EQUITABLE GAS COMPANY,
a division of Equitable Resources, Inc.
before the
PENNSYLVANIA PUBLIC UTILITY COMMISSION
Docket No. R-2008-2029325

INFORMATION SUBMITTED PURSUANT TO:
Title 52 Pennsylvania Code § 53.51, et seq.,
Pa. P.U.C. Regulations Re: Filing of Rate Changes

EXHIBIT VI
STANDARD DATA REQUESTS
VOLUME 1 OF 3

11/19/08

Revenue Requirements Interrogatories
(Part 1 of 2)

RJS

Equitable Exhibit VI

Docket No. R-2008-2029325

Volume 1 of 3

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EQUITABLE GAS COMPANY

A Division of

EQUITABLE RESOURCES, INC.

Before the

PENNSYLVANIA PUBLIC UTILITY COMMISSION

EXHIBIT VI

STANDARD DATA REQUESTS

Volume 1 of 3

REVENUE REQUIREMENTS INTERROGATORIES

(Part 1 of 2)

INFORMATION SUBMITTED PURSUANT TO:

Title 52 Pennsylvania Code § 53.51, et seq.,
Pa. P.U.C. Regulations Re Filing of Rate Changes

Equitable Gas Company's 2008 General Rate Filing

Equitable Gas Company
Response to Standard Data Requests
REVENUE REQUIREMENT INTERROGATORIES

Item 1: Please provide a copy of the Company's detailed quarterly balance sheet and monthly income statements for the historic test year through the most recent month available.

Response: See attached for the monthly income statements for the historic test year, twelve months ended December 31, 2007 and three months ended March 31, 2008. Please refer to the Rate of Return Interrogatories Item 2 for the quarterly balance sheets.

Equitable Gas Company
Response to Standard Data Requests
REVENUE REQUIREMENT INTERROGATORIES - Item 1
Monthly Income Statement

Account #			Mar-08	Feb-08	Jan-08	Total 2008
480	480000	Residential Gas Sales	44,533,228	56,744,590	62,004,497	163,282,315
481	481000	Comm & Ind Gas Sales	10,396,665	12,393,666	13,728,294	36,518,625
487	487000	Fofeited Discounts	126,903	124,314	78,309	329,526
488	488000	Misc. Service Revenues	58,705	65,730	72,170	196,605
489.1	489100	Transportation - Gathering	516,279	558,455	470,758	1,545,492
489.3	489300	Transportation - Distribution	9,490,569	11,478,149	12,005,073	32,973,791
493	493000	Rent from Gas Property	322	1,024	-	1,346
495	495000	Other Gas Revenues	9,817	9,869	8,354	28,040
400		Operating Revenues	65,132,488	81,375,797	88,367,455	234,875,740
		Operating Expenses	51,423,985	64,164,720	72,646,238	188,234,943
		Maintenance Expenses	1,058,691	771,174	866,839	2,696,704
403		Depreciation Expense	1,481,692	1,447,598	1,423,229	4,352,519
404		Amortization Expense	234,110	233,109	232,916	700,135
408.1		Taxes Other Than Income, UOI	234,247	338,612	352,225	925,084
409.1		Income Taxes, UOI	4,599,191	1,723,900	1,577,200	7,900,291
410.1		Deferred Income Taxes, UOI	(5,609,300)	2,300	1,900	(5,605,100)
411.4		Investment Tax Credit, UOI	(758)	(758)	(758)	(2,274)
		Total Operating Expenses	53,421,858	68,680,655	77,099,789	199,202,302
		Operating Income	11,710,630	12,695,142	11,267,666	35,673,438
417		Non-Utility Expenses	304	188	1,218	1,710
419		Interest and Dividend Income	(301,842)	(216,037)	(142,025)	(659,904)
419.1		AFUDC	(49,668)	(45,989)	(45,118)	(140,775)
421		Misc Non-Operating Income	-	-	-	-
421.1		Gain on Disposition of Property	-	-	-	-
		Total Other Income	(351,206)	(261,838)	(185,925)	(798,969)
426.1		Donations	76	-	-	76
426.5		Other Deductions	(356,478)	(2,777,917)	(2,996,270)	(6,130,665)
		Total Income Deductions	(356,402)	(2,777,917)	(2,996,270)	(6,130,589)
409.2		Income Taxes, Other	-	-	-	-
410.2		Deferred Income Taxes, Other	-	-	-	-
420		Investment Tax Credit, Other	(55,500)	(55,500)	(55,500)	(166,500)
		Total Other Taxes	(55,500)	(55,500)	(55,500)	(166,500)
		Net Other Income and Deductions	(763,108)	(3,095,255)	(3,237,695)	(7,096,058)
430		Interest on Debt to Assoc Companies	1,782,104	1,661,798	1,858,301	5,302,203
431		Other Interest Expense	1,980	1,513	979	4,472
432		AFUDC, Credit	(29,646)	(27,428)	(26,908)	(83,982)
		Total Interest Charges	1,754,438	1,635,883	1,832,372	5,222,693
		Net Income	10,719,300	14,154,514	12,672,989	37,546,803

Equitable Gas Company
Response to Standard Data Requests
REVENUE REQUIREMENT INTERROGATORIES - Item 1
Monthly Income Statement

Account #		Dec-07	Nov-07	Oct-07	Sep-07
480	480000 Residential Gas Sales	49,841,267	35,264,207	14,203,696	8,763,089
481	481000 Comm & Ind Gas Sales	10,779,663	6,366,088	2,928,817	1,714,439
487	487000 Fofeited Discounts	71,761	141,891	144,465	144,919
488	488000 Misc. Service Revenues	109,455	141,120	107,500	111,330
489.1	489100 Transportation - Gathering	644,879	468,704	424,012	423,676
489.3	489300 Transportation - Distribution	9,726,036	6,262,692	2,723,974	2,152,663
493	493000 Rent from Gas Property	774	-	-	-
495	495000 Other Gas Revenues	3,861	2,116	2,225	2,865
400	Operating Revenues	71,177,696	48,646,818	20,534,689	13,312,981
	Operating Expenses	60,788,760	40,817,974	18,982,784	10,984,249
	Maintenance Expenses	849,178	894,336	934,161	846,609
403	Depreciation Expense	1,565,646	1,430,718	1,428,328	1,421,678
404	Amortization Expense	232,522	222,537	222,040	220,591
408.1	Taxes Other Than Income, UOI	417,144	289,745	213,220	210,443
409.1	Income Taxes, UOI	27,932,895	(120,500)	(2,607,700)	(3,260,900)
410.1	Deferred Income Taxes, UOI	(773,838)	26,200	564,900	2,302,600
411.4	Investment Tax Credit, UOI	4,636	(1,250)	(1,250)	(1,250)
	Total Operating Expenses	91,016,943	43,559,760	19,736,483	12,724,020
	Operating Income	(19,839,247)	5,087,058	798,206	588,961
417	Non-Utility Expenses	1,692	797	153	700
419	Interest and Dividend Income	18,818	181,026	144,584	(331,433)
419.1	AFUDC	(38,689)	(51,384)	(41,836)	(40,554)
421	Misc Non-Operating Income	-	-	-	-
421.1	Gain on Disposition of Property	-	-	-	-
	Total Other Income	(18,179)	130,439	102,901	(371,287)
426.1	Donations	-	-	-	-
426.5	Other Deductions	8,087,015	(709,286)	(903,319)	(1,402,801)
	Total Income Deductions	8,087,015	(709,286)	(903,319)	(1,402,801)
409.2	Income Taxes, Other	(6,482,472)	-	-	-
410.2	Deferred Income Taxes, Other	(6,384,801)	-	-	-
420	Investment Tax Credit, Other	205,836	(55,500)	(55,500)	(55,500)
	Total Other Taxes	(12,661,438)	(55,500)	(55,500)	(55,500)
	Net Other Income and Deductions	(4,592,602)	(634,347)	(855,918)	(1,829,588)
430	Interest on Debt to Assoc Companies	1,957,746	1,894,593	1,963,638	1,907,218
431	Other Interest Expense	134,843	20,159	17,691	23,072
432	AFUDC, Credit	(23,081)	(30,657)	(24,951)	(24,455)
	Total Interest Charges	2,069,508	1,884,095	1,956,378	1,905,835
	Net Income	(17,316,153)	3,837,310	(302,254)	512,714

Equitable Gas Company
Response to Standard Data Requests
REVENUE REQUIREMENT INTERROGATORIES - Item 1
Monthly Income Statement

Account #			Aug-07	Jul-07	Jun-07	May-07
480	480000	Residential Gas Sales	7,912,054	7,973,138	7,436,326	10,544,147
481	481000	Comm & Ind Gas Sales	1,687,003	1,722,452	1,501,514	2,516,137
487	487000	Fofeited Discounts	134,294	128,621	177,383	197,359
488	488000	Misc. Service Revenues	103,530	99,080	100,760	110,735
489.1	489100	Transportation - Gathering	341,886	449,472	429,603	492,315
489.3	489300	Transportation - Distribution	2,020,501	1,916,691	1,966,212	3,679,256
493	493000	Rent from Gas Property	-	170	269	-
495	495000	Other Gas Revenues	1,950	2,538	5,766	6,345
400		Operating Revenues	12,201,218	12,292,162	11,617,833	17,546,294
		Operating Expenses	11,226,338	12,048,086	9,077,794	15,735,471
		Maintenance Expenses	1,021,791	913,580	767,623	1,024,522
403		Depreciation Expense	1,460,913	1,454,972	1,456,941	1,457,735
404		Amortization Expense	219,739	215,881	226,925	218,381
408.1		Taxes Other Than Income, UOI	212,432	214,454	222,828	247,718
409.1		Income Taxes, UOI	(2,618,600)	(1,718,700)	(1,577,400)	(1,769,427)
410.1		Deferred Income Taxes, UOI	(229,400)	(150,500)	63,200	378,504
411.4		Investment Tax Credit, UOI	(1,250)	(1,250)	(1,250)	(1,250)
		Total Operating Expenses	11,291,963	12,976,523	10,236,661	17,291,654
		Operating Income	909,255	(684,361)	1,381,171	254,641
417		Non-Utility Expenses	609	1,615	561	690
419		Interest and Dividend Income	(388,773)	(608,853)	(686,193)	(707,388)
419.1		AFUDC	(38,813)	(34,935)	(28,869)	(27,341)
421		Misc Non-Operating Income	-	-	-	(12,631)
421.1		Gain on Disposition of Property	-	-	-	-
		Total Other Income	(426,977)	(642,173)	(714,501)	(746,670)
426.1		Donations	-	-	-	2,000
426.5		Other Deductions	(1,291,945)	466,708	2,176,350	5,164
		Total Income Deductions	(1,291,945)	466,708	2,176,350	7,164
409.2		Income Taxes, Other	-	-	-	-
410.2		Deferred Income Taxes, Other	-	-	-	-
420		Investment Tax Credit, Other	(55,500)	(55,500)	(55,500)	(55,500)
		Total Other Taxes	(55,500)	(55,500)	(55,500)	(55,500)
		Net Other Income and Deductions	(1,774,422)	(230,965)	1,406,349	(795,006)
430		Interest on Debt to Assoc Companies	1,970,792	1,968,898	1,903,430	1,966,878
431		Other Interest Expense	24,651	19,750	23,243	24,910
432		AFUDC, Credit	(23,148)	(20,835)	(17,218)	(16,306)
		Total Interest Charges	1,972,295	1,967,813	1,909,455	1,975,482
		Net Income	711,382	(2,421,209)	(1,934,633)	(925,835)

Equitable Gas Company
Response to Standard Data Requests
REVENUE REQUIREMENT INTERROGATORIES - Item 1
Monthly Income Statement

Account #			Apr-07	Mar-07	Feb-07	Jan-07	Total 2007
480	480000	Residential Gas Sales	29,491,820	35,719,303	64,033,475	51,427,733	322,610,254
481	481000	Comm & Ind Gas Sales	6,325,020	8,689,554	14,950,714	10,469,014	69,650,415
487	487000	Fofeited Discounts	150,101	113,982	112,750	114,907	1,632,433
488	488000	Misc. Service Revenues	105,700	63,505	76,165	79,675	1,208,555
489.1	489100	Transportation - Gathering	330,385	322,753	419,483	422,821	5,169,989
489.3	489300	Transportation - Distribution	5,556,897	7,533,061	10,812,217	8,133,652	62,483,852
493	493000	Rent from Gas Property	376	-	-	-	1,589
495	495000	Other Gas Revenues	11,244	13,771	808	6,413	59,902
400		Operating Revenues	41,971,543	52,455,929	90,405,612	70,654,215	462,816,989
		Operating Expenses	34,572,548	42,858,655	71,907,021	56,418,090	385,417,770
		Maintenance Expenses	899,861	851,432	921,528	930,825	10,855,446
403		Depreciation Expense	1,463,403	1,418,494	1,413,322	1,412,731	17,384,881
404		Amortization Expense	262,950	220,233	218,980	269,600	2,750,379
408.1		Taxes Other Than Income, UOI	202,820	330,716	346,296	331,382	3,239,198
409.1		Income Taxes, UOI	(737,126)	(5,422,047)	5,842,400	2,754,100	16,696,995
410.1		Deferred Income Taxes, UOI	(106,104)	3,566,300	(2,706,000)	(1,275,600)	1,660,262
411.4		Investment Tax Credit, UOI	(1,250)	(1,250)	(1,250)	(1,250)	(9,114)
		Total Operating Expenses	36,557,102	43,822,533	77,942,297	60,839,878	437,995,817
		Operating Income	5,414,440	8,633,396	12,463,315	9,814,337	24,821,172
417		Non-Utility Expenses	203	461	553	344	8,378
419		Interest and Dividend Income	(247,108)	(91,723)	95,564	426,020	(2,195,459)
419.1		AFUDC	(21,201)	(13,811)	(28,292)	(26,035)	(391,760)
421		Misc Non-Operating Income	(76,405)	-	-	-	(89,036)
421.1		Gain on Disposition of Property	-	-	9,094	-	9,094
		Total Other Income	(344,511)	(105,073)	76,919	400,329	(2,658,783)
426.1		Donations	-	-	-	-	2,000
426.5		Other Deductions	673,055	4,313,934	836,989	89,200	12,341,064
		Total Income Deductions	673,055	4,313,934	836,989	89,200	12,343,064
409.2		Income Taxes, Other	-	-	-	-	(6,482,472)
410.2		Deferred Income Taxes, Other	-	-	-	-	(6,384,801)
420		Investment Tax Credit, Other	(55,500)	(55,500)	(55,500)	(55,500)	(404,664)
		Total Other Taxes	(55,500)	(55,500)	(55,500)	(55,500)	(13,271,938)
		Net Other Income and Deductions	273,044	4,153,361	858,408	434,029	(3,587,657)
430		Interest on Debt to Assoc Companies	1,901,537	1,962,964	1,773,000	1,697,190	22,867,884
431		Other Interest Expense	25,735	13,099	17,005	15,297	359,455
432		AFUDC, Credit	(11,613)	(7,565)	(15,497)	(14,260)	(229,586)
		Total Interest Charges	1,915,659	1,968,498	1,774,508	1,698,227	22,997,753
		Net Income	3,225,737	2,511,537	9,830,399	7,682,081	5,411,076

Equitable Gas Company
Response to Standard Data Requests
REVENUE REQUIREMENT INTERROGATORIES

Item 2: Please provide the actual number of customers by rate schedule as of December 31 for the last five years.

Response:

	December 31,				
Rate	2003	2004	2005	2006	2007
RS	209,893	210,322	209,195	210,578	211,710
GSS	13,467	13,403	13,402	13,422	13,714
GSL	848	854	954	822	662
FDS	30,070	30,707	30,403	29,051	28,970
GDS	3,358	3,551	3,279	3,187	3,093
DDS	3	3	3	3	3
AGS	16	42	75	92	98
	257,655	258,882	257,311	257,155	258,250

Equitable Gas Company
Response to Standard Data Requests
REVENUE REQUIREMENT INTERROGATORIES

Item 3: Please provide the average number of customers by rate schedule for the last five years.

Response:

	Average Number of Customers				
Rate	2003	2004	2005	2006	2007
RS	207,706	209,167	207,803	207,423	209,611
GSS	13,343	13,352	13,260	13,245	13,556
GSL	767	824	864	864	675
FDS	30,788	30,421	30,264	30,234	28,844
GDS	3,531	3,636	3,476	3,248	3,143
DDS	3	3	3	3	3
AGS	16	29	59	84	95
	256,154	257,433	255,728	255,099	255,928

Equitable Gas Company
Response to Standard Data Requests
REVENUE REQUIREMENT INTERROGATORIES

Item 4: Please provide the actual number of customers by rate schedule at the end of each month from the commencement of the historic test year through the most recent month available and update as additional data become available.

Response:

	RS	GSS	GSL	FDS	GDS	DDS	AGS
Jan-2007	211,137	13,569	819	29,334	3,177	3	98
Feb-2007	211,694	13,586	816	29,404	3,181	3	98
Mar-2007	211,076	13,589	772	29,946	3,176	3	98
Apr-2007	209,219	13,614	639	29,653	3,170	3	98
May-2007	208,513	13,516	631	29,124	3,160	3	98
Jun-2007	208,057	13,470	633	28,742	3,171	3	98
Jul-2007	207,723	13,470	631	28,407	3,139	3	98
Aug-2007	207,880	13,446	624	28,184	3,140	3	98
Sep-2007	208,182	13,482	623	27,899	3,110	3	98
Oct-2007	209,130	13,531	623	28,006	3,105	3	98
Nov-2007	211,012	13,688	626	28,462	3,097	3	98
Dec-2007	211,710	13,714	662	28,970	3,093	3	98
Jan-2008	211,856	13,758	670	29,604	3,092	3	98
Feb-2008	211,547	13,744	669	30,270	3,086	3	98
Mar-2008	210,959	13,702	669	30,762	2,984	3	98

Equitable Gas Company
Response to Standard Data Requests
REVENUE REQUIREMENT INTERROGATORIES

Item 5: If past weather normalized sales or sales trends are used in models or otherwise relied on in reaching sales projections, please provide actual and normalized throughput by rate schedule as of December 31 for the last three years. Where applicable, separately identify sales and transportation throughput.

Response:

	2005 Throughput		2006 Throughput		2007 Throughput	
	Actual	Normalized	Actual	Normalized	Actual	Normalized
Sales						
RS	19,885,286	19,065,641	16,751,901	18,038,170	18,987,521	18,790,982
GSS	2,588,377	2,654,369	2,436,912	2,678,835	2,784,792	2,786,472
GSL	1,716,190	1,796,731	1,547,807	1,793,480	1,437,322	1,435,508
Total Sales	24,189,853	23,516,741	20,736,620	22,510,484	23,209,635	23,012,962
Transportation						
FDS	3,568,419	3,435,620	3,182,650	3,431,590	3,390,531	3,386,052
GDS	20,199,188	20,689,612	17,775,400	19,432,910	20,363,208	20,376,332
Total Transportation	23,767,608	24,125,232	20,958,050	22,864,500	23,753,739	23,762,384
Total	47,957,460	47,641,973	41,694,670	45,374,984	46,963,374	46,775,346

Equitable Gas Company
Response to Standard Data Requests
REVENUE REQUIREMENT INTERROGATORIES

Item 6: If past weather normalized sales or sales trends are used in models or otherwise relied on in reaching sales projections, please provide actual and normalized throughput by month by rate schedule from the beginning of the historic test year and the future test year through the most recent month available and update as additional data become available. Separately identify sales and transportation throughput and provide the workpapers which develop normalized sales.

Response: Please see the attached spreadsheet which summarizes actual and normalized throughput by month by rate schedule from the beginning of the historic test year and the future test year through the most recent month available. Also attached are the workpapers which developed normalized sales. Throughput adjustments and the development of normalized sales are discussed in the testimony of Robert M. Narkevic.

Equitable Gas Company
Response to Standard Data Requests
REVENUE REQUIREMENT INTERROGATORIES
Item No. 6

Actual Throughput 12 Months Ended December 31, 2007

	January	February	March	April	May	June	July	August	September	October	November	December	Total
Rate RS	3,277,484	4,164,362	2,178,383	1,789,506	503,717	310,079	332,940	331,931	395,370	726,156	2,029,097	2,948,494	18,987,521
Rate FDS	251,284	312,834	168,880	133,299	38,037	21,031	22,034	21,692	25,447	45,211	125,868	186,997	1,352,613
CAP	312,771	419,019	271,869	208,918	75,587	38,268	31,689	30,606	34,804	68,477	199,763	346,127	2,037,899
GSS	370,422	635,436	491,083	276,182	136,473	66,788	58,313	55,283	58,543	65,762	153,303	417,206	2,784,792
GSL	190,928	314,660	237,776	140,707	68,561	42,522	34,760	31,016	33,150	35,428	101,111	206,703	1,437,322
GDS	1,675,307	2,008,867	1,494,855	1,198,984	726,071	600,927	592,231	619,301	582,103	786,064	1,243,819	1,610,510	13,139,041
DDS	585,013	903,062	626,679	643,399	476,044	517,217	459,172	539,464	466,260	399,043	441,069	939,146	6,995,567
Total	6,663,208	8,758,241	5,469,524	4,390,995	2,024,490	1,596,832	1,531,140	1,629,293	1,595,677	2,126,141	4,294,030	6,655,183	46,734,754

Normalized Throughput 12 Months Ended December 31, 2007

	January	February	March	April	May	June	July	August	September	October	November	December	Total
Rate RS	3,484,146	3,251,362	2,471,072	1,512,228	637,460	310,079	332,940	331,931	428,219	998,596	1,938,383	3,094,565	18,790,982
Rate FDS	267,185	244,028	191,898	112,338	50,253	20,286	22,034	21,692	25,447	61,783	120,249	196,291	1,333,484
CAP	333,051	324,988	310,914	174,174	114,122	45,618	31,689	30,606	34,804	98,173	190,491	363,939	2,052,568
GSS	392,436	497,473	560,050	234,494	198,910	72,823	58,313	55,283	59,409	71,784	148,179	437,317	2,786,472
GSL	201,333	249,773	269,150	120,272	96,457	48,195	34,760	31,016	33,412	37,360	97,448	216,330	1,435,508
GDS	1,758,394	1,620,742	1,653,216	1,058,231	884,671	655,353	592,252	608,503	620,653	974,540	1,269,580	1,684,630	13,380,765
DDS	585,013	903,062	626,679	643,399	476,044	517,217	459,172	539,464	466,260	399,043	441,069	939,146	6,995,567
Total	7,021,557	7,091,427	6,082,979	3,855,137	2,457,916	1,669,572	1,531,161	1,618,495	1,668,204	2,641,278	4,205,400	6,932,220	46,775,346

Normalized Throughput 12 Months Ended December 31, 2008

	January	February	March	April	May	June	July	August	September	October	November	December	Total
Rate RS	3,377,557	3,158,610	2,410,266	1,477,360	624,514	304,872	327,016	325,937	419,198	974,349	1,894,343	3,031,021	18,325,043
Rate FDS	267,185	244,028	191,898	112,338	50,253	20,286	22,034	21,692	25,447	61,783	120,249	196,291	1,333,484
CAP	439,436	416,799	378,806	209,770	137,759	55,913	39,354	38,154	43,900	122,047	227,357	418,755	2,528,051
GSS	392,436	497,473	560,050	234,494	198,910	72,823	58,313	55,283	59,409	71,784	148,179	437,317	2,786,472
GSL	201,333	249,773	269,150	120,272	96,457	48,195	34,760	31,016	33,412	37,360	97,448	216,330	1,435,508
GDS	1,729,188	1,602,219	1,632,910	1,045,699	871,648	648,237	587,047	601,714	613,864	961,977	1,254,281	1,661,343	13,210,127
DDS	585,013	903,062	626,679	643,399	476,044	517,217	459,172	539,464	466,260	399,043	441,069	939,146	6,995,567
Total	6,992,148	7,071,965	6,069,758	3,843,332	2,455,585	1,667,545	1,527,697	1,613,259	1,661,490	2,628,343	4,182,927	6,900,205	46,614,253

Actual Throughput 2008

	January	February	March	April	May	June	July	August	September	October	November	December	Total
Rate RS	3,287,056	3,371,354	2,587,281	0	0	0	0	0	0	0	0	0	9,245,691
Rate FDS	210,767	213,667	166,220	0	0	0	0	0	0	0	0	0	590,654
CAP	399,103	427,701	365,663	0	0	0	0	0	0	0	0	0	1,192,467
GSS	534,665	566,289	448,097	0	0	0	0	0	0	0	0	0	1,549,052
GSL	242,512	208,188	194,199	0	0	0	0	0	0	0	0	0	644,899
GDS	2,516,966	1,906,160	1,700,226	0	0	0	0	0	0	0	0	0	6,123,351
DDS	944,190	897,028	817,667	0	0	0	0	0	0	0	0	0	2,658,886
Total	8,135,260	7,590,387	6,279,353	0	0	0	0	0	0	0	0	0	22,005,000

Equitable Gas Company   Base Rate Case
WEATHER NORMALIZATION FOR TME 12/31/2008

	Customers	Baseload	Heat Factor	Normal HDD	Normalized Heat	Adjusted	1% conservation	Normalized Total
Residential Sales								
Jan-08	206,543	330,422	0.01392	1070	3,077,914	3,408,336	(30,779)	3,377,557
Feb-08	207,514	331,976	0.01470	936	2,855,186	3,187,162	(28,552)	3,158,610
Mar-08	207,675	332,233	0.01309	772	2,099,023	2,431,256	(20,990)	2,410,266
Apr-08	205,999	329,552	0.01335	422	1,159,402	1,488,954	(11,594)	1,477,360
May-08	205,257	328,365	0.00785	186	299,141	627,506	(2,991)	624,514
Jun-08	204,563	304,872	0.00000	34	-	304,872	-	304,872
Jul-08	204,027	327,016	0.00000	3	-	327,016	-	327,016
Aug-08	204,126	325,937	0.00000	6	-	325,937	-	325,937
Sep-08	204,250	326,754	0.00491	93	93,377	420,131	(934)	419,198
Oct-08	205,418	328,623	0.00843	376	652,248	980,871	(6,522)	974,349
Nov-08	207,935	332,649	0.01163	652	1,577,468	1,910,118	(15,775)	1,894,343
Dec-08	209,226	334,715	0.01314	991	2,723,542	3,058,257	(27,235)	3,031,021
	206,044	3,933,115		5,541	14,537,301	18,470,416	(145,373)	18,325,043
CAP								
Jan-08	18,976	32,066	0.02006	1070	407,370	439,436		
Feb-08	18,976	32,066	0.02167	936	384,733	416,799		
Mar-08	18,976	32,066	0.02367	772	346,740	378,806		
Apr-08	18,976	32,066	0.02221	422	177,703	209,770		
May-08	18,976	32,066	0.02999	186	105,693	137,759		
Jun-08	18,976	32,066	0.03724	34	23,847	55,913		
Jul-08	18,976	39,354	0.00000	3	-	39,354		
Aug-08	18,976	38,154	0.00000	6	-	38,154		
Sep-08	18,976	43,900	0.00000	93	-	43,900		
Oct-08	18,976	32,066	0.01260	376	89,981	122,047		
Nov-08	18,976	32,066	0.01578	652	195,291	227,357		
Dec-08	18,976	32,066	0.02057	991	386,689	418,755		
	18,976	410,005		5,541	2,118,047	2,528,051		

Equitable Gas Company __ Base Rate Case
WEATHER NORMALIZATION FOR TME 12/31/2007

	Customers	Throughput	Baseload	Heat Load	Actual HDD	Normal HDD	Normalized Heat	Normalized Total
Residential Sales								
Jan-07	211,137	3,277,484	337,772	2,939,712	1,000	1,070	3,146,374	3,484,146
Feb-07	211,694	4,164,362	338,663	3,825,699	1,229	936	2,912,699	3,251,362
Mar-07	211,076	2,178,383	337,674	1,840,708	666	772	2,133,398	2,471,072
Apr-07	209,219	1,789,506	334,703	1,454,803	521	422	1,177,525	1,512,228
May-07	208,513	503,717	333,574	170,143	104	186	303,886	637,460
Jun-07	208,057	310,079	310,079	-	21	34	-	310,079
Jul-07	207,723	332,940	332,940	-	3	3	-	332,940
Aug-07	207,880	331,931	331,931	-	7	6	-	331,931
Sep-07	208,182	395,370	333,044	62,326	61	93	95,175	428,219
Oct-07	209,130	726,156	334,561	391,594	222	376	664,035	998,596
Nov-07	211,012	2,029,097	337,572	1,691,525	689	652	1,600,811	1,938,383
Dec-07	211,710	2,948,494	338,688	2,609,806	938	991	2,755,877	3,094,565
	209,611	18,987,521	4,001,203	14,986,317	5461	5541		18,790,982

Base load factor 0.051606

	Customers	Throughput	Baseload	Heat Load	Actual HDD	Normal HDD	Normalized Heat	Normalized Total
Residential Transport								
Jan-07	14,848	251,284	25,091	226,193	1,000	1,070	242,095	267,185
Feb-07	14,510	312,834	24,519	288,314	1,229	936	219,508	244,028
Mar-07	14,276	168,880	24,124	144,756	666	772	167,774	191,898
Apr-07	13,804	133,299	23,326	109,972	521	422	89,012	112,338
May-07	13,313	38,037	22,497	14,314	104	186	25,785	48,282
Jun-07	13,171	21,031	22,257	-	21	34	-	22,257
Jul-07	13,039	22,034	22,034	-	3	3	-	22,034
Aug-07	12,874	21,692	21,692	-	7	6	-	21,692
Sep-07	12,770	25,447	25,447	-	61	93	-	25,447
Oct-07	12,658	45,211	21,390	23,821	222	376	40,393	61,783
Nov-07	12,482	125,868	21,092	104,776	689	652	99,157	120,249
Dec-07	12,396	186,997	20,947	166,050	938	991	175,344	196,291
	13,345	1,352,613	274,416	1,078,197	5461	5541		1,333,484

Base load factor 0.054511

	Customers	Throughput	Baseload	Heat Load	Actual HDD	Normal HDD	Normalized Heat	Normalized Total
Residential CAP								
Jan-07	14,382	312,771	24,303	288,468	1,000	1,070	308,747	333,051
Feb-07	14,796	419,019	25,003	394,017	1,229	936	299,985	324,988
Mar-07	15,575	271,869	26,319	245,550	666	772	284,595	310,914
Apr-07	15,756	208,918	26,625	182,293	521	422	147,549	174,174
May-07	15,720	75,587	26,564	49,023	104	186	87,557	114,122
Jun-07	15,482	38,268	26,162	12,106	21	34	19,456	45,618
Jul-07	15,280	31,689	31,689	-	3	3	-	31,689
Aug-07	15,222	30,606	30,606	-	7	6	-	30,606
Sep-07	15,044	34,804	34,804	-	61	93	-	34,804
Oct-07	15,264	68,477	25,794	42,683	222	376	72,379	98,173
Nov-07	15,899	199,763	26,867	172,897	689	652	163,624	190,491
Dec-07	16,492	346,127	27,869	318,258	938	991	336,071	363,939
	15,409	2,037,899	332,604	1,705,295	5461	5541		2,052,568

Equitable Gas Company Base Rate Case
WEATHER NORMALIZATION FOR TME 12/31/2007

Rate GSS	Customers	Throughput	Baseload	Heat Load	Actual HDD	Normal HDD	Normalized Heat	Normalized Total
Jan-07	13,569	370,422	57,266	313,155	1,000	1,070	335,170	392,436
Feb-07	13,586	635,436	57,338	578,098	1,229	936	440,135	497,473
Mar-07	13,589	491,083	57,351	433,732	666	772	502,699	560,050
Apr-07	13,614	276,182	57,456	218,725	521	422	177,037	234,494
May-07	13,516	136,473	57,043	79,431	104	186	141,867	198,910
Jun-07	13,470	66,788	56,849	9,940	21	34	15,975	72,823
Jul-07	13,470	58,313	58,313	-	3	3	-	58,313
Aug-07	13,446	55,283	55,283	-	7	6	-	55,283
Sep-07	13,482	58,543	56,899	1,643	61	93	2,509	59,409
Oct-07	13,531	65,762	57,106	8,656	222	376	14,678	71,784
Nov-07	13,688	153,303	57,769	95,534	689	652	90,411	148,179
Dec-07	13,714	417,206	57,878	359,327	938	991	379,439	437,317
	162,675	2,784,792	686,551	2,098,241	5461	5541		2,786,472

Baseload Factor 0.136141

Rate GSL	Customers	Throughput	Baseload	Heat Load	Actual HDD	Normal HDD	Normalized Heat	Normalized Total
Jan-07	819	190,928	42,925	148,003	1,000	1,070	158,408	201,333
Feb-07	816	314,660	42,768	271,893	1,229	936	207,006	249,773
Mar-07	772	237,776	40,462	197,314	666	772	228,689	269,150
Apr-07	639	140,707	33,491	107,217	521	422	86,782	120,272
May-07	631	68,561	33,072	35,489	104	186	63,386	96,457
Jun-07	633	42,522	33,176	9,345	21	34	15,019	48,195
Jul-07	631	34,760	34,760	-	3	3	-	34,760
Aug-07	624	31,016	31,016	-	7	6	-	31,016
Sep-07	623	33,150	32,652	498	61	93	760	33,412
Oct-07	623	35,428	32,652	2,776	222	376	4,708	37,360
Nov-07	626	101,111	32,809	68,302	689	652	64,639	97,448
Dec-07	662	206,703	34,696	172,007	938	991	181,634	216,330
	8,099	1,437,322	424,479	1,012,843	5461	5541		1,435,508

Baseload Factor 1.690687

Equitable Gas Company Base Rate Case
WEATHER NORMALIZATION FOR TME 12/31/2007

Rate GDS Large Commercial

	Customers	Throughput	Baseload	Heat Load	Actual HDD	Normal HDD	Normalized Heat	Normalized Total
Jan-07	803	488,675	80,274	408,400	1,000	1,070	437,111	517,386
Feb-07	803	600,373	80,274	520,098	1,229	936	395,977	476,252
Mar-07	803	402,272	80,274	321,997	666	772	373,198	453,472
Apr-07	803	305,814	80,274	225,540	521	422	182,553	262,827
May-07	803	129,771	80,274	49,497	104	186	88,404	168,678
Jun-07	803	82,418	80,274	2,144	21	34	3,445	83,720
Jul-07	803	80,644	80,644	-	3	3	-	80,644
Aug-07	803	79,905	79,905	-	7	6	-	79,905
Sep-07	803	75,508	75,508	-	61	93	-	75,508
Oct-07	803	135,630	80,274	55,355	222	376	93,867	174,141
Nov-07	803	322,527	80,274	242,253	689	652	229,261	309,535
Dec-07	803	477,149	80,274	396,874	938	991	419,087	499,362
	803	3,180,685	958,527	2,222,158	5461	5541		3,181,430

Baseload Factor 3.224781

Rate GDS Large Industrial

	Customers	Throughput	Baseload	Heat Load	Actual HDD	Normal HDD	Normalized Heat	Normalized Total
Jan-07	67	83,359	41,357	42,002	1,000	1,070	44,954	86,312
Feb-07	67	99,232	41,357	57,875	1,229	936	44,063	85,420
Mar-07	67	79,299	41,357	37,942	666	772	43,975	85,333
Apr-07	67	63,055	41,357	21,697	521	422	17,562	58,919
May-07	67	49,609	41,357	8,252	104	186	14,738	56,096
Jun-07	67	41,999	41,357	642	21	34	1,031	42,389
Jul-07	67	37,966	37,966	-	3	3	-	37,966
Aug-07	67	44,749	44,749	-	7	6	-	44,749
Sep-07	67	47,085	41,357	5,727	61	93	8,746	50,103
Oct-07	67	54,907	41,357	13,550	222	376	22,977	64,334
Nov-07	67	66,297	41,357	24,940	689	652	23,602	64,960
Dec-07	67	83,081	41,357	41,723	938	991	44,059	85,416
	67	750,638	496,288	254,350	5461	5541		761,996

Baseload Factor 19.91204

Equitable Gas Company   Base Rate Case
WEATHER NORMALIZATION FOR TME 12/31/2007

Rate GDS Small Commercial	Customers	Throughput	Baseload	Heat Load	Actual HDD	Normal HDD	Normalized Heat	Normalized Total
Jan-07	1,459	108,793	11,866	96,928	1,000	1,070	103,742	115,607
Feb-07	1,459	161,897	11,866	150,031	1,229	936	114,227	126,092
Mar-07	1,459	118,803	11,866	106,938	666	772	123,942	135,807
Apr-07	1,459	69,183	11,866	57,317	521	422	46,393	58,258
May-07	1,459	28,856	11,866	16,990	104	186	30,345	42,211
Jun-07	1,459	17,130	11,866	5,264	21	34	8,460	20,326
Jul-07	1,459	12,382	12,382	-	3	3	-	12,382
Aug-07	1,459	11,350	11,350	-	7	6	-	11,350
Sep-07	1,459	11,600	11,600	-	61	93	-	11,600
Oct-07	1,459	17,456	11,866	5,590	222	376	9,479	21,345
Nov-07	1,459	50,218	11,866	38,353	689	652	36,296	48,162
Dec-07	1,459	113,141	11,866	101,276	938	991	106,944	118,810
	17,508	720,808	142,122	578,686	5461	5541		721,949

Baseload Factor 0.262346

Rate GDS Small Industrial	Customers	Throughput	Baseload	Heat Load	Actual HDD	Normal HDD	Normalized Heat	Normalized Total
Jan-07	16	914	119	795	1,000	1,070	851	970
Feb-07	16	1,494	119	1,375	1,229	936	1,047	1,166
Mar-07	16	1,130	119	1,011	666	772	1,172	1,291
Apr-07	16	556	119	437	521	422	354	472
May-07	16	150	119	31	104	186	56	175
Jun-07	16	146	119	27	21	34	43	162
Jul-07	16	123	123	-	3	3	-	123
Aug-07	16	115	115	-	7	6	-	115
Sep-07	16	87	87	-	61	93	-	87
Oct-07	16	69	69	-	222	376	-	69
Nov-07	16	281	119	162	689	652	153	272
Dec-07	16	875	119	756	938	991	799	918
	192	5,940	1,345	4,595	5461	5541		5,820

Baseload Factor 0.239819

Equitable Gas Company
Response to Standard Data Requests
REVENUE REQUIREMENT INTERROGATORIES

Item 7: Please provide the workpaper developing the Company's FTY load growth adjustment.

