall have the right to inspect and test customer's facilities for suspected unsafe conditions at any time.

6.03 **Defective Customer Equipment**: In any case where Company discovers that a dangerous condition exists with regard to customer's appliances, equipment, or piping, it may, without advance notice, shut off the service and immediately notify customer. Service shall not be resumed until such dangerous condition has been eliminated. If customer is aware that gas is escaping from any equipment or pipe in or about customer's premises, or in case of interruption of service, customer shall notify Company at once.

6.04 **Company Equipment on Customer's Premises**

6.04.01 **Facilities on Customer's Premises**: If required, customer shall furnish, without cost to Company, right-of-way for mains or other facilities necessary to serve customer. Where customer is not owner of the premises to be served, written consent of the owner shall be furnished to Company.

6.04.02 **Protection of Equipment on Customer's Premises**: All facilities owned and installed by Company at its own expense are the property of Company. If the meter or other equipment belonging to Company are damaged or destroyed due to negligence or misuse by customer or by any member of customer's family, or by an agent, or employee or other representative of customer, then the cost of necessary repairs and/or replacements shall be paid by customer.

6.05 **Company's Access to Customer's Premises**: Company's representatives shall have free access to customer's premises for the purpose of reading the meter or inspecting the metering equipment and all other equipment relating to Company's service or for making necessary repairs or tests to its equipment, or for removing its meter and equipment.

6.06 **Tampering with and Care of Company's Property**: No one other than a Company representative or other person authorized by Company shall be permitted to repair or remove Company's meter or facilities, or any of the property of Company on or about customer's premises.

Any unauthorized person tampering with Company's meter or facilities is in violation of this restriction and such tampering shall be considered cause for immediate discontinuance of service by Company. Any seals placed by Company on meters or regulators shall not be broken or disturbed by anyone other than authorized representatives of Company.

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6.07 **Charges for Work Done on Customer's Premises by Company**: Except as provided in Subsection 6.02.02 Inspection and Testing of Customer's Facilities, Company shall charge for all materials furnished and for all work done on a customer's premises beyond the point of delivery except in cases where gas odor or a suspected unsafe condition is being investigated. The charges shall apply for trouble calls not occasioned by negligence on the part of Company, for repair of appliances, and any other work or service requested and authorized by the customer. Company shall not charge for replacement or repair of equipment furnished and owned by Company on the customer's premises except when repairs or replacements are caused by negligence or misuse by the customer or the customer's agents.

Except as provided in Section 7.02 Equipment Furnished by Company, Company may charge for upgrades necessitated by a change in service requirements of customer or any other work requested and authorized by customer.

These charges shall be based upon Company’s existing schedule of charges.

6.08 **Notice to Company to Discontinue Service**: Any contract made for service shall continue in full force and effect during its term. Service shall be discontinued by a customer in accordance with the terms of the contract. If no terms are specified, the customer may discontinue service upon giving a two day notice to Company. In case no such notice is given to Company, the terminating customer shall be responsible for all service supplied until such notice is given to Company. In the case of rental property, the owner may contract in writing for service to be continued automatically in owner's name, with full responsibility for payment of all service thereafter delivered, when service is terminated at the request of any tenant.

6.09 **Request for Investigation of Unsatisfactory Service**: If a customer feels that service is not adequate and sufficient, Company should be advised in writing of the nature of the complaint in order that a proper investigation may be made.

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7. **Company's Service Obligations**

7.01 **Information Regarding Service**: Company cooperates with contractors, individuals, other utilities and the Commission by participating in the "Kansas One-Call System, Inc." The purpose of the system is to disseminate fast accurate information at no cost regarding the location of underground facilities. Additionally, Company will furnish information regarding the location of its mains and the Character of Service available to any location upon request at any of its offices.

7.02 **Equipment Furnished by Company**

7.02.01 Company shall furnish all necessary shut off valves, regulators, relief valves, meters, meter settings and service lines to serve Customers.

7.02.02 All facilities furnished and installed by Company on the premises of Customer for the supplying of service to Customer shall be and remain the exclusive property of Company.

7.02.03 All Company-owned facilities on the premises of Customer shall be operated by and maintained at the expense of Company. Such facilities may be replaced by Company at any time and may be removed by Company upon termination of Customer's service agreement or upon discontinuance of service as provided in Section 5 Discontinuation of Service.

7.03 **Meter Locations**

7.03.01 **New Meter Installations**

(1) **Residential and Small Nonresidential Meters**: Company's general policy is to place new Residential and small Nonresidential meters at the building wall. Company may, however, at its sole discretion, place the meter at either the building wall or the property line or in an easement.

(2) **Large Nonresidential Meters**: All new meter set locations for large Nonresidential Customers will be determined by mutual agreement between Customer and Company. Any such location must provide for an adequate margin of safety from public road and in-plant traffic.

Customer shall have the duty to notify Company in writing of any changes in traffic patterns or other conditions which subsequently render any agreed-upon location unsafe.

7.03.02 **Existing Meters**: When replacing a Service Line or Yard Line, an existing inside or outside meter may be relocated at Company's option in accordance with its policies for new installations as provided in Subsection 7.03.01, New Meter Installations.

7.03.03 **Inside Meters**: Inside metering shall be prohibited except when, in Company's judgment, it is not practicable to locate the meter outside the building.

7.04 **Service Lines and Yard Lines**

7.04.01 **Leak Surveys**

(1) Service Lines and Yard Lines shall be periodically leak surveyed by Company at its expense.

(2) Leak surveys shall be performed in accordance with applicable laws and regulations of the regulatory bodies having jurisdiction in such matters.

(3) Company shall not assume any ownership responsibility of customer-owned lines based only on leak survey or maintenance activities being performed.

7.04.02 **Service Line and Yard Line Maintenance**

(1) Company or Company Agent shall perform, at Company's expense, all maintenance of Company-owned and/or Customer-owned Service Lines and Yard Lines, when the need for such becomes apparent to Company.

(2) If a customer-owned Service/Yard Line is in need of repair, or, if it has been declared to be a potential safety hazard by Company, Company may, at its option, replace the line instead of repairing it.

(3) If it is necessary to replace the Service/Yard Line, Customer shall be deemed to have granted Company an easement for such line unless Customer requests termination of service. This replacement shall be done in accordance with Subsection 7.04.03 Service Line and Yard Line Installation or Replacement.

(4) Any additional Service Line and/or Yard Line required shall also be installed by Company or Company-authorized personnel and shall be owned, operated and maintained by Company.

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7.04.03 **Service Line and Yard Line Installation or Replacement**

(1) Company shall furnish or replace, at its own expense, that portion of the service line which lies in the public street or right of way, and which extends from the gas main to the customer's property line.

(2) For piping 1 ¼ inch in diameter or less, the Customer receiving service shall be billed for additional Service and/or Yard Line installation or replacement at the cost of $4.54 per foot in excess of 200 feet. For piping greater than 1 ¼ inch in diameter, the customer receiving service shall be billed for actual construction costs.

(a) Customer shall also be billed for any construction costs including labor, overheads and material used in unusual construction conditions including but not limited to piping that is to be installed in frozen ground, rock, under paved areas or other obstructions, regardless of Service Line/Yard Line length.

(b) A copy of Company's estimate showing the costs of labor, overheads and material required to perform the work hereunder shall be furnished to customer upon request prior to construction, unless safety conditions are to be addressed and the response does not afford the opportunity to prepare an estimate.

(3) All replacements of Customer-owned Service/Yard Lines shall be performed by Company or Company-authorized personnel and shall thereafter be owned, operated and maintained by Company.

(4) Replacement of Customer-owned Service/Yard Lines will occur in accordance with Company's schedule and the requirements of regulatory authorities having jurisdiction herein.

(5) **Billing and Payment Options**

(a) For installations or replacements of service lines 1 ¼ inch in diameter or less where the excess costs exceed $500, Company may, after giving due consideration to the total costs and Customer's ability to make the required payment, enter into a special payment agreement with Customer to permit payment over a period of up to 36 months.

(b) For installations or replacements of service lines greater than

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1¼ inch in diameter where costs exceed $500, Company will present Customer a bill which will be due and payable upon receipt.

(c) For new Service Line and Yard Line Installations where costs are estimated to be $500 or less, Company will present Customer a bill for such costs, which shall be due and payable upon receipt. Upon payment, Company shall install or cause to be installed, the required lines.

(d) For replacement of customer-owned lines where costs are $500 or less, Customer will be billed for such costs, which shall be due and payable upon receipt. Customer may be permitted to pay the balance in equal monthly installments over a period not to exceed 12 months.

(e) Customer's failure to pay the excess costs in accordance with the pay agreement shall be sufficient cause to discontinue service to Customer upon due notice and in accordance with these General Terms and Conditions.

7.05 **Company Liability**: Customer shall save Company harmless from all claims for trespass, injury to persons, or damage to lawns, trees, shrubs, buildings or other property that may be caused by reason of the installation, operation, or replacement of the Service Line, Yard Line and other necessary appurtenances to serve Customer unless it shall affirmatively appear that the injury to persons or damage to property complained of has been caused by willful default or negligence on the part of Company or its accredited personnel.

Company may refuse or discontinue service if an inspection or test reveals leakage, escape or loss of gas on customer's premises. Company will not be liable for any loss, damage or injury whatsoever caused by such leakage, escape or loss of gas from Customer's Service Line, Yard Line, Ancillary Lines, house piping, appliances or other equipment.

Company shall not be liable to Customer for any damages, consequential or otherwise, caused by external forces not within the exclusive control of the Company.

7.06 **Exclusions**: Company shall have no obligation to perform leak surveys or to provide cathodic protection on a Customer-Owned Distribution Network.

7.07 **Inspection and Testing of Customer's Facilities**: After the commencement of service, Company's obligations regarding inspection of Customer-owned Service Lines and Yard

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Lines will be governed by the applicable provisions of Subsection 7.04, Service Lines and Yard Lines. Company will not otherwise be obligated to inspect Customer's facilities, although at its discretion Company shall have the right to inspect and test Customer's facilities for suspected unsafe conditions at any time.

7.08 **Continuity of Service**: Company will use reasonable diligence to supply steady and continuous gas service at the point of delivery, but will not be liable to Customer for any damages occasioned by irregularities or interruptions, except when directly and proximately caused by the reckless, willful or wanton act of Company, its Agents or employees.

7.09 **Relocation of Company's Equipment at Customer's Request**: Customer shall consult Company before causing or permitting any construction over any Company owned facility. Customer shall not enclose any exposed portion of Company owned facilities. Company shall require Customer reimbursement of any costs due to a change in the location of meters or other equipment made at the request of Customer. Company's equipment will be removed or relocated only by Company authorized personnel.

7.10 **Company's Responsibility**: Company assumes no responsibility for any loss, damage or injury whatsoever caused by leakage, escape or loss of gas after same has passed through Company's Point of Delivery and will not be responsible for the inspection or repair of defects in Customer's piping, fixtures, or appliances in or on Customer's premises, and will not be responsible for any injury, loss or damage resulting from such defects or improper installation.

In accordance with its normal work procedures, Company shall exercise reasonable care when installing, maintaining or replacing Company facilities located on Customer's premises. However, beyond such normal procedures, Company assumes no responsibility for trespass, injury to persons, or damage to lawns, trees, shrubs, building or other property that may be caused by reason of or related to installation, maintenance or replacement of Company's facilities to serve Customer, unless it shall be shown affirmatively that the injury to persons or damage to property complained of, has been caused by willful default or negligence on the part of Company.

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8. **Extension Policy**

8.01 **Extension of Distribution Mains**

8.01.01 **Distribution Mains**: The term "distribution mains" is used herein to designate the pipe and other related facilities of Company, excluding service lines, which are located downstream of town border stations or other points where Company determines that the primary function of such facilities is to distribute natural gas among customers as opposed to moving natural gas through transmission lines.

8.01.02 **Extension Requests**:

(1) A distribution main extension may normally be requested by a customer as defined in Section 1.11 Customer or by developers, including but not limited to area developers, construction companies, contractors and similar entities and shall be subject to the customer-related provisions in this Section 8 unless otherwise ordered or approved by the Commission.

(2) **Main Extension Agreement**: Company and requesting party may enter into a Main Extension Agreement regarding terms mutually determined and agreed upon by both parties.

8.01.03 **Economic Evaluation**: Company may conduct an Economic Evaluation of the project to determine whether extension is of Ordinary or Extraordinary in nature as defined below:

(1) **Ordinary Extensions**: Company will make ordinary extensions of its distribution mains as and when necessary to serve prospective customers located within the corporate limits of a city or suburban area adjacent thereto, or within unincorporated communities.

(a) The Ordinary Extension Allowance shall be the length of the actual extension up to 100 feet per customer served.

(b) The Ordinary Extension Value shall be the Ordinary Extension Allowance times the per foot cost of the distribution main project, not including extraordinary costs due to unusual construction conditions or barriers or of special equipment or facilities.

(2) **Extraordinary Extensions**: Company may determine any distribution main extension to be of an extraordinary nature.

(a) An extraordinary extension shall be one:

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i. From which the prospective service usage is so limited that it is doubtful whether the revenues from the extension will pay a fair return on the investment pursuant to an Economic Evaluation conducted by the Company, or

ii. For which the cost of making such extension is prohibitive due to unusual construction conditions or barriers, even though the length of the extension does not exceed 100 feet per applicant, or

iii. Which incorporates special equipment or facilities to serve the customer’s load requirements.

(b) When a distribution main extension is determined to be of an extraordinary nature or exceeds the Ordinary Extension Allowance, Company shall have the right to require:

i. A construction contribution sufficient to compensate Company for the extraordinary costs above the Ordinary Extension Value, or

ii. A satisfactory guarantee of revenue through adjustment of the minimum bill provisions of the applicable rate.

8.01.04 **Construction Contribution**: Company may require a potentially refundable advance payment of the total estimated Ordinary or Extraordinary construction costs for main installations, unless the Company determines the anticipated revenue is sufficient to prevent an undue burden on existing Customers.

(1) The amount of the construction contribution required will be estimated by Company. If Company requires a construction contribution in advance of any construction or modification of Company's facilities as herein described, it shall be understood that such contribution is based on estimated costs.

(2) Company reserves the right to modify such contribution after actual costs become known. The term "estimated cost" as used herein will be the estimated cost for materials, labor and work equipment required, plus Company's related overheads. A copy of Company's estimate showing the costs of labor, overheads and material required to perform the work hereunder will be furnished to customer upon request prior to construction.

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8.01.05 **Contribution Refunds**: The amount of refund for construction contributions shall be determined according to terms defined in the Main Extension Agreement, if applicable, for natural gas utilization as calculated in the Economic Evaluation performed by Company.

(1) **Refund Requests**: Refunds for construction contributions shall be made to the party who paid the contribution.

(a) It shall be the responsibility of the party who made the construction contribution to request Company to calculate and issue a refund.

(b) The requesting party shall have 60 days from the expiration of the calculation period designated in the Main Extension Agreement to request a refund.

(c) Refunds will be issued within a period of 7 years from the date of a Main Extension Agreement for active connections to the extension and not to a further extension.

(2) **Total Refunds**: At no time shall the aggregate refunds exceed the advance payment.

(3) **Unrefunded Contributions**: Any portion of a construction contribution remaining after 7 years from the date of the main extension agreement shall become a nonrefundable contribution in aid of construction and no additional Main Tap Charges from new applicants or extension allowances from Company will be applicable to the extension.

