Tab 10

Philadelphia Gas Works

Pennsylvania Public Utility Commission
52 Pa. Code §53.61, et seq.

Item 53.64(c) Thirty days prior to the filing of a tariff reflecting an increase or decrease in natural gas costs, each Section 1307(f) gas utility seeking recovery of purchased gas costs under that section shall provide notice to the public, under § 53.68 (relating to notice requirements), and shall file the following supporting information with the Commission, with a copy to the Consumer Advocate, Small Business Advocate and to intervenors upon request:

(11) If any rate structure or rate allocation changes are to be proposed, a detailed explanation of each proposal, reasons therefore, number of customers affected, net effect on each customer class, and how the change relates to or is justified by changes in gas costs proposed in the Section 1307(f) tariff filing. Explain how gas supply, transportation and storage capacity costs are allocated to customers which are primarily nonheating, interruptible or transportation customers.

Response:

PGW is not proposing any rate structure or rate allocation changes in the instant proceeding, therefore, no testimony or schedules have been provided in this pre-filing to support such changes.

PGW will provide testimony regarding gas procurement policies, strategies and the GCR calculation in its 1307f March 1 filing.

Tab 11

Docket No. R-18XXX
Item 53.64 (c)(12)

Philadelphia Gas Works

Pennsylvania Public Utility Commission
52 Pa. Code §53.61, et seq.

Item 53.64(c) Thirty days prior to the filing of a tariff reflecting an increase or decrease in natural gas costs, each Section 1307(f) gas utility seeking recovery of purchased gas costs under that section shall provide notice to the public, under § 53.68 (relating to notice requirements), and shall file the following supporting information with the Commission, with a copy to the Consumer Advocate, Small Business Advocate and to intervenors upon request:

(12) A schedule depicting the most recent 5-year consecutive 3-day peak data by customer class (or other historic peak day data used for system planning), daily volumetric throughput by customer class (including end-user transportation throughput), gas interruptions and high, low and average temperature during each day.

Response:

Schedule 1 – Three-day peak for FY 12-13 through FY 16-17.

There were not any gas interruptions during the period of FY 12-13 through FY 16-17.

3 DAY PEAK ANALYSIS

Winter		Average	Hi	Low	Total	Firm	Cogen	LBS	BPS	GTS	IT
2012 - 2013	Jan 23	21	24	19	542,095	474,747	40	78	235	3,499	63,496
2012 - 2013	Jan 24	23	28	19	520,871	454,814	40	79	225	3,697	62,016
2012 - 2013	Jan 25	23	31	20	532,130	467,509	41	79	224	3,645	60,632
2013 - 2014	Jan 22	14	19	8	576,853	513,402	59	0	114	2,422	60,855
2013 - 2014	Jan 23	18	26	13	550,700	485,528	61	0	104	1,698	63,310
2013 - 2014	Jan 24	22	29	15	544,086	478,302	61	0	114	3,716	61,893
2014 - 2015	Feb 15	11	17	4	645,370	563,253	0	0	0	4,018	78,099
2014 - 2015	Feb 16	16	21	9	617,947	527,584	0	0	0	3,957	86,406
2014 - 2015	Feb 17	24	30	19	532,242	452,250	0	0	0	3,751	76,241
2015- 2016	Feb 12	26	30	22	490,537	407,974	43	0	0	3,984	78,536
2015- 2016	Feb 13	16	24	9	583,377	498,793	43	0	0	3,870	80,671
2015- 2016	Feb 14	18	24	11	562,929	489,468	43	0	0	3,653	69,765
2016- 2017	Jan 7	21	25	17	496,220	432,592	0	0	0	3,905	59,723
2016- 2017	Jan 8	21	27	18	528,423	461,805	0	0	0	3,791	62,827
2016- 2017	Jan 9	24	31	19	519,336	449,873	0	0	0	3,709	65,754

Tab 12

Docket No. R-18XXX
Item 53.64 (c)(13)

Philadelphia Gas Works

Pennsylvania Public Utility Commission
52 Pa. Code §53.61, et seq.

Item 53.64(c) Thirty days prior to the filing of a tariff reflecting an increase or decrease in natural gas costs, each Section 1307(f) gas utility seeking recovery of purchased gas costs under that section shall provide notice to the public, under § 53.68 (relating to notice requirements), and shall file the following supporting information with the Commission, with a copy to the Consumer Advocate, Small Business Advocate and to intervenors upon request:

(13) Identification and support for any peak day methodology used to project future gas demands and studies supporting the validity of the methodology.

Response: Please see the attached Peak Day analysis. Also attached are excerpts from the August, 2006 ICF International *Natural Gas Supply Study* which supports PGW's peak day methodology.

Peak Day Analysis

PGW performs a peak day analysis on an annual basis to determine its projected sendout requirements during peak conditions. Essentially this process is completed by collecting sendout and average temperature data for all days where the temperature is at or below 32 degrees Fahrenheit, excluding holidays and weekends. All interruptible transportation volumes are removed from total sendout to arrive at firm sendout on a daily basis.

Common statistical practices warrant that no less than thirty (30) data points be utilized in the analysis to ensure its integrity. For this analysis, PGW has utilized data from the period winter of FY 14-15 through FY 16-17 which would reflect the most current consumption behaviors of its customers. This period yielded 53 data points where the average temperature was at or below 32 degrees Fahrenheit.

Degree days are calculated by subtracting the average daily temperature from sixty-five (65).

A standard linear regression was performed on the data using the calculated degree-days and the actual firm daily sendout information. Additionally, in order to confirm the accuracy of the analysis, and to smooth the charting of the data, a quadratic and a cubic regression analysis were also completed.

A resulting R^2 (Correlation Coefficient) indicates an 82.1 % correlation between firm sendout and degree-days. The multiple regression correlation co-efficient, R^2, is a measure of the proportion of variability explained by, or due to the regression (linear relationship) in a sample of paired data. It is a number between zero and one and a value close to zero suggests a poor model.

To verify the level of confidence we can ascribe to the model, we developed the attached Linear Regression Confidence Level Table. Essentially, this table compares the actual versus projected sendout to determine the level of variance expressed as a standard deviation. A standard deviation represents the positive square root of the variance where the variance simply represents the dispersion about the mean. In this analysis the sample standard deviation is 26,150 MCF.

The sample loses one degree of freedom for each estimated parameter. Thus, with a sample of 100 paired values and two estimated parameters (one for the constant and one for the coefficient of "degree days"), there are 100-2=98 degrees of freedom. In this analysis we had 53 data points and there were 51 Degrees of Freedom.

Finally, based upon the models developed, it can be determined that the company's projected peak day sendout should be set at 672,749 MCF per day at 0 degree Fahrenheit. This calculation is performed using the X Coefficient (i.e. slope) multiplied by the number of degree days and adding the Constant (Y Intercept).

Winter 15-17 Data for Daily Temperatures <= 32 Degrees Fahrenheit

W/O Holidays, Weekends

Day	Date	Daily Temp	Degree Days X	X^2	X^3	Actual Firm Sendout (Mcf)	Firm Sendout Per DD (Mcf)	Linear Projected Firm Sendout (Mcf)	Quadratic Projected Firm Sendout (Mcf)	Cubic Projected Firm Sendout (Mcf)
Tuesday	11/18/2014	28	37	1,369	50,653	350,906	9,484	384,746	384,660	384,449
Wednesday	12/31/2014	32	33	1,089	35,937	340,403	10,315	343,603	344,097	344,563
Monday	1/5/2015	29	36	1,296	46,656	348,249	9,674	374,461	374,483	374,328
Tuesday	1/6/2015	25	40	1,600	64,000	400,833	10,021	415,604	415,335	415,254
Wednesday	1/7/2015	18	47	2,209	103,823	488,236	10,388	487,604	487,759	488,272
Thursday	1/8/2015	22	43	1,849	79,507	479,237	11,145	446,461	446,229	446,485
Friday	1/9/2015	28	37	1,369	50,653	413,890	11,186	384,746	384,660	384,449
Tuesday	1/13/2015	26	39	1,521	59,319	391,385	10,036	405,318	405,086	404,923
Wednesday	1/14/2015	31	34	1,156	39,304	373,561	10,987	353,889	354,202	354,374
Friday	1/16/2015	31	34	1,156	39,304	357,367	10,511	353,889	354,202	354,374
Wednesday	1/21/2015	32	33	1,089	35,937	344,596	10,442	343,603	344,097	344,563
Monday	1/26/2015	28	37	1,369	50,653	379,785	10,264	384,746	384,660	384,449
Tuesday	1/27/2015	27	38	1,444	54,872	407,871	10,733	395,032	394,861	394,651
Wednesday	1/28/2015	29	36	1,296	46,656	397,632	11,045	374,461	374,483	374,328
Friday	1/30/2015	27	38	1,444	54,872	396,701	10,440	395,032	394,861	394,651
Monday	2/2/2015	28	37	1,369	50,653	391,048	10,569	384,746	384,660	384,449
Tuesday	2/3/2015	28	37	1,369	50,653	395,063	10,677	384,746	384,660	384,449
Thursday	2/5/2015	23	42	1,764	74,088	426,585	10,157	436,175	435,907	436,046
Friday	2/6/2015	31	34	1,156	39,304	393,873	11,584	353,889	354,202	354,374
Monday	2/9/2015	30	35	1,225	42,875	365,974	10,456	364,175	364,330	364,299
Thursday	2/12/2015	27	38	1,444	54,872	399,536	10,514	395,032	394,861	394,651
Friday	2/13/2015	22	43	1,849	79,507	454,929	10,580	446,461	446,229	446,485
Tuesday	2/17/2015	24	41	1,681	68,921	452,250	11,030	425,890	425,609	425,632
Wednesday	2/18/2015	25	40	1,600	64,000	420,596	10,515	415,604	415,335	415,254
Thursday	2/19/2015	12	53	2,809	148,877	539,717	10,183	549,319	550,780	549,807
Friday	2/20/2015	16	49	2,401	117,649	552,584	11,277	508,176	508,669	509,025
Monday	2/23/2015	19	46	2,116	97,336	463,598	10,078	477,319	477,340	477,843
Tuesday	2/24/2015	24	41	1,681	68,921	445,516	10,866	425,890	425,609	425,632
Thursday	2/26/2015	29	36	1,296	46,656	379,463	10,541	374,461	374,483	374,328
Friday	2/27/2015	25	40	1,600	64,000	405,365	10,134	415,604	415,335	415,254
Thursday	3/5/2015	21	44	1,936	85,184	421,654	9,583	456,747	456,575	456,939
Friday	3/6/2015	23	42	1,764	74,088	423,507	10,084	436,175	435,907	436,046
Monday	1/4/2016	21	44	1,936	85,184	407,940	9,271	456,747	456,575	456,939
Tuesday	1/5/2016	27	38	1,444	54,872	398,646	10,491	395,032	394,861	394,651
Monday	1/11/2016	31	34	1,156	39,304	334,881	9,849	353,889	354,202	354,374
Wednesday	1/13/2016	28	37	1,369	50,653	379,941	10,269	384,746	384,660	384,449
Tuesday	1/19/2016	26	39	1,521	59,319	430,686	11,043	405,318	405,086	404,923
Thursday	1/21/2016	31	34	1,156	39,304	361,668	10,637	353,889	354,202	354,374
Friday	1/22/2016	27	38	1,444	54,872	397,773	10,468	395,032	394,861	394,651
Wednesday	2/10/2016	31	34	1,156	39,304	355,015	10,442	353,889	354,202	354,374

Winter 15-17 Data for Daily Temperatures <= 32 Degrees Fahrenheit

W/O Holidays, Weekends

Day	Date	Daily Temp	Degree Days X	X^2	X^3	Actual Firm Sendout (Mcf)	Firm Sendout Per DD (Mcf)	Linear Projected Firm Sendout (Mcf)	Quadratic Projected Firm Sendout (Mcf)	Cubic Projected Firm Sendout (Mcf)
Thursday	2/11/2016	24	41	1,681	68,921	435,736	10,628	425,890	425,609	425,632
Friday	2/12/2016	26	39	1,521	59,319	419,340	10,752	405,318	405,086	404,923
Thursday	2/18/2016	32	33	1,089	35,937	345,555	10,471	343,603	344,097	344,563
Thursday	12/15/2016	21	44	1,936	85,184	442,443	10,056	456,747	456,575	456,939
Friday	12/16/2016	28	37	1,369	50,653	398,274	10,764	384,746	384,660	384,449
Monday	12/19/2016	28	37	1,369	50,653	362,151	9,788	384,746	384,660	384,449
Friday	1/6/2017	29	36	1,296	46,656	352,566	9,794	374,461	374,483	374,328
Monday	1/9/2017	24	41	1,681	68,921	449,790	10,970	425,890	425,609	425,632
Friday	2/3/2017	30	35	1,225	42,875	355,990	10,171	364,175	364,330	364,299
Thursday	2/9/2017	27	38	1,444	54,872	369,581	9,726	395,032	394,861	394,651
Friday	3/10/2017	30	35	1,225	42,875	311,755	8,907	364,175	364,330	364,299
Tuesday	3/14/2017	28	37	1,369	50,653	376,677	10,180	384,746	384,660	384,449
Wednesday	3/15/2017	28	37	1,369	50,653	398,105	10,760	384,746	384,660	384,449
			53	2,809	148,877	401,631	10,395	549,319	550,780	549,807
			Count	53						

Firm Sendout Projection Based Data From 15-17
Data for Daily Temperatures <= 32 Degrees Fahrenheit

R Squared	Change	Student's T	Degrees of Freedom	Critical Value	@ 97.5% Significant
0.820896	0.820896	15.288901	51	1.99	Yes
0.820938	0.000042	0.108545	50	1.98	No
0.820970	0.000032	0.094049	49	1.98	No

Degrees of Freedom	51	50	49
97.5% Significance Level	1.99	1.98	1.98
95.0% Significance Level	1.66	1.66	1.66

LinearProjection at Zero Degrees Fahrenheit	672,749	Mcf
Linear Projection at 15 Degrees Fahrenheit	518,462	Mcf

*Student's T = Square Root[(Increase * Degrees of Freedom)/(1 - R Squared)]*

*Linear SO = Constant + (X * X Coefficient)*

*Quadratic SO = Constant + (X * X Coeff) + (X1u2 * X1u2 Coeff)*

*Cubic SO = Constant + (X * X Coeff) + (X1u2 * X1u2 Coeff) + (X1u3 * X1u3 Coeff)*