Response:

Please see attachments for Revenue Requirement Interrogatory Item No. 6 identifying the change in residential customers and throughput for the future test year.

Future test year throughput also reflects the loss of one large commercial transportation customer:

	Number of Customers	Normalized Annual Adjustment
Large Commercial Transport	1	(170,637)

Equitable Gas Company
Response to Standard Data Requests
REVENUE REQUIREMENT INTERROGATORIES

Item 8: Please provide a complete copy of the computer output generated by the Company's statistical analysis package for all residential, commercial, public authority and industrial econometric models of gas demand estimated by the Company, but not presented in the filing.

Response: All methods used by the Company to project gas demand are included in the filing.

Equitable Gas Company
Response to Standard Data Requests
REVENUE REQUIREMENT INTERROGATORIES

Item 9: Identify the historical data source(s) for each dependent and independent variable utilized to develop the econometric models of gas demands for each forecasted customer group.

Response: The Company uses monthly heating degree days and number of customers as independent variables for projecting gas demand. The Company currently uses a 20 year average which was calculated using data obtained from the National Oceanic Atmospheric Administration (NOAA). The dependent variable, customer usage, has two factors: use per degree day and base load use per day. Use per degree day is based on the most recent twelve months of usage. Base load is determined by analyzing the summer usage.

Item 10: Identify the source(s) and supporting documentation for the FTY value of each independent variable which required forecasting in the Company's gas demand models.

Response: Please refer to Revenue Requirement Interrogatory Nos. 9 and 11. Also, please refer to the attachments for Revenue Requirement Interrogatory Item No. 6 for the copies of the models used to calculate normalized volumes and the testimony of Robert M. Narkevic.

Equitable Gas Company
Response to Standard Data Requests
REVENUE REQUIREMENT INTERROGATORIES

Item 11: Please provide in hard copy and on a computer diskette in Lotus 1-2-3, QuattroPro or other spreadsheet format, the dependent and independent variable databases relied upon to produce the Company's gas demand models. For variables based on averages, include the observations which comprise the average (e.g., gas prices).

Response: The dependent and independent variable databases relied upon to produce the Company's gas demand model include degree day reports from National Oceanic Atmospheric Administration (NOAA), an independent study by the AGA of consumer response to natural gas prices, an internal Company study of its customers' reaction to price elasticity, and downloaded information from the Company's billing system. The downloaded information is voluminous and contains sensitive usage and pricing data, therefore samples of different reports are provided. Files are available for review at the Company's office. Also, please refer to the attachments for Revenue Requirement Interrogatory Item No. 6 for the copies of the models used to calculate normalized volumes and the testimony of Robert M. Narkevic.

An Economic Analysis of Consumer Response to Natural Gas Prices

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Executive Summary

Introduction and Key Findings

The consumption of natural gas per household has been declining, on a weather-normalized basis, since about 1980. Over time, natural gas consumers have been tightening their homes, purchasing more efficient appliances and turning down their thermostats. Given the significant increase in natural gas prices since 2000, the American Gas Association (AGA) decided to examine whether or not the trend in declining use has changed in this higher-priced environment. The results of this study are based on monthly data submitted by 46 local natural gas distribution companies that serve nearly 30 percent of all residential natural gas customers throughout the U.S. Some companies submitted data as far back as the early 1980's. The key findings of the study are as follows.

- A trend in declining use per residential natural gas customer of 1 percent annually has been documented[2] back to 1980. This decline rate has accelerated since the year 2000.
  - Weather-adjusted use per residential customer fell by 13.1 percent from 2000 through 2006.
  - The annual rate of decline in this 2000 to 2006 timeframe more than doubled relative to the pre-2000 period, increasing to 2.2 percent annually.
  - Further acceleration was witnessed in the 2004 to 2006 period, as evidenced by a 4.9 percent annual rate of decline.
  - The decline in use per customer has accelerated since 2000 in all 9 geographic regions analyzed.

- No appreciable changes in the price elasticity of demand were observed post-2000. Price elasticity of demand refers to the percentage change in demand for a good relative to a percentage change in price. Although the elasticity has not changed over time, it should be noted that natural gas is an essential product that provides heat, hot water and cooking. Despite the essential nature of natural gas, consumers have continued to reduce their consumption at a relatively constant rate with respect to changing prices. Therefore, the large price increases post-2000 have resulted in the large consumption declines noted above.
  - This study found a short-run price elasticity of –0.09 and a long-run price elasticity of -0.18. (Long-run elasticity refers to a period of time long enough for consumers to change the capital stock of their energy consuming equipment and the shell efficiency of their homes.)

[2] 2004 AGA Energy Analysis: Patterns in Residential Natural Gas Consumption, 1980-2001.

- These price elasticity estimates are relatively consistent with previous works on this subject.
- The econometric analysis presented in this study predicts a decline of 13.9 percent between 2000 and 2006; the actual decline was 13.1 percent. The decline is attributable to a price effect and the longer-run trend towards tighter homes and more efficient appliances. The price elasticity effect is 7.9 percent - equal to the elasticity estimate of -0.18 times the 44 percent real price increase. The remaining 6.0 percent is explained by the longer-run trend towards tighter homes and more efficient appliances.
- As a general rule of thumb, at the national level we would expect a 10 percent increase in the price of natural gas to result in nearly a 3 percent decline in the average residential use per customer 12 months later – 1 percent attributable to more conservation with existing appliances, 1 percent attributable to the price-induced purchase of more efficient appliances, and 1 percent attributable to the natural turnover of equipment that occurs annually.

Background

Residential natural gas consumption is strongly influenced by three factors: seasonal heating needs; response to price change; and the efficiency changes in appliances and home shells caused by a natural turnover rate to more efficient homes and gas appliances. On a weather-adjusted basis, the price and the long run conservation effects are key determinants of changes in residential natural gas consumption. The price effects can be further decomposed into short-term and long-term effects. Short term effects are decisions made by consumers with the current capital stock. Residential customers "turning down the thermostat" would be considered a short term effect. Long term effects are distinguished from short term effects by the inclusion of the decision to purchase more efficient energy consuming appliances and prematurely retiring less efficient ones. The price elasticity in the long-run is the sum of (1) the short-run demand and (2) the additional changes that occur to quantity demanded one year later because of natural gas price effects on the efficiency of the appliance capital stock and on the shell efficiency of homes[3]. While the separate efficiency and conservation effects due to appliance and housing shell turnover are difficult to disentangle in the current sample, they do appear to be discernable from the long term price effects.

To address these issues, AGA commissioned a study to document changes in use per residential customer on a weather normalized basis, particularly since the year 2000, and to identify the reasons for these changes. Other objectives of this study were: to obtain updated elasticity estimates for all nine US Census Regions and for the US; to test for an increase in

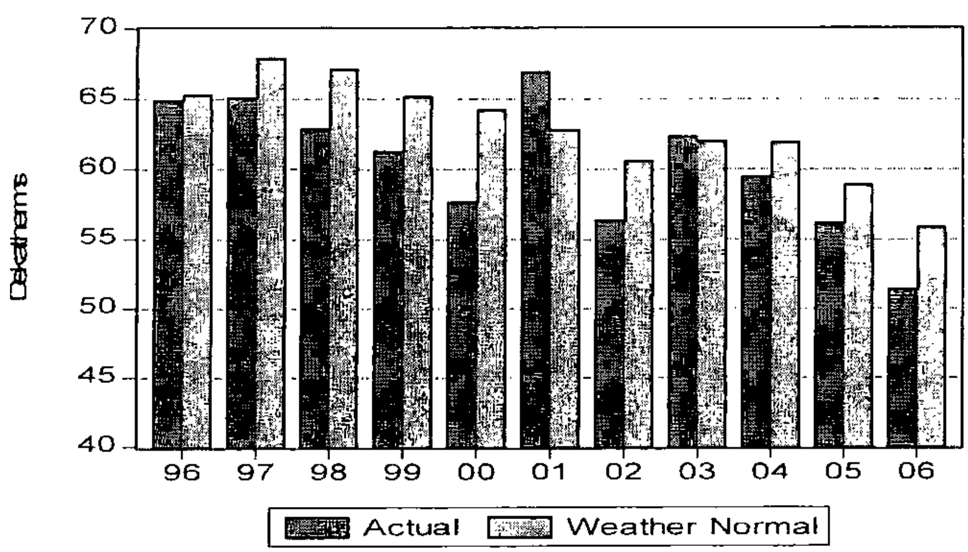
[3] It should be noted that if natural gas prices decrease, consumers will not replace recently purchased efficient equipment with less efficient equipment. So there maybe asymmetry with respect to the impact of natural gas prices on appliance and shell efficiency. The efficiency gains in appliance equipment that have occurred in the last several years will not disappear if natural gas prices go down. However, declining prices may lead consumers turning up thermostats to increase comfort levels (in the short-run). In the very long-run, a decline in prices could lead to an increase in burner tips per customer.

the price elasticity of demand for natural gas since the year 2000; and to estimate a natural rate of decline in use per customer due to technology-induced gains in appliance and shell efficiency and a change in conservation attitudes that would occur even in an environment of constant real natural gas prices.

Decline in Use per Customer

Demand for natural gas per residential customer has been declining since the 1980's, and in recent years this decline has accelerated. Between 1980 and 2001, weather adjusted natural gas use per consumer in the US declined almost 1 percent on an annual basis. Since 2000, however, the decline for winter only use has accelerated, decreasing 13.1 percent nationally between 2000 and 2006 for the sample of companies analyzed in this report. Figure ES1 below shows the winter season use per customer in actual and weather normal dekatherms from 1996-2006 using the data collected by AGA.[4] It is clear that actual and weather normalized use per customer has been declining since 1997 and this decline has accelerated since 2004.

Figure ES1
US Annual Winter Use per Customer



[4] The data was collected from 46 Local Distribution Companies (LDCs) in 29 states, representing 28 percent of all residential customers. An LDC is a gas utility that serves a specific rate jurisdiction. Some of the companies in this sample have multiple jurisdictions in their corporate structure. The winter season for this report is defined as the sum of the monthly consumption between October and March.

Table ES1 disaggregates the national winter season weather normal use per residential customer across the nine US Census Regions and for the US The decline in weather normal use per customer has occurred across all US Census regions. The decline ranges from 5.7 dekatherms per customer for the West South Central region to 10.9 dekatherms for the East North Central region. The percentage decline in use per customer ranged from 9.2 percent for the Middle Atlantic Region to 14.8 percent for the Pacific Region.

Table ES1
Annual Winter Season Weather Normal
Natural Gas Use per Residential Customer,
By Region and for the U.S.
(Dekatherms per Customer)

Census Region	2000	2001	2002	2003	2004	2005	2006	Percent Change
National	64.3	62.8	60.6	62.0	61.9	58.9	55.9	-13.1%
East North Central	81.1	79.2	80.1	77.8	76.1	73.1	70.2	-13.4%
East South Central	64.9	64.2	61.3	62.2	60.8	58.7	55.9	-13.9%
Middle Atlantic	93.7	95.0	91.2	93.5	92.8	88.3	85.1	-9.2%
Mountain	80.6	77.9	75.8	76.4	71.8	72.0	70.5	-12.5%
New England	80.7	79.8	75.3	82.3	80.3	75.9	72.4	-10.3%
Pacific	43.8	40.9	40.0	41.8	40.6	40.4	37.3	-14.8%
South Atlantic	71.7	69.4	63.8	69.1	62.0	62.5	62.5	-12.8%
West North Central	80.1	79.5	79.8	80.4	78.3	75.9	70.2	-12.4%
West South Central	46.3	46.4	40.2	44.1	54.1	41.7	40.6	-12.3%

Price Elasticity and "Natural" Conservation Estimates

This study found that neither a practical nor statistically significant change in the price elasticity of residential natural gas consumption occurred in the post year 2000 period. The price elasticity of residential natural gas demand appears to have remained relatively constant since the 1990s. This implies the large percentage price increase since 2000 accounted for the decline in natural gas use, rather than an increased sensitivity or greater response by households to a given price change. The study also found that independent of natural gas price increases, the naturally occurring decline due to the technology driven gain in appliance and home thermal shell efficiency, as well as changes in conservation attitudes was 1 percent per year.

Table ES2 illustrates that for the sample of companies in the study, the short run price elasticity of demand averaged -0.09, while the long run estimated averaged -0.18. Therefore, given a 10 percent increase in the price of natural gas, consumption would decline 2.8 percent; 1.8 percent for price response, added to 1.0 percent decline due to the normal turnover of appliances and other "natural" conservation measures. There is very little regional variation in the total impact of a 10 percent increase in real prices on use per customer. The impact in all regions was close to the national estimate of 2.8 percent, with the Mountain region being the lowest at 1.9 percent and the South Atlantic region being the highest at 3.7 percent.

The study also found that the elasticity estimates calculated using the sample data were generally consistent with the elasticity estimates found in the energy economics literature.[5]

Table ES2
Summary of National and Regional
Natural Gas Price Elasticity Estimates*

Region	Short-run elasticity	Long-run elasticity**	Annual Time Trend	Total Response to a 10% Price Increase***
National	-0.09	-0.18	-1.0%	-2.8%
East North Central	-0.08	-0.22	-1.0%	-3.2%
East South Central	-0.01	-0.01	-2.0%	-2.1%
Middle Atlantic	-0.10	-0.20	-1.3%	-3.3%
Mountain	-0.07	-0.10	-0.9%	-1.9%
New England	-0.08	-0.25	-0.4%	-2.9%
Pacific	-0.07	-0.12	-0.8%	-2.0%
South Atlantic	-0.12	-0.29	-0.8%	-3.7%
West North Central	-0.09	-0.15	-1.1 %	-2.6%
West South Central	-0.13	-0.16	-1.6%	-3.2%

* Estimates obtained from the "fixed effects" pooled regression
** Cumulative: includes impacts of short-run elasticities
*** The total response to a 10% price increase is the sum of the long-run elasticity and the annual time trend effect.

Implications

These price elasticity estimates and the natural conservation trends are able to explain the post 2000 winter consumption per household per customer actual experience.

Between 2000 and 2006, real natural gas prices for the sample companies in this study rose 44 percent, which according to our analysis would lead to approximately a 7.9 percent (0.18 x 44 percent) decline in use per customer by the year 2006. In addition to this 7.9 percent price induced decline in weather normal use per household, there would be an additional 6.0 percent (6 x 1.0 percent) decline because of the natural annual rate of turnover of old gas appliances to newer more efficient appliances. Hence, our analysis predicts a decline of 13.9 percent over the six-year period, which is very close to the actual decline of 13.1 percent.

[5] See Appendix C of the main report for a summary of the elasticity estimates found in the energy economics literature.

Overall decline in Winter Gas Use per Customer		Price Effect Elasticity with Price Increase		Conservation and Turnover to More Efficient Appliances
13.9%	=	$0.18 \times 44\%$	+	$6 \times 1.0\%$
	=	7.9%	+	6.0%

In the expression above, the left hand term is the overall predicted decline of winter gas use per customer, the first term on the right hand side is the price effect reflecting the elasticity estimate multiplied by the price increase, and the second term the effect from conservation and turnover to more efficient appliances that occurs naturally every year with or without a price increase.

The results from analyzing the AGA sample data lead to a general rule of thumb. This rule does not apply to all companies in all situations, but the general rule with its caveats provides valuable insight to the underlying processes governing consumer behavior. This rule appears to capture consumers' winter price sensitive consumption behavior reasonably well across both the LDCs and Census regions. Twelve months after a 10 percent increase in natural gas prices at the national level, there will be nearly a 3 percent decline in natural gas use per customer on a national level. This 3 percent decline is comprised of about a 1 percent drop in gas use with the current capital stock, about a 1 percent drop in use per customer because households respond to the higher gas prices by replacing still functional appliances with more efficient units, and about a 1 percent drop in gas usage per customer due to the natural turnover of old gas appliances to the more efficient gas appliances that are available in the market each year. This rule of thumb will vary by LDC because they are heterogeneous in terms of weather, housing stocks, and standards of living.

Other factors that impacts residential energy use are the many programs that encourage consumers to save energy. These include:

- The federal government encourages conservation through weatherization programs funded by the Low-Income Household Energy Assistance Program (LIHEAP), tax credits for the purchase of efficient appliances and housing shell improvements, and consumer education on the importance of saving energy.
- State and local governments also encourage efficiency through similar programs.
- Many utilities provide rebates, incentives, and assistance to their customers to conserve energy use. For example, electric and natural gas utilities provided more than $140 million in 2005 to assist low-income customers to weatherize their homes.[6]

From a planning and policy perspective, even if gas prices do not increase in a given year, there will still be approximately a 1 percent fall in gas usage per household in the following

[6] Source: http://liheap.ncat.org/tables/FY2005/05stlvtb.htm

year. This is driven by the historical forces related to the natural turnover of old appliances to the more efficient appliances that are available on the market each year. The annual time trend impacts will vary somewhat by LDC, because of regional differences in weather, appliance stocks, housing shell efficiency, demographic and economic characteristics.

There is a caveat. We cannot address whether the phenomenon will continue at the same rate for the long-term. Further gains in efficiency in absolute and relative terms may or may not have the same impact as they did previously. This is an issue for more detailed engineering studies on the efficiency of appliances and housing shells and economic research on the change in conservation habits of consumers for energy use and winter season comfort levels. We would note, however, that legislative and regulatory pressure for greater efficiency is likely to increase as climate change becomes a more pronounced national and international priority.

The policy implications of the 13.1 percent decline since 2000 are significant. First, regulators must recognize these trends and allow rate structures to incorporate these variations. Second, the natural turnover of appliances and increases in thermal shell efficiency from new construction will result in continued conservation, impacting utility operations. Third, even if future natural gas prices remain constant or even decrease, the appliance and house shell efficiency gains achieved in prior years will not be reversed.

Future Research

As with any study, there is room for future research. Suggestions for future research are the following:

- Obtain data from natural gas companies that did not participate in the initial study.
- Try different specifications of the model.
- Use the Iterative Bayes Shrinkage Estimation Technique to get individual LDC parameter estimates.
- Consider the impact of competition from the electric utility industry.

Introduction

Demand for natural gas per residential customer has been declining since the 1980's, and in recent years this decline has increased. Between 1980 and 2001, weather adjusted natural gas use per consumer in the US declined almost 1 percent on an annual basis. Since 2000, however, the decline for winter only use has accelerated, decreasing 13.1 percent between 2000 and 2006 for the sample of companies analyzed in this report.

It is important from a budgeting point of view for Local Distribution Companies (LDCs) to understand the cause of this decline. Was it caused by the recent increases in natural gas prices and customer's response to these price increases? Did customers change their behavior in response to these price increases? Have they become more sensitive to natural gas price movements or has the price induced response behavior remained relatively the same over time? Did customers switch to more efficient gas appliances in response to these natural gas price increases? Is it due to technological innovations which lead to increased efficiencies in appliances and thermal shells of homes? These efficiencies are in some sense passive as older appliances are replaced with more efficient models through natural attrition.

To address these issues, the American Gas Association (AGA) funded a study to re-estimate the price elasticity of natural gas demand by residential households using a sample of data that covers the recent period of large natural gas price increases. The main objective of this study was to document changes in use per residential customer on a weather normalized basis, particularly since the year 2000, and to identify the reasons for these changes. A second purpose of this study was to test for an increase in the price elasticity[7] of demand for natural gas since the year 2000. A third and equally important purpose of this study was to obtain updated elasticity estimates for all nine US Census Regions and for the US as a whole. Finally, the study attempts to estimate a natural rate of decline in use per customer due to technology induced gains in appliance and shell efficiency that would even occur in an environment of constant real natural gas prices.

There are hundreds of studies on the elasticities of natural gas demand. These studies have generated a range of elasticity estimates. If one goes back to the 1970's and even to the 1960s, these estimates vary over a wide range. Estimates of short-run price elasticity range from as low as –0.05 in Beirlein, Dunn and McConnon (1981) to a high of –0.68 in Barnes, Gillingham & Hagemann (1982). For long-run price elasticity estimates, the range of estimates is even higher, with the low being -0.017 in Hewlett (1977) to a high of –3.42 in Beirlein, Dunn and McConnon (1981). See Dahl and Roman (2004) and Dahl, et. al. (2005) for recent surveys of energy elasticity demand estimates. Other surveys of energy demand price elasticity estimates are Taylor (1975 and 1977), Bohi (1981), Bohi and Zimmerman (1984), Al-Sahlawi (1989), Dahl (1993), and Espy and Espy (2004). See Appendix C for a brief literature review of price elasticity estimates.

[7] The price elasticity of demand is defined as the ratio of the percent change in quantity demanded of a particular good to the percent change in the price of that good, such as natural gas demand in this study.

Many of the studies estimated elasticities of natural gas demand with data aggregated at the state and national level and collected by the States; or collected by the Energy Information Administration (EIA). Examples of these are Balestra and Nerlove (1966), Jaskow and Baughman (1976), Berndt and Watkins (1977), and more recently, Maddala, Trost, Li, and Joutz (1997). Other studies use individual micro data to estimate demand elasticities. Examples of these are Hewlett (1977), Barnes, Gillingham and Hagemann (1982), and Green and Gilbert (1983). While the former studies using state and national aggregate data may provide some useful information at the state and national level, and the latter studies may provide good estimates of individual demand elasticities, neither provide adequate estimates at the individual LDC level of aggregation. Most of these studies do not allow for a natural rate of decline in use per customer due to technologically induced efficiency gains in appliances and thermal shells of homes. In addition, there are few, if any, studies that use current data that includes the recent run-up in natural gas prices. This study will fill these gaps in the literature by using high quality data collected and compiled at the individual LDC level and covering the period as recent as March, 2006.

This paper is divided into the following five sections. In Section 1, background information at the regional, as well as the national level, is provided. The information includes residential natural gas consumption, the declining trend of consumption, and price movements. In Section 2, the database constructed from the survey of LDCs is described. Section 3 explains the mathematical equations used to estimate short- and long-run price elasticity of demand. Empirical results of short-run and long-run elasticity and the declining trend in gas usage are presented in Section 4. The report concludes in Section 5 with a summary of the results and policy implications. In addition, there is a list of suggestions for future research. References and technical appendices can be found at the end of the report. The appendices include construction of the weather-normalized series for use per customer, a map of the Census regions, a brief literature review, and a discussion of statistical hypothesis testing.

Section 1: Background

Residential natural gas consumption per customer in the US has been declining. Figure 1 below shows the winter season use per consumption actual and weather normal (in dekatherms) from 1996 to 2006 using the data collected from the sample LDCs. The winter season for this report is defined as the sum of the monthly consumption between October and March.

Figure 1
US Annual Winter Use per Customer

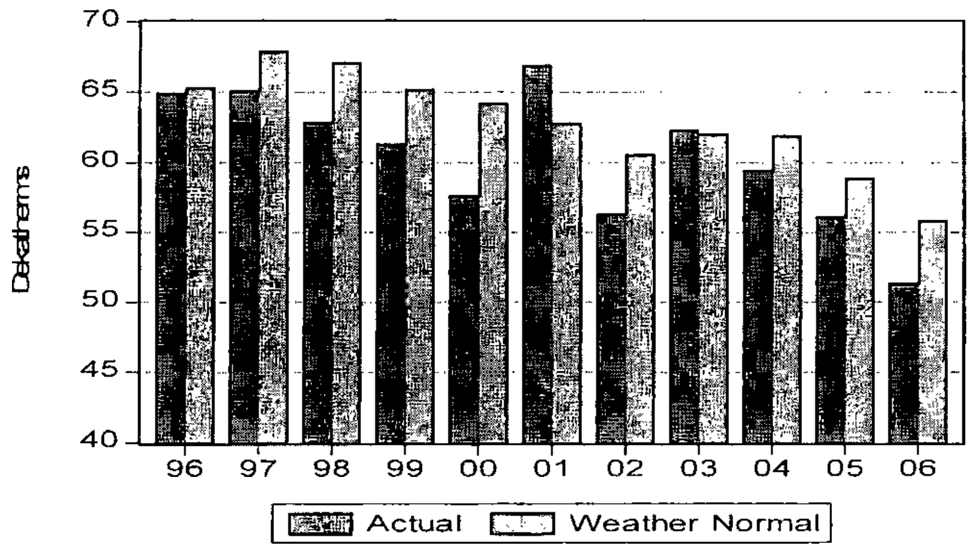


Table 1: US Annual Winter Use per Residential Customer in Dekatherms				
Year	Actual		Winter Normal	
	Level	Percent Change	Level	Percent Change
1996	64.9		65.3	
1997	65.2	0.5	67.9	4.0
1998	62.9	-3.5	67.1	-1.2
1999	61.3	-2.5	65.2	-2.8
2000	57.7	-5.9	64.3	-1.4
2001	67.0	16.1	62.8	-2.3
2002	56.4	-15.8	60.6	-3.5
2003	62.3	10.5	62.0	2.3
2004	59.5	-4.5	61.9	-0.2
2005	56.2	-5.6	58.9	-4.9
2006	51.4	-8.5	55.9	-5.1
Annual Percent *Change 1996-2000*		**-1.64**		**-1.48**

As can be seen from Figure 1 and Table 1, there has been a marked decline in weather normal use per customer. The annual percent change from 1996 to 2006 was -1.64 percent and -1.48 percent respectively, for actual and weather normal consumption. Since 2000, however, the decline for winter only use has accelerated, decreasing 13.1 percent between 2000 and 2006 and by 9.7 percent between 2004 and 2006 for the sample of companies analyzed in this report.

The phenomenon of declining weather normal use per customer is not new[8]. Some even feel it started on February 1, 1977 when then President Jimmy Carter, after only two weeks in office, said in his now famous fireside chat:

"All of us must learn to waste less energy. Simply by keeping our thermostats, for instance, at 65 degrees in the daytime and 55 degrees at night we could save half the current shortage of natural gas."

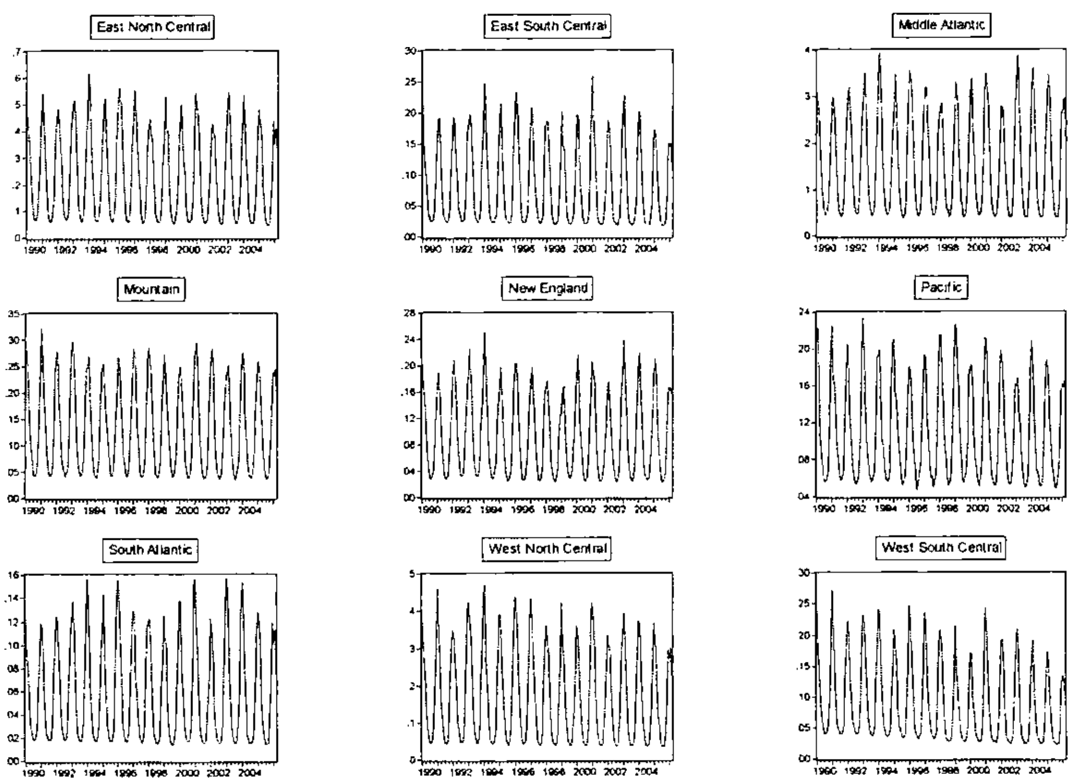
In the years since, the first President Bush established the first National Energy Strategy in June of 1989, and the government has imposed efficiency standards, subsidized technological improvements in both shell and appliance efficiency, and generally encouraged its citizenry to conserve on energy. Efficiency improvements are sure to continue, and if natural gas prices stay high, it will most certainly encourage natural gas

[8] Between 1978 and 1982, energy consumption per household actually decreased by 26%. See EIA's Annual Energy Review, URL http://www.eia.doe.gov/emeu/aer/ep/ep_frame.html.

customers to trade in old inefficient appliances for newer more efficient ones. The impact on the natural gas industry will be an obvious decrease in revenue accruing to natural gas LDC's.

This study will examine the reasons for this decline in use per customer, with particular emphasis on estimating the short-run and long-run price elasticity of natural gas demand since the year 2000. It will also analyze and measure the rate of decline caused by the natural turnover rate of old inefficient appliances with newer more efficient ones. The trends in the AGA sample are validated from trends in other data. The U.S. Energy Information Administration (EIA) reports aggregate estimates of residential consumption in BCF/day and residential prices in $/MCF on a monthly basis from 1990 to the present. The EIA sample data covers all LDCs in the US. These series are plotted by US Census Region in residential consumption per household per day in Figure 2 and in nominal and real terms in ($2000)/MCF in Figure 3 below. A map of the US Census Regions is shown in Appendix B. These figures provide a comparison with the subsequent figures from the AGA survey database. They demonstrate that the trends and patterns in the survey are consistent with a recognized national source of data even before adjusting for normal weather.

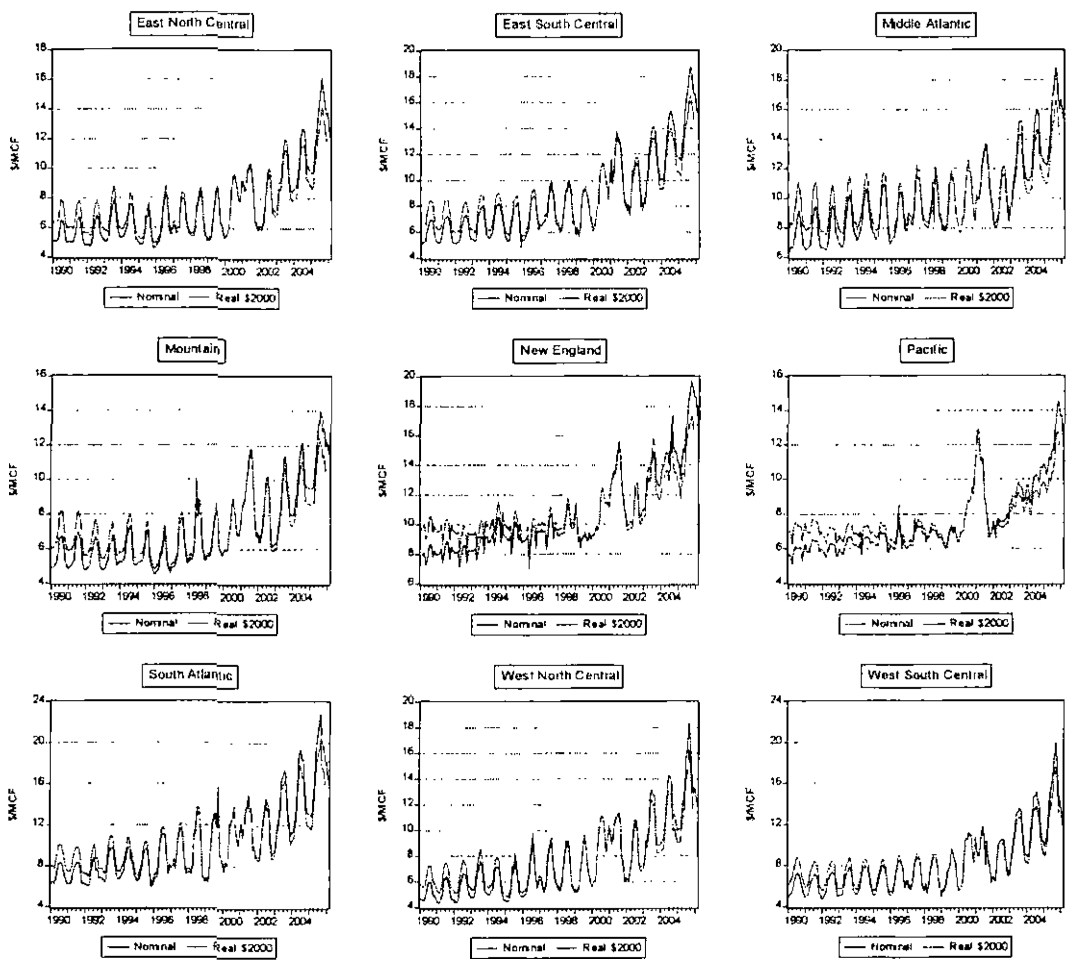
Figure 2
Regional Consumption per Customer per Day
Mcf per Day



Source: U.S. Energy Information Administration

Regional consumption per customer appears to decline for every region for most of the period and particularly after 2000. This has occurred while residential natural gas prices have more than doubled over the same period.

Figure 3
Nominal and Real ($2000) Delivered Natural Gas Prices

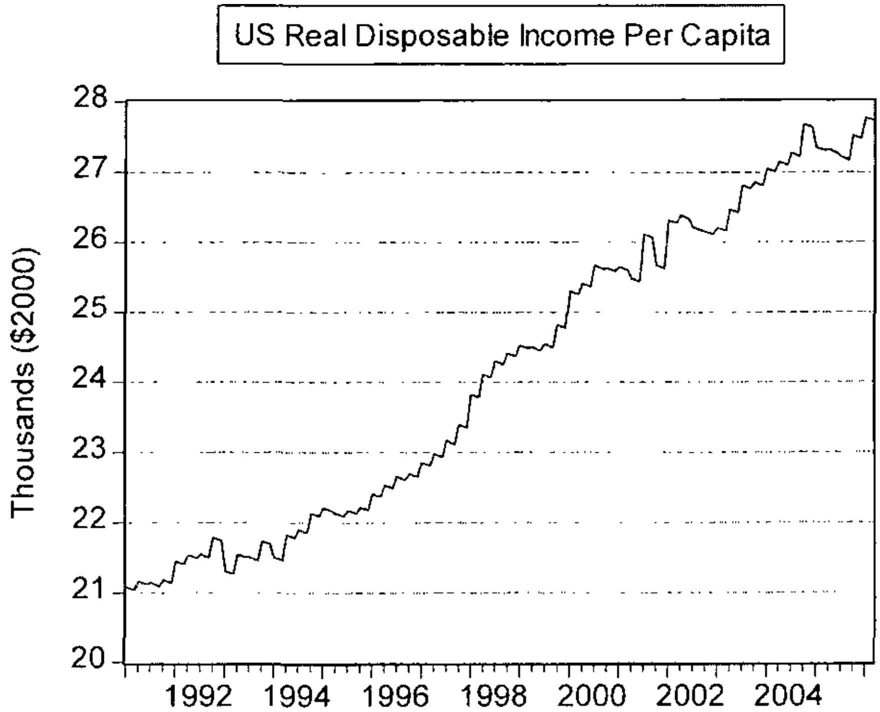


Source: U.S. Energy Information Administration

Residential natural gas prices were fairly stable between 1990 and 1997 during the so-called "gas bubble" period. However, they have been increasing, particularly since 2000 due to a variety of factors, including increasing oil prices (Villar and Joutz, October 2006). Nominal prices have risen faster in some regions than in others; the spread in nominal terms has been between $12/MCF to almost $20/MCF. The real price has more than doubled to over $12/MCF. Natural gas prices have risen about 35 percent to 40 percent faster than the general U.S. price level since 1990. Figure 3 shows the monthly residential natural gas prices per MCF according to the EIA. Figure 4 shows U.S. real disposable income per capita has risen about 33 percent from $21,000 to $28,000 today.

