Tab 4

Philadelphia Gas Works
Forecasted Summary of Total Fuel Purchased
January 2011-August 2012

Volumes (Dth)

	Jan-11	Feb-11	Mar-11	Apr-11	May-11	Jun-11	Jul-11	Aug-11	Sep-11	Oct-11
Spot Purchases - Transco	1,235,770	2,809,421	2,735,651	3,117,179	2,731,788	1,358,436	928,869	333,816	1,504,018	3,190,252
Spot Purchases - Tetco	405,914	357,486	1,068,432	99,060	219,075	-	6,236	606,037	36,710	139,863
Transco Supply 1	-	-	-	-	-	-	-	-	-	-
Transco Supply 2	625,000	50,000	90,006	440,000	323,000	395,000	624,000	409,361	23,350	25,000
Transco Supply 3	155,000	140,000	155,000	-	-	-	-	-	-	-
Transco Supply 4	-	-	-	-	-	-	-	-	-	-
Transco Supply 5	-	-	-	-	-	-	-	-	-	-
Transco Supply 6	310,000	140,000	77,500	300,000	310,000	300,000	310,000	310,000	300,000	310,000
Transco Supply 7	420,000	140,000	483,766	140,000	80,000	220,000	360,000	-	40,000	20,000
Transco Supply 8	775,000	-	-	-	-	-	-	-	-	-
Transco Supply 9	-	-	-	-	-	-	-	-	-	-
Transco Supply 10	155,000	140,000	15,500	150,000	155,000	150,000	77,500	-	75,000	-
Transco Supply 11	-	-	-	-	-	-	-	-	-	-
Transco Supply 12	155,000	-	-	-	-	-	-	-	-	-
Transco Supply 13	-	-	-	-	-	-	-	-	-	-
Transco Supply 14	-	-	-	-	-	-	-	-	-	-
Transco Supply 15	-	-	-	-	-	-	-	-	-	-
Transco Supply 16	-	-	-	-	-	-	-	-	-	-
Transco Supply 17	-	-	-	-	-	-	-	-	-	-
Transco Supply 18	-	-	-	-	-	-	-	-	-	-
Transco Supply 19	-	-	-	-	-	-	-	-	-	-
Transco Supply 20	155,000	140,000	-	-	-	-	-	-	-	-
Transco Supply 21	-	-	-	-	-	-	-	-	-	-
Transco Supply 22	-	-	-	-	-	-	-	-	-	-
Transco Supply 23	155,000	140,000	155,000	-	-	-	-	-	-	-
Tetco Supply 1	336,772	10,978	21,956	177,842	176,830	165,644	163,986	1,976	158,728	169,914
Tetco Supply 2	155,000	140,000	-	-	-	-	-	-	-	-
Tetco Supply 3	-	-	-	-	-	-	-	-	-	-
Tetco Supply 4	-	-	-	-	-	-	-	-	-	-
Tetco Supply 5	155,000	-	-	-	-	-	-	-	-	-
Tetco Supply 6	-	-	-	-	-	-	-	-	-	-
Tetco Supply 7	-	-	-	-	-	-	-	-	-	-
Tetco Supply 8	-	-	-	-	-	-	-	-	-	-
Tetco Supply 9	-	-	-	-	-	-	-	-	-	-
Tetco Supply 10	-	-	-	-	-	-	-	-	-	-
Tetco Supply 11	-	-	-	-	-	-	-	-	-	-
Tetco Supply 12	-	-	-	-	-	-	-	-	-	-
Tetco Supply 13	1,000,065	720,000	886,082	137,927	40,000	-	38,355	-	-	227,519
Tetco Supply 14	465,000	420,000	310,000	-	-	-	-	-	-	-
Tetco Supply 15	-	-	-	-	-	-	-	-	-	-
Tetco Supply 16	155,000	140,000	155,000	-	-	-	-	-	-	-
Tetco Supply 17	418,500	378,000	418,500	-	-	-	-	-	-	-
Tetco Supply 18	155,000	140,000	-	-	-	-	-	-	-	-
Tetco Supply 19	-	-	-	-	-	-	-	-	-	-
Total Volumes	7,387,020	6,005,885	6,572,394	4,562,008	4,035,693	2,589,080	2,508,946	1,661,191	2,137,805	4,082,548

Philadelphia Gas Works
Forecasted Summary of Total Fuel Purchased
January 2011-August 2012

Volumes (Dth)

	Nov-11	Dec-11	Jan-12	Feb-12	Mar-12	Apr-12	May-12	Jun-12	Jul-12	Aug-12
Spot Purchases - Transco	3,052,379	2,643,146	2,556,066	2,411,829	3,024,222	3,164,464	2,850,166	1,797,899	1,710,509	35,396
Spot Purchases - Tetco	796,103	1,959,442	865,687	598,859	880,714	275,982	32,173	6,664	17,342	672,803
Transco Supply 1	-	-	-	-	-	-	-	-	-	-
Transco Supply 2	425,000	775,000	750,000	725,000	325,000	425,000	25,000	-	-	141,585
Transco Supply 3	-	-	-	-	-	-	-	-	-	-
Transco Supply 4	-	-	-	-	-	-	-	-	-	-
Transco Supply 5	-	-	-	-	-	-	-	-	-	-
Transco Supply 6	300,000	310,000	310,000	290,000	310,000	300,000	310,000	300,000	310,000	-
Transco Supply 7	20,000	340,000	500,000	440,000	320,000	240,000	280,000	240,000	200,000	371,661
Transco Supply 8	-	-	-	-	-	-	-	-	-	-
Transco Supply 9	-	-	-	-	-	-	-	-	-	-
Transco Supply 10	-	-	-	-	-	-	-	-	-	-
Transco Supply 11	-	-	-	-	-	-	-	-	-	-
Transco Supply 12	-	-	-	-	-	-	-	-	-	-
Transco Supply 13	-	-	-	-	-	-	-	-	-	-
Transco Supply 14	-	-	-	-	-	-	-	-	-	-
Transco Supply 15	-	-	-	-	-	-	-	-	-	-
Transco Supply 16	-	-	-	-	-	-	-	-	-	-
Transco Supply 17	-	-	-	-	-	-	-	-	-	-
Transco Supply 18	-	-	-	-	-	-	-	-	-	-
Transco Supply 19	-	-	-	-	-	-	-	-	-	-
Transco Supply 20	-	-	-	-	-	-	-	-	-	-
Transco Supply 21	-	-	-	-	-	-	-	-	-	-
Transco Supply 22	-	-	-	-	-	-	-	-	-	-
Transco Supply 23	-	-	-	-	-	-	-	-	-	-
Tetco Supply 1	107,078	19,960	6,986	21,956	25,948	163,342	180,782	173,548	182,758	30,628
Tetco Supply 2	-	-	-	-	-	-	-	-	-	-
Tetco Supply 3	-	-	-	-	-	-	-	-	-	-
Tetco Supply 4	-	-	-	-	-	-	-	-	-	-
Tetco Supply 5	-	-	-	-	-	-	-	-	-	-
Tetco Supply 6	-	-	-	-	-	-	-	-	-	-
Tetco Supply 7	-	-	-	-	-	-	-	-	-	-
Tetco Supply 8	-	-	-	-	-	-	-	-	-	-
Tetco Supply 9	-	-	-	-	-	-	-	-	-	-
Tetco Supply 10	-	-	-	-	-	-	-	-	-	-
Tetco Supply 11	-	-	-	-	-	-	-	-	-	-
Tetco Supply 12	-	-	-	-	-	-	-	-	-	-
Tetco Supply 13	564,312	628,378	420,643	40,000	60,000	20,000	20,000	20,000	18,330	169,070
Tetco Supply 14	-	-	-	-	-	-	-	-	-	-
Tetco Supply 15	-	-	-	-	-	-	-	-	-	-
Tetco Supply 16	-	-	-	-	-	-	-	-	-	-
Tetco Supply 17	-	-	-	-	-	-	-	-	-	-
Tetco Supply 18	-	-	-	-	-	-	-	-	-	-
Tetco Supply 19	-	-	-	-	-	-	-	-	-	-
Total Volumes	5,264,871	6,675,926	5,409,382	4,527,643	4,945,885	4,588,788	3,698,121	2,538,111	2,438,938	1,421,143

Philadelphia Gas Works
Forecasted Summary of Total Fuel Purchased
January 2011-August 2012

	Jan-11	Feb-11	Mar-11	Apr-11	May-11	Jun-11	Jul-11	Aug-11	Sep-11	Oct-11
Williams	$ 2,902,466	$ 2,739,014	$ 2,643,885	$ 2,647,385	$ 2,631,967	$ 2,587,840	$ 2,575,189	$ 2,525,872	$ 2,397,025	$ 2,444,860
Texas Eastern	$ 2,490,474	$ 2,421,315	$ 2,369,779	$ 1,876,929	$ 1,853,551	$ 1,864,159	$ 1,821,430	$ 1,904,790	$ 1,440,665	$ 1,411,180
Dominion	$ 137,440	$ 124,559	$ 121,624	$ 128,658	$ 128,666	$ 128,423	$ 128,666	$ 134,885	$ 128,423	$ 127,696
Equitrans	$ 47,837	$ 48,193	$ 47,979	$ 49,299	$ 49,824	$ 49,299	$ 49,824	$ 49,824	$ 49,299	$ 46,676
Spot Purchases - Transco	$ 5,276,737	$ 12,698,581	$ 12,392,501	$ 14,089,649	$ 12,484,269	$ 6,262,390	$ 4,347,109	$ 1,572,275	$ 7,098,964	$ 15,249,405
Spot Purchases - Tecto	$ 1,700,779	$ 1,587,238	$ 4,754,520	$ 439,827	$ 983,647	$ -	$ 28,685	$ 2,805,951	$ 170,333	$ 657,354
Transco Supply 1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Transco Supply 2	$ 2,971,000	$ 499,000	$ 709,977	$ 2,257,900	$ 1,754,378	$ 2,104,150	$ 3,204,280	$ 2,208,332	$ 402,710	$ 421,750
Transco Supply 3	$ 728,500	$ 658,000	$ 728,500	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Transco Supply 4	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Transco Supply 5	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Transco Supply 6	$ 1,307,813	$ 632,100	$ 358,050	$ 1,159,500	$ 1,581,000	$ 1,490,640	$ 1,474,453	$ 1,405,075	$ 1,355,640	$ 1,432,200
Transco Supply 7	$ 2,029,000	$ 845,600	$ 2,427,061	$ 860,800	$ 601,200	$ 1,242,200	$ 1,920,400	$ 235,600	$ 416,800	$ 331,200
Transco Supply 8	$ 3,225,550	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Transco Supply 9	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Transco Supply 10	$ 739,350	$ 667,800	$ 73,935	$ 676,125	$ 663,013	$ 646,875	$ 337,513	$ -	$ 354,000	$ -
Transco Supply 11	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Transco Supply 12	$ 656,813	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Transco Supply 13	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Transco Supply 14	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Transco Supply 15	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Transco Supply 16	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Transco Supply 17	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Transco Supply 18	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Transco Supply 19	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Transco Supply 20	$ 624,650	$ 617,400	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Transco Supply 21	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Transco Supply 22	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Transco Supply 23	$ 728,112	$ 657,650	$ 728,112	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Tetco Supply 1	$ 1,508,311	$ 177,808	$ 226,770	$ 907,919	$ 911,853	$ 868,569	$ 872,221	$ 136,815	$ 854,699	$ 916,482
Tetco Supply 2	$ 645,575	$ 605,850	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Tetco Supply 3	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Tetco Supply 4	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Tetco Supply 5	$ 629,300	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Tetco Supply 6	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Tetco Supply 7	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Tetco Supply 8	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Tetco Supply 9	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Tetco Supply 10	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Tetco Supply 11	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Tetco Supply 12	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Tetco Supply 13	$ 5,615,805	$ 3,945,940	$ 4,579,962	$ 846,395	$ 421,400	$ 234,000	$ 418,232	$ 241,800	$ 234,000	$ 1,311,139
Tetco Supply 14	$ 2,021,975	$ 1,796,900	$ 1,367,255	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Tetco Supply 15	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Tetco Supply 16	$ 626,975	$ 566,300	$ 626,975	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Tetco Supply 17	$ 1,727,320	$ 1,560,160	$ 1,727,320	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Tetco Supply 18	$ 639,375	$ 567,700	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Tetco Supply 19	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
FT PAYBACK ADJUSTMENT	$ -	$ -	$ -	$ -	$ -	$ 146,834	$ 149,044	$ 149,915	$ 150,233	$ 152,143
Total Costs	$ 38,981,157	$ 33,417,108	$ 35,884,205	$ 25,940,386	$ 24,064,766	$ 17,331,710	$ 17,028,957	$ 13,071,303	$ 14,752,326	$ 24,197,799

Philadelphia Gas Works
Forecasted Summary of Total Fuel Purchased
January 2011-August 2012

Schedule 3
item 53.64(c)(1)