Linear Regression Confidence Level Table

Count	Degree Days X	Firm Sendout (Mcf) Y	Projected Linear Firm Sendout (Mcf) Ydc	Difference Actual Versus Projected Y - Yc	Actual Versus Projected Squared $(Y - Yc)^2$	(Degree Days - Xm) X - Xm	(Degree Days - Xm) Squared $(X - Xm)^2$	sdyc	t*sdyc	Lower Acc Lower	Upper Acc Ydc + t*sdydc	"- 1 SD" Lower	"+ 1 SD" Ydc + sdydc	"- 2 SD" Lower	"+ 2 SD" Ydc + 2sdydc
1	33	340,403	343,603	(3,200)	10,237,327	(6)	32	4,731	9,421	334,182	353,024	323,432	363,774	303,261	383,945
2	33	344,596	343,603	993	986,665	(6)	32	4,731	9,421	334,182	353,024	323,432	363,774	303,261	383,945
3	33	345,555	343,603	1,952	3,810,597	(6)	32	4,731	9,421	334,182	353,024	323,432	363,774	303,261	383,945
4	34	373,561	353,889	19,672	386,981,981	(5)	22	4,211	8,384	345,504	362,273	333,718	374,060	313,547	394,231
5	34	357,367	353,889	3,478	12,094,381	(5)	22	4,211	8,384	345,504	362,273	333,718	374,060	313,547	394,231
6	34	393,873	353,889	39,984	1,598,700,410	(5)	22	4,211	8,384	345,504	362,273	333,718	374,060	313,547	394,231
7	34	334,881	353,889	(19,008)	361,310,819	(5)	22	4,211	8,384	345,504	362,273	333,718	374,060	313,547	394,231
8	34	361,668	353,889	7,779	60,507,811	(5)	22	4,211	8,384	345,504	362,273	333,718	374,060	313,547	394,231
9	34	355,015	353,889	1,126	1,267,134	(5)	22	4,211	8,384	345,504	362,273	333,718	374,060	313,547	394,231
10	35	365,974	364,175	1,800	3,239,142	(4)	13	3,739	7,445	356,729	371,620	344,004	384,346	323,833	404,517
11	35	355,990	364,175	(8,185)	66,990,397	(4)	13	3,739	7,445	356,729	371,620	344,004	384,346	323,833	404,517
12	35	311,755	364,175	(52,420)	2,747,833,901	(4)	13	3,739	7,445	356,729	371,620	344,004	384,346	323,833	404,517
13	36	348,249	374,461	(26,211)	687,040,709	(3)	7	3,337	6,645	367,815	381,106	354,290	394,631	334,119	414,802
14	36	397,632	374,461	23,172	536,926,669	(3)	7	3,337	6,645	367,815	381,106	354,290	394,631	334,119	414,802
15	36	379,463	374,461	5,002	25,023,407	(3)	7	3,337	6,645	367,815	381,106	354,290	394,631	334,119	414,802
16	36	352,566	374,461	(21,894)	479,362,783	(3)	7	3,337	6,645	367,815	381,106	354,290	394,631	334,119	414,802
17	37	350,906	384,746	(33,840)	1,145,160,954	(2)	3	3,033	6,039	378,707	390,785	364,575	404,917	344,404	425,088
18	37	413,890	384,746	29,144	849,360,039	(2)	3	3,033	6,039	378,707	390,785	364,575	404,917	344,404	425,088
19	37	379,785	384,746	(4,961)	24,614,972	(2)	3	3,033	6,039	378,707	390,785	364,575	404,917	344,404	425,088
20	37	391,048	384,746	6,302	39,709,941	(2)	3	3,033	6,039	378,707	390,785	364,575	404,917	344,404	425,088
21	37	395,063	384,746	10,317	106,430,849	(2)	3	3,033	6,039	378,707	390,785	364,575	404,917	344,404	425,088
22	37	379,941	384,746	(4,805)	23,091,127	(2)	3	3,033	6,039	378,707	390,785	364,575	404,917	344,404	425,088
23	37	398,274	384,746	13,528	183,003,603	(2)	3	3,033	6,039	378,707	390,785	364,575	404,917	344,404	425,088
24	37	362,151	384,746	(22,595)	510,531,780	(2)	3	3,033	6,039	378,707	390,785	364,575	404,917	344,404	425,088
25	37	376,677	384,746	(8,069)	65,116,730	(2)	3	3,033	6,039	378,707	390,785	364,575	404,917	344,404	425,088
26	37	398,105	384,746	13,358	178,440,798	(2)	3	3,033	6,039	378,707	390,785	364,575	404,917	344,404	425,088
27	38	407,871	395,032	12,839	164,828,195	(1)	0	2,857	5,690	389,342	400,722	374,861	415,203	354,690	435,374
28	38	396,701	395,032	1,669	2,786,173	(1)	0	2,857	5,690	389,342	400,722	374,861	415,203	354,690	435,374
29	38	399,536	395,032	4,504	20,289,217	(1)	0	2,857	5,690	389,342	400,722	374,861	415,203	354,690	435,374
30	38	398,646	395,032	3,614	13,059,338	(1)	0	2,857	5,690	389,342	400,722	374,861	415,203	354,690	435,374
31	38	397,773	395,032	2,740	7,510,314	(1)	0	2,857	5,690	389,342	400,722	374,861	415,203	354,690	435,374

Linear Regression Confidence Level Table

Count	Degree Days X	Firm Sendout (Mcf) Y	Projected Linear Firm Sendout (Mcf) Ydc	Difference Actual Versus Projected Y - Yc	Actual Versus Projected Squared (Y - Ye)²	(Degree Days - Xm) X - Xm	(Degree Days - Xm) Squared (X - Xm)²	sdyc	t*sdyc	Lower Acc Lower	Upper Acc Ydc + t*sdydc	"- 1 SD" Lower	"+ 1 SD" Ydc + sdydc	"- 2 SD" Lower	"+ 2 SD" Ydc + 2sdydc
32	38	369,581	395,032	(25,451)	647,740,172	(1)	0	2,857	5,690	389,342	400,722	374,861	415,203	354,690	435,374
33	39	391,385	405,318	(13,933)	194,137,958	0	0	2,835	5,645	399,673	410,963	385,147	425,489	364,976	445,660
34	39	430,686	405,318	25,368	643,512,583	0	0	2,835	5,645	399,673	410,963	385,147	425,489	364,976	445,660
35	39	419,340	405,318	14,022	196,618,709	0	0	2,835	5,645	399,673	410,963	385,147	425,489	364,976	445,660
36	40	400,833	415,604	(14,771)	218,168,467	1	2	2,969	5,912	409,692	421,515	395,433	435,775	375,262	455,946
37	40	420,596	415,604	4,993	24,925,261	1	2	2,969	5,912	409,692	421,515	395,433	435,775	375,262	455,946
38	40	405,365	415,604	(10,239)	104,834,893	1	2	2,969	5,912	409,692	421,515	395,433	435,775	375,262	455,946
39	41	452,250	425,890	26,360	694,852,111	2	6	3,240	6,451	419,438	432,341	405,719	446,061	385,548	466,232
40	41	445,516	425,890	19,626	385,184,307	2	6	3,240	6,451	419,438	432,341	405,719	446,061	385,548	466,232
41	41	435,736	425,890	9,847	96,953,766	2	6	3,240	6,451	419,438	432,341	405,719	446,061	385,548	466,232
42	41	449,790	425,890	23,900	571,217,976	2	6	3,240	6,451	419,438	432,341	405,719	446,061	385,548	466,232
43	42	426,585	436,175	(9,591)	91,983,544	3	11	3,617	7,203	428,973	443,378	416,004	456,346	395,833	476,517
44	42	423,507	436,175	(12,668)	160,484,253	3	11	3,617	7,203	428,973	443,378	416,004	456,346	395,833	476,517
45	43	479,237	446,461	32,776	1,074,272,567	4	19	4,071	8,107	438,354	454,568	426,290	466,632	406,119	486,803
46	43	454,929	446,461	8,468	71,711,663	4	19	4,071	8,107	438,354	454,568	426,290	466,632	406,119	486,803
47	44	421,654	456,747	(35,093)	1,231,521,955	5	29	4,580	9,120	447,627	465,867	436,576	476,918	416,405	497,089
48	44	407,940	456,747	(48,807)	2,382,140,558	5	29	4,580	9,120	447,627	465,867	436,576	476,918	416,405	497,089
49	44	442,443	456,747	(14,304)	204,613,978	5	29	4,580	9,120	447,627	465,867	436,576	476,918	416,405	497,089
50	46	463,598	477,319	(13,721)	188,262,496	7	54	5,700	11,350	465,969	488,668	457,148	497,490	436,977	517,661
51	47	488,236	487,604	632	399,251	8	70	6,293	12,531	475,074	500,135	467,434	507,775	447,263	527,946
52	49	552,584	508,176	44,408	1,972,028,070	10	107	7,519	14,973	493,203	523,150	488,005	528,347	467,834	548,518
53	53	539,717	549,319	(9,602)	92,206,427	14	206	10,064	20,041	529,278	569,360	529,148	569,490	508,977	589,661
	53		549,319	(549,319)	301,751,776,227	14	206	10,064	20,041	529,278	569,360	529,148	569,490	508,977	589,661
Tot/Avg	39	401,631	360,787		21,564,019,133		934								

t = 1.99

Xm = 39					
Population Variance=		406,868,286			
				Upper Range	Lower Range
Population Standard Deviation of Regression	=	20,171	1s	421,802	381,460
			2s	441,973	361,289
Standard error of sendout projection		20,563			
T-factor		1.99			
(T factor) * (Std error of projection)		40,946			

Regression Results

Winter 15-17

Based On Data for Daily Temperatures <= 32 Degrees Fahrenheit

Regression Output:

Regression Output:		
Constant		4,171
Std Err of Y Est		26,150
R Squared		0.8209
No. of Observations		53
Degrees of Freedom		51
X Coefficient(s)	10,286	
Std Err of Coef.	673	
Zero Degree Temp Sendout		549,319
DD	53	

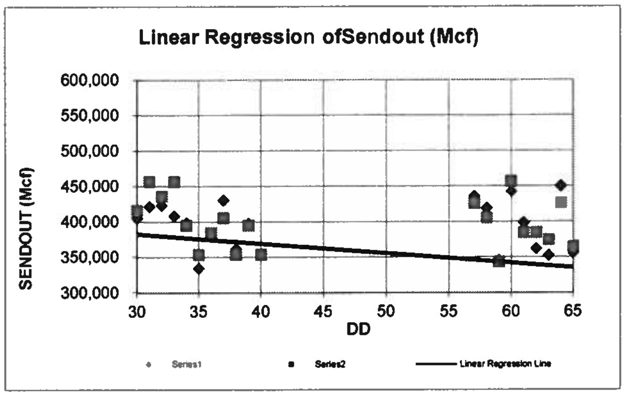
Quadratic

Regression Output:		
Constant		24,231
Std Err of Y Est		186,684
R Squared		1
No. of Observations		53
Degrees of Freedom		50
	X	X^2
X Coefficient(s)	9293.6895	12
Std Err of Coef.	9165.4603	111
		550,780

Cubic

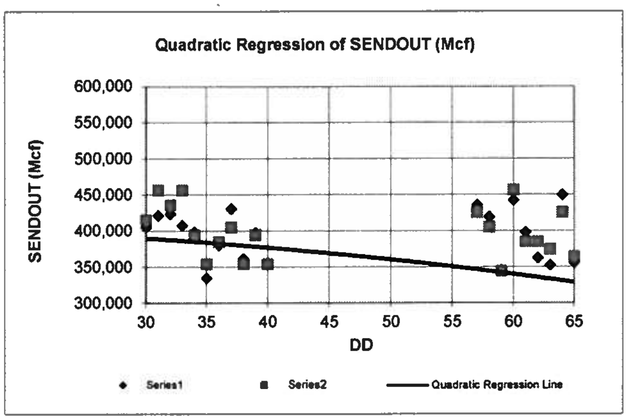
Regression Output:			
Constant		158,142	
Std Err of Y Est		1,436,281	
R Squared		1	
No. of Observations		53	
Degrees of Freedom		49	
	X	X^2	X^3
X Coefficient(s)	(479)	247	(2)
Std Err of Coef.	104,322	2,502	20
		549,807	

Regression Chart Analysis
Based Upon Data For Temperatures Of <=32 Degrees F.
Winters 15-17



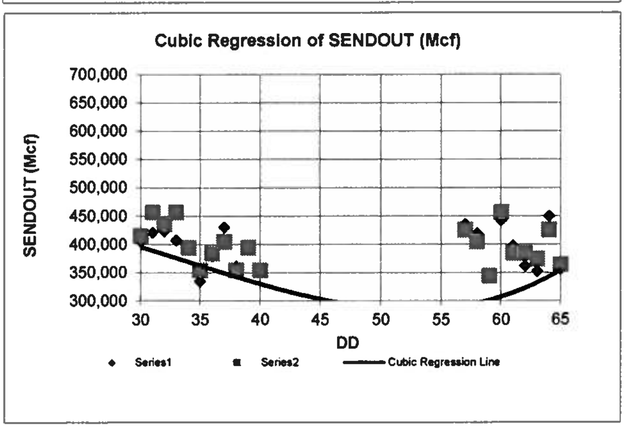
Linear Regression Output

	X	
Constant		4,171
Std. Error of Y Estimate		26,150
R Squared		0.821
Number of Observations		53
Degrees of Freedom		51
X Coefficient	10286	
Std. Err. Of Coefficeint	673	



Quadratic Regression Output

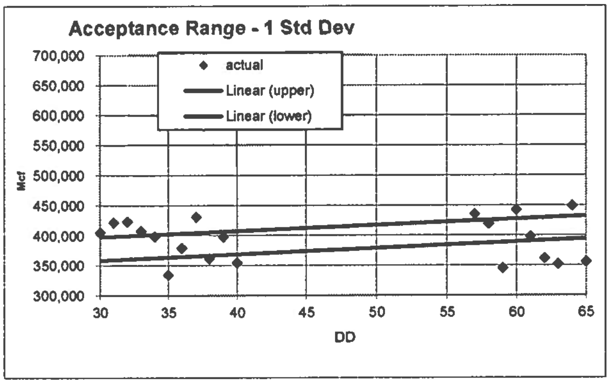
	X	X ^ 2
Constant		24,231
Std. Error of Y Estimate		186,684
R Squared		0.821
Number of Observations		53
Degrees of Freedom		50
X Coefficient	9,294	12
Std. Err. Of Coefficeint	9,165	111



Cubic Regression Output

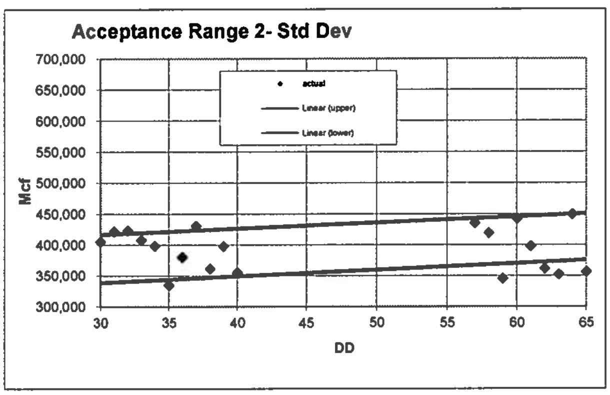
	X	X ^ 2	X ^ 3
Constant		158,142	
Std. Error of Y Estimate		1,436,281	
R Squared		0.821	
Number of Observations		53	
Degrees of Freedom		49	
X Coefficient	-479	247	-2
Std. Err. Of Coefficeint	104322	2502	20