While income is important in any economic analysis of demand, income was not included in our final model for several reasons. First, estimates of real disposable income (per customer, household, or person) are difficult to obtain at the LDC level, which is the building block of this research. Second, the services from natural gas is a normal good, one would expect a positive income effect, which should have been reflected in a positive trend in natural gas use per household. However, in our sample and specification, we observe a negative trend in use per household. The income series are highly positively autocorrelated and trend-like; see Figure 4. The income coefficient(s) were erratic and even negative. This is consistent with the declining use per household due to a naturally occurring and non-natural gas price-induced replacement of old inefficient appliances with new more efficient appliances. At present, we believe a time trend appropriately captures this new technology-induced naturally occurring adoption of more energy efficient appliances and improvements in housing shell efficiency or conservation. Third, our findings are similar to surveys of natural gas demand by Bohi (1981), Dahl (1993, and personal discussions about preliminary results regarding an update to Dahl's previous study). In a number of papers, Bohi dismisses the large income elasticities from some static cross section estimates and concluded that income is not found to be an important variable in natural gas demand. Dahl found that income effects in residential demand models are consistently small in both aggregate and disaggregate data. Both authors suggest that representing the income effect in residential is problematic and sensitive to the particular study.

Figure 4



Source: Bureau of Economic Analysis, U.S. Department of Commerce

Table 2 shows the cumulative decline of winter weather normal use per customer between 2000 and 2006 for the sample of the LDCs. The focus of Table 2 is the post 2000 period. The intent is to capture the effects of the large increases in natural gas prices and (possible) conservation activities by consumers.[9] The fall, on average, is greater than two per cent per year for six of the nine Census Regions and for the U.S.

[9] The pre-2000 period will be addressed in the statistical modeling sections.

Table 2
Annual Winter Season Weather Normal Natural Gas Use per Residential Customer, By Region and for the U.S.
(Dekatherms per Customer)

Census Region	2000	2001	2002	2003	2004	2005	2006	Percent Change
National	64.3	62.8	60.6	62.0	61.9	58.9	55.9	-13.1%
East North Central	81.1	79.2	80.1	77.8	76.1	73.1	70.2	-13.4%
East South Central	64.9	64.2	61.3	62.2	60.8	58.7	55.9	-13.9%
Middle Atlantic	93.7	95.0	91.2	93.5	92.8	88.3	85.1	-9.2%
Mountain	80.6	77.9	75.8	76.4	71.8	72.0	70.5	-12.5%
New England	80.7	79.8	75.3	82.3	80.3	75.9	72.4	-10.3%
Pacific	43.8	40.9	40.0	41.8	40.6	40.4	37.3	-14.8%
South Atlantic	71.7	69.4	63.8	69.1	62.0	62.5	62.5	-12.8%
West North Central	80.1	79.5	79.8	80.4	78.3	75.9	70.2	-12.4%
West South Central	46.3	46.4	40.2	44.1	54.1	41.7	40.6	-12.3%

Table 2 shows the overall decline between 2000 and 2006 for the AGA sample of LDCs. As shown in Table 2, the decline in weather normal use per customer for the national sample is from 64.3 dekatherms in 2000 to 55.9 dekatherms per household in 2006. This represents a cumulative decline of 13.1 percent or an average decline of 2.2 percent per year. The decline since 2004 is even more dramatic, going from 61.9 dekatherms per household in 2004 to 55.9 dekatherms in 2006, nearly a 6 percent decline per year. As shown in this table, every region in the US experienced a decline in use per residential customer.

Section 2: Data

Sixteen AGA member companies provided data for this study. The companies supplied monthly data on residential consumption, average prices, number of customers, heating-degree data, and economic data. Most companies were able to provide a time series of data starting in 1992 and in some cases even into the 1980s. Three companies were unable to contribute data prior to 1999 for accounting or reorganization reasons. The remaining fifteen corporations comprise 46 local distribution companies. This represents more than 16 million customers and 28 percent of all residential customers nationwide.

Micro data on individual consumers is best suited for obtaining estimates of price elasticities. In rate case decisions and in internal LDC corporate strategy decisions however, the most relevant and useful piece of information is how the external forces that bombard it now impact the LDC. These external forces can vary from announcements by Presidents, changes in a competitors pricing, new gas appliance technologies, economic recessions, and gas price increases imposed by fuel surcharges. Since it is the impact of these forces on actual individual LDC's that is relevant, current data on consumption and prices collected by each individual LDC and aggregated at the individual LDC level is best suited to measure the impact of these external forces on a LDC in the current time period.

But data on a single LDC is often not enough information. The problem with using current data from only one LDC is that the number of observations will be quite small, and statistical reliability will be compromised. Instead of tens of thousands of observations on individual consumers, one may be left with 50 or 60 observations for any given LDC during the important winter season months. From a statistical reliability point of view then, it is important to obtain on many different individual LDCs, data that are collected by each individual LDC rather than using survey data collected by government agencies such as the EIA.

In this study, the breadth and depth of the data collected by the AGA has not to our knowledge been done before. The breadth of the data spans the entire US, covering 46 different LDCs. The depth of the data covers almost a decade or more for most of the companies. Therefore, this is a data set that is uniquely suited for the analysis of residential natural gas consumption in the US.

The number of LDCs in each of the nine Census Regions and the percent of total customers the sample covers for each Region is given in Table 3 below.

Table 3
Percent of Total Residential Customers Represented by the AGA Sample

Census Regions	Census Abbreviation	Number of participating LDCs	Coverage
East North Central	ENC	3	8%
East South Central	ESC	3	11%
Mid-Atlantic	MAC	6	45%
Mountain	MTN	5	42%
New England	NEC	8	50%
Pacific	PAC	5	39%
South Atlantic	SAC	5	17%
West North Central	WNC	3	20%
West South Central	WSC	8	32%

Section 3: Approaches to Estimating Short- and Long-run Price Elasticity of Demand

Economists often distinguish between a short-run response and long-run response when referring to how a household changes its natural gas usage when faced with price and income changes. The short-run response is defined as a household's natural gas demand response to natural gas price and income changes given their current capital stock of natural gas-using appliances and shell efficiency of the house. The long-run response is defined as a household's response to natural gas prices changes and income changes after the household has had time to change their stock of gas using appliances and house shell efficiency.

The idea behind the short-run and long-run responses to price changes is that when natural gas prices change, a household's short-run response is to alter the intensity with which they use their current stock of natural gas-using appliances. The long-run response to a change in natural gas prices is to alter the number and efficiency of natural gas using appliances, while at the same time changing the shell efficiency of the house.

A household's percentage change in natural gas demand per one percent change in natural gas price is called the price elasticity of natural gas demand. When this percentage change is computed for a household with a given stock of natural gas-using appliances and house shell efficiency, it is termed the short-run price elasticity of natural gas demand for that household. When this percentage change is computed over a time period long enough to allow a household to change it's stock and efficiencies of house and natural gas using appliances, it is termed the long-run price elasticity of natural gas demand for that household. A similar definition is given to short-run and long-run income elasticities of natural gas demand. If the natural gas demand equation is specified in logarithmic form, the price and income coefficients in a regression equation can be interpreted as the price and income elasticities.

A Dynamic Model of Capital Stock Choice and Natural Gas Demand

For a typical household, natural gas is demanded not for its own sake but for use in furnaces, appliances and the like. The household's accumulated energy saving "capital stock" is determined by income, habits, and past prices of fuels. Consequently, in any period, the household's demand for natural gas is a function of the current price, which influences how intensively the stock of equipment is used, and past prices, which influences the size and composition of that stock. A very simple structural model (Fisher and Kaysen, 1962) of these effects for a given household might be

Demand: $Y_t = \alpha + \beta_1 X_{t-1} + \lambda Z_t + \delta(K_t + E_t) + \varepsilon_t$ (1)

Equipment: $K_t = \gamma_1 X_{t-12} + \gamma_2 Z_t$ (2)

Efficiency: $E_t = \gamma_3 T_t,$ (3)

where Y_t is use per household of weather normalized Natural gas at time t, X_{t-1} is the real (base = \$2000) price of natural gas at time t - 1, Z_t is real (base = \$2000) household income at time t, K_t is capital stock with a given efficiency E_t at time t, T_t is a annual time trend to capture technological improvements in the efficiency of the capital stock, and ε_t is a random error term.

We use the real price lagged one period to capture the short-run response to a price change since the current price is not known until the gas bill arrives in the next billing period. Hence, a household's price-induced consumption adjustment during this period is based on last period's real gas price.

If equation (1) is in natural logarithms for Y_t, X_{t-1} and Z_t, the coefficient β_1 can be interpreted at the short-run price elasticity of natural gas demand. It measures the responsiveness of natural gas demand at time t to a change in natural gas price at time t-1 for a fixed capital stock of natural gas appliances K_t. In order to derive the long-run price elasticity of natural gas demand, we need to substitute equations (2) and (3) into equation (1) to get

$$Y_t = \alpha + \beta_1 X_{t-1} + \beta_2 X_{t-12} + \beta_3 Z_t + \beta_4 T_t + \varepsilon_t \quad (4)$$

If all variables except the time trend are in logarithms, then the coefficient on X_{t-1} is an estimate of the short-run price elasticity, the sum of the coefficients on all price variables is an estimate of the long-run price elasticity, and a negative coefficient (β_4) on the annual time trend is the decline in use per household of natural gas demand due to the adoption of newer and more efficient capital equipment. Although the length of the lag (t-12) on price in equation (2) to capture the capital stock adjustment process is somewhat arbitrary in this formulation, one can put other restrictions on the shape and length of the price and lagged price coefficients by using models such as the Koyck (1954) or Almon (1965) lag.

The coefficient β_1 in equation (4) gives the short-run price elasticity of natural gas demand. In equation (4) the coefficient β_2 captures capital stock adjustments that depend on past natural gas prices, while still allowing for an annual decline in use per customer that occurs because of a non-gas price induced rate of turnover of the capital stock to more energy efficient equipment. The sum of the coefficients $\beta_1 + \beta_2$ represents the long-run elasticity of natural gas demand. The coefficient β_4 on the time trend variable represents the pure turnover to newer more efficient capital equipment after subtracting out the gas price effect on this turnover rate captured by β_2. A negative coefficient (β_4) on the annual time trend is the annual decline in use per household of natural gas demand due to the natural adoption of newer and more efficient capital equipment.

Section 4: Empirical Results Using the AGA Sample of LDCs

The AGA study is interested in answering the following five questions:

(a) What are the changes in natural gas use per residential customer on a weather normalized basis since the year 2000?
(b) What is the short-run price elasticity of demand for residential natural gas customers?
(c) What is the long-run price elasticity of demand for residential natural gas customers?
(d) Has elasticity of natural gas demand changed since 2000?
(e) What is the annual reduction in natural gas usage per customer due to the natural replacement of old inefficient natural gas appliances with more energy efficient appliances; and the building of new homes with greater shell efficiencies compared to existing homes?

To answer these questions we estimated two variants of equations[10] (1) to (3). The first variant assumes the short-run price elasticity has a structural shift in the year 2000 and the second model assumes there is no shift in the short-run price elasticity in the year 2000 and beyond. These two equations are given below as (4a) and (4b), respectively:

$$Y_t = \alpha + \beta_1 X_{t-1} + \delta_{2000} X_{t-1} * D2000 + \beta_2 X_{t-12} + \beta_4 T_t + \varepsilon_t, \tag{4a}$$

$$Y_t = \alpha + \beta_1 X_{t-1} + \beta_2 X_{t-12} + \beta_4 T_t + \varepsilon_t, \tag{4b}$$

where all variables except the time trend are in natural logarithms and D2000 is a 0,1 indicator variable, equal to 0 if the time period is pre year 2000, and equal to 1 if the time period is the year 2000 or greater. The dependent variable Y_t in equations (4a) and (4b) is daily natural gas use per customer in month t.

In equation (4a), the coefficient δ_{2000} is a shift coefficient on the price elasticity given by β_1. The interpretation of δ_{2000} is that β_1 represents the price elasticity of natural gas demand for the period prior to the year 2000, and $\beta_1 + \delta_{2000}$ gives the price elasticity of natural gas demand for the year 2000 and beyond. So a negative δ_{2000} in equation (4a) would indicate that demand

[10] We omitted the income variable Z_t for the reasons outlined the Background Section of the paper. First, estimates of real disposable income (per customer, household, or person) are difficult to obtain at the LDC level, which is the building block of this research. Second, the services from natural gas is a normal good, one would expect a positive income effect, which should has been reflected in a positive trend in natural gas use per household. However, in our sample and specification, we observe a negative trend in use per household. The income series are highly positively autocorrelated and trend-like; see Figure 4. The income coefficient(s) were erratic and even negative. This is consistent with the declining use per household due to a naturally occurring and non-natural gas price-induced replacement of old inefficient appliances with new more efficient appliances. At present, we believe a time trend appropriately captures this new technology-induced naturally occurring adoption of more energy efficient appliances and improvements in housing shell efficiency or conservation.

has become more elastic since the year 2000. The coefficient β_2 captures capital stock adjustments that depend on past natural gas prices, while still allowing for an annual decline in use per customer that occurs because of a non-gas price induced rate of turnover of the capital stock to more energy efficient equipment. A negative coefficient (β_4) on the annual time trend is the annual decline in use per household of natural gas demand due to the adoption of newer and more efficient capital equipment.

The sum of the coefficients $\beta_1 + \delta_{2000}$ in equation (4a) gives the short-run price elasticity of natural gas demand in the post-2000 period, the sum of the coefficients $\beta_1 + \delta_{2000} + \beta_2$ represents the long-run elasticity of natural gas demand in the post-2000 period, and the coefficient β_4 on the time trend variable represents the pure turnover to newer more efficient capital equipment after subtracting out the gas price effect on this turnover rate captured by β_2.

The interpretation of the coefficients for equation (4b) is similar, except in equation (4b) the slope shift coefficient δ_{2000} for the short-run elasticity is constrained to zero.

Shrinkage Estimators

With a panel data set such at the one used in this study, there is always the question of whether to pool the data and obtain a single estimate of the parameters from the whole sample, or to estimate the equations separately for each cross-section. The implicit assumption in the fixed effects model is that the intercepts are different for each cross-section, but the slope coefficients are the same for all cross sections. This may not be a tenable assumption. Indeed, in practice the constancy of slope coefficients across different cross-section units is often rejected. This implies that the equations should be estimated separately for each cross-section rather than obtaining an overall pooled estimate.

The problem with the two usual estimation methods of either pooling the data or obtaining separate estimates for each cross section is that both are based on extreme assumptions. If the data are pooled as in the fixed effects model, it is assumed the coefficients are all the same. If separate estimates are obtained for each cross section, it is assumed that the coefficients are all different for each cross section. The truth probably lies somewhere in-between. The coefficients are not exactly the same, but there is some similarity between them.

One way to allow for some similarity among the slope coefficients without constraining them to be exactly the same is to assume the coefficients all come from a joint distribution with a common mean and non-zero covariance matrix. This suggests that the resulting coefficient estimates should be a weighted average of the overall pooled estimate and the separate time series estimates based on each cross section. Thus, each cross-section estimate is "shrunk" towards the overall pooled estimate.

For example, consider the model given by equation (4b) and using aggregate data on the nine census Regions to estimate the coefficients. This model is:

$$Y_{it} = \alpha_i + \beta_{i1}X_{i,t-1} + \beta_{i2}X_{i,t-12} + \beta_{i4}T_{it} + \varepsilon_{it},$$

i = 1,2,3,…..,N (N = 9, Census Regions)

t = 1,2,3,…..T (Time Periods)

The implicit assumption in the fixed effects model is that we retain the i subscript on α but remove the subscript on the β's. The implicit assumption if we run separate regressions for each cross section is that the i subscript is retained on both α and all the β's.

A shrinkage estimator sometimes suggested is the Stein rule estimator defined by:

$$\tilde{\beta}_i = (1 - \frac{c}{F})\hat{\beta}_i + (\frac{c}{F})\hat{\beta}_p, \tag{5}$$

where $\tilde{\beta}_i$ is the shrinkage estimator, $\hat{\beta}_i$ is the separate ordinary least square (OLS) estimate from each time series, $\hat{\beta}_p$ is the fixed effects pooled estimator. The F is the F-test statistic used to test the null hypothesis that all the β's are equal across each cross-section. The constant c is given by

$$c = \frac{(N-1)K-2}{NT-NK+2}, \tag{6}$$

and K = 3 and N = 9 in equation 4b.

We will present the shrinkage estimates for the nine Census Regions below when we discuss the regional results.

National Results

We estimated equations (4a) and (4b) for each of the LDCs using OLS on monthly data for the winter season months[11] of October to March. These results are given in the last column of Tables 4 and 5. The average of these individual LDC estimates indicates that the short-run price elasticity of natural gas demand is –0.11, the short-run price elasticity shift in post 2000 is positive but for all practical purposes is zero, the long-run price elasticity given by $\beta_1 + \beta_2$ is –0.20, and the natural annual rate of decline[12] in use per customer due to the adoption of new gas appliance capital equipment is 0.8 percent per year.

[11] Although the dependent variables used to estimate the model are only for the months of October to March, the lagged independent real price variables represent actual lagged calendar month real prices. Hence, for the observation on weather normal use per household in October, the lagged real price (t-1) will be the September real price. Similarly, the lagged real price variable (t-12) for an October observation will be the real price of natural gas in October of the previous calendar year.

[12] If the coefficient on the time trend (T) in equation 4a and 4b is negative, it means there is an annual decline in natural gas weather normal use per customer. The percent decline will be equal to the coefficient on the time trend multiplied by 100%. For example, in Table 4 for the National sample, we see the coefficient on the

We also estimated equations (4a) and (4b) in a pooled regression where each LDC is given company specific intercepts for each of the six winter months in the sample, but all the slope coefficients were assumed to be the same across all LDCs. These estimates are shown in column two of Tables 4 and 5 below. Based on these estimates, we see the short-run price elasticity is –0.09, there is neither a practical nor a statistically significant[13] shift in the elasticity in post 2000, the long-run price elasticity given by $\beta_1 + \beta_2$ is –0.18, and the natural annual rate of decline due to the adoption of new capital equipment is 1.0 percent per year in Table 5. Note the results did not indicate a change in price elasticity in the post-2000 time period in Table 4.

Although we did not obtain Iterative Bayes shrinkage estimates for each individual LDC, based on our experience we expect the average of these shrinkage estimates to fall between the pooled with LDC dummy results and the average of the individual OLS LDC regression results. We conclude therefore, that the short-run price elasticity of natural gas for the national sample lies between –0.09 and –0.10, the long-run price elasticity is between –0.18 and -0.20, and the natural annual rate of decline due to the adoption of new gas appliance capital equipment is between 0.7 percent and 1.0 percent per year. This natural annual rate of decline is consistent with a finding by an earlier AGA report on the decline in weather adjusted gas use per customer. See the AGA report "2004 AGA Energy Analysis: Patterns in Residential Natural Gas Consumption, 1980-2001".

From Table 5 we see the total annual percent decline in use per household one year after a ten percent price increase[14] is between 2.7 percent and 2.8 percent.

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time trend variable is –0.011 for the pooled with LDC dummy variables model. This means there is a 0.011 x 100% = 1.1% annual decline in natural gas weather normal use per customer.

[13] We base this conclusion on the statistical significance of the coefficient on the variable "Ln(Price$_{t-1}$)*D2000" in Table 4. See Appendix D for a discussion of the meaning of the term "statistical significance" in statistical hypothesis testing.

[14] Since both the dependent and independent variables are in natural logarithms in equations (4a) and (4b), the coefficients on the two price variables are price elasticities, which give the percent decline in use per customer quantity demanded per one percent increase in price. Similarly, a negative coefficient on the time trend gives the proportionate decline in use per customer per one-year increase in time. To get the percent decline in use per customer one year after a 10 percent increase in price, we have:

percent decline = 10*coefficient on P_{t-1} + 10*coefficient P_{t-12} + 100*coefficient on time trend.

Table 4
National Elasticity Model Estimates for Equation (4a)
(t-stats in parentheses)

Variable	**Pooled With LDC Fixed Effects Dummies**	**Average of Individual LDC OLS Estimates**
$Ln(Price_{t-1})$	-0.09 (-6.46)	-0.10
$Ln(Price_{t-1})$*D2000	0.0036 (0.97)	-0.0003
$Ln(Price_{t-12})$	-0.09 (-5.93)	-0.09
Annual Time Trend	-0.011 (-9.47)	-0.008
$Rbar^2$	0.97	
Std. Error of Regression	0.115	
Mean of the Dependent Variable	1.183	
AIC	-1.403	
Schwarz Criterion	-0.906	
Number of Observations	3023	41

Table 5
National Elasticity Model Estimates for Equation (4b)
(t-stats in parentheses)

Variable	**Pooled With LDC Fixed Effects Dummies**	**Average of Individual LDC OLS Estimates**
$Ln(Price_{t-1})$	-0.09 (-6.44)	-0.10
$Ln(Price_{t-12})$	-0.09 (-5.92)	-0.10
Annual Time Trend	-0.010 (-12.25)	-0.007
$Rbar^2$	0.97	
Std. Error of Regression	0.115	
Mean of the Dependent Variable	1.183	
AIC	-1.403	
Schwarz Criterion	-0.908	
Number of Observations	3023	41

Regional Results

Figure 5 shows the normalized consumption of natural gas use per household by U.S. Census region for the AGA sample. There appears to be a decline over much of the sample in all nine Census Regions.

Figure 5
Regional Weather Normal Consumption per Customer
(Dth)

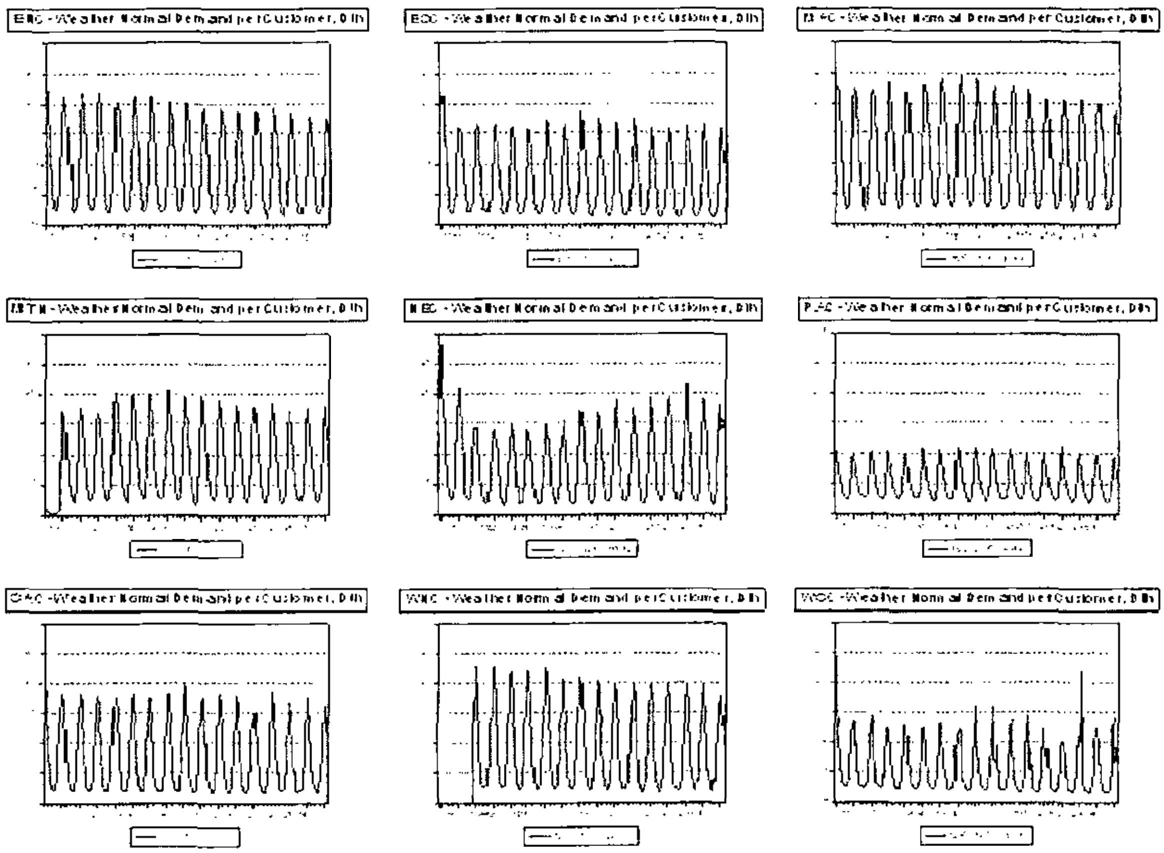
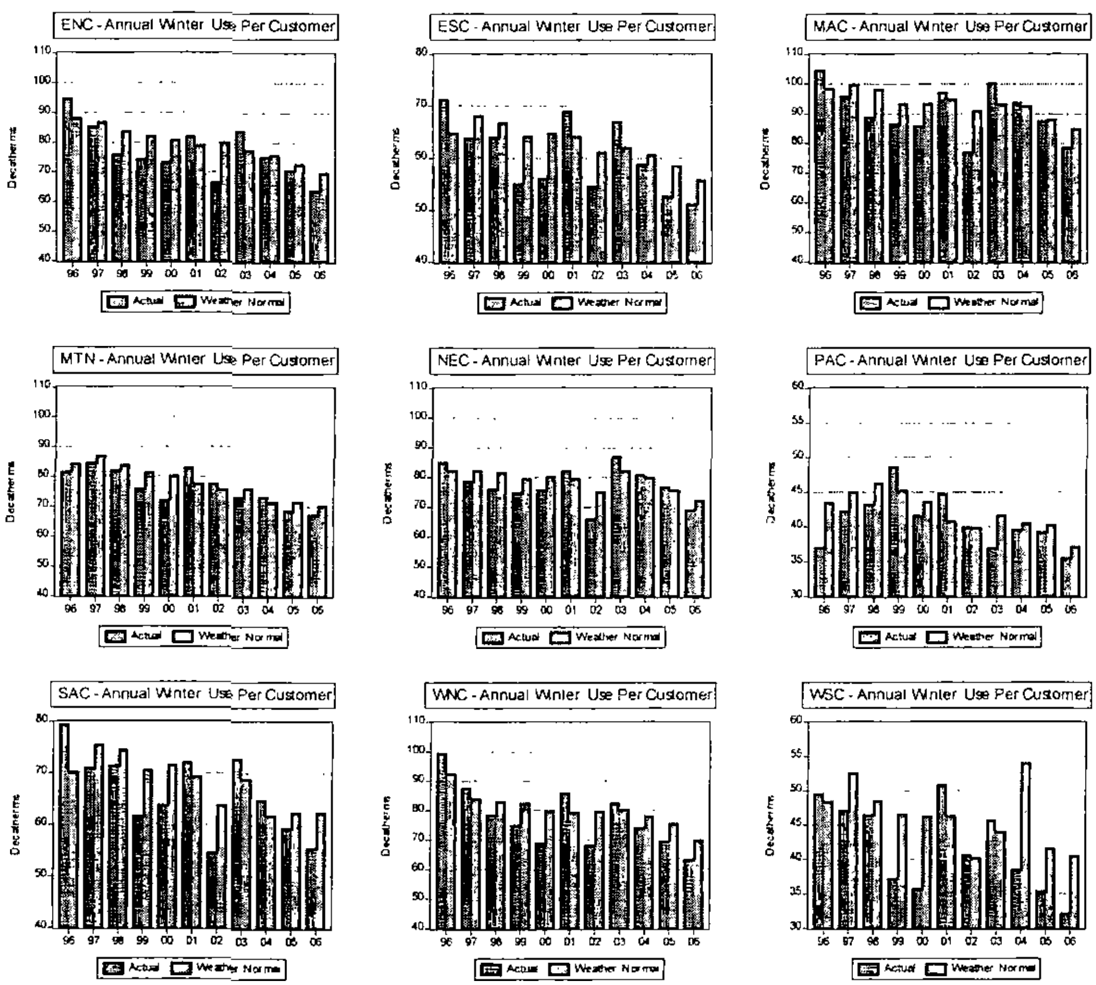


Figure 6 shows the actual and normalized winter season consumption for natural gas per customer by U.S. Census region for the AGA sample. Again, there is a decline over much of the sample in all regions.

Figure 6
Regional Annual Winter Use per Customer
(Dth)



Regional OLS Estimates

Tables 6A and 6B to Tables 14A and 14B give the estimates of equations (4a) and (4b) for each of the nine census Regions using data on the individual LDCs in each of the respective regions. For the most part, the regional results are similar to the national results, with some differences noted below.

East North Central Region

The regression output for the ENC Region is given in Tables 6A and 6B. In Table 6A, we estimate neither a practical nor a statistically significant shift in the short-run elasticity in the post 2000 year period. According to equation (4b) in Table 6B, the short-run elasticity is between -0.08 and –0.12, and is statistically significantly different from zero in the pooled model. The long-run elasticity is between –0.22 and –0.27. In the pooled regression, we observe a statistically significant annual declining rate of weather normal use per household demand of 1.0 percent. From Table 6B we see the total annual percent decline in use per customer one year after a ten percent price increase is between 2.8 percent and 3.2 percent, which is close to the annual percent decline in the national sample.

Table 6A
ENC Regional Elasticity Model Estimates for Equation (4a)
(t-stats in parentheses)

Variable	Pooled With LDC Fixed Effects Dummies	Average of Individual LDC OLS Estimates
$Ln(Price_{t-1})$	-0.09 (-3.02)	-0.12
$Ln(Price_{t-1})$*D2000	0.005 (0.51)	-0.006
$Ln(Price_{t-12})$	-0.14 (-3.63)	-0.16
Annual Time Trend	-0.011 (-3.92)	0.0013
$Rbar^2$	0.99	
Std. Error of Regression	0.064	
Mean of the Dependent Variable	1.319	
AIC	-2.569	
Schwarz Criterion	-2.200	
Number of Observations	195	3

Table 6B
ENC Regional Elasticity Model Estimates for Equation (4b)
(t-stats in parentheses)

Variable	Pooled With LDC Fixed Effects Dummies	Average of Individual LDC OLS Estimates
$Ln(Price_{t-1})$	-0.08 (-3.02)	-0.12
$Ln(Price_{t-12})$	-0.14 (-3.66)	-0.15
Annual Time Trend	-0.010 (-4.57)	-0.001
$Rbar^2$	0.99	
Std. Error of Regression	0.063	
Mean of the Dependent Variable	1.319	
AIC	-2.578	
Schwarz Criterion	-2.225	
Number of Observations	195	3

East South Central Region

The regression output for the ESC Region is given in Tables 7A and 7B. In Table 7A, we estimate neither a practical nor a statistically significant shift in the short-run elasticity in the post 2000 year period. According to equation (4b) in Table 7B, the short-run elasticity is -0.06 when computed from the average of the individual LDC results and for all practical purposes is zero in the pooled regression. The long-run elasticity is between –0.01 and –0.12. In the pooled regression, we observe a statistically significant annual declining rate of weather normal use per household demand of 2.0 percent. From Table 7B we see the total annual percent decline in use per customer one year after a ten percent price increase is between 2.0 percent and 2.1 percent, which is slightly lower than the annual percent decline in the national sample.

Table 7A
ESC Regional Elasticity Model Estimates for Equation (4a)
(t-stats in parentheses)

Variable	Pooled With LDC Fixed Effects Dummies	Average of Individual LDC OLS Estimates
$Ln(Price_{t-1})$	-0.007 (-0.12)	-0.08
$Ln(Price_{t-1})$*D2000	0.0169 (1.09)	0.02
$Ln(Price_{t-12})$	-0.03 (-0.47)	-0.06
Annual Time Trend	-0.023 (-4.92)	-0.016
$Rbar^2$	0.97	
Std. Error of Regression	0.129	
Mean of the Dependent Variable	1.013	
AIC	-1.167	
Schwarz Criterion	-0.835	
Number of Observations	227	3

Table 7B
ESC Regional Elasticity Model Estimates for Equation (4b)
(t-stats in parentheses)

Variable	Pooled With LDC Fixed Effects Dummies	Average of Individual LDC OLS Estimates
$Ln(Price_{t-1})$	0.012 (0.23)	-0.06
$Ln(Price_{t-12})$	-0.026 (-0.44)	-0.06
Annual Time Trend	-0.020 (-5.33)	-0.012
$Rbar^2$	0.97	
Std. Error of Regression	0.129	
Mean of the Dependent Variable	1.013	
AIC	-1.170	
Schwarz Criterion	-0.853	
Number of Observations	227	3

Middle Atlantic Region

The regression output for the MAC Region is given in Tables 8A and 8B. In Table 8A, we estimate neither a practical nor a statistically significant shift in the short-run elasticity in the post 2000 year period. According to equation (4b) in Table 8B, the short-run elasticity is -0.13 when computed from the average of the individual LDC results, and is –0.10 in the pooled regression. The long-run elasticity is between –0.18 and –0.20. In the pooled regression we observe a statistically significant annual declining rate of weather normal use per household demand of 1.3 percent. Table 8B we see the total annual percent decline in use per customer one year after a ten percent price increase is between 2.5 percent and 3.3 percent, which is close to the annual percent decline in the national sample.

Table 8A
MAC Regional Elasticity Model Estimates for Equation (4a)
(t-stats in parentheses)

Variable	**Pooled With LDC Fixed Effects Dummies**	**Average of Individual LDC OLS Estimates**
$Ln(Price_{t-1})$	-0.11 (-2.35)	-0.12
$Ln(Price_{t-1})$*D2000	0.01 (1.21)	0.005
$Ln(Price_{t-12})$	-0.09 (-1.70)	-0.04
Annual Time Trend	-0.015 (-5.21)	-0.009
$Rbar^2$	0.97	
Std. Error of Regression	0.100	
Mean of the Dependent Variable	1.508	
AIC	-1.681	
Schwarz Criterion	-1.325	
Number of Observations	465	6

Table 8B
MAC Regional Elasticity Model Estimates for Equation (4b)
(t-stats in parentheses)

Variable	**Pooled With LDC Fixed Effects Dummies**	**Average of Individual LDC OLS Estimates**
$Ln(Price_{t-1})$	-0.10 (-2.24)	-0.13
$Ln(Price_{t-12})$	-0.10 (-1.77)	-0.05
Annual Time Trend	-0.013 (-5.80)	-0.007
$Rbar^2$	0.97	
Std. Error of Regression	0.100	
Mean of the Dependent Variable	1.508	
AIC	-1.682	
Schwarz Criterion	-1.335	
Number of Observations	465	6

Mountain Region

The regression output for the MTN Region is given in Tables 9A and 9B. In Table 9A, we estimate shift of –0.035 in the short-run elasticity in post 2000 and beyond. According to equation (4b) in Table 9B, the short-run elasticity is -0.11 when computed from the average of the individual LDC results and is –0.07 and statistically significant in the pooled regression. The long-run elasticity is between –0.10 and –0.19. In the pooled regression we observe a statistically significant annual declining rate of weather normal use per household demand of 0.9 percent. In Table 9B we see the total annual percent decline in use per customer one year after a ten percent price increase is between 1.9 percent and 2.8 percent, which in the pooled regression (1.9 percent) is slightly lower than the annual percent decline in the national sample.