	Nov-11	Dec-11	Jan-12	Feb-12	Mar-12	Apr-12	May-12	Jun-12	Jul-12	Aug-12
Williams	$ 2,545,869	$ 2,628,984	$ 2,763,190	$ 2,704,469	$ 2,764,831	$ 2,738,677	$ 2,722,940	$ 2,678,160	$ 2,668,210	$ 2,581,509
Texas Eastern	$ 1,464,744	$ 2,257,507	$ 2,260,318	$ 2,255,464	$ 2,428,979	$ 2,116,722	$ 2,110,949	$ 2,109,033	$ 2,070,864	$ 2,159,994
Dominion	$ 126,168	$ 129,372	$ 138,625	$ 133,007	$ 122,851	$ 124,778	$ 128,649	$ 128,407	$ 128,649	$ 134,885
Equitrans	$ 45,169	$ 48,159	$ 48,700	$ 48,424	$ 47,768	$ 49,299	$ 49,824	$ 49,299	$ 49,824	$ 49,824
Spot Purchases - Transco	$ 15,048,230	$ 13,612,203	$ 13,521,590	$ 12,662,101	$ 15,574,745	$ 15,569,161	$ 14,051,318	$ 8,899,602	$ 8,535,439	$ 177,689
Spot Purchases - Tecto	$ 3,861,100	$ 9,934,371	$ 4,510,230	$ 3,096,099	$ 4,465,221	$ 1,335,753	$ 156,038	$ 32,453	$ 85,147	$ 3,020,887
Transco Supply 1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Transco Supply 2	$ 2,387,750	$ 4,293,500	$ 4,269,750	$ 4,089,000	$ 1,976,000	$ 2,393,250	$ 425,500	$ 292,500	$ 302,250	$ 1,013,007
Transco Supply 3	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Transco Supply 4	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Transco Supply 5	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Transco Supply 6	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Transco Supply 7	$ 326,600	$ 1,986,600	$ 2,880,600	$ 2,416,400	$ 1,883,600	$ 1,416,400	$ 1,616,000	$ 1,416,000	$ 1,233,600	$ 2,101,338
Transco Supply 8	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Transco Supply 9	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Transco Supply 10	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Transco Supply 11	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Transco Supply 12	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Transco Supply 13	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Transco Supply 14	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Transco Supply 15	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Transco Supply 16	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Transco Supply 17	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Transco Supply 18	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Transco Supply 19	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Transco Supply 20	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Transco Supply 21	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Transco Supply 22	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Transco Supply 23	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Tetco Supply 1	$ 640,626	$ 230,263	$ 165,462	$ 242,578	$ 260,622	$ 909,212	$ 994,679	$ 963,380	$ 1,015,228	$ 265,185
Tetco Supply 2	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Tetco Supply 3	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Tetco Supply 4	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Tetco Supply 5	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Tetco Supply 6	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Tetco Supply 7	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Tetco Supply 8	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Tetco Supply 9	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Tetco Supply 10	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Tetco Supply 11	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Tetco Supply 12	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Tetco Supply 13	$ 3,002,029	$ 3,431,550	$ 2,432,962	$ 316,000	$ 546,000	$ 330,800	$ 338,800	$ 331,400	$ 331,798	$ 1,000,922
Tetco Supply 14	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Tetco Supply 15	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Tetco Supply 16	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Tetco Supply 17	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Tetco Supply 18	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Tetco Supply 19	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
FT PAYBACK ADJUSTMENT	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 377,456	$ 380,506	$ 382,794
Total Costs	$ 29,448,286	$ 38,552,510	$ 32,991,427	$ 27,963,540	$ 30,070,616	$ 26,984,052	$ 22,594,696	$ 16,522,778	$ 16,040,503	$ 12,122,447

TRANSCONTINENTAL

Cost of Natural Gas

Suppliers	**Jan-11**	**Feb-11**	**Mar-11**	**Apr-11**	**May-11**	**Jun-11**	**Jul-11**	**Aug-11**	**Sep-11**	**Oct-11**
TR Spot	$ 5,276,737	$ 12,698,581	$ 12,392,501	$ 14,089,649	$ 12,484,269	$ 6,262,390	$ 4,347,109	$ 1,572,275	$ 7,098,964	$ 15,249,405
Supplier 1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Supplier 2	$ 2,971,000	$ 499,000	$ 709,977	$ 2,257,900	$ 1,754,378	$ 2,104,150	$ 3,204,280	$ 2,208,332	$ 402,710	$ 421,750
Supplier 3	$ 728,500	$ 658,000	$ 728,500	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Supplier 4	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Supplier 5	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Supplier 6	$ 1,307,813	$ 632,100	$ 358,050	$ 1,159,500	$ 1,581,000	$ 1,490,640	$ 1,474,453	$ 1,405,075	$ 1,355,640	$ 1,432,200
Supplier 7	$ 2,029,000	$ 845,600	$ 2,427,061	$ 860,800	$ 601,200	$ 1,242,200	$ 1,920,400	$ 235,600	$ 416,800	$ 331,200
Supplier 8	$ 3,225,550	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Supplier 9	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Supplier 10	$ 739,350	$ 667,800	$ 73,935	$ 676,125	$ 663,013	$ 646,875	$ 337,513	$ -	$ 354,000	$ -
Supplier 11	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Supplier 12	$ 656,813	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Supplier 13	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Supplier 14	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Supplier 15	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Supplier 16	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Supplier 17	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Supplier 18	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Supplier 19	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Supplier 20	$ 624,650	$ 617,400	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Supplier 21	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Supplier 22	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Supplier 23	$ 728,112	$ 657,650	$ 728,112	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Suppliers	$ 18,287,525	$ 17,276,131	$ 17,418,137	$ 19,043,974	$ 17,083,859	$ 11,746,255	$ 11,283,754	$ 5,421,282	$ 9,628,114	$ 17,434,555
Transportation Costs										
Tr Spot -Sup 22	$ 357,331	$ 196,302	$ 165,955	$ 154,501	$ 126,640	$ 82,831	$ 78,117	$ 30,449	$ 66,752	$ 130,072
Williams Total	$ 357,331	$ 196,302	$ 165,955	$ 154,501	$ 126,640	$ 82,831	$ 78,117	$ 30,449	$ 66,752	$ 130,072
Total Costs	$ 18,644,856	$ 17,472,433	$ 17,584,092	$ 19,198,475	$ 17,210,499	$ 11,829,085	$ 11,361,872	$ 5,451,731	$ 9,694,867	$ 17,564,627

TRANSCONTINENTAL

Cost of Natural Gas

Suppliers	Nov-11	Dec-11	Jan-12	Feb-12	Mar-12	Apr-12	May-12	Jun-12	Jul-12	Aug-12
TR Spot	$ 15,048,230	$ 13,612,203	$ 13,521,590	$ 12,662,101	$ 15,574,745	$ 15,569,161	$ 14,051,318	$ 8,899,602	$ 8,535,439	$ 177,689
Supplier 1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Supplier 2	$ 2,387,750	$ 4,293,500	$ 4,269,750	$ 4,089,000	$ 1,976,000	$ 2,393,250	$ 425,500	$ 292,500	$ 302,250	$ 1,013,007
Supplier 3	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Supplier 4	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Supplier 5	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Supplier 6	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Supplier 7	$ 326,600	$ 1,986,600	$ 2,880,600	$ 2,416,400	$ 1,883,600	$ 1,416,400	$ 1,616,000	$ 1,416,000	$ 1,233,600	$ 2,101,338
Supplier 8	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Supplier 9	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Supplier 10	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Supplier 11	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Supplier 12	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Supplier 13	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Supplier 14	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Supplier 15	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Supplier 16	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Supplier 17	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Supplier 18	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Supplier 19	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Supplier 20	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Supplier 21	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Supplier 22	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Supplier 23	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Suppliers	$ 17,762,580	$ 19,892,303	$ 20,671,940	$ 19,167,500	$ 19,434,345	$ 19,378,811	$ 16,092,818	$ 10,608,102	$ 10,071,289	$ 3,292,034
Transportation Costs										
Tr Spot -Sup 22	$ 218,460	$ 267,233	$ 356,322	$ 307,652	$ 192,597	$ 152,701	$ 122,556	$ 81,804	$ 76,926	$ 10,965
Williams Total	$ 218,460	$ 267,233	$ 356,322	$ 307,652	$ 192,597	$ 152,701	$ 122,556	$ 81,804	$ 76,926	$ 10,965
Total Costs	$ 17,981,041	$ 20,159,536	$ 21,028,262	$ 19,475,153	$ 19,626,942	$ 19,531,513	$ 16,215,374	$ 10,689,905	$ 10,148,216	$ 3,302,999

TRANSCONTINENTAL

Volumes (Dth)

Suppliers	**Jan-11**	**Feb-11**	**Mar-11**	**Apr-11**	**May-11**	**Jun-11**	**Jul-11**	**Aug-11**	**Sep-11**	**Oct-11**
TR Spot	1,235,770	2,809,421	2,735,651	3,117,179	2,731,788	1,358,436	928,869	333,816	1,504,018	3,190,252
Supplier 1	-	-	-	-	-	-	-	-	-	-
Supplier 2	625,000	50,000	90,006	440,000	323,000	395,000	624,000	409,361	23,350	25,000
Supplier 3	155,000	140,000	155,000	-	-	-	-	-	-	-
Supplier 4	-	-	-	-	-	-	-	-	-	-
Supplier 5	-	-	-	-	-	-	-	-	-	-
Supplier 6	310,000	140,000	77,500	300,000	310,000	300,000	310,000	310,000	300,000	310,000
Supplier 7	420,000	140,000	483,766	140,000	80,000	220,000	360,000	-	40,000	20,000
Supplier 8	775,000	-	-	-	-	-	-	-	-	-
Supplier 9	-	-	-	-	-	-	-	-	-	-
Supplier 10	155,000	140,000	15,500	150,000	155,000	150,000	77,500	-	75,000	-
Supplier 11	-	-	-	-	-	-	-	-	-	-
Supplier 12	155,000	-	-	-	-	-	-	-	-	-
Supplier 13	-	-	-	-	-	-	-	-	-	-
Supplier 14	-	-	-	-	-	-	-	-	-	-
Supplier 15	-	-	-	-	-	-	-	-	-	-
Supplier 16	-	-	-	-	-	-	-	-	-	-
Supplier 17	-	-	-	-	-	-	-	-	-	-
Supplier 18	-	-	-	-	-	-	-	-	-	-
Supplier 19	-	-	-	-	-	-	-	-	-	-
Supplier 20	155,000	140,000	-	-	-	-	-	-	-	-
Supplier 21	-	-	-	-	-	-	-	-	-	-
Supplier 22	-	-	-	-	-	-	-	-	-	-
Supplier 23	155,000	140,000	155,000	-	-	-	-	-	-	-
Total Volumes	4,140,770	3,699,421	3,712,424	4,147,179	3,599,788	2,423,436	2,300,369	1,053,178	1,942,368	3,545,252

TRANSCONTINENTAL

Volumes (Dth)

Suppliers	**Nov-11**	**Dec-11**	**Jan-12**	**Feb-12**	**Mar-12**	**Apr-12**	**May-12**	**Jun-12**	**Jul-12**	**Aug-12**
TR Spot	3,052,379	2,643,146	2,556,066	2,411,829	3,024,222	3,164,464	2,850,166	1,797,899	1,710,509	35,396
Supplier 1	-	-	-	-	-	-	-	-	-	-
Supplier 2	425,000	775,000	750,000	725,000	325,000	425,000	25,000	-	-	141,585
Supplier 3	-	-	-	-	-	-	-	-	-	-
Supplier 4	-	-	-	-	-	-	-	-	-	-
Supplier 5	-	-	-	-	-	-	-	-	-	-
Supplier 6	300,000	310,000	310,000	290,000	310,000	300,000	310,000	300,000	310,000	-
Supplier 7	20,000	340,000	500,000	440,000	320,000	240,000	280,000	240,000	200,000	371,661
Supplier 8	-	-	-	-	-	-	-	-	-	-
Supplier 9	-	-	-	-	-	-	-	-	-	-
Supplier 10	-	-	-	-	-	-	-	-	-	-
Supplier 11	-	-	-	-	-	-	-	-	-	-
Supplier 12	-	-	-	-	-	-	-	-	-	-
Supplier 13	-	-	-	-	-	-	-	-	-	-
Supplier 14	-	-	-	-	-	-	-	-	-	-
Supplier 15	-	-	-	-	-	-	-	-	-	-
Supplier 16	-	-	-	-	-	-	-	-	-	-
Supplier 17	-	-	-	-	-	-	-	-	-	-
Supplier 18	-	-	-	-	-	-	-	-	-	-
Supplier 19	-	-	-	-	-	-	-	-	-	-
Supplier 20	-	-	-	-	-	-	-	-	-	-
Supplier 21	-	-	-	-	-	-	-	-	-	-
Supplier 22	-	-	-	-	-	-	-	-	-	-
Supplier 23	-	-	-	-	-	-	-	-	-	-
Total Volumes	3,797,379	4,068,146	4,116,066	3,866,829	3,979,222	4,129,464	3,465,166	2,337,899	2,220,509	548,642

TRANSCONTINENTAL

	Jan-11	Feb-11	Mar-11	Apr-11	May-11	Jun-11	Jul-11	Aug-11	Sep-11	Oct-11
WSS										
Injection	$ 111	$ -	$ -	$ 1,820	$ 2,810	$ 2,720	$ 2,810	$ 2,810	$ 2,720	$ 2,357
Withdrawal	$ 3,762	$ 2,901	$ 2,927	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Demand Charges	$ 46,429	$ 46,429	$ 46,429	$ 46,429	$ 46,429	$ 46,429	$ 46,429	$ 46,429	$ 46,429	$ 46,429
Total Charges	$ 50,302	$ 49,330	$ 49,356	$ 48,250	$ 49,239	$ 49,149	$ 49,239	$ 49,239	$ 49,149	$ 48,786
S2										
Injection	$ 141	$ -	$ -	$ 2,121	$ 3,770	$ 2,148	$ 2,220	$ 2,220	$ 2,148	$ 2,076
Withdrawal	$ 4,220	$ 2,877	$ 1,692	$ 578	$ -	$ -	$ -	$ -	$ -	$ -
Demand Charges	$ 28,528	$ 28,528	$ 28,528	$ 28,528	$ 28,528	$ 28,528	$ 28,528	$ 28,528	$ 28,528	$ 28,528
Total Charges	$ 32,889	$ 31,405	$ 30,220	$ 31,227	$ 32,298	$ 30,676	$ 30,747	$ 30,747	$ 30,676	$ 30,604
GSS										
Injection	$ 680	$ -	$ -	$ 15,763	$ 31,772	$ 26,684	$ 27,401	$ 26,809	$ 6,880	$ 5,963
Withdrawal	$ 40,175	$ 18,335	$ 6,028	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Demand Charges	$ 254,290	$ 254,290	$ 254,290	$ 254,290	$ 254,290	$ 254,290	$ 254,290	$ 254,290	$ 254,290	$ 254,290
Total Charges	$ 295,145	$ 272,625	$ 260,318	$ 270,053	$ 286,062	$ 280,974	$ 281,691	$ 281,099	$ 261,171	$ 260,253
EMINENCE										
Injection	$ 189	$ -	$ -	$ 2,835	$ 5,858	$ 4,506	$ 4,037	$ 3,098	$ 2,255	$ 2,029
Withdrawal	$ 4,885	$ 4,559	$ 5,048	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Demand Charges	$ 99,490	$ 99,490	$ 99,490	$ 99,490	$ 99,490	$ 99,490	$ 99,490	$ 99,490	$ 99,490	$ 99,490
Total Charges	$ 104,563	$ 104,049	$ 104,537	$ 102,324	$ 105,348	$ 103,995	$ 103,526	$ 102,588	$ 101,744	$ 101,519
Total Injection Charges	$ 1,121	$ -	$ -	$ 22,539	$ 44,210	$ 36,057	$ 36,467	$ 34,937	$ 14,002	$ 12,425
Total Withdrawal Charges	$ 53,042	$ 28,672	$ 15,695	$ 578	$ -	$ -	$ -	$ -	$ -	$ -
Total Demand Charges	$ 428,737	$ 428,737	$ 428,737	$ 428,737	$ 428,737	$ 428,737	$ 428,737	$ 428,737	$ 428,737	$ 428,737
Total Storage	$ 482,900	$ 457,408	$ 444,431	$ 451,854	$ 472,947	$ 464,794	$ 465,204	$ 463,674	$ 442,739	$ 441,162