(4) **Confidential Information**: Company shall maintain the confidentiality associated with a Qualified Customer's usage, pursuant to Section 1.08 Confidentiality. The Qualified Customer may, at its sole discretion, provide Company with a signed affidavit permitting Company to release such information to the party who made the construction contribution, although Company shall have no responsibility to secure such affidavit from a Qualified Customer. In the absence of such authority, any disputes shall be presented to the Commission for resolution.

8.01.06 **Customer's Guarantee**: Company shall not be obligated to make any extension of its distribution system unless Customer executes a contract in writing with suitable guarantees that Customer will use the service for at least one year, or unless the owner of the property served by such extension or some other responsible person shall guarantee that the service will be used for at least one year.

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8.01.07 **Determination of the Extension Route**: The distance of the premises from the nearest existing distribution main having sufficient available capacity to provide adequate service to customer and to other customers connected thereto shall be measured along easements, streets, roads, highways, and alleys but not across private property.

(1) In those instances where unusual conditions exist and where good engineering practices dictate that an alternative to the shortest route be selected, Company reserves the right to determine such alternate route and base construction cost estimates accordingly, as referenced in the subparts of 8.01.03 Economic Evaluation.

(2) Company may refuse service to an applicant who would extend piping across another's property to circumvent payment for a main extension.

(3) Crossings of streets and alleys shall not be included in computing the total length of the extension unless:

(a) the crossings are avoidable because of the added efficiency, economy or safety of other options, or

(b) the crossings are required to provide sufficient and reliable service to the customer or development, or

(c) the crossings are installed primarily to increase reliability or capacity of Company's overall gas distribution system.

8.01.08 **Right-of-Way Limitations**: Company shall not in any case be required to secure private rights-of-way for the purpose of making extensions of distribution mains or other facilities to property owned or otherwise controlled by Customer. Customer will provide or procure for Company such private rights-of-way as are satisfactory to Company for the construction, operation and maintenance by Company of its facilities necessary or incidental to the supplying of service. When necessary, Company shall endeavor to secure franchise rights from the municipality to cover extensions required, but will not make extensions on municipal streets or alleys not covered by lawful franchise grants.

8.01.09 **Extensions on Unimproved Streets and Alleys**: Company shall not be required to construct any extensions of distribution mains in any street or alley for which the property lines, sidewalk lines and curb lines have not been previously established to the final grade. In cases where the street or alley is ungraded, Company shall not be required to extend its distribution mains unless the existing contour of the ground is within 12 inches of the final grade at the proposed locations of Company's mains. Free and safe access to and through such streets and alleys must be provided.

8.01.10 **Service Lines**: Company's investment in Service Lines and provisions for leak surveys and maintenance are included in Subsection 7.04 Service Lines and Yard Lines.

8.01.11 **Extensions to be Property of Company**: All extensions made under these rules shall at all times be and remain the property of Company.

8.01.12 **Other Restrictions**: Distribution mains will not be extended unless Company is certificated by the Commission to provide service in the area or Company possesses a waiver from the gas utility holding certification for the area. The character and type of the main extension and its route shall be decided by Company.

8.02 **Service from Transmission Lines**

8.02.01 **Transmission Taps**: Unless otherwise stated herein, conditions of service to customers served from Company's distribution mains shall be equally applicable to service from transmission lines. New connections for service from Company's transmission lines will be made under the following conditions:

(1) The point of delivery for utility service shall be located within the boundaries of Company's certificated area as established by the Commission.

(2) Customer shall be responsible for the installation, operation and maintenance of customer's piping from the outlet of the meter to the point of usage.

(3) The feasibility and location of transmission taps and related metering facilities shall be determined by Company considering ease of access for installation, meter reading and maintenance.

(4) Company may charge customer its average actual costs of providing a transmission tap.

(5) Company may require customer to execute a standard agreement for service from transmission lines.

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(6) If at any time Company desires to change the operation of its transmission lines or to relocate or remove them for any reason and such changes, relocation, or removal would interfere with service to customer, service may be discontinued upon approval of the Commission and 90 days written notice to customer.

(7) If service is supplied to a third party through sub-metering from a customer-owned line over which Company has no control, service may be discontinued upon request of customer and Company will not be obligated to provide continued service to the third party nor shall Company be liable for any damages caused by the discontinuance of service.

(8) All construction of buildings within Company's easement is prohibited and the construction of buildings for human habitation within 50 feet of the pipeline is discouraged.

8.02.02 **Transmission Service Limitation:** Although Company shall endeavor to accommodate potential customers requesting service from transmission lines, it is recognized that such requests may be denied due to Company's prior obligation to serve its existing customers, insufficient available capacity, unavailable or substandard gas supply or other operating and safety requirements. However, each potential customer will be given a cost estimate to receive utility service based on Company's line extension policy and Company's sole discretion to select the point of supply.

8.03 **Service from Irrigation Mains**

8.03.01 **Availability of Service**: New or additional service from irrigation mains will be provided from existing Company-owned irrigation mains provided such mains have adequate capacity and pressure to provide the service requested by customer without the installation of additional facilities. If additional facilities are required, they may be added in accordance with Subsection 8.01 Extension of Distribution Mains.

8.03.02 **Additions or Changes to Irrigation Systems**: Customer will contact Company prior to the connection of any additional engines, added horsepower or before making any other changes that might affect capacity and pressure requirements on an existing system or metering facilities. Company shall review customer's request and inform customer whether the requested change in service is available.

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8.03.03 **Sub-metering on Privately-Owned Irrigation Gas Systems**: Company shall not be obligated to install sub-metering to provide service from a privately-owned irrigation gas system and sub- metering by customer is not permitted. New residential utility service to a third party will not be provided from customer-owned pipe systems designed for irrigation purposes.

8.04 **Service to Mobile Home Courts**: Unless otherwise stated herein, conditions of service to customers served from Company's distribution mains shall be applicable to service to permanent-type mobile home courts. Company shall not be obligated to supply service to mobile homes on a temporary, seasonal or short term basis.

8.04.01 **Permanent Court**: A permanent-type mobile home court shall be defined as a development which contains at least one mobile home and provides such features as hard-surfaced driveways, hard-surfaced walkways, underground sewer and water facilities.

8.04.02 **Rights-of-Way**: A mobile home court owner shall obtain and furnish to Company, without charge, all necessary easements and rights-of-way on property owned and controlled by the owner.

8.04.03 **New Mobile Home Court Distribution Systems**: Utility service to mobile home courts shall be provided from Company's distribution system. Company shall install all necessary distribution facilities, including mains and service lines, both inside and outside the property lines of the mobile home court, pursuant to the provisions in Section 8.01. All points of gas usage therein shall be metered and no master metered service shall be allowed.

8.04.04 **Existing Mobile Home Court Distribution Systems:** Company shall not be required to serve mobile homes through customer-owned distribution systems.

(1) Company shall assume ownership and maintenance responsibilities of an existing customer-owned mobile home court distribution system when it is identified or when Company acquires certification to serve the territory in which it is located.

(2) Prior to providing service, Company shall repair or replace existing systems which do not meet applicable construction standards and specifications, pursuant to the provisions in Section 8.01.

(3) All mains, service lines, meters, regulators and other related appurtenances shall be owned, operated, and maintained by Company.

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(4) All points of gas usage within the court shall be metered and any master meter assembly removed.

8.04.05 **Service Connections**: Connection of a mobile home to the mobile home court distribution system shall be made in accordance with standards acceptable to Company.

(1) The customer shall install, own and maintain all service connections and other piping from the point of delivery to each usage point.

(2) Company may, at its option, locate its meter at a point away from a mobile home pad site served by a mobile home court distribution system. The service/yard line from this meter shall terminate with a rigid pipe rising near but not beneath the mobile home pad site. The point of delivery shall be the outlet of that rigid riser.

(3) The connection between the rigid riser or the meter and the mobile home shall be made outside the mobile home with a Company-approved flexible connector not exceeding 6 feet in length.

8.04.06 **Customer Billing**: Company shall render a monthly service bill for each meter installed.

(1) Service to each usage point shall be provided under the rate schedule applicable to the service being rendered.

(2) The service bill may be rendered directly to the occupant of a mobile home site according to the provisions of Section 2.02 Application for Service.

(3) Bills for service to all other meters installed in the mobile home court shall be rendered to the court operator.

8.04.07 **Resale of Service Prohibited**: A mobile home court owner or operator shall not separately charge the occupant of any mobile home for gas service. Such separate charge constitutes a resale of utility service and is prohibited.

8.04.08 **Inspection of Facilities**: Service shall at all times be subject to inspection and approval of the conditions of a user's premises, of the mobile home court distribution system and of terminal facilities for the receipt and use of gas utility service.

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9. **Measurement Standards**

9.01 **Measurement**: Company shall define its deliveries of natural gas in thousands of cubic feet (Mcf).

9.01.01 **Definition**: One cubic foot of natural gas is defined as that quantity of gas which fills one cubic foot of space at an absolute pressure of 14.65 pounds per square inch at a temperature of 60 degrees Fahrenheit.

9.01.02 **Assumptions**: Company may assume that gas delivered obeys Boyle's Law, that atmospheric pressure is 14.4 pounds per square inch absolute and that the flowing temperature of the gas in the meter is 60 degrees Fahrenheit.

9.01.03 **Delivery Pressure**: Company reserves the right to specify the pressure at points of delivery.

(1) **Delivery Pressure at Meter**: Under normal operating conditions, utility service shall be delivered at a nominal pressure of four ounces above atmospheric pressure. At Company's option, gas may be delivered at a higher pressure to satisfy a customer's requirements.

(2) **Delivery Pressure of Transportation Service Gas**: The pressure at which Company delivers a customer’s gas to the customer shall be mutually agreed upon from time to time. The agreed-upon pressure shall reflect the customer’s requirements, Company’s delivery system and other pertinent factors.

9.01.04 **Pressure and Temperature Correction**: At Company's option, the volume of gas registered by the meter may be adjusted to a volume based on 60 degrees Fahrenheit and a pressure of four ounces above the atmospheric pressure of 14.4 pounds per square inch absolute, computed in accordance with Boyle's Law governing pressure and volume of gases with correction for deviation.

9.02 **Metering**: The registration of Company's meters shall be accepted and received at all times and placed as prima facie evidence of the amount of energy used by a customer.

9.02.01 **Required Meter Accuracy Prior to Installation**: Metering devices shall be accurate to within one percent fast or two percent slow before being installed, in accordance with the rules and regulations established in Docket 34,856-U.

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9.02.02 **Testing Equipment**: Company shall provide and be responsible for the proper calibration of such testing equipment and apparatus as may be necessary to comply with the Rules and Regulations of the Commission.

9.02.03 **Routine Meter Testing**: Company shall routinely test gas meters in accordance with its schedule. When a meter is found to be more than two percent fast or two percent slow, Company shall refund to, or may collect from, a customer the overcharge or undercharge in accordance with Section 9.02.05 Adjustment of Bills for Meter Error.

9.02.04 **Meter Tests at Customer's Request**: Upon written request by a customer, Company shall test the accuracy of the customer's meter.

(1) If the results of the test show the meter accurate within the limits of two percent fast or two percent slow, the customer shall be assessed a charge as stated in Section 12.10 Meter Test Fee.

(2) If the meter is found to be more than two percent fast or two percent slow, Company shall bear the cost of the test and related expenses and shall refund to, or may collect from, the customer the overcharge or undercharge in accordance with Section 9.02.05 Adjustment of Bills for Meter Error.

9.02.05 **Adjustment of Bills for Meter Error**: Billing adjustments shall be prepared for metering errors.

(1) **Fast or Slow Registering Meters**: When a billing adjustment is prepared for metering error, it shall be based on the calculated corrected meter readings for a period not exceeding six months or for the time the meter has been in service at that location if less than six months. If it can be shown that the error was due to some cause, the date of which can be fixed, the over charge or under charge shall be computed back to, but not beyond, such date.

(2) **Non-registering Meters**: If the meter is found not to register for any period, Company shall estimate the utility service used during this period in accordance with Section 4.05.02 Correction of Erroneous Bills.

(3) **Non-reporting Automatic Meter Reading (AMR) Devices**: If AMR device is found not to have reported known usage for any period; Company shall allocate the utility service used during this period in

accordance with Sections 4.04.05 Estimating Procedure and 4.05.02 Correction of Erroneous Bills.

(4) **Payment**: Company may permit payments to be made in installments over a reasonable period of time. No refund or bill less than the amount stated in Section 12.09 Adjusted Bill Amount need be issued or made.

9.02.06 **Sub-Metering**: When an additional meter is installed at the sole discretion of Company for use as sub-meter for the customer's convenience, a monthly charge may be made for the use of such meter, depending on its size. Sub-metering by the customer is not permitted.

9.03 **Gas Quality**

9.03.01 **Quality of Gas Received**: After June 1, 2007, unless specifically stated otherwise in a written agreement, gas received into Company's transmission or distribution systems shall conform to the following specifications:

(1) It shall contain no more than 0.25 grains of hydrogen sulfide per 100 cubic feet, nor more than 0.50 grains of total sulphur per 100 cubic feet.

(2) Its temperature shall be no less than 25 degrees Fahrenheit and no more than 120 degrees Fahrenheit.

(3) It shall contain no more than seven pounds of water vapor per 1,000 Mcf.

(4) It shall contain no more than 2% carbon dioxide by volume.

(5) It shall contain no more than 100 parts per million oxygen by volume.

(6) Its delivery pressure shall be sufficient to permit receipt of the gas by Company's delivery system.

(7) Its dry heat content shall be no less than 950 British Thermal Units (Btu) per cubic foot and no more than 1,100 Btu per cubic foot at a pressure base of 14.65 pounds per square inch gauge (psig), and

(8) Its hydrocarbon dew point shall not exceed 25 degrees Fahrenheit at the Company's current line pressure.

9.03.02 **Quality of Gas Delivered**: Company shall strive to deliver natural gas to customers which meet the requirements of Section 9.03.01 Quality of Gas Received.

9.04 **Heat Content**: The heat content of gas delivered to customers shall be the heat content available on Company's system at the particular delivery point at the time of delivery.

9.04.01 **Minimum Heat Content**: The heat content may vary from delivery point to delivery point and from time to time and nothing contained herein shall be construed as obligating Company to alter the usual operation of Company's delivery system to achieve deliveries for a prescribed heat content at any point or points. In accordance with Commission Docket No. 34,856-U, Company shall not deliver gas to a customer having a heat content lower than 800 British Thermal Units per cubic foot, except by permission of the Commission.

9.04.02 **Measurement of Heat Content of Gas Received**

(1) **‘K’ System**: The heat content of gas received on Company's ‘k’ system shall be determined by multiplying the heat value of gas received from supplying pipeline(s), stated in Btu per cubic foot, by the gas volumes received for the customer during the billing period.

(2) **‘T’ System**: The heat content of gas received on Company's ‘t’ system shall be calculated by the same method except that the per-cubic-foot heat content of the individual gas source shall be used.

9.04.03 **Measurement of Heat Content of Gas Delivered**

(1) **‘K’ System**: The heat content of a customer's gas delivered by Company's ‘k’ system shall be determined by multiplying the per-cubic-foot heat content of the customer's supplying pipeline connected to Company's ‘k’ system by the volume of gas delivered to the customer. If the customer's gas is from multiple supplying pipelines connected to Company's ‘k’ system, the per-cubic-foot heat content used in the above calculation shall be the prorated share of each pipeline's per-cubic-foot heat content based on the amount of the customer's gas supplied from each pipeline.