Regression Chart Analysis
Based Upon Data For Temperatures Of <=32 Degrees F.
Winters 15-17



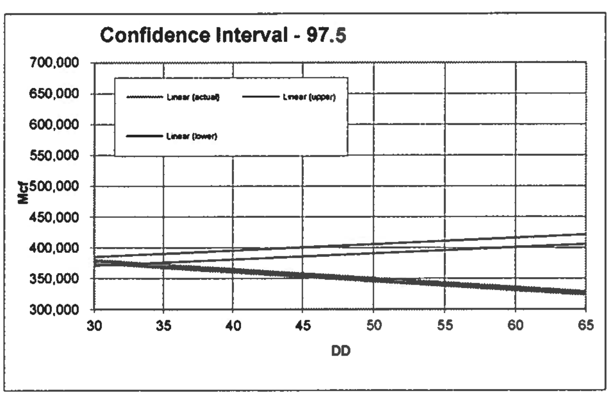
Acceptance Range @ 1 Standard Deviation

Regression Squared	406,868,286
Regression	20,171
Upper Range 1sd	421,802
Lower Range 1sd	381,460



Acceptance Range @ 2 Standard Deviation

Regression Squared	406,868,286
Regression	20,171
Upper Range 2sd	441,973
Lower Range 2sd	361,289



Confidence Interval: 97.5%

Regression Squared	406,868,286
Standard error of sendout projection	20,563
X Mean	39
T Distribution	1.99

ICF INTERNATIONAL

PGW Natural Gas Supply Study

Prepared for
Philadelphia Gas Works

August 2006

Outline

- Introduction
- Market Context
- Design Winter and Day Analysis
- Supply Analysis and Issues
- Conclusions and Recommendations

Purpose of Demand Estimation Review

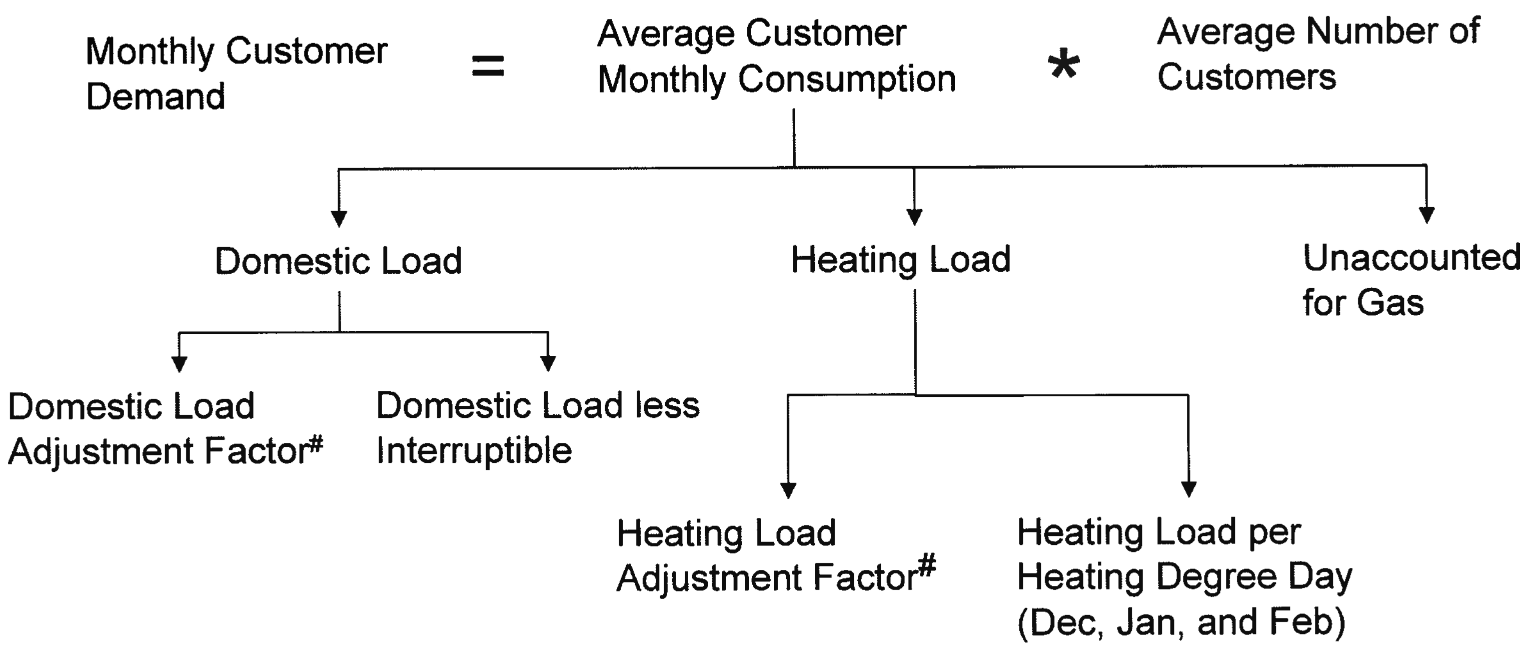
- Design day and winter parameters drive investment decisions and asset allocations
  - Pipeline capacity
  - Storage capacity and utilization
  - LNG storage and vaporization
- Design parameters in turn impact system costs
  - Capacity payments
  - Inventory holding costs
- ICF used design day and design winter estimates to determine the appropriate gas asset mix

PGW's Approach to Estimating Demand

ICF INTERNATIONAL

- PGW uses a combination of inputs into demand estimation
  - Historical demand trends for each customer class
  - Customer surveys
  - End use studies – appliance characteristics
  - Judgment of system operators
- Demand is related to temperature through heating degree days (HDD)
- Capacity planning focuses on the "Design Winter" and "Design Day"
  - These are concepts of peak demand that define the largest amount of gas that PGW must be able to deliver to meet system requirements and maintain system integrity
  - These represent statistically derived historical system peak limits

PGW Demand Estimation Methodology Overview



#Adjustment Factors account for error in estimation of demand in previous year

PGW Demand Estimation Methodology Evaluation

- Domestic Load is estimated by using latest year customer load thus accounting for improvements in energy efficiency of customer appliances
- Heating Load Adjustment Factor is estimated using normalized Heating Degree Days thus representing only error in estimation methodology
- Design Day demand estimated using firm load thus making the forecasting regression methodology robust
- Design Day demand estimated using four year peak day heating degree days allowing for a good fit

Philadelphia Winter Heating Degree Days

ICF INTERNATIONAL

Data Set (1976-2005)	Nov	Dec	Jan	Feb	Mar	Winter Season
Historical Mean Degree Days	533	862	1,028	844	671	3,938[b]
Historical Peak Degree Days	762	1,219	1,400	1,183	911	4,535[b]
No. of Sample Observations	30	30	30	30	30	30
Sample Standard Deviation	95	144	162	129	99	213
Data Relative to Mean[a] (%)	18	17	16	15	15	5[b]
PGW's Design Degree Days	608	1,005	1,191	973	778	4,555

Notes:

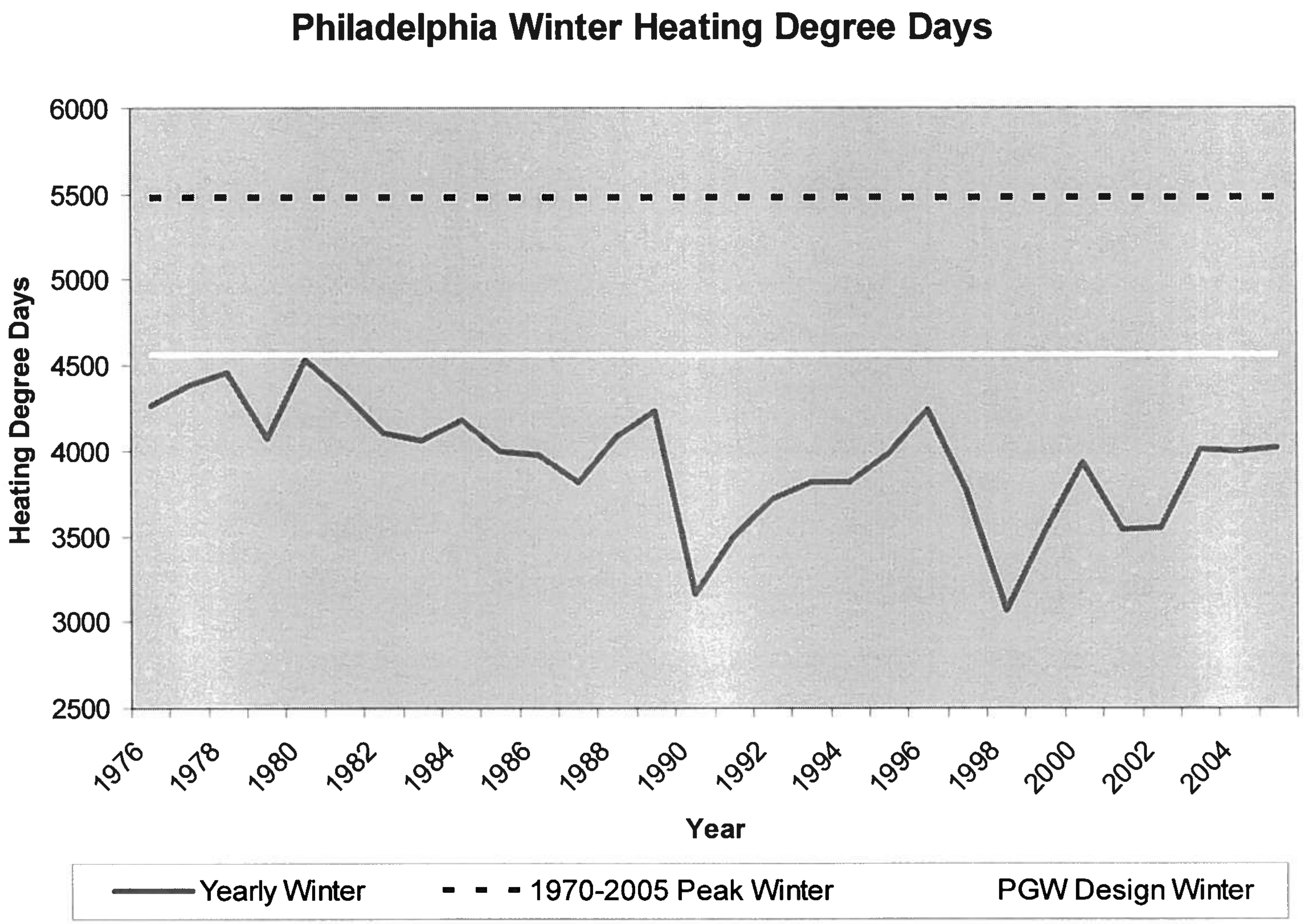
[a] It is coefficient of variation, calculated as (sample standard deviation/sample mean)*100.

[b] Individual months do not add up to this total, because it has been calculated independently using the historical winter season data or the standard deviation for the season total.

PGW Design Degree Days are higher than NOAA estimate because of the location and frequency of measurements. PGW measures several times per day at the Richmond Plant. NOAA uses a simple average of the high and low temperatures.

Passion. Expertise. Results.

PGW Design Winter Heating Degree Days



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PGW's Design Year Estimates

- The previous slide compares the design winter based on coldest winter in 30 years with historical winter weather and the theoretically coldest winter, measured in heating degree days (HDDs).
- Recent winters have been warmer than in the 1980s, and the trend suggests warming.
- PGW's design winter is still substantially below the theoretical coldest winter
  - Theoretical coldest winter includes the coldest winter months picked from the last 30 years and assumes each month is the thirty year cold month

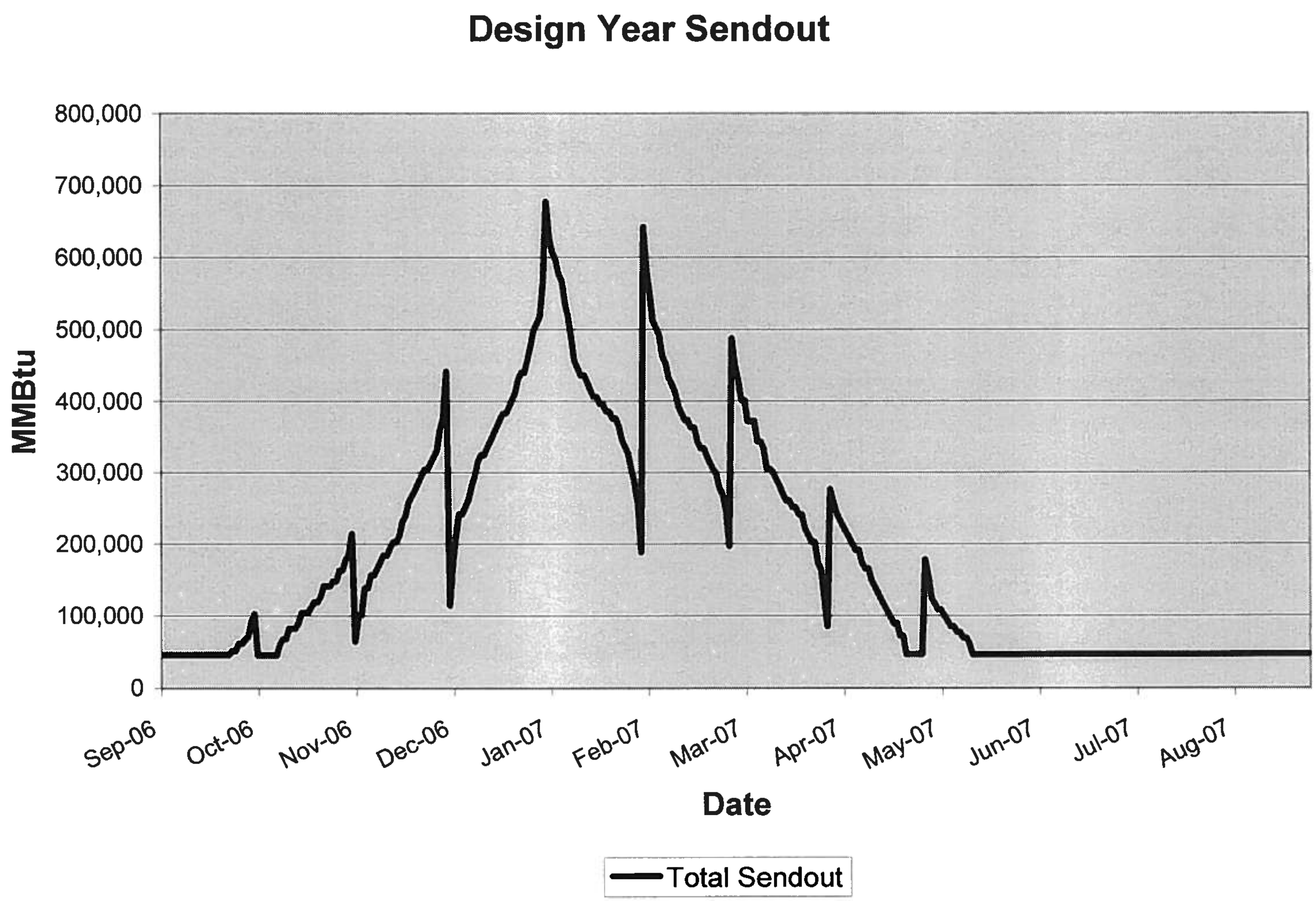
Findings on Peak and Winter Demand

- PGW's approach remains essentially the same as was reviewed in the previous study.
- PGW's approach yields a forecast of design day and design winter that are reasonable estimations.
  - The design conditions are below "theoretical" worst case (which could yield higher than necessary investments)
  - The probability of meeting design winter conditions remains approximately once in every 16 years.
- PGW's approach incorporates recent trends in local markets towards more efficient equipment and demand response to prices.
- Potential for demand growth is modest (given local and national trends).