Forecasted Summary of Firm Transportation

	Jan-11	Feb-11	Mar-11	Apr-11	May-11	Jun-11	Jul-11	Aug-11	Sep-11	Oct-11
Demand Charges	$ 2,316,931	$ 2,315,352	$ 2,288,195	$ 2,287,511	$ 2,287,077	$ 2,286,695	$ 2,286,563	$ 2,286,445	$ 2,285,813	$ 2,285,182
Capacity Release Credit	$ (254,696)	$ (230,048)	$ (254,696)	$ (246,480)	$ (254,696)	$ (246,480)	$ (254,696)	$ (254,696)	$ (398,280)	$ (411,556)
Net Demand Charge	$ 2,062,235	$ 2,085,304	$ 2,033,499	$ 2,041,031	$ 2,032,381	$ 2,040,215	$ 2,031,867	$ 2,031,749	$ 1,887,533	$ 1,873,626

TRANSCONTINENTAL

	Nov-11	Dec-11	Jan-12	Feb-12	Mar-12	Apr-12	May-12	Jun-12	Jul-12	Aug-12
WSS										
Injection	$ -	$ -	$ -	$ -	$ -	$ 1,981	$ 2,412	$ 2,331	$ 2,409	$ 2,409
Withdrawal	$ 1,554	$ 3,391	$ 3,598	$ 3,137	$ 3,112	$ -	$ -	$ -	$ -	$ -
Demand Charges	$ 46,429	$ 46,429	$ 46,429	$ 46,429	$ 46,429	$ 46,429	$ 46,429	$ 46,429	$ 46,429	$ 46,429
Total Charges	$ 47,983	$ 49,821	$ 50,027	$ 49,566	$ 49,542	$ 48,411	$ 48,841	$ 48,760	$ 48,838	$ 48,838
S2										
Injection	$ -	$ -	$ -	$ -	$ -	$ 1,912	$ 2,763	$ 2,148	$ 2,220	$ 2,220
Withdrawal	$ 1,955	$ 2,085	$ 4,908	$ 3,554	$ 1,671	$ 535	$ -	$ -	$ -	$ 169
Demand Charges	$ 28,528	$ 28,528	$ 28,528	$ 28,528	$ 28,528	$ 28,528	$ 28,528	$ 28,528	$ 28,528	$ 28,528
Total Charges	$ 30,483	$ 30,612	$ 33,435	$ 32,081	$ 30,199	$ 30,975	$ 31,291	$ 30,676	$ 30,747	$ 30,917
GSS										
Injection	$ -	$ -	$ -	$ -	$ -	$ 15,763	$ 32,577	$ 27,185	$ 27,401	$ 7,110
Withdrawal	$ 6,437	$ 24,234	$ 66,954	$ 33,122	$ 3,715	$ -	$ -	$ -	$ -	$ -
Demand Charges	$ 254,290	$ 254,290	$ 254,290	$ 254,290	$ 254,290	$ 254,290	$ 254,290	$ 254,290	$ 254,290	$ 254,290
Total Charges	$ 260,727	$ 278,524	$ 321,244	$ 287,412	$ 258,005	$ 270,053	$ 286,867	$ 281,475	$ 281,691	$ 261,400
EMINENCE										
Injection	$ -	$ -	$ -	$ -	$ -	$ 2,835	$ 5,219	$ 3,006	$ 3,106	$ 3,106
Withdrawal	$ 2,442	$ 5,048	$ 5,048	$ 4,722	$ 5,048	$ -	$ -	$ -	$ -	$ -
Demand Charges	$ 99,490	$ 99,490	$ 99,490	$ 99,490	$ 99,490	$ 99,490	$ 99,490	$ 99,490	$ 99,490	$ 99,490
Total Charges	$ 101,932	$ 104,537	$ 104,537	$ 104,211	$ 104,537	$ 102,324	$ 104,709	$ 102,496	$ 102,596	$ 102,596
Total Injection Charges	$ -	$ -	$ -	$ -	$ -	$ 22,491	$ 42,972	$ 34,670	$ 35,135	$ 14,844
Total Withdrawal Charges	$ 12,389	$ 34,757	$ 80,507	$ 44,535	$ 13,546	$ 535	$ -	$ -	$ -	$ 169
Total Demand Charges	$ 428,737	$ 428,737	$ 428,737	$ 428,737	$ 428,737	$ 428,737	$ 428,737	$ 428,737	$ 428,737	$ 428,737
Total Storage	$ 441,126	$ 463,494	$ 509,243	$ 473,271	$ 442,283	$ 451,763	$ 471,708	$ 463,406	$ 463,872	$ 443,750

Forecasted Summary of Firm Transportation

	Nov-11	Dec-11	Jan-12	Feb-12	Mar-12	Apr-12	May-12	Jun-12	Jul-12	Aug-12
Demand Charges	$ 2,284,563	$ 2,309,812	$ 2,309,181	$ 2,308,549	$ 2,282,037	$ 2,281,393	$ 2,280,761	$ 2,280,130	$ 2,279,498	$ 2,278,880
Capacity Release Credit	$ (398,280)	$ (411,556)	$ (411,556)	$ (385,004)	$ (152,086)	$ (147,180)	$ (152,086)	$ (147,180)	$ (152,086)	$ (152,086)
Net Demand Charge	$ 1,886,283	$ 1,898,256	$ 1,897,625	$ 1,923,545	$ 2,129,951	$ 2,134,213	$ 2,128,675	$ 2,132,950	$ 2,127,412	$ 2,126,794

Texas Eastern
Cost of Natural Gas

Suppliers	Jan-11	Feb-11	Mar-11	Apr-11	May-11	Jun-11	Jul-11	Aug-11	Sep-11	Oct-11
TE Spot	$ 1,700,779	$ 1,587,238	$ 4,754,520	$ 439,827	$ 983,647	$ -	$ 28,685	$ 2,805,951	$ 170,333	$ 657,354
Supplier 1	$ 1,508,311	$ 177,808	$ 226,770	$ 907,919	$ 911,853	$ 868,569	$ 872,221	$ 136,815	$ 854,699	$ 916,482
Supplier 2	$ 645,575	$ 605,850	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Supplier 3	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Supplier 4	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Supplier 5	$ 629,300	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Supplier 6	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Supplier 7	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Supplier 8	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Supplier 9	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Supplier 10	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Supplier 11	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Supplier 12	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Supplier 13	$ 5,615,805	$ 3,945,940	$ 4,579,962	$ 846,395	$ 421,400	$ 234,000	$ 418,232	$ 241,800	$ 234,000	$ 1,311,139
Supplier 14	$ 2,021,975	$ 1,796,900	$ 1,367,255	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Supplier 15	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Supplier 16	$ 626,975	$ 566,300	$ 626,975	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Supplier 17	$ 1,727,320	$ 1,560,160	$ 1,727,320	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Supplier 18	$ 639,375	$ 567,700	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Supplier 19	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Sub Total	$ 15,115,415	$ 10,807,896	$ 13,282,801	$ 2,194,141	$ 2,316,899	$ 1,102,569	$ 1,319,139	$ 3,184,566	$ 1,259,033	$ 2,884,975
Transportation Costs										
TE Spot-Sup10	$ 181,579	$ 124,649	$ 111,119	$ 61,508	$ 52,971	$ 44,532	$ 31,757	$ 104,749	$ 26,315	$ 32,164
Total TE	$ 181,579	$ 124,649	$ 111,119	$ 61,508	$ 52,971	$ 44,532	$ 31,757	$ 104,749	$ 26,315	$ 32,164
ANR	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Equitrans	$ -	$ -	$ -	$ 15,429	$ 15,943	$ 15,429	$ 15,943	$ 15,943	$ 15,429	$ 12,857
Total Costs	$ 15,296,995	$ 10,932,545	$ 13,393,920	$ 2,271,077	$ 2,385,813	$ 1,162,529	$ 1,366,839	$ 3,305,258	$ 1,300,776	$ 2,929,996

Texas Eastern
Cost of Natural Gas

Suppliers	Nov-11	Dec-11	Jan-12	Feb-12	Mar-12	Apr-12	May-12	Jun-12	Jul-12	Aug-12
TE Spot	$ 3,861,100	$ 9,934,371	$ 4,510,230	$ 3,096,099	$ 4,465,221	$ 1,335,753	$ 156,038	$ 32,453	$ 85,147	$ 3,020,887
Supplier 1	$ 640,626	$ 230,263	$ 165,462	$ 242,578	$ 260,622	$ 909,212	$ 994,679	$ 963,380	$ 1,015,228	$ 265,185
Supplier 2	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Supplier 3	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Supplier 4	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Supplier 5	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Supplier 6	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Supplier 7	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Supplier 8	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Supplier 9	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Supplier 10	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Supplier 11	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Supplier 12	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Supplier 13	$ 3,002,029	$ 3,431,550	$ 2,432,962	$ 316,000	$ 546,000	$ 330,800	$ 338,800	$ 331,400	$ 331,798	$ 1,000,922
Supplier 14	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Supplier 15	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Supplier 16	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Supplier 17	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Supplier 18	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Supplier 19	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Sub Total	$ 7,503,755	$ 13,596,184	$ 7,108,654	$ 3,654,677	$ 5,271,842	$ 2,575,765	$ 1,489,516	$ 1,327,233	$ 1,432,173	$ 4,286,995
Transportation Costs										
TE Spot-Sup10	$ 56,114	$ 126,760	$ 90,531	$ 81,187	$ 96,938	$ 52,061	$ 52,548	$ 42,007	$ 27,162	$ 102,654
Total TE	$ 56,114	$ 126,760	$ 90,531	$ 81,187	$ 96,938	$ 52,061	$ 52,548	$ 42,007	$ 27,162	$ 102,654
ANR	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Equitrans	$ -	$ -	$ -	$ -	$ -	$ 15,429	$ 15,943	$ 15,429	$ 15,943	$ 15,943
Total Costs	$ 7,559,869	$ 13,722,944	$ 7,199,185	$ 3,735,864	$ 5,368,781	$ 2,643,254	$ 1,558,008	$ 1,384,669	$ 1,475,278	$ 4,405,592

Philadelphia Gas Works
Forecasted Summary of Total Fuel Purchased
January 2011-August 2012

Texas Eastern
Volumes

Suppliers	**Jan-11**	**Feb-11**	**Mar-11**	**Apr-11**	**May-11**	**Jun-11**	**Jul-11**	**Aug-11**	**Sep-11**	**Oct-11**
	-	-	-	-	-	-	-	-	-	-
TE Spot	405,914	357,486	1,068,432	99,060	219,075	-	6,236	606,037	36,710	139,863
Supplier 1	336,772	10,978	21,956	177,842	176,830	165,644	163,986	1,976	158,728	169,914
Supplier 2	155,000	140,000	-	-	-	-	-	-	-	-
Supplier 3	-	-	-	-	-	-	-	-	-	-
Supplier 4	-	-	-	-	-	-	-	-	-	-
Supplier 5	155,000	-	-	-	-	-	-	-	-	-
Supplier 6	-	-	-	-	-	-	-	-	-	-
Supplier 7	-	-	-	-	-	-	-	-	-	-
Supplier 8	-	-	-	-	-	-	-	-	-	-
Supplier 9	-	-	-	-	-	-	-	-	-	-
Supplier 10	-	-	-	-	-	-	-	-	-	-
Supplier 11	-	-	-	-	-	-	-	-	-	-
Supplier 12	-	-	-	-	-	-	-	-	-	-
Supplier 13	1,000,065	720,000	886,082	137,927	40,000	-	38,355	-	-	227,519
Supplier 14	465,000	420,000	310,000	-	-	-	-	-	-	-
Supplier 15	-	-	-	-	-	-	-	-	-	-
Supplier 16	155,000	140,000	155,000	-	-	-	-	-	-	-
Supplier 17	418,500	378,000	418,500	-	-	-	-	-	-	-
Supplier 18	155,000	140,000	-	-	-	-	-	-	-	-
Supplier 19	-	-	-	-	-	-	-	-	-	-
Total	3,246,250	2,306,464	2,859,970	414,829	435,905	165,644	208,577	608,013	195,438	537,296

Philadelphia Gas Works
Forecasted Summary of Total Fuel Purchased
January 2011-August 2012

Texas Eastern Volumes

Suppliers	**Nov-11**	**Dec-11**	**Jan-12**	**Feb-12**	**Mar-12**	**Apr-12**	**May-12**	**Jun-12**	**Jul-12**	**Aug-12**
	-	-	-	-	-	-	-	-	-	-
TE Spot	796,103	1,959,442	865,687	598,859	880,714	275,982	32,173	6,664	17,342	672,803
Supplier 1	107,078	19,960	6,986	21,956	25,948	163,342	180,782	173,548	182,758	30,628
Supplier 2	-	-	-	-	-	-	-	-	-	-
Supplier 3	-	-	-	-	-	-	-	-	-	-
Supplier 4	-	-	-	-	-	-	-	-	-	-
Supplier 5	-	-	-	-	-	-	-	-	-	-
Supplier 6	-	-	-	-	-	-	-	-	-	-
Supplier 7	-	-	-	-	-	-	-	-	-	-
Supplier 8	-	-	-	-	-	-	-	-	-	-
Supplier 9	-	-	-	-	-	-	-	-	-	-
Supplier 10	-	-	-	-	-	-	-	-	-	-
Supplier 11	-	-	-	-	-	-	-	-	-	-
Supplier 12	-	-	-	-	-	-	-	-	-	-
Supplier 13	564,312	628,378	420,643	40,000	60,000	20,000	20,000	20,000	18,330	169,070
Supplier 14	-	-	-	-	-	-	-	-	-	-
Supplier 15	-	-	-	-	-	-	-	-	-	-
Supplier 16	-	-	-	-	-	-	-	-	-	-
Supplier 17	-	-	-	-	-	-	-	-	-	-
Supplier 18	-	-	-	-	-	-	-	-	-	-
Supplier 19	-	-	-	-	-	-	-	-	-	-
Total	1,467,492	2,607,780	1,293,316	660,815	966,662	459,324	232,955	200,212	218,429	872,501