Table 9A
MTN Regional Elasticity Model Estimates for Equation (4a)
(t-stats in parentheses)

Variable	Pooled With LDC Fixed Effects Dummies	Average of Individual LDC OLS Estimates
$Ln(Price_{t-1})$	-0.014 (-0.52)	-0.08
$Ln(Price_{t-1})$*D2000	-0.035 (-4.19)	-0.02
$Ln(Price_{t-12})$	-0.018 (-0.75)	-0.07
Annual Time Trend	-0.004 (-2.47)	-0.007
$Rbar^2$	0.99	
Std. Error of Regression	0.060	
Mean of the Dependent Variable	1.262	
AIC	-2.700	
Schwarz Criterion	-2.353	
Number of Observations	298	4

Table 9B
MTN Regional Elasticity Model Estimates for Equation (4b)
(t-stats in parentheses)

Variable	Pooled With LDC Fixed Effects Dummies	Average of Individual LDC OLS Estimates
$Ln(Price_{t-1})$	-0.07 (-2.73)	-0.11
$Ln(Price_{t-12})$	-0.03 (-1.33)	-0.08
Annual Time Trend	-0.009 (-6.22)	-0.009
$Rbar^2$	0.99	
Std. Error of Regression	0.060	
Mean of the Dependent Variable	1.262	
AIC	-2.644	
Schwarz Criterion	-2.309	
Number of Observations	298	4

New England Region

The regression output for the NEC Region is given in Tables 10A and 10B. In Table 10A, we estimate a statistically significant shift in the short-run price elasticity in the post 2000 year period, although in this case it is a shift that lowers the short-run price elasticity and is not practically significant with only 0.015 decrease. According to equation (4b) in Table 10B, the short-run elasticity is -0.08 when computed from the average of the individual LDC results and is also –0.08 and statistically significant in the pooled regression. The long-run elasticity is between –0.25 and –0.28. In the pooled regression we observe a statistically significant annual declining rate of weather normal use per customer demand of 0.4 percent. Table 10B we see the total annual percent decline in use per customer one year after a ten percent price increase is between 2.9 percent and 3.0 percent, which is close to the annual percent decline in the national sample.

Table 10A
NEC Regional Elasticity Model Estimates for Equation (4a)
(t-stats in parentheses)

Variable	Pooled With LDC Fixed Effects Dummies	Average of Individual LDC OLS Estimates
Ln($Price_{t-1}$)	-0.09 (-3.34)	-0.09
Ln($Price_{t-1}$)*D2000	0.015 (2.44)	0.01
Ln($Price_{t-12}$)	-0.17 (-5.06)	-0.20
Annual Time Trend	-0.008 (-4.24)	-0.005
$Rbar^2$	0.97	
Std. Error of Regression	0.096	
Mean of the Dependent Variable	1.307	
AIC	-1.767	
Schwarz Criterion	-1.413	
Number of Observations	660	8

Table 10B
NEC Regional Elasticity Model Estimates for Equation (4b)
(t-stats in parentheses)

Variable	Pooled With LDC Fixed Effects Dummies	Average of Individual LDC OLS Estimates
Ln($Price_{t-1}$)	-0.08 (-2.86)	-0.08
Ln($Price_{t-12}$)	-0.17 (-5.00)	-0.20
Annual Time Trend	-0.004 (-3.73)	-0.002
$Rbar^2$	0.97	
Std. Error of Regression	0.097	
Mean of the Dependent Variable	1.307	
AIC	-1.760	
Schwarz Criterion	-1.412	
Number of Observations	660	8

Pacific Region

The regression output for the PAC Region is given in Tables 11A and 11B. In Table 11A, we estimate a statistically significant shift in the short-run price elasticity in the post 2000 year period, although from a practical point of view this decline is small with an impact of only 0.02. According to equation (4b) in Table 11B, the short-run elasticity is -0.07 when computed from the average of the individual LDC results and is also –0.07 and statistically significant in the pooled regression. The long-run elasticity is between –0.12 and –0.15. In the pooled regression we observe a statistically significant annual declining rate of weather normal use per customer of 0.8 percent. In Table 11B, we see the total annual percent decline in use per customer one year after a ten percent price increase of 2.0 percent, which is lower than the annual percent decline in the national sample.

Table 11A
PAC Regional Elasticity Model Estimates for Equation (4a)
(t-stats in parentheses)

Variable	Pooled With LDC Fixed Effects Dummies	Average of Individual LDC OLS Estimates
$Ln(Price_{t-1})$	-0.04 (-1.29)	-0.03
$Ln(Price_{t-1})$*D2000	-0.02 (-2.13)	-0.02
$Ln(Price_{t-12})$	-0.05 (-1.66)	-0.07
Annual Time Trend	-0.005 (-1.96)	-0.004
$Rbar^2$	0.98	
Std. Error of Regression	0.072	
Mean of the Dependent Variable	0.910	
AIC	-2.314	
Schwarz Criterion	-1.929	
Number of Observations	258	4

Table 11B
PAC Regional Elasticity Model Estimates for Equation (4b)
(t-stats in parentheses)

Variable	Pooled With LDC Fixed Effects Dummies	Average of Individual LDC OLS Estimates
$Ln(Price_{t-1})$	-0.07 (-2.61)	-0.07
$Ln(Price_{t-12})$	-0.05 (-1.83)	-0.08
Annual Time Trend	-0.008 (-3.87)	-0.005
$Rbar^2$	0.98	
Std. Error of Regression	0.073	
Mean of the Dependent Variable	0.910	
AIC	-2.302	
Schwarz Criterion	-1.931	
Number of Observations	258	4

South Atlantic Region

The regression output for the SAC Region is given in Tables 12A and 12B. In Table 12A, we estimate neither a practical nor a statistically significant shift in the short-run elasticity in the post 2000 year period. According to equation (4b) in Table 12B, the short-run elasticity is -0.11 when computed from the average of the individual LDC results and is -0.12 and statistically significant in the pooled regression. The long-run elasticity is between -0.24 and -0.29. In the pooled regression we observe a statistically significant annual declining rate of weather normal use per customer of 0.8 percent. Table 12B, we see the total annual percent decline in use per customer one year after a ten percent price increase is between 3.4 percent to 3.7 percent, which is higher than the annual percent decline in the national sample.

Table 12A
SAC Regional Elasticity Model Estimates for Equation (4a)
(t-stats in parentheses)

Variable	Pooled With LDC Fixed Effects Dummies	Average of Individual LDC OLS Estimates
$Ln(Price_{t-1})$	-0.115 (-3.09)	-0.10
$Ln(Price_{t-1})$*D2000	-0.002 (-0.15)	-0.005
$Ln(Price_{t-12})$	-0.17 (-4.16)	-0.13
Annual Time Trend	-0.008 (-2.58)	-0.009
$Rbar^2$	0.97	
Std. Error of Regression	0.109	
Mean of the Dependent Variable	1.218	
AIC	-1.509	
Schwarz Criterion	-1.146	
Number of Observations	280	4

Table 12B
SAC Regional Elasticity Model Estimates for Equation (4b)
(t-stats in parentheses)

Variable	Pooled With LDC Fixed Effects Dummies	Average of Individual LDC OLS Estimates
$Ln(Price_{t-1})$	-0.12 (-3.30)	-0.11
$Ln(Price_{t-12})$	-0.17 (-4.18)	-0.13
Annual Time Trend	-0.008 (-3.76)	-0.010
$Rbar^2$	0.97	
Std. Error of Regression	0.108	
Mean of the Dependent Variable	1.218	
AIC	-1.516	
Schwarz Criterion	-1.166	
Number of Observations	280	4

West North Central Region

The regression output for the WNC Region is given in Tables 13A and 13B. In Table 13B, we estimate a statistically significant shift in the short-run price elasticity in the post 2000 year period, although it is a shift that lowers the short-run price elasticity by only–0.014 and from a practical point of view is not significant. According to equation (4b) in Table 13B, the short-run elasticity is -0.08 when computed from the average of the individual LDC results and is –0.09 and statistically significant in the pooled regression. The long-run elasticity is between -0.13 and -0.15. In the pooled regression we observe a statistically significant annual declining rate of weather normal use per customer of 1.1 percent. In Table 13B we see the total annual percent decline in use per customer one year after a ten percent price increase is between 2.5 percent and 2.6 percent, which is close to the annual percent decline in the national sample.

Table 13A
WNC Regional Elasticity Model Estimates for Equation (4a)
(t-stats in parentheses)

Variable	**Pooled With LDC Fixed Effects Dummies**	**Average of Individual LDC OLS Estimates**
Ln($Price_{t-1}$)	-0.10 (-5.19)	-0.09
Ln($Price_{t-1}$)*D2000	0.014 (1.98)	0.01
Ln($Price_{t-12}$)	-0.06 (-2.62)	-0.05
Annual Time Trend	-0.014 (-5.48)	-0.014
$Rbar^2$	0.99	
Std. Error of Regression	0.048	
Mean of the Dependent Variable	1.314	
AIC	-3.141	
Schwarz Criterion	-2.765	
Number of Observations	190	3

Table 13B
WNC Regional Elasticity Model Estimates for Equation (4b)
(t-stats in parentheses)

Variable	**Pooled With LDC Fixed Effects Dummies**	**Average of Individual LDC OLS Estimates**
Ln($Price_{t-1}$)	-0.09 (-4.78)	-0.08
Ln($Price_{t-12}$)	-0.06 (-2.69)	-0.05
Annual Time Trend	-0.011 (-5.35)	-0.012
$Rbar^2$	0.99	
Std. Error of Regression	0.048	
Mean of the Dependent Variable	1.314	
AIC	-3.129	
Schwarz Criterion	-2.770	
Number of Observations	190	3

West South Central Region

The regression output for the WSC Region is given in Tables 14A and 14B. In Table 14A, we estimate neither a practical nor a statistically significant shift in the short-run elasticity in the post 2000 year period. According to equation (4b) in Table 14B, the short-run elasticity is -0.14 when computed from the average of the individual LDC results and is – 0.13 and statistically significant in the pooled regression. The long-run elasticity is -0.16 in both the pooled regression and when computed as the average of the individual LDC OLS estimates. In the pooled regression we observe a statistically significant annual declining rate of weather normal use per customer of 1.6 percent. In Table 14B, we see the total annual percent decline in use per customer one year after a ten percent price increase is between 2.9 percent and 3.2 percent, which is close to the annual percent decline in the national sample.

Table 14A
WSC Regional Elasticity Model Estimates for Equation (4a)
(t-stats in parentheses)

Variable	Pooled With LDC Fixed Effects Dummies	Average of Individual LDC OLS Estimates
$Ln(Price_{t-1})$	-0.12 (-1.71)	-0.13
$Ln(Price_{t-1})$*D2000	-0.008 (-0.48)	-0.009
$Ln(Price_{t-12})$	-0.03 (-0.40)	-0.02
Annual Time Trend	-0.015 (-2.52)	-0.01
$Rbar^2$	0.92	
Std. Error of Regression	0.198	
Mean of the Dependent Variable	0.722	
AIC	-0.318	
Schwarz Criterion	0.048	
Number of Observations	450	6

Table 14B
WSC Regional Elasticity Model Estimates for Equation (4b)
(t-stats in parentheses)

Variable	Pooled With LDC Fixed Effects Dummies	Average of Individual LDC OLS Estimates
$Ln(Price_{t-1})$	-0.13 (-1.87)	-0.14
$Ln(Price_{t-12})$	-0.03 (-0.40)	-0.02
Annual Time Trend	-0.016 (-3.79)	-0.013
$Rbar^2$	0.92	
Std. Error of Regression	0.198	
Mean of the Dependent Variable	0.722	
AIC	-0.322	
Schwarz Criterion	0.034	
Number of Observations	450	6

Shrinkage Estimates

We also estimate equation (4a) and (4b) with a type of shrinkage estimator, time series data on the Nine Census Regions, aggregated over the respective LDCs in each region. We will apply the Stein rule estimator discussed above in the sub-section on Shrinkage Estimators. The advantage of shrinkage estimators is that they allow for some similarity among the slope coefficients without constraining them to be exactly the same as in the case of pooled estimates.

Using aggregate regional data, Table 15 below gives the pooled fixed effects estimates of equation (4b) and the average of the individual regional coefficient estimates. These estimates are similar to the estimates presented in Table 5B based on individual LDC data. Note that in Table 5B the impact of a 10 percent price increase was a 2.8 percent decline in use per customer one year later. Using regional aggregate data we see the impact of a ten percent price increase is a similar 2.9 percent decline in use per customer one year later.

Table 15
Regional Elasticity Model Estimates using aggregate data for Equation (4b)
(t-stats in parentheses)

Variable	Pooled With Regional Dummies	Average of Individual Regions
$Ln(Price_{t-1})$	-0.12 (-3.4)	-0.10
$Ln(Price_{t-12})$	-0.06 (-1.63)	-0.08
Annual Time Trend	-0.011 (-3.72)	-0.011
$Rbar^2$	0.98	
Std. Error of Regression	0.094	
Mean of the Dependent Variable	12.14	
AIC	-1.79	
Schwarz Criterion	-1.34	
Number of Observations	540	9

Tables 16 to 24 below present the Stein Shrinkage coefficient estimates of equation (4b) using aggregate regional data. In this case, the shrinkage results are very close to the individual OLS estimates for each Region since F = 0.86 and c = 0.04 since T=60. Plugging into equation (5) we get:

$$\tilde{\beta}_i = 0.95\hat{\beta}_i + 0.05\hat{\beta}_p, \tag{7}$$

East North Central Region

Table 16 shows the shrinkage estimates of the short-run and long-run elasticity derived from equation (7) for the ENC Region is -0.047 and -0.122, and the annual time trend shows a declining annual rate of 1.7 percent.

Table 16

ENC - Regional Model Elasticity Estimates with Aggregate Data for Equation 4b

Variable	OLS on Individual Regional Data		Shrinkage Estimator
	Estimate	t-stat	
$\mathbf{Ln(Price_{t-1})}$	-0.043	-0.349	-0.047
$\mathbf{Ln(Price_{t-12})}$	-0.076	-0.544	-0.075
Annual Time Trend	-0.017	-1.530	-0.017
Number of Observations	60		

East South Central Region

Table 17 shows the shrinkage estimates of the short-run and long-run elasticity derived from equation (7) for East South Central is -0.030 and -0.085, and the annual time trend shows a declining annual rate of 1.8 percent.

Table 17

ESC – Regional Model Elasticity Estimates with Aggregate Data for Equation 4b

Variable	OLS on Individual Regional Data		Shrinkage Estimator
	estimate	t-stat	
$\mathbf{Ln(Price_{t-1})}$	-0.026	-0.180	-0.030
$\mathbf{Ln(Price_{t-12})}$	-0.055	-0.337	-0.055
Annual Time Trend	-0.018	-1.270	-0.018
Number of Observations	60		

Middle Atlantic Region

Table 18 shows the shrinkage estimates of the short-run and long-run elasticity derived from equation (7) for the Middle Atlantic Region is -0.164 and -0.46, and the annual time trend shows a declining annual rate of 0.6 percent.

Table 18

MAC - Regional Model Elasticity Estimates with Aggregate Data for Equation 4b

Variable	OLS on Individual Regional Data		Shrinkage Estimator
	estimate	t-stat	
Ln($Price_{t-1}$)	-0.167	-1.198	-0.164
Ln($Price_{t-12}$)	-0.309	-1.887	-0.296
Annual Time Trend	0.006	0.633	0.006
Number of Observations	60		

Mountain Region

Table 19 shows the shrinkage estimates of the short-run and long-run elasticity derived from equation (7) for the Mountain Region is -0.058 and -0.076, and the annual time trend shows a declining annual rate at of 2.22 percent.

Table 19

MTN - Regional Model Elasticity Estimates with Aggregate Data for Equation 4b

Variable	OLS on Individual Regional Data		Shrinkage Estimator
	estimate	t-stat	
Ln($Price_{t-1}$)	-0.055	-0.675	-0.058
Ln($Price_{t-12}$)	0.022	0.263	0.018
Annual Time Trend	-0.022	-2.767	-0.022
Number of Observations	60		

New England Region

Table 20 shows the shrinkage estimates of the short-run and long-run elasticity derived from equation (7) for the New England Region is -0.074 and -0.364, and the annual time trend shows a declining annual rate of 0.3 percent.

Table 20

NEC - Regional Model Elasticity Estimates with Aggregate Data for Equation 4b

Variable	OLS on Individual Regional Data		Shrinkage Estimator
	Estimate	t-stat	
Ln(Price$_{t-1}$)	-0.072	-0.537	-0.074
Ln(Price$_{t-12}$)	-0.302	-1.767	-0.290
Annual Time Trend	-0.003	-0.384	-0.003
Number of Observations	60		

Pacific Region

Table 21 shows the shrinkage estimates of the short-run and long-run elasticity derived from equation (7) for the Pacific Region is -0.089 and -0.179, and the annual time trend shows a declining annual rate of 1.0 percent.

Table 21

PAC - Regional Model Elasticity Estimates with Aggregate Data for Equation 4b

Variable	OLS on Individual Regional Data		Shrinkage Estimator
	estimate	t-stat	
Ln(Price$_{t-1}$)	-0.087	-1.066	-0.089
Ln(Price$_{t-12}$)	-0.092	-1.194	-0.090
Annual Time Trend	-0.010	-1.157	-0.010
Number of Observations	60		

South Atlantic Region

Table 22 shows the shrinkage estimates of the short-run and long-run elasticity derived from equation (7) for the South Atlantic Region is -0.182 and -0.327, and the annual time trend shows a declining annual rate of 1.9 percent.

Table 22

SAC - Regional Model Elasticity Estimates with Aggregate Data for Equation 4b

Variable	OLS on Individual Regional Data		Shrinkage Estimator
	estimate	t-stat	
Ln($Price_{t-1}$)	-0.185	-1.747	-0.182
Ln($Price_{t-12}$)	0.156	1.371	0.145
Annual Time Trend	-0.019	-1.989	-0.019
Number of Observations	60		

West North Central Region

Table 23 shows the shrinkage estimates of the short-run and long-run elasticity derived from equation (7) for the West North Central Region is -0.088 and -0.120, and the annual time trend shows a declining annual rate of 0.90 percent.

Table 23

WNC - Regional Model Elasticity Estimates with Aggregate Data for Equation 4b

Variable	OLS on Individual Regional Data		Shrinkage Estimator
	estimate	t-stat	
Ln($Price_{t-1}$)	-0.086	-0.966	-0.088
Ln($Price_{t-12}$)	-0.031	-0.355	-0.032
Annual Time Trend	-0.009	-1.053	-0.009
Number of Observations	60		

West South Central Region

Table 24 shows the shrinkage estimates of the short-run and long-run elasticity derived from equation (7) for the West South Central Region is -0.209 and -0.258, and the annual time trend shows a declining annual rate of 1.1 percent.

Table 24

WSC - Regional Model Elasticity Estimates with Aggregate Data for Equation 4b

Variable	OLS on Individual Regional Data		Shrinkage Estimator
	estimate	t-stat	
Ln(Price$_{t-1}$)	-0.214	-1.719	-0.209
Ln(Price$_{t-12}$)	-0.049	-0.368	-0.049
Annual Time Trend	-0.011	-0.946	-0.011
Number of Observations	60		

Our overall assessment of the regional models is that individual coefficients vary[15] greatly across the nine regional models and are often insignificant. This is due to the small sample sizes relative to the national sample, multicollinearity between the two lagged prices, and to some extent multicollinearity with the time trend as well. Yet the average impact of a 10 percent price increase on use per household is remarkably stable and negative across all nine Census Regions in the pooled regressions using individual LDC data. This total decline after a 10 percent price increase for the nine Census Regions is roughly centered on the national impact of a 2.8 percent decline in weather normal use per customer; with the Mountain Region having a 1.9 percent impact at the low end of the range and the South Atlantic Region having a 3.7 percent impact at the high end of the range.

[15] There may be differences in shell efficiency and new home construction and LDC sponsored energy conservations programs across regions that would lead to some heterogeneity in coefficient estimates across the nine census regions. We feel the iterative Bayes shrinkage estimator could remove much of the inconsistency between the national and regional coefficient estimates in a follow up study.

Section 5: Summary of Results and Policy Implications

This research project was initiated to examine the decline in residential natural gas consumption since 2000 and to determine whether there had been a change in the response by residential consumers to higher (and more volatile) natural gas prices. The data that were collected and analyzed support two important findings and a general rule of thumb. This rule appears to capture consumers' winter price sensitive consumption behavior reasonably well across the LDCs and Census regions.

First, consumption is strongly influenced by seasonal heating needs, response to price change, and the efficiency changes in appliances and home shell efficiency coupled with conservation behavior by consumers. While the separate efficiency and conservation effects due to appliance and housing shell turnover are difficult to disentangle in the current sample, they appear to be discernable from the price effects. Table 25 gives a summary of the national and separate regional price and naturally occurring time trend effects found in this study.

Second, we could not find evidence supporting an appreciable change in the short-run price elasticity of natural gas consumption in the post year 2000 period.

Table 25
Summary of National and Regional
Natural Gas Price Estimates[16]

Region	Short-run elasticity	Long-run elasticity*	Annual Time Trend	Total Response to a 10% Price Increase**
National	-0.09	-0.18	-1.0%	-2.8%
East North Central	-0.08	-0.22	-1.0%	-3.2%
East South Central	-0.01	-0.01	-2.0%	-2.1%
Middle Atlantic	-0.10	-0.20	-1.3%	-3.3%
Mountain	-0.07	-0.10	-0.9%	-1.9%
New England	-0.08	-0.25	-0.4%	-2.9%
Pacific	-0.07	-0.12	-0.8%	-2.0%
South Atlantic	-0.12	-0.29	-0.8%	-3.7%
West North Central	-0.09	-0.15	-1.1 %	-2.6%
West South Central	-0.13	-0.16	-1.6%	-3.2%

* Cumulative: includes impacts of short-run elasticities
** The total response to a 10 percent price increase is the sum of the long-run elasticity and the annual time trend effect.

The results from the price elasticity estimates and the combination of efficiency and conservation estimates are able to explain the post 2000 winter consumption per customer actual experience. Normal winter season natural gas use per household in the US has declined

[16] Estimates obtained from the "fixed effects" pooled regression.

about 13.1 percent between 2000 and 2006. There has been an increase in real natural gas prices of 44 percent for the same time period, which according to our analysis would lead to approximately a 7.9 percent (0.18 x 44 percent) decline in use per customer by the year 2006. In addition to this 7.9 percent price induced decline in weather normal use per household, there would be an additional 6.0 percent (6 x 1.0 percent) decline because of the natural annual rate of turnover of old gas appliances to newer more efficient appliances. Hence, our analysis predicts a decline of 13.9 percent over the six-year period, which is very close to the actual decline of 13.1 percent.

$$
\begin{array}{lclcc}
\textit{Overall decline} & & \textit{Price Effect} & & \textit{Conservation and} \\
\textit{in Winter Gas Use} & = & \textit{Elasticity with} & + & \textit{Turnover to More} \\
\textit{per Customer} & & \textit{Price Increase} & & \textit{Efficient Appliances} \\
13.9\% & = & 0.18\, x\, 44\% & + & 6\, x\, 1.0\% \\
 & = & 7.9\% & + & 6.0\%
\end{array}
$$

In the expression above, the left hand term is the overall declining rate of winter gas use per customer, the first term on the right hand side is the price effect reflecting elasticity with price increase, and the second term the effect from conservation and turnover to more efficient appliances that occurs naturally every year with or without a price increase.

This proposed rule of thumb suggests that twelve months after a 10 percent increase in natural gas prices at the national level, there will be nearly a 3 percent decline in natural gas use per customer. This 3 percent decline is comprised of about a 1 percent drop in gas use with the current capital stock, about a 1 percent drop in use per customer because households respond to the higher gas prices by buying more efficient appliances, and a 1 percent drop in gas usage per customer due to the natural turnover to more efficient gas appliances each year. This rule of thumb will vary by LDC because they are heterogeneous in terms of weather, housing stocks, and standards of living.

It should be noted that the 1 percent price-induced drop with the current capital stock is what economist refer to as the elasticity of "short-run" demand. This refers to customers "turning down the thermostat". There is a second 1 percent price induce drop in use per customer that occurs one year later due to consumers buying more efficient appliances and increasing the tightness of the home. The price elasticity in the "long-run" is the sum of the short-run demand elasticity and the additional changes that occur to quantity demanded one year later because of natural gas price impacts on consumer choice of appliance and home thermal shell efficiency.

The heightened conservation behavior by consumers is partly due to the many government and utility programs that currently exist to encourage residential consumers to save energy:

- The federal government encourages conservation through weatherization programs funded by the Low-Income Household Energy Assistance Program (LIHEAP), tax credits for purchase of efficient appliances and shell improvements, and consumer education on the importance of saving energy.

- State and local governments also encourage efficiency through similar programs
- Many utilities provide rebates, incentives, and assistance to their customers to improve use of energy. For example, electric and natural gas utilities provided more than $140 million in 2005 to assist low-income customers to weatherize their homes {Source: http://liheap.ncat.org/tables/FY2005/05stlvtb.htm }

From a planning and policy perspective, even if gas prices do not increase in a given year, there will still be approximately a 1 percent fall in gas usage per household in the following year. This is driven by the historical forces related to the natural turnover of old appliances to the more efficient appliances that are available on the market each year. The annual time trend impacts will vary somewhat by LDC, because of regional differences in weather, appliance stocks, housing shell efficiency, demographic and economic characteristics.

There is a caveat. We cannot address whether the phenomenon will continue at the same rate for the long-term. Further gains in efficiency in absolute and relative terms may or may not have the same impact as they did previously. This is an issue for more detailed engineering studies on the efficiency of appliances and housing shells and economic research on the change in conservation habits of consumers for energy use and winter season comfort levels. We would note, however, that legislative and regulatory pressure for greater efficiency is likely to increase as climate change becomes a more pronounced national and international priority.

The policy implications of the 13.1 percent decline since 2000 are significant. First, regulators must recognize these trends and allow rate structures to incorporate these variations. Second, the natural turnover of appliances and increases in shell efficiency from new construction will result in continued conservation, regardless of price changes, impacting utility operations. Third, even if future gas prices remain constant or even decrease, the appliance and home shell efficiency gains achieved in prior years will not be reversed.

Suggestions for Future Research

As with any study, there is room for future research. Suggestions for future research are the following:

- Obtain data from Natural Gas Companies that did not participate in the initial study.
- Try different specifications of the model.
- Use the Iterative Bayes Shrinkage Estimation Technique to get individual LDC parameter estimates.
- Consider the impact of competition from the electric utility industry.

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Appendix A: Construction of Weather-Normalized Series for Use per Customer

Step 1. Calculate the ratio of HDDN to HDD (normal heating degree days / actual heating degree days.) this is referred to as the weather normalization factor

Step 2. Construct a proxy for base natural gas consumption per customer for each "year". Calculate the average of July and August for each year.

Step 3. Subtract the base consumption from Actual consumption for the September through June for the next 10 months. Refer to this as "heating" consumption. Example: the average of July and August 1999 will be subtracted from September 1999 through June 2000. Retain the actual values for July and August 1999 in the "heating" consumption variable.

Step 4. Calculate the weather normal consumption per customer series. Multiply the "heating" consumption variable by the weather normalization factor. Intuitively, a very cold winter will have relatively high levels of consumption. The very cold weather means that the denominator in the weather normalization factor is large relative to the normal HDD. Multiplying the large consumption variable times the factor, which is less than one, will bring back or reduce consumption towards the normal "heating" consumption level.

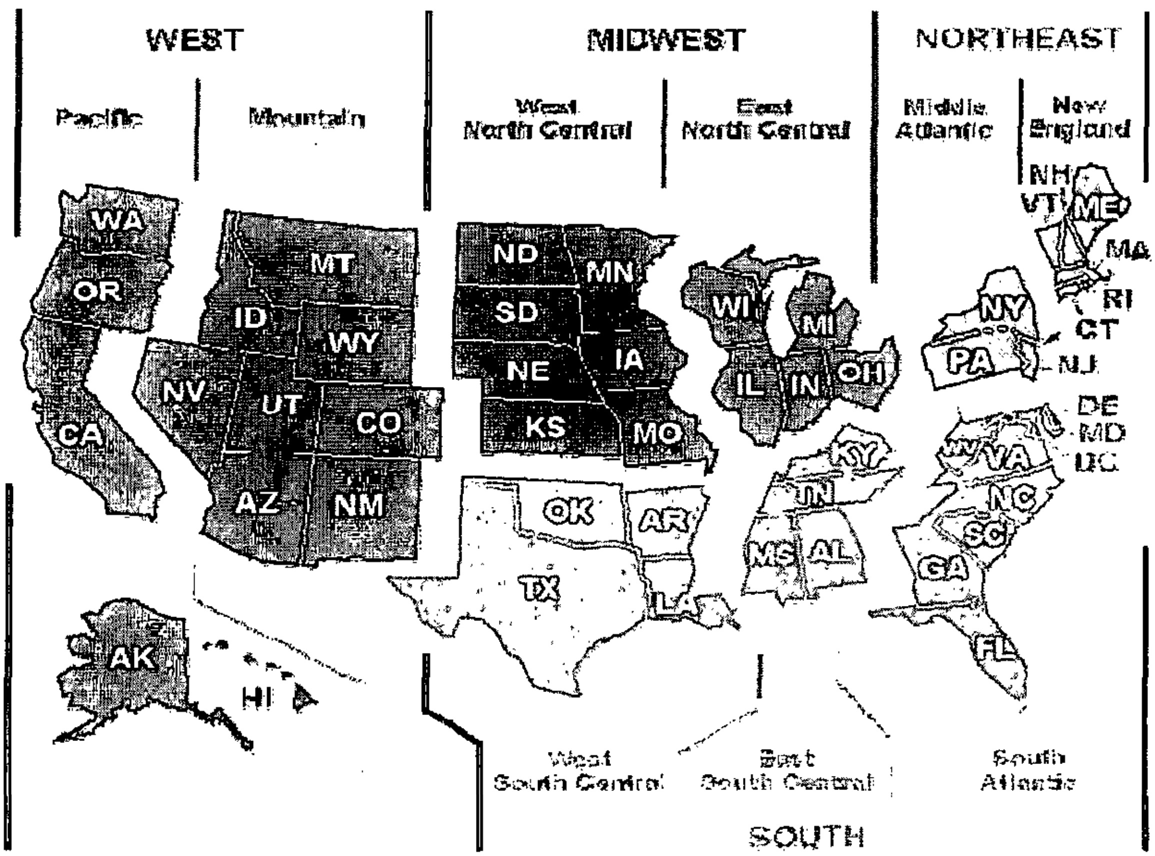
Step 5. Add the base consumption per customer back into the September through June normal heating consumption levels.

Variable list omitting the region identifiers:

HDD	– Actual Heating Degree Days
HDDN	- Normal Heating Degree Days
CUNG	- Natural Gas Use per Customer per Month
ZSAJQUS	- Days per Month
WNF	- Weather Normalization Factor WNF = HDDN / HDD
Base	- Average of July and August in a year
HCUNG	- "Heating" Natural Gas Use per Customer per Month HCUNG = CUNG – Base
NCUNG	- "Normalized" Natural Gas Use per Customer per Month NCUNG = (HCUNG * WNF) + Base
CUNGW	- Actual Daily Natural Gas Use per Customer per Month CUNGW = CUNG / ZSAJQUS
NCUNGW	- "Normalized" Natural Gas Use per Customer per Month NCUNGW = NCUNG / ZSAJQUS

Appendix B: U.S. Census Regions

Figure B.1
U.S. Census Region Map



Source: U.S. Dept. of Energy http://www.eia.doe.gov/emeu/cbecs/census_maps.html

Table B.1
U.S. Census Region Definitions

Division 1 New England	Division 3 East North Central	Division 5 South Atlantic	Division 7 West South Central	Division 9 Pacific
Connecticut	Illinois	Delaware	Arkansas	Alaska
Maine	Indiana	District of Columbia	Louisiana	California
Massachusetts	Michigan	Florida	Oklahoma	Hawaii
New Hampshire	Ohio	Georgia	Texas	Oregon
Rhode Island	Wisconsin	Maryland		Washington
Vermont		North Carolina		
		South Carolina		
		Virginia		
		West Virginia		

Division 2 Middle Atlantic	Division 4 West North Central	Division 6 East South Central	Division 8 Mountain
New Jersey	Iowa	Alabama	Arizona
New York	Kansas	Kentucky	Colorado
Pennsylvania	Minnesota	Mississippi	Idaho
	Missouri	Tennessee	Montana
	Nebraska		Nevada
	North Dakota		New Mexico
	South Dakota		Utah
			Wyoming

Source: Energy Information Administration, Office of Integrated Analysis and Forecasting.

U.S. Census Region Pneumonic	
ENC	East North Central
ESC	East South Central
MAC	Middle Atlantic
MTN	Mountain
NEC	New England
PAC	Pacific
SAC	South Atlantic
WNC	West North Central
WSC	West South Central

Appendix C: Literature Review[17]

There are many studies on the price and income elasticities of residential energy goods in general, and of residential natural gas demand in particular. Table 1 below lists some of these studies, along with the short-run and long-run estimates. See Dahl and Roman (2004) and Dahl (2005) for recent surveys of energy elasticity demand estimates. Other surveys of energy demand price elasticity estimates are Taylor (1975 and 1977), Bohi (1981), Bohi and Zimmerman (1984), Al-Sahlawi (1989), Dahl (1993), and Espy and Espy (2004). Common drawbacks of these studies are: (1) they do not include data that contain the recent increases in residential natural gas prices, (2) they do not focus on the winter season demand, (3) they do not contain company level data across the entire US, and (4) most do not allow for a non-price related decline in use per customer that occurs automatically as consumers replace old inefficient appliances with newer more efficient ones.

The AGA study overcomes the missing elements in the existing literature by looking at individual company level winter season monthly data from all nine US Census Regions over the period 1981 to 2006. Also, the AGA study allows for a naturally occurring decline in use per customer that results from the replacement of old inefficient gas appliances with newer more efficient models.

There have been many papers written that estimate the price elasticity of residential demand for natural gas. A partial list of these papers is given in the references section. Estimates of short-run price elasticity range from as low as –0.05 in Beirlein, Dunn and McConnon (1981) to as high as –0.68 in Barnes, Gillingham & Hagemann (1982). For long-run price elasticity estimates the range of estimates is even higher, with the low being -0.017 in Hewlett (1977) to as high as –3.42 in Beirlein, Dunn and McConnon (1981).

It is fair to say there is no real consensus on residential natural gas price elasticity demand estimates. For overall residential energy demand in general, the median estimate of short-run price elasticity is about –0.2, with the long-run dynamic models with lagged dependent variables yielding a median estimate of about –0.48. For natural gas in particular, using EIA state level aggregate data, Maddala, et. al. (1997) estimate the average short-run price elasticity of natural gas is –0.1 and the long-run price elasticity of residential natural gas demand is –0.27.

[17] This appendix benefited from discussions and on-going research by Professor Carol Dahl, the Colorado School of Mines, Golden, Colorado. All errors are ours.

Table C.1
Residential Price Elasticity Estimates

Authors	Data	Estimation Method	Short-run	Long-run
Balestra & Nerlove (1966)	Pooled: 36 States for 1957-62)	GLS(EC)	NA	-0.63
Jaskow & Baughman (1976)	Pooled: 48 States for 1968-72	OLS	-0.15	-1.01
Berndt & Watkins (1977)	Pooled: Ontario and British Columbia for 1959-74	Maximum Likelihood	-0.15	-0.69
Hewlett (1977)	Cross Section: New York State household survey	OLS	NA	-0.45
Hewlett (1977)	Pooled: New York State customer survey for 1976 and 1977.	OLS	NA	-0.17
Beirlein, Dunn & McConnon (1981)	Pooled: 9 States for 1967-77	OLS	-0.23	-2.90
		GLS (EC)	-0.23	-2.96
		GLS (EC-SUR)	-0.05	-3.42
Barnes, Gillingham & Hagemann (1982)	Pooled: 10,000 households in 23 US cities. Quarterly data for 1972-73.	IV	-0.68	NA
Green & Gilbert (1983)	Cross-Sectional: non-poverty homeowners and poverty homeowners	OLS	NA	-1.25
		OLS	NA	-1.09
Blattenberger, Taylor, & Rennhack (1983)	Pooled: 48 states for 1961-74	GLS (EC)	-0.32	-0.39
Green, Salley, Grass & Osei (1986)	Pooled: between 6 and 7 thousand households for 1974 to 1979.	OLS	-0.16	NA

Appendix D: Statistical Hypothesis Testing

The practical question that is addressed in statistical hypothesis testing concerns the relative strength of some "treatment"; such as does price have an impact on weather normal use per household natural gas demand. The question addressed might be: Do the data contained in the sample present sufficient evidence that increases in price lead to a lower use per household natural gas demand?

The reasoning employed in testing a hypothesis bears a striking resemblance to the procedure used in a court trial. In tying a person for a crime, the court assumes the accused innocent until proven guilty. The prosecution collects and presents all the available evidence in an attempt to contradict the "not guilty" hypothesis and hence to obtain a conviction. However, if the prosecution fails to disprove the "not guilty" hypothesis, this does not prove that the accused is "innocent" but merely that there is not sufficient evidence to conclude that the accused is "guilty".