ICF's Approach to Estimating Design Winter Sendout

- First step is to use design winter parameters for 2006-2007 provided by PGW for its PGC filings with the Philadelphia Gas Commission.
  - These data are from September through August and in the form of load duration curves for each month.
- Data were converted to April through March and randomized to reflect typical random weather and gas pricing patterns.
  - Converting data for April through March makes modeling storage easier
  - Gas sendout and prices are correlated
- Design and average years were differentiated.
  - All the analysis is based on daily, sequential sendout
  - Average and design years differ only in winter sendout

Design Year Sendout for Planning – Sept. 1 to August 31



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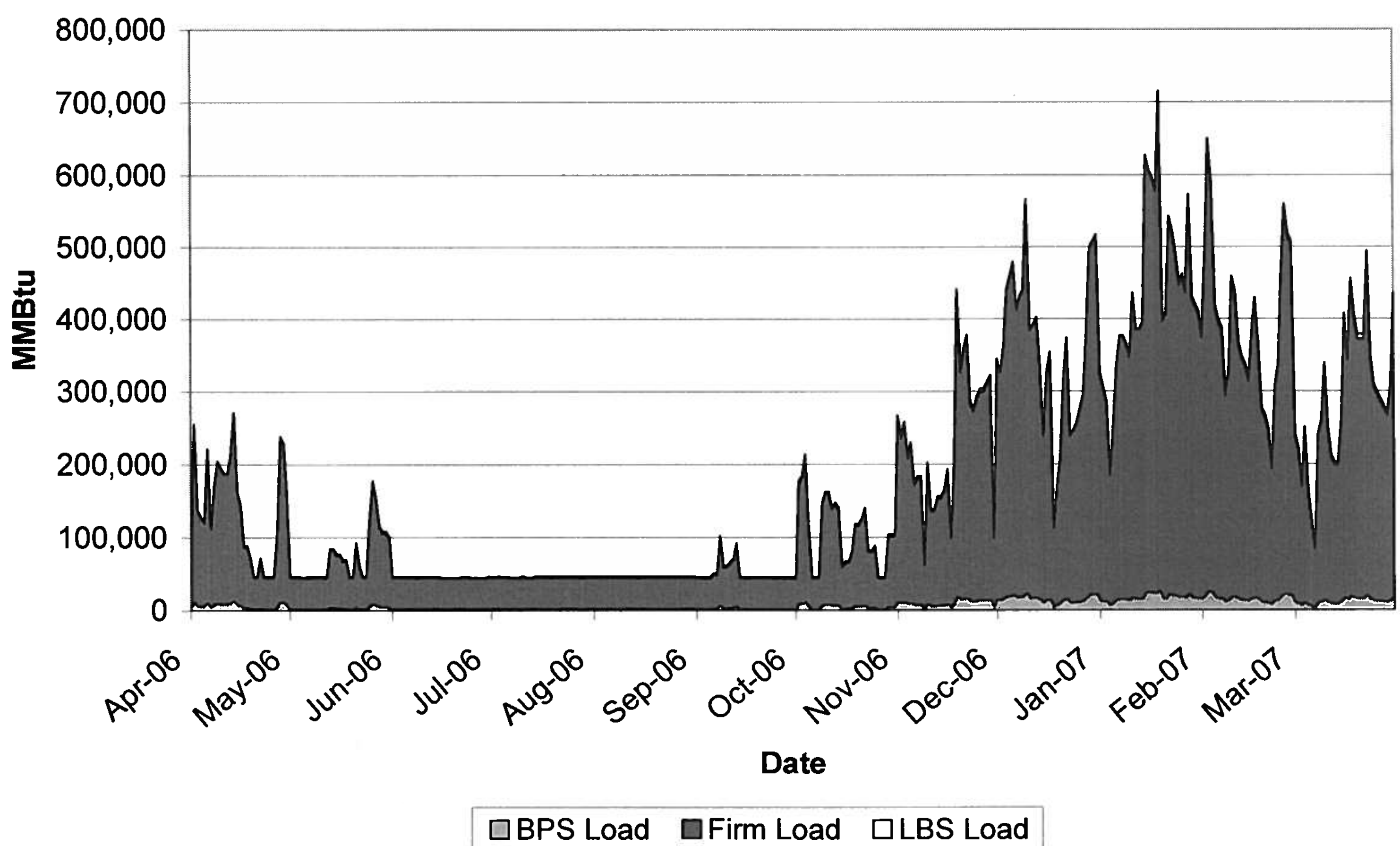
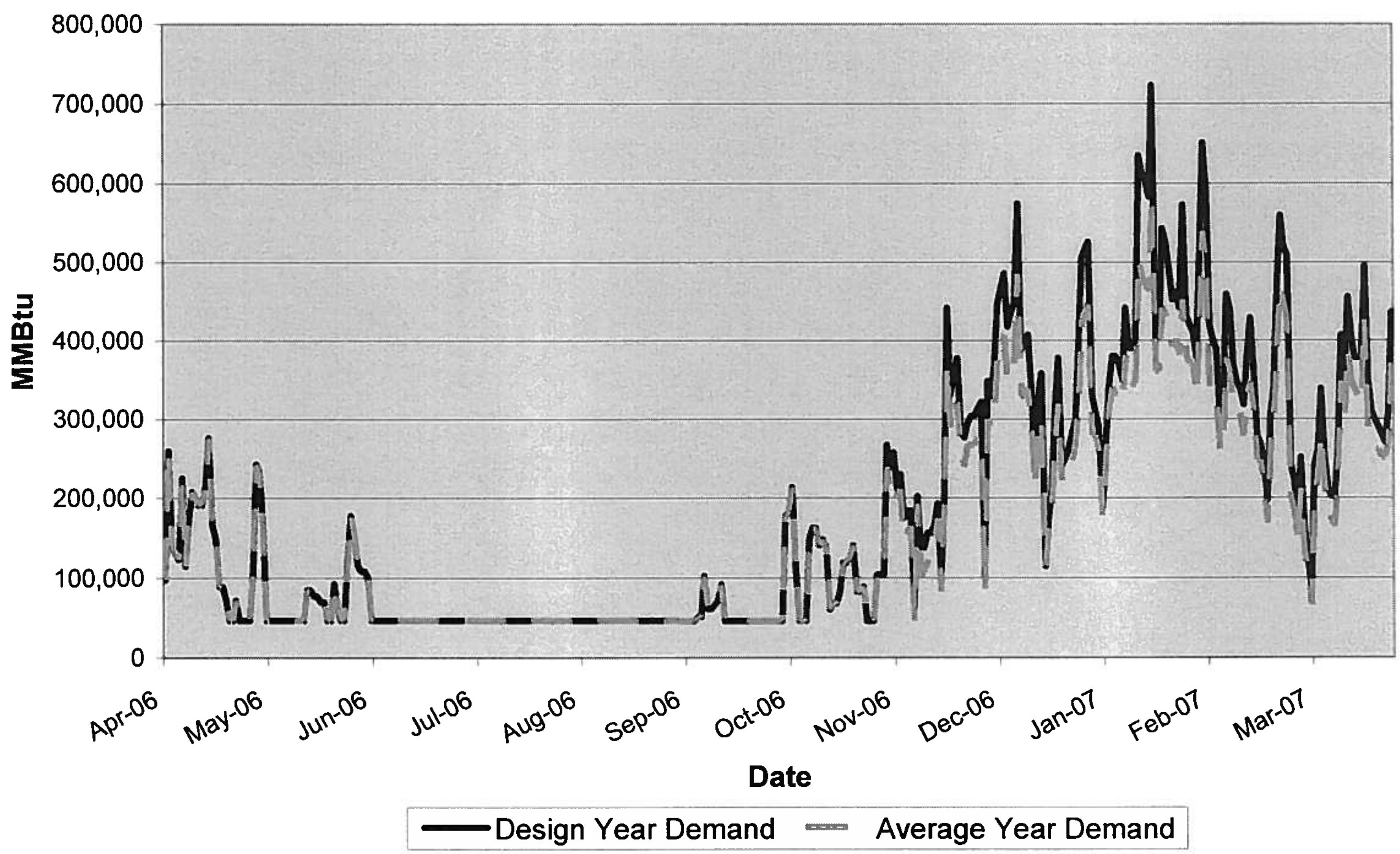
Sendout Reordered and Randomized – April 1 to March 31

PGW Reference Case Sendout

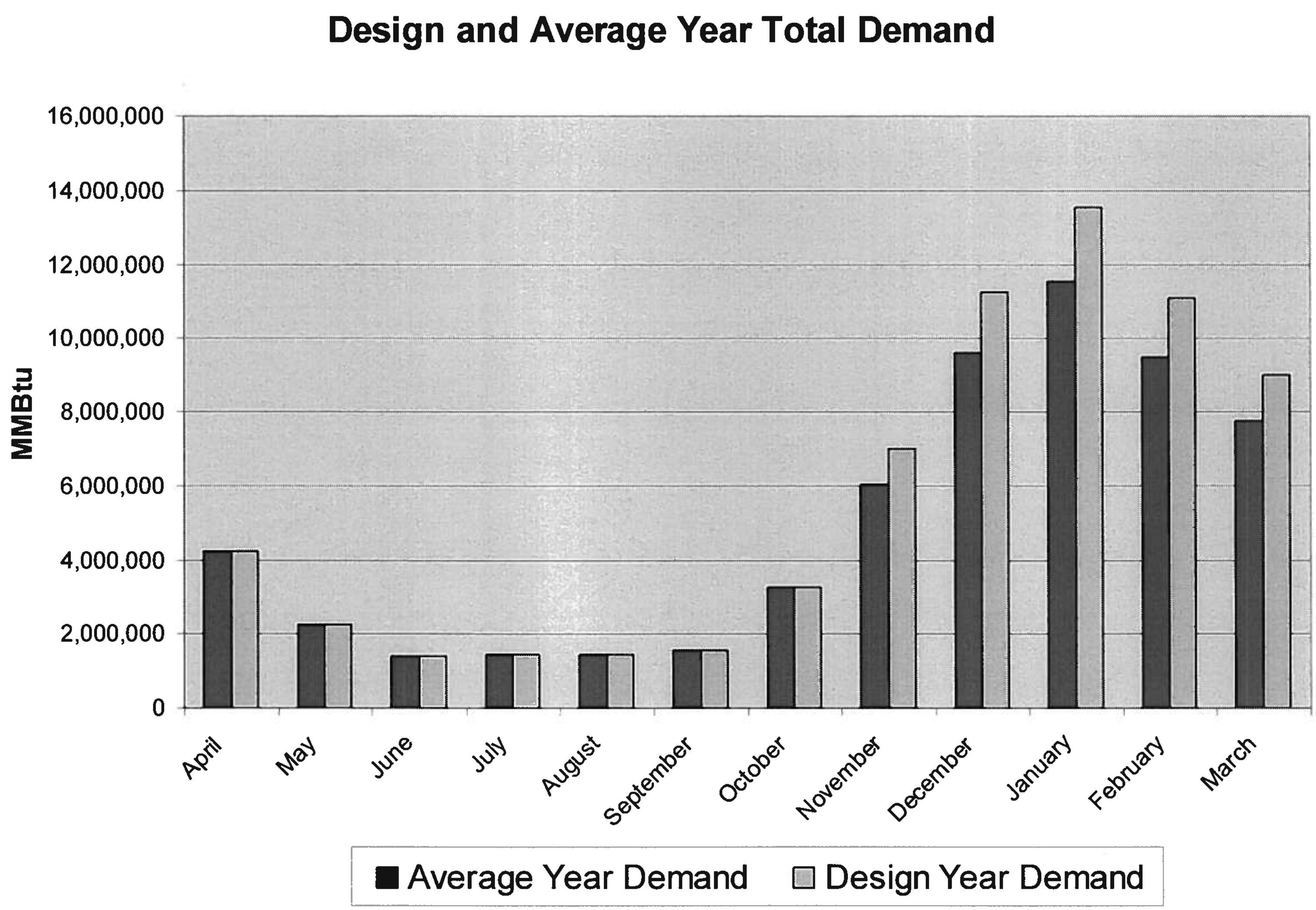


Demand Patterns Modeled Consistent with Gas Prices

Design and Average Year Total Demand



Design and Average Winter Demand -- Simplified



Observation: Design Day Deliverability is an Incomplete Measure of Asset Value

- Comparing Design Day requirements with available options is not a complete analysis.
- PGW operates with a 12 percent reserve margin over Design Day sendout requirements. This does not appear unreasonable.
  - Deliverability options on Design Day include
    - Transco long haul pipeline capacity
    - Transco GSS storage
    - Tetco/Dominion/Equitrans Storage delivered through Tetco FTS services
    - LNG
    - PAID – released capacity which has no long term fixed costs
- Design Day does not account for "Design Hour" requirements to maintain system pressures
- Design Day does not account for storage optionality in volatile gas markets.

Conclusions and Recommendations

- PGW's approach to estimating design winter and day conditions is reasonable and yields results that are prudent for capacity planning purposes.
- PGW uses its full pipeline capacity during winter seasons. Overall capacity utilization is higher for Transco, which is the lower cost pipeline, than it is for Tetco.
  - PGW has some opportunities to release capacity on these pipes, or engage in off-system sales when capacity is not needed for native load.
  - PGW should not permanently release capacity without call-back rights for winter seasons.
- PGW storage services appear adequate to meet peak requirements.