Texas Eastern
Storages

	Jan-11	Feb-11	Mar-11	Apr-11	May-11	Jun-11	Jul-11	Aug-11	Sep-11	Oct-11
SS1A										
Injections	$ 363	$ -	$ -	$ 5,449	$ 11,262	$ 10,898	$ 7,090	$ 11,262	$ 4,005	$ 3,872
Withdrawal	$ 23,151	$ 23,008	$ 10,625	$ 1,845	$ -	$ -	$ -	$ -	$ -	$ -
Capacity	$ 28,522	$ 28,522	$ 28,522	$ 28,522	$ 28,522	$ 28,522	$ 28,522	$ 28,522	$ 28,522	$ 28,522
Demand	$ 220,956	$ 220,956	$ 220,956	$ 220,956	$ 220,956	$ 220,956	$ 220,956	$ 220,956	$ 220,956	$ 220,956
Total Charges	$ 272,993	$ 272,487	$ 260,103	$ 256,773	$ 260,740	$ 260,377	$ 256,569	$ 260,740	$ 253,483	$ 253,350
SS1B										
Injections	$ 338	$ -	$ -	$ 5,069	$ 10,271	$ 8,889	$ 4,139	$ 10,475	$ 4,005	$ 3,872
Withdrawal	$ 21,523	$ 13,984	$ 9,221	$ 2,259	$ -	$ -	$ -	$ -	$ -	$ -
Capacity	$ 26,529	$ 26,529	$ 26,529	$ 26,529	$ 26,529	$ 26,529	$ 26,529	$ 26,529	$ 26,529	$ 26,529
Demand	$ 104,402	$ 104,402	$ 104,402	$ 104,402	$ 104,402	$ 104,402	$ 104,402	$ 104,402	$ 104,402	$ 104,402
Total Charges	$ 152,792	$ 144,916	$ 140,152	$ 138,259	$ 141,202	$ 139,821	$ 135,070	$ 141,407	$ 134,936	$ 134,803
GSSTE										
Injections	$ -	$ -	$ -	$ 7,511	$ 7,519	$ 7,277	$ 7,519	$ 13,738	$ 7,277	$ 6,549
Injections/Retention Fuel	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Withdrawal	$ 16,293	$ 3,412	$ 477	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Capacity	$ 56,825	$ 56,825	$ 56,825	$ 56,825	$ 56,825	$ 56,825	$ 56,825	$ 56,825	$ 56,825	$ 56,825
Demand	$ 64,322	$ 64,322	$ 64,322	$ 64,322	$ 64,322	$ 64,322	$ 64,322	$ 64,322	$ 64,322	$ 64,322
Total Charges	$ 137,440	$ 124,559	$ 121,624	$ 128,658	$ 128,666	$ 128,423	$ 128,666	$ 134,885	$ 128,423	$ 127,696
EQUITRANS										
Injections	$ -	$ -	$ -	$ 310	$ 321	$ 310	$ 321	$ 321	$ 310	$ 259
Withdrawal	$ 138	$ 494	$ 279	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Capacity	$ 13,689	$ 13,689	$ 13,689	$ 13,689	$ 13,689	$ 13,689	$ 13,689	$ 13,689	$ 13,689	$ 13,689
Demand	$ 7,472	$ 7,472	$ 7,472	$ 7,472	$ 7,472	$ 7,472	$ 7,472	$ 7,472	$ 7,472	$ 7,472
Total Charges	$ 21,299	$ 21,655	$ 21,440	$ 21,472	$ 21,482	$ 21,472	$ 21,482	$ 21,482	$ 21,472	$ 21,420
Total Injection Charges	$ 701	$ -	$ -	$ 18,340	$ 29,373	$ 27,375	$ 19,069	$ 35,796	$ 15,597	$ 14,551
Total Injections/Retention Fuel	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Withdrawal Charges	$ 61,105	$ 40,899	$ 20,602	$ 4,104	$ -	$ -	$ -	$ -	$ -	$ -
Total Capacity Charges	$ 125,566	$ 125,566	$ 125,566	$ 125,566	$ 125,566	$ 125,566	$ 125,566	$ 125,566	$ 125,566	$ 125,566
Total Demand Charges	$ 397,151	$ 397,151	$ 397,151	$ 397,151	$ 397,151	$ 397,151	$ 397,151	$ 397,151	$ 397,151	$ 397,151
Total Transportation Charge	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	$ 584,523	$ 563,616	$ 543,319	$ 545,161	$ 552,090	$ 550,092	$ 541,786	$ 558,513	$ 538,315	$ 537,268

Forecasted Summary of Firm Transportation

	Jan-11	Feb-11	Mar-11	Apr-11	May-11	Jun-11	Jul-11	Aug-11	Sep-11	Oct-11
Texas Eastern Demand	$ 2,083,149	$ 2,059,944	$ 2,058,443	$ 2,057,639	$ 2,057,128	$ 2,056,680	$ 2,056,525	$ 2,056,386	$ 2,055,643	$ 2,054,901
Capacity Release Credits	$ (200,038)	$ (180,680)	$ (200,038)	$ (637,249)	$ (658,491)	$ (637,249)	$ (658,491)	$ (658,491)	$ (1,029,713)	$ (1,064,037)
Net Total	$ 1,883,111	$ 1,879,264	$ 1,858,405	$ 1,420,389	$ 1,398,637	$ 1,419,430	$ 1,398,034	$ 1,397,895	$ 1,025,930	$ 990,864
Equitrans	$ 26,538	$ 26,538	$ 26,538	$ 12,399	$ 12,399	$ 12,399	$ 12,399	$ 12,399	$ 12,399	$ 12,399
Total Demand Charges	$ 1,909,649	$ 1,905,802	$ 1,884,943	$ 1,432,788	$ 1,411,036	$ 1,431,829	$ 1,410,433	$ 1,410,294	$ 1,038,329	$ 1,003,263

Texas Eastern
Storages

	Nov-11	Dec-11	Jan-12	Feb-12	Mar-12	Apr-12	May-12	Jun-12	Jul-12	Aug-12
SS1A										
Injections	$ -	$ -	$ -	$ -	$ -	$ 5,449	$ 11,220	$ 10,677	$ 4,139	$ 11,032
Withdrawal	$ 247	$ 6,157	$ 36,910	$ 23,540	$ 11,079	$ 2,079	$ -	$ -	$ -	$ 1,135
Capacity	$ 28,522	$ 28,522	$ 28,522	$ 28,522	$ 28,522	$ 28,522	$ 28,522	$ 28,522	$ 28,522	$ 28,522
Demand	$ 220,956	$ 220,956	$ 220,956	$ 220,956	$ 220,956	$ 220,956	$ 220,956	$ 220,956	$ 220,956	$ 220,956
Total Charges	$ 249,726	$ 255,635	$ 286,388	$ 273,018	$ 260,557	$ 257,006	$ 260,698	$ 260,156	$ 253,617	$ 261,645
SS1B										
Injections	$ -	$ -	$ -	$ -	$ -	$ 5,069	$ 10,271	$ 7,497	$ 4,139	$ 10,475
Withdrawal	$ 3,512	$ 13,986	$ 23,015	$ 20,763	$ 8,797	$ 1,729	$ -	$ -	$ -	$ -
Capacity	$ 26,529	$ 26,529	$ 26,529	$ 26,529	$ 26,529	$ 26,529	$ 26,529	$ 26,529	$ 26,529	$ 26,529
Demand	$ 104,402	$ 104,402	$ 104,402	$ 104,402	$ 104,402	$ 104,402	$ 104,402	$ 104,402	$ 104,402	$ 104,402
Total Charges	$ 134,443	$ 144,917	$ 153,946	$ 151,694	$ 139,728	$ 137,729	$ 141,202	$ 138,428	$ 135,070	$ 141,407
GSSTE										
Injections	$ -	$ -	$ -	$ -	$ -	$ 3,630	$ 7,502	$ 7,260	$ 7,502	$ 13,738
Injections/Retention Fuel	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Withdrawal	$ 5,022	$ 8,226	$ 17,479	$ 11,860	$ 1,704	$ 1	$ -	$ -	$ -	$ -
Capacity	$ 56,825	$ 56,825	$ 56,825	$ 56,825	$ 56,825	$ 56,825	$ 56,825	$ 56,825	$ 56,825	$ 56,825
Demand	$ 64,322	$ 64,322	$ 64,322	$ 64,322	$ 64,322	$ 64,322	$ 64,322	$ 64,322	$ 64,322	$ 64,322
Total Charges	$ 126,168	$ 129,372	$ 138,625	$ 133,007	$ 122,851	$ 124,778	$ 128,649	$ 128,407	$ 128,649	$ 134,885
EQUITRANS										
Injections	$ -	$ -	$ -	$ -	$ -	$ 310	$ 321	$ 310	$ 321	$ 321
Withdrawal	$ 292	$ 460	$ 1,001	$ 725	$ 69	$ -	$ -	$ -	$ -	$ -
Capacity	$ 13,689	$ 13,689	$ 13,689	$ 13,689	$ 13,689	$ 13,689	$ 13,689	$ 13,689	$ 13,689	$ 13,689
Demand	$ 7,472	$ 7,472	$ 7,472	$ 7,472	$ 7,472	$ 7,472	$ 7,472	$ 7,472	$ 7,472	$ 7,472
Total Charges	$ 21,453	$ 21,621	$ 22,162	$ 21,886	$ 21,230	$ 21,472	$ 21,482	$ 21,472	$ 21,482	$ 21,482
Total Injection Charges	$ -	$ -	$ -	$ -	$ -	$ 14,458	$ 29,314	$ 25,745	$ 16,100	$ 35,566
Total Injections/Retention Fuel	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Withdrawal Charges	$ 9,074	$ 28,828	$ 78,404	$ 56,888	$ 21,649	$ 3,809	$ -	$ -	$ -	$ 1,135
Total Capacity Charges	$ 125,566	$ 125,566	$ 125,566	$ 125,566	$ 125,566	$ 125,566	$ 125,566	$ 125,566	$ 125,566	$ 125,566
Total Demand Charges	$ 397,151	$ 397,151	$ 397,151	$ 397,151	$ 397,151	$ 397,151	$ 397,151	$ 397,151	$ 397,151	$ 397,151
Total Transportation Charge	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	$ 531,791	$ 551,546	$ 601,122	$ 579,605	$ 544,366	$ 540,984	$ 552,031	$ 548,462	$ 538,817	$ 559,418

Forecasted Summary of Firm Transportation

	Nov-11	Dec-11	Jan-12	Feb-12	Mar-12	Apr-12	May-12	Jun-12	Jul-12	Aug-12
Texas Eastern Demand	$ 2,054,174	$ 2,053,431	$ 2,052,689	$ 2,051,946	$ 2,051,204	$ 2,050,446	$ 2,049,704	$ 2,048,961	$ 2,048,219	$ 2,047,492
Capacity Release Credits	$ (1,029,713)	$ (323,236)	$ (323,236)	$ (302,382)	$ (119,448)	$ (380,519)	$ (393,203)	$ (380,519)	$ (393,203)	$ (393,203)
Net Total	$ 1,024,461	$ 1,730,195	$ 1,729,453	$ 1,749,564	$ 1,931,756	$ 1,669,927	$ 1,656,500	$ 1,668,442	$ 1,655,015	$ 1,654,288
Equitrans	$ 23,716	$ 26,538	$ 26,538	$ 26,538	$ 26,538	$ 12,399	$ 12,399	$ 12,399	$ 12,399	$ 12,399
Total Demand Charges	$ 1,048,177	$ 1,756,734	$ 1,755,991	$ 1,776,103	$ 1,958,294	$ 1,682,326	$ 1,668,899	$ 1,680,841	$ 1,667,414	$ 1,666,687

CAPACITY RELEASE (Dth)

	TRANSCO		TETCO		TETCO		TOTAL DOLLARS		TOTAL VOLUMES	
	Contract 3691		Contract 800232		Contract 800515-514 Paid					
	VOLUMES	DOLLARS	VOLUMES	DOLLARS	VOLUMES	DOLLARS	TRANSCO	TETCO	TRANSCO	TETCO
Sep-10	-	$ -	-	$ -	-	$ -	$ -	$ -	-	-
Oct-10	-	$ -	-	$ -	-	$ -	$ -	$ -	-	-
Nov-10	-	$ -	-	$ -	-	$ -	$ -	$ -	-	-
Dec-10	-	$ -	-	$ -	-	$ -	$ -	$ -	-	-
Jan-11	620,000	$ 254,696	486,948	$ 200,038	-	$ -	$ 254,696	$ 200,038	620,000	486,948
Feb-11	560,000	$ 230,048	439,824	$ 180,680	-	$ -	$ 230,048	$ 180,680	560,000	439,824
Mar-11	620,000	$ 254,696	486,948	$ 200,038	-	$ -	$ 254,696	$ 200,038	620,000	486,948
Apr-11	600,000	$ 246,480	471,240	$ 193,585	1,080,000	$ 443,664	$ 246,480	$ 637,249	600,000	1,551,240
May-11	620,000	$ 254,696	486,948	$ 200,038	1,116,000	$ 458,453	$ 254,696	$ 658,491	620,000	1,602,948
Jun-11	600,000	$ 246,480	471,240	$ 193,585	1,080,000	$ 443,664	$ 246,480	$ 637,249	600,000	1,551,240
Jul-11	620,000	$ 254,696	486,948	$ 200,038	1,116,000	$ 458,453	$ 254,696	$ 658,491	620,000	1,602,948
Aug-11	620,000	$ 254,695	486,948	$ 200,038	1,116,000	$ 458,453	$ 254,695	$ 658,491	620,000	1,602,948
TOTAL September 10 - August 11	4,860,000	$ 1,996,487	3,817,044	$ 1,568,042	5,508,000	$ 2,262,686	$ 1,996,487	$ 3,830,728	4,860,000	9,325,044

Philadelphia Gas Works
Capacity Release Credits
Septembery 2011-August 2012

CAPACITY RELEASE (Dth)

	TRANSCO		TETCO		TETCO		TOTAL DOLLARS		TOTAL VOLUMES	
	Contract 3691		Contract 800232		Contract 800515-514 Paid					
	VOLUMES	DOLLARS	VOLUMES	DOLLARS	VOLUMES	DOLLARS	TRANSCO	TETCO	TRANSCO	TETCO
Sep-11	600,000	$ 398,280	471,240	$ 312,809	1,080,000	$ 716,904	$ 398,280	$ 1,029,713	600,000	1,551,240
Oct-11	620,000	$ 411,556	486,948	$ 323,236	1,116,000	$ 740,801	$ 411,556	$ 1,064,037	620,000	1,602,948
Nov-11	600,000	$ 398,280	471,240	$ 312,809	432,000	$ 716,904	$ 398,280	$ 1,029,713	600,000	903,240
Dec-11	620,000	$ 411,556	486,948	$ 323,236	-	$ -	$ 411,556	$ 323,236	620,000	486,948
Jan-12	620,000	$ 411,556	486,948	$ 323,236	-	$ -	$ 411,556	$ 323,236	620,000	486,948
Feb-12	560,000	$ 385,004	439,824	$ 302,382	-	$ -	$ 385,004	$ 302,382	560,000	439,824
Mar-12	620,000	$ 152,086	486,948	$ 119,448	-	$ -	$ 152,086	$ 119,448	620,000	486,948
Apr-12	600,000	$ 147,180	471,240	$ 115,595	1,080,000	$ 264,924	$ 147,180	$ 380,519	600,000	1,551,240
May-12	620,000	$ 152,086	486,948	$ 119,448	1,116,000	$ 273,755	$ 152,086	$ 393,203	620,000	1,602,948
Jun-12	600,000	$ 147,180	471,240	$ 115,595	1,080,000	$ 264,924	$ 147,180	$ 380,519	600,000	1,551,240
Jul-12	620,000	$ 152,086	486,948	$ 119,448	1,116,000	$ 273,755	$ 152,086	$ 393,203	620,000	1,602,948
Aug-12	620,000	$ 152,086	486,948	$ 119,448	1,116,000	$ 273,755	$ 152,086	$ 393,203	620,000	1,602,948
TOTAL September 11 - August 12	7,300,000	$ 3,318,936	5,733,420	$ 2,606,692	8,136,000	$ 3,525,721	$ 3,318,936	$ 6,132,413	7,300,000	13,869,420

Tab 5

PGW ST. 1

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

DIRECT TESTIMONY OF

KENNETH S. DYBALSKI

ON BEHALF OF
PHILADELPHIA GAS WORKS

Docket No. R-2011-2224739

Philadelphia Gas Works
Proposed 2011 Annual GCR Adjustment

March 1, 2011

Q. PLEASE STATE YOUR NAME AND POSITION WITH THE COMPANY.

A. My name is Kenneth S. Dybalski. My position is Director, Gas Planning & Rates at the Philadelphia Gas Works.

Q. HOW LONG HAVE YOU HELD THIS POSITION?

A. I assumed the position of Director, Gas Planning & Rates in 2006. Prior to this position, I was the Manager of Gas Planning from 2001 to 2006.