(2) **‘T’ System**: The per-cubic-foot heat content of the gas delivered by Company's ‘t’ system shall be determined by Company measurement or by the current method used by Company to determine average heat content. The customer's heat content is calculated as above.

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9.04.04 **Additional Equipment for Measuring Heat Content**: A customer shall be required to compensate Company for all costs incurred in determining the heat content of the customer's gas if no heat content measurement is available, or if the available measurement is unacceptable to Company or the customer.

(1) When a customer requires additional heat content measurement, Company shall determine the type and location of measurement equipment, and install the equipment at the customer's sole expense.

(2) A customer requesting the installation of heat content measurement equipment shall be required to utilize the equipment for a minimum period of 12 consecutive months following its installation.

(3) The customer shall pay Company a monthly charge, reasonably calculated, to reimburse Company for operating expenses associated with heat content measurement.

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10. **Requirements for Transportation Service**

10.01 **Company's Responsibility**: Company shall deliver to a customer volumes of gas which are thermally equivalent to the volumes of gas received for the customer at a receipt point, less any amount retained by Company according to Section 10.06 Retainage.

10.02 **Customer's Responsibility**: A customer, by taking service under a transportation service rate schedule, warrants and agrees that:

10.02.01 Gas received by Company for the customer shall be free from all adverse claims, liens, and encumbrances.

10.02.02 Company shall be held harmless and indemnified by the customer from and against all suits, actions, causes of action, claims and demands, including attorneys' fees and costs, arising from or out of any adverse claims by third parties claiming ownership of, or an interest in said gas caused by the failure to provide clear title to the gas,

10.02.03 Company shall not be responsible in any way for damages or claims relating to the customer's gas or the facilities of the customer or others containing such gas prior to receipt into Company's facilities or after delivery to the customer, and

10.02.04 The customer's gas shall at all times remain vested in the customer.

10.03 **Customer's Agent**: Company-approved agents shall be allowed to deliver gas to Company's system for a transportation service customer.

10.03.01 **Agent's Responsibilities**: An agent arranging for delivery of gas for a transportation service customer must receive Company approval prior to delivering gas to Company's system. Agents receiving Company approval and choosing aggregated balancing as described in Section 10.04 Aggregation shall enter into a signed agreement with Company, which shall acknowledge the agent's responsibilities under Section 10.09 Cash Out and Section 11.06 Penalties for Unauthorized Usage.

10.03.02 **Affidavit**: A customer to be represented must provide Company with an affidavit identifying its agent. This authorization shall be in a form agreeable to Company and shall remain in effect until a signed replacement is received by Company.

10.03.03 **Billing**: Company shall provide to a customer's agent a duplicate monthly billing statement upon the customer's written request. Company may accept

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payment from the customer's agent; however, the customer shall continue to be responsible for all charges on the account. In the event of any billing dispute, Company shall notify the customer directly and shall not be required to notify the customer's agent.

10.04 **Aggregation**: Customers' agents shall be allowed to aggregate their customers' usages for purposes of balancing.

10.04.01 **Aggregation Areas**: Company shall establish aggregation areas within geographic, operational, administrative, and/or other appropriate parameters.

10.04.02 **Aggregation Groups**: An agent shall establish its customers within each aggregation area into a group or groups. Customers not assigned to an aggregation group shall be individually balanced.

10.04.03 **Changes to Aggregation Groups**: Company must receive changes to aggregation groups, in writing, prior to the last working day of a month. Changes shall become effective on the first day of the following month except that aggregation groups shall be as designated prior to the first effective day of an OFO or POC.

10.05 **Nominations**: A customer or the customer's agent shall provide to the Company's nomination website, the customer's Standard and/or intraday Nomination using the following nomination cycles. All times listed below are Central Clock Time (CCT). For March 31, 2016, the new day-ahead nomination timelines will apply for those nominations effective April 1, 2016:

(1) **The Timely Nomination Cycle**: 1:00 p.m. for nominations leaving the control of the nominating party; 1:15 p.m. for receipt of nominations by Company, scheduled quantities effective at 9:00 a.m. the next Gas Day.

(2) **The Evening Nomination Cycle**: 6:00 p.m. for nominations leaving control of the nominating party; 6:15 p.m. for receipt of nominations by Company, scheduled quantities effective at 9:00 a.m. the next Gas Day.

(3) **The Intraday 1 Nomination Cycle**: 10:00 a.m. for nominations leaving control of the nominating party; 10:15 a.m. for receipt of nominations by Company, scheduled quantities effective at 2:00 p.m. the same Gas Day.

(4) **The Intraday 2 Nomination Cycle**: 2:30 p.m. for nominations leaving control of the nominating party; 2:45 p.m. for receipt of nominations by Company, scheduled quantities effective at 6:00 p.m. the same Gas Day.

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(5) **The Intraday 3 Nomination Cycle**: 7:00 p.m. for nominations leaving control of the nominating party; 7:15 p.m. for receipt of nominations by Company, scheduled quantities effective at 10:00 p.m. the same Gas Day.

10.06 **Retainage:** Retainage is a quantity of gas necessary to compensate Company for lost and unaccounted for gas and gas used in Company's operations. Retainage shall be stated as a percentage of a customer's gas received by Company and shall be determined annually by Company.

10.07 **Daily Quantity of Transportation Service Gas**: A customer or the customer's agent shall maintain, as nearly as practicable, uniform daily rates of gas delivery. The customer shall take delivery of gas at the same uniform rate as the gas is received by Company. However, should variations between deliveries to the customer and receipts by the Company cause operational problems on Company's system, Company may discontinue receipt of gas until such variations are corrected.

10.08 **Quality of Transportation Service Gas**: The gas procured by a customer or the customer's agent for receipt by Company shall conform to the standards prescribed in Company's applicable rate schedules and these GT&C.

10.08.01 **Merchantable Quality**: The gas shall at all times be merchantable gas of a quality required by Company's system to which the gas is being delivered. The gas shall be free from any foreign materials (e.g. dirt, dust, gums, iron particles, water, other entrained liquids, or other impurities) which might render it unmerchantable or interfere with the proper operation of pipelines, meters, regulators, or other facilities through which it flows or is used. Company may refuse to receive gas not meeting the quality requirements of Section 9.03.01 Quality of Gas Received. Receipt by Company of any gas not meeting these quality requirements shall not obligate Company to continue the receipts, nor shall it remove the customer's obligation to provide Company with gas meeting those specifications.

10.08.02 **Determination of Quality**: A customer shall bear all expenses connected with the determination of the quality of the customer's gas received by Company if the customer or the customer's agent arranges for the purchase of gas from a supplier from which Company does not currently receive gas directly into Company's delivery system. Company shall not be obligated to deliver this gas until an agreement exists between Company and the supplier, which Company shall not unreasonably withhold, setting forth the terms of interconnection, quality standards, and the respective rights of Company and the supplier in connection with deliveries of gas.

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10.09 **Cash Out**: Monthly volumes of gas delivered to a transportation service customer should, to the extent practicable, match Company's receipts for the customer less any amount retained by Company according to Section 10.06 Retainage. Agents may balance the aggregated volumes of gas for groups of customers they represent, according to the terms of Section 10.04 Aggregation.

10.09.01 **Monthly Cash Out**: Differences between deliveries and retainage-adjusted receipts shall be reconciled on a monthly basis between Company and a customer or the customer's agent.

(1) If Company's retainage adjusted receipts for the customer are less than deliveries to the customer, the customer or the customer's agent shall pay:

(a) No charge for each MMBtu of cumulative imbalance up to the greater of 5% of actual usage or 25 MMBtu per customer, to be carried over on account to the following month.

(b) 1.15 times the Cash Out Price for each MMBtu of imbalance which is greater than 5%, up to and including 10% of actual usage, and

(c) 1.3 times the Cash Out Price for each MMBtu of imbalance which is greater than 10% of actual usage.

(2) If Company's retainage adjusted receipts for the customer exceed deliveries to the customer, the customer or the customer's agent shall receive:

(a) No payment for each MMBtu of cumulative imbalance up to the greater of 5% of actual usage or 25 MMBtu per customer, to be carried over on account to the following month.

(b) 0.85 times the Cash Out Price for each MMBtu of imbalance which is greater than 5% of actual usage, up to and including 10%, and

(c) 0.7 times the Cash Out Price for each MMBtu of imbalance which is greater than 10% of actual usage

10.09.02 **Cash Out at Final Billing**: In the event a final bill for transportation service is rendered, regardless of the cause for termination of the transportation service, Company shall cash out the customer or the customer's agent.

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(1) If Company's retainage adjusted cumulative final receipts for the customer are less than cumulative final deliveries to the customer, the customer or the customer's agent shall pay:

(a) 1.0 times the Cash Out Price for each MMBtu of cumulative imbalance up to the greater of 5% of actual usage or 25 MMBtu per customer.

(b) 1.15times the Cash Out Price for each MMBtu of imbalance which is greater than 5% up to and including 10% of actual usage, and

(c) 1.3 times the Cash Out Price for each MMBtu of imbalance which is greater than 10% of actual usage.

(2) If Company's retainage adjusted cumulative final receipts for the customer exceed cumulative final deliveries to the customer, the customer or the customer's agent shall receive:

(a) 1.0 times the Cash Out Price for each MMBtu of cumulative imbalance up to the greater of 5% of actual usage or 25 MMBtu per customer.

(b) 0.85 times the Cash Out Price for each MMBtu of imbalance which is greater than 5% of actual usage, up to and including 10%, and

(c) 0.7 times the Cash Out Price for each MMBtu of imbalance which is greater than 10% of actual usage.

10.09.03 **Cash Out Price**: The monthly Cash Out Price shall be determined as the arithmetic average of the midpoint prices published in Gas Daily for each day of the month, for:

(1) Southern Star Central Gas Pipelines (Texas, Oklahoma, Kansas)

(2) Panhandle Eastern Pipe Line Company (Texas, Oklahoma)

(3) ANR Pipeline Company (Oklahoma), and

(4) Natural Gas Pipeline Company of America (Midcontinent).

If the Cash Out Price is not published for any of the above, the average will be calculated on the prices published.

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10.10 **Capacity Limitations**: A customer may have delivery of gas curtailed in the event of system supply emergencies or capacity limitations. Company's obligation to deliver a customer's gas shall be as stated in Section 11, Priority of Service. The determination of delivery system capacity limitations shall be at Company's sole discretion. The customer may request Company to make reasonable enlargements to its delivery system, if capacity limitations restrict the volume of gas which the customer may desire to be delivered. Company shall fulfill these requests provided the actual cost, including indirect costs, of delivery system enlargements are borne by the customer. The expanded facilities shall remain the property of Company, free and clear of any lien or equity by the customer. Nothing contained herein shall be construed as obligating Company to construct any extensions or expansions of its facilities.

10.11 **Limitation of Transportation Service and Other Charges**: Delivery of a customer's gas shall be available only where permitted by the gas supply contracts and rate schedules under which gas is supplied to Company. Any delivery conditions or limitations imposed on Company by the contracts and rate schedules shall be applicable to delivery of gas to the customer. Should delivery of gas cause the incurrence of demand charges, standby charges, reservation charges, penalties or like charges from Company's gas suppliers or transporters, and these charges are in addition to charges for gas actually received by Company and not anticipated by the rate schedule or rider schedule under which the customer takes service, these charges shall be billed to the customer. Additionally, should a change in the customer's service characteristics cause the charges anticipated above to be recovered from other customers, these charges shall be billed to the customer. Any disputes regarding the customer's responsibility for these charges shall be referred to the Commission for resolution.

10.12 **Third Party Metering**: If a customer's gas is received by Company through meters which are not owned and operated by Company or the customer, the customer or the customer's agent shall, at the earliest practicable time, but not later than 10 days following the end of the billing period, cause the supplier to furnish Company a statement showing the amount of transportation service gas, in Mcf and dekatherm per day, delivered to Company for the customer during the billing period. The customer or the customer's agent, upon request, shall cause to be furnished to Company all charts, or satisfactory copies thereof, upon which the statement provided for above were based. Any original charts furnished shall be returned within 30 days. By accepting gas, the customer agrees to maintain records of the volumes of gas received by Company for the customer and to allow Company to inspect the records upon request during the customer's regular business hours.

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10.13 **Change from Sales to Transportation Service**: Company shall use its best efforts to promptly affect all customer requests to change from a sales service tariff to a transportation service tariff.

10.13.01 **Valid Request**: Company shall consider a valid request to have been made upon receipt of a properly completed Transportation Affidavit, in accordance with Section 10.03.02 Affidavit. Company must receive Affidavit by the 20^{th} day of the month preceding the month in which the initiation of transportation service is requested.

10.13.02 **Administrative Limit**: Company shall consider its internal, external, and administrative limitations and shall determine the number of Affidavits it can process each month, which shall be the Administrative Limit.

10.13.03 **Monthly Additions**: Should the number of received Affidavits exceed the Administrative Limit, Company shall prorate any remaining processing capacity among all agents submitting Affidavits on the day. Company shall list customers according to an agent's preferred ranking, if provided, unless operational concerns prevent the desired priority. Affidavits properly received and not processed in the current month shall be given priority in the following month in the order received by Company and ahead of any subsequent Affidavits.

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11. **Pipeline System Restrictions and Priorities**

11.01 **Conditions Requiring Restriction in Service**

11.01.01 **Service Restriction**: Company may fully or partially restrict service to customers when, in Company's sole determination, restriction is necessary to protect the supply and/or delivery of gas to customers with higher priority uses.

11.01.02 **Operational Request**: Company may fully or partially restrict customer to accommodate for operational repairs and maintenance on Company's pipeline system.

11.02 **Notice**: Notice of an operational request may be provided as Company warrants and a Critical Notice of a service restriction shall be provided as far in advance as practicable and may be changed by Company as conditions warrant. Critical Notice shall be given to each affected customer by either telephone, in writing, facsimile or, electronic mail. Customers shall designate one or more person for Company to contact on operational matters at any time on a 24-hour a day, 365 days a year basis. Such contact person must have adequate authority and expertise to handle such operational matters. If Company is unable to contact any Customer because the contact person(s) is unavailable or the Customer has failed to provide such contact, the Customer shall be solely responsible for any consequences arising from such failure of communications.

Notification of the customer's agent shall fulfill the requirement of this paragraph whenever the customer's usage is aggregated for balancing under Section 10.04 Aggregation.

During emergency situations, Company may use commercial radio and/or television to notify customers.

11.03 **Critical Use Periods**: Company may issue an Operational Flow Order (OFO) whenever necessary to instruct customers to control their usage to avoid either Under-Deliveries or Over-Deliveries.

11.03.01 **Standard OFO**: A Standard OFO shall require the customer to take pre-emptive or preventive actions and/or measures in order to neutralize or reduce threats to, or to otherwise preserve the integrity of all or a portion of Company's system, or to insure compliance with the requirements of upstream pipeline companies.

11.03.02 **Emergency OFO**: An Emergency OFO shall require the customer to take immediate actions and/or measures in order to neutralize or reduce threats to, or to otherwise preserve the integrity of all or a portion of Company's system, or to insure compliance with the requirements of upstream pipeline companies.

11.03.03 **Authorized Usage**: A transportation service customer's authorized usage during an OFO shall be equal to that customer's retainage adjusted confirmed nomination.

11.03.04 **Interrupted Supply**: Whenever a transportation service customer's supply is partially or totally interrupted for any reason, that customer's authorized usage shall be limited to the retainage adjusted volume being delivered to Company on behalf of that customer.