The statistical problem in this study portrays "natural gas price" as the accused. The hypothesis to be tested, called the **null hypothesis**, is that price does not negatively impact the weather normal use per household natural gas demand. The evidence in this case is contained in the sample drawn from the population of LDCs who supply this demand. The researcher, playing the role of the prosecutor, believes that an **alternative hypothesis** is true - namely, that natural gas price does have a negative impact on natural gas use per household demand. Hence, the researcher attempts to use the evidence contained in the sample to reject the null hypothesis (no impact of natural gas price on natural gas demand) and thereby to support the alternative hypothesis, the contention that price does in fact inversely impact natural gas demand.

The statistician will calculate a test statistic from the information contained in the sample. All possible values the test statistic may assume are divided into two groups – one called the rejection region and the other the acceptance region. After the sample is collected the test statistic is calculated and observed. If the test statistic takes on a value in the rejection region, the null hypothesis is rejected. Otherwise, one fails to reject the null hypothesis.

You will notice that the researcher is faced with two possible types of errors. On the one hand, the researcher might reject the null hypothesis when it is true, and falsely conclude that natural gas price does negatively impact the natural gas demand. This would result in forecasting lower revenues after a rate increase than would actually be the case. On the other hand, the researcher might decide not to reject the null hypothesis when it is false, and falsely conclude that natural gas price does not impact natural gas demand. This error would result in forecasting higher revenues after a rate increase than would actually be the case.

Rejecting the null hypothesis when it is true is called a Type I error for a statistical test. The probability of making a type I error is usually denoted by the Greek symbol α, and is referred to as the "statistical significance level". In practice some common values used for

α are 0.10 (a 10 percent chance of a Type I error), 0.05 (a 5 percent chance of a Type I error), 0.025 (a 2.5 percent chance of a Type I error), and 0.01 (a 1 percent chance of a Type I error).

The probability α will increase or decrease as we increase or decrease the size of the rejection region. Then why not decrease the size of the rejection region and make α as small as possible? Unfortunately, decreasing α increases the probability of not rejecting the null hypothesis when it is false and some alternative hypothesis is true. This second type of error is called the type II error for a statistical test and its probably is commonly denoted by the Greek symbol β. More formally, accepting the null hypothesis when it is false is called a type II error for a statistical test. The probability of making a type II error when some specific alternative is true is denoted by β.

Notice that both errors cannot be committed simultaneously. A type I error is possible only if the decision is to reject the null hypothesis; a type II error is possible only if the decision in to not reject the null hypothesis.

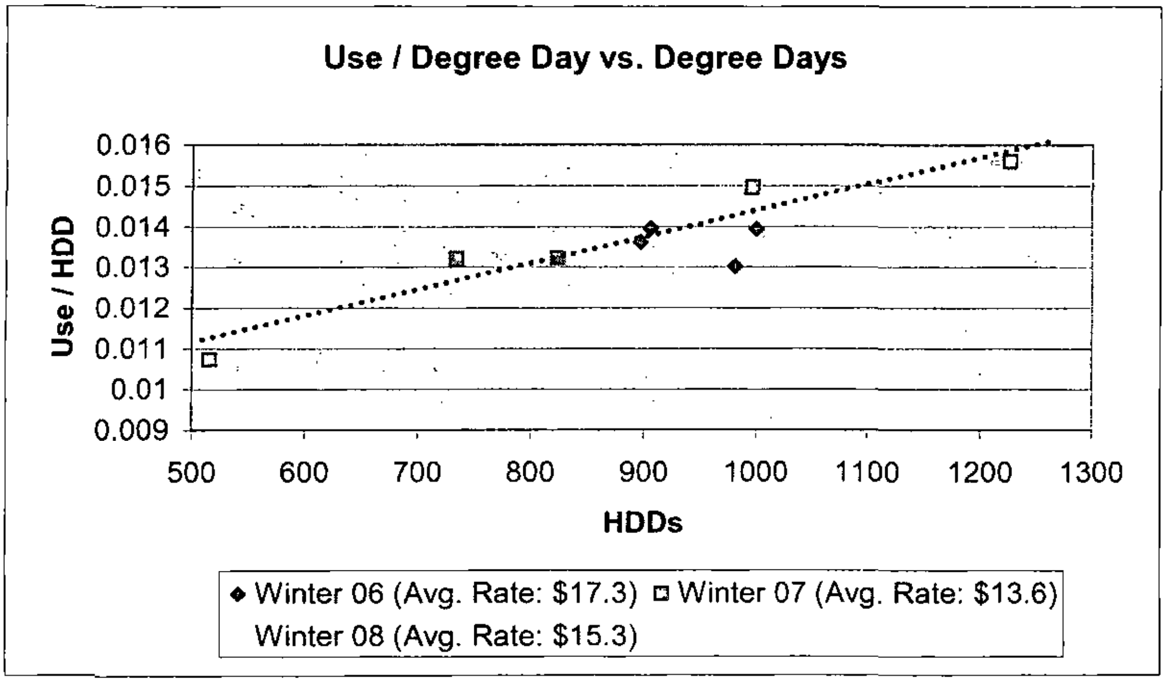
When the null hypothesis is rejected in favor of the alternative hypothesis, it is called a statistically significant test. When one fails to reject the null hypothesis, it is referred to as a statistically insignificant test.

As noted on page 29 of Maddala (2001), a statistically significant test means, "sampling variation is an unlikely explanation of the discrepancy between the null hypothesis and the *sample values (estimate)". On the other hand, a statistically insignificant test means,* "sampling variation is a likely explanation of the discrepancy between the null hypothesis and the sample value".

The appropriate test statistic for the null hypotheses tested in this report is the t-statistic, which is reported for each of the coefficients in equations (4a) and (4b). For sample sizes larger than 120 and for an alternative hypothesis that states the price coefficient is less than zero, a t-statistic less than -1.28 is statically significant at the 10 percent level, a t-statistic less than -1.64 is statistically significant at the 5 percent level, a t-statistic less than -1.96 is statically significant at the 2.5 percent level, and a t-statistic less than -2.33 is statistically significant at the 1 percent level.

Use / Degree Day vs. Degree Days Price Sensitivity
All PA Customers

		HDDs	Use/DD
Winter 06 (Avg. Rate: $17.3)			
	Nov 2005	442	0.010953845
	Dec 2005	981	0.013017851
	Jan 2006	1,000	0.013937857
	Feb 2006	897	0.013619779
	Mar 2006	906	0.013963716
Winter 07 (Avg. I	Nov 2006	516	0.010731038
	Dec 2006	734	0.01322023
	Jan 2007	824	0.013233979
	Feb 2007	1,226	0.015594855
	Mar 2007	996	0.014952972
Winter 08 (Avg. I	Nov 2007	377	0.00856544
	Dec 2007	854	0.013529594
	Jan 2008	983	0.014625375
	Feb 2008	1,040	0.014722346
	Mar 2008	1,001	0.014519034



Rate History

Average Rate (Ma	Nov		Dec		Jan		Feb		Mar		Average	
2005 - 2006	$	17.0	$	16.9	$	17.5	$	17.5	$	17.5	$	17.3
2006 - 2007	$	13.2	$	13.2	$	14.0	$	14.0	$	13.9	$	13.6
2007 - 2008	$	15.3	$	15.3	$	15.3	$	15.3	$	15.3	$	15.3

Price Sensitivity Analysis

	HDDs	Use/DD	Rate	Use/DD Change	Rate Change
Jan 2006	1,000	0.0139379	$ 17.3		
Mar 2007	996	0.0149530	$ 13.6	7%	-21%
Mar 2008	1,001	0.0145190	$ 15.3	-3%	12%

>> Similar HDDs >> Assumption: No HDDs impact to Use/DD

>> Calculation of price sensitivity

>> What if analysis: If the price increase by $1, how much margin EGC will lose due to price sensitivity

Use/DD change per $ 1 increase =	-1.8%
Use/DD/Customer Impact	-0.0002644
Average # of PA residential customer	241,584
07 actual HDDs	5,332
Total MCF decreases/$1 increase	(340,631)

Equitable Gas Company
Response to Standard Data Requests
REVENUE REQUIREMENT INTERROGATORIES

Item 12: In the form identical to the previous question, please provide a database for all independent variables which were analyzed by the Company, but exclude from the filed gas demand models.

Response: The Company did not analyze any independent variables which were excluded from the filed gas demand models.

Equitable Gas Company
Response to Standard Data Requests
REVENUE REQUIREMENT INTERROGATORIES

Item 13: For each customer receiving service at less than the maximum applicable tariff rate, please provide:

a. actual consumption for the two most recent calendar years;

b. actual consumption for the HTY and the most recent twelve month period for which data is available;

c. the currently applicable rate;

d. an explanation for the rate discount.

Response:

Equitable Gas Company
Customers at Less Than the Maximum Applicable Tariff Rate

Response	(a) Total Mcf 2006	(a) & (b) Total Mcf 2007	(c) Current Average Effective Rate Per Mcf
Rate GDS			
Commercial	5,189,478	5,687,048	$ 1.35
Industrial	2,595,774	3,022,522	$ 0.71
Rate DDS	5,468,129	6,995,567	$ 0.58

d. The Company evaluates each customer based on site specific criteria which include but are not limited to end use, load factor, economic viability, incremental sales potential, new technological applicability, alternate fuel capability and overlapping service territory. These criteria are used to determine if a customer is eligible to receive a negotiated and/or discounted rate.

Equitable Gas Company
Response to Standard Data Requests
REVENUE REQUIREMENT INTERROGATORIES

Item 14: Please provide a copy of the Company's detailed capital budgets for the preceding and current calendar years which underlie the projected test year capital additions in this case.

Response: The detailed 2007 and 2008 Capital Budgets for Equitable Gas Company – PA Division are attached.

EQUITABLE GAS COMPANY PA DIVISION
2007 CAPITAL BUDGET

PROJECT #	CATEGORY / DETAIL DESCRIPTION		AMOUNT
	PRODUCTION & GATHERING		
11013608	CONSTRUCT NEW COMPRESSOR STATION	$	3,000,000
	TOTAL PRODUCTION & GATHERING PLANT	$	3,000,000
	TRANSMISSION PLANT		
11013601	PURCHASE & INSTALL DOUBLE WALL TANK WITH FOUNDATION AT SHOEMAKER & CROOKED CREEK STATIONS	$	50,000
11013602	WATER PUMP UPGRADE/REPLACEMENT AT SHOEMAKER & CREIGHTON STATION		144,000
11013603	REBUILD BOTH ENGINES AT CREIGHTON COMPRESSOR STATION		166,000
11013604	REBUILD ENGINES & COMPRESSOR AT VARIOUS COMPRESSOR STATIONS		148,000
11013605	RENEW WINDOWS AT FISHER, SHOEMAKER AND CREIGHTON COMPRESSOR STATIONS		21,000
11013606	INSTALL SUCTION CONTROLLERS AT SHOEMAKER AND CREIGHTON STATIONS		112,000
11013607	VARIOUS COMPRESSOR STATION WORK		145,000
	TOTAL TRANSMISSION PLANT	$	786,000
	DISTRIBUTION PLANT		
11013609	NEW BUSINESS MAINLINE EXTENSIONS	$	3,100,000
11013611	RENEW - DEMANDS OF PUBLIC AUTHORITIES		1,432,600
11013612	RENEW - DEMANDS OF PUBLIC AUTHORITIES- Reimbursable $ 1,058,745		-
11013613	RENEW - VARIOUS MAINS - OPERATIONAL DECISIONS NON-COLOR CODED		1,607,400
11013614	RENEW - VARIOUS MAINS - COLOR CODED RED/ORANGE <8-INCH -10 MILES R/O-20 MILES		10,160,000
11013615	RENEW 1400' OF 12" D-114, IRWIN RUN & VARIOUS STS,WEST MIFFLIN (505' R/O)		307,000
11013616	RENEW 1200' OF 24" CAST IRON, STATE ROUTE 885, WEST MIFFLIN -CAST IRON PROJECT		350,000
11013617	RENEW 1455' OF 12" ST, MCBRIDE PARK, W MIFFLIN & 31ST WARD OF PGH		276,000
11013618	RENEW 700' OF 16" ST, EUCLID & MAPLE AVE, DRAVOSBURG (177' RED/ORANGE)		242,000
11013619	RENEW 2000' OF 12" ST, 200" 6", BROADWAY AVE, EAST MCKEESPORT (358' RED/ORANGE)		460,500
11013620	RENEW 700' OF 24" CAST IRON, BRENTWOOD AVE (660' RED -YEAR 1902)		253,000

EQUITABLE GAS COMPANY PA DIVISION
2007 CAPITAL BUDGET

PROJECT #	CATEGORY / DETAIL DESCRIPTION	AMOUNT
11013621	RENEW 500' OF 12" ST, ALLENDALE ST, 20TH WARD (379' RED/ORANGE)	212,000
11013622	RENEW 1000' OF 10" ST WOODWARD AVE,STOWE TWP(940' RED/ORANGE)AND 1000' OF 6" ST	394,300
11013623	RENEW 1200' OF 12" ST, ADON ST, 20TH WARD,CITY PGH (277' ORANGE, INSTALLED 1888)	409,000
11013624	RENEW 2628' OF 10" ST,GRANT AVE, SHALER TWP(705' RED/ORANGE, INSTALLED 1892)	1,000,000
11013625	NEW SERVICE LINES - Region A	925,000
11013626	NEW SERVICE LINES - Region B	530,000
11013627	NEW SERVICE LINES - Apollo	54,000
11013628	RENEW AND RETIRE SERVICE LINES PA	2,330,000
11013629	RENEW RD-005 BROTHERS @ FALLOWFIELD TWP. FALLOWFIELD	58,000
11013630	RENEW RE-124 FREDANNA ST. @ FREDANNA ST. 31ST WARD, PGH.	53,000
11013631	RENEW HRD87 & HRD 89 PLAPORT @ WEST RUN RD, 31ST WARD, PGH	115,000
11013632	RENEW RA-71 DOYLE @ OAKRIDGE-WHITEHALL BORO	125,000
11013633	RENEW RA-049 PLEASANT HILLS PLAN-WHITEHALL BORO	65,000
11013634	RENEW RB-088 YORK DR @ JACKS RUN-ROSS	125,000
11013635	ROOFS, FENCES, DOORS AT VARIOUS REGULATOR STATIONS	65,000
11013636	REPLACE WATER BATH HEATER-RB-055 REISS RUN RD	85,000
11013637	MISC ODORIZER EQUIPMENT	20,000
11013638	PURCHASE TURBINE METERS	40,000
11013639	PURCHASE 400 CLASS METERS	65,000
11013640	PURCHASE ELECTRONIC INSTRUMENTATION	65,000
11013641	PURSCHASE LARGE NON-DIAPHRAGM METERS	293,000
11013642	PURCHASE LARGE TEMPERATURE COMPENSATED METERS	200,000
11013643	PURCHASE DOMESTIC METERS	365,000
11013644	PURCHASE COMMERCIAL & INDUSTRIAL REGULATORS AND RELIEFS	105,000
11013645	PURCHASE REPLACEMENT REGULATORS FOR FISHER 399-OBSOLETE	175,000
11013646	PURCHASE ELECTRONIC INSTRUMENTATION AND GAUGES	55,000
11013647	NEW METER INSTALLATIONS - Region A	200,000
11013648	NEW METER INSTALLATIONS - Region B	100,000
11013649	NEW METER INSTALLATIONS - Apollo	54,000
	TOTAL DISTRIBUTION PLANT	26,470,800

EQUITABLE GAS COMPANY PA DIVISION
2007 CAPITAL BUDGET

PROJECT #	CATEGORY / DETAIL DESCRIPTION		AMOUNT
	GENERAL PLANT		
11013650	MISCELLANEOUS TOOLS & EQUIPMENT	$	89,500
11013651	TELESCADA REMOTE GAS PRESSURE MONITORING-PILOT PROGRAM (5-UNITS)		15,000
11013652	MISCELLANEOUS TOOLS AND EQUIPMENT		50,000
11013653	TOOLS AND EQUIPMENT		36,000
11013654	CURB LOCATOR & GAS DETECTION		12,500
11013655	MISCELLANEOUS TOOLS & EQUIPMENT		100,000
11013656	PURCHASE 50 - 75 TON COLUMN PRESS		2,000
11013657	PURCHASE STEAM JENNY		4,000
11013658	READI DEVELOPMENT		660,000
11013659	READI - ONLINE BILL PAYMENT		486,000
11013660	PC & LAPTOP REPLACEMENT		231,000
11013661	LEAK SURVEY / AUTOMATED READ PILOT		90,000
11013662	GIS INTERGRATION		500,000
	TOTAL GENERAL PLANT	$	2,276,000
	AUTOMOTIVE PLANT		
11013663	VEHICLE REPLACEMENTS - PA	$	1,934,400
11013664	PURCHASE PORTABLE AIR COMPRESSOR (250-300 PSIG)-tag along compressor for vehicle		25,000
11013665	PURCHASE 5-7 TON FORKLIFT WITH PNEUMATIC TIRES		28,000
	TOTAL AUTOMOTIVE PLANT	$	1,987,400
TOTAL PA DIVISION CAPITAL BUDGET		$	34,520,200

EQUITABLE GAS COMPANY PA DIVISION
2008 CAPITAL BUDGET

PROJECT #	CATEGORY / DESCRIPTION		AMOUNT
	PRODUCTION & GATHERING		
11013892	LIMESTONE COMPRESSOR STATION UPGRADE - INSTALLATION COSTS	$	4,000,000
11013894	CONSTRUCT NEW FISHER COMPRESSOR STATION AND DPNG / DTI INTERCONNECT		10,000,000
11013897	PURCHASE & INSTALL OVERHEAD CRANES @ CROOKED CREEK, ATWOOD,VILLAGE & HILL ST.		150,000
11013867	INSTALL 11 SEGMENT METERS AND RTU'S FOR LUF MEASUREMENT - APOLLO DISTRICT		405,000
	TOTAL PRODUCTION & GATHERING PLANT	$	14,555,000
	TRANSMISSION PLANT		
11013893	SHOEMAKER COMPRESSOR STATION - M4 CONVERSION	$	40,000
11013896	PURCHASE & INSTALL JIB CRANES MCC BUILDING @ SHOEMAKER & CREIGHTON STATIONS		30,000
11013898	PURCHASE & INSTALL HEATERS MCC BUILDING @ SHOEMAKER & CREIGHTON STATIONS		6,000
11013899	PURCHASE & INSTALL ROOF FANS MCC BUILDING @ SHOEMAKER & CREIGHTON STATIONS		10,000
11013900	PURCHASE & INSTALL PUMPS, VALVES & SWITCHES ON STORAGE TANKS - CREIGHTON & SHOEMAKER STATIONS		20,000
11013901	RENEW PLATE VALVES WITH POPPET VALVES @ VARIOUS COMPRESSOR STATIONS		52,000
11013902	RENEW COOPER POWER CYLINDERS FOR CREIGHTON & SHOEMAKER STATIONS		95,000
11013903	REBUILD BOTH ENGINES AT SHOEMAKER COMPRESSOR STATION		195,000
11013904	REBUILD COMPRESSORS AT SHOEMAKER & CREIGHTON COMPRESSOR STATIONS		128,000
11013905	RENEW UPS SYSTEM @ CROOKED CREEK COMPRESSOR STATION		25,000
11013906	VARIOUS COMPRESSOR STATION WORK		170,000
	TOTAL TRANSMISSION PLANT	$	771,000
	DISTRIBUTION PLANT		
11013842	RENEW - DEMANDS OF PUBLIC AUTHORITIES	$	1,884,000

EQUITABLE GAS COMPANY PA DIVISION
2008 CAPITAL BUDGET

PROJECT #	CATEGORY / DESCRIPTION	AMOUNT
11013843	RENEW - VARIOUS MAINS - OPERATIONAL DECISIONS NON-COLOR CODED	1,600,000
11013844	RENEW - VARIOUS MAINS - COLOR CODED RED/ORANGE <8-Inch	8,000,000
11013845	RENEW 1455' OF 12" ST, MCBRIDE PARK, W MIFFLIN & 31ST WARD OF PGH	369,000
11013846	D-279 RENEW 10" ST ON R/W OFF SARDIS RD, MURRYSVILLE	116,000
11013847	RENEW 700' OF 16" ST, EUCLID & MAPLE AVE, DRAVOSBURG	311,000
11013965	STEUBEN ST., CRAFTON (LINCOLN AVE.- NORMA ST.)INSTALL 583'-10" ST, 596'-6" AND 35'-4" PL	476,000
11013849	WASHINGTON RD., MT. LEBANON (SHADY DR.- LEBANON AVE.)INSTALL 1810'-12" STEEL PIPE	1,109,000
11013850	FORT PITT BLVD., CITY PGH. (SMITHFIELD ST.- GRANT AVE)INSTALL 624'-16" AND 10'-20" STEEL PI	694,000
11013851	WELSH WAY, CITY OF PGH. (S. 12TH ST. TO END OF WELSH WAY)INSTALL 922'-20" STEEL & RETIRE 811'-30" CAST IRON AND 111'-20" STEEL PIPE	780,000
11013852	VARIOUS PIPELINE REPLACEMENTS	360,000
11013853	RENEW 500'-20"ST, SECTION OF PIPELINE F 211 (CREEK CROSSING), BETHEL TOWNSHIP	212,000
11013854	RENEW 13,728' OF 2" ST W 8,195 OF- 3" PE , RETIRE (5) DISTRICT REG, MATHER GREEN COUNTY	100,000
11013855	M-77 UPRATE 350# TO 500# JONES FARM TO M-81, DUQUESNE	10,000
11013856	D-146 UPRATE 60# TO 90# NOBLE DRIVE TO HAYS STATION	145,000
11013857	RENEW CP SYSTEM (H-156 FROM THE M-78 INTERCONNECT TO RAGER MT.)	220,000
11013858	INSTALL 200' - 4" TO RETIRE RD-005 BRATHERS, ROGERS LN (SR 71) FALLOWFIELD TWP	72,000
11013859	INSTALL 1800" TO RETIRE RE 165, ELWELL ST, 31ST WARD	102,000
11013860	ANODE INSTALLATIONS	1,308,000
11013861	RENEW & RETIRE SERVICE LINES	3,380,000
11013862	NEW REGULATOR FOR D114 (RE-270)	68,000
11013863	RENEW RA-71 DOYLE @ OAKRIDGE-WHITEHALL BORO	125,000
11013864	RENEW RA-064 ADON @ ALLENDALE	125,000
11013865	RENEW RB-088 YORK DR @ JACKS RUN-ROSS	125,000
11013866	ROOFS, FENCES, DOORS AT VARIOUS REGULATOR STATIONS	75,000
11013868	MISC ODORIZER EQUIPMENT	20,000
11013869	PURCHASE TURBINE METERS	40,000
11013870	PURCHASE 400 CLASS METERS	130,000
11013871	PURCHASE ELECTRONIC INSTRUMENTATION	65,000
11013872	PURSCHASE LARGE NON-DIAPHRAGM METERS	75,000

EQUITABLE GAS COMPANY PA DIVISION
2008 CAPITAL BUDGET

PROJECT #	CATEGORY / DESCRIPTION		AMOUNT
11013873	PURCHASE LARGE TEMPERATURE COMPENSATED METERS		100,000
11013874	PURCHASE DOMESTIC METERS		340,000
11013875	PURCHASE & INSTALL BUFFALO VALVES		78,000
11013876	PURCHASE COMMERCIAL & INDUSTRIAL REGULATORS AND RELIEFS		110,000
11013909	MAINLINE EXTENSIONS		3,100,000
11013911	NEW SERVICE LINES		1,601,000
11013912	NEW METER INSTALLATIONS		384,000
	TOTAL DISTRIBUTION PLANT		27,809,000
	GENERAL PLANT		
11013879	TOOLS AND EQUIPMENT	$	12,500
11013880	ELECTRO-FUSION EQUIPMENT $200,000 & VARIOUS TOOLS $50,000		250,000
11013881	TOOLS AND EQUIPMENT		30,000
11013882	MISCELLANEOUS TOOLS AND EQUIPMENT		50,000
11013883	MISCELLANEOUS TOOLS AND EQUIPMENT		62,500
11013884	MISCELLANEOUS TOOLS AND EQUIPMENT - LEAK SURVEY		35,000
11013885	CURB BOX LOCATORS/ELECTRONIC KUHLMAN GAUGES		25,000
11013886	TELESCADA REMOTE GAS PRESSURE MONITORING		20,000
11013887	MISCELLANEOUS TOOLS AND EQUIPMENT		35,000
11013888	BREATHING APARATUS, CONFINED SPACE AIR HANDLER		75,000
11013889	PAVE GINGER HILL DRIVEWAY & PARKING LOT		65,000
11013908	PC REPLACEMENT/NEW HIRE EQ		466,690
11014029	WORK MANAGEMENT PHASE 1		910,000
11014030	READI DEVELOPMENTS -		412,880
11014031	EGC WEBSITE DESIGN& DEVELOPMENT		400,000
11014032	READI CUSTOMER SELF-SERVICE PORTAL		349,356
11014033	GIS IMPLEMENTATION		279,864
11014034	CUSTOMER CORRESPONDENCE IMAGING SYSTEM		217,120

EQUITABLE GAS COMPANY PA DIVISION
2008 CAPITAL BUDGET

PROJECT #	CATEGORY / DESCRIPTION		AMOUNT
11014035	PROOF OF CONCEPT& IMPLEMENTATION - HANDHELD DEVICES FOR MOBILE WORKFORCE		148,646
11014036	SERVICE LINE MANAGEMENT SYSTEM DEVELOPMENT		142,950
11014037	CALL CENTER CIS FRONT END .NET TECHNOLOGY		87,360
11014038	GPS DEVICES & SOFTWARE FOR FIELD TEAMS		84,480
11014039	LODESTAR/READI/ALTRA RATE INTERFACE DEVELOPMENT		81,200
11014040	CONFIGURE READI TO HANDLE NOTICE/MAILER PRINTING		74,800
11014041	RADIO INFRASTRUCTURE REDESIGN & REPLACEMENT		250,000
11014042	GPS DEVICES FOR SERVICE TRUCKS		202,500
11014043	ENGINEERING PC AND SOFTWARE UPGRADE		147,620
11014044	JOB SCHEDULER		60,000
11014045	WEB METHODS 7.1 UPGRADE		20,000
	TOTAL GENERAL PLANT	$	4,995,466
	TELECOMMUNICATIONS PLANT		
11013890	VARIOUS TELECOM WORK	$	172,000
	TOTAL TELECOMMUNICATIONS PLANT	$	172,000
	AUTOMOTIVE PLANT		
11013891	VEHICLE REPLACEMENTS -PA	$	2,301,700
	TOTAL AUTOMOTIVE PLANT	$	2,301,700
TOTAL PA DIVISION CAPITAL BUDGET		$	50,604,166

Equitable Gas Company
Response to Standard Data Requests
REVENUE REQUIREMENT INTERROGATORIES

Item 15: Please provide a variance or other similar report comparing actual and budgeted construction expenditures at the conclusion of each budget period for the past three years and as of the most recent date available.

Response: Attached are capital expenditure reports for calendar years 2005, 2006 and 2007 and year-to-date May 2008 (the most recent date available).

Equitable Gas Company
Capital Expenditure Report
For the Calendar Years 2005 - 2008

Program	Budget 2005	Actual 2005	Variance Over / (Under)
Transmission & Gathering			
Transm & Gathering - Line Replacements	$ -	$ 9,138	$ 9,138
Transm & Gathering - Compressor Stations	1,370,000	1,584,911	214,911
Transm & Gathering - Other		-	-
Total Transmission & Gathering	1,370,000	1,594,049	224,049
Distribution			
Dist - New Mainline Extensions	4,575,000	2,049,967	(2,525,033)
Dist - New Service Lines	1,175,000	1,499,411	324,411
Dist - New Meter Installations	200,000	293,134	93,134
	5,950,000	3,842,512	(2,107,488)
Dist - Mainline Replacement	19,355,000	19,502,088	147,088
Dist - Service Line Replacement	7,930,000	7,171,420	(758,580)
Dist - Measuring & Regulating Stations	1,400,000	1,024,228	(375,772)
Dist - New Meters / Regulators Purchases	820,000	649,611	(170,389)
Dist - Metscan / AMR Installations	4,960,000	8,868,591	3,908,591
Dist - Other		10,493	10,493
	34,465,000	37,226,431	2,761,431
Total Distribution	40,415,000	41,068,943	653,943
General			
Gen - Tools and Equipment	213,000	43,733	(169,267)
Gen - Shop Equipment		3,050	3,050
Gen - Office Furniture and Equipment	12,000	-	(12,000)
Gen - Buildings	-	-	-
Gen - Telecommunications	200,000	73,627	(126,373)
Gen - Automotive	1,225,000	893,634	(331,366)
Gen - Other	-	202,560	202,560
Total General	1,650,000	1,216,604	(433,396)
IT (Intangible and Computer Related)	3,155,000	2,927,831	(227,169)
TOTAL PA CAPITAL EXPENDITURES	$ 46,590,000	$ 46,807,427	$ 217,427

Equitable Gas Company
Capital Expenditure Report
For the Calendar Years 2005 - 2008

Program	Budget 2006	Actual 2006	Variance Over / (Under)
Transmission & Gathering			
Transm & Gathering - Line Replacements	$ 308,000	$ -	$ (308,000)
Transm & Gathering - Compressor Stations	6,325,000	916,093	(5,408,907)
Transm & Gathering - Other		-	-
Total Transmission & Gathering	6,633,000	916,093	(5,716,907)
Distribution			
Dist - New Mainline Extensions	3,100,000	3,343,140	243,140
Dist - New Service Lines	1,290,000	1,390,499	100,499
Dist - New Meter Installations	315,000	180,636	(134,364)
	4,705,000	4,914,275	209,275
Dist - Mainline Replacement	18,017,000	16,113,799	(1,903,201)
Dist - Service Line Replacement	6,930,000	6,669,499	(260,501)
Dist - Measuring & Regulating Stations	1,895,000	3,271,591	1,376,591
Dist - New Meters / Regulators Purchases	710,000	470,977	(239,023)
Dist - Metscan / AMR Installations	7,839,000	6,704,747	(1,134,253)
Dist - Other	-	(68,672)	(68,672)
	35,391,000	33,161,941	(2,229,059)
Total Distribution	40,096,000	38,076,216	(2,019,784)
General			
Gen - Tools and Equipment	160,000	331,631	171,631
Gen - Shop Equipment		-	-
Gen - Office Furniture and Equipment	10,000	24,024	14,024
Gen - Buildings	-	309,222	309,222
Gen - Telecommunications	450,000	136,988	(313,012)
Gen - Automotive	1,508,000	2,135,323	627,323
Gen - Other	-	17,675	17,675
Total General	2,128,000	2,954,863	826,863
IT (Intangible and Computer Related)	3,057,000	5,599,028	2,542,028
TOTAL PA CAPITAL EXPENDITURES	$ 51,914,000	$ 47,546,200	$ (4,367,800)

Equitable Gas Company
Capital Expenditure Report
For the Calendar Years 2005 - 2008

Program	Budget 2007	Actual 2007	Variance Over / (Under)
Transmission & Gathering			
Transm & Gathering - Line Replacements		$ -	$ -
Transm & Gathering - Compressor Stations	4,500,000	4,249,799	(250,201)
Transm & Gathering - Other		539,792	539,792
Total Transmission & Gathering	4,500,000	4,789,591	289,591
Distribution			
Dist - New Mainline Extensions	2,600,000	1,476,960	(1,123,040)
Dist - New Service Lines	1,509,000	1,235,802	(273,198)
Dist - New Meter Installations	354,000	360,208	6,208
	4,463,000	3,072,970	(1,390,030)
Dist - Mainline Replacement	16,700,000	16,480,902	(219,098)
Dist - Service Line Replacement	2,330,000	4,666,856	2,336,856
Dist - Measuring & Regulating Stations	1,641,000	2,481,405	840,405
Dist - New Meters / Regulators Purchases	1,133,000	697,052	(435,948)
Dist - Metscan / AMR Installations	350,000	264,480	(85,520)
Dist - Other	-	1,811,269	1,811,269
	22,154,000	26,401,964	4,247,964
Total Distribution	26,617,000	29,474,934	2,857,934
General			
Gen - Tools and Equipment	259,000	295,690	36,690
Gen - Shop Equipment	-	-	-
Gen - Office Furniture and Equipment	-	226,503	226,503
Gen - Buildings	-	969,654	969,654
Gen - Telecommunications	-	37,331	37,331
Gen - Automotive	1,987,000	2,085,986	98,986
Gen - Other		-	-
Total General	2,246,000	3,615,164	1,369,164
IT (Intangible and Computer Related)	894,000	3,056,820	2,162,820
TOTAL PA CAPITAL EXPENDITURES	$ 34,257,000	$ 40,936,509	$ 6,679,509

Equitable Gas Company
Capital Expenditure Report
For the Calendar Years 2005 - 2008

Program	Budget May 2008	Actual May 2008	Variance Over / (Under)
Transmission & Gathering			
Transm & Gathering - Line Replacements	$ 500,000	$ 1,141,446	$ 641,446
Transm & Gathering - Compressor Stations	3,800,000	2,491,028	(1,308,972)
Transm & Gathering - Other		-	-
Total Transmission & Gathering	4,300,000	3,632,474	(667,526)
Distribution			
Dist - New Mainline Extensions	1,005,000	380,072	(624,928)
Dist - New Service Lines	486,000	255,033	(230,967)
Dist - New Meter Installations	125,000	70,796	(54,204)
	1,616,000	705,901	(910,099)
Dist - Mainline Replacement	5,974,000	4,346,188	(1,627,812)
Dist - Service Line Replacement	1,405,000	1,485,187	80,187
Dist - Measuring & Regulating Stations	1,998,000	1,735,780	(262,220)
Dist - New Meters / Regulators Purchases	292,000	530,642	238,642
Dist - Metscan / AMR Installations	-		-
Dist - Other	-	193,660	193,660
	9,669,000	8,291,457	(1,377,543)
Total Distribution	11,285,000	8,997,358	(2,287,642)
General			
Gen - Tools and Equipment	250,000	100,410	(149,590)
Gen - Shop Equipment			-
Gen - Office Furniture and Equipment		227	227
Gen - Buildings			-
Gen - Telecommunications	110,000	117,924	7,924
Gen - Automotive	800,000	661,523	(138,477)
Gen - Other			-
Total General	1,160,000	880,084	(279,916)
IT (Intangible and Computer Related)	1,400,000	806,839	(593,161)
TOTAL PA CAPITAL EXPENDITURES	$ 18,145,000	$ 14,316,755	$ (3,828,245)

Equitable Gas Company
Response to Standard Data Requests
REVENUE REQUIREMENT INTERROGATORIES

Item 16: Please provide a breakdown of other gas revenue for the three preceding calendar years.

Response:

FERC Acct	Account Description	Other Revenue for the Twelve Months Ended December 2005	2006	2007
487	Forfeited Discounts	1,682,516	1,512,243	1,557,851
488	Miscellaneous Service Revenues	1,064,305	1,164,789	1,208,555
493	Rent from Gas Property	6,348	5,311	1,588
495	Other Gas Revenues	185,489	236,194	59,903

Equitable Gas Company
Response to Standard Data Requests
REVENUE REQUIREMENT INTERROGATORIES

Item 17: For those items for which data is available, please provide the following actual monthly balance by account for the historic and future test periods to present:

a. depreciable utility plant in service;
b. nondepreciable utility plan in service;
c. construction work in progress;
d. accumulated deferred income tax;
e. materials and supplies;
f. customer advances for construction;
g. contributions in aid of construction;
h. accumulated depreciation;
i. prepayments by type;
j. customer deposits;
k. injury and damages reserve.

Response: See attached.