Q. WHAT ARE YOUR VARIOUS JOB RESPONSIBILITIES?

A. In my present position, I am responsible for developing and coordinating short and long term planning of gas demand, gas supply, raw material expense and revenue; overseeing the preparation of sales, sendout, revenue and fuel expense projections; developing peak day/hour load projections; overseeing the development of the various filings before the Pennsylvania Public Utility Commission (PUC) and Philadelphia Gas Commission (PGC), including the quarterly and annual Gas Cost Rate (GCR) filings; preparing the Integrated Resource Planning Report; and providing supporting documentation for gas costs related to PGW's Operating Budget before the PGC.

Q. PLEASE SUMMARIZE YOUR EDUCATIONAL BACKGROUND.

A. I have received a BS and MBA from Temple University in Philadelphia, Pennsylvania.

Q. HAVE YOU EVER PROVIDED TESTIMONY BEFORE THIS COMMISSION?

A. Yes. I submitted testimony for the PGW 1307f Annual GCR Filings in Docket Nos. R-2010-20157062, R-2009-2088076, R-2008-2021348 and R-00072110. I have also submitted testimony in PGW's most recent base rate proceeding (Docket No. R-2009-2139884) and PGW's 2008 Extraordinary Rate Request (Docket No. R-2008-2073938).

Q. HOW IS YOUR TESTIMONY STRUCTURED

A. First, I describe PGW's rate design and Gas Cost Rate (GCR) calculation methodology. Second, I describe the level of heating degree-days utilized in this filing. Third, I identify the methodology for determining the number of customers and calculating firm sales. Fourth, I discuss the calculation for the Unaccounted for Adjustment Factor (UAF). Fifth, I discuss Off System Sales and Capacity Release credits. Sixth, I discuss the methodology for projecting soft-off volumes. Lastly, I will discuss the reasonableness of PGW's gas costs.

Q. PLEASE DESCRIBE THE IMPACT OF THE PROPOSED CHANGE IN PGW's GCR IN THIS PROCEEDING.

A. PGW's GCR on September 1, 2010 was $6.9050 and this rate was decreased to $6.2753 in the Company's first quarterly GCR filing on December 1, 2010. PGW's second quarter GCR filing, also submitted to the PUC concurrently with this filing increases the GCR to $6.5400 effective March 1, 2011. The proposed rate to be effective September 1, 2011 is $6.3077.

Q. PLEASE SUMMARIZE THE EVIDENCE THAT PGW IS SUBMITTING IN SUPPORT OF ITS PROPOSED GCR ADJUSTMENT.

A. Tab 2 of this filing contains the sheets supporting the filing requirements of Section 53.64 (a) for the proposed GCR for the period September 1, 2011 through August 31, 2012.

Schedule 1 identifies the Levelized Gas Cost Rate. Specifically, this schedule identifies the GCR Firm Sales Volumes in Mcfs ("S"), Total Applicable GCR Expense ("C"), and adjustments for Prior Year Reconciliation and Interest ("E"). An adjustment is also included for the Interruptible Revenue Credit (IRC). Additionally, this schedule calculates the company's total projected recovery of the net GCR applicable expenses by multiplying the Firm Sales Volume times the proposed GCR to determine if these rates adequately cover the Net Applicable GCR Expense (a Net Over/Under Recovery amount is displayed to prove the calculation).

Schedule 2 identifies the calculation of GCR Firm Sales in Mcfs ("S") and the Applicable Volumes. The company utilizes Total Volumes and subtracts the volumes associated with Firm Transportation, Interruptible Sales and AC Sales to arrive at GCR Firm Sales ("S"). Also included in Schedule 2 are the Applicable Volumes which is comprised of GCR Firm Sales less 20% of the sales attributable to Senior Citizens (Senior Citizen Discount Sales) plus the Firm Transportation Volumes.

Schedule 3 identifies the Projected Applicable Fuel Expense. Specifically, this schedule identifies PGW's Net Natural Gas Expense and Total Applicable Expenses. To arrive at the Net Natural Gas Expense, the total cost of commodity and pipeline charges for firm sales are calculated per month. Two credits are then applied for the portion of gas costs recovered from PGW's Interruptible Sales customers (i.e. the "Interruptible Credit") and for gas used by PGW (i.e. "Gas Used by Utility"). Next, the Company calculates the net effect of gas supplies being transferred into and out of storage and LNG. The result is the Net Natural Gas Expense. To arrive at the Total Applicable Expenses in Schedule 3, the fuel expenses for Purchased Electric and miscellaneous are added to the Net Natural Gas Expenses to arrive at Total Applicable Expenses.

Schedule 4a ("Interest Rate Calculation") provides the interest rate for the over/under recovery and is calculated on the over/under recovery in calendar year 2010. Schedule 4b ("Interest Calculation") provides the calculation of the interest expense or credit for the period of September 2010 through August 2011 for the under/over recovery of fuel costs and the interest for the natural gas refunds. Schedule 4c ("Interest on Natural Gas Refunds") provides information on historic refunds that have been received by the Company resulting from various cases before the Federal Energy Regulatory Commission and the interest on these refunds. Schedule 4d provides the calculation of the interest for the demand and commodity charges.

Schedule 5 presents the GCR Statement of Reconciliation for the forecast period of September 2011 to August 2012.

Schedule 6 presents the GCR Statement of Reconciliation for the actual / estimated period of September 2010 to August 2011.

Schedule 7 presents the finalized GCR Statement of Reconciliation for the historic period of September 2009 to August 2010.

Schedule 8 calculates total projected recovery with the proposed GCR.

Schedule 9 shows the changes in rates identifying the proposed changes to the GCR and distribution charge and the impact on the proposed total commodity rate.

Schedule 10(a) shows the calculation of the Universal Service & Energy Conservation Surcharge to be effective September 1, 2011. Schedule 10(b) is the reconciliation of the Universal Service & Energy Conservation Surcharge for period of September 2010 to August 2011.

Schedule 11(a) shows the calculation of the Interruptible Revenue Credit to be effective September 1, 2011. Schedule 11(b) is the reconciliation of the Interruptible Revenue Credit for Fiscal Year 2010.

Schedule 12 shows the calculation of the Other Post Employment Benefit Surcharge to be effective September 1, 2011.

Schedule 13(a) shows the calculation of the Efficiency Cost Recovery Surcharge to be effective September 1, 2011. Schedule 13(b) is the reconciliation of the Efficiency Cost Recovery Surcharge for Fiscal Year 2011.

Schedule 14(a) and 14(b) are the Restructuring and Consumer Education Surcharge and the Surcharge Reconciliation for FY 2010.

Schedule 15(a) and 15(b) are the calendar year 2010 reconciliation of the Supplier and Storage Peaking Charge (SSPC).

Schedule 16 identifies the natural gas prices that were used in the preparation of this filing.

Q. WHAT IS THE TIME PERIOD FOR FORECASTING PGW'S FUTURE GAS COSTS?

A. PGW's forecast period is a twenty (20) month period that commences on January 1, 2011 (two months before this filing) and eight months before the effective date of the tariff on September 1, 2011. The 2011-12 GCR year is from September 1, 2011 to August 31, 2012, however, since the required forecast covers 20 months, it must begin eight months earlier, consistent with Commission regulations.

Q. PLEASE PROVIDE A GENERAL DESCRIPTION OF PGW'S RATE DESIGN AND GCR CALCULATION METHODOLOGY.

A. The volumetric rates charged to PGW's customers are the distribution charge and the Gas Cost Rate. The distribution charge consists of the Delivery Charge; the Universal Service and Energy Conservation Surcharge; the Efficiency Cost Recovery Surcharge; Other Post Retirement Benefit Surcharge and the Restructuring and Consumer Education Surcharge. The Universal Service and Energy Conservation Surcharge provides for the recovery of Customer Responsibility Program (CRP) discounts; Senior Citizen Discounts; the costs of the Conservation Works Program and the Enhanced Low Income Retrofit Program (ELIRP); and CRP arrearage forgiveness. The Efficiency Cost Recovery Surcharge recovers the cost of energy efficiency programs for the noted firm rate classes. The Other Post Retirement Benefit Surcharge recovers the amount to fund these obligations. The Restructuring and Consumer Education Surcharge recovers Commission approved costs which the Company had incurred to meet the requirements of the Natural Choice and Competition Act and applicable Commission regulations, orders and other regulatory requirements.

The second element of the rate is the Gas Cost Rate or GCR factor. This charge is a mechanism used to flow through the costs of natural gas costs and other raw materials in a timely and equitable manner. The specific elements of PGW's GCR are set forth in PGW's Tariff.

Generally, the cost of gas purchased to serve the requirements of PGW's customers constitutes the largest single item in the delivered price of gas. In the past, all natural gas costs were recovered through base rates (distribution charge). However, in the early 1970's, the price of gas lost its stability and underwent rapid escalation during and after a worldwide oil crisis. To combat this instability and prevent the economic harm to all parties caused by regulatory lag in reflecting these price fluctuations in base rates, the concept of a fuel adjustment surcharge mechanism was introduced by PGW. This mechanism provides the flexibility to rapidly reflect current conditions without the time delay inherent in a full-scale base rate alteration. The intent is to achieve an annual balance of the costs incurred for fuel and its pass-through to customers. The costs for pipeline transportation, storage capacity and related fuel prices charged by the interstate pipeline suppliers are largely outside of distributor control. The State Public Utility Commission oversees the pass-through of these charges and the balancing activity. The Gas Cost Rate Section in PGW's Tariff identifies the appropriate formula for such a balance and the charges that may be recovered through this mechanism. Charges for natural gas and other raw materials are included in the GCR. In addition, the interest expense for the over or under recovery of gas costs and natural gas refunds are also included in the GCR. No labor, storage, or profit component is added by PGW. The GCR represents the direct pass-through of actual costs incurred.

Only costs related to meeting customer sendout requirements, including associated plant fuel, may be included as a fuel expense for GCR purposes. Purchases diverted into storage and/or LNG become an expense only when withdrawn for customer delivery. Costs associated with purchases made to supply interruptible customers are excluded from the Total Applicable GCR Expenses used to calculate the GCR. Also, demand costs for pipeline transportation for the firm transportation customers are excluded from the GCR.

Various adjustments are then made to the total applicable expenses eligible for the GCR. Natural gas refunds and interest on the refunds are credited in the calculation of the GCR in the fiscal year received. An adjustment is made to correct for any over or under recovery during the previous period resulting from differences between rates used to project the prior GCR and those actually experienced. The interest expense or credit on the over or under recovery is applied to calculate the total adjustment. An additional adjustment is also made for the Interruptible Revenue Credit which is a credit that firm sales customers receive for the interruptible sales margin.

To determine the unit level of the GCR, the remaining total expenses must be divided by the sum of the volumes over which they can be effectively distributed which is the firm sales volume.

Q. WHAT IS THE BASIS FOR THE PRICES USED IN DETERMINING THE GAS COSTS USED IN THIS FILING?

A. The pricing methodology utilized by the Company is what was contained in the settlement of the 2010-11 GCR Proceeding and used in the quarterly filings since the settlement with the inclusion of the additional months in the 20-month forecast. Specifically, the company utilized actual prices for January 2011 and the NYMEX Futures close data (as of January 14, 2011) for the 19 forecast months of February 2011 through August 2012.

Q. HOW DOES THE PROJECTED LEVEL OF GAS COSTS FOR THE FORECAST PERIOD COMPARE WITH THE LEVEL OF GAS COSTS FORECASTED IN THE COMPANY'S LAST ANNUAL GCR FILING?

A. The level of gas costs forecasted for 2011-2012 is lower than the level PGW had forecasted for the 2010-2011 GCR. The level of costs in the 2011-2012 period are being influenced by the decrease in prices for natural gas compared to the prior year.

Q. DESCRIBE THE LEVEL OF HEATING DEGREE-DAYS THAT WERE USED IN YOUR ANALYSIS.

A. The Company utilizes the temperatures recorded at the PGW Richmond Plant to calculate the average temperature for a given day. The Company subtracts the average temperature from 65 degrees to calculate the number of degree-days for the day. The degree-days for all of the days in the year are aggregated to arrive at the total number of degree-days for the year. Next, the Company calculates the average heating degree-days for the past 30 years to arrive at the forecasted heating degree-days in a normal year and in this filing PGW is using the 30 year average of 4,360 degree days.