11.03.05 **Curtailment of Transportation Service**: A transportation service customer shall not be required to curtail as long as the customer's gas is delivered to Company's delivery system, except during Supply Emergencies subject to the conditions of Section 11.04.06 Company's Right to Purchase Transportation Gas.

11.04 **Period of Curtailment**: Company may require its sales service and transportation service customers to limit, in whole or in part, their use of Company's facilities during a Period of Curtailment (POC), taking into consideration priority of use or other factors it deems necessary to ensure public health and safety.

11.04.01 **Authorized Usage**: Company shall, at its sole discretion, authorize customers a usage level which is appropriate to the conditions of the POC.

11.04.02 **Curtailment Priority**: Curtailment shall first apply to the lowest priority category (Priority Category Three) and successively to each higher priority category as required. The categories to be used by Company to allocate available service, listed from highest to lowest priority, are:

Priority Category One: Customers served under Company's Residential Sales Service rate schedules and customers taking service the curtailment of which would endanger human life or safety. A customer shall not be considered endangered if an alternate fuel capability is feasible.

Priority Category Two: Customers not included in Priority Category One taking service under Company's General Sales Service or General Transportation Service rate schedules and customers taking service the curtailment of which would endanger property. A customer shall not be considered endangered if an alternate fuel capability is feasible.

Priority Category Three: Customers not included in other priority categories.

11.04.03 **Exception to Curtailment Priority**: Company may curtail customers in higher priority categories before curtailing customers in lower priority categories only if curtailing lower priority category customers would not be useful in maintaining deliveries to the higher priority customers.

11.04.04 **Allocation of Partial Capacity**: Should only partial service capacity be available for an affected category, deliveries within that category shall be limited to a customer's pro rata share of service available to that category. This share shall be based on the ratio of the customer's requirement in the category for which partial capacity is available to the sum of all customers' requirements in the same category.

11.04.05 **Alternate Fuel Capability**: Company shall determine if it is feasible for a customer to install and use alternate fuel capability. The customer is deemed to have alternate fuel capability if Company determines an installation is feasible whether or not facilities are actually installed. Disputes over Company's determination shall be referred to the Commission for resolution.

11.04.06 **Company's Right to Purchase Transportation Gas**: Company shall have the authority but not the requirement to purchase a transportation service customer's gas during any POC which restricts, or would otherwise restrict, Category One customers.

(1) **Notice**: Company shall use its best efforts to give the customer 24 hours advance notification of the need for any such purchase, but Company shall not be liable for failure to give advance notice when circumstances do not permit.

(2) **Reimbursement**: Company shall reimburse the customer an amount equal to the verifiable actual replacement cost of any alternative fuel used by the customer to replace natural gas purchased by Company. Company shall account for the reimbursement as a purchased gas expense.

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11.04.07 **Emergency Usage during POCs**: A customer may request to use gas above authorized levels to forestall irreparable injury to life or property. Requests by telephone shall be followed immediately by a written request. Written requests shall state the nature, cause, and expected duration of the emergency and may be submitted by facsimile or electronic mail. The customer must act to eliminate the cause of the emergency as soon as practicable. The charge for usage above authorized levels shall be determined at the time Company receives the customer's request. Disputes concerning this charge shall be referred to the Commission for resolution.

11.04.08 **Relief from Liability**: Company shall be relieved of all liabilities, penalties, charges, payments, and claims of whatever kind, contractual or otherwise, resulting from or arising out of Company's failure to deliver all or any portion of the volumes of gas desired by a customer or group of customers during a POC. Company's relief shall apply if curtailment is according to these General Terms and Conditions or any other orders or directives of duly constituted authorities including, but not limited to, the Kansas Corporation Commission.

11.05 **Unauthorized Deliveries**: Over-Deliveries and/or Under-Deliveries which vary from Company's authorized usage level under an OFO or during a POC, may be subject to the penalties described in Section 11.06 Penalties for Unauthorized Usage.

11.05.01 **Individual Customers**: Unauthorized Deliveries for individually balanced customers shall be calculated by comparing each customer's authorized usage with actual usage.

11.05.02 **Aggregation Groups**: Unauthorized Deliveries for aggregation groups subject to aggregated balancing as defined under Section 10.04 Aggregation, shall be calculated by comparing the group members' total authorized usage with their total actual usage. The actual usage of a customer which is included in more than one aggregation group shall be allocated between groups on a ratio of the customer's confirmed nominations.

11.05.03 **RDQ Balancing**: A transportation service customer may agree to deliver to Company, in lieu of Company's requirement to install EFM, a predetermined Required Daily Quantity (RDQ) of natural gas. Nominations based on assigned RDQ shall be subject to retainage.

(1) Qualification for RDQ Balancing: RDQ Balancing shall be available for

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transportation service meters recording a peak-month usage of less than 1,500 Mcf in the most recent 12 month period ending April 30. A customer accepting an RDQ shall remain eligible for transportation service without installing EFM. An RDQ-qualified customer shall be assigned to RDQ Balancing unless the customer notifies Company otherwise.

(2) **RDQ Administration**: An RDQ-balanced customer shall be notified of its assigned RDQ within 30 days after initiating transportation service. Company shall each year review the customer's most recent 12 month usage for the period ending April 30 and recalculate the customer's RDQ. Company shall, prior to August 1, notify the customer, and the customer's agent if aggregated for balancing purposes, of a revised RDQ, which shall be effective for the next 12 month period beginning November 1. The customer or customer's agent shall inform Company of any dispute over the RDQ within 30 days of their notification.

(3) **Unauthorized Over-Deliveries**: During POCs or when required by an OFO to prevent Over-Deliveries, a customer shall cause Company to receive natural gas in the amount of the RDQ. The customer may be subject to an Unauthorized Over-Delivery Penalty if Company receives less than 100% of the customer's assigned RDQ plus retainage.

(4) **Unauthorized Under-Deliveries**: When required by an OFO to prevent Under-Deliveries, a customer shall cause Company to receive an amount of natural gas equal to the lesser of their assigned RDQ times 30% plus retainage or their current confirmed nomination. The customer may be subject to the applicable Unauthorized Under-Delivery Penalty if Company receives more than the amount authorized by this paragraph.

(5) **Actual Usage of RDQ Customers**: Company shall not be required to read RDQ-balanced meters to implement the requirements of an OFO or POC, for which the customer's actual usage shall be deemed to equal the assigned RDQ. When calculating Unauthorized Over-Delivery Penalties for an aggregation group which includes both EFM meters and meters subject to RDQ Balancing, the aggregated nominations shall be applied to the aggregated RDQ meters first.

(6) **Temporary RDQ**: A customer may request a temporary revision of its

assigned RDQ. Company shall consider the request only if it is received prior to 72 hours after the occurrence of a significant event that would temporarily change the customer's usage during an OFO. Requests by telephone shall be followed immediately by a written request stating the nature, cause, and expected duration of the event. Company shall respond no later than 72 hours after the customer's written request. Any revised RDQ shall become effective upon Company's responding notification to the customer and shall continue for no more than 30 days or until the customer's operation has returned to normal, whichever occurs first. Company may, at its option and at the customer's request, extend the temporary RDQ for an additional period(s).

11.05.04 **Meter Reading**: Actual usage during an OFO shall normally be provided by electronic flow measurement (EFM) equipment. If Company is unable to obtain data from a customer's EFM device, the customer's usage shall be determined by actual meter reads.

11.05.05 **Previous Imbalances**: Gas imbalances from previous months shall not be allowed to offset any Unauthorized Over- or Under-Delivery.

11.05.06 **Refusal to Comply**: Company may disconnect from its system or refuse to accept the nomination of a customer which endangers system stability and/or safety by continuing to incur Unauthorized Deliveries.

11.06 **Penalties for Unauthorized Usage**: A customer's unauthorized usage under an OFO or POC may cause the incurrence of penalties.

11.06.01 **Tolerance Levels**: Penalties may be assessed:

(1) During an OFO or POC, when Unauthorized Deliveries to EFM meters exceed + or - 5% of authorized daily delivery levels.

(2) During an OFO or POC, when Unauthorized Over-Deliveries to RDQ meters are less than daily delivery levels or when Unauthorized Under-Deliveries exceed authorized daily delivery levels.

11.06.02 **Penalties during OFOs and POCs**: Penalties for Unauthorized Over-Deliveries or Under-Deliveries shall be calculated as follows.

(1) **Standard OFO Penalties**: For each day of the Standard OFO, the greater of $5 or 2½ times the daily midpoint stated on Gas Daily's Index for Southern Star Central Gas Pipelines (Oklahoma) times the

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MMBtu of Unauthorized Over- or Under-Deliveries that exceed the tolerance level applicable under Section 11.06.01.

(2) **Emergency OFO Penalties**: For each day of the Emergency OFO, the greater of $10 or 5 times the daily midpoint stated on Gas Daily's Index for Southern Star Central Gas Pipelines (Oklahoma) times the MMBtu of Unauthorized Over- or Under-Deliveries that exceed the tolerance level applicable under Section 11.06.01.

(3) **POC Penalties**: For each day of the POC, the greater of $20 or 10 times the daily midpoint stated on Gas Daily's Index for Southern Star Central Gas Pipelines (Oklahoma) times the MMBtu of Unauthorized Over- or Under-Deliveries that exceed the tolerance level applicable under Section 11.06.01.

11.06.03 **Responsibility for Payment**: Unauthorized Over- or Under-Delivery Penalties for individually balanced customers shall be billed to and collected from the applicable customer. Unauthorized Over- or Under-Delivery Penalties for aggregation groups shall be billed to and collected from the agent representing the aggregated customers.

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12. **Statement of Miscellaneous Charges and Amounts:**

		Reference Section	Amount
12.01	Service Initiation Charge	2.13.01	$ 5.00
12.02	Meter Reading Charge	4.03.02 and 4.04.02	$ 10.00
12.03	Credit Due Amount	4.05.01	$ 10.00
12.04	Bill Error Amount	4.05.02	$ 2.00
12.05	Collection or Disconnection Charge	5.08	$ 10.00
12.06	Reconnection Charge	5.09	$ 15.00
12.07	Insufficient Funds Check Charge	4.01.05	$ 30.00
12.08	Insufficient Funds Service Charge	4.01.05	$ 30.00
12.09	Adjusted Bill Amount	4.05.01 and 9.02.05	$ 2.00
12.10	Meter Test Fee	9.02.04	$ 40.00
12.11	Base Residential Usage	8.01.07(4)(a)	138 Mcf
12.12	Credit/Debit/ATM Card Fee per transaction up to and including $500	4.01.05(4)	$ 2.13
12.13	Diversion Reconnection Charge	5.09	$ 55.00

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Residential Sales Service

Availability

Available in and around the communities specified in the Index to residential customers at single locations. Service is subject to the Definitions and Conditions section below.

Net Monthly Bill

$ 20.45	Service Charge, plus
	Applicable adjustments and charges provided in Company's Gas System Reliability Surcharge, plus
$ 2.1262	Delivery Charge per Mcf for all gas delivered, plus
	Applicable adjustments and charges provided in Company's Cost of Gas Rider, Weather Normalization Adjustment Rider and Ad Valorem Tax Surcharge Rider.

The Net Monthly Bill shall be no less than the Service Charge plus any minimum charges set forth in a customer's Service Agreement.

Definitions and Conditions

1. Sales service under this rate schedule is available to residential customers for use by the customer as provided for in Company's General Terms and Conditions for Gas Service.
2. Sales service is provided for the charge specified in the Net Monthly Bill when supplied from Company's existing facilities. When additional facilities are needed to serve a customer, an additional charge may be required.
3. Sales service under this rate schedule is subject to the provisions and applicable charges contained in Company's General Terms and Conditions for Gas Service, or successor documents, approved by the Commission.
4. All provisions of this rate schedule are subject to changes made by order of the Commission.

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General Sales Service Small

Availability

Available in and around the communities specified in the Index to nonresidential customers at single locations. Not available for service to separately metered generators with a capacity less than 20 kilowatts. Service is subject to the Definitions and Conditions section below.

Net Monthly Bill

$28.65	Service Charge, plus
	Applicable adjustments and charges provided in Company’s Gas System Reliability Surcharge, plus
$2.1262	Delivery Charge per Mcf for all gas delivered, plus
	Applicable adjustments and charges provided in Company's Cost of Gas Rider, Weather Normalization Adjustment Rider and Ad Valorem Tax Surcharge Rider.

The Net Monthly Bill shall be no less than the Service Charge plus any minimum charges set forth in a customer’s Service Agreement.

Definitions and Conditions

1. Annual deliveries less than 200 Mcf at an individual meter during the last 12 billing periods shall qualify a customer for service under this rate schedule.
2. If a customer does not select a general service rate schedule for which it may qualify, Company may select the applicable general service rate schedule on the customer’s behalf. A customer may change the general service rate schedule which the customer is being billed during the first 12 months of service under the selected rate schedule. Thereafter, the customer is prohibited from making more than one change in a 12-month period.
3. Sales service is provided for the charge specified in the Net Monthly Bill section when supplied from Company's existing facilities. When additional facilities are needed to serve a customer, an additional charge may be required.
4. Multiple meter installations, installed at a single location for a customer's convenience, shall be billed additional Service Charges for each additional meter installation.
5. Sales service under this rate schedule is subject to the provisions and applicable charges contained in Company’s General Terms and Conditions for Gas Service, or successor documents, approved by the Commission.
6. All provisions of this rate schedule are subject to changes made by order of the Commission.

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General Sales Service Large

Availability
Available in and around the communities specified in the Index to nonresidential customers at single locations. Not available for service to separately metered generators with a capacity less than 20 kilowatts. Service is subject to the Definitions and Conditions section below.

Net Monthly Bill

$36.00	Service Charge, plus
	Applicable adjustments and charges provided in Company’s Gas System Reliability Surcharge, plus
$1.6819	Delivery Charge per Mcf for all gas delivered, plus
	Applicable adjustments and charges provided in Company's Cost of Gas Rider, Weather Normalization Adjustment Rider and Ad Valorem Tax Surcharge Rider.

The Net Monthly Bill shall be no less than the Service Charge plus any minimum charges set forth in a customer’s Service Agreement.

Definitions and Conditions
1. Annual deliveries between 200 and 1,500 Mcf at an individual meter during the last 12 billing periods shall qualify a customer for service under this rate schedule.
2. If a customer does not select a general service rate schedule for which it may qualify, Company may select the applicable general service rate schedule on the customer’s behalf. A customer may change the general service rate schedule which the customer is being billed during the first 12 months of service under the selected rate schedule. Thereafter, the customer is prohibited from making more than one change in a 12-month period.
3. Sales service is provided for the charge specified in the Net Monthly Bill section when supplied from Company's existing facilities. When additional facilities are needed to serve a customer, an additional charge may be required.
4. Multiple meter installations, installed at a single location for a customer's convenience, shall be billed additional Service Charges for each additional meter installation.
5. Sales service under this rate schedule is subject to the provisions and applicable charges contained in Company’s General Terms and Conditions for Gas Service, or successor documents, approved by the Commission.
6. All provisions of this rate schedule are subject to changes made by order of the Commission.

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General Sales Service Transport Eligible

Availability

Available in and around the communities specified in the Index to nonresidential customers at single locations. Not available for service to separately metered generators with a capacity less than 20 kilowatts. Service is subject to the Definitions and Conditions section below.

Net Monthly Bill

$60.00	Service Charge, plus
	Applicable adjustments and charges provided in Company's Gas System Reliability Surcharge, plus
$1.4598	Delivery Charge per Mcf for all gas delivered, plus
	Applicable adjustments and charges provided in Company's Cost of Gas Rider, Weather Normalization Adjustment Rider and Ad Valorem Tax Surcharge Rider.