Equitable Gas Company
Response to Standard Data Requests - Question 17
REVENUE REQUIREMENT INTERROGATORIES

Month	Depreciable Utility Plant in Service (a)	Nondepreciable Utility Plant in Service (b)	Construction Work in Progress (c)	Accumulated Deferred Income Tax (d)	Materials & Supplies (e)	Customer Advances for Construction (f)	Contributions in Aid of Construction (g)	Accumulated Depreciation (h)
Jan-2007	837,039,274	767,703	12,665,214	(91,453,459)	1,483,952	-	-	289,651,244
Feb-2007	837,699,220	741,784	13,106,308	(92,106,709)	1,706,867	-	-	289,552,728
Mar-2007	837,863,812	741,784	16,418,043	(92,773,564)	1,508,173	-	-	289,179,972
Apr-2007	841,744,911	741,784	14,818,487	(93,716,723)	1,318,155	-	-	290,568,639
May-2007	841,129,651	741,784	15,378,519	(94,799,486)	1,483,239	-	-	288,441,290
Jun-2007	840,247,396	741,784	15,392,301	(95,554,831)	1,846,425	-	-	286,420,671
Jul-2007	842,524,411	741,784	17,181,182	(96,837,547)	1,186,146	-	-	287,871,037
Aug-2007	845,220,736	741,784	17,132,290	(97,603,500)	1,156,056	-	-	289,348,433
Sep-2007	846,853,979	741,784	19,480,425	(98,878,201)	1,161,175	-	-	290,358,700
Oct-2007	850,381,715	741,784	20,231,259	(100,304,702)	1,081,699	-	-	291,681,731
Nov-2007	854,155,938	741,784	19,019,750	(101,122,219)	1,062,218	-	-	293,022,285
Dec-2007	862,954,208	741,784	11,566,092	(95,902,177)	1,015,253	-	-	294,390,044
Jan-2008	865,103,779	741,784	12,222,115	(96,603,330)	948,096			295,504,149
Feb-2008	867,112,457	741,784	13,025,933	(97,304,483)	913,428			296,973,042
Mar-2008	865,901,409	741,784	14,497,705	(98,005,636)	908,173			296,074,712

Equitable Gas Company
Response to Standard Data Requests
REVENUE REQUIREMENT INTERROGATORIES

Item 17 I. For those items for which data is available, please provide the following actual monthly balance by account for the historic and future test periods to present.

	PPD PENSION	PPD RENT AGH CENTER BRIDGE	PPD AGA DUES	PPD PGA DUES	PPD MAINT.	PPD RETENTION BONUS	PPD OTHER RENT
Jan-07	14,897,982	28,241	54,400	64,772	71,524	70,278	530,000
Feb-07	14,758,815	25,674	33,270	58,883	247,452	67,222	585,000
Mar-07	14,619,648	23,106	12,141	52,995	240,830	64,167	530,000
Apr-07	14,480,481	20,539	50,353	47,107	132,233	61,111	
May-07	14,341,314	17,971	29,223	41,218	172,826	58,056	
Jun-07	15,238,059	15,404	8,094	35,330	218,548	55,000	
Jul-07	15,098,892	12,837	46,683	29,442	254,461	51,944	
Aug-07	14,959,725	10,269	25,365	23,553	216,179	48,889	102,081
Sep-07	15,487,718	7,702	4,047	17,665	207,639	45,833	
Oct-07	15,418,134	31,087	42,070	11,777	149,635	42,778	
Nov-07	15,348,551	28,520	20,752	5,888	109,194	39,722	
Dec-07	14,039,402	30,808	62,432	-	91,313	36,667	15,061
Total Prepaids as of 12/31/07 (Pennsylvania Division Only)		14,275,683					
Jan-08	13,989,318	28,241	41,622	62,783	92,794	33,612	(15,061)
Feb-08	13,939,234	25,673	35,844	57,076	220,590	30,557	
Mar-08	13,889,150	23,106	13,529	51,851	295,073	27,502	
Total Prepaids as of 3/31/08 (Pennsylvania Division Only)		14,300,212					

Equitable Gas Company
Response to Standard Data Requests
REVENUE REQUIREMENT INTERROGATORIES

Item 17 J. For those items for which data is available, please provide the following actual monthly balance by account for the historic and future test periods to present.

	Customer Deposits
Jan-07	$ (4,168,262)
Feb-07	(4,115,452)
Mar-07	(4,055,553)
Apr-07	(3,859,238)
May-07	(3,735,348)
Jun-07	(3,641,573)
Jul-07	(3,569,478)
Aug-07	(3,447,163)
Sep-07	(3,473,131)
Oct-07	(3,404,897)
Nov-07	(3,364,481)
Dec-07	(3,484,804)
Jan-08	(3,527,421)
Feb-08	(3,595,878)
Mar-08	(3,669,181)

Item 17 K. For those items for which data is available, please provide the following actual monthly balance by account for the historic and future test periods to present.

	WC PAY RESERVES	WC RESERVES ACCOUNT ADJS	GENERAL LIABILITY	AUTO LIABILITY	ENVIRONMENTAL RESERVE
Jan-07	(509,802)	137,930	(978,424)	(360,674)	(72,865)
Feb-07	(485,895)	151,007	(1,181,988)	(364,093)	(72,865)
Mar-07	(411,450)	160,603	(1,006,101)	(581,434)	(72,865)
Apr-07	(412,414)	170,912	(1,234,101)	(583,591)	(72,865)
May-07	(394,190)	170,452	(1,460,623)	(586,642)	(72,865)
Jun-07	(419,907)	180,762	(1,437,225)	(213,553)	(72,865)
Jul-07	(395,328)	146,335	(1,664,151)	(218,253)	(72,865)
Aug-07	(381,217)	129,319	(1,891,051)	(220,285)	(72,865)
Sep-07	(465,958)	144,091	(2,025,144)	(324,075)	(72,865)
Oct-07	(460,952)	132,155	(2,251,725)	(328,775)	(72,865)
Nov-07	(455,951)	143,840	(2,475,607)	(333,475)	(72,865)
Dec-07	(517,942)	157,534	(320,168)	(360,265)	(72,865)
Total as of 12/31/2007		(1,113,706)			
Jan-08	(516,438)	170,013	(544,949)	(363,654)	(72,865)
Feb-08	(508,209)	182,488	(760,651)	(367,043)	(72,865)
Mar-08	(409,068)	195,522	(965,032)	(95,366)	(72,865)
Total as of 3/31/08		(1,346,809)			

Equitable Gas Company
Response to Standard Data Requests
REVENUE REQUIREMENT INTERROGATORIES

Item 18: Please provide a copy of all workpapers supporting the Company's lead/lag study.

Response: Please see attached

EQUITABLE GAS COMPANY
SUMMARY OF CASH WORKING CAPITAL -LEAD-LAG STUDY
TWELVE MONTHS ENDED DECEMBER 31, 2007

Cost Category	Pro Forma Expense	Daily Requirement	Revenue Lag Days	Expense Lag Days	Page No. Reference	Net Lag Days	Working Capital Requirement
(1)	(2)	(3)	(4)	(5)	(6)	(7)=(4)-(5)	(3)*(7)
OPERATING EXPENSES							
Gas Purchased	304,687,435	834,760	49.29	45.91	4,8,9,10	3.38	2,821,489
Payroll	22,491,609	61,621	49.29	17.09	11	32.20	1,984,191
Employee Benefits	6,588,861	18,052	49.29	11.03	27	38.26	690,683
Corporate Services	16,400,236	44,932	49.29	14.71	13	34.58	1,553,723
Injuries & Damages Insurance	4,779,238	13,094	49.29	(164.74)	19	214.03	2,802,458
Uncollectibles	13,450,508	36,851	49.29	49.29	3	-	-
Other O & M Expense	26,518,306	72,653	49.29	35.47	14,15,16,17,18	13.82	1,004,063
Total Operating Expense	394,916,194						
Depreciation & Amortization	21,446,256						
TAXES OTHER THAN INCOME	2,325,555	6,371	49.29	(66.05)	30	115.34	734,854
INCOME TAXES							
Current -Federal	6,550,916	17,948	49.29	36.50	28	12.79	229,551
Current - State	2,077,346	5,691	49.29	51.58	28	(2.29)	(13,005)
Deferred - Federal & State	4,252,547						
Investment Tax Credit	(9,114)						
INTEREST ON DEBT	15,855,958	43,441	49.29	72.58	32	(23.29)	(1,011,867)
PA Sales and Use Taxes	5,629,365	15,423	49.29	35.33	29	13.96	215,360
TOTAL CASH WORKING CAPITAL REQUIREMENT							11,011,500

Note: Weighted average lag days for multiple pages reference

EQUITABLE GAS COMPANY
SUMMARY OF CASH WORKING CAPITAL -LEAD-LAG STUDY AT PRESENT BASE RATES
TWELVE MONTHS ENDED DECEMBER 31, 2008

Cost Category	Pro Forma Expense	Daily Requirement	Revenue Lag Days	Expense Lag Days	Page No. Reference	Net Lag Days	Working Capital Requirement
(1)	(2)	(3)	(4)	(5)	(6)	(7)=(4)-(5)	(3)*(7)
OPERATING EXPENSES							
Gas Purchased	359,315,773	984,427	49.29	45.91	4,8,9,10	3.4	3,330,278
Payroll	24,095,087	66,014	49.29	17.09	11	32.2	2,125,649
Employee Benefits	7,069,423	19,368	49.29	11.03	27	38.3	741,058
Corporate Services	15,990,000	43,808	49.29	14.71	13	34.6	1,514,858
Injuries & Damages Insurance	4,803,788	13,161	49.29	(164.74)	19	214.0	2,816,853
Uncollectibles	25,049,825	68,630	49.29	49.29	3	-	-
Other O & M Expense	28,100,026	76,986	49.29	35.47	14,15,16,17,18	13.8	1,063,748
Total Operating Expense	464,423,924						
Depreciation & Amortization	23,471,055						
TAXES OTHER THAN INCOME	2,185,866	5,989	49.29	(66.05)	30	115.3	690,713
INCOME TAXES							
Current -Federal	(3,182,873)	(8,720)	49.29	36.50	28	12.8	(111,531)
Current - State	(1,009,313)	(2,765)	49.29	51.58	28	(2.3)	6,319
Deferred - Federal & State	8,545,747						
Investment Tax Credit	(5,529)						
INTEREST ON DEBT	16,972,650	46,500	49.29	72.58	32	(23.3)	(1,083,130)
PA Sales and Use Taxes	6,287,006	17,225	49.29	35.33	29	13.96	240,519
TOTAL CASH WORKING CAPITAL REQUIREMENT							11,335,335

Note: Weighted average lag days for multiple pages reference

Equitable Gas Company

Revenue Lag
For The Twelve Months Ended December 31, 2007

Month	Revenue	A/R (EOM)
January	59,146,220	29,963,411
February	97,281,991	76,772,276
March	82,543,084	89,702,472
April	51,016,593	77,524,728
May	30,829,408	59,008,131
June	17,341,140	49,402,421
July	15,097,506	30,083,843
August	14,315,674	15,712,296
September	14,194,818	22,919,553
October	15,690,457	(9,203,129)
November	30,121,445	(8,202,576)
December	68,802,427	42,904,782
TOTAL	496,380,763	476,588,208
Average Daily	1,359,947	39,715,684

Revenue Collection Lag (1)	29.20
Service Lag (2)	15.21
Billing Lag (3)	4.88
Total Revenue Lag (days)	49.29

Notes:

(1) Based on the division of the sum of the daily accounts receivable balances by the sum of daily cash collections.

(2) Computed as: 365 days/12 months = 30.42 average days per month/2 (midpoint) = 15.21 days

(3) Based on the average lag days between meter reading and the mailing of the bill

Equitable Gas Company

Purchased Gas Summary
For The Twelve Months Ended December 31, 2007

Period Covered From (A)	To (B)	Mid-Point of Period (C)	Date Paid (D)	Days Lag (D-C) (E)	Amount of Expense (F)	Dollar Days (E*F) (G)
Transportation						
Equitrans						
12/1/2006	12/31/2006	12/16/2006	1/25/2007	40.00	3,289,620	131,584,796
1/1/2007	1/31/2007	1/16/2007	2/26/2007	41.00	3,301,833	135,375,171
2/1/2007	2/28/2007	2/14/2007	3/26/2007	39.50	3,324,261	131,308,324
3/1/2007	3/31/2007	3/16/2007	4/25/2007	40.00	3,311,588	132,463,535
4/1/2007	4/30/2007	4/15/2007	5/25/2007	39.50	2,642,827	104,391,648
5/1/2007	5/31/2007	5/16/2007	6/25/2007	40.00	2,615,249	104,609,948
6/1/2007	6/30/2007	6/15/2007	7/25/2007	39.50	2,681,277	105,910,458
7/1/2007	7/31/2007	7/16/2007	8/27/2007	42.00	2,709,413	113,795,328
8/1/2007	8/31/2007	8/16/2007	9/25/2007	40.00	2,672,024	106,880,942
9/1/2007	9/30/2007	9/15/2007	10/25/2007	39.50	2,681,557	105,921,485
10/1/2007	10/31/2007	10/16/2007	11/26/2007	41.00	2,705,805	110,937,985
11/1/2007	11/30/2007	11/15/2007	12/26/2007	40.50	3,444,888	139,517,969
	TOTAL			40.21	35,380,341	1,422,697,591
Dominion Transmission						
12/1/2006	12/31/2006	12/16/2006	1/25/2007	40.00	160,263	6,410,510
1/1/2007	1/31/2007	1/16/2007	2/26/2007	41.00	962,725	39,471,718
2/1/2007	2/28/2007	2/14/2007	3/26/2007	39.50	208,997	8,255,365
3/1/2007	3/31/2007	3/16/2007	4/25/2007	40.00	227,638	9,105,508
4/1/2007	4/30/2007	4/15/2007	5/25/2007	39.50	74,005	2,923,181
5/1/2007	5/31/2007	5/16/2007	6/25/2007	40.00	84,546	3,381,824
6/1/2007	6/30/2007	6/15/2007	7/25/2007	39.50	88,037	3,477,467
7/1/2007	7/31/2007	7/16/2007	8/27/2007	42.00	89,053	3,740,222
8/1/2007	8/31/2007	8/16/2007	9/25/2007	40.00	86,472	3,458,873
9/1/2007	9/30/2007	9/15/2007	10/25/2007	39.50	83,425	3,295,276
10/1/2007	10/31/2007	10/16/2007	11/26/2007	41.00	83,860	3,438,272
11/1/2007	11/30/2007	11/15/2007	12/26/2007	40.50	192,065	7,778,633
	TOTAL			40.47	2,341,084	94,736,849
VPEM (Dominion Transmission)						
12/1/2006	12/31/2006	12/16/2006	1/25/2007	40.00	269,818	10,792,724
1/1/2007	1/31/2007	1/16/2007	2/26/2007	41.00	257,079	10,540,234
2/1/2007	2/28/2007	2/14/2007	3/26/2007	39.50	682,615	26,963,305
3/1/2007	3/31/2007	3/16/2007	4/25/2007	40.00	260,667	10,426,681
4/1/2007	4/30/2007	4/15/2007	5/25/2007	39.50	90,793	3,586,307
5/1/2007	5/31/2007	5/16/2007	6/25/2007	40.00	4,199,243	167,969,731
6/1/2007	6/30/2007	6/15/2007	7/25/2007	39.50	2,173,746	85,862,969
7/1/2007	7/31/2007	7/16/2007	8/27/2007	42.00	1,966,482	82,592,256
8/1/2007	8/31/2007	8/16/2007	9/25/2007	40.00	1,740,733	69,629,327
9/1/2007	9/30/2007	9/15/2007	10/25/2007	39.50	1,530,347	60,448,718
10/1/2007	10/31/2007	10/16/2007	11/26/2007	41.00	1,776,653	72,842,761
11/1/2007	11/30/2007	11/15/2007	12/26/2007	40.50	259,047	10,491,410
	TOTAL			40.25	15,207,224	612,146,423
Texas Eastern Pipeline						
12/1/2006	12/31/2006	12/16/2006	1/25/2007	40.00	1,195,348	47,813,932
1/1/2007	1/31/2007	1/16/2007	2/26/2007	41.00	1,183,649	48,529,611
2/1/2007	2/28/2007	2/14/2007	3/26/2007	39.50	1,225,204	48,395,548
3/1/2007	3/31/2007	3/16/2007	4/25/2007	40.00	1,248,176	49,927,037
4/1/2007	4/30/2007	4/15/2007	5/25/2007	39.50	1,313,965	51,901,620
5/1/2007	5/31/2007	5/16/2007	6/25/2007	40.00	1,299,085	51,963,396
6/1/2007	6/30/2007	6/15/2007	7/25/2007	39.50	1,533,686	60,580,588
7/1/2007	7/31/2007	7/16/2007	8/27/2007	42.00	1,267,158	53,220,627
8/1/2007	8/31/2007	8/16/2007	9/25/2007	40.00	1,278,232	51,129,264
9/1/2007	9/30/2007	9/15/2007	10/25/2007	39.50	1,308,061	51,668,402
10/1/2007	10/31/2007	10/16/2007	11/26/2007	41.00	1,311,299	53,763,273
11/1/2007	11/30/2007	11/15/2007	12/26/2007	40.50	1,190,779	48,226,559
	TOTAL			40.19	15,354,642	617,119,857
	GRAND TOTAL				68,283,290	2,746,700,720
	WEIGHTED AVERAGE DAYS			40.23		

Equitable Gas Company

Purchased Gas Summary
For The Twelve Months Ended December 31, 2007

	Period Covered		Mid-Point of	Date	Days Lag	Amount of	Dollar Days
	From	To	Period	Paid	(D-C)	Expense	(E*F)
VENDOR	(A)	(B)	(C)	(D)	(E)	(F)	(G)
EQUITABLE ENERGY	12/1/2006	12/31/2006	12/16/2006	1/25/2007	40 00	363,078	14,523,103
KYWV - Transport	12/1/2006	12/31/2006	12/16/2006	1/25/2007	40.00	39,501	1,580,051
CIPCO	12/1/2006	12/31/2006	12/16/2006	1/25/2007	40.00	(625,066)	(25,002,628)
ANADARKO	12/1/2006	12/31/2006	12/16/2006	1/25/2007	40.00	272,905	10,916,198
BP ENERGY/Amoco	12/1/2006	12/31/2006	12/16/2006	1/25/2007	40 00	1,348,500	53,940,000
Colonial	12/1/2006	12/31/2006	12/16/2006	1/25/2007	40.00	230,826	9,233,024
CONSTELLATION POWER	12/1/2006	12/31/2006	12/16/2006	1/25/2007	40.00	1,281,972	51,278,872
DELTA/SEMPRA	12/1/2006	12/31/2006	12/16/2006	1/25/2007	40.00	41,750	1,670,000
DOMINION FIELD SVC	12/1/2006	12/31/2006	12/16/2006	1/25/2007	40.00	23,965	958,608
DOMINION HOPE	12/1/2006	12/31/2006	12/16/2006	1/25/2007	40 00	67,752	2,710,066
EAGLE ENERGY	12/1/2006	12/31/2006	12/16/2006	1/25/2007	40.00	1,285,218	51,408,723
EASTERN MARKETING	12/1/2006	12/31/2006	12/16/2006	1/25/2007	40.00	810,273	32,410,933
Magellan Envirogas	12/1/2006	12/31/2006	12/16/2006	1/25/2007	40.00	185,476	7,419,053
DEVON GAS	12/1/2006	12/31/2006	12/16/2006	1/25/2007	40 00	5,250,160	210,006,400
OCCIDENTAL	12/1/2006	12/31/2006	12/16/2006	1/25/2007	40.00	1,232,400	49,296,000
PPM ENERGY	12/1/2006	12/31/2006	12/16/2006	1/25/2007	40 00	2,792,213	111,688,500
PINE MOUNTAIN	12/1/2006	12/31/2006	12/16/2006	1/25/2007	40.00	9,289	371,553
TOTAL GAS & POWER	12/1/2006	12/31/2006	12/16/2006	1/25/2007	40.00	3,765 221	150,608,828
Coal Gas Recovery	12/1/2006	12/31/2006	12/16/2006	1/25/2007	40 00	284,365	11,374,584
Gathering	12/1/2006	12/31/2006	12/16/2006	1/25/2007	40 00	218,937	8,757,498
			Total		40 00	18,878,734	755,149,365
EQUITABLE ENERGY	1/1/2007	1/31/2007	1/16/2007	2/26/2007	41 00	(168,098)	(6,892,030)
CIPCO	1/1/2007	1/31/2007	1/16/2007	2/26/2007	41 00	243,142	9,968,838
ANADARKO	1/1/2007	1/31/2007	1/16/2007	2/26/2007	41.00	100,470	4,119,270
BP ENERGY/Amoco	1/1/2007	1/31/2007	1/16/2007	2/26/2007	41 00	300,425	12,317,433
CENTRAL CRUDE	1/1/2007	1/31/2007	1/16/2007	2/26/2007	41.00	971,906	39,848,138
CINERGY	1/1/2007	1/31/2007	1/16/2007	2/26/2007	41.00	39,727	1,628,797
Colonial	1/1/2007	1/31/2007	1/16/2007	2/26/2007	41 00	58,000	2,378,008
DELTA/SEMPRA	1/1/2007	1/31/2007	1/16/2007	2/26/2007	41 00	277,267	11,367,948
DOMINION FIELD SVC	1/1/2007	1/31/2007	1/16/2007	2/26/2007	41 00	1,443,958	59,202,277
DOMINION HOPE	1/1/2007	1/31/2007	1/16/2007	2/26/2007	41.00	92,327	3,785,415
EASTERN MARKETING	1/1/2007	1/31/2007	1/16/2007	2/26/2007	41.00	533,230	21,862,446
Magellan Envirogas	1/1/2007	1/31/2007	1/16/2007	2/26/2007	41 00	142,133	5,827,453
DEVON GAS	1/1/2007	1/31/2007	1/16/2007	2/26/2007	41.00	3 712,560	152,214,960
OCCIDENTAL	1/1/2007	1/31/2007	1/16/2007	2/26/2007	41 00	1,943,889	79,699,463
PPM ENERGY	1/1/2007	1/31/2007	1/16/2007	2/26/2007	41 00	1,518,022	62,238,918
PINE MOUNTAIN	1/1/2007	1/31/2007	1/16/2007	2/26/2007	41 00	11,406	467,628
PLATTS	1/1/2007	1/31/2007	1/16/2007	2/26/2007	41 00	1,985	81,385
SOUTHWESTERN	1/1/2007	1/31/2007	1/16/2007	2/26/2007	41.00	1,158,936	47,516,387
TOTAL GAS & POWER	1/1/2007	1/31/2007	1/16/2007	2/26/2007	41.00	168,149	6,894,095
TW PHILLIPS	1/1/2007	1/31/2007	1/16/2007	2/26/2007	41 00	17,647	723,520
Coal Gas Recovery	1/1/2007	1/31/2007	1/16/2007	2/26/2007	41.00	174,843	7,168,560
Gathering	1/1/2007	1/31/2007	1/16/2007	2/26/2007	41.00	295,257	12,105,531
			Total		41.00	13,037,181	534,524,439
EQUITABLE ENERGY	2/1/2007	2/28/2007	2/14/2007	3/26/2007	39.50	262,403	10,364,910
CIPCO	2/1/2007	2/28/2007	2/14/2007	3/26/2007	39.50	254,519	10,053,511
ANADARKO	2/1/2007	2/28/2007	2/14/2007	3/26/2007	39 50	859,539	33,951,791
CENTRAL CRUDE	2/1/2007	2/28/2007	2/14/2007	3/26/2007	39 50	1,217,164	48,077,997
Colonial	2/1/2007	2/28/2007	2/14/2007	3/26/2007	39.50	491,796	19,425,922
DELTA/SEMPRA	2/1/2007	2/28/2007	2/14/2007	3/26/2007	39 50	132,792	5,245,284
DOMINION FIELD SVC	2/1/2007	2/28/2007	2/14/2007	3/26/2007	39.50	9,318	368,053
DOMINION HOPE	2/1/2007	2/28/2007	2/14/2007	3/26/2007	39 50	110,574	4,367,686
EASTERN MARKETING	2/1/2007	2/28/2007	2/14/2007	3/26/2007	39.50	473,441	18,700,938
Magellan Envirogas	2/1/2007	2/28/2007	2/14/2007	3/26/2007	39.50	123,249	4,868,320
DEVON GAS	2/1/2007	2/28/2007	2/14/2007	3/26/2007	39 50	4,131,520	163,195,041
OCCIDENTAL	2/1/2007	2/28/2007	2/14/2007	3/26/2007	39.50	4,831,061	190,826,924
PPM ENERGY	2/1/2007	2/28/2007	2/14/2007	3/26/2007	39.50	1,328,291	52,467,501
PINE MOUNTAIN	2/1/2007	2/28/2007	2/14/2007	3/26/2007	39.50	15,100	596,456
PLANALYTICS	2/1/2007	2/28/2007	2/14/2007	3/26/2007	39.50	62,500	2,468,750
SOUTHWESTERN	2/1/2007	2/28/2007	2/14/2007	3/26/2007	39 50	548,650	21,671,675
TOTAL GAS & POWER	2/1/2007	2/28/2007	2/14/2007	3/26/2007	39.50	1,384,123	54,672,866
Coal Gas Recovery	2/1/2007	2/28/2007	2/14/2007	3/26/2007	39.50	187,344	7,400,094
Nexen	2/1/2007	2/28/2007	2/14/2007	3/26/2007	39.50	211,988	8,373,522
Gathering	2/1/2007	2/28/2007	2/14/2007	3/26/2007	39.50	185,935	7,344,441
		Total			39.50	16,821,308	664 441,682

Equitable Gas Company

Purchased Gas Summary
For The Twelve Months Ended December 31, 2007

VENDOR	Period Covered From (A)	To (B)	Mid-Point of Period (C)	Date Paid (D)	Days Lag (D-C) (E)	Amount of Expense (F)	Dollar Days (E*F) (G)
EQUITABLE ENERGY	3/1/2007	3/31/2007	3/16/2007	4/25/2007	40 00	188,781	7,551,245
CIPCO	3/1/2007	3/31/2007	3/16/2007	4/25/2007	40.00	263,112	10,524,483
ANADARKO	3/1/2007	3/31/2007	3/16/2007	4/25/2007	40.00	56,264	2,250,565
BP ENERGY/Amoco	3/1/2007	3/31/2007	3/16/2007	4/25/2007	40 00	171,609	6,864,343
CENTRAL CRUDE	3/1/2007	3/31/2007	3/16/2007	4/25/2007	40 00	1,182,472	47,298,882
Colonial	3/1/2007	3/31/2007	3/16/2007	4/25/2007	40.00	235,886	9,435,420
DOMINION FIELD SVC	3/1/2007	3/31/2007	3/16/2007	4/25/2007	40.00	10,786	431,430
DOMINION HOPE	3/1/2007	3/31/2007	3/16/2007	4/25/2007	40.00	134,089	5,363,575
EASTERN MARKETING	3/1/2007	3/31/2007	3/16/2007	4/25/2007	40.00	638,161	25,526,439
Magellan Envirogas	3/1/2007	3/31/2007	3/16/2007	4/25/2007	40 00	(12,049)	(481,963)
DEVON GAS	3/1/2007	3/31/2007	3/16/2007	4/25/2007	40.00	5,188,390	207,535,603
OCCIDENTAL	3/1/2007	3/31/2007	3/16/2007	4/25/2007	40 00	2,994,673	119,786,931
PPM ENERGY	3/1/2007	3/31/2007	3/16/2007	4/25/2007	40.00	2,408,822	96,352,895
PINE MOUNTAIN	3/1/2007	3/31/2007	3/16/2007	4/25/2007	40.00	12,669	506,748
SOUTHWESTERN	3/1/2007	3/31/2007	3/16/2007	4/25/2007	40.00	209,994	8,399,744
TOTAL GAS & POWER	3/1/2007	3/31/2007	3/16/2007	4/25/2007	40 00	50,741	2,029,651
TW PHILLIPS	3/1/2007	3/31/2007	3/16/2007	4/25/2007	40.00	20,751	830,050
Coal Gas Recovery	3/1/2007	3/31/2007	3/16/2007	4/25/2007	40 00	207,367	8,294,684
FORTIS	3/1/2007	3/31/2007	3/16/2007	4/25/2007	40.00	80,717	3,228,662
Gathering	3/1/2007	3/31/2007	3/16/2007	4/25/2007	40.00	266,591	10,663,658
			Total		40 00	14,309,826	572,393,026
EQUITABLE ENERGY	4/1/2007	4/30/2007	4/15/2007	5/25/2007	39 50	148,986	5,884,951
CIPCO	4/1/2007	4/30/2007	4/15/2007	5/25/2007	39.50	264,471	10,446,597
ANADARKO	4/1/2007	4/30/2007	4/15/2007	5/25/2007	39.50	286,920	11,333,340
BP ENERGY/Amoco	4/1/2007	4/30/2007	4/15/2007	5/25/2007	39.50	1,573,122	62,138,314
CENTRAL CRUDE	4/1/2007	4/30/2007	4/15/2007	5/25/2007	39.50	1,030,596	40,708,548
Colonial	4/1/2007	4/30/2007	4/15/2007	5/25/2007	39.50	2 222,624	87,793,656
CONOCO	4/1/2007	4/30/2007	4/15/2007	5/25/2007	39.50	1,432,440	56,581,380
DELTA/SEMPRA	4/1/2007	4/30/2007	4/15/2007	5/25/2007	39 50	467,800	18 478,100
DOMINION FIELD SVC	4/1/2007	4/30/2007	4/15/2007	5/25/2007	39.50	12,247	483,766
DOMINION HOPE	4/1/2007	4/30/2007	4/15/2007	5/25/2007	39.50	78,994	3,120,264
EAGLE ENERGY	4/1/2007	4/30/2007	4/15/2007	5/25/2007	39.50	1,091,776	43,125,165
EASTERN MARKETING	4/1/2007	4/30/2007	4/15/2007	5/25/2007	39.50	696,877	27,526,622
DEVON GAS	4/1/2007	4/30/2007	4/15/2007	5/25/2007	39.50	4,624,800	182,679,602
OCCIDENTAL	4/1/2007	4/30/2007	4/15/2007	5/25/2007	39 50	2,976,508	117,572,051
PPM ENERGY	4/1/2007	4/30/2007	4/15/2007	5/25/2007	39.50	701,747	27,719,022
PINE MOUNTAIN	4/1/2007	4/30/2007	4/15/2007	5/25/2007	39.50	19,700	778,145
TOTAL GAS & POWER	4/1/2007	4/30/2007	4/15/2007	5/25/2007	39 50	560 650	22,145 681
TW PHILLIPS	4/1/2007	4/30/2007	4/15/2007	5/25/2007	39.50	32,506	1,283,972
Coal Gas Recovery	4/1/2007	4/30/2007	4/15/2007	5/25/2007	39.50	439,972	17,378,888
FORTIS	4/1/2007	4/30/2007	4/15/2007	5/25/2007	39.50	194,274	7,673,823
Atlas america	4/1/2007	4/30/2007	4/15/2007	5/25/2007	39.50	1,193,700	47,151,150
Gathering	4/1/2007	4/30/2007	4/15/2007	5/25/2007	39 50	229,143	9,051,167
			Total		39 50	20,279,853	801,054,203
EQUITABLE ENERGY	5/1/2007	5/31/2007	5/16/2007	6/25/2007	40.00	(23,833)	(953,336)
CIPCO	5/1/2007	5/31/2007	5/16/2007	6/25/2007	40.00	287,815	11,512,587
BP ENERGY/Amoco	5/1/2007	5/31/2007	5/16/2007	6/25/2007	40 00	41,155	1,646,213
CENTRAL CRUDE	5/1/2007	5/31/2007	5/16/2007	6/25/2007	40 00	585,018	23,400,734
Colonial	5/1/2007	5/31/2007	5/16/2007	6/25/2007	40.00	922,095	36,883,816
CONOCO	5/1/2007	5/31/2007	5/16/2007	6/25/2007	40.00	1,470,888	58,835,520
DOMINION FIELD SVC	5/1/2007	5/31/2007	5/16/2007	6/25/2007	40.00	19,268	770,724
DOMINION HOPE	5/1/2007	5/31/2007	5/16/2007	6/25/2007	40 00	57,744	2,309,764
EAGLE ENERGY	5/1/2007	5/31/2007	5/16/2007	6/25/2007	40 00	499,696	19,987,820
EASTERN MARKETING	5/1/2007	5/31/2007	5/16/2007	6/25/2007	40.00	778,781	31,151,250
Magellan Envirogas	5/1/2007	5/31/2007	5/16/2007	6/25/2007	40.00	(771,029)	(30,841,146)
DEVON GAS	5/1/2007	5/31/2007	5/16/2007	6/25/2007	40.00	4,747,960	189,918,401
OCCIDENTAL	5/1/2007	5/31/2007	5/16/2007	6/25/2007	40 00	1,257,293	50,291,705
PPM ENERGY	5/1/2007	5/31/2007	5/16/2007	6/25/2007	40 00	80,618	3,224,707
PINE MOUNTAIN	5/1/2007	5/31/2007	5/16/2007	6/25/2007	40 00	10,747	429,900
SOUTHWESTERN	5/1/2007	5/31/2007	5/16/2007	6/25/2007	40 00	139,590	5,583,600
TOTAL GAS & POWER	5/1/2007	5/31/2007	5/16/2007	6/25/2007	40.00	571,611	22,864,456
TW PHILLIPS	5/1/2007	5/31/2007	5/16/2007	6/25/2007	40 00	24,703	988,114
Coal Gas Recovery	5/1/2007	5/31/2007	5/16/2007	6/25/2007	40.00	477,450	19,098,000
FORTIS	5/1/2007	5/31/2007	5/16/2007	6/25/2007	40.00	41,182	1,647,279
Atlas america	5/1/2007	5/31/2007	5/16/2007	6/25/2007	40.00	1 277,204	51,088,154
Gathering	5/1/2007	5/31/2007	5/16/2007	6/25/2007	40.00	270,068	10,802,726
			Total		40.00	12,766,025	510,640,986