Q. HOW HAS THE COMPANY CALCULATED THE NUMBER OF CUSTOMERS IN EACH RATE CLASS?

A. PGW determined the actual number of customer billings on December 31, 2010 using the PGW Gas Sales and Revenue Reports. Next, the Marketing Department load forecast was used to factor in the addition and loss of customers. Finally, the customer numbers were adjusted for the loss of customers due to non-payment terminations.

Q. WHAT IS THE METHOLOGY FOR CALCULATING THE WEATHER NORMALIZED BILLED SALES?

A. PGW used a two step process to arrive at the appropriate level of usage per customer. First, a trial domestic factor is developed by customer class from sales reported for the summer months (July-September).

This average factor was then utilized in the sendout formula with the customer counts for the months of July, August, and September 2009. A comparison between what the formula calculates and the actual experienced for those three months is ascertained and the trial domestic factors are finalized to replicate the total sendout experienced. The finalized domestic factors (DOMS) are then utilized in conjunction with the actual sales and customer counts for the months of December 2009 through February 2010 to determine the average Mcf per degree day for each of the individual months for the remaining temperature sensitive load. The results are weighted by degree-days to give an average value that is utilized as a trial value for the heating factor.

The finalized domestic factor and the trial heating factor developed, as such, are then applied in the sendout calculations, together with customer counts for the months of December 2009 through February 2010 (the peak winter heating period) to project an estimated sendout for each of these months. The projected sendout is then compared with the actual sendout. Any variation between the projected and actual is adjusted to force the replication of the actual sendout resulting in the determination of a finalized heating factor. The finalized heating factor is used to forecast the heating load and monthly adjustments are made based on monthly historic usage.

Utilizing these domestic and heating factors, billed sales are then forecasted using 4,360 degree days and the number of customers.

Q. WHAT IS THE UNACCOUNTED FOR GAS PERCENTAGE USED IN THIS FILING?

A. The level of unaccounted for gas used in this filing is 3.7 % and is based on a 3-year average.

Q. WHAT IS THE TOTAL AMOUNT OF OFF SYSTEM SALES, CAPACITY RELEASE CREDITS, AND ASSET MANAGEMENT CREDITS THAT ARE INCORPORATED IN THE GCR?

A. PGW has projected that the amount of off system sales, capacity release credits, and asset management credits within the GCR period of 2011-12 will amount to $12,601,799. Of that amount, $ 9,451,349 (75%) was credited to the GCR.

Q. HOW HAS PGW PROJECTED SOFT-OFF VOLUMES?

A. As agreed in the Joint Petition for Settlement of PGW's 2010-2011 GCR Proceeding (Docket Nos. R-2010-2157062) which was approved by the PUC, PGW is using a 3-year average for the projected amount of soft-off volumes.

Q. BASED UPON THE ABOVE SUPPORTING DATA, DO YOU BELIEVE THAT PGW'S GAS COSTS ARE REASONABLE?

A. Yes, PGW's GCR only contains the direct pass-through of actual costs incurred and projections of the same (for both gas costs and certain non-gas costs that were previously approved by the PUC). As stated by Mr. Moser in his testimony, PGW follows a least cost gas procurement strategy.

<u>LIQUEFIED NATURAL GAS SERVICE – RATE LNG</u>

Q. WHY IS PGW INCLUDING A TARIFF PAGE FOR "LIQUEFIED NATURAL GAS SERVICE – RATE LNG" IN THIS FILING?

A. PGW included Liquefied Natural Gas Service – Rate LNG in its most recent base rate case (Docket No. R-2009-2139884)[1] but mistakenly did not include this tariff page in its August 9, 2010 Compliance Filing even though this service was incorporated into the settlement agreement.[2]

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

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[1] *PaPUC v. PGW*, Docket No. R-2009-2139884. On December 18, 2009, PGW filed Supplement No. 36 to Tariff Gas – Pa. P.U.C. No. 2 which included the First Revised Page No. 142 and supporting testimony in PGW St. 5.

[2] The Terms and Conditions of Settlement in Section II., paragraph 15 of the May 12, 2010 Joint Petition for Settlement provides "The Joint Petitioners hereby respectfully request that, except as provided below, PGW's base rate increase filing and DSM program be approved as filed".

Tab 6

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

DIRECT TESTIMONY OF

DOUGLAS A. MOSER

ON BEHALF OF
PHILADELPHIA GAS WORKS

Docket No. R-2011-2224739

Philadelphia Gas Works
Proposed 2011 Annual GCR Adjustment

March 1, 2011

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND CURRENT POSITION WITH PGW.

A. My name is Douglas A. Moser. My position with PGW is the Senior Vice President of Gas Management.

Q. PLEASE SUMMARIZE YOUR BACKGROUND AND EXPERIENCE.

A. I received a Bachelor of Science degree in Chemical Engineering from Pennsylvania State University in 1979. I have also received a Masters in Business Administration from Widener University in 1990.

I have held the following positions at PGW: Engineering Assistant; Production Engineer; Supervisor – Gas Conditioning; Operations Engineer – Gas Processing Department; Manager – Gas Control; Manager – Gas Acquisition; and Senior Project Manager – Strategic Planning Department.

Q. HAVE YOU EVER PROVIDED TESTIMONY BEFORE THIS COMMISSION?

A. Yes. I submitted testimony for the PGW 1307f Annual GCR Filings in Docket Nos. R-2010-20157062, R-2009-2088076, R-2008-2021348 and R-00072110.

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

A. My testimony discusses:

- PGW's gas purchasing policies and strategies applicable to the current filing period (i.e. FY 2012 – September 1, 2011 to August 31, 2012) and the prior GCR period (i.e. FY 2011 – September 1, 2010 – August 31, 2011);
- PGW's design day requirement;
- Capacity release, off-system sales and asset management fee sharing;
- Capacity resources;
- Asset management

- Purchasing program compliance;
- Dominion Transmission class action litigation; and
- Price analysis and buying advisory service.

Q. PLEASE PROVIDE A GENERAL DESCRIPTION OF PGW'S GAS DISTRIBUTION SYSTEM.

A. PGW's gas distribution system is located in Southeastern Pennsylvania in the County and City of Philadelphia. Since this is not a gas-producing area, PGW and its natural gas customers are dependent upon the interstate natural gas pipeline system to deliver natural gas into the PGW gas distribution system. PGW relies on the interstate pipeline for all natural gas supply, storage, and transportation services, except for PGW's own on-system peak shaving facilities. PGW owns and operates a LNG facility that is used both to meet intraday, daily and seasonal supply needs as well as to meet peak day requirement.

Q. PLEASE IDENTIFY PGW'S CURRENT INTERSTATE SUPPLIERS.

A. Spectra Energy's Texas Eastern Transmission pipeline and Williams' Transco Gas Pipeline comprise the two interstate natural gas pipelines that deliver gas to PGW's city gates. In addition, Dominion Transmission Inc. (DTI) and Equitrans, Inc. (Equitrans) provide natural gas storage services that PGW uses to meet winter peak requirements. These storage services require intermediate transportation services from Spectra Energy to deliver storage withdrawals to the PGW gas distribution system.

II. <u>GAS PURCHASING POLICIES AND SUPPLY STRATEGY</u>

Q. DOES PGW UTILIZE A LEAST-COST PROCUREMENT POLICY IN ITS GAS PURCHASING POLICIES AND SUPPLY STRATEGY?

A. Yes.

Q. PLEASE DESCRIBE PGW'S SUPPLY STRATEGY.

A. PGW's supply strategy[1] (which is currently being used during the FY 2011 GCR period and which the Company intends to use during the FY 2012 GCR period) is a portfolio approach in both contract structure and pricing. The portfolio approach of purchasing gas supply allows PGW to remove some of the volatility in purchasing natural gas supplies for its ratepayers. Without the use of the portfolio approach, the firm ratepayer would be totally at the mercy of market volatility.

The Company's gas supply portfolio is divided into five distinct categories: (1) "first of the month index pricing"; (2) physical forward purchased contracts; (3) storage; (4) winter only supply contracts; and (5) LNG.

(1) The advantage of a first of the month index arrangement is that the operational flexibility of these contracts allows the company to increase or decrease the volume in response to changes in sendout requirements at a known price.

(2) The Company uses a purchasing strategy to fix the price for a portion of the gas supply each month for each of the succeeding 12 months. This strategy has the effect of stabilizing the purchase price while removing the speculative aspect of when to purchase the supply.

(3) The Company utilizes three pipeline storage fields which act as additional sources of supply. The gas procured under these contracts also act as a physical fixed price counter to market conditions.

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[1] All natural gas supply strategies are presented to the Company's Supply Committee for review and approval. The Supply Committee is comprised of senior corporate management as well as Gas Acquisition, Gas Planning, Gas Control, Gas Supply and Regulatory departmental management. The Supply Committee meets monthly.

(4) The Company enters into winter-only supply contracts. This arrangement provides additional benefit by relieving the firm ratepayer from paying supply demand charges any longer than is necessary.

(5) The Company operates its own liquefaction & vaporization plants and LNG storage which serve as peak shaving facilities.

Spectra Energy and Williams Gas Pipeline represent the only interstate pipeline facilities with physical connections to the PGW service territory. As a result, all of PGW's supply contracts utilize these pipelines and the contracts also recognize pipeline receipt and delivery rights. These contracts contain the ability to "lock up" the price for upcoming months or to have the pricing default to an agreed upon market index if there is no market advantage in fixing a price before the month begins. As a result, PGW not only ensures security of supply from the pipelines but also can take advantage of varying basis differentiated pricing in the market. This differentiated pricing results from the fact that all shippers of natural gas receive their gas at varying locations along the pipeline. PGW uses a city-gate delivered price in comparing the various alternatives available. The city gate delivered price is computed considering the "into the pipe price of gas" plus all incremental charges levied by the transporting pipeline to deliver the gas to the city gate. These prices include, but are not limited to, fuel shrinkage, transportation charges and ACA charges.

Additionally, PGW utilizes bundled storages and LNG to meet operational requirements. The bundled storages provide off-system storage and LNG provides on-system storage. While both types of storages are important to fulfill operational requirements, PGW's on-system LNG storage is vital during peak days when customer demand exceeds the amount of gas that can be physically provided through PGW's city gates.

Once operational requirements are met, these assets are then used in the overall cost saving strategies. For example, once design winter sendout requirements are ensured, the Company may utilize bundled storage and LNG as a substitute for higher priced gases. PGW's summer policy uses a similar approach to address system supply and storage refill. The Gas Supply department also uses forecasted prices as a benchmark to purchase gas volumes for both system supply and storage refill below the projected cost (when possible) on a proportional basis, while leaving a portion of its needs to default to "first of the month" pricing.

Q. DOES PGW PURCHASE GAS FROM ANY AFFILIATED INTEREST?

A. No.

Q. WHILE PGW IS ENSURING THE LEAST COST PROCUREMENT, HOW DOES IT PROVIDE FOR SYSTEM RELIABILITY?

A. PGW physically sources the gas in accordance with its firm pipeline paths. The pipelines give PGW firm entitlements on their systems for the sourcing of gas for which PGW pays a demand charge. By sourcing supply this way, PGW ensures its sole entitlement to this space on the pipeline and can not be accused of infringement. Transporting gas from different locations also mitigates the impact of potential regional disruptions because not all of the supply enters the pipe at the same location. As a result, if there is a disruption at one location, not all of PGW's supply will be affected.

PGW's Gas Planning Department also runs a supply status model during the winter operating season which recognizes normal and design winter conditions and the latest actual balance of gas in all storage facilities. Gas Management utilizes the output of this model to make recommendations or changes in its supply operating strategy to ensure that peak day needs and design winter conditions can be met from that point forward.

Q. DOES PGW PERIODICALLY REVIEW ITS EXISTING CONTRACTS TO DETERMINE IF THEY ARE APPROPRIATE?

A. Yes, PGW reviews each of its existing contracts on a regular basis to ensure that none of the contracts are adverse to its customers' interests. Whenever appropriate, PGW initiates renegotiations (if the contract permits) to change the terms.

Q. IN YOUR OPINION, ARE THE GAS COSTS INCURRED BY PGW DURING THE 2010-11 GCR PERIOD REASONABLE?

A. Yes. The 2010-2011 gas costs are the result of the least cost gas procurement strategy outlined in my testimony.

III. DESIGN DAY REQUIREMENT

Q. PLEASE PROVIDE AN OVERVIEW OF THE DESIGN DAY REQUIREMENT.

A. Details of PGW's design day methodology and an account of the 2010/2011 winter design day requirement can be found in the response to item 53.64 (c)(13) and item 53.64(c)(14) in the information provided in PGW's February 1, 2011 and March 1, 2011 GCR Filings, respectively.

IV. CAPACITY RELEASE, OFF-SYSTEM SALES MARGIN AND ASSET MANAGEMENT FEES

Q. HAS PGW BEEN RETAINING A PORTION OF NET PROCEEDS FROM CAPACITY RELEASE CREDITS, OFF-SYSTEM SALES MARGIN AND ASSET MANAGEMENT FEES?

A. Yes. During the 2008-2009 GCR proceeding (Docket No. R-2008-2021348), the parties agreed that PGW will retain 25% of all off-system sales margins and capacity release credits with the remaining 75% applied as an offset to purchased gas costs. The retention began on September 1, 2008, for all off-system sales margins and capacity release credits booked on or after that date, and shall end on August 31, 2011 unless the Commission approves continuation. The Company also agreed to include in its March 1, 2011 annual 1307(f) filing:

(a) A report containing:

i. the actual off-system sales margin and capacity release credit data for the two year period of September 1, 2008 to August 31, 2010 and the retained portions thereof; and

ii. confirmation that the retained funds were segregated in a capital fund to be used for infrastructure repair and replacement.

(b) An off-system sales margin and capacity release credit retention proposal for the Purchased Gas Cost period(s) beginning on September 1, 2011.

Additionally, during the 2009-2010 GCR proceeding (Docket No. R-2009-2088076), the parties agreed that PGW will retain 25% of all asset management margins or credits with the remaining 75% applied as an offset to purchased gas costs. The retention was permitted on September 1, 2009, for all asset management margins or credits booked on or after that date, and shall end on August 31, 2011 unless the Commission approves continuation. The Company also agreed to include in its March 1, 2011 annual 1307(f) filing:

(a) A report containing:

i. the asset management margin or credit data for the one year period of September 1, 2009 to August 31, 2010 and the retained portions thereof; and

ii. confirmation that the retained funds were segregated in a capital fund to be used for infrastructure repair and replacement.

(b) An asset management margin or credit retention proposal for the PGC period(s) beginning on September 1, 2011. PGW shall request that the sharing percentages and other proposed changes, if any, be determined by the Commission's order in the FY 2012 PGC proceeding.