The Net Monthly Bill shall be no less than the Service Charge plus any minimum charges set forth in a customer's Service Agreement.

Definitions and Conditions

1. Annual deliveries great than 1,500 Mcf at an individual meter during the last 12 billing periods shall qualify a customer for service under this rate schedule.
2. If a customer does not select a general service rate schedule for which it may qualify, Company may select the applicable general service rate schedule on the customer's behalf. A customer may change the general service rate schedule which the customer is being billed during the first 12 months of service under the selected rate schedule. Thereafter, the customer is prohibited from making more than one change in a 12-month period.
3. Sales service is provided for the charge specified in the Net Monthly Bill section when supplied from Company's existing facilities. When additional facilities are needed to serve a customer, an additional charge may be required.
4. Multiple meter installations, installed at a single location for a customer's convenience, shall be billed additional Service Charges for each additional meter installation.
5. Sales service under this rate schedule is subject to the provisions and applicable charges contained in Company's General Terms and Conditions for Gas Service, or successor documents, approved by the Commission.
6. All provisions of this rate schedule are subject to changes made by order of the Commission.

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As-Available Gas Sales Service

Available
At points designated by a customer and accepted by Company.

Applicable
Upon election of a customer and acceptance by Company, this rate is applicable to contract natural gas sales service supplied to customers with a maximum daily quantity (MDQ) for sales gas hereunder equal to or in excess of 5,000 MMBtu per day and which otherwise meet the qualifications of this rate schedule.

As-Available Gas Sales Service is not available to a customer who has purchased natural gas under one of Company's other rate schedules during the preceding 12 months or who, in the event of a curtailment of service hereunder, would seek natural gas sales service from Company under an alternative rate schedule.

Rates
The rates for service hereunder shall be negotiated between a customer and Company.

Cost of Gas Offsets
Service under this schedule is not subject to Company's Cost of Gas Rider (COGR); however, with respect to the revenue collected under this schedule, certain amounts shall be used to reduce the cost of purchased gas and purchased transportation services for Company's other customers taking sales service who are subject to the COGR. Such amounts shall be the sum of:

(a) 100% of the incremental cost of transportation services purchased by Company to deliver the as-available sales gas hereunder,

(b) 100% of the incremental cost of gas purchased by Company for resale to AAGS customers,

(c) 90% of all revenues collected from customers hereunder after excluding items (a) and (b) above.

The incremental cost of transportation services purchased by Company to deliver the as-available sales gas shall be the cost of transportation services which, except for this as-available sales service, would not have been purchased by Company to supply customers subject to Company's COGR.

The incremental cost of gas, including the cost of the associated fuel use, purchased by Company for resale to a customer shall be the cost of gas which, except for this as-available sales service, would not have been purchased by Company to supply customers subject to Company's COGR.

The revenues collected from customers pursuant to this schedule, less amounts used for COGR offsets as described above, shall remain with Company without further obligation to refund or credit, in any form, such revenue to its customers.

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As-Available Gas Sales Service

Definitions and Conditions

1. Unless otherwise agreed by Company and a customer, the customer shall be required to nominate its requirements for as-available gas service for each day of a billing month at least 5 business days prior to the beginning of the billing month. The customer may revise any daily nomination prior to 48 hours before the subject day begins. Unless Company otherwise notifies the customer at least 36 hours before the beginning of a day, the customer's nomination for that day shall be accepted subject to any curtailment orders that Company may later issue.
2. A customer shall make all reasonable efforts to take gas at a uniform rate each day equal to the nomination authorized for that day. Unless otherwise agreed by Company, the failure of the customer on any day to take an amount of gas equal to the nomination in effect for that day shall subject the customer to interruption or cancellation of service and penalties of $25.00 per MMBtu for each MMBtu above or below the nomination, plus any costs incurred by Company because of the customer's failure to purchase the amount of gas authorized by Company.
3. Deliveries of as-available sales gas hereunder may be curtailed at any time Company determines it has insufficient volumes of such gas to sell or has insufficient capacity to transport such gas. Company may also curtail or otherwise deny service hereunder at any time Company determines that the purchase and delivery of as-available gas is uneconomic or impedes its system planning or operations in any manner. In the event of a curtailment, the customer shall immediately conform its purchase of as-available gas to the level specified by Company. Company shall provide as much advance notice of curtailment to the customer as practicable. The customer shall be liable for any demand charge, standby charge, reservation charge, overrun penalty or any other charge or penalty attributable to the customer's failure to conform its purchase to the level specified by Company as such charges or penalties may be billed to Company by Company's gas supplier(s) and/or transporter(s). In addition, the customer shall be subject to a penalty of $25.00 per MMBtu for each MMBtu taken in excess of the authorized amount during curtailment.
4. Company shall be bound to sell as-available natural gas hereunder only to the extent it agrees to do so and shall not be liable for loss or damage to a customer in the event of a refusal to make such sales, or for any curtailment of such sales.
5. Service hereunder is further subject to Company's General Terms and Conditions for Gas Service (GT&C) as approved by the Commission. In the event of conflict between this rate schedule and Company's GT&C, this rate schedule shall control.

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Small Generator Sales Service

Availability
Available to nonresidential customers at single locations in and around the communities specified in the Index for separately metered electric generators. Service is subject to the Definitions and Conditions section below.

Net Monthly Bill

$52.20	Service Charge, plus
	Applicable adjustments and charges provided in Company's Gas System Reliability Surcharge, plus
$0.6427	Delivery Charge per Mcf for all gas delivered, plus
	Applicable adjustments and charges provided in Company's Cost of Gas Rider, Weather Normalization Adjustment Rider and Ad Valorem Tax Surcharge Rider.

The Net Monthly Bill shall be no less than the Service Charge plus any minimum charges set forth in a customer's Service Agreement.

Definitions and Conditions
1. Sales service is provided for the charge specified in the Net Monthly Bill section when supplied from Company's existing facilities. When additional facilities are needed to serve a customer, an additional charge may be required.
2. Sales service under this rate schedule is subject to the provisions and applicable charges contained in Company's General Terms and Conditions for Gas Service, or successor documents, approved by the Commission.
3. All provisions of this rate schedule are subject to changes made by order of the Commission.

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Kansas Gas Supply Sales Service D

Availability
Available to customers which were served under this tariff on September 15, 2003, and which continue to be served hereunder. Service is subject to the Definitions and Conditions section below.

Net Monthly Bill

$350.00	Service Charge, plus
	Applicable adjustments and charges provided in Company's Gas System Reliability Surcharge, plus
$0.8673	Delivery Charge per Mcf for all gas delivered, plus
	Applicable adjustments and charges provided in Company's Cost of Gas Rider and Ad Valorem Tax Surcharge Rider.

Definitions and Conditions
1. Service shall be provided only from Company's existing facilities. When additional facilities are needed to serve customer, an additional charge may be needed.
2. Service under this rate schedule is subject to the provisions and applicable charges contained in Company's General Terms and Conditions for Gas Service, or successor documents, approved by the Commission.
3. All provisions of this rate schedule are subject to changes made by order of the Commission.

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Gas Irrigation Sales Service

Availability
Available in and around the communities specified in the Index to nonresidential customers at single locations for the purpose of crop irrigation. Service is subject to the Definitions and Conditions section below.

Net Monthly Bill

$36.00	Service Charge, plus
	Applicable adjustments and charges provided in Company’s Gas System Reliability Surcharge, plus
$1.6819	Delivery Charge per Mcf for all gas delivered, plus
	Applicable adjustments and charges provided in Company's Cost of Gas Rider and Ad Valorem Tax Surcharge Rider.

The Net Monthly Bill shall be no less than the Service Charge plus any minimum charges set forth in a customer’s Service Agreement.

Definitions and Conditions
1. Sales service is provided for the charge specified in the Net Monthly Bill section when supplied from Company's existing facilities. When additional facilities are needed to serve a customer, an additional charge may be required.
2. Multiple meter installations, installed at a single location for a customer's convenience, shall be billed additional Service Charges for each additional meter installation.
3. Service under this rate schedule is subject to the provisions and applicable charges contained in Company’s General Terms and Conditions for Gas Service, or successor documents, approved by the Commission.
4. All provisions of this rate schedule are subject to changes made by order of the Commission.

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Sales Service for Resale

Availability

Available to utilities and municipal gas systems at single locations for gas for resale outside Company's service territory. Service is subject to Definitions and Conditions below**.**

Net Monthly Bill

$85.00	Service Charge, plus
	Applicable adjustments and charges provided in Company's Gas System Reliability Surcharge, plus
$1.2497	Delivery Charge per Mcf for all gas delivered, plus
	Applicable adjustments and charges provided in Company's Cost of Gas Rider and Ad Valorem Tax Surcharge Rider.

The Net Monthly Bill shall be no less than the Service Charge plus any minimum charges set forth in a customer's Service Agreement.

Definitions and Conditions

1. Sales service is provided for the charge specified in the Net Monthly Bill section when supplied from Company's existing facilities. When additional facilities are needed to serve a customer, an additional charge may be required.
2. Multiple meter installations, installed at a single location for a customer's convenience, shall be billed additional Service Charges for each additional meter installation.
3. Service under this rate schedule is subject to the provisions and applicable charges contained in Company's General Terms and Conditions for Gas Service, or successor documents, approved by the Commission.
4. All provisions of this rate schedule are subject to changes made by order of the Commission.

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Small Transportation Service

Availability

Available in and around the communities specified in the Index to nonresidential customers. Service is subject to the Definitions and Conditions section below.

Net Monthly Bill

$60.00	Service Charge, plus
	Applicable adjustments and charges provided in Company’s Gas System Reliability Surcharge, plus
$1.4598	Delivery Charge per Mcf for all gas delivered, plus
	Applicable adjustments and charges provided in Company's Ad Valorem Tax Surcharge Rider.

The Net Monthly Bill shall be no less than the Service Charge plus any minimum charges set forth in a customer’s Service Agreement.

Definitions and Conditions

1. Annual deliveries of at least 1,500 Mcf at a single location during the last 12 billing periods shall qualify a customer for service under this schedule. A customer, once qualified, shall remain eligible for service under this schedule.
2. A customer shall meet all conditions of the following tariffs to maintain service under this rate schedule:
   a. Electronic Flow Measurement Rider
   b. Company's General Terms and Conditions for Gas Service (GTC), Section 10 Requirements for Transportation Service.
3. Company may base a bill on a customer’s normal meter reading cycle, but may issue that bill at the beginning of the next billing month. Although the bill may indicate a different period, it shall reflect actual information obtained from the regular-cycle meter reading. A customer served under this rate schedule and who desires a calendar month-based bill must install electronic flow measurement equipment and will not be eligible for RDQ balancing.
4. Service under this rate schedule shall be terminated upon notification by the customer, but not before the next regular-cycle meter reading date.
5. Transportation service is provided for the charge specified in the Net Monthly Bill section when supplied from Company's existing facilities. When additional facilities are needed to serve a customer, an additional charge may be required.

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Small Transportation Service

6. Multiple meter installations, installed at a single location for a customer's convenience, shall be billed additional Service Charges for each additional meter installation. Usage recorded on these multiple meters shall be aggregated for purposes of qualifying for this rate schedule.
7. Transportation service under this rate schedule is subject to the provisions and applicable charges contained in Company's GTC, or successor documents, approved by the Commission.
8. All provisions of this rate schedule are subject to changes made by order of the Commission.

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Small Transportation Service

Availability

Available in and around the communities specified in the Index to nonresidential customers. Service is subject to the Definitions and Conditions section below**.**

Net Monthly Bill

$60.00	Service Charge, plus
	Applicable adjustments and charges provided in Company's Gas System Reliability Surcharge, plus
$1.9170	Delivery Charge per Mcf for all gas delivered, plus
	Applicable adjustments and charges provided in Company's Ad Valorem Tax Surcharge Rider.

The Net Monthly Bill shall be no less than the Service Charge plus any minimum charges set forth in a customer's Service Agreement.

Definitions and Conditions

1. Annual deliveries of at least 1,500 Mcf at a single location during the last 12 billing periods shall qualify a customer for service under this schedule. A customer, once qualified, shall remain eligible for service under this schedule.
2. A customer shall meet all conditions of the following tariffs to maintain service under this rate schedule:
   a. Electronic Flow Measurement Rider
   b. Company's General Terms and Conditions for Gas Service (GTC), Section 10 Requirements for Transportation Service.
3. Company may base a bill on a customer's normal meter reading cycle, but may issue that bill at the beginning of the next billing month. Although the bill may indicate a different period, it shall reflect actual information obtained from the regular-cycle meter reading. A customer served under this rate schedule and who desires a calendar month-based bill must install electronic flow measurement equipment and will not be eligible for RDQ balancing.
4. Service under this rate schedule shall be terminated upon notification by the customer, but not before the next regular-cycle meter reading date.
5. Transportation service is provided for the charge specified in the Net Monthly Bill section when supplied from Company's existing facilities. When additional facilities are needed to serve a customer, an additional charge may be required.

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Small Transportation Service

6. Multiple meter installations, installed at a single location for a customer's convenience, shall be billed additional Service Charges for each additional meter installation. Usage recorded on these multiple meters shall be aggregated for purposes of qualifying for this rate schedule.
7. Transportation service under this rate schedule is subject to the provisions and applicable charges contained in Company's GTC, or successor documents, approved by the Commission.
8. All provisions of this rate schedule are subject to changes made by order of the Commission.

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Large Volume Transportation Service

Availability
Available in and around the communities specified in the Index to nonresidential customers. Service is subject to the Definitions and Conditions section below**.**

Net Monthly Bill
Service Charge:

$208.00	Tier 1 (Annual Use: Below 10,000 Mcf)
$252.00	Tier 2 (Annual Use: 10,001-20,000 Mcf)
$323.00	Tier 3 (Annual Use: 20,001-40,000 Mcf)
$392.00	Tier 3 (Annual Use: Above 40,001 Mcf) plus, for each Tier
	Applicable adjustments and charges provided in Company's Gas System Reliability Surcharge, plus
$0.8714	Delivery Charge (applicable to all Tiers) per Mcf for all gas delivered, plus
	Applicable adjustments and charges provided in Company's Ad Valorem Tax Surcharge Rider.

The Net Monthly Bill shall be no less than the Service Charge plus any minimum charges set forth in a customer's Service Agreement.

Definitions and Conditions

1. Peak delivery of at least 1,500 Mcf at a single location during any of the last 12 billing periods shall qualify a customer for service under this schedule. Qualification for this rate schedule shall be reviewed by June 1 of each year. A customer may be removed from this rate schedule effective each November 1 if the customer's peak delivery during the 12 most recent billing periods ending April 30 is less than 1,500 Mcf. The customer so removed shall receive transportation service under the rate schedule applicable to the customer's reduced requirement. The customer shall be returned to this rate schedule, upon request, after re-establishing a peak delivery of at least 1,500 Mcf.
2. Annual Use shall be the total volumes billed to the applicable meter in the most recent 12 month billing period ending April 30. Company may rely on estimated historical usage or projected volumes to establish Annual Use when actual usage is not available.
3. A customer shall meet all conditions of the following tariffs to maintain service under this rate schedule:
   a. Electronic Flow Measurement Rider
   b. Company's General Terms and Conditions for Gas Service (GTC), Section 10 Requirements for Transportation Service.