Equitable Gas Company

Purchased Gas Summary
For The Twelve Months Ended December 31, 2007

	Period Covered		Mid-Point of	Date	Days Lag	Amount of	Dollar Days
	From	To	Period	Paid	(D-C)	Expense	(E*F)
VENDOR	(A)	(B)	(C)	(D)	(E)	(F)	(G)
EQUITABLE ENERGY	6/1/2007	6/30/2007	6/15/2007	7/25/2007	39.50	(10,380)	(409,996)
CIPCO	6/1/2007	6/30/2007	6/15/2007	7/25/2007	39.50	273,626	10,808,226
ANADARKO	6/1/2007	6/30/2007	6/15/2007	7/25/2007	39.50	1,243,194	49,106,163
CENTRAL CRUDE	6/1/2007	6/30/2007	6/15/2007	7/25/2007	39.50	602,873	23,813,468
CONOCO	6/1/2007	6/30/2007	6/15/2007	7/25/2007	39 50	1,438,380	56,816,010
CONSTELLATION POWER	6/1/2007	6/30/2007	6/15/2007	7/25/2007	39.50	1,159,078	45,783,565
DOMINION FIELD SVC	6/1/2007	6/30/2007	6/15/2007	7/25/2007	39.50	21,826	862,141
DOMINION HOPE	6/1/2007	6/30/2007	6/15/2007	7/25/2007	39 50	21,581	852,458
EAGLE ENERGY	6/1/2007	6/30/2007	6/15/2007	7/25/2007	39.50	443,015	17,499,086
EASTERN MARKETING	6/1/2007	6/30/2007	6/15/2007	7/25/2007	39 50	1,005,936	39,734,490
DEVON GAS	6/1/2007	6/30/2007	6/15/2007	7/25/2007	39.50	4,644,600	183,461,702
OCCIDENTAL	6/1/2007	6/30/2007	6/15/2007	7/25/2007	39 50	6,891,157	272,200,686
PPM ENERGY	6/1/2007	6/30/2007	6/15/2007	7/25/2007	39 50	2 407,625	95,101,171
PINE MOUNTAIN	6/1/2007	6/30/2007	6/15/2007	7/25/2007	39 50	1,807	71,383
PLANALYTICS	6/1/2007	6/30/2007	6/15/2007	7/25/2007	39 50	62,500	2,468,750
TOTAL GAS & POWER	6/1/2007	6/30/2007	6/15/2007	7/25/2007	39.50	4,757,473	187,920,189
TW PHILLIPS	6/1/2007	6/30/2007	6/15/2007	7/25/2007	39.50	43,984	1,737,355
Coal Gas Recovery	6/1/2007	6/30/2007	6/15/2007	7/25/2007	39.50	568,620	22,460,504
FORTIS	6/1/2007	6/30/2007	6/15/2007	7/25/2007	39 50	(0)	(0)
Atlas amenca	6/1/2007	6/30/2007	6/15/2007	7/25/2007	39 50	1,003,883	39,653,362
Gathenng	6/1/2007	6/30/2007	6/15/2007	7/25/2007	39.50	322,257	12,729,153
		Total			39 50	26,903,035	1,062,669,868
EQUITABLE ENERGY	7/1/2007	7/31/2007	7/16/2007	8/27/2007	42.00	(252,308)	(10,596,947)
CIPCO	7/1/2007	7/31/2007	7/16/2007	8/27/2007	42 00	304,739	12,799,035
Atlas Resources	7/1/2007	7/31/2007	7/16/2007	8/27/2007	42 00	(182,216)	(7,653,071)
BP ENERGY/Amoco	7/1/2007	7/31/2007	7/16/2007	8/27/2007	42 00	233,154	9,792,478
CENTRAL CRUDE	7/1/2007	7/31/2007	7/16/2007	8/27/2007	42.00	321,966	13,522,572
CONSTELLATION POWER	7/1/2007	7/31/2007	7/16/2007	8/27/2007	42 00	1,096,294	46,044,356
DELTA/SEMPRA	7/1/2007	7/31/2007	7/16/2007	8/27/2007	42 00	1,246,491	52,352,633
DOMINION FIELD SVC	7/1/2007	7/31/2007	7/16/2007	8/27/2007	42.00	18,542	778,780
DOMINION HOPE	7/1/2007	7/31/2007	7/16/2007	8/27/2007	42.00	15,297	642,456
EAGLE ENERGY	7/1/2007	7/31/2007	7/16/2007	8/27/2007	42.00	31,677	1,330,447
EASTERN MARKETING	7/1/2007	7/31/2007	7/16/2007	8/27/2007	42 00	70 923	2,978,776
DEVON GAS	7/1/2007	7/31/2007	7/16/2007	8/27/2007	42.00	4,388,980	184,337,159
OCCIDENTAL	7/1/2007	7/31/2007	7/16/2007	8/27/2007	42.00	1,438,740	60,427,064
PPM ENERGY	7/1/2007	7/31/2007	7/16/2007	8/27/2007	42 00	2,414,628	101,414,367
PINE MOUNTAIN	7/1/2007	7/31/2007	7/16/2007	8/27/2007	42 00	(261)	(10,956)
PLANALYTICS	7/1/2007	7/31/2007	7/16/2007	8/27/2007	42 00	5,000	210,000
TOTAL GAS & POWER	7/1/2007	7/31/2007	7/16/2007	8/27/2007	42.00	2,822,435	118,542,270
TW PHILLIPS	7/1/2007	7/31/2007	7/16/2007	8/27/2007	42.00	282,419	11,861,586
Coal Gas Recovery	7/1/2007	7/31/2007	7/16/2007	8/27/2007	42 00	514,139	21,593,820
FORTIS	7/1/2007	7/31/2007	7/16/2007	8/27/2007	42.00	1,939,361	81,453,180
Atlas amenca	7/1/2007	7/31/2007	7/16/2007	8/27/2007	42 00	52,797	2,217,455
Gathenng	7/1/2007	7/31/2007	7/16/2007	8/27/2007	42 00	189,497	7 958,859
		Total			42.00	16,952,293	711,996,318
EQUITABLE ENERGY	8/1/2007	8/31/2007	8/16/2007	9/25/2007	40 00	523,614	20,944,555
CIPCO	8/1/2007	8/31/2007	8/16/2007	9/25/2007	40 00	304,491	12,179,654
BP ENERGY/Amoco	8/1/2007	8/31/2007	8/16/2007	9/25/2007	40.00	321,500	12,860,000
CENTRAL CRUDE	8/1/2007	8/31/2007	8/16/2007	9/25/2007	40.00	808,975	32,359,018
SEMPRA/DELTA	8/1/2007	8/31/2007	8/16/2007	9/25/2007	40.00	72,706	2,908,224
DOMINION FIELD SVC	8/1/2007	8/31/2007	8/16/2007	9/25/2007	40 00	18,358	734,334
DOMINION HOPE	8/1/2007	8/31/2007	8/16/2007	9/25/2007	40.00	15,113	604,531
EAGLE ENERGY	8/1/2007	8/31/2007	8/16/2007	9/25/2007	40.00	965,181	38,607,236
EASTERN MARKETING	8/1/2007	8/31/2007	8/16/2007	9/25/2007	40.00	69,766	2,790,620
DEVON GAS	8/1/2007	8/31/2007	8/16/2007	9/25/2007	40 00	3,888,560	155,542,399
OCCIDENTAL	8/1/2007	8/31/2007	8/16/2007	9/25/2007	40.00	1,900,323	76,012,917
PPM ENERGY	8/1/2007	8/31/2007	8/16/2007	9/25/2007	40.00	759,332	30,373,292
PINE MOUNTAIN	8/1/2007	8/31/2007	8/16/2007	9/25/2007	40 00	2,424	96,946
TOTAL GAS & POWER	8/1/2007	8/31/2007	8/16/2007	9/25/2007	40 00	2,825,239	113,009,545
TW PHILLIPS	8/1/2007	8/31/2007	8/16/2007	9/25/2007	40.00	124,985	4,999,403
Coal Gas Recovery	8/1/2007	8/31/2007	8/16/2007	9/25/2007	40 00	459,472	18,378,899
Gathering	8/1/2007	8/31/2007	8/16/2007	9/25/2007	40.00	209,292	8,371,673
		Total			40.00	13,269,331	530,773,247

Equitable Gas Company

Purchased Gas Summary
For The Twelve Months Ended December 31, 2007

VENDOR	Period Covered From (A)	To (B)	Mid-Point of Period (C)	Date Paid (D)	Days Lag (D-C) (E)	Amount of Expense (F)	Dollar Days (E*F) (G)
EQUITABLE ENERGY	9/1/2007	9/30/2007	9/15/2007	10/25/2007	39.50	246,772	9,747,481
CIPCO	9/1/2007	9/30/2007	9/15/2007	10/25/2007	39.50	319 437	12,617,764
BP ENERGY/Amoco	9/1/2007	9/30/2007	9/15/2007	10/25/2007	39.50	155,470	6,141,057
CENTRAL CRUDE	9/1/2007	9/30/2007	9/15/2007	10/25/2007	39.50	621,254	24,539,522
Colonial	9/1/2007	9/30/2007	9/15/2007	10/25/2007	39 50	49.394	1,951,079
SEMPRA/DELTA	9/1/2007	9/30/2007	9/15/2007	10/25/2007	39 50	2,817,990	111,310,605
DOMINION FIELD SVC	9/1/2007	9/30/2007	9/15/2007	10/25/2007	39.50	19,982	789,283
DOMINION HOPE	9/1/2007	9/30/2007	9/15/2007	10/25/2007	39 50	14,707	580,942
EASTERN MARKETING	9/1/2007	9/30/2007	9/15/2007	10/25/2007	39.50	58,905	2,326,748
DEVON GAS	9/1/2007	9/30/2007	9/15/2007	10/25/2007	39.50	3,348 000	132,246,000
OCCIDENTAL	9/1/2007	9/30/2007	9/15/2007	10/25/2007	39.50	487,861	19,270,499
PINE MOUNTAIN	9/1/2007	9/30/2007	9/15/2007	10/25/2007	39.50	(2,356)	(93,053)
TOTAL GAS & POWER	9/1/2007	9/30/2007	9/15/2007	10/25/2007	39.50	1,314,870	51,937,363
TW PHILLIPS	9/1/2007	9/30/2007	9/15/2007	10/25/2007	39.50	140,827	5,562,652
Coal Gas Recovery	9/1/2007	9/30/2007	9/15/2007	10/25/2007	39.50	367,720	14,524,950
Gathering	9/1/2007	9/30/2007	9/15/2007	10/25/2007	39 50	309,830	12,238,279
Intercontinental Exchange	9/1/2007	9/30/2007	9/15/2007	10/25/2007	39.50	1,000	39,500
SNL Financial	9/1/2007	9/30/2007	9/15/2007	10/25/2007	39.50	1,297	51,232
		Total			39.50	10,272,960	405,781,902
EQUITABLE ENERGY	10/1/2007	10/31/2007	10/16/2007	11/26/2007	41.00	(288,353)	(11,822,493)
CIPCO	10/1/2007	10/31/2007	10/16/2007	11/26/2007	41.00	296,529	12,157,685
CENTRAL CRUDE	10/1/2007	10/31/2007	10/16/2007	11/26/2007	41 00	36,091	1,479,745
SEMPRA/DELTA	10/1/2007	10/31/2007	10/16/2007	11/26/2007	41.00	3,520,121	144,324,961
DOMINION FIELD SVC	10/1/2007	10/31/2007	10/16/2007	11/26/2007	41 00	18,848	772,760
DOMINION HOPE	10/1/2007	10/31/2007	10/16/2007	11/26/2007	41.00	15,676	642,727
EASTERN MARKETING	10/1/2007	10/31/2007	10/16/2007	11/26/2007	41.00	81,468	3,340,188
DEVON GAS	10/1/2007	10/31/2007	10/16/2007	11/26/2007	41.00	4,075,260	167,085,662
TENASKA	10/1/2007	10/31/2007	10/16/2007	11/26/2007	41.00	6,700	274,700
OCCIDENTAL	10/1/2007	10/31/2007	10/16/2007	11/26/2007	41.00	88,268	3,618,987
PINE MOUNTAIN	10/1/2007	10/31/2007	10/16/2007	11/26/2007	41.00	3,211	131,652
TOTAL GAS & POWER	10/1/2007	10/31/2007	10/16/2007	11/26/2007	41.00	2,681,275	109,932,261
TW PHILLIPS	10/1/2007	10/31/2007	10/16/2007	11/26/2007	41.00	44,454	1,822,630
Coal Gas Recovery	10/1/2007	10/31/2007	10/16/2007	11/26/2007	41.00	500,688	20,528,194
Gathering	10/1/2007	10/31/2007	10/16/2007	11/26/2007	41.00	360,886	14,796,312
Intercontinental Exchange	10/1/2007	10/31/2007	10/16/2007	11/26/2007	41.00	500	20,500
SNL Financial	10/1/2007	10/31/2007	10/16/2007	11/26/2007	41.00	897	36,777
		Total			41.00	11,442,518	469,143,250
EQUITABLE ENERGY	11/1/2007	11/30/2007	11/15/2007	12/26/2007	40.50	(637,336)	(25,812,091)
CIPCO	11/1/2007	11/30/2007	11/15/2007	12/26/2007	40 50	275,356	11,151,934
BP ENERGY/Amoco	11/1/2007	11/30/2007	11/15/2007	12/26/2007	40.50	2,865,898	116,068,853
CENTRAL CRUDE	11/1/2007	11/30/2007	11/15/2007	12/26/2007	40.50	691.000	27,985,500
Colonial	11/1/2007	11/30/2007	11/15/2007	12/26/2007	40.50	89,410	3,621,121
CONOCO	11/1/2007	11/30/2007	11/15/2007	12/26/2007	40.50	425,039	17,214,080
CORAL	11/1/2007	11/30/2007	11/15/2007	12/26/2007	40 50	222,620	9,016,110
SEMPRA/DELTA	11/1/2007	11/30/2007	11/15/2007	12/26/2007	40 50	100,440	4,067,820
DOMINION FIELD SVC	11/1/2007	11/30/2007	11/15/2007	12/26/2007	40.50	17,024	689,480
DOMINION HOPE	11/1/2007	11/30/2007	11/15/2007	12/26/2007	40.50	26,282	1,064,405
EAGLE ENERGY	11/1/2007	11/30/2007	11/15/2007	12/26/2007	40.50	442,528	17,922,393
EASTERN MARKETING	11/1/2007	11/30/2007	11/15/2007	12/26/2007	40 50	85,388	3,458,194
Gas Trader	11/1/2007	11/30/2007	11/15/2007	12/26/2007	40.50	595	24,098
DEVON GAS	11/1/2007	11/30/2007	11/15/2007	12/26/2007	40.50	4,451,400	180,281,697
TENASKA	11/1/2007	11/30/2007	11/15/2007	12/26/2007	40.50	1,012,100	40,990,050
OCCIDENTAL	11/1/2007	11/30/2007	11/15/2007	12/26/2007	40.50	962,487	38,980,724
PINE MOUNTAIN	11/1/2007	11/30/2007	11/15/2007	12/26/2007	40 50	3,262	132,100
PLATTS	11/1/2007	11/30/2007	11/15/2007	12/26/2007	40.50	2,340	94,770
SEQUENT	11/1/2007	11/30/2007	11/15/2007	12/26/2007	40 50	260,300	10,542,150
SOUTHWESTERN	11/1/2007	11/30/2007	11/15/2007	12/26/2007	40 50	424,987	17,211,957
TOTAL GAS & POWER	11/1/2007	11/30/2007	11/15/2007	12/26/2007	40.50	2,975,572	120,510,647
TW PHILLIPS	11/1/2007	11/30/2007	11/15/2007	12/26/2007	40.50	3,400,456	137,718,462
Coal Gas Recovery	11/1/2007	11/30/2007	11/15/2007	12/26/2007	40 50	512,290	20,747,751
Gathering	11/1/2007	11/30/2007	11/15/2007	12/26/2007	40.50	388,860	15,748,820
Intercontinental Exchange	11/1/2007	11/30/2007	11/15/2007	12/26/2007	40.50	500	20,250
SNL Financial	11/1/2007	11/30/2007	11/15/2007	12/26/2007	40 50	897	36,329
TOTAL					40.50	18,999,694	769,487,604

TOTAL GAS COST 193,932,758 7,788,055,891

WEIGHTED AVERAGE DAYS 40.16

Equitable Gas Company

Purchased Gas Summary
For The Twelve Months Ended December 31, 2007

Period Covered From (A)	To (B)	Mid-Point of Period (C)	Date Paid (D)	Days Lag (D-C) (E)	Amount of Expense (F)	Dollar Days (E*F) (G)
APPALACHIAN/Small Gas Purchase						
11/1/2006	11/30/2006	11/15/2006	1/15/2007	60.50	6,226,001	376,673,038
12/1/2006	12/31/2006	12/16/2006	2/15/2007	61.00	10,891,870	664,404,059
1/1/2007	1/31/2007	1/16/2007	3/15/2007	58.00	6,722,208	389,888,066
2/1/2007	2/28/2007	2/14/2007	4/16/2007	60.50	8,730,980	528,224,289
3/1/2007	3/31/2007	3/16/2007	5/15/2007	60.00	10,080,847	604,850,817
4/1/2007	4/30/2007	4/15/2007	6/15/2007	60.50	5,688,135	344,132,171
5/1/2007	5/31/2007	5/16/2007	7/16/2007	61.00	8,682,073	529,606,426
6/1/2007	6/30/2007	6/15/2007	8/15/2007	60.50	13,175,858	797,139,383
7/1/2007	7/31/2007	7/16/2007	9/17/2007	63.00	9,857,652	621,032,048
8/1/2007	8/31/2007	8/16/2007	10/15/2007	60.00	9,233,303	553,998,196
9/1/2007	9/30/2007	9/15/2007	11/15/2007	60.50	6,511,716	393,958,842
10/1/2007	10/31/2007	10/16/2007	12/17/2007	62.00	10,023,227	621,440,080
TOTAL GAS COST					105,823,869	6,425,347,415
WEIGHTED AVERAGE DAYS				60.72		

Equitable Gas Company

Purchased Gas Summary
For The Twelve Months Ended December 31, 2007

Period Covered From (A)	To (B)	Mid-Point of Period (C)	Date Paid (D)	Days Lag (D-C) (E)	Amount of Expense (F)	Dollar Days (E*F) (G)
Agency Gas Cost (Commercial & Industrial)						
12/1/2006	12/31/2006	12/16/2006	1/31/2007	46.00	7,441,064	342,288,945
1/1/2007	1/31/2007	1/16/2007	2/28/2007	43.00	8,924,336	383,746,440
2/1/2007	2/28/2007	2/14/2007	3/31/2007	44.50	11,052,580	491,839,805
3/1/2007	3/31/2007	3/16/2007	4/30/2007	45.00	8,482,006	381,690,273
4/1/2007	4/30/2007	4/15/2007	5/31/2007	45.50	7,324,792	333,278,058
5/1/2007	5/31/2007	5/16/2007	6/30/2007	45.00	3,710,746	166,983,581
6/1/2007	6/30/2007	6/15/2007	7/31/2007	45.50	2,952,728	134,349,137
7/1/2007	7/31/2007	7/16/2007	8/31/2007	46.00	2,799,754	128,788,679
8/1/2007	8/31/2007	8/16/2007	9/30/2007	45.00	2,705,526	121,748,667
9/1/2007	9/30/2007	9/15/2007	10/31/2007	45.50	2,449,422	111,448,697
10/1/2007	10/31/2007	10/16/2007	11/30/2007	45.00	3,344,780	150,515,085
11/1/2007	11/30/2007	11/15/2007	12/31/2007	45.50	5,432,513	247,179,324
	TOTAL				66,620,247	2,993,856,690
	WEIGHTED AVERAGE DAYS			44.94		

Equitable Gas Company

Payroll (Include FICA, FUTA, SUTA,Local, State and Federal Taxes)
For The Twelve Months Ended December 31, 2007

Period Covered From (A)	To (B)	Mid-Point of Period (C)	Date Paid (D)	Days Lag (D-C) (E)	Amount of Expense (F)		Dollar Days (E*F) (G)
Payroll- Non-Union							
12/18/2006	12/31/2006	12/24/2006	1/10/2007	16.50	663,113	$	10,941,372
1/1/2007	1/14/2007	1/7/2007	1/24/2007	16.50	663,604	$	10,949,464
1/14/2007	1/27/2007	1/20/2007	2/6/2007	16.50	3,557,439	$	58,697,742
1/15/2007	1/28/2007	1/21/2007	2/7/2007	16.50	665,254	$	10,976,696
1/29/2007	2/11/2007	2/4/2007	2/21/2007	16.50	656,666	$	10,834,985
2/12/2007	2/25/2007	2/18/2007	3/7/2007	16.50	650,454	$	10,732,489
2/26/2007	3/11/2007	3/4/2007	3/21/2007	16.50	682,704	$	11,264,622
3/12/2007	3/25/2007	3/18/2007	4/4/2007	16.50	658,826	$	10,870,631
3/26/2007	4/8/2007	4/1/2007	4/18/2007	16.50	657,239	$	10,844,448
4/9/2007	4/22/2007	4/15/2007	5/2/2007	16.50	663,850	$	10,953,517
4/23/2007	5/6/2007	4/29/2007	5/16/2007	16.50	669,857	$	11,052,641
5/7/2007	5/20/2007	5/13/2007	5/30/2007	16.50	664,132	$	10,958,178
5/21/2007	6/3/2007	5/27/2007	6/13/2007	16.50	666,519	$	10,997,560
6/4/2007	6/17/2007	6/10/2007	6/27/2007	16.50	663,067	$	10,940,598
6/18/2007	7/1/2007	6/24/2007	7/11/2007	16.50	664,892	$	10,970,725
7/2/2007	7/15/2007	7/8/2007	7/25/2007	16.50	662,533	$	10,931,794
7/16/2007	7/29/2007	7/22/2007	8/8/2007	16.50	649,673	$	10,719,597
7/30/2007	8/12/2007	8/5/2007	8/22/2007	16.50	648,531	$	10,700,760
8/13/2007	8/26/2007	8/19/2007	9/5/2007	16.50	635,798	$	10,490,665
8/27/2007	9/9/2007	9/2/2007	9/19/2007	16.50	640,692	$	10,571,425
9/10/2007	9/23/2007	9/16/2007	10/3/2007	16.50	591,651	$	9,762,245
9/24/2007	10/7/2007	9/30/2007	10/17/2007	16.50	593,444	$	9,791,825
10/8/2007	10/21/2007	10/14/2007	10/31/2007	16.50	596,533	$	9,842,789
10/22/2007	11/4/2007	10/28/2007	11/14/2007	16.50	598,294	$	9,871,849
11/5/2007	11/18/2007	11/11/2007	11/28/2007	16.50	590,987	$	9,751,290
11/19/2007	12/2/2007	11/25/2007	12/12/2007	16.50	629,265	$	10,382,879
12/3/2007	12/16/2007	12/9/2007	12/26/2007	16.50	589,239	$	9,722,448
TOTAL				16.50	$ 20,274,257	$	334,525,232

Equitable Gas Company

Payroll (Include FICA, FUTA, SUTA,Local, State and Federal Taxes)
For The Twelve Months Ended December 31, 2007

Period Covered From (A)	To (B)	Mid-Point of Period (C)	Date Paid (D)	Days Lag (D-C) (E)	Amount of Expense (F)	Dollar Days (E*F) (G)
12/18/2006	12/31/2006	12/24/2006	1/12/2007	18.50	$ 393,762	$ 7,284,592
1/1/2007	1/14/2007	1/7/2007	1/26/2007	18.50	$ 386,120	$ 7,143,218
1/14/2007	1/27/2007	1/20/2007	2/6/2007	16.50	$ 656,326	$ 10,829,386
1/15/2007	1/28/2007	1/21/2007	2/9/2007	18.50	$ 369,857	$ 6,842,359
1/29/2007	2/11/2007	2/4/2007	2/23/2007	18.50	$ 374,081	$ 6,920,495
2/12/2007	2/25/2007	2/18/2007	3/9/2007	18.50	$ 387,408	$ 7,167,050
2/26/2007	3/11/2007	3/4/2007	3/23/2007	18.50	$ 373,400	$ 6,907,904
3/12/2007	3/25/2007	3/18/2007	4/4/2007	16.50	$ 330,927	$ 5,460,295
3/26/2007	4/8/2007	4/1/2007	4/20/2007	18.50	$ 351,323	$ 6,499,475
4/9/2007	4/22/2007	4/15/2007	5/4/2007	18.50	$ 347,062	$ 6,420,646
4/23/2007	5/6/2007	4/29/2007	5/18/2007	18.50	$ 334,124	$ 6,181,290
5/7/2007	5/20/2007	5/13/2007	6/1/2007	18.50	$ 336,230	$ 6,220,264
5/21/2007	6/3/2007	5/27/2007	6/15/2007	18.50	$ 353,260	$ 6,535,307
6/4/2007	6/17/2007	6/10/2007	6/29/2007	18.50	$ 337,679	$ 6,247,055
6/18/2007	7/1/2007	6/24/2007	7/13/2007	18.50	$ 341,521	$ 6,318,131
7/2/2007	7/15/2007	7/8/2007	7/27/2007	18.50	$ 345,752	$ 6,396,418
7/16/2007	7/29/2007	7/22/2007	8/10/2007	18.50	$ 333,438	$ 6,168,603
7/30/2007	8/12/2007	8/5/2007	8/24/2007	18.50	$ 347,811	$ 6,434,508
8/13/2007	8/26/2007	8/19/2007	9/7/2007	18.50	$ 337,253	$ 6,239,172
8/27/2007	9/9/2007	9/2/2007	9/21/2007	18.50	$ 335,121	$ 6,199,732
9/10/2007	9/23/2007	9/16/2007	10/5/2007	18.50	$ 331,445	$ 6,131,739
9/24/2007	10/7/2007	9/30/2007	10/19/2007	18.50	$ 352,580	$ 6,522,721
10/8/2007	10/21/2007	10/14/2007	11/2/2007	18.50	$ 355,828	$ 6,582,810
10/22/2007	11/4/2007	10/28/2007	11/16/2007	18.50	$ 355,294	$ 6,572,939
11/5/2007	11/18/2007	11/11/2007	11/30/2007	18.50	$ 375,779	$ 6,951,905
11/19/2007	12/2/2007	11/25/2007	12/14/2007	18.50	$ 395,601	$ 7,318,624
12/3/2007	12/16/2007	12/9/2007	12/28/2007	18.50	$ 351,392	$ 6,500,744
	TOTAL			18.30	$ 9,890,372	$ 180,997,383
	GRAND TOTAL				$ 30,164,629	$ 515,522,615
	WEIGHTED AVERAGE DAYS			17.09		

Equitable Gas Company

CORPORATE SERVICES
For The Twelve Months Ended December 31, 2007

Period Covered From (A)	To (B)	Mid-Point of Period (C)	Date Paid (D)	Days Lag (D-C) (E)	Amount of Expense (F)	Dollar Days (E*F) (G)
1/1/2007	1/31/2007	1/16/2007	1/31/2007	15.00	$ 1,311,496	$ 19,672,443
2/1/2007	2/28/2007	2/14/2007	2/28/2007	13.50	$ 1,354,246	$ 18,282,324
3/1/2007	3/31/2007	3/16/2007	3/31/2007	15.00	$ 1,354,246	$ 20,313,693
4/1/2007	4/30/2007	4/15/2007	4/30/2007	14.50	$ 1,354,246	$ 19,636,570
5/1/2007	5/31/2007	5/16/2007	5/31/2007	15.00	$ 1,354,246	$ 20,313,693
6/1/2007	6/30/2007	6/15/2007	6/30/2007	14.50	$ 1,267,733	$ 18,382,130
7/1/2007	7/31/2007	7/16/2007	7/31/2007	15.00	$ 1,354,246	$ 20,313,693
8/1/2007	8/31/2007	8/16/2007	8/31/2007	15.00	$ 1,354,246	$ 20,313,693
9/1/2007	9/30/2007	9/15/2007	9/30/2007	14.50	$ 1,331,410	$ 19,305,442
10/1/2007	10/31/2007	10/16/2007	10/31/2007	15.00	$ 1,354,246	$ 20,313,693
11/1/2007	11/30/2007	11/15/2007	11/30/2007	14.50	$ 1,354,246	$ 19,636,570
12/1/2007	12/31/2007	12/16/2007	12/31/2007	15.00	$ 1,449,883	$ 21,748,250
TOTAL					$ 16,194,492	$ 238,232,197
WEIGHTED AVERAGE DAYS				14.71		

Equitable Gas Company

Other O&M
For The Twelve Months Ended December 31, 2007

Period Covered From (A)	To (B)	Mid-Point of Period (C)	Date Paid (D)	Days Lag (D-C) (E)	Amount of Expense (F)	Dollar Days (E*F) (G)
Vehicle						
11/25/2006	12/24/2006	12/9/2006	1/11/2007	32.50	$ 382,881	$ 12,443,628
12/25/2006	1/24/2007	1/9/2007	2/13/2007	35.00	$ 184,650	$ 6,462,743
1/25/2007	2/24/2007	2/9/2007	3/20/2007	39.00	$ 147,632	$ 5,757,638
2/25/2007	3/24/2007	3/10/2007	4/12/2007	32.50	$ 149,542	$ 4,860,113
3/25/2007	4/24/2007	4/9/2007	5/15/2007	36.00	$ 156,525	$ 5,634,905
4/25/2007	5/24/2007	5/9/2007	6/14/2007	35.50	$ 167,526	$ 5,947,179
5/25/2007	6/24/2007	6/9/2007	7/19/2007	40.00	$ 169,450	$ 6,777,998
6/25/2007	7/24/2007	7/9/2007	8/13/2007	34.50	$ 158,905	$ 5,482,227
7/25/2007	8/24/2007	8/9/2007	9/13/2007	35.00	$ 220,240	$ 7,708,402
8/25/2007	9/24/2007	9/9/2007	10/11/2007	32.00	$ 151,067	$ 4,834,128
9/25/2007	10/24/2007	10/9/2007	11/15/2007	36.50	$ 235,949	$ 8,612,130
10/25/2007	11/24/2007	11/9/2007	12/15/2007	36.00	$ 172,386	$ 6,205,885
TOTAL				35.15	$ 2,296,752	$ 80,726,976
Commercial Credit Card						
12/21/2006	1/20/2007	1/5/2007	1/21/2007	16.00	$ 73,165	$ 1,170,645
1/21/2007	2/20/2007	2/5/2007	2/21/2007	16.00	$ 87,799	$ 1,404,782
2/21/2007	3/20/2007	3/6/2007	3/21/2007	14.50	$ 99,323	$ 1,440,190
3/21/2007	4/20/2007	4/5/2007	4/21/2007	16.00	$ 75,468	$ 1,207,481
4/21/2007	5/20/2007	5/5/2007	5/21/2007	15.50	$ 82,112	$ 1,272,740
5/21/2007	6/20/2007	6/5/2007	6/21/2007	16.00	$ 122,613	$ 1,961,803
6/21/2007	7/20/2007	7/5/2007	7/21/2007	15.50	$ 105,664	$ 1,637,790
7/21/2007	8/20/2007	8/5/2007	8/21/2007	16.00	$ 113,428	$ 1,814,850
8/21/2007	9/20/2007	9/5/2007	9/21/2007	16.00	$ 94,221	$ 1,507,528
9/21/2007	10/20/2007	10/5/2007	10/21/2007	15.50	$ 110,194	$ 1,708,010
10/21/2007	11/20/2007	11/5/2007	11/21/2007	16.00	$ 68,327	$ 1,093,233
11/21/2007	12/20/2007	12/5/2007	12/21/2007	15.50	$ 239,316	$ 3,709,402
TOTAL				15.67	$ 1,271,630	$ 19,928,455
GRAND TOTAL					$ 3,568,382	$ 100,655,431
WEIGHTED AVERAGE DAYS				28.21		

Equitable Gas Company

Other O&M -Other Goods and Services
For The Twelve Months Ended December 31, 2007

Period Covered From (A)	To (B)	Mid-Point of Period (C)	Date Paid (D)	Days Lag (D-C) (E)		Amount of Expense (F)		Dollar Days (E*F) (G)
12/1/2006	12/31/2006	12/16/2006	1/18/2007	33.00	$	983,277	$	32,448,148
1/1/2007	1/31/2007	1/16/2007	2/20/2007	35.00	$	662,632	$	23,192,134
2/1/2007	2/28/2007	2/14/2007	3/20/2007	33.50	$	884,122	$	29,618,086
3/1/2007	3/31/2007	3/16/2007	4/19/2007	34.00	$	996,975	$	33,897,150
4/1/2007	4/30/2007	4/15/2007	5/22/2007	36.50	$	995,527	$	36,336,727
5/1/2007	5/31/2007	5/16/2007	6/19/2007	34.00	$	936,335	$	31,835,381
6/1/2007	6/30/2007	6/15/2007	7/19/2007	33.50	$	1,445,705	$	48,431,110
7/1/2007	7/31/2007	7/16/2007	8/21/2007	36.00	$	951,872	$	34,267,381
8/1/2007	8/31/2007	8/16/2007	9/20/2007	35.00	$	666,368	$	23,322,876
9/1/2007	9/30/2007	9/15/2007	10/18/2007	32.50	$	1,138,789	$	37,010,630
10/1/2007	10/31/2007	10/16/2007	11/20/2007	35.00	$	1,016,442	$	35,575,484
11/1/2007	11/30/2007	11/15/2007	12/20/2007	34.50	$	962,121	$	33,193,170
TOTAL					$	11,640,164	$	399,128,278
WEIGHTED AVERAGE DAYS				34.29				

Equitable Gas Company

Other O&M -OSS
For The Twelve Months Ended December 31, 2007

Period Covered From (A)	To (B)	Mid-Point of Period (C)	Date Paid (D)	Days Lag (D-C) (E)	Amount of Expense (F)	Dollar Days (E*F) (G)
NCO						
12/1/2006	12/31/2006	12/16/2006	1/25/2007	40.00	$ 244,966	$ 9,798,631
1/1/2007	1/31/2007	1/16/2007	3/6/2007	49.00	$ 264,743	$ 12,972,398
1/1/2007	1/31/2007	1/16/2007	2/27/2007	42.00	$ 3,629	$ 152,433
2/1/2007	2/28/2007	2/14/2007	6/26/2007	131.50	$ 169,055	$ 22,230,714
2/1/2007	2/28/2007	2/14/2007	3/27/2007	40.50	$ 7,599	$ 307,770
3/1/2007	3/31/2007	3/16/2007	4/26/2007	41.00	$ 186,215	$ 7,634,804
4/1/2007	4/30/2007	4/15/2007	5/24/2007	38.50	$ 5,446	$ 209,657
4/1/2007	4/30/2007	4/15/2007	6/26/2007	71.50	$ 251,290	$ 17,967,209
5/1/2007	5/31/2007	5/16/2007	6/28/2007	43.00	$ 251,604	$ 10,818,955
6/1/2007	6/30/2007	6/15/2007	8/30/2007	75.50	$ 263,553	$ 19,898,247
6/1/2007	6/30/2007	6/15/2007	7/26/2007	40.50	$ 6,185	$ 250,477
7/1/2007	7/31/2007	7/16/2007	8/28/2007	43.00	$ 253,449	$ 10,898,322
8/1/2007	8/31/2007	8/16/2007	9/27/2007	42.00	$ 229,005	$ 9,618,227
9/1/2007	9/30/2007	9/15/2007	10/25/2007	39.50	$ 203,143	$ 8,024,166
10/1/2007	10/31/2007	10/16/2007	12/6/2007	51.00	$ 245,014	$ 12,495,719
11/1/2007	11/30/2007	11/15/2007	12/27/2007	41.50	$ 209,741	$ 8,704,266
TOTAL				51.88	$ 2,794,637	$ 151,981,995
Trafford						
12/1/2006	12/31/2006	12/16/2006	1/30/2007	45.00	$ 71,669	$ 3,225,119
1/1/2007	1/31/2007	1/16/2007	2/27/2007	42.00	$ 125,596	$ 5,275,037
2/1/2007	2/28/2007	2/14/2007	3/30/2007	43.50	$ 128,023	$ 5,569,011
3/1/2007	3/31/2007	3/16/2007	4/26/2007	41.00	$ 121,062	$ 4,963,522
4/1/2007	4/30/2007	4/15/2007	5/31/2007	45.50	$ 167,437	$ 7,618,381
5/1/2007	5/31/2007	5/16/2007	6/28/2007	43.00	$ 175,704	$ 7,555,273
6/1/2007	6/30/2007	6/15/2007	7/31/2007	45.50	$ 147,839	$ 6,726,694
7/1/2007	7/31/2007	7/16/2007	8/30/2007	45.00	$ 137,299	$ 6,178,455
8/1/2007	8/31/2007	8/16/2007	9/27/2007	42.00	$ 114,209	$ 4,796,782
9/1/2007	9/30/2007	9/15/2007	10/30/2007	44.50	$ 98,991	$ 4,405,080
10/1/2007	10/31/2007	10/16/2007	12/6/2007	51.00	$ 178,689	$ 9,113,126
11/1/2007	11/30/2007	11/15/2007	1/6/2008	51.50	$ 275,307	$ 14,178,315
TOTAL				45.49	$ 1,741,825	$ 79,604,796

Equitable Gas Company

Other O&M -OSS
For The Twelve Months Ended December 31, 2007

Period Covered From (A)	To (B)	Mid-Point of Period (C)	Date Paid (D)	Days Lag (D-C) (E)	Amount of Expense (F)	Dollar Days (E*F) (G)
HEATH Consultants						
12/1/2006	12/31/2006	12/16/2006	1/23/2007	38.00	54,526	2,071,997
1/1/2007	1/31/2007	1/16/2007	2/22/2007	37.00	101,752	3,764,835
2/1/2007	2/28/2007	2/14/2007	3/27/2007	40.50	90,957	3,683,739
3/1/2007	3/31/2007	3/16/2007	4/24/2007	39.00	73,759	2,876,593
4/1/2007	4/30/2007	4/15/2007	5/22/2007	36.50	103,969	3,794,884
5/1/2007	5/31/2007	5/16/2007	6/21/2007	36.00	134,115	4,828,128
6/1/2007	6/30/2007	6/15/2007	7/24/2007	38.50	182,908	7,041,943
7/1/2007	7/31/2007	7/16/2007	8/23/2007	38.00	34,836	1,323,776
8/1/2007	8/31/2007	8/16/2007	9/20/2007	35.00	37,733	1,320,665
9/1/2007	9/30/2007	9/15/2007	10/25/2007	39.50	154,528	6,103,839
10/1/2007	10/31/2007	10/16/2007	11/20/2007	35.00	73,650	2,577,735
11/1/2007	11/30/2007	11/15/2007	12/20/2007	34.50	149,469	5,156,687
	TOTAL			37.29	1,192,201	44,544,821
C LEON SHERMAN & ASSOCIATES PC						
12/1/2006	12/31/2006	12/16/2006	1/30/2007	45.00	87,651	3,944,273
1/1/2007	1/31/2007	1/16/2007	3/1/2007	44.00	76,761	3,377,494
2/1/2007	2/28/2007	2/14/2007	3/20/2007	33.50	57,826	1,937,187
4/1/2007	4/30/2007	4/15/2007	5/22/2007	36.50	155,913	5,690,830
5/1/2007	5/31/2007	5/16/2007	5/22/2007	6.00	15,191	91,148
6/1/2007	6/30/2007	6/15/2007	7/24/2007	38.50	7,479	287,928
7/1/2007	7/31/2007	7/16/2007	8/28/2007	43.00	24,015	1,032,646
9/1/2007	9/30/2007	9/15/2007	10/4/2007	18.50	9,285	171,770
9/1/2007	9/30/2007	9/15/2007	11/13/2007	58.50	24,893	1,456,247
10/1/2007	10/31/2007	10/16/2007	12/13/2007	58.00	39,241	2,275,993
	TOTAL			38.15	498,256	20,265,517
	GRAND TOTAL				$ 6,226,919	$ 296,397,129
	WEIGHTED AVERAGE DAYS			47.60		