Tab 13

Docket No. R-18XXX
Item 53.64 (c)(14)

Philadelphia Gas Works

Pennsylvania Public Utility Commission
52 Pa. Code §53.61, et seq.

Item 53.64(c) Thirty days prior to the filing of a tariff reflecting an increase or decrease in natural gas costs, each Section 1307(f) gas utility seeking recovery of purchased gas costs under that section shall provide notice to the public, under § 53.68 (relating to notice requirements), and shall file the following supporting information with the Commission, with a copy to the Consumer Advocate, Small Business Advocate and to intervenors upon request:

(14) Analysis and data demonstrating, on an historic and projected future basis, the minimum gas entitlements needed to provide reliable and uninterrupted service to priority one customers during peak periods.

Response: Attached is the Capacity Resource and Asset Management Evaluation Report completed by Summit Energy in January, 2011.

JAN 25, 2011

Capacity Resource and Asset Management

EVALUATION REPORT

SummitEnergy

PGW®

Table of Contents

Executive Summary

After conducting a thorough review of PGW's existing asset portfolio, historical operations, and future load projections; and based upon the assumptions and market dynamics stated herein, Summit has identified several recommendations for the utility's consideration. All recommendations have been made based upon the fundamental premise that PGW's primary objective is providing reliable and cost-effective natural gas supply to its customer base. Each of the recommendations can be considered independently of the others.

After comparing PGW's capacity to its design forecast, Summit recommends the utility evaluate eliminating or reducing portions of its existing asset base, provided favorable asset management arrangements cannot be attained. A stack ranking methodology of the cost of each asset was utilized to help determine the most appropriate areas of focus. Based upon its volume and high cost, Summit recommends the release of PGW's Equitrans storage. In addition to eliminating the Equitrans storage from the utility's portfolio, Summit also recommends consideration be given to reducing its Dominion storage (in addition to its associated Tetco FTS-7 and FTS-8 contracts). We estimate that with a reduction of 10,000 Dth of demand of the Dominion storage (along with the associated storage capacity and FTS transport contracts) PGW would still be capable of serving design scenarios. Despite the utility's ability to meet design scenarios with the recommended capacity reductions, it is important to note that such reductions will increase the utility's reliance on LNG and reduce capacity release credits to the gas cost rate. Additionally, reduction of the Dominion storage from approximately 4 Bcf to 3 Bcf could result in new contract rates that may diminish some or all of the potential savings.

While Summit recommends consideration of the elimination and reduction of some assets, we also recommend maintaining others due to their associated value. First and foremost, we recommend PGW retain all existing long-haul interstate capacity due to both its cost-effectiveness as well as the utility's lateral delivery requirements. Additionally, as both Tetco and Transco are fully subscribed it is questionable whether such capacity could ever be regained in the future if it were surrendered.

While we also currently recommend the retention of PGW's production area storage, the market should continue to be monitored for changing dynamics that would impact or alter the future value of the storage assets. Despite the protection that is afforded against balancing penalties and supply disruptions in the production area, this type of storage becomes less valuable in a marketplace lacking volatility.

Summit also recommends PGW continue to actively monitor potential new asset opportunities. With the significant changes that are taking place in the natural gas complex and particularly in the Northeastern US, it is possible that new supply and/or capacity alternatives could develop that could displace or replace current assets.

When taking into account PGW's assets and historical operations, one additional recommendation is to evaluate the feasibility of creating a more dynamic management of the utility's underutilized long-haul capacity. While the utility currently manages an active capacity release program, it is possible that additional benefits could be gained through administering an even more vigorous program. More participation in weekly long-haul capacity releases could yield incremental returns over and above what has historically been received. Based on current market conditions and the complexities involved, Summit would recommend PGW manage any enhanced release program at this time versus relying on a third party.

The market dynamics in the Northeast have vastly changed in the past several years and are still rapidly evolving. Therefore, Summit recommends a short-term approach to any further contractual asset retention. It is also Summit's belief that PGW would be well served to internally re-evaluate its asset portfolio on a regular basis (annual to every two years) to ensure it can take better advantage of any future market developments.

In conclusion, Summit advocates that PGW utilize the enclosed report to consider these recommendations and take action accordingly.

Introduction and Scope

The following report outlines independent analysis conducted by Summit Energy Services, Inc. (Summit) regarding the natural gas capacity resources of Philadelphia Gas Works (PGW). This assessment was constructed based upon a thorough investigation of the utility's existing gas capacity asset portfolio, the utility's servicing obligations, and a detailed review of existing and projected market fundamentals. The study consisted of the following:

- Review and analysis of PGW current gas supply infrastructure assets (pipeline capacity, storage, and LNG)
- Assessment of range of appropriate levels of capacity resources
- Investigation of alternative supply and/or capacity options
- Examination of value of utilizing third party asset management
- Review of asset management payment structures

Background

PGW initially engaged Summit through a competitive request for proposal to perform a thorough evaluation of both PGW's capacity portfolio holdings and its commodity purchasing strategies. PGW program evaluations have been periodically performed by independent parties in the past, the most recent being a study issued by a third party in 2006. Such studies must be re-evaluated at discrete time intervals to consider changes not only in the load characteristics of PGW itself, but also to evaluate changes that occur in both the commodity and capacity markets.

Summit Approach

Upon engagement, Summit reviewed historical testimony of PGW personnel outlining the utility's operational practices as well as the aforementioned study from 2006. In addition, Summit reviewed testimony from prior Gas Cost Rate (GCR) proceedings.

PGW has historically maintained the perspective that keeping the existing infrastructure portfolio intact best enables the utility to provide safe, adequate, and reliable service to its customers. Although there were recommendations which advocated the future consideration of shedding the most marginal economic assets in the portfolio, the previous study largely supported the utility's viewpoint. A contrary opinion from a GCR proceeding participant, however, called for more definitive action, stating that PGW had a large amount of excess capacity that needed to be relinquished, and that its current portfolio holdings were causing the GCR to be inflated.

As Summit prepared to re-evaluate the PGW portfolio and provide its own assessment, the utility collected and disseminated updated information to Summit including the following:

- Most current information concerning historical design day, design year, and actual delivery send out data
- Utility-controlled Liquefied Natural Gas (LNG) liquefaction and vaporization capacities, boil-off histories, and historical monthly inventories
- Capacity release and off-system sales histories, including both long-term and short-term transactions
- Third party supplier agreements designating volumes, price structures, optionality, delivery points, etc.
- Commodity purchasing program details, including historical purchase information

The provided data was supplemented with questions set forth by Summit as additional information was required, as well as with detailed interviews of PGW strategic and tactical personnel. These discussions provided opportunities to learn about operational constraints and details that were not set forth in the provided documentation. This was particularly necessary with the LNG asset evaluation, as this was not jurisdictional at the interstate level and lacked the visibility of FERC-mandated tariffs for long-haul and storage capacity.

Summit next engaged in its own analysis independent of PGW. This consisted of first establishing a set of assigned costs for each capacity asset in the PGW portfolio. This included a standard set of assumptions involving the commodity cost, heating values, utilization of current interstate pipeline tariffs, and other factors to make sure assets were evaluated using equivalent measures.

Summit included all relevant costs for each asset to assign an "as delivered" cost. This included demand charges, commodity charges, fuel, as well as any carrying costs for assets such as storage and LNG. Storage assets also included transportation for both injection and withdrawal capacity to deliver to the PGW city gate. Additional considerations such as storage cycling requirements and load factor assumptions were also integrated. After each asset was assigned a cost, Summit then stack ranked the assets to ascertain relative costs.

Once such analysis was complete, Summit prepared both a "snapshot analysis" of how PGW is currently managed, as well as a set of recommendations to best position PGW in the future in light of market shifts. These findings and recommendations are incorporated herein.

PGW Historical Operations

Reviewing the historical performance of PGW operations, Summit concludes that PGW has succeeded in its core mission of ensuring that all system delivery requirements are fulfilled. PGW has not had to curtail firm service customers and has been able to satisfy all design day and design winter delivery scenarios. Thus, it is evident that the current asset portfolio is adequate to meet needs now and into the anticipated future. This does not answer the question, however, of whether PGW carries excess capacity in its portfolio. This issue is discussed in the recommendation section of this report.

Long-haul Transportation Capacity

Due to the nature of peaking assets not being required at all times, utilities are naturally over-subscribed (or "long") on their capacity during most periods. While it would be optimal to have "load following" capacity, it is not feasible for pipelines to provide this service. Thus, most interstate pipeline long-haul firm transportation and storage are based upon demand charges for the largest amount of capacity the purchaser requires on a given day. This requires a careful balancing of one's needs.

Generally, PGW has performed well balancing such needs. Interstate long-haul capacity is first scheduled to serve "as needed" daily demand, with any unutilized capacity next being scheduled to deliver gas into either interstate storage or PGW-owned LNG liquefaction facilities. Any excess capacity beyond such needs is released into a relatively liquid secondary capacity market using an internal bidding system supplemented by the applicable interstate pipeline electronic bulletin board (EBB) system. This allows other entities to bid on such capacity, though PGW permits the originally selected bidder to retain a right of first refusal to match the right of the highest bid.

PGW's participation in the secondary capacity markets allows them to effectively recoup or "monetize" assets on otherwise sunk costs. The values of these assets can fluctuate over time, and are typically less valuable in times of lower demand.

Storage Capacity

Storage is critical towards achieving the goal of delivering peak day needs, as interstate capacity alone is insufficient for this task. Interstate storage is another asset that PGW extensively utilizes, and is largely divided into production area storage (Gulf region) and market area storage (Pennsylvania market area). These classifications are important due to their very different strategic characteristics.

Production area storage tends to have large amounts of capacity associated per storage field (many are abandoned gas reservoirs), and usually does not have equivalent long-haul transportation contracts associated directly with it, although there are usually receipt point rights that match the storage field.

Production storage has three primary functions. First, it can be used when there are temporary issues with obtaining gas from the furthest points in the Gulf due to hurricanes or well freeze-offs in the winter season. Owners of such storage can make withdrawals until the supply disruption ends.

Second, variations between actual usage and nominations can be managed with storage assets to avoid daily balancing penalties. Additionally, the potential for large penalties (upward of $50/Dth) to be incurred during Operational Flow Order (OFO) periods would be less likely to materialize, as needed gas can be drawn from storage or unnecessary gas can be injected. This is valuable during crisis times when it is difficult to purchase or sell incremental gas.

Finally, the use of storage in "contango" markets (those where future pricing is significantly higher than current month pricing) make it less expensive to purchase gas in current months, carry volumes in storage, and then withdraw it during higher priced periods. As long as the future month price premium exceeds the cost of the storage assets, storage is a tool for price risk management, in addition to its physical reliability.

Market area storage shares many of the same characteristics as production area storage, but there are some key differentiators. As many of the storage fields have physically less capacity, PGW is required to contract for multiple storage services, each of which has differing pricing and deliverability structures. This does have an ancillary benefit, however, since it effectively diversifies their portfolio across multiple locations, and allows for receipt of gas at additional delivery points in the event of force majeure.

Market area storage is designed to provide security of supply in the event long line purchases are lost, to meet peak day demand and design year requirements, and to provide swing and balancing service. In addition, it provides a physical price hedge for a portion of the portfolio. PGW manages these fields to be regularly "cycled" according to minimum pipeline requirements.

PGW-Owned LNG Infrastructure

PGW has substantial LNG assets that are owned and maintained internally, including storage facilities at Richmond (4,045,800 Mcf capacity) and Passyunk (253,000 Mcf capacity). These assets are critical to the utility's ability to meet design day capacity needs due to their large vaporization and send out capabilities (411,000 Mcf/day and 47,000 Mcf/day, respectively). As is typical with LNG storage managed by utilities, PGW holds LNG in order to meet high deliverability needs on a short-term basis, often in the form of "needle-peak" demand spikes in the winter season.

LNG has several drawbacks when compared to more traditional natural gas deliveries. First, liquefaction occurs at much slower rates than the vaporization itself, so replenishing exhausted supplies requires considerably more time. While a market exists for delivered LNG, the associated costs are uneconomical. Second, PGW's current liquefaction system achieves maximum efficiency only during select parts of the year (late winter and autumn), so it is a rigid schedule.

While there are limitations, the LNG capacity PGW owns has some unique benefits. First, the capacity itself is substantial (approximately 4.3 Bcf). Although it would only satisfy 10 days of deliverability at full utilization, the LNG provides insurance against a catastrophic upstream event. Second, it serves as an economic arbitrage tool in the event of a price spike. In such an event, PGW could look to sell incoming pipeline/storage gas to another delivery point for a short period of time, and displace such delivery with LNG. Thus, while illiquid relative to capacity markets, LNG assets could actually result in higher monetization in selected instances. Lastly, as they are self-owned, these LNG assets are not subject to the same rules governing interstate storage, including cycling requirements, variable tariff pricing over time, etc.

Capacity Monetization

PGW employs a variety of strategies to balance its own load requirements and effectively mitigate demand charges. They have increasingly become an active participant in the capacity release market and generally have had little difficulty finding a third party to whom it could release its excess pipeline demand. PGW releases capacity as available on either a monthly or semi-monthly basis dependent upon how actual load is performing relative to plan. They have been successful at obtaining values for some longer term and winter releases near, at, or above maximum tariff rates. This practice helps to offset nearly all demand charges associated with those volumes that are released. Conversely, shorter term releases made during the summer season have often yielded values that are well below actual demand cost, which in turn fail to recover the total cost of the released volumes. Over recent years, PGW's expanded capacity release activities have yielded an average release benefit increase of over 600% when comparing the early 2000's to the years leading up to 2010.

In addition to the capacity release strategy, PGW historically has looked at off-system sales (i.e., bundling capacity availability with natural gas itself and selling to third parties at delivery points other than PGW). This option has several limitations per PGW's current resource mix. The off-system sales market is much more short-term in nature (often for a few days at most) and for maximum benefits requires marketing of the supply. Additionally, unlike capacity release, which utilizes the pipeline EBB to monitor and credit back demand dollars, PGW has to devote resources to nominate gas and bill the buyer accordingly. This method of cost recovery works best when pricing substantially rises due to system constraints or extreme weather conditions. In select years past, this was strictly done during instances where PGW was solicited by a third party. Such activities yielded financial benefit for the utility and were based upon existing market conditions.

PGW has also recently employed a one year asset management agreement for a portion of its storage capacity. This type of release has the potential to recover all or more than the value of the actual demand charges. A third party will often pay a premium for such assets (as often pipeline storage can be oversubscribed) to more effectively arbitrage trading positions.