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Large Volume Transportation Service

4. The Delivery Charge may be reduced by Company to meet a competitive alternative to Company’s transportation service. The customer shall be required to sign a special agreement listing the reduced charge, term of service and other conditions of the service to be provided to the customer. Discounts shall be subject to the following conditions:
   a. The rate reduction must be necessary to retain or obtain a customer who has a credible competitive alternative available.
   b. The amount of the discount from the maximum approved tariff rate must be the least necessary to retain or obtain the customer.
   c. Under the discounted rate, the customer must, at a minimum, cover all incremental costs of serving that customer, plus make a contribution to common fixed costs.
   d. Company’s decision to enter into a discounted service agreement and the amount of the discount shall be subject to review at Company’s next rate case.
   e. In situations where the discounted service agreement involves a Company affiliate, Company shall file with the Commission a copy of the agreement with all supporting documentation and worksheets, within 10 days of the date of the agreement.
5. Transportation service is provided for the charge specified in the Net Monthly Bill section when supplied from Company's existing facilities. When additional facilities are needed to serve a customer, an additional charge may be required.
6. Multiple meter installations, installed at a single location for a customer's convenience, shall be billed additional Service Charges for each additional meter installation. Usage recorded on these multiple meters shall be aggregated for purposes of qualifying for this rate schedule.
7. Transportation service under this rate schedule is subject to the provisions and applicable charges contained in Company's GTC or successor documents, approved by the Commission.
8. All provisions of this rate schedule are subject to changes made by order of the Commission.

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Large Volume Transportation Service

Availability

Available in and around the communities specified in the Index to nonresidential customers. Service is subject to the Definitions and Conditions section below**.**

Net Monthly Bill

Service Charge:

$288.00	Tier 1 (Annual Use: Below 10,000 Mcf)
$367.00	Tier 2 (Annual Use: 10,001-20,000 Mcf)
$495.00	Tier 3 (Annual Use: 20,001-40,000 Mcf)
$621.00	Tier 3 (Annual Use: Above 40,001 Mcf) plus, for each Tier
	Applicable adjustments and charges provided in Company’s Gas System Reliability Surcharge, plus
$1.3103	Delivery Charge (applicable to all Tiers) per Mcf for all gas delivered, plus
	Applicable adjustments and charges provided in Company's Ad Valorem Tax Surcharge Rider.

The Net Monthly Bill shall be no less than the Service Charge plus any minimum charges set forth in a customer’s Service Agreement.

Definitions and Conditions

1. Peak delivery of at least 1,500 Mcf at a single location during any of the last 12 billing periods shall qualify a customer for service under this schedule. Qualification for this rate schedule shall be reviewed by June 1 of each year. A customer may be removed from this rate schedule effective each November 1 if the customer’s peak delivery during the 12 most recent billing periods ending April 30 is less than 1,500 Mcf. The customer so removed shall receive transportation service under the rate schedule applicable to the customer’s reduced requirement. The customer shall be returned to this rate schedule, upon request, after re-establishing a peak delivery of at least 1,500 Mcf.
2. Annual Use shall be the total volumes billed to the applicable meter in the most recent 12 month billing period ending April 30. Company may rely on estimated historical usage or projected volumes to establish Annual Use when actual usage is not available.
3. A customer shall meet all conditions of the following tariffs to maintain service under this rate schedule:
   a. Electronic Flow Measurement Rider
   b. Company’s General Terms and Conditions for Gas Service (GTC), Section 10 Requirements for Transportation Service.

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Large Volume Transportation Service

4. The Delivery Charge may be reduced by Company to meet a competitive alternative to Company’s transportation service. The customer shall be required to sign a special agreement listing the reduced charge, term of service and other conditions of the service to be provided to the customer. Discounts shall be subject to the following conditions:

   a. The rate reduction must be necessary to retain or obtain a customer who has a credible competitive alternative available.

   b. The amount of the discount from the maximum approved tariff rate must be the least necessary to retain or obtain the customer.

   c. Under the discounted rate, the customer must, at a minimum, cover all incremental costs of serving that customer, plus make a contribution to common fixed costs.

   d. Company’s decision to enter into a discounted service agreement and the amount of the discount shall be subject to review at Company’s next rate case.

   e. In situations where the discounted service agreement involves a Company affiliate, Company shall file with the Commission a copy of the agreement with all supporting documentation and worksheets, within 10 days of the date of the agreement.

5. Transportation service is provided for the charge specified in the Net Monthly Bill section when supplied from Company's existing facilities. When additional facilities are needed to serve a customer, an additional charge may be required.

6. Multiple meter installations, installed at a single location for a customer's convenience, shall be billed additional Service Charges for each additional meter installation. Usage recorded on these multiple meters shall be aggregated for purposes of qualifying for this rate schedule.

7. Transportation service under this rate schedule is subject to the provisions and applicable charges contained in Company's GTC or successor documents, approved by the Commission.

8. All provisions of this rate schedule are subject to changes made by order of the Commission.

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Wholesale Transportation Service

Availability
Available to utilities and municipal gas systems at single locations on Company’s transmission system for transportation of gas for resale outside Company's service territory. Service is subject to the Definitions and Conditions section below.

Net Monthly Bill

$85.00	Service Charge, plus
	Applicable adjustments and charges provided in Company’s Gas System Reliability Surcharge Rider, plus
$1.2497	Delivery Charge per Mcf for all gas delivered, plus
	Applicable adjustments and charges provided in Company’s Ad Valorem Tax Surcharge Rider.

The Net Monthly Bill shall be no less than the Service Charge plus any minimum charges set forth in a customer’s Service Agreement.

Definitions and Conditions
1. Annual deliveries of at least 3,000 Mcf at a single location during the last 12 billing periods shall qualify a customer for service under this schedule. A customer, once qualified, shall remain eligible for service under this schedule.
2. A customer shall meet all conditions of the following tariffs to maintain service under this rate schedule:
   a. Electronic Flow Measurement Rider
   b. Company's General Terms and Conditions for Gas Service (GTC), Section 10, Requirements for Transportation Service.
3. The Delivery Charge may be reduced by Company to meet a competitive alternative to Company's delivery service. The customer shall be required to sign a special agreement listing the reduced charge, term of service and other conditions of the service to be provided to the customer. Discounts shall be subject to the following conditions:
   a. The rate reduction must be necessary to retain or obtain a customer who has a credible competitive alternative available.
   b. The amount of the discount from the maximum approved tariff rate must be the least necessary to retain or obtain the customer.
   c. Under the discounted rate, the customer must, at a minimum, cover all incremental costs of serving that customer, plus make a contribution to common fixed costs.

Wholesale Transportation Service

d. Company's decision to enter into a discounted service agreement and the amount of the discount shall be subject to review at Company's next rate case.

e. In situations where the discounted service agreement involves a Company affiliate, Company shall file with the Commission a copy of the agreement with all supporting documentation and worksheets, within 10 days of the date of the agreement.

4. Transportation service is provided for the charge specified in the Net Monthly Bill section when supplied from Company's existing facilities. When additional facilities are needed to serve a customer, an additional charge may be required.

5. Multiple meter installations, installed at a single location for a customer's convenience, shall be billed additional Service Charges for each meter installation. Usage recorded on these multiple meters shall be aggregated for purposes of qualifying for this rate schedule.

6. Transportation service under this rate schedule is subject to the provisions and applicable charges contained in Company's GTC, or successor documents, approved by the Commission.

7. All provisions of this rate schedule are subject to changes made by order of the Commission.

Interruptible Gas Transportation Service

Availability
Available at points on the Company's integrated gas transmission system for natural gas transportation service under contract to customers not relying on Company for continuous service. Transportation service is not available under this schedule where such service would replace or otherwise be a substitute for service under another of Company's approved tariffs.

Net Monthly Bill
Service under this schedule shall be at a negotiated rate not less than Company's variable cost of providing the service but not exceeding the maximum Delivery Charge rate set forth in Rate Schedule WTt.

Definitions and Conditions
1. Service under this schedule is provided under the provisions of a contract between Company and customer, on a temporary, as-available basis and only when service can be supplied without impairment of service to Company's other customers.
2. Company and customer may enter into a Base Contract defining performance standards which are acceptable to both parties. Pricing may be reflected on daily "deal sheets" to ensure a timely response to market-based rates.
3. Transportation service under this schedule is not available when it would replace or otherwise be a substitute for service under Company's other retail or wholesale sales and/or transportation tariffs.
4. Service under this rate schedule is subject to the provisions and applicable charges contained in Company's General Terms and Conditions for Gas Service, or successor documents, approved by the Commission.
5. All provisions of this rate schedule are subject to changes made by order of the Commission.

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Gas Irrigation Transportation Service

Availability

Available in and around the communities specified in the Index to nonresidential customers at single locations for the purpose of crop irrigation. Service is subject to the Definitions and Conditions section below**.**

Net Monthly Bill

$36.00	Service Charge, plus
	Applicable adjustments and charges provided in Company's Gas System Reliability Surcharge Rider, plus
$1.6819	Delivery Charge per Mcf for all gas delivered, plus
	Applicable adjustments and charges provided in Company's Ad Valorem Tax Surcharge Rider

The Net Monthly Bill shall be no less than the Service Charge plus any minimum charges set forth in a customer's Service Agreement.

Definitions and Conditions

1. Qualification for this rate schedule shall be determined by the customer's use of the natural gas delivered thereunder and for crop irrigation. No minimum usage shall be required to qualify for transportation service under this rate schedule.
2. Company may base a bill on a customer's normal meter reading cycle, but may issue that bill at the beginning of the next billing month. Although the bill may indicate a different period, it shall reflect actual information obtained from the regular-cycle meter reading.
3. Service under this rate schedule shall be terminated upon notification by the customer, but not before the next regular-cycle meter reading date.
4. The Delivery Charge may be reduced by Company to meet a competitive alternative to Company's delivery service. The customer shall be required to sign a special agreement listing the reduced charge, term of service and other conditions of the service to be provided to the customer. Discounts shall be subject to the following conditions:
   a. The rate reduction must be necessary to retain or obtain a customer who has a credible competitive alternative available.
   b. The amount of the discount from the maximum approved tariff rate must be the least necessary to retain or obtain the customer.
   c. Under the discounted rate, the customer must, at a minimum, cover all incremental costs of serving that customer, plus make a contribution to common fixed costs.

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Gas Irrigation Transportation Service

d. Company's decision to enter into a discounted service agreement and the amount of the discount shall be subject to review at Company's next rate case.

e. In situations where the discounted service agreement involves a Company affiliate, Company shall file with the Commission a copy of the agreement with all supporting documentation and worksheets, within 10 days of the date of the agreement.

5. Transportation service is provided for the charge specified in the Net Monthly Bill section when supplied from Company's existing facilities. When additional facilities are needed to serve a customer, an additional charge may be required.

6. Multiple meter installations, installed at a single location for a customer's convenience, shall be billed additional Service Charges for each meter installation. Usage recorded on these multiple meters shall be aggregated for purposes of qualifying for this rate schedule.

7. Transportation service under this rate schedule is subject to the provisions and applicable charges contained in Company's GTC, or successor documents, approved by the Commission.

8. All provisions of this rate schedule are subject to changes made by order of the Commission.

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Compressed Natural Gas General Transportation Service

Availability

Available in and around the communities specified in the Index to operators and retail distributors at single locations for the sole purpose of compressing natural gas for use as a fuel in vehicles. Service is subject to the Definitions and Conditions section below**.**

Net Monthly Bill

$60.00	Service Charge, plus
	Applicable adjustments and charges provided in Company's Gas System Reliability Surcharge Rider, plus
$0.8199	Delivery Charge per Mcf for all gas delivered, plus
	Applicable adjustments and charges provided in Company's Ad Valorem Tax Surcharge Rider

The Net Monthly Bill shall be no less than the Service Charge plus any minimum charges set forth in a customer's Service Agreement.

Definitions and Conditions

1. A customer shall meet all conditions of Company's General Terms and Conditions for Gas Service (GTC), Section 10 Requirements for Transportation Service, to maintain service under this rate schedule.
2. The Delivery Charge may be reduced by Company to meet a competitive alternative to Company's delivery service. The customer shall be required to sign a special agreement listing the reduced charge, term of service and other conditions of the service to be provided to the customer. Discounts shall be subject to the following conditions:
    a. The rate reduction must be necessary to retain or obtain a customer who has a credible competitive alternative available.
    b. The amount of the discount from the maximum approved tariff rate must be the least necessary to retain or obtain the customer.
    c. Under the discounted rate, the customer must, at a minimum, cover all incremental costs of serving that customer, plus make a contribution to common fixed costs.
    d. Company's decision to enter into a discounted service agreement and the amount of the discount shall be subject to review at Company's next rate case.
    e. In situations where the discounted service agreement involves a Company affiliate, Company shall file with the Commission a copy of the agreement with all supporting documentation and worksheets, within 10 days of the date of the agreement.

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Compressed Natural Gas General Transportation Service

3. Transportation service is provided for the charge specified in the Net Monthly Bill section when supplied from Company's existing facilities. When additional facilities are needed to serve a customer, an additional charge may be required.
4. Multiple meter installations, installed at a single location for a customer's convenience, shall be billed additional Service Charges for each meter installation. Usage recorded on these multiple meters shall be aggregated for purposes of qualifying for this rate schedule.
5. Transportation service under this rate schedule is subject to the provisions and applicable charges contained in Company's GTC, or successor documents, approved by the Commission.
6. All provisions of this rate schedule are subject to changes made by order of the Commission.

Cost of Gas Rider

Applicability

This rider is applicable to the RS, GSS, GSL, GSTE, SGS, KGSSD, GIS and SSR rate schedules. In addition, certain provisions of this rider may be applicable to customers taking service under Company's transportation rate schedules. Service is subject to the Definitions and Conditions section below**.**

Net Monthly Charge

1. All factors shall be calculated to the nearest $0.0001/Mcf. All charges set forth in the rate schedule under which the customer takes service shall also apply.
2. The Net Monthly Gas Charge shall be the charges, if any, for the volume (in Mcf) of sales service gas delivered to a customer during the billing period multiplied by the Net Gas Cost (NGC) on a rate area specific basis.
3. A separate monthly NGC shall be calculated for natural gas sold to the Company's Gas Irrigation Sales Service (GIS) customers which are served from a gas gathering system upon which they cannot transport and upon which the source of gas is limited to unprocessed supplies coming from wells connected to the gas gathering system.
    a. During the billing months of March through October, this separate NGC shall include only costs attributable to the specific gas supply, which the systemwide NGC shall not include. Notwithstanding other provisions of this Rider, this separate NGC shall not include charges or credits for unrelated supplier refunds, capacity release, as-available gas sales, line losses or the Gas Hedge Program.
    b. In the billing months of November through February, all customers shall be charged the systemwide NGC.
    c. Annual unrecovered gas billings attributable to customers served by this separate NGC shall be combined with the corresponding systemwide costs to calculate a systemwide uncollectible factor, which shall be a part of the separate NGC during the billing months of March through October.
4. Line Loss Limitation: In the event the line loss factor for the Computation Year exceeds the limit value of 4.00%, the Company shall compute the Base Gas Cost (BGC) using the 4.00% limit value rather than the actual value.

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Cost of Gas Rider

5. NGC shall be the sum of all factors described in this rider as determined by the formula:

NGC = BGC + ACA + SR + OC

Where:

BGC = Base Gas Cost. BGC shall be the projected weighted average cost of gas (per Mcf) purchased by Company from all supply sources. The annual projection and any revised projections throughout the Computation Year shall be calculated according to the formula:

$$\frac{P + E + S + G}{(.01)\ V}$$

Where:

P = The estimated total dollar cost of gas to be sold calculated by summing the products of: the most recent unit cost of purchased gas from each supplier and the estimated purchase volumes from each supplier, and the most recent unit cost of transportation services, as defined in 18 CFR 284 or as approved by the Commission, and the estimated transportation service to be purchased from each supplier.