Q. DID PGW PREPARE A REPORT CONTAINING THE CAPACITY RELEASE CREDIT, OFF SYSTEM SALES MARGIN AND ASSET MANAGEMENT MARGIN/CREDIT DATA AND THE RETAINED PORTIONS THEREOF?

A. Yes. The report is provided as Exhibit DAM-1.

Q. CAN PGW CONFIRM THAT THE RETAINED FUNDS WERE SEGREGATED IN A CAPITAL FUND TO BE USED FOR INFRASTRUCTURE REPAIR AND REPLACEMENT?

A. Yes. Joseph R. Bogdonavage, PGW's Interim Chief Financial Officer and Executive Vice President, has confirmed that the funds were segregated into a separate financial reporting fund in both FY 2009 and FY 2010. Furthermore, the retention amounts shown in Exhibit DAM-1 are a part of the non-borrowed funds that PGW spent in its FY 2009 and FY 2010 capital programs in the amounts of $9.8 million and $18 million, respectively.

Q. DOES PGW HAVE A RETENTION PROPOSAL FOR THE PGC PERIODS BEGINNING ON SEPTEMBER 1, 2011?

A. Yes. PGW proposes to continue the retention of 25% of capacity release credits, off system sales margin and asset management margin/credit/fees and the application of the remaining 75% to the gas cost rate.

Q. DO OTHER PENNSYLVANIA NATURAL GAS DISTRIBUTION COMPANIES ("NGDCs") HAVE SHARING MECHANISMS FOR CAPACITY RELEASE AND OFF SYSTEM SALES CREDITS?

A. Yes. Please see Exhibit DAM-2 for a chart which provides a description of the sharing mechanisms currently in place. Six of the largest NGDCs have sharing mechanisms similar to PGW's and the sharing percentage for all of the NGDCs is 25%.

Q. WHAT ARE THE BENEFITS OF THIS PROPOSAL?

A. Other Pennsylvania NGDCs retain portions of capacity release credits and off-system sales margins for the benefit of their shareholders instead of their customers. PGW's purpose is entirely different. <u>All</u> benefits would flow to customers and only to customers. One portion of the benefits would flow back to customers immediately, as they do now, through the GCR, while the remainder would continue to flow to a dedicated capital fund. Use of these funds exclusively on capital projects will directly result in the Company borrowing less money, thus reducing the customers' obligations for transaction fees, interest on the bonds, and debt service coverage requirements. This will, in turn, reduce the customers' cost for capital projects.

Q. PLEASE EXPLAIN THAT LAST POINT.

A. Simply put, the less money PGW borrows, the lower its future debt re-payments and interest payments, therefore, base rates in future rate cases will not be as high as they would be without the retention of these revenues. Additionally, for every $1 that PGW must borrow in long term debt in order to fund its capital program, the related base rate impact is $1.50 because of the 1.5 times debt service coverage plus interest and transaction costs.

Q. WHY IS THIS RELEVANT TO A LEAST COST GAS PROCUREMENT POLICY?

A. In the same manner as it is for those other utilities that are allowed to allocate a portion of the benefit to shareholders: the utility and the customers receive benefit from the policy, creating an incentive (and funds) to maximize efforts to make off system sales and capacity release transactions. In addition, PGW's proposal should be viewed within the larger, combined context that the "least cost fuel procurement policy [is] consistent with [a utility's] obligation to provide safe, adequate and reliable service to its customers."[2] This proposal does indeed provide least cost opportunities for PGW ratepayers overall and, at the same time, dedication of the capacity release credits, off system sales margins, and asset management fees to capital projects supports safe, adequate and reliable service.

V. CAPACITY RESOURCES

Q. HAS PGW RETAINED THE SERVICES OF A THIRD PARTY TO REVIEW ITS CAPACITY RESOURCES?

A. Yes, PGW retained the services of Summit Energy Services to review its capacity resources.[3] Summit Energy Services provides energy management to organizations in a

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[2] 66 Pa.C.S. § 1318.

[3] Section III, paragraph 7 of last year's settlement agreement provides:

PGW agrees to retain the services of a third party to review its capacity resources. The third party will advise PGW as to the appropriate level of capacity resources needed to help ensure least cost procurement, consistent with PGW's obligation to provide safe, adequate and reliable service to its customers. Included within its review, the third party vendor will advise the Company regarding possible asset management arrangements, including a review wide range of industries and manages more than $20 billion in annual energy expenditures for more than 650 companies and thousands of facilities.

Q. IS PGW PROVIDING THE RESULTS OF THIS REVIEW WITH THIS FILING?

A. Yes. PGW instructed Summit to provide a written report discussing the results of its review. This report is provided in Tab 7 of PGW's March 1, 2011 Purchased Gas Cost annual filing. PGW originally planned to provide the results of Summit's review in a power point format similar to the August 2006 ICF International Natural Gas Supply Study along with supporting testimony. Subsequently, PGW determined that a written narrative in the form of the above-referenced report would provide all of the relevant information in one source.

Q. WHAT DOES SUMMIT RECOMMEND AND HOW DOES PGW PLAN TO RESPOND TO SUMMIT'S RECOMMENDATIONS?

A. Summit made several recommendations one of which I will address in this testimony. Summit recommended that PGW evaluate elimination or reduction of a portion of its current asset base after assessing asset management opportunities. Summit specifically identified the Equitrans storage and the Dominion storage (along with the Dominion storage related transportation contracts -- Tetco FTS-7 and FTS-8). As recommended by Summit, PGW will first explore an asset management arrangement in order to determine if value at or above the cost of these assets can be attained. To this end, PGW issued an RFP on January 24, 2011 requesting proposals for asset management

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of the best practices regarding the payment structure of such arrangements. PGW will provide the results of this review along with supporting testimony of the aforementioned third party in its next annual GCR filing on March 1, 2011.

of any one or all of its storages for the term of April 1, 2011 through March 31, 2012. Within this context, PGW will determine if it is cost beneficial to retain the Equitrans storage. As for the Dominion storage, PGW's threshold analysis will be to determine the value that can be attained through an asset management arrangement ("AMA") for 1 Bcf of the approximate total Dominion storage capacity of 4 Bcf. Nonetheless, PGW may potentially retain the Dominion storage even if the value from an AMA does not exceed the cost of the Dominion storage because reducing the total capacity from 4 to 3 Bcf results in an entire renegotiation of the storage contract (if PGW simply renews the contract, current rates still apply). This renegotiation opens up the possibility of Dominion charging more for 3 Bcf of storage capacity than the amount PGW currently pays for 4 Bcf of storage capacity.

VI. ASSET MANAGEMENT

Q. WHAT IS THE CURRENT STATUS PGW'S ASSET MANAGEMENT ARRANGMENT?

A. As set forth is paragraph III. 3. in last year's settlement agreement, PGW entered into an asset management arrangement with a third party on May 7, 2010 and the arrangement involves the release of 1.5 Bcf of the Washington WSS storage service for a period ending March 31, 2011.

Q. DOES PGW INTEND TO EXPLORE THE POSSIBILITY OF ANOTHER ASSET MANAGEMENT ARRANGMENT?

A. Yes, as discussed in the Capacity Resources section directly above, PGW issued an RFP on January 24, 2011 requesting proposals for asset management of any one or all of its storages for the term of April 1, 2011 through March 31, 2012. PGW intends to frame its evaluation of the asset management RFP responses within the context of the recommendations set forth in the Summit Energy Services report.

VII. PURCHASING PROGRAM COMPLIANCE

Q. DID PGW COMPLY WITH THE PURCHASING PROGRAM SET FORTH IN APPENDIX B OF LAST YEAR'S SETTLEMENT AGREEMENT?

A. Yes, Appendix B, Schedules 1 and 2 of last year's settlement agreement set forth the volumes which define PGW's purchasing program for the year beginning on September 1, 2010 and ending on August 31, 2011. Please see Exhibit DAM-3 which shows the volumes purchased during the period of September 2010 to December 2010 in compliance with last year's settlement agreement.[4]

VIII. DOMINION TRANSMISSION

Q. HAS PGW BEEN MONITORING WHETHER *JACQUET ET AL. V. DOMINION TRANSMISSION, INC. ET AL.* SURVIVES THE MOTION TO DISMISS AND IS GIVEN CLASS ACTION DESIGNATION?

A. Yes. On December 30, 2010, the United States District Court for the Southern District of West Virginia ruled in favor of the defendants' Motion to Dismiss.[5] The

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[4] Paragraph III.2.(f) of last year's settlement agreement provides:

> As part of its March 1, 2011 filing, PGW will provide schedules demonstrating how it has complied with Appendix B (Schedules 1 and 2) to this Settlement.

[5] PGW is reporting the status of *Jacquet et al.* because the following is set forth in paragraph III.4. of last year's settlement agreement:

> PGW agrees to take any reasonable steps which may be necessary in order to assure that its GCR customers are included in the class if *Jacquet et al. v. Dominion Transmission, Inc. et al.* survives the motion to dismiss and is given class action designation. PGW will report on its efforts (if *Jacquet* survives the motion to dismiss and is given class action designation) in its next annual GCR filing on March 1, 2011.

Judgment Order is provided as Exhibit DAM-4 to this testimony. As a result of the foregoing, PGW will not take any further action in this matter.

IX. PRICE ANALYSIS AND BUYING ADVISORY SERVICE

Q. PGW CURRENTLY USES PLANALYTICS ENERGY BUYER SERVICES AND IS CURRENTLY PERMITTED TO RECOVER THE ANNUAL $125,000 FEE VIA THE GAS COST RATE DURING THE 2010- 2011 GCR PERIOD. WHAT TYPES OF SERVICES DOES PLANANYTICS PROVIDE TO PGW?

A. Planalytics provides the following services:

- Price feed from Nymex and Globex for natural gas, crude oil, heating oil and RBOB (reformulated gasoline);
- Buying suggestions up to 18 months in the future;
- A charting tool for technical analysis;
- Short and medium range weather forecasts;
- Weather alerts (issued in advance of significant weather events);
- Planalytic's pre-season hurricane forecast and in-season updates; and
- Additional energy buyer features include reporting (i.e. mark-to-market, transaction history, etc.) and portfolio/hedging parameters.

Q. WHAT WAS INCORPORATED INTO PGW'S 2010-2011 GCR PROCEEDING SETTLEMENT AGREEMENT WITH REGARD TO THE PLANANLYTICS ENERGY BUYER SERVICES?

A. PGW agreed to the following:

> PGW is permitted to recover the Planalytics fee for price analysis and buying advisory services (not to exceed $125,000) for the 2010-2011 GCR period. Continued recovery of the fee beyond the 2010-2011 GCR period must be addressed in next year's Purchased Gas Cost proceeding. PGW's use of the Planalytics service is intended to operate within the constraints of the gas supply plan detailed in Appendix B, and not as a replacement to it. Specifically, PGW

will only adopt recommendations made by Planalytics with respect to the timing of its gas price hedges if such recommendations are consistent with the requirements of Appendix B, Schedule 2. PGW agrees to present an analysis of the Planalytics service for calendar year 2010 in its next annual GCR filing on March 1, 2011. The analysis will show February 2010 and July 2010 purchases for which PGW relied upon Planalytics advisory services, and will compare the purchase prices to the average monthly NYMEX futures prices for the relevant periods.

Q. DID PGW PREPARE THE FEBRUARY 2010 AND JULY 2010 ANALYSIS SET FORTH IN THE SETTLEMENT AGREEMENT?

A. Yes. Please see Exhibit DAM-5 which shows the purchased volumes for which PGW relied upon the Planalytics advisory services (as one of the tools that the Company employs when making its purchasing decisions). The analysis shows the February 2010 purchase price for the daily delivery of natural gas during a future month and compares that purchase price to the average NYMEX futures price during February 2010 for the same future month. For example, PGW contracted for an MDQ of 3,000 Dth in February 2010 for delivery in March 2010. The contract price is $5.3600 per Dth and the average NYMEX future price during February 2010 for March 2010 is $5.2190 per Dth. PGW's analysis also shows the total cost extensions for both the contract price and the average NYMEX future price. The results for the February 2010 analysis shows that if the same volumes could have been purchased at the average NYMEX future price, the total cost of gas would have been $57,454 less than the cost of gas based on actual contract prices. Similarly, the results for the July 2010 analysis shows that if the same volumes could have been purchased at the average NYMEX future price, the total cost of gas would have been $50,077 less than the cost of gas based on actual contract prices.

Although this two month analysis does not show a positive differential, the Planalytics' service provides a comprehensive amount of information that the Company finds useful in the procurement of all gas supply. Nonetheless, PGW understands that it must reach a new agreement as to the continuing recovery of the Planalytics fee and the Company looks forward to discussing this issue with the parties involved in this year's proceeding.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

Philadelphia Gas Works
Capacity Release, Off-Sytem Sales Margin and Asset Management Credit/Margin
FY 2009 and FY 2010

	FY 2009 (9/1/08 to 8/31/09)	FY 2010 (9/1/09 to 8/31/10)
Capacity Release Credits	$ 16,111,021.01	$12,278,175.41
Off-system Sales Margin	8,632.00	-
Asset Management Credit/Margin	-	364,464.00
Total	16,119,653.01	12,642,639.41
Retention Percentage	25%	25%
Retention Amount	4,029,913.25	3,160,659.85

Pennsylvania Natural Gas Distribution Companies - Sharing Formulas

Utility	Type of Revenue Retained	Sharing %	Source
Columbia	Off-system sales margin and capacity release.	25% of total.	Columbia Gas Tariff – Pa. P.U.C. No. 9, Supplement No. 161, 8th Revised Pg. No. 159, Issued December 30, 2010, Effective January 1, 2011.
NFG	Off-system sales margin, capacity release, gas storage fill contracts savings and asset management arrangements under FERC Order 712 for capacity releases associated with identified capacity contracts.	25% of total.	NFG Gas Tariff – Pa. P.U.C. No. 9, Supplement No. 42, 2nd Revised Pg. No. 154, Issued July 30, 2004, Effective August 1, 2004 & Supplement No. 95, 7th Revised Pg. No. 155, Issued July 31, 2009, Effective August 1, 2009.
PECO	Off-system sales margin, capacity release and asset management agreement revenue.	25% of total.	PECO Gas Tariff – Pa. P.U.C. No. 2, Supplement No. 99, 18th Revised Pg. No. 35, Issued November 29, 2010, Effective December 1, 2010.
UGI (Central Penn)	Off-system sales margin, locational exchange revenues, capacity release and storage asset management fees.	25% of total.	UGI Central Penn Gas Tariff - PA P.U.C. No. 3, Supplement No. 49, 5th Revised Page 8.1, Issued November 30, 2010, Effective December 1, 2010.
UGI (Penn Natural)	Off-system sales margin, capacity release, exchanges of natural gas and storage asset management fees.	25% of total.	UGI Penn Natural Gas Tariff – Pa. P.U.C. No. 8, Supplement No. 4, 3rd Revised Pg. No. 31, Issued November 30, 2010, Effective December 1, 2010.
UGI	Off-system sales margin, locational exchange revenues, capacity release and storage asset management fees.	25% of total.	UGI Gas Tariff – Pa. P.U.C. No. 5, Supplement No. 69, 6th Revised Pg. No. 30, Issued November 25, 2008, Effective December 1, 2008.