PGW has utilized this strategy successfully for their Transco WSS production storage, releasing approximately half of their storage position to a third party at a rate that exceeded the utility's actual tariff costs. Under this Asset Management Agreement (AMA), PGW releases 1.5 Bcf of Transco WSS storage capacity in return for $1.1 million via monthly payment installments. The third party arrangement, which is currently the only instance of PGW utilizing the services of an outsourced asset manager, has been a lucrative agreement for the utility based on the market value of the storage capacity. That said, it should be noted such values of storage will fluctuate with the market and the value that can be derived will vary.

Assumptions

Summit approached its analysis with a core set of assumptions. Some of these are more numerical in nature to better evaluate the assets in the portfolio on an "apples to apples" basis. Others more specifically focus around organizational goals.

Reliability

Summit operated under the fundamental premise that PGW has a mandated public service duty to ensure that its service delivery requirements must always be met. This is a different operational mindset than what is held by many non-utility entities. For instance, a for-profit industrial might elect to shut down production and sell off any gas if premium prices existed in the marketplace. Other companies, such as trading entities, might incorporate a greater element of risk into their decision-making by reducing capacity commitments and relying on supply availability at the time it is required.

Summit also focused on unique attributes of the PGW system, especially its reliance on interstate pipeline laterals and its limited LNG liquefaction capabilities. Although PGW is served by the interstate pipeline system, PGW is actually fed by laterals off of the main pipeline system which constrains deliveries during winter peak demand times when the laterals are delivering full requirements. In addition, Summit examined the relative subscription rates of capacity and storage on the interstate systems to determine the availability to replace any asset removed from the capacity portfolio. Based on such analysis, one core assumption is that there currently tends to be a limited ability to replace service with alternative firm asset commitments. Last, Summit assumed that a financial commitment (i.e., a delivered contract with liquidated damages) was inferior to a physical asset, due to downstream damage that could be created in the event the supplier was unable to fulfill delivery requirements during a peak day.

Economics

Summit prepared its analysis with a standard set of economic assumptions to ensure uniformity as it evaluated each capacity asset in the PGW portfolio. While such assumptions would change over the contract life of the respective assets and under varying commodity pricing thresholds, the relative values of each asset generally remain consistent.

Forward pricing of natural gas changes daily, so to incorporate consistency in our analysis, our first assumption was a base case NYMEX estimate of $5.00/Dth. Additionally, analysis was run using NYMEX estimates ranging from $3.50/Dth to $7.00/Dth in various scenarios.

Summit also used currently effective tariffs to project demand and commodity charges, fuel ratios and storage ratchet requirements. Such numbers are subject to future rate case adjustments, but generally have more stability than the natural gas commodity itself. While different pipeline filings could affect the value of one capacity asset versus another, such changes occur infrequently and can be evaluated periodically to ensure where they each rank from a cost standpoint. PGW has swing contracts within their supply portfolio that carry an additional pipeline demand component, as these are no-notice contracts. The models do not take these additional demand charges into account, as the impact of these charges on the stack ranking would be negligible.

Operations

Where necessary, Summit assumed a Btu conversion of 1.03 to convert Mcf measurements to Dth. This is also the value used by PGW in many of their conversions, and typically, there is low variation in Btu factors across interstate pipelines.

Historical data indicates consistent year-over-year load declines independent of weather factors, which has been confirmed by PGW's own analysis. While this decline is generally modest (approximately half a percent per year), this reinforces the need to perform an internal review of its assets based on current and future needs. For our analysis, Summit used the 2010/2011 Design Day/Year model (shown on next page). Summit did not model asset needs based on a normal load forecast as this was considered imprudent given PGW's core mission of customer reliability.

Second, Summit assumed historical storage injection and withdrawal patterns, including fulfilling cycling requirements as governed by tariffs. This includes injecting gas on a daily and seasonal basis, which limits maximizing more aggressive “fill” strategies that would be based solely on price. Similarly, withdrawal from each individual storage field creates both a floor and a cap on deliverability. Summit assumed compliance with applicable pipeline tariffs as well as a fairly consistent cycling pattern based upon historical data.

2010-11 Design Forecast* (MDth)

	Sep-10	Oct-10	Nov-10	Dec-10	Jan-11	Feb-11	Mar-11	Apr-11	May-11	Jun-11	Jul-11	Aug-11
1	42.0	42.5	62.3	115.3	678.7	645.5	475.2	282.3	189.3	42.6	42.6	42.3
2	42.0	42.5	89.7	174.6	628.6	585.8	447.3	264.7	155.0	42.6	42.6	42.3
3	42.0	42.5	108.0	204.3	598.6	555.9	419.4	238.4	129.3	42.6	42.6	42.3
4	42.0	42.5	126.2	224.1	588.6	516.1	400.7	229.6	120.7	42.6	42.6	42.3
5	42.0	42.5	135.3	243.8	558.5	506.2	391.4	220.8	112.2	42.6	42.6	42.3
6	42.0	42.5	144.5	273.5	538.5	486.3	382.1	212.0	103.6	42.6	42.6	42.3
7	42.0	42.5	153.6	283.4	518.5	466.4	372.8	203.2	95.0	42.6	42.6	42.3
8	42.0	57.7	162.7	293.3	498.4	456.4	363.5	194.4	95.0	42.6	42.6	42.3
9	42.0	57.7	171.9	303.2	488.4	446.4	354.2	185.6	86.5	42.6	42.6	42.3
10	42.0	65.4	181.0	313.1	478.4	436.5	344.9	176.8	86.5	42.6	42.6	42.3
11	42.0	73.0	190.1	322.9	468.4	426.5	335.6	176.8	77.9	42.6	42.6	42.3
12	42.0	80.6	199.2	332.8	458.4	416.6	326.3	168.0	69.3	42.6	42.6	42.3
13	42.0	80.6	208.4	342.7	448.4	406.6	317.0	159.2	69.3	42.6	42.6	42.3
14	42.0	88.2	217.5	352.6	438.3	396.7	307.7	150.4	60.8	42.6	42.6	42.3
15	42.0	95.9	226.6	362.5	428.3	386.7	298.4	141.6	60.8	42.6	42.6	42.3
16	42.0	103.5	235.7	372.4	418.3	376.8	289.1	132.8	43.6	42.6	42.6	42.3
17	42.0	103.5	244.9	382.3	418.3	366.8	279.8	124.1	43.6	42.6	42.6	42.3
18	42.0	111.1	254.0	392.2	408.3	356.9	270.5	115.3	43.6	42.6	42.6	42.3
19	42.0	111.1	263.1	402.0	398.3	346.9	261.1	106.5	43.6	42.6	42.6	42.3
20	42.0	118.8	272.2	411.9	388.3	337.0	251.8	97.7	43.6	42.6	42.6	42.3
21	42.0	118.8	281.4	421.8	378.3	327.0	242.5	88.9	43.6	42.6	42.6	42.3
22	42.0	126.4	290.5	431.7	368.2	317.1	233.2	88.9	43.6	42.6	42.6	42.3
23	47.5	126.4	299.6	441.6	358.2	307.1	223.9	71.3	43.6	42.6	42.6	42.3
24	47.5	134.0	308.8	451.5	348.2	297.2	214.6	71.3	43.6	42.6	42.6	42.3
25	53.0	134.0	308.8	471.3	338.2	267.3	205.3	44.9	43.6	42.6	42.6	42.3
26	58.6	141.7	317.9	481.2	328.2	257.4	196.0	44.9	43.6	42.6	42.6	42.3
27	58.6	149.3	327.0	491.0	318.2	247.4	177.4	44.9	43.6	42.6	42.6	42.3
28	69.6	164.6	345.3	510.8	298.1	197.6	168.1	44.9	43.6	42.6	42.6	42.3
29	80.7	172.2	372.6	510.8	288.1		149.5	44.9	43.6	42.6	42.6	42.3
30	97.2	195.1	427.4	530.6	258.1		121.6	44.9	43.6	42.6	42.6	42.3
31		218.0		580.0	188.0		84.3		43.6		42.6	42.3

*Based on the temperature pattern for a design year in the PGW Model. PGW's design day send out at 0° is 681,200 Mcf.

Market Dynamics

An analysis of historical market drivers and pricing trends is often effective for establishing a forecast for future contingencies. This approach, however, loses efficacy if new pricing drivers are introduced such that the supply and demand fundamentals of the market are altered. The following analysis reveals that many pre-2007 market conditions are no longer domestic driving factors today. Further, a new paradigm has evolved in the natural gas complex specifically impacting Northeast gas transportation markets.

US Natural Gas Landscape

In 2006 and 2007, most, if not all, energy markets were indicative of the rapid economic growth experienced both domestically in the US, and abroad. Natural gas consumption continued to witness an upward growth trend into 2007, pushing demand to record levels. Optimism of seemingly unstoppable growth for energy helped push fuel prices to elevated levels and had most market analysts expecting an extended upward trend in prices, which in turn resulted in growing investor interest.

Coming out of 2007, demand evidence was compelling: US natural gas consumption in the first half of 2008 exceeded that of 2007, setting new five-year highs. Demand was not alone in supporting prices during this time. After many years of strong investment in natural gas exploration and production (the gas rig count had been setting new highs for four years running), natural gas production in the US was unable to keep pace with demand. The amount of gas in storage was insufficient at five-year average levels. The result: a steady uptrend in pricing through 2008.

The impact of the "Great Recession" on US natural gas consumption was delayed, but by early 2009, demand had fallen to five-year minimums. Despite this, US natural gas production remained very strong as a result of the favorable investment environment of 2008. In fact, gas production in the US set new highs in 2009. High volumes of natural gas in storage resulted and subsequently persisted throughout 2009. As such, gas prices fell coming out of 2008 and heading into 2009.

In mid 2009, US natural gas consumption began showing signs of recovery and had recovered to near five-year highs by early 2010. US natural gas production also continued to show impressive growth as a result of shale production and storage volumes reached an all-time high in November 2010. Logically, gas prices have remained near the $4-$5 range since March.

As we turn to 2011 and beyond, a few major themes emerge as key drivers for the US natural gas market. Demand hinges on industrial market recovery as well as technological advancements through increased investment in the exploration and production industry. The fundamental outlook going forward is for strong growth in production to persist at rates greater than the expected growth in consumption. As such, Summit anticipates prices to remain relatively flat through 2011 and into 2012. Over the next 5 years, our outlook is for the market to move in a slightly upward direction; however, prices are not expected to reach the highs seen pre-2009.

Regional Transportation Pricing Landscape: Northeast

Basis costs in the Northeast historically have been heavily influenced by the incremental escalation of regional natural gas demand while interstate pipeline capacity infrastructure has remained relatively static. The resulting shortage of pipeline capacity to bring sufficient gas into the region created a floor for regional transportation prices making the Northeast a premium gas market. Other regional market drivers like weather, particularly the severity and duration of winter temperatures and precipitation, LNG capabilities, and Canadian gas imports into the region have also been key pricing drivers.

Much has changed in the Northeast since the 2006 study of PGW's assets was completed. The 2006 study was written in the wake of two major hurricanes in 2005 that introduced extreme national natural gas pricing volatility and took significant Gulf supplies off-system for the winter of 2005-2006. Since 2006, we have not seen similar destructive hurricane activity hit producing regions in the Gulf. Subsequently, the credit crisis of 2008 introduced another macro-environment alteration to the industry. Additionally, the cost of obtaining capital for the whole of the industry increased.

The largest market drivers in the Northeast post-2006 have not been the credit crisis nor hurricane activity. Rather, the Northeast natural gas market has responded to simple supply and demand fundamentals consisting of an increase in production and pipeline infrastructure and a simultaneous dip in consumer demand.

In 2008, Northeast natural gas consumption was approximately 9 Bcf/day. In late 2008, the last leg of the Rockies Express Pipeline brought an additional 1.8 Bcf/day into the region via the TCO pipeline system. This provided a 20% boost to Northeast supplies and brought immediate relief to the historically premium regional pricing complex.

Marcellus Shale gas has also introduced increased supply into the Northeast. This intra-region supply is expected to eventually bring as much as 6 Bcf/day into the Northeast's supply mix. Currently, Marcellus Shale is contributing 0.7 to 1.3 Bcf/day of supply. The long-term impact of this shale find is dependent on the following: further build-out of a pipeline gathering system that will connect Marcellus Shale gas to major interstate pipelines, the domestic price of natural gas (which will impact break-even rates for Marcellus drilling rigs), and environmental legislation regarding the hydraulic fracturing required to pull shale gas from underground formations.

The natural gas pipeline infrastructure in the Northeast has experienced exponential growth since 2009. Fifteen new pipeline extensions are set to be completed in the Northeast region by 2013 that will allow approximately 11 Bcf/day[1] in additional gas throughput. This increase in infrastructure is a dramatic shift from the early to mid 2000's when new pipeline build-outs were far less common. Historically, due to the lack of infrastructure, basis prices were bid up to premium levels as various parties competed for the remaining pipeline volumes that were not consumed by upstream pipeline market

[1] www.ferc.gov/industries/gas/gen-info/horizon-pipe.pdf

participants. The new infrastructure has already provided significant relief to regional basis prices and has allowed the new supply from the Rockies and Marcellus Shale to move with more freedom in the region.

While the EIA has not yet released its calendar-year 2010 natural gas consumption numbers for the Northeast states, we expect demand to have decreased proportionately to the broader macro-economic impact of the United States recession.

The changes to the supply and demand landscape of the Northeast outlined above have caused regional transportation prices and assets to decline in value. Excess intra-region supply threatens to displace a large portion of gas entering the region from the Gulf, Rockies, and Canada. While interstate pipeline capacity assets into the Northeast, particularly from the Gulf, have managed to retain value (likely due to a 'wait-and-see' approach as to whether the new supply paradigm will persist in the Northeast), regional basis prices have retreated significantly since early 2009. The new supplies have all but removed the historical pricing volatility in the region.

Summit Analysis Process

Based upon Summit's historical findings of the PGW program as well as the above mentioned dynamics in the marketplace that have occurred in the last several years, Summit designed its own "cost to deliver" model that effectively stack ranks each contracted capacity asset in the PGW portfolio. While the model is based upon the assumptions stated herein, these have been examined through multiple scenarios, and our analysis indicates relative asset rankings generally remain consistent.

The model integrated financial costs including the natural gas commodity as well as associated tariff charges. Additional costs associated with storage assets, such as transportation costs to deliver withdrawals from storage and applicable carrying costs unique to each storage agreement, were also incorporated.

These assets were stack ranked solely on a cost basis. In the first set of scenarios, cost models assumed no spread between winter and summer prices (i.e., NYMEX values flat throughout year). As seen in the table on the following page, the impact of increases in commodity cost to the relative weighted average costs is marginal. Even if NYMEX values were to return to their historical settlement highs, the stack rankings within each category remain consistent.