This amount shall be reduced by the estimated dollar Cost of Gas Offsets from the As-Available Gas Sales schedule.

In the event that changes in the rates paid for purchased gas will take place within the Computation Year, as specified by contract provisions currently in effect, the estimated unit cost of purchased gas from each supplier or the estimated average unit cost of transportation services for the Computation Year may be used in the calculation in place of the most recent unit cost.

E = The estimated (positive or negative) net cost of exchange gas transactions expected to occur during the Computation Year. This item shall not include transactions related to gas in storage.

S = The estimated cost of gas to be withdrawn from storage and sold, during the Computation Year.

G = Estimated costs for gathering services provided to Company during the Computation Year.

V = The estimated volume of sales service gas in Mcf for the Computation Year.

ACA = Actual Cost Adjustment. The annual difference, if any, between the BGC projected for the preceding Computation Year and actual recoveries of costs of gas to meet sales service requirements shall be charged or credited through the ACA Factor.

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Cost of Gas Rider

a. The monthly differences between the BGC projected and actual recoveries of cost of gas shall be summed to produce a cumulative total under/over recovered cost at the end of each Computation Year. This balance, divided by the total volumes of sales service gas delivered during the preceding Computation Year, shall be the ACA Factor.

(1) Actual cost of gas shall exclude refunds.

(2) Cost of Gas recovered shall be the sum of BGC, ACA, and the actual Cost of Gas Offsets from the As-Available Gas Sales schedules.

(3) Unrecovered Gas Billings: Gas related costs calculated and billed to COGR customers, does not include transportation or other non-gas related customer accounts, which have been recorded as uncollectable during the preceding Computation Year, shall adjust the cumulative total under/over recovered cost used to calculate the ACA factor.

(a) The Unrecovered Gas Billings included in the annual ACA calculation will not include interest or collection fees/charges.

(b) Company's Unrecovered Gas Billing expenses attributable to charges under this COGR are included in the FERC Account No. 191.

b. The ACA Factor shall be filed with the Commission and applied to sales service gas beginning with the next monthly billing cycle. The ACA Factor shall remain in effect until superseded by a subsequent calculation.

SR = Supplier Refunds. Supplier Refunds of Company's payments in excess of those ultimately authorized by the governing regulatory body, including interest received, shall be credited to the refund reserve account~~s~~ and refunded to customers through the Supplier Refund factor.

a. The Supplier Refund factor shall be the amount credited to the refund reserve account. If the Supplier Refund factor is less than $0.0010/Mcf, the refund shall be held in the reserve account~~s~~ until the close of the current Computation Year, at which time it shall be applied to the total accumulated under/over recovery for the ACA calculation.

If the Supplier Refund factor is equal to or greater than $0.0010/Mcf, Company shall include the Supplier Refund factor as a negative adjustment to the cost of gas purchased by Company to meet sales service requirements. Any balance remaining in Company's refund reserve account~~s~~ upon completion of a refund shall be held until the close of the current Computation Year, at which time it shall be applied to the total accumulated under/over recovery for ACA calculation.

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Cost of Gas Rider

b. Company shall report to the Commission its intended Supplier Refund plan within 30 days after its receipt of each refund. The refund period shall generally be 12 months, except as lengthened or shortened by Company to avoid a total refund which is materially above or below the refundable amount.

c. Nothing contained herein shall preclude the Commission from modifying the Company's refund procedure on a case-by-case basis.

OC = Other Charges or Credits. Other Charges or credits shall be included as a separate component of the Cost of Gas and included only to the extent provided by a separate schedule, rider, or section of COGR, and approved by the Commission.

a. Overrun Penalties: Overrun penalties shall be separately accumulated. Company shall maintain a continuing monthly comparison of the actual penalties paid and the amount recovered from customers. The differences of the comparisons shall be accumulated to produce an Accumulated Penalty Balance. The Accumulated Penalty balance shall be reduced by the amount of Overrun Penalties credited to Electronic Flow Measurement (EFM) devices pursuant to EFMR rate schedule. An Accumulated Penalty Recovery Factor shall be calculated annually by dividing the accumulated balance of under/over recovered penalties by the volume of actual sales during the Computation Year. The Accumulated Penalty Recovery Factor shall be a component of the OC. The Accumulated Penalty Balance shall be adjusted by the monthly penalty under/over recovery.

b. Capacity Release: Company shall forecast the capacity release credits expected to be received during the Computation Year. Company shall then calculate an Estimated Capacity Release Factor by dividing 50% of the forecast by estimated sales during the same period. The Estimated Capacity Release Factor shall be a component of the OC. Company shall maintain a continuing monthly comparison of the actual capacity release credits received and the capacity release credits distributed. The differences of the comparisons shall be accumulated to produce an Accumulated Capacity Release Balance. An Accumulated Capacity Release Factor shall be calculated annually by dividing the accumulated balance of under/over distributed credits by the volume of actual sales during the Computation Year. The Accumulated Capacity Release Balance shall be adjusted by the monthly capacity release under/over disbursements.

c. Gas Hedge Program: Company shall operate its Gas Hedge Program pursuant to the Commission’s orders in Docket No. 05-KGSG-580-HED.

    (1) Cost and revenues associated with any purchase or sale of financial derivatives, the net balance of which shall not exceed the approved annual hedge budget amount, shall be recovered as the Hedge Recovery OC component during the months of April through October.

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Cost of Gas Rider

(a) The Hedge Recovery OC component shall be a volumetric charge calculated by dividing the projected net balance by the sales volumes projected to occur in the months of April through October.

(b) Company shall show the amounts collected from customers through the Hedge Recovery OC component as a separate line item on the customer's bill.

(2) Costs and revenues generated from the settlement of financial derivatives related to Gas Hedge Program sales shall be flowed back as the Hedge Settlement OC component during the months of November through March.

(a) The Hedge Settlement OC component shall be a volumetric charge or credit that is calculated each month from November through March by dividing the monthly estimated hedge payoff amount by the sales volumes projected to occur in that respective month. The estimated payoff amount shall be adjusted to the actual payoff amount in the following month's calculation.

(b) Company shall not be required to show the Hedge Settlement OC component as a separate line item on the customer's bill.

(3) The Hedge Program Year shall be the 12 months beginning with April and ending with March. Any variance remaining at the end of the Hedge Program Year shall be included in the subsequent Actual Cost Adjustment calculation.

Definitions and Conditions

1. All provisions set forth in the rate schedule under which a customer takes service apply to the extent they are not superseded by provisions of this rider.
2. The Computation Year, consisting of the 12 month period ending June 30, shall be the base period for calculation unless otherwise specified.
3. Appropriate Net Gas Costs are those which are properly included in FERC Account Nos. 800, 801, 802, 803, 804, 805, 806, 808, 809, and 811.
4. A monthly report shall be filed with the Commission, describing the costs associated with gas and transportation services purchased by Company to meet sales service requirements and included in this rider. The report shall detail the calculations for Base Gas Cost and shall reflect all factors applicable to Net Gas Cost as well as any relevant current or deferred balances.

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Economic Development Rider - Gas

Purpose
The purpose of this Economic Development Rider is to encourage industrial, commercial and military development in Kansas. These activities will attract capital investment to the State, diversify the Company's customer base and create jobs.

Availability
Service under this rider is available to customers qualified to receive service under Company's rate schedules (STk, STt, LVTk, and LVTt).

Applicable
Upon election by a customer and acceptance by Company, this rider is applicable to new large volume customers and to the added consumption of existing customers who have been served under the general service or large volume rate schedules, or rate schedules superseded by the large volume rate schedules, for the twelve months prior to customer's election of this rider (the base period).

Upon prior written approval by Company, all sales or transportation volumes delivered to a new customer shall be considered qualified volumes, provided the customer's annual usage exceeds 25,000 Mcf, with respect to the incentive provisions of this rider. For an existing customer, qualified volumes shall be the sales or transportation volumes delivered during each contract year in excess of the base period volumes, provided the customer's annual natural gas requirement in each contract year exceeds the base period requirement by at least 25,000 Mcf, with respect to the incentive provisions of this rider.

All requests for service under this rider shall be considered by Company; however, in no event shall any provision of this rider apply to a customer's consumption for a period prior to the date Company accepts the customer's application hereunder. If a qualifying customer's use of natural gas subsequently becomes insufficient to meet the requirements of this rider or Company's rate schedules for large volume customers, the incentive provisions contained herein shall cease and the customer shall be served under the applicable rate schedule for such reduced requirements. The availability of this rider shall be limited to customers not involved in selling or providing goods and services directly to the general public.

Incentive Provisions
The contract for service hereunder shall begin on the first day of the next billing period following Company approval of a customer's application and shall continue for a period of five years. Customers receiving service under this rider shall be billed at the standard rates and charges as adjusted by the following incentive provisions:

1. **Rate Discount**: With respect to the qualified volumes, the volumetric charge for transportation shall have a maximum discount of 50% during the first contract year, 40% during the second

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Economic Development Rider - Gas

contract year, 30% during the third contract year, 20% during the fourth contract year, and 10% during the fifth contract year. After the fifth contract year, this incentive provision shall cease.

2. **Local Service Facilities**: Company shall require a contribution in aid of construction for facilities installed to serve a customer if Company's analysis of expected revenues from the new or expanded load on an ongoing basis, calculated at the discounted rates and charges, is determined to be insufficient to justify the investment in the facilities.

The total dollar amount of the incentives provided under this rider shall not exceed one percent (1%) of Company's jurisdictional gross revenues during each calendar year, provided; however, Company shall have the right at any time and for good cause shown to seek a modification of this limitation upon application to the Commission

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Electronic Flow Measurement Rider

Applicability

Applicable to all customers served under rate schedules STk, STt, LVTk, LVTt and WTt and located in and around the communities specified in the Index. Service is subject to the Definitions and Conditions section below.

Net Monthly Bill

$25.00 for each meter upon which Electronic Flow Measurement equipment (EFM) is installed, plus any charge to reimburse Company for the installed cost of the EFM, plus if applicable,

$15.00 for each meter connected to Company-maintained cellular data equipment.

Definitions and Conditions

1. EFM shall be required on all meters serving transportation accounts, except for the provisions of Definition and Condition #2 (below). Company shall install, operate, and own all EFM. Company shall provide and bill the customer the actual cost for any requested assistance beyond maintenance to Company's EFM and/or connection.
   a. The requirements of this provision shall be judged to have been met pending a customer's sequential assignment to Company's EFM installation schedule.
   b. Company may, at its sole discretion, waive the requirements of this provision for a customer which uses gas primarily during Company's off-peak season.
   c. A customer which declines Company's EFM installation, or which does not provide a Contribution in Aid of Construction (CIAC), or which does not install and/or maintain an operable dedicated telephone circuit, all as required by this rider, shall be ineligible for transportation service.
   d. In the event that existing customer-maintained communication facilities fail to adequately transmit meter data, Company shall promptly notify a customer of the need to install or maintain an operable dedicated telephone circuit. The customer must repair the phone circuit or elect to switch to Equipment Option 2 as outlined in part 3 below. If, after 60 days from initial notification, the customer fails to provide an operational dedicated phone circuit or select the applicable Equipment Option, the Company, at its sole discretion, may disqualify such customer from transportation service and place the account on the appropriate General Sales rate.
2. RDQ Balancing: Notwithstanding the provisions above, according to the Required Daily Quantity (RDQ) Balancing provisions in Section 11, Pipeline System Restrictions & Priorities of Company's General Terms and Conditions for Gas Service (GTC), a customer may agree to deliver during a Period of Curtailment (POC) a predetermined RDQ of natural gas to a transportation service meter which records a peak-month usage of less than 1,500 Mcf in the most recent 12 month period ending April 30, in lieu of the Company's requirement to install EFM. However, meters upon which

Electronic Flow Measurement Rider

EFM equipment has already been installed shall not be eligible for the RDQ Balancing option and the customer shall be subject to all charges set out in the Net Monthly Bill section.

3. A customer shall reimburse Company for the installed cost of EFM which shall become the sole property of Company. This CIAC for labor, material, and overhead costs associated with the installation shall be one of the following options:

   Option 1: $ 3,400 per meter for installation of EFM equipment with an electronic correction device and modem to transmit meter and usage data via a customer-provided and maintained, dedicated landline phone circuit, or

   Option 2: $4800 per meter for installation of EFM equipment with an electronic correction device and modem to transmit meter and usage data via a Company-provided cellular connection. Customer is required to provide and maintain AC power to the meter setting, if available. Otherwise, customer may arrange for Company-provided and maintained solar power equipment necessary to operate EFM equipment. The cellular equipment option is only available if there is reliable cellular service at the meter setting. If reliable cellular service is not available, the customer will be required to install a dedicated phone circuit under Option 1 or be ineligible for transportation service.

   Customers can, at any time, select another data/power option if adequate services are available to support the selection. The cost to upgrade shall be the difference of initial installation costs listed above.

   In the event the customer elects to downgrade Equipment Options, Company is not required to refund prior installation costs.

   Some cellular service installations may require a remote mounted cellular antenna, remote mounted solar panel(s), up-sized solar panel(s) or other modifications that are above and beyond basic installation. Company will promptly notify customer in such events and provide a cost estimate prior to installation. Customer will be responsible for these additional costs.

4. A customer shall make an additional CIAC sufficient to cover the cost of any non-EFM related work performed and/or equipment installed at the customer's request. All such facilities and/or equipment shall become the sole property of Company. Payment shall be due from the customer at the time equipment is installed, except that Company may permit the customer to finance the EFM over a four year period at 8% per annum.

5. Company shall notify the customer of its intent to install EFM, as well as the scope and estimated cost thereof.

   a. A customer shall provide adequate space for the installation of the EFM.

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Electronic Flow Measurement Rider

b. A customer shall provide and maintain, at its cost, a dedicated telephone circuit or a Company-accepted alternative, according to Company's EFM Standards. Company and the customer shall mutually agree upon electric power and telephone connection location.

c. A customer's acceptance of Company's installation plan shall be assumed unless the customer declines in writing within 15 days of Company's notice. If customer selects equipment Option 1, the customer shall, within 60 days of acceptance, complete the installation of the required telephone circuit, at the customer's own expense, after which time Company shall install EFM equipment. If customer selects Equipment Option 2, Company will perform a site evaluation to determine if adequate cellular and/or sun exposure is available.

6. At a customer's request, Company may provide a data link or contact closure meeting Company's Standards from Company's EFM to the customer at the meter site so the customer can receive data with the same type of output signal as Company. At the customer's request, Company shall inspect and evaluate the customer's connection during normal Company working hours.

7. Upon a customer's written request made prior to April 30 of each year, and agreement by Company given prior to May 31 of that same year and which shall not be unreasonably withheld, Company may credit 50% of assessed and paid Overrun Penalties incurred by the customer in the preceding winter heating season of November through March, to EFM. The credit shall be limited to the per meter CIAC required by Definition and Condition #2 (above). A credit for EFM is available only on new, Company-installed EFM and when Company is not assessed Overrun Penalties for a similar time period pursuant to a pipeline's authorized tariff.

8. In the event of equipment failure, Company shall use uncorrected mechanical readings, historical data and/or customer supplied data to estimate billing data.