2010-2011 GCR Settlement Agreement Provision
Purchasing Program Compliance

Appendix B - Schedule 1	Settlement (Dth)	% of Total	Sep-10 Actual (Dth)	Oct-10 Actual (Dth)	Nov-10 Actual (Dth)	Dec-10 Actual (Dth)	Jan-11 Actual (Dth)
Non-discretionary component							
Price hedging -							
mo'ly incr'l contracts	9,580,000	18.8%	796,000	798,000	796,000	796,000	-
Physical hedging							
(depending on beg. inv.)	12,000,000	23.5%	386,370	399,249	346,064	-	
Market Rates Component	21,580,000	42.3%	1,182,370	1,197,249	1,142,064	796,000	-
FOM Call Options	18,250,000	35.8%	2,272,560	2,348,622	2,272,560	2,348,622	
	39,830,000	78.1%	3,454,930	3,545,871	3,414,624	3,144,622	-
Discretionary	11,170,000	21.9%	467,630	507,751	2,862,936	3,342,500	
TOTAL PURCHASES	51,000,000	100.0%	3,922,560	4,053,622	6,277,560	6,487,122	-

Appendix B - Schedule 2
Price hedging - monthly incremental contracts

K Month	Sep-10	Sep-10	Oct-10	Oct-10	Nov-10	Nov-10	Dec-10	Dec-10	Jan-11	Jan-11
Delivery Month	Actual (Dth)	Settlement (Dth)	Actual (Dth)	Settlement (Dth)	Actual (Dth)	Settlement (Dth)	Actual (Dth)	Settlement (Dth)	Actual (Dth)	Settlement (Dth)
Oct-10	70,000	70,000								
Nov-10	70,000	70,000	70,000	70,000						
Dec-10	70,000	70,000	70,000	70,000	70,000	70,000				
Jan-11	70,000	70,000	70,000	70,000	70,000	70,000	70,000	70,000		
Feb-11	70,000	70,000	70,000	70,000	70,000	70,000	70,000	70,000		70,000
Mar-11	70,000	70,000	70,000	70,000	70,000	70,000	70,000	70,000		70,000
Apr-11	60,000	60,000	60,000	60,000	60,000	60,000	60,000	60,000		60,000
May-11	62,000	62,000	62,000	62,000	62,000	62,000	62,000	62,000		62,000
Jun-11	60,000	60,000	62,000	60,000	60,000	60,000	60,000	60,000		60,000
Jul-11	62,000	62,000	62,000	62,000	62,000	62,000	62,000	62,000		62,000
Aug-11	62,000	62,000	62,000	62,000	62,000	62,000	62,000	62,000		62,000
Sep-11	70,000	70,000	70,000	70,000	70,000	70,000	70,000	70,000		70,000
Oct-11			70,000	70,000	70,000	70,000	70,000	70,000		70,000
Nov-11					70,000	70,000	70,000	70,000		70,000
Dec-11							70,000	70,000		70,000
Jan-12										70,000
Feb-12										
Mar-12										
Apr-12										
May-12										
Jun-12										
Jul-12										
Aug-12										
	796,000	796,000	798,000	796,000	796,000	796,000	796,000	796,000	0	796,000

Feb-11 Actual (Dth)	Mar-11 Actual (Dth)	Apr-11 Actual (Dth)	May-11 Actual (Dth)	Jun-11 Actual (Dth)	Jul-11 Actual (Dth)	Aug-11 Actual (Dth)	Cumulative Actual (Dth)
-	-	-	-	-	-	-	3,186,000
							1,131,683
-	-	-	-	-	-	-	4,317,683
							9,242,364
-	-	-	-	-	-	-	13,560,047
							7,180,817
-	-	-	-	-	-	-	20,740,864

Feb-11 Actual (Dth)	Feb-11 Settlement (Dth)	Mar-11 Actual (Dth)	Mar-11 Settlement (Dth)	Apr-11 Actual (Dth)	Apr-11 Settlement (Dth)	May-11 Actual (Dth)	May-11 Settlement (Dth)	Jun-11 Actual (Dth)	Jun-11 Settlement (Dth)	Jul-11 Actual (Dth)	Jul-11 Settlement (Dth)	Aug-11 Actual (Dth)	Aug-11 Settlement (Dth)	Cumulative Actual (Dth)	Cumulative Settlement (Dth)
														70,000	70,000
														140,000	140,000
														210,000	210,000
														280,000	280,000
														280,000	350,000
	70,000													280,000	420,000
	60,000		60,000											240,000	420,000
	62,000		62,000		62,000									248,000	496,000
	60,000		60,000		60,000		60,000							242,000	540,000
	62,000		62,000		62,000		62,000		62,000					248,000	620,000
	62,000		62,000		62,000		62,000		62,000		62,000			248,000	682,000
	70,000		70,000		70,000		70,000		70,000		70,000		70,000	280,000	840,000
	70,000		70,000		70,000		70,000		70,000		70,000		70,000	210,000	770,000
	70,000		70,000		70,000		70,000		70,000		70,000		70,000	140,000	700,000
	70,000		70,000		70,000		70,000		70,000		70,000		70,000	70,000	630,000
	70,000		70,000		70,000		70,000		70,000		70,000		70,000	0	560,000
	70,000		70,000		70,000		70,000		70,000		70,000		70,000	0	490,000
			70,000		70,000		70,000		70,000		70,000		70,000	0	420,000
					60,000		60,000		60,000		60,000		60,000	0	300,000
							62,000		62,000		62,000		62,000	0	248,000
									60,000		60,000		60,000	0	180,000
											62,000		62,000	0	124,000
													62,000	0	62,000
0	796,000	0	796,000	0	796,000	0	796,000	0	796,000	0	796,000	0	796,000	3,186,000	9,552,000

Exhibit DAM-4

UNITED STATES DISTRICT COURT
SOUTHERN DISTRICT OF WEST VIRGINIA
AT CHARLESTON

BETSY J. JACQUET, PATRICIA E. KUZARA,
and others similarly situated,

Plaintiffs,

v. Civil Action No. 2:05-0548

DOMINION TRANSMISSION, INC.,
DOMINION RESOURCES, INC.,
DOMINION VIRGINIA POWER, and
DOMINION NORTH CAROLINA POWER,

Defendants.

JUDGMENT ORDER

In accordance with the memorandum opinion and order entered this same day in the above-styled civil action, it is ORDERED and ADJUDGED that the plaintiffs, Betsy J. Jacquet, Patricia E. Kuzara, and others similarly situated, take nothing against the defendants in this action and that judgment be, and it hereby is, entered in favor of defendants. It is further ORDERED that this action be, and it hereby is, dismissed with prejudice and stricken from the docket.

The Clerk is directed to forward copies of this judgment order to all counsel of record and any unrepresented parties.

DATED: December 30, 2010

John T. Copenhaver, Jr.
United States District Judge

February 2010 Analysis	MDQ	Contract Date	Delivery Month	Contract Price	Average of Nymex Closes	Nymex Close Minus Contract Price	No. of Days in Delivery Month	Cost at Contract Price	Cost at Average Nymex Close	Diff
Cokinos	3,000	02/09/2010	March 10	$5.3600	$5.2190	($0.1410)	31	$498,480	$485,367	($13,113)
Hess	2,000	02/09/2010	April 10	$5.3300	$5.2140	($0.1160)	30	$319,800	$312,840	($6,960)
Hess	2,000	02/09/2010	May 10	$5.3300	$5.2720	($0.0580)	31	$330,460	$326,864	($3,596)
Hess	2,000	02/09/2010	June 10	$5.3300	$5.3460	$0.0160	30	$319,800	$320,760	$960
Hess	2,000	02/09/2010	July 10	$5.3300	$5.0860	($0.2440)	31	$330,460	$315,332	($15,128)
Hess	2,000	02/09/2010	August 10	$5.3300	$5.4810	$0.1510	31	$330,460	$339,822	$9,362
Hess	3,000	02/09/2010	September 10	$5.3300	$5.5170	$0.1870	30	$479,700	$496,530	$16,830
Hess	3,000	02/09/2010	October 10	$5.3300	$5.6290	$0.2990	31	$495,690	$523,497	$27,807
Shell	3,000	02/09/2010	November 10	$6.4550	$5.9330	($0.5220)	30	$580,950	$533,970	($46,980)
Shell	3,000	02/09/2010	December 10	$6.4550	$6.2480	($0.2070)	31	$600,315	$581,064	($19,251)
Shell	3,000	02/09/2010	January 11	$6.4550	$6.4570	$0.0020	31	$600,315	$600,501	$186
Shell	3,000	02/09/2010	February 11	$6.4550	$6.4230	($0.0320)	28	$542,220	$539,532	($2,688)
						Subtotal		$5,428,650	$5,376,079	($52,571)
Sempra	5,000	02/09/2010	March 10	$5.3550	$5.2190	($0.1360)	31	$830,025	$808,945	($21,080)
Sempra	5,000	02/09/2010	March 10	$5.3450	$5.2190	($0.1260)	31	$828,475	$808,945	($19,530)
BP	5,000	02/04/2010	March 10	$4.9025	$5.2190	$0.3165	31	$759,888	$808,945	$49,058
BP	5,000	02/04/2010	March 10	$5.3050	$5.2190	($0.0860)	31	$822,275	$808,945	($13,330)
						Subtotal		$3,240,663	$3,235,780	($4,883)
						Feb 2010 Total		$8,669,313	$8,611,859	($57,454)

July 2010 Analysis										
Cokinos	2,500	07/09/2010	August 10	$4.5150	$4.3450	($0.1700)	31	$349,913	$336,738	($13,175)
Cokinos	2,500	07/09/2010	September 10	$4.5150	$4.5780	$0.0630	30	$338,625	$343,350	$4,725
Cokinos	2,500	07/09/2010	October 10	$4.5150	$4.6340	$0.1190	31	$349,913	$359,135	$9,223
Anadarko	2,500	07/09/2010	November 10	$4.7700	$4.8910	$0.1210	30	$357,750	$366,825	$9,075
Shell	3,000	07/09/2010	December 10	$5.3500	$5.1650	($0.1850)	31	$497,550	$480,345	($17,205)
Shell	3,000	07/09/2010	January 11	$5.3500	$5.3310	($0.0190)	31	$497,550	$495,783	($1,767)
Shell	3,000	07/09/2010	February 11	$5.3500	$5.3000	($0.0500)	28	$449,400	$445,200	($4,200)
Shell	3,000	07/09/2010	March 11	$5.3500	$5.2010	($0.1490)	31	$497,550	$483,693	($13,857)
Macquire Cook	2,500	07/09/2010	April 11	$5.1450	$5.0360	($0.1090)	30	$385,875	$377,700	($8,175)
Macquire Cook	2,500	07/09/2010	May 11	$5.1450	$5.0820	($0.0630)	31	$398,738	$393,855	($4,882)
Macquire Cook	2,500	07/09/2010	June 11	$5.1450	$5.0190	($0.1260)	30	$385,875	$376,425	($9,450)
Macquire Cook	2,500	07/09/2010	July 11	$5.1450	$5.1400	($0.0050)	31	$398,738	$398,350	($387)
						Jul 2010 Total		$4,907,475	$4,857,399	($50,077)

Tab 7

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

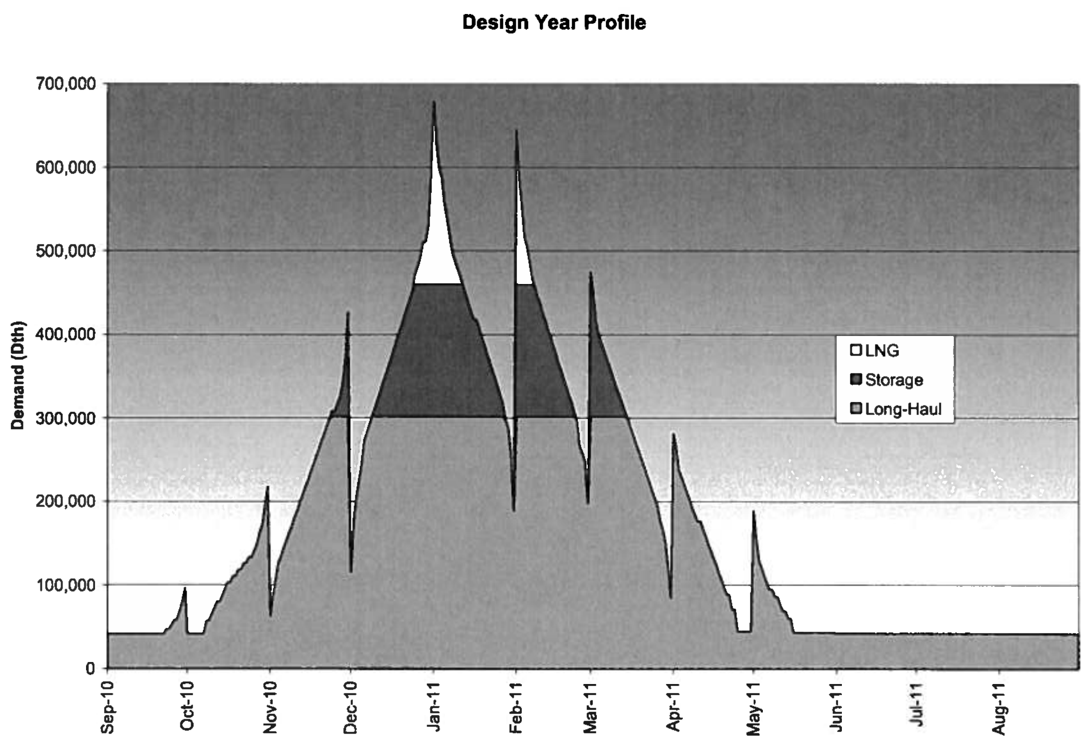
Long-Haul Transport	Capacity (Dth)	Estimated WACOG ($/Dth)
Tetco CDS	75,000	$6.145
Tetco FT-1	59,822	$6.130
Transco FT	167,179	$5.827

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.