		NYMEX: $3.5/Dth Year-Round	NYMEX: $5/Dth Year-Round	NYMEX: $7/Dth Year-Round
Market Area Storage	Equitrans SS3	$7.665	$9.442	$11.811
	Tetco SS1-A*	$6.307	$8.035	$10.339
	Dom GSS Tetco FTS8	$6.062	$7.766	$10.037
	Dom GSS Tetco FTS7	$6.022	$7.726	$9.998
	Tetco SS1-B	$5.743	$7.471	$9.776
	Transco GSS	$5.314	$6.976	$9.192
	Transco S2	$5.290	$6.955	$9.174
	LNG	$4.329	$5.953	$8.119
Production Area Storage	Transco ESS1	$5.447	$7.036	$9.155
	Transco ESS2	$5.447	$7.036	$9.155
	WSS Transco FT*	$4.594	$6.200	$8.341
Long-Haul Transport	Tetco CDS	$4.504	$6.145	$8.333
	Tetco FT-1	$4.490	$6.130	$8.318
	Transco FT	$4.237	$5.827	$7.947

*Tetco SS1-A and WSS Transco FT are primary tools employed by PGW to avoid interstate pipeline balancing penalties on differentials between actual consumed and delivered volumes.

Next, cost models assumed $5.00 NYMEX in summer months, with summer-to-winter spreads of $.50, $1.00, and $2.00. Since most gas is consumed in the winter months, the model assumed storage gas was bought in the summer and used in the winter, while long-haul was based on winter pricing. As seen in the table below, growth in summer-to-winter spreads increases the value of all storage assets, and the lowest cost storage options begin to provide a lower weighted average cost of gas than long-haul; however, the increased value does not outweigh the costs for Equitrans in any of the sample scenarios. In addition, such large summer-to-winter commodity spreads are not expected to materialize in the foreseeable future, as spreads have eroded in recent years due to gas-fired power generation and high storage levels.

		NYMEX: $5/Dth Summer, $5.5/Dth Winter	NYMEX: $5/Dth Summer, $6/Dth Winter	NYMEX: $5/Dth Summer, $7/Dth Winter
Market Area Storage	Equitrans SS3	$9.442	$9.442	$9.442
	Tetco SS1-A	$8.035	$8.035	$8.035
	Dom GSS Tetco FTS8	$7.766	$7.766	$7.766
	Dom GSS Tetco FTS7	$7.726	$7.726	$7.726
	Tetco SS1-B	$7.471	$7.471	$7.471
	Transco GSS	$6.976	$6.976	$6.976
	Transco S2	$6.955	$6.955	$6.955
	LNG	$5.953	$5.953	$5.953
Production Area Storage	Transco ESS1	$7.036	$7.036	$7.036
	Transco ESS2	$7.036	$7.036	$7.036
	WSS Transco FT	$6.200	$6.200	$6.200
Long-Haul Transport	Tetco CDS	$6.692	$7.239	$8.333
	Tetco FT-1	$6.677	$7.224	$8.318
	Transco FT	$6.357	$6.887	$7.947

Based on the scenarios examined on the previous page, changes in the absolute cost of gas do not have a significant impact on the relative cost of delivery options. Additionally, large summer-to-winter commodity spreads are not expected, and modest spreads do not result in changes to the assessment of the highest cost assets. Thus, recommendations for optimization are based on the $5.00 year-round NYMEX scenario.

Asset Stack Ranking

Market Area Storage	Max Storage Quantity (Dth)	Storage Demand (Dth)	Estimated WACOG ($/Dth)
Equitrans SS3	522,500	4,998	$9.442
Tetco SS1-A	2,647,080	44,118	$8.035
Dom GSS Tetco FTS8	3,007,810	22,495	$7.766
Dom GSS Tetco FTS7	911,161	6,815	$7.726
Tetco SS1-B	2,462,120	20,847	$7.471
Transco GSS	4,123,733	53,871	$6.976
Transco S2	466,554	5,191	$6.955
LNG	4,428,073	469,680	$5.953

Production Area Storage	Max Storage Quantity (Dth)	Storage Demand (Dth)	Estimated WACOG ($/Dth)
Transco ESS1	482,792	47,986	$7.036
Transco ESS2	656,013	65,201	$7.036
WSS Transco FT	3,335,909	39,246	$6.200

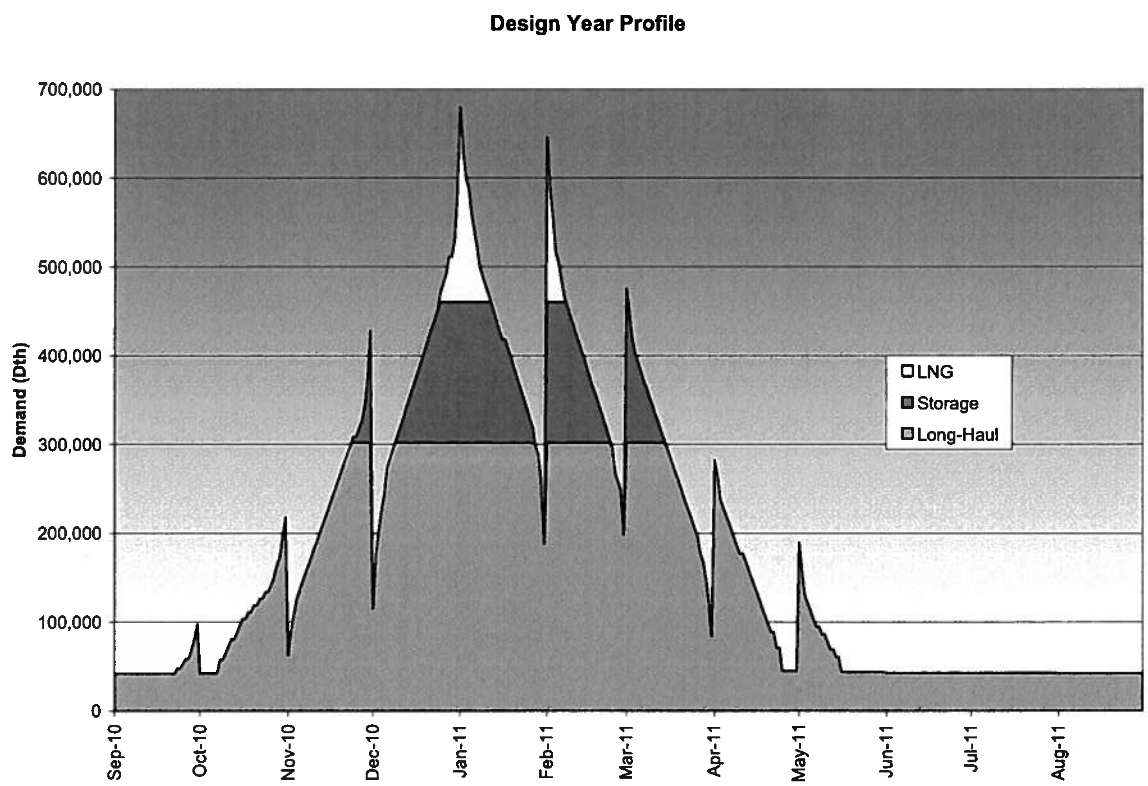
Long-Haul Transport	Capacity (Dth)	Estimated WACOG ($/Dth)
Tetco CDS	75,000	$6.145
Tetco FT-1	59,822	$6.130
Transco FT	167,179	$5.827

Based upon our initial analysis of storage assets (table above), Equitrans storage was the highest cost delivered asset to serve PGW. Tetco SS1-A was the next highest cost asset due to its relatively high reservation of demand, though this asset plays a significant part in meeting PGW's balancing needs on the Tetco pipeline. Long-haul transportation across Tetco or Transco is intuitively the cheapest option, as it is taken directly from the production area, assessed fuel and transportation costs, and then delivered directly to the market. Storage requires additional costs (demand, storage capacity, fuel, and associated transportation), which raise the total cost of delivery.

After the initial stage of cost-based stack ranking, Summit next created a delivery prioritization model that incorporated relative receipt and delivery constraints of each asset. Thus, long-haul and short-haul interstate capacity is inherently limited by the maximum daily quantity (MDQ) of each transport agreement. Similarly, some storage agreements not only have limits on their injections, withdrawals, and total capacity, but also on seasonal requirements such as ensuring certain percentages of gas in storage are actually withdrawn. Finally, PGW-owned LNG not only has capacity restrictions, but also operational constraints on its liquefaction. These constraints are more physical than contractual.

Summit then incorporated the 2010-2011 peak design consumption model and evaluated alternative scenarios when considering the appropriate ways to guarantee deliveries are met. This included ensuring that maximum deliveries were made via already contracted assets delivering at variable costs, thus avoiding additional incremental purchases. Also, LNG reserves were always maintained to ensure adequate deliverability from vaporization would exist for any necessary peak day/year.

Given PGW's limited capability to aggressively refill its LNG capacity, Summit not only evaluated the needs of a single design year, but also that of two consecutive design years. The results illustrate that as the highest cost storage capacity is eliminated, PGW quickly approaches a scenario where it might not be able to meet its operational requirements.



LNG Usage – Design Year Scenarios

Non-LNG Assets	Non-LNG Capacity (1)	LNG Inventory Needed for Design Winter (1,2)	LNG Inventory Needed for Consecutive Design Winters (1,3)
All current assets	460,336	2,237,800	2,965,601
Current asset mix less 5,000 Dth of demand	455,336	2,371,900	3,233,801
Current asset mix less 7,500 Dth of demand	452,836	2,441,900	3,373,801
Current asset mix less 10,000 Dth of demand	450,336	2,513,053	3,516,106
Current asset mix less 12,500 Dth of demand	447,836	2,586,075	3,662,151
Current asset mix less 15,000 Dth of demand	445,336	2,664,129	3,818,257

(1) Volumes in Dth.
(2) Volume represents the design demand in excess of non-LNG capacity, inclusive of boil-off volumes for withdrawal season.
(3) Volume represents the minimum amount of LNG necessary at the beginning of withdrawal season in year 1 to meet two consecutive design winters; this assumes 2,000,000 Dth of liquefaction in a calendar year.

Summit's modeling revealed that any combination of assets that satisfy consecutive design year requirements would always result in some unutilized capacity in any reasonable asset mix. Given that PGW will necessarily be "long" in most circumstances, Summit then proceeded to evaluate which assets could either be directly monetized (capacity release) or indirectly monetized (asset management relationships, off-system sales).

Outsourced Asset Management

PGW requested that Summit advise the Company regarding possible AMAs, including a review of the best practices regarding the payment structure of such arrangements. An asset management program provides for the utility to turn over the management of all or some of its assets to a third party. Under this arrangement, the asset manager commits to satisfy the utility's delivery obligations in return for having the ability to use the asset or assets however the manager decides when such deliveries are not required. The release of one's entire asset portfolio is a popular strategy for smaller municipalities (~5 Bcf or less of annual firm requirements) who will bundle and assign their assets while simultaneously fulfilling their delivery requirements. It enables the utility to reap a larger recovery of dollars than they would have by self-managing their portfolio.

With the exception of the aforementioned AMA for a portion of PGW's storage, PGW does not currently employ this type of asset management strategy and generally retains institutional self-control of its asset base with the exception of capacity release programs. There are numerous asset managers in the marketplace with the primary objectives of providing reliable gas supply to the utility city gate, managing the utility's existing asset base, and optimizing the value of such contracts. Additionally, there are numerous natural gas distributors who utilize the services of a third party asset manager. Despite this utilization, however, the strategy is not necessarily the most appropriate approach for all gas distributors, nor does it appear to be a rapidly increasing practice. Instead, many utilities regularly perform internal review of their capacity needs.

For a utility, releasing control and management of one's assets to a third party can, at times, pose significant risks and complexities that may offset the benefits achieved by the program. The primary benefit that can be achieved under a third party asset management agreement is the optimization of those assets, some of whose benefits may otherwise be unrealized. Outsourced firms may be better positioned to deliver optimization value because of the following:

- Inherently possess larger scale and flexibility
- More substantial and broader market presence/expertise
- Greater resource availability
- Core operational function

Additionally, there may be value derived from an outsourced AMA as it may enable the utility to focus more intently on customer service and its distribution operations.

While there can be benefits from AMAs, there are also numerous risks to consider. Some of the risks that may exist for a gas distributor evaluating such an arrangement consist of the following:

- Diminished control over a primary business function
- Loss of expertise in a key operational arena
- Exposure to counterparty risk
- Program profitability limitations
- Performance/auditing validation

If PGW considers the possible utilization of an outsourced asset management firm, the utility should carefully weigh the pertinent risks and benefits to ensure the goals of the program align with their overall business objectives. PGW should also consider any internal operational benefits or constraints that may enhance or deter the introduction of such a third party firm. In addition, it is prudent to be cognizant of futures pricing and market dynamics in order to assess the potential viability and profitability of entering an AMA.

Current market levels reflect a summer-to-winter spread differential of approximately $0.55/Dth, therefore demonstrating a relatively low level of potential profit should any holder look to arbitrage a storage asset. This can be contrasted with market levels from December 2009 (one year ago) when a summer-to-winter spread differential of approximately $1.00/Dth existed in the market. In this example, the asset's potential value was nearly cut in half over just a 12-month span. A more distant market snapshot from the 2006 – 2007 timeframe would reflect a $3.00/Dth differential. This second example renders a $2.45/Dth decrease in value when compared to current market. These various points in time demonstrate how storage profitability can rapidly erode in an ever-changing marketplace.

Due to Summit's market outlook, we do not anticipate a significant increase in the summer-to-winter spreads over the short-term, thus reducing the overall value that can be derived from PGW's storage assets. Because of current market conditions and the aforementioned spread analysis, the likelihood of interested parties willing to enter AMAs is reduced as is the compensation that could be realized.

However, due to the nature of the evolving natural gas market, individual PGW assets may present an AMA opportunity (as opposed to a third party assuming the entire utility portfolio). This is due to the fact that many niche counterparties might ascribe a higher value to a specific asset than another based upon their own unique requirements. As an example, a growing producer with Marcellus Shale production in Pennsylvania might highly value storage and short-haul capacity, but have little interest in long-haul capacity from the Gulf coast. Thus, an exploration of the options surrounding each independent asset could yield greater value than the entire portfolio as well as increase the number of interested parties.

Should market fundamentals support entering into an AMA, there are various forms of compensation that can be structured with the asset manager. The most prevalent payment constructs consist of 1) outright fixed payment over the term of the agreement and 2) shared-benefit payments based on a percentage split of the gains from the optimization. An asset with a greater value will typically render increased flexibility in terms of negotiating compensation structures as well as potentially other contractual criteria. Ultimately, each party's projected valuations of the asset(s), risk appetite, and regulatory constraints can shape the compensation structure of the agreement.