9. A customer shall hold Company harmless from all claims for trespass, injury to persons, or damage to lawns, trees, shrubs, buildings or other property that may be caused by reason of the installation, operation, or replacement of the EFM or customer connection and other necessary equipment to serve the customer unless it shall be affirmatively proved that the injury to persons or damage to property complained of has been caused by willful default or negligence on the part of Company or its accredited personnel.

10. Service under this rider is subject to the provisions and applicable charges contained in Company's GTC or successor documents, approved by the Commission.

11. All provisions of this rider are subject to changes made by order of the Commission.

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Weather Normalization Adjustment Rider

Applicability
This rider is applicable to all service provided to all customers served under sales rate schedules RS, GSS, GSL and GSTE. Service is subject to the Definitions and Conditions section below.

Net Annual Charge
A Weather Normalization Adjustment (WNA) factor shall be applied to all monthly usage to refund revenue excesses or collect revenue deficiencies which occur as a result of deviations from normal weather. The WNA factor shall be calculated by the formula:

WNA Factor = [Revenue + Adjustment] / Volumes

Where:

Revenue = WDF * Rate * Customers for the WNA Calculation Period

WDF = Weather Deviation Factor is the per capita volume deviation due to non-normal weather.
(NHDDp – AHDDp) * HSFp + (NHDDc – AHDDc) * HSFc
Where p = prior month data and c = current month data for the given class and weather station.

NHDD = Normal Heating Degree Days for the applicable month.

AHDD = Actual Heating Degree Days for the applicable month.

HSF = Heat Sensitivity Factor is the usage per degree day calculation which is specific to the applicable weather station and Company service schedule.

Customers = Count of customers for the given class and weather station.

Rate = The applicable customer delivery charge per Mcf.

Volumes = Estimated volumes for the current WNA Collection Period.

Adjustment = Revenue from the prior year WNA Calculation Period less Recoveries.

Recoveries = WNA Factor times the monthly actual sales volumes.

Definitions and Conditions

1. All provisions set forth in the rate schedule under which a customer takes service shall apply to the extent they are not superseded by provisions of this rider.
2. WNA factors shall be calculated to the nearest $0.0001 per Mcf.
3. The Heat Sensitivity Factors and the Heating Degree Day normals, as approved in KCC Docket No. 16-KGSG- -RTS, shall be used for each rate schedule and weather station.
4. The WNA Collection Year, consisting of the twelve month period ending June 30 of each

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Weather Normalization Adjustment Rider

calendar year, shall define the period during which a WNA factor is collected.

5. The WNA Calculation Period, consisting of the seven cycle billing months of October through April prior to the WNA Collection Year, shall define the period over which the revenue excess or deficiency is calculated.
6. Company shall file a report with the Commission by June 25 of each year, detailing the calculations deriving the WNA factors authorized by this rider to be applied during the subsequent WNA Collection Year.

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Gas System Reliability Surcharge Rider

Availability

This rider is applicable to every bill for service provided under each of the Company's sales and transportation rate schedules except where not permitted under a separately negotiated contract with a customer. Not applicable to bills for As-Available Gas Sales Service or Interruptible Gas Transportation Service.

Net Monthly Charge

The Gas System Reliability Surcharge (GSRS) shall be a fixed monthly amount calculated as the applicable GSRS times the number of meters serving the customer's account, as indicated by the total number of Service Charges billed.

RS	Residential Sales Service	$	0.00
GSS	General Sales Service Small	$	0.00
GSL	General Sales Service Large	$	0.00
GSTE	General Sales Service Transport Eligible	$	0.00
SGS	Small Generator Sales Service	$	0.00
KGSSD	Kansas Gas Supply D	$	0.00
GIS	Gas Irrigation Sales Service	$	0.00
SSR	Sales Service Resale	$	0.00
STk	Small Transportation Service (k)	$	0.00
STt	Small Transportation Service (t)	$	0.00
LVTk	Large Volume Transportation Service (k)		
Annual Use:	Below 10,000 Mcf	$	0.00
	10,001 Mcf – 20,000 Mcf	$	0.00
	20,001 Mcf – 40,000 Mcf	$	0.00
	Above 40,001 Mcf	$	0.00
LVTt	Large Volume Transportation Service (t)		
Annual Use:	Below 10,000 Mcf	$	0.00
	10,001 Mcf – 20,000 Mcf	$	0.00
	20,001 Mcf – 40,000 Mcf	$	0.00
	Above 40,001 Mcf	$	0.00
WTt	Wholesale Transportation Service (t)	$	0.00
GITt	Gas Irrigation Transportation Service (t)	$	0.00
CNG	Compressed Natural Gas General Transportation	$	0.00

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Gas System Reliability Surcharge Rider

Definitions and Conditions

1. The provisions of this GSRS Rider are intended to recover charges for natural gas public utility plant projects pursuant to K.S.A. 66-2201 through K.S.A. 66-2204.
2. The GSRS shall be reflected on a customer's bill as a separate line item.
3. The Annual Use for customers served under a Large Volume Transportation (LVT) rate schedule shall be the total volumes billed to the applicable meter in the 12 months ending the most recent April 30. Company may rely on estimated historical usage or projected volumes to establish Annual Use when actual usage is not available
4. At the end of each twelve-month calendar period a GSRS is in effect, Company shall reconcile the difference between the revenues resulting from that GSRS and the pre-tax revenues found by the Commission to be appropriate for that period. Company shall calculate a GSRS adjustment which shall, upon Commission approval, recover or refund the difference.
5. All provisions of this rider are subject to changes made by order of the Commission.

Gas Transportation for Schools Rider

Availability

Available to approved, separately metered school facilities dedicated to the education of students between kindergarten and grade 12. Not applicable to day care facilities, pre-schools, post-secondary institutions, for-profit schools, residences, or churches.

Net Monthly Bill

The bill for service under this Rider shall be calculated as stated in the applicable Small Transportation Service (ST) rate schedule.

Definitions and Conditions

1. All provisions set forth in the applicable transportation service rate schedule shall apply to the extent they are not superseded by the provisions of this Rider.
2. Approved meters are those for which, in the Company's sole determination, the ownership, operational control, and the responsibility for payment of all charges rest with a single entity, and which provide service exclusively to school facilities.
3. Approved meters located on a customer's contiguous property may be consolidated into a single account for billing purposes, in accordance with the Company's General Terms and Conditions for Gas Service (GTC).
4. For purposes of balancing, an individual school district may aggregate its authorized meters that are not otherwise included in a Marketer Agent's aggregation group. A school district that acts as its own aggregation agent must meet all requirements as specified in GTC Section 10.04 Aggregation.
5. Service under this rider shall be terminated upon notification by the customer, but not before the next scheduled meter reading date.
6. Monthly balancing shall be in accordance with the Company's GTC, Section 10 Requirements for Transportation Service.

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Ad Valorem Tax Surcharge Rider

Applicability
This rider is applicable to every bill for service provided under each of the Company's sales and transportation rate schedules except where not permitted under a separately negotiated contract with a customer. Not applicable to bills for As-Available Gas Sales Service or Interruptible Gas Transportation Service.

Net Monthly Charge
$-0.0200 Ad Valorem Tax Surcharge per Mcf

The Ad Valorem Tax Surcharge shall be applied to the Delivery Charge on a customer's regular monthly bill. A positive amount shall indicate a charge to the customer and a negative amount shall be a refund. It shall be calculated as:

The sum of the total Ad Valorem taxes levied for the year

minus

The Ad Valorem taxes included in Company's current rates as filed with the Commission in Docket No. 12-KGSG-835-RTS

plus

Any amount under collected by prior Ad Valorem Tax Surcharges, or

minus

Any amount over collected by prior Ad Valorem Tax Surcharges

divided by

The total settlement volumes used in Docket No. 12-KGSG-835-RTS to calculate Company's current rates.

Definitions and Conditions
1. The Ad Valorem Tax Surcharge is intended to recover changes in the real estate and personal property taxes pursuant to K.S.A. 66-117(f).
2. The Ad Valorem Tax Surcharge shall become a part of the total bill for gas service and need not be itemized separately on the customer's bill.
3. All provisions of this rider are subject to changes made by order of the Commission

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Cost of Service Adjustment (COSA) Plan

1. **Applicability**

1.01 The rider is applicable to all sales and transportation rate schedules except where not permitted under a separately negotiated customer contract.

1.02 The rate adjustments implemented under this mechanism will reflect annual changes in the Company's cost to provide natural gas distribution service.

2. **Purpose**

The purpose of this mechanism is to provide an annual earnings review in order to adjust rates to reflect the most recent historic costs necessary in the provision of natural gas utility service.

3. **Application**

Each annual application submitted by Kansas Gas Service (Company or KGS) shall calculate the revenue requirement of the company consistent with standard ratemaking principles adopted by the Kansas Corporation Commission (KCC or Commission). No provision contained within this tariff will limit the Company's ability to file a general rate change application, or the Commission's authority to file a show-cause proceeding. Kansas Gas Service shall have the burden of proof to demonstrate the reasonableness of its application and resulting rates.

The Company shall file an Application for a Commission determination pursuant to this COSA Rate Schedule for calendar years 2017, 2018 and 2019, with each filing to be submitted by the following April 15th. The Application shall include pre-filed testimony in support of the test period financial information as well as each pro-forma test period adjustment. During this three-year period, the COSA shall be considered a pilot program. Any subsequent Applications made pursuant to terms outlined in this tariff would require the approval of the KCC.

3.01 The Company shall, on or before April 15, file an application with the KCC and provide copies to Staff of the KCC, and the Citizens Utility Ratepayer Board (CURB). Historic information prior to the test period need not be provided. Where applicable, the data provided below shall include the test period actual data, listing of individual adjustments to test period data by FERC account and the as-adjusted balance. The filing shall include information consistent with the requirements of sections of K.A.R. 82-1-231 listed below:

Section 1: Application, letter of transmittal and authorization
Section 2: General Public Notification
Section 3: Summary of Rate Base, Operating Income and Rate of Return,
Section 4: Plant in Service
Section 5: Accumulated Provision for Depreciation and Amortization
Section 6: Working Capital
Section 7: Capital and Cost of Money
Section 9: Test Period and pro forma Income Statements

Cost of Service Adjustment (COSA) Plan

Section 10: Depreciation and Amortization
Section 11: Taxes
Section 12: Allocation Ratios
Section 18: Allocation of revenue requirement to customer classes, development of proposed rate design, proof of revenues and proposed tariffs

3.02 The filing shall be accompanied by work papers provided to the KCC Staff and CURB supporting each of the pro-forma adjustments.

3.03 The pro-forma adjusted operating expenses, excluding depreciation expense and all taxes, shall not exceed 104% of the previous year's as adjusted operating and maintenance (O&M) expenses, excluding depreciation expense and all taxes. The initial 4% O&M limitation shall be calculated on a per annum basis as of December 31, 2015. This provision shall represent a limit by which operating expenses may not increase for purposes of calculating the Earned Return on Equity (EROE) as discussed below. The KCC's authorized operating expenses within the KGS base rate proceeding shall be used as a baseline upon which subsequent operating expense limits would be determined. Any costs incurred as a result of new governmental mandates subsequent to December 31, 2015, shall not be included for purposes of calculating the O&M limitation.

3.04 An expedited processing schedule shall be established to provide notice and due process to all interested parties, including customers. Any calculations disputed by the parties shall be identified to the Company prior to June 15. The parties shall work in good faith to resolve all disputes prior to June 15. The KCC Staff report and recommendation will be provided to the KCC by June 30 and the Company's response to Staff's report and recommendation shall be filed with the Commission within seven business days following the filing of Staff's report and recommendation.

3.05 Unless disputed by the parties, any rate schedules incorporating the COSA Plan by reference will become effective by Order of the Commission with the first billing cycle in September. If the parties have not resolved the disputed issues, the issues will be set for hearing before the Commission. If the Commission has not issued an order by September 1 following the date of an application, then the rate schedules may be placed into effect and collected on an interim basis, subject to refund.

3.06 The revenue requirement increase or decrease as identified within Sections 3 and 18 listed above shall be determined pursuant to the return on equity parameters identified in Section 4 below.

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Cost of Service Adjustment (COSA) Plan

4. **Application of the COSA Plan**

4.01 The Company's Allowed Return on Equity (AROE) is that set pursuant to the order of the Commission contained within the 2016 KGS base rate filing. This AROE shall be the effective AROE until modified by Commission order. Such modification shall be applied prospectively.

4.02 The Earned Return on Equity (EROE) shall be recalculated annually under this Plan, for use in determining any rate change adjustments that become effective during subsequent years. Except as otherwise provided in other sections of this tariff, the calculation shall be performed using the same methodology used to calculate the EROE pursuant to KGS' 2016 base rate filing.

4.03 The Company will submit revised rate schedules to the Commission each time the rates are adjusted pursuant to this Rate Schedule.

5. **Term**

This Rate Schedule shall become effective upon issuance of a Commission order and terminate at the end of the pilot program period approved by the Commission, or as the result of a final order being issued in a general rate case or show cause proceeding.

6. **Force Majeure Provision**

If any cause beyond the reasonable control of the Company, including, but not limited to, natural disaster, orders or acts of civil or military authority, terrorist attacks, or government mandates, which results in a deficiency in the revenues which are not readily capable of being addressed in a timely manner under this Rate Schedule, the Company may file for rate relief.

7. **Application of COSA Calculation Procedure**

7.01 For each 12-month period ending December 31, the Company shall file an Application for a Commission determination pursuant to this COSA Rate Schedule to determine whether the Company's jurisdictional non-fuel revenues should be increased, decreased, or left unchanged. If it is determined that the jurisdictional non-fuel revenues should be increased or decreased, the Company's rate schedules will be adjusted in the manner set forth in this Rate Schedule. Any revenue modifications will be allocated to the Company's customers based upon the customer class cost of service allocation approved by the KCC in the KGS 2016 base rate case filing. The revised rate schedules will become effective by Order of the Commission for the September cycle one bills and will remain in effect until changed under the provisions set forth in this Rate Schedule and by order of the Commission.

7.02 Rates applicable to each class shall be split between Customer Charge and Commodity Charge in the same proportion to total revenue as the underlying rates approved by the KCC in the most recent KGS base rate proceeding.

Cost of Service Adjustment (COSA) Plan

8. **Annual COSA Plan Calculation**

8.01 The calendar year shall be the test year.

8.02 Rate Base and cost of service shall be computed in the same manner as approved by the Commission in KGS 2016 base rate case. This section does not prohibit the parties from requesting certain modifications to these rate change adjustments.

8.03 The Company's actual capitalization ratio as of the end of the test period shall be used to calculate the revenue requirement, except that the equity component shall not exceed 60%. The Company's weighted cost of debt at December 31 of test period shall be used to calculate the overall rate of return.

8.04 Actual year operating Revenues shall be modified consistent with the Commissions' findings in KGS' 2016 base rate case. The as adjusted Operating Revenues shall include, but not necessarily limited to test period weather normalization accruals and shall be determined based upon weather coefficients as determined in the KGS 2016 base rate case.

8.05 Actual test year operating Expenses shall also be modified consistent with the Commissions' findings in KGS 2016 base rate case based upon annualized December 31 year-end data for the following:

a. Depreciation expense calculated based upon December 31 balances multiplied by Commission authorized depreciation rates.

b. Labor costs based upon employees' compensation levels and employment levels as of December 31.

c. Actual test year expenses will be adjusted consistent with Commission findings on appropriate items to include/exclude in the revenue requirement pursuant to its order in the 2016 KGS base rate case.

d. The cost impacts of tax changes or governmental mandates shall be annualized.

e. Other adjustments as appropriate.

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