Due to the nature of PGW's core objectives of providing reliable and cost-effective gas supply to its customer base, Summit would consider a set monthly payment schedule as a best practice, provided such payment represents a value PGW deems as fair and appropriate for such asset(s) in the marketplace. This type of structure would produce guaranteed payments that would benefit ratepayers. By securing a set value for the asset upon entering the AMA, market risk can be eliminated and therefore a known compensation threshold would be established. Furthermore, a fixed price agreement avoids the speculative nature associated with a shared-benefit arrangement that is reliant upon future market outcomes to determine its revenue.

Summit Recommendations

Based upon our analysis of current PGW operating parameters, existing and continuing market trends, and an integrated analysis, Summit makes the following recommendations.

1. **Evaluate elimination or reduction of portion of current asset base after assessing asset management opportunities, and leverage PGW-owned LNG assets.**

   - Eventual release of Equitrans storage as it is the highest unit cost asset in the PGW portfolio; the net cost of this asset per year is approximately $541,000 (after adjustments for net capacity release credits). However, due to contractual notification of abandonment provisions and the unique geographical position of this asset within the Marcellus Shale supply basin, it would be prudent to first perform an RFP to determine if opportunity exists for a third party AMA that would guarantee value above PGW's cost.
   - While Tetco SS1-A is the next highest cost delivery option in the stack ranking, it provides PGW with flexibility in balancing load. For every 1 degree of variance between actual and expected temperatures, PGW experiences a change in demand of approximately 10,000 Dth. Since PGW is able to retroactively balance their load through their SS1 assets, PGW's exposure to balancing penalties is reduced. Hence, Tetco SS1 assets should be retained.
   - The next highest cost asset is Dominion storage, along with its Tetco FTS-7 and FTS-8 contracts. Reduction of 10,000 Dth of demand at contract renewal (along with associated storage capacity and FTS transport contracts) would not impede PGW's ability to serve customers in design scenarios. The net cost of this asset per year is approximately $670,000 (after adjustments for net capacity release credits). It is important to note that there is potential that FTS-7 and FTS-8 contracts could eventually bring Marcellus Shale gas into PGW, thereby changing their functionality and subsequent value. Since the Dominion agreement is specially negotiated, any subsequent renewal needs to factor in both the risk and opportunities of both new pricing and delivery terms changing; reduction of the Dominion storage from approximately 4 Bcf to 3 Bcf could result in new contract rates that may diminish some or all of the potential savings.
   - PGW should maintain their LNG inventory consistent with the appropriate level of risk, understanding that their liquefaction capabilities are limited, in order to serve consecutive design winters. Any elimination and/or reduction of designated assets would necessarily entail a greater reliance upon PGW's own LNG assets.
   - Many natural gas utilities in PA and surrounding areas do not have utility-owned LNG facilities. For those that do, LNG usage on a peak design day comprises of approximately 27% of the total portfolio; however, when propane is incorporated with LNG into peak day usage for these same utilities, the proportion increases to 32%. Currently, PGW's LNG comprises 32% of their peak design day portfolio. Reducing portions of their non-LNG capacity as referenced in this report would increase this amount to 34%.

2. **Production area storage still worthwhile assets; however internal evaluation should be an on-going process**

    - It serves as protection against supply area production "shocks" and interstate pipeline balancing penalties.
    - It is valued as a hedging tool on inter-seasonal basis becoming less valuable as market volatility has flattened.
    - Monetization opportunities exist with asset managers, but value may decrease with lessened volatility.
    - Internal evaluation of WSS and Eminence storage value should occur regularly.

3. **Maintain current long-haul interstate capacity allocations**

    - Pipeline lateral delivery requirements necessitate preservation of delivery rights.
    - It is the least expensive delivery option.
    - Transco and Tetco capacity to market area is currently fully subscribed and could potentially be lost if surrendered.
    - Long-haul assets are easiest to monetize when not required due to liquid secondary release market.

4. **Evaluate more dynamic/active resource management (internal or external) for underutilized assets**

    - Traditional asset management (entire portfolio turnover to third party with payment/shared savings structure) is likely unworkable due to complexity and declining liquidity of capable providers.
    - Certain individual assets, particularly those where long-term elimination or reduction is contemplated, should be bid out for potential AMAs to validate the market value of such assets against PGW's costs.
    - More aggressive tactics such as weekly long-haul capacity releases marketed to others should be considered even if potentially requiring additional resources.

5. **Monitor supply/capacity market for more economical infrastructure**

    - Marcellus Shale/transport projects should be entertained to determine if they can displace Transco/Tetco storage and/or portion of LNG-filled capacity.
    - Opportunities to increase long-haul capacity at expense of short-haul capacity/storage also should be considered.
    - Both history and anticipated infrastructure projects strongly suggest that market pricing will be fluid and volatile for the foreseeable future. This makes forecasting the optimal asset mix impossible for any substantial length of time. Thus, PGW is best positioned to continuously evaluate its assets by not committing to long-term contracts, thus maintaining flexibility to shift its portfolio between short-haul and long-haul pipeline capacity and its own LNG capacity.

Adoption of Recommendations and Path Forward

Summit advocates that PGW utilize this report and consider these recommendations, while also establishing processes to more fully monetize its existing capacity assets. In addition, the market dynamics in the Northeast have vastly changed over the past several years and appear to be still evolving rapidly. Thus, Summit recommends a short-term approach to any further contractual asset retention and PGW would be well served to internally re-evaluate its asset portfolio on a regular (annual to every two years) basis to ensure it can take better advantage of any future market developments.

Tab 14

Docket No. R-18XXX

Item 53.64(i)(1)

Philadelphia Gas Works
Pennsylvania Public Utility Commission
52 PA Code 53.61, et seg.

Item 53.64(i) Utilities shall comply with the following:

(1) Thirty days prior to the filing of a tariff reflecting increases or decreases in purchased gas expenses, gas utilities under 66 Pa.C.S. § 1307 (f) recovering expenses under that section shall file a statement for the 12-month period ending 2 months prior to the filing date under 66 Pa.C.S.§ 1307(f) as published in accordance with subsection (b) which shall specify:

(i) The total revenues received under 66 Pa.C.S. § 1307(a), (b) or (f), including fuel revenues received, whether shown on the bill as 66 Pa.C.S.§ 1307(f) as published in accordance with subsection (b) which shall specify:

(ii) The total gas expenses incurred.

(iii) The difference between the amounts in sub paragraphs (I) and (ii).

(iv) Evidence explaining how actual costs incurred differ from the costs allowed under subparagraph (ii).

(v) How these costs are consistent with a least cost fuel procurement policy, as required by 66 Pa.C.S. § 1318 (relating to determination of just and reasonable natural gas rates).

Response: Please see attached schedule. Additionally, please refer to Item 53.64(c)(6) for a detailed discussion regarding the company's least cost fuel procurement policy.

CALENDAR YEAR 2017
PHILADELPHIA GAS WORKS
C-FACTOR RECONCILIATION

MONTH	NET COST OF FUEL 1	TOTAL GCR REVENUE BILLED 2	C FACTOR % of GCR 3	C FACTOR REVENUE BILLED 4 = (2 * 3)	LOAD BALANCING REVENUE 5	LNG SALES GCR BILLED REVENUE 6	TOTAL C FACTOR REVENUE BILLED 7 = (4 + 5 + 6)	NATURAL GAS REFUNDS 8	OVER/ (UNDER) RECOVERY 9 = (7 + 8 - 1)
	($)	($)		($)	($)	($)	($)	($)	($)
JANUARY 2017	30,560,326	34,670,444	101.2%	35,097,124	75,857	1,622	35,174,603	0	4,614,277
FEBRUARY	31,023,141	27,997,826	101.3%	28,352,401	92,917	0	28,445,318	0	(2,577,823)
MARCH	25,128,443	26,815,639	101.3%	27,155,243	93,172	0	27,248,414	0	2,119,971
APRIL	10,811,146	21,550,758	101.6%	21,904,004	93,633	0	21,997,637	0	11,186,491
MAY	10,354,017	8,774,556	102.0%	8,953,535	92,562	0	9,046,096	0	(1,307,921)
JUNE	7,380,023	6,208,276	102.0%	6,334,909	91,521	0	6,426,430	0	(953,593)
JULY	656,232	4,440,729	101.8%	4,522,126	92,249	0	4,614,375	0	3,958,143
AUGUST	8,160,424	4,129,628	101.6%	4,195,864	93,320	0	4,289,184	0	(3,871,240)
SEPTEMBER	6,660,769	4,400,670	101.6%	4,471,254	93,712	0	4,564,966	0	(2,095,803)
OCTOBER	7,858,969	4,340,618	101.2%	4,391,271	109,718	0	4,500,989	0	(3,357,980)
NOVEMBER	17,769,207	10,995,238	100.8%	11,081,020	113,717	0	11,194,736	0	(6,574,471)
DECEMBER	27,095,257	25,504,332	100.8%	25,703,309	112,668	0	25,815,977	0	(1,279,280)
Totals	183,457,954	179,828,714		182,162,059	1,155,045	1,622	183,318,726	0	(139,228)

STATEMENT OF RECONCILIATION
UNIVERSAL SERVICES & ENERGY CONSERVATION SURCHARGE
CALENDAR YEAR 2017

Month		USC Applicable Volumes	USC Charge	USC Revenue Billed	USC Expenses	Monthly Over/(Under) Recovery	Cumulative Over/(Under) Recovery
December 2016							($8,742,884)
January 2017	Actual	8,819,225	$ 1.3045	$ 11,504,679	$ 13,419,769	$ (1,915,089)	($10,657,974)
February	Actual	7,178,104	$ 1.3045	$ 9,363,837	$ 12,257,565	$ (2,893,728)	($13,551,702)
March	Actual	6,357,678	$ 1.3837	$ 8,796,801	$ 10,100,491	$ (1,303,689)	($14,855,391)
April	Actual	4,732,361	$ 1.4628	$ 6,922,497	$ 7,077,738	$ (155,241)	($15,010,632)
May	Actual	1,993,474	$ 1.4628	$ 2,916,054	$ 2,387,656	$ 528,397	($14,482,235)
June	Actual	1,471,294	$ 1.4555	$ 2,141,468	$ 473,926	$ 1,667,542	($12,814,693)
July	Actual	1,114,534	$ 1.4482	$ 1,614,069	$ (569,755)	$ 2,183,824	($10,630,869)
August	Actual	1,050,023	$ 1.4482	$ 1,520,644	$ (183,170)	$ 1,703,814	($8,927,055)
September	Actual	1,160,592	$ 1.4092	$ 1,635,448	$ (944,104)	$ 2,579,552	($6,347,502)
October	Actual	1,228,327	$ 1.3701	$ 1,682,931	$ (145,235)	$ 1,828,165	($4,519,337)
November	Actual	3,034,129	$ 1.3701	$ 4,157,061	$ 3,285,532	$ 871,529	($3,647,808)
December	Actual	6,319,455	$ 1.4845	$ 9,381,230	$ 9,481,610	$ (100,380)	($3,748,188)

USC Expenses	Jan-17	Feb-17	Mar-17	Apr-17	May-17	Jun-17	Jul-17	Aug-17	Sep-17	Oct-17	Nov-17	Dec-17	Total
ELIRP Expense	$ 10,299	$ 887,272	$ 384,814	$ 14,514	$ 744,026	$ 429,352	$ 462,272	$ 1,011,051	$ -	$ 430,271	$ 367,950	$ 373,571	$ 5,115,392
ELIRP Labor	$ 9,808	$ 9,788	$ 14,621	$ 13,132	$ 13,075	$ 17,188	$ 13,645	$ 15,713	$ 14,196	$ 13,745	$ 5,432	$ 17,247	$ 157,590
CRP Discount	$ 11,987,815	$ 10,152,493	$ 8,410,876	$ 5,992,880	$ 752,518	$ (786,284)	$ (1,755,818)	$ (1,978,781)	$ (1,713,498)	$ (1,406,870)	$ 2,023,880	$ 8,006,203	$ 39,685,413
CRP Forgiveness	$ 678,708	$ 578,057	$ 746,293	$ 629,213	$ 688,848	$ 685,067	$ 615,783	$ 679,553	$ 662,258	$ 712,670	$ 636,542	$ 585,157	$ 7,898,149
Senior Citizen Discount	$ 733,139	$ 629,955	$ 543,886	$ 427,999	$ 189,190	$ 128,603	$ 94,363	$ 89,294	$ 92,940	$ 104,949	$ 251,729	$ 499,432	$ 3,785,478
Bad Debt Expense Offset*					$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total	$ 13,419,769	$ 12,257,565	$ 10,100,491	$ 7,077,738	$ 2,387,656	$ 473,926	$ (569,755)	$ (183,170)	$ (944,104)	$ (145,235)	$ 3,285,532	$ 9,481,610	$ 56,642,022

CRP Participation	Jan-17	Feb-17	Mar-17	Apr-17	May-17	Jun-17	Jul-17	Aug-17	Sep-17	Oct-17	Nov-17	Dec-17
Rate Case Participation Rate	84,000	84,000	84,000	84,000	84,000	84,000	84,000	84,000	84,000	84,000	84,000	60,000
Actual Participation Rate*	49,009	48,580	47,668	48,099	48,502	47,852	47,966	48,547	48,523	48,693	48,904	49,310
CRP Under(Over) Participation	34,991	35,420	36,332	35,901	35,498	36,148	36,034	35,453	35,477	35,307	35,096	10,690

Average Shortfall Per CRP Participant		Jan-17	Feb-17	Mar-17	Apr-17	May-17	Jun-17	Jul-17	Aug-17	Sep-17	Oct-17	Nov-17	Dec-17
CRP Discount		$ 11,987,815	$ 10,152,493	$ 8,410,876	$ 5,992,880	$ 752,518	$ (786,284)	$ (1,755,818)	$ (1,978,781)	$ (1,713,498)	$ (1,406,870)	$ 2,023,880	$ 8,006,203
Actual Participation Rate		49,009	48,580	47,668	48,099	48,502	47,852	47,966	48,547	48,523	48,693	48,904	49,310
Average Shorfall per CRP Participant		$ 245	$ 209	$ 176	$ 125	$ 16	$ (16)	$ (37)	$ (41)	$ (35)	$ (29)	$ 41	$ 162
Shortfall*		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Bad Debt Expense Offset*	7.1%	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
Bad Debt Expense Offset*	7.5%												$ -

*Bad Debt Expense Offset Applicable When Actual CRP Participation Exceeds 84,000 for January through November and 60,000 for December.

Tab 15

Docket No. R-18XXX
Item 53.65 (1)

Philadelphia Gas Works

Pennsylvania Public Utility Commission
52 Pa. Code §53.61, et seq.

Item 53.65 (1)

The costs of the affiliated gas, transportation or storage as compared to the average market price of other gas, transportation or storage and the price of other sources of gas, transportation and storage.

Response:

PGW has no affiliates, see response to 53.64(c)(1) for price of gas, transportation and storage.