Equitable Gas Company

Other O&M
For The Twelve Months Ended December 31, 2007

Period Covered From (A)	To (B)	Mid-Point of Period (C)	Date Paid (D)	Days Lag (D-C) (E)	Amount of Expense (F)	Dollar Days (E*F) (G)
Pittsburgh Mailing & ADS						
1/1/2007	1/5/2007	1/3/2007	1/9/2007	6.00	10,313	61,881
1/8/2007	1/12/2007	1/10/2007	1/18/2007	8.00	22,145	177,161
1/15/2007	1/19/2007	1/17/2007	1/23/2007	6.00	22,510	135,059
1/22/2007	1/26/2007	1/24/2007	2/1/2007	8.00	29,839	238,710
1/29/2007	2/2/2007	1/31/2007	2/13/2007	13.00	12,829	166,780
2/5/2007	2/9/2007	2/7/2007	2/15/2007	8.00	21,301	170,410
2/12/2007	2/16/2007	2/14/2007	2/21/2007	7.00	23,152	162,064
2/19/2007	2/23/2007	2/21/2007	3/6/2007	13.00	21,976	285,693
2/26/2007	3/2/2007	2/28/2007	3/20/2007	20.00	20,511	410,228
3/5/2007	3/9/2007	3/7/2007	3/20/2007	13.00	17,629	229,175
3/12/2007	3/16/2007	3/14/2007	3/20/2007	6.00	22,091	132,547
3/19/2007	3/23/2007	3/21/2007	3/29/2007	8.00	25,604	204,834
3/26/2007	3/30/2007	3/28/2007	5/8/2007	41.00	25,199	1,033,142
4/2/2007	4/6/2007	4/4/2007	4/12/2007	8.00	9,577	76,612
4/9/2007	4/13/2007	4/11/2007	5/8/2007	27.00	22,666	611,975
4/16/2007	4/20/2007	4/18/2007	4/26/2007	8.00	22,874	182,993
4/23/2007	4/27/2007	4/25/2007	5/8/2007	13.00	30,414	395,386
4/30/2007	5/4/2007	5/2/2007	5/8/2007	6.00	17.046	102,277
5/7/2007	5/11/2007	5/9/2007	5/24/2007	15.00	22,661	339,913
5/14/2007	5/18/2007	5/16/2007	5/24/2007	8.00	22,922	183,374
5/21/2007	5/25/2007	5/23/2007	5/31/2007	8.00	30,350	242,802
5/28/2007	6/1/2007	5/30/2007	6/5/2007	6.00	8,872	53,232
6/4/2007	6/8/2007	6/6/2007	6/26/2007	20.00	22,153	443,056
6/11/2007	6/15/2007	6/13/2007	6/26/2007	13.00	23,682	307,862
6/18/2007	6/22/2007	6/20/2007	6/28/2007	8.00	26,879	215,030
6/25/2007	6/29/2007	6/27/2007	7/3/2007	6.00	20,610	123,662
7/2/2007	7/6/2007	7/4/2007	7/10/2007	6.00	13,133	78,799
7/9/2007	7/13/2007	7/11/2007	7/17/2007	6.00	22,415	134,490
7/16/2007	7/20/2007	7/18/2007	8/2/2007	15.00	24,918	373,763
7/23/2007	7/27/2007	7/25/2007	8/7/2007	13.00	29,954	389,407
7/30/2007	8/3/2007	8/1/2007	8/7/2007	6.00	10,230	61,378
8/1/2007	8/31/2007	8/16/2007	11/6/2007	82.00	89,149	7,310,186
9/1/2007	9/30/2007	9/15/2007	12/13/2007	88.50	102,429	9,065,002
TOTAL					848,033	24,098,883
WEIGHTED AVERAGE DAYS				15.74		

Equitable Gas Company

Injuries and Damages Insurance
For The Twelve Months Ended December 31, 2007

Period Covered From (A)	To (B)	Mid-Point of Period (C)	Date Paid (D)	Days Lag (D-C) (E)	Amount of Expense (F)	Dollar Days (E*F) (G)
Directors and Officers Liability						
3/27/2007	3/27/2008	9/26/2007	3/29/2007	(181.00)	$ 125,093	$ (22,641,831)
3/27/2007	3/27/2008	9/26/2007	4/2/2007	(177.00)	19,670	(3,481,502)
Fiduciary Liability						
3/27/2007	3/27/2008	9/26/2007	3/29/2007	(181.00)	38,134	(6,902,183)
Crime						
3/27/2007	3/27/2008	9/26/2007	3/29/2007	(181.00)	782	(141,593)
3/27/2007	3/27/2008	9/26/2007	11/7/2007	42.00	89	3,758
Automobile						
8/11/2007	8/11/2008	2/10/2008	8/21/2007	(173.00)	41,779	(7,227,822)
Excess Liability						
8/11/2007	8/11/2008	2/10/2008	8/14/2007	(180.00)	216,185	(38,913,253)
8/11/2007	8/11/2008	2/10/2008	8/16/2007	(178.00)	708,044	(126,031,917)
Property						
11/1/2006	11/1/2007	5/2/2007	1/28/2007	(94.50)	158512.3	(14,979,412)
11/1/2007	11/1/2008	5/2/2008	11/5/2007	(179.00)	130,635	(23,383,588)
11/1/2007	11/1/2008	5/2/2008	11/16/2007	(168.00)	4,376	(735,084)
Property -Surplus						
11/1/2006	11/1/2007	5/2/2007	1/10/2007	(112.50)	6,743	(758,626)
Broker Fees						
9/1/2006	9/1/2007	3/2/2007	1/2/2007	(59.50)	14,338	(853,081)
9/1/2006	9/1/2007	3/2/2007	4/2/2007	30.50	14,245	434,473
9/1/2007	9/1/2008	3/2/2008	9/28/2007	(156.00)	14,153	(2,207,884)
9/1/2007	9/1/2008	3/2/2008	10/2/2007	(152.00)	14,153	(2,151,271)
8/11/2007	8/11/2008	2/10/2008	12/12/2007	(60.00)	38,623	(2,317,380)
Punitive						
11/8/2007	11/8/2008	5/9/2008	8/31/2007	(252.00)	16,976	(4,277,839)
11/8/2007	11/8/2008	5/9/2008	8/31/2007	(252.00)	15,706	(3,958,000)
Worker Compensation (excess)						
8/11/2007	8/11/2008	2/10/2008	8/31/2007	(163.00)	90,446	(14,742,773)
Bonds						
11/1/2007	11/30/2008	5/16/2008	12/30/2007	(138.50)	772	(106,937)
10/1/2007	10/31/2008	4/16/2008	11/30/2007	(138.00)	715	(98,648)
9/1/2007	9/30/2008	3/16/2008	10/30/2007	(138.50)	280	(38,780)
8/1/2007	8/31/2008	2/15/2008	9/30/2007	(138.00)	29	(3,958)
7/1/2007	7/31/2008	1/15/2008	8/30/2007	(138.00)	4,336	(598,409)
6/1/2007	6/30/2008	12/15/2007	7/30/2007	(138.50)	161	(22,299)
5/1/2007	5/31/2008	11/15/2007	6/30/2007	(138.00)	1,695	(233,960)
4/1/2007	4/30/2008	10/15/2007	5/30/2007	(138.50)	1,702	(235,699)
3/1/2007	3/31/2008	9/15/2007	4/30/2007	(138.00)	257	(35,397)
2/1/2007	2/29/2008	8/16/2007	3/30/2007	(139.50)	2,338	(326,193)
1/1/2007	1/31/2008	7/17/2007	2/28/2007	(139.50)	1,388	(193,626)
12/1/2006	12/31/2007	6/16/2007	1/30/2007	(137.50)	393	(54,038)
TOTAL					$ 1,682,748	$ (277,214,753)
WEIGHTED AVERAGE DAYS				(164.74)		

Equitable Gas Company

Pensions and Benefits
For The Twelve Months Ended December 31, 2007

Period Covered From (A)	To (B)	Mid-Point of Period (C)	Date Paid (D)	Days Lag (D-C) (E)		Amount of Expense (F)		Dollar Days (E*F) (G)
401(k) Match & Retirement Contribution								
12/18/2006	12/31/2006	12/24/2006	1/10/2007	16.50	$	72,786	$	1,200,962
1/1/2007	1/14/2007	1/7/2007	1/24/2007	16.50	$	72,499	$	1,196,241
1/14/2007	1/27/2007	1/20/2007	2/6/2007	16.50	$	1,365	$	22,514
1/15/2007	1/28/2007	1/21/2007	2/7/2007	16.50	$	72,831	$	1,201,710
1/29/2007	2/11/2007	2/4/2007	2/21/2007	16.50	$	74,988	$	1,237,304
2/12/2007	2/25/2007	2/18/2007	3/7/2007	16.50	$	76,896	$	1,268,791
2/26/2007	3/11/2007	3/4/2007	3/21/2007	16.50	$	75,214	$	1,241,039
3/12/2007	3/25/2007	3/18/2007	4/4/2007	16.50	$	74,029	$	1,221,475
3/26/2007	4/8/2007	4/1/2007	4/18/2007	16.50	$	78,705	$	1,298,625
4/9/2007	4/22/2007	4/15/2007	5/2/2007	16.50	$	78,300	$	1,291,958
4/23/2007	5/6/2007	4/29/2007	5/16/2007	16.50	$	77,181	$	1,273,491
5/7/2007	5/20/2007	5/13/2007	5/30/2007	16.50	$	77,740	$	1,282,718
5/21/2007	6/3/2007	5/27/2007	6/13/2007	16.50	$	76,628	$	1,264,361
6/4/2007	6/17/2007	6/10/2007	6/27/2007	16.50	$	78,087	$	1,288,434
6/18/2007	7/1/2007	6/24/2007	7/11/2007	16.50	$	78,434	$	1,294,161
7/2/2007	7/15/2007	7/8/2007	7/25/2007	16.50	$	78,595	$	1,296,816
7/16/2007	7/29/2007	7/22/2007	8/8/2007	16.50	$	76,409	$	1,260,743
7/30/2007	8/12/2007	8/5/2007	8/22/2007	16.50	$	77,497	$	1,278,699
8/13/2007	8/26/2007	8/19/2007	9/5/2007	16.50	$	75,779	$	1,250,358
8/27/2007	9/9/2007	9/2/2007	9/19/2007	16.50	$	76,346	$	1,259,702
9/10/2007	9/23/2007	9/16/2007	10/3/2007	16.50	$	72,114	$	1,189,886
9/24/2007	10/7/2007	9/30/2007	10/17/2007	16.50	$	73,682	$	1,215,749
10/8/2007	10/21/2007	10/14/2007	10/31/2007	16.50	$	73,822	$	1,218,067
10/22/2007	11/4/2007	10/28/2007	11/14/2007	16.50	$	73,104	$	1,206,219
11/5/2007	11/18/2007	11/11/2007	11/28/2007	16.50	$	74,464	$	1,228,664
11/19/2007	12/2/2007	11/25/2007	12/12/2007	16.50	$	56,481	$	931,933
12/3/2007	12/16/2007	12/9/2007	12/26/2007	16.50	$	71,765	$	1,184,119
	TOTAL			16.50	$	1,945,742	$	32,104,741
401(k) Admin Fees								
10/1/2006	12/31/2006	11/15/2006	1/25/2007	70.50	$	207	$	14,585
1/1/2007	3/31/2007	2/14/2007	5/24/2007	98.50	$	240	$	23,617
4/1/2007	6/30/2007	5/16/2007	8/27/2007	103.00	$	499	$	51,358
7/1/2007	9/30/2007	8/15/2007	11/8/2007	84.50	$	453	$	38,289
	TOTAL			91.43	$	1,398	$	127,849
ESPP Discount								
12/1/2006	12/31/2006	12/16/2006	1/8/2007	23.00	$	1,962	$	45,117
1/1/2007	1/31/2007	1/16/2007	2/7/2007	22.00	$	2,001	$	44,020
2/1/2007	2/28/2007	2/14/2007	3/6/2007	19.50	$	2,055	$	40,075
3/1/2007	3/31/2007	3/16/2007	4/5/2007	20.00	$	2,138	$	42,769
4/1/2007	4/30/2007	4/15/2007	5/4/2007	18.50	$	2,171	$	40,169
5/1/2007	5/31/2007	5/16/2007	6/7/2007	22.00	$	3,143	$	69,145
6/1/2007	6/30/2007	6/15/2007	7/6/2007	20.50	$	2,221	$	45,540
7/1/2007	7/31/2007	7/16/2007	8/6/2007	21.00	$	2,025	$	42,528
8/1/2007	8/31/2007	8/16/2007	9/10/2007	25.00	$	2,020	$	50,511
9/1/2007	9/30/2007	9/15/2007	10/4/2007	18.50	$	2,069	$	38,278
10/1/2007	10/31/2007	10/16/2007	11/6/2007	21.00	$	2,791	$	58,621
11/1/2007	11/30/2007	11/15/2007	12/6/2007	20.50	$	2,009	$	41,175
	TOTAL			20.97	$	26,607	$	557,948
ESPP Admin Fees								
10/1/2006	12/31/2006	11/15/2006	3/6/2007	110.50	$	4,011	$	443,174
1/1/2007	3/31/2007	2/14/2007	6/12/2007	117.50	$	4,151	$	487,704
4/1/2007	6/30/2007	5/16/2007	9/13/2007	120.00	$	3,938	$	472,524
7/1/2007	9/30/2007	8/15/2007	12/6/2007	112.50	$	3,714	$	417,879
	TOTAL			115.17	$	15,813	$	1,821,280

Equitable Gas Company

Pensions and Benefits
For The Twelve Months Ended December 31, 2007

Period Covered From (A)	To (B)	Mid-Point of Period (C)	Date Paid (D)	Days Lag (D-C) (E)		Amount of Expense (F)		Dollar Days (E*F) (G)
HSA Company Contribution								
1/1/2007	12/31/2007	7/2/2007	1/5/2007	(178.00)	$	145,500	$	(25,899,000)
1/1/2007	12/31/2007	7/2/2007	1/26/2007	(157.00)	$	12,750	$	(2,001,750)
2/26/2007	12/31/2007	7/30/2007	3/21/2007	(131.00)	$	2,188	$	(286,563)
3/12/2007	12/31/2007	8/6/2007	4/4/2007	(124.00)	$	688	$	(85,250)
4/9/2007	12/31/2007	8/20/2007	5/2/2007	(110.00)	$	688	$	(75,625)
10/8/2007	12/31/2007	11/19/2007	10/31/2007	(19.00)	$	438	$	(8,313)
	TOTAL			(174.77)	$	162,250	$	(28,356,500)
HSA Account Fees								
1/1/2007	1/31/2007	1/16/2007	1/24/2007	8.00	$	666	$	5,330
1/1/2007	1/31/2007	1/16/2007	1/25/2007	9.00	$	20	$	176
2/1/2007	2/28/2007	2/14/2007	2/21/2007	6.50	$	696	$	4,521
3/1/2007	3/31/2007	3/16/2007	3/23/2007	7.00	$	699	$	4,891
4/1/2007	4/30/2007	4/15/2007	4/24/2007	8.50	$	696	$	5,912
5/1/2007	5/31/2007	5/16/2007	5/24/2007	8.00	$	696	$	5,564
6/1/2007	6/30/2007	6/15/2007	6/26/2007	10.50	$	692	$	7,269
7/1/2007	7/31/2007	7/16/2007	7/27/2007	11.00	$	689	$	7,579
8/1/2007	8/31/2007	8/16/2007	8/21/2007	5.00	$	679	$	3,396
9/1/2007	9/30/2007	9/15/2007	9/26/2007	10.50	$	683	$	7,166
10/1/2007	10/31/2007	10/16/2007	10/26/2007	10.00	$	673	$	6,728
11/1/2007	11/30/2007	11/15/2007	11/26/2007	10.50	$	673	$	7,064
12/1/2007	12/31/2007	12/16/2007	12/26/2007	10.00	$	673	$	6,728
	TOTAL			8.79	$	8,232	$	72,322

Equitable Gas Company

Pensions and Benefits
For The Twelve Months Ended December 31, 2007

Period Covered From (A)	To (B)	Mid-Point of Period (C)	Date Paid (D)	Days Lag (D-C) (E)		Amount of Expense (F)		Dollar Days (E*F) (G)
Medical Claims, Admin & Enrollment Fees Actives								
12/23/2006	12/29/2006	12/26/2006	1/4/2007	9.00	$	60,114	$	541,025
12/30/2006	1/5/2007	1/2/2007	1/11/2007	9.00	$	50,988	$	458,892
1/6/2007	1/12/2007	1/9/2007	1/18/2007	9.00	$	49,843	$	448,588
1/13/2007	1/19/2007	1/16/2007	1/25/2007	9.00	$	38,631	$	347,681
1/20/2007	1/26/2007	1/23/2007	2/1/2007	9.00	$	54,589	$	491,300
1/27/2007	2/2/2007	1/30/2007	2/8/2007	9.00	$	38,709	$	348,377
2/3/2007	2/9/2007	2/6/2007	2/15/2007	9.00	$	34,634	$	311,703
2/10/2007	2/16/2007	2/13/2007	2/22/2007	9.00	$	30,010	$	270,087
2/17/2007	2/23/2007	2/20/2007	3/1/2007	9.00	$	62,734	$	564,603
2/24/2007	3/2/2007	2/27/2007	3/8/2007	9.00	$	37,688	$	339,193
3/3/2007	3/9/2007	3/6/2007	3/15/2007	9.00	$	26,204	$	235,836
3/10/2007	3/16/2007	3/13/2007	3/22/2007	9.00	$	28,206	$	253,852
3/17/2007	3/23/2007	3/20/2007	3/29/2007	9.00	$	25,665	$	230,987
3/24/2007	3/30/2007	3/27/2007	4/5/2007	9.00	$	69,737	$	627,637
3/31/2007	4/6/2007	4/3/2007	4/12/2007	9.00	$	25,257	$	227,317
4/7/2007	4/13/2007	4/10/2007	4/19/2007	9.00	$	35,743	$	321,686
4/14/2007	4/20/2007	4/17/2007	4/26/2007	9.00	$	19,487	$	175,380
4/21/2007	4/27/2007	4/24/2007	5/3/2007	9.00	$	104,315	$	938,833
4/28/2007	5/4/2007	5/1/2007	5/10/2007	9.00	$	34,044	$	306,398
5/5/2007	5/11/2007	5/8/2007	5/17/2007	9.00	$	74,532	$	670,789
5/12/2007	5/18/2007	5/15/2007	5/24/2007	9.00	$	94,191	$	847,715
5/19/2007	5/25/2007	5/22/2007	5/31/2007	9.00	$	94,721	$	852,490
5/26/2007	6/1/2007	5/29/2007	6/7/2007	9.00	$	17,523	$	157,707
6/2/2007	6/8/2007	6/5/2007	6/14/2007	9.00	$	84,423	$	759,809
6/9/2007	6/15/2007	6/12/2007	6/21/2007	9.00	$	42,735	$	384,614
6/16/2007	6/22/2007	6/19/2007	6/28/2007	9.00	$	50,669	$	456,018
6/23/2007	6/29/2007	6/26/2007	7/5/2007	9.00	$	62,447	$	562,022
6/30/2007	7/6/2007	7/3/2007	7/12/2007	9.00	$	28,388	$	255,492
7/7/2007	7/13/2007	7/10/2007	7/19/2007	9.00	$	31,854	$	286,685
7/14/2007	7/20/2007	7/17/2007	7/26/2007	9.00	$	42,333	$	380,998
7/21/2007	7/27/2007	7/24/2007	8/2/2007	9.00	$	48,818	$	439,359
7/28/2007	8/3/2007	7/31/2007	8/9/2007	9.00	$	90,251	$	812,256
8/4/2007	8/10/2007	8/7/2007	8/16/2007	9.00	$	33,825	$	304,424
8/11/2007	8/17/2007	8/14/2007	8/23/2007	9.00	$	44,024	$	396,218
8/18/2007	8/24/2007	8/21/2007	8/30/2007	9.00	$	33,064	$	297,573
8/25/2007	8/31/2007	8/28/2007	9/6/2007	9.00	$	72,755	$	654,796
9/1/2007	9/7/2007	9/4/2007	9/13/2007	9.00	$	66,822	$	601,395
9/8/2007	9/14/2007	9/11/2007	9/20/2007	9.00	$	88,538	$	796,841
9/15/2007	9/21/2007	9/18/2007	9/27/2007	9.00	$	51,959	$	467,631
9/22/2007	9/28/2007	9/25/2007	10/4/2007	9.00	$	80,666	$	725,991
9/29/2007	10/5/2007	10/2/2007	10/11/2007	9.00	$	57,410	$	516,690
10/6/2007	10/12/2007	10/9/2007	10/18/2007	9.00	$	41,471	$	373,240
10/13/2007	10/19/2007	10/16/2007	10/25/2007	9.00	$	70,610	$	635,487
10/20/2007	10/26/2007	10/23/2007	11/1/2007	9.00	$	91,255	$	821,294
10/27/2007	11/2/2007	10/30/2007	11/8/2007	9.00	$	40,296	$	362,660
11/3/2007	11/9/2007	11/6/2007	11/15/2007	9.00	$	59,742	$	537,675
11/10/2007	11/16/2007	11/13/2007	11/22/2007	9.00	$	18,118	$	163,059
11/17/2007	11/23/2007	11/20/2007	11/29/2007	9.00	$	1,043	$	9,389
11/24/2007	11/30/2007	11/27/2007	12/6/2007	9.00	$	97,524	$	877,713
12/1/2007	12/7/2007	12/4/2007	12/13/2007	9.00	$	80,621	$	725,585
12/8/2007	12/14/2007	12/11/2007	12/20/2007	9.00	$	51,957	$	467,614
12/15/2007	12/21/2007	12/18/2007	12/27/2007	9.00	$	65,352	$	588,168
TOTAL				9.00	$	2,736,530	$	24,628,772

Equitable Gas Company

Pensions and Benefits
For The Twelve Months Ended December 31, 2007

Period Covered From (A)	To (B)	Mid-Point of Period (C)	Date Paid (D)	Days Lag (D-C) (E)		Amount of Expense (F)		Dollar Days (E*F) (G)
Active Vision								
1/1/2007	1/31/2007	1/16/2007	3/8/2007	51.00	$	5,257	$	268,099
2/1/2007	2/28/2007	2/14/2007	3/8/2007	21.50	$	5,346	$	114,936
3/1/2007	3/31/2007	3/16/2007	6/21/2007	97.00	$	5,369	$	520,760
4/1/2007	4/30/2007	4/15/2007	6/21/2007	66.50	$	5,241	$	348,497
5/1/2007	5/31/2007	5/16/2007	6/21/2007	36.00	$	5,260	$	189,364
6/1/2007	6/30/2007	6/15/2007	6/21/2007	5.50	$	5,234	$	28,787
7/1/2007	7/31/2007	7/16/2007	8/21/2007	36.00	$	5,234	$	188,426
8/1/2007	8/31/2007	8/16/2007	8/21/2007	5.00	$	5,190	$	25,948
9/1/2007	9/30/2007	9/15/2007	12/4/2007	79.50	$	5,122	$	407,219
10/1/2007	10/31/2007	10/16/2007	12/4/2007	49.00	$	4,838	$	237,056
11/1/2007	11/30/2007	11/15/2007	12/4/2007	18.50	$	4,716	$	87,252
12/1/2007	12/31/2007	12/16/2007	12/20/2007	4.00	$	4,683	$	18,731
	TOTAL			39.60	$	61,489	$	2,435,075
Executive Health Exams								
1/1/2007	12/31/2007	7/2/2007	1/4/2007	(179.00)	$	1,825	$	(326,675)
1/1/2007	12/31/2007	7/2/2007	3/6/2007	(118.00)	$	3,650	$	(430,700)
1/1/2007	12/31/2007	7/2/2007	3/15/2007	(109.00)	$	1,825	$	(198,925)
1/1/2007	12/31/2007	7/2/2007	8/2/2007	31.00	$	1,925	$	59,675
	TOTAL			(97.20)	$	9,225	$	(896,625)
Active Life, AD&D, LTD								
1/1/2007	1/31/2007	1/16/2007	3/8/2007	51.00	$	16,105	$	821,339
2/1/2007	2/28/2007	2/14/2007	3/8/2007	21.50	$	16,105	$	346,263
3/1/2007	3/31/2007	3/16/2007	6/21/2007	97.00	$	16,130	$	1,564,645
4/1/2007	4/30/2007	4/15/2007	6/21/2007	66.50	$	16,126	$	1,072,350
5/1/2007	5/31/2007	5/16/2007	6/21/2007	36.00	$	16,106	$	579,811
6/1/2007	6/30/2007	6/15/2007	6/21/2007	5.50	$	16,153	$	88,839
7/1/2007	7/31/2007	7/16/2007	8/21/2007	36.00	$	15,760	$	567,362
8/1/2007	8/31/2007	8/16/2007	8/21/2007	5.00	$	15,756	$	78,782
9/1/2007	9/30/2007	9/15/2007	12/4/2007	79.50	$	13,852	$	1,101,234
10/1/2007	10/31/2007	10/16/2007	12/4/2007	49.00	$	13,699	$	671,231
11/1/2007	11/30/2007	11/15/2007	12/4/2007	18.50	$	13,579	$	251,216
12/1/2007	12/31/2007	12/16/2007	12/20/2007	4.00	$	13,564	$	54,258
	TOTAL			39.34	$	182,935	$	7,197,330
Active Dental								
1/1/2007	1/31/2007	1/16/2007	3/8/2007	51.00	$	21,087	$	1,075,434
2/1/2007	2/28/2007	2/14/2007	3/8/2007	21.50	$	21,186	$	455,501
3/1/2007	3/31/2007	3/16/2007	6/12/2007	88.00	$	21,389	$	1,882,228
4/1/2007	4/30/2007	4/15/2007	6/12/2007	57.50	$	20,772	$	1,194,382
5/1/2007	5/31/2007	5/16/2007	6/12/2007	27.00	$	20,793	$	561,421
6/1/2007	6/30/2007	6/15/2007	6/12/2007	(3.50)	$	20,647	$	(72,263)
7/1/2007	7/31/2007	7/16/2007	8/7/2007	22.00	$	20,375	$	448,257
8/1/2007	8/31/2007	8/16/2007	10/4/2007	49.00	$	20,185	$	989,089
9/1/2007	9/30/2007	9/15/2007	10/4/2007	18.50	$	20,285	$	375,265
10/1/2007	10/31/2007	10/16/2007	11/8/2007	23.00	$	18,585	$	427,448
11/1/2007	11/30/2007	11/15/2007	12/4/2007	18.50	$	19,210	$	355,390
12/1/2007	12/31/2007	12/16/2007	12/20/2007	4.00	$	18,473	$	73,890
	TOTAL			31.96	$	242,987	$	7,766,042

Equitable Gas Company

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Period Covered From (A)	To (B)	Mid-Point of Period (C)	Date Paid (D)	Days Lag (D-C) (E)	Amount of Expense (F)	Dollar Days (E*F) (G)
Employee Assistance Program						
1/1/2007	1/31/2007	1/16/2007	3/1/2007	44.00	$ 1,155	$ 50,807
2/1/2007	2/28/2007	2/14/2007	3/1/2007	14.50	$ 1,158	$ 16,793
3/1/2007	3/31/2007	3/16/2007	4/13/2007	28.00	$ 1,176	$ 32,928
4/1/2007	4/30/2007	4/15/2007	5/8/2007	22.50	$ 1,183	$ 26,615
5/1/2007	5/31/2007	5/16/2007	5/25/2007	9.00	$ 1,181	$ 10,631
6/1/2007	6/30/2007	6/15/2007	6/19/2007	3.50	$ 1,276	$ 4,467
7/1/2007	7/31/2007	7/16/2007	7/10/2007	(6.00)	$ 1,257	$ (7,543)
8/1/2007	8/31/2007	8/16/2007	8/7/2007	(9.00)	$ 1,255	$ (11,298)
9/1/2007	9/30/2007	9/15/2007	9/13/2007	(2.50)	$ 1,265	$ (3,163)
10/1/2007	10/31/2007	10/16/2007	11/8/2007	23.00	$ 1,286	$ 29,568
11/1/2007	11/30/2007	11/15/2007	11/13/2007	(2.50)	$ 1,285	$ (3,212)
12/1/2007	12/31/2007	12/16/2007	12/11/2007	(5.00)	$ 1,293	$ (6,465)
	TOTAL			9.49	$ 14,770	$ 140,129
Aon Admin Fees						
1/1/2007	1/31/2007	1/16/2007	4/17/2007	91.00	$ 13,937	$ 1,268,266
2/1/2007	2/28/2007	2/14/2007	6/12/2007	117.50	$ 14,727	$ 1,730,367
3/1/2007	3/31/2007	3/16/2007	6/12/2007	88.00	$ 15,036	$ 1,323,136
4/1/2007	4/30/2007	4/15/2007	8/21/2007	127.50	$ 12,650	$ 1,612,858
5/1/2007	5/31/2007	5/16/2007	8/21/2007	97.00	$ 17,289	$ 1,677,049
6/1/2007	6/30/2007	6/15/2007	8/30/2007	75.50	$ 11,728	$ 885,450
7/1/2007	7/31/2007	7/16/2007	11/13/2007	120.00	$ 12,445	$ 1,493,404
8/1/2007	8/31/2007	8/16/2007	11/13/2007	89.00	$ 16,645	$ 1,481,417
9/1/2007	9/30/2007	9/15/2007	12/11/2007	86.50	$ 12,517	$ 1,082,700
10/1/2007	10/31/2007	10/16/2007	12/18/2007	63.00	$ 11,017	$ 694,092
11/1/2007	11/30/2007	11/15/2007	12/27/2007	41.50	$ 10,404	$ 431,747
	TOTAL			92.19	$ 148,394	$ 13,680,486
	ACTIVE EMPLOYEE BENEFITS				$ 5,556,372	$ 61,278,850
	WEIGHTED AVERAGE DAYS			11.03		

Equitable Gas Company

Pensions and Benefits
For The Twelve Months Ended December 31, 2007

Period Covered From (A)	To (B)	Mid-Point of Period (C)	Date Paid (D)	Days Lag (D-C) (E)		Amount of Expense (F)		Dollar Days (E*F) (G)
Medical Claims, Admin & Enrollment Fees Retirees								
12/23/2006	12/29/2006	12/26/2006	1/4/2007	9.00	$	25,484	$	229,354
12/30/2006	1/5/2007	1/2/2007	1/11/2007	9.00	$	30,828	$	277,450
1/6/2007	1/12/2007	1/9/2007	1/18/2007	9.00	$	41,913	$	377,220
1/13/2007	1/19/2007	1/16/2007	1/25/2007	9.00	$	31,136	$	280,226
1/20/2007	1/26/2007	1/23/2007	2/1/2007	9.00	$	66,024	$	594,220
1/27/2007	2/2/2007	1/30/2007	2/8/2007	9.00	$	58,889	$	530,002
2/3/2007	2/9/2007	2/6/2007	2/15/2007	9.00	$	16,291	$	146,617
2/10/2007	2/16/2007	2/13/2007	2/22/2007	9.00	$	30,137	$	271,233
2/17/2007	2/23/2007	2/20/2007	3/1/2007	9.00	$	42,881	$	385,929
2/24/2007	3/2/2007	2/27/2007	3/8/2007	9.00	$	36,071	$	324,642
3/3/2007	3/9/2007	3/6/2007	3/15/2007	9.00	$	16,542	$	148,878
3/10/2007	3/16/2007	3/13/2007	3/22/2007	9.00	$	29,097	$	261,869
3/17/2007	3/23/2007	3/20/2007	3/29/2007	9.00	$	25,906	$	233,157
3/24/2007	3/30/2007	3/27/2007	4/5/2007	9.00	$	63,816	$	574,345
3/31/2007	4/6/2007	4/3/2007	4/12/2007	9.00	$	13,933	$	125,399
4/7/2007	4/13/2007	4/10/2007	4/19/2007	9.00	$	24,408	$	219,676
4/14/2007	4/20/2007	4/17/2007	4/26/2007	9.00	$	52,453	$	472,076
4/21/2007	4/27/2007	4/24/2007	5/3/2007	9.00	$	73,327	$	659,947
4/28/2007	5/4/2007	5/1/2007	5/10/2007	9.00	$	12,871	$	115,837
5/5/2007	5/11/2007	5/8/2007	5/17/2007	9.00	$	30,109	$	270,980
5/12/2007	5/18/2007	5/15/2007	5/24/2007	9.00	$	18,597	$	167,375
5/19/2007	5/25/2007	5/22/2007	5/31/2007	9.00	$	35,786	$	322,072
5/26/2007	6/1/2007	5/29/2007	6/7/2007	9.00	$	28,350	$	255,151
6/2/2007	6/8/2007	6/5/2007	6/14/2007	9.00	$	26,888	$	241,996
6/9/2007	6/15/2007	6/12/2007	6/21/2007	9.00	$	19,321	$	173,889
6/16/2007	6/22/2007	6/19/2007	6/28/2007	9.00	$	27,184	$	244,659
6/23/2007	6/29/2007	6/26/2007	7/5/2007	9.00	$	42,179	$	379,613
6/30/2007	7/6/2007	7/3/2007	7/12/2007	9.00	$	14,712	$	132,411
7/7/2007	7/13/2007	7/10/2007	7/19/2007	9.00	$	15,403	$	138,628
7/14/2007	7/20/2007	7/17/2007	7/26/2007	9.00	$	36,496	$	328,465
7/21/2007	7/27/2007	7/24/2007	8/2/2007	9.00	$	18,989	$	170,904
7/28/2007	8/3/2007	7/31/2007	8/9/2007	9.00	$	21,393	$	192,533
8/4/2007	8/10/2007	8/7/2007	8/16/2007	9.00	$	11,950	$	107,546
8/11/2007	8/17/2007	8/14/2007	8/23/2007	9.00	$	30,243	$	272,190
8/18/2007	8/24/2007	8/21/2007	8/30/2007	9.00	$	13,831	$	124,475
8/25/2007	8/31/2007	8/28/2007	9/6/2007	9.00	$	32,796	$	295,168
9/1/2007	9/7/2007	9/4/2007	9/13/2007	9.00	$	13,908	$	125,169
9/8/2007	9/14/2007	9/11/2007	9/20/2007	9.00	$	26,709	$	240,385
9/15/2007	9/21/2007	9/18/2007	9/27/2007	9.00	$	17,984	$	161,860
9/22/2007	9/28/2007	9/25/2007	10/4/2007	9.00	$	41,344	$	372,094
9/29/2007	10/5/2007	10/2/2007	10/11/2007	9.00	$	24,956	$	224,604
10/6/2007	10/12/2007	10/9/2007	10/18/2007	9.00	$	21,576	$	194,184
10/13/2007	10/19/2007	10/16/2007	10/25/2007	9.00	$	9,314	$	83,827
10/20/2007	10/26/2007	10/23/2007	11/1/2007	9.00	$	49,589	$	446,297
10/27/2007	11/2/2007	10/30/2007	11/8/2007	9.00	$	28,977	$	260,792
11/3/2007	11/9/2007	11/6/2007	11/15/2007	9.00	$	31,426	$	282,830
11/10/2007	11/16/2007	11/13/2007	11/22/2007	9.00	$	25,408	$	228,674
11/17/2007	11/23/2007	11/20/2007	11/29/2007	9.00	$	38,781	$	349,031
11/24/2007	11/30/2007	11/27/2007	12/6/2007	9.00	$	44,493	$	400,441
12/1/2007	12/7/2007	12/4/2007	12/13/2007	9.00	$	28,863	$	259,769
12/8/2007	12/14/2007	12/11/2007	12/20/2007	9.00	$	14,807	$	133,264
12/15/2007	12/21/2007	12/18/2007	12/27/2007	9.00	$	20,614	$	185,525
	TOTAL			9.00	$	1,554,986	$	13,994,877

Equitable Gas Company

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Period Covered From (A)	To (B)	Mid-Point of Period (C)	Date Paid (D)	Days Lag (D-C) (E)	Amount of Expense (F)	Dollar Days (E*F) (G)
Security Blue						
1/1/2007	1/31/2007	1/16/2007	3/8/2007	51.00	$ 88,064	$ 4,491,247
2/1/2007	2/28/2007	2/14/2007	3/8/2007	21.50	$ 87,624	$ 1,883,925
3/1/2007	3/31/2007	3/16/2007	6/12/2007	88.00	$ 86,732	$ 7,632,458
4/1/2007	4/30/2007	4/15/2007	6/12/2007	57.50	$ 87,601	$ 5,037,069
5/1/2007	5/31/2007	5/16/2007	6/12/2007	27.00	$ 87,905	$ 2,373,440
6/1/2007	6/30/2007	6/15/2007	6/12/2007	(3.50)	$ 86,993	$ (304,476)
7/1/2007	7/31/2007	7/16/2007	8/7/2007	22.00	$ 85,473	$ 1,880,410
8/1/2007	8/31/2007	8/16/2007	8/21/2007	5.00	$ 89,729	$ 448,646
9/1/2007	9/30/2007	9/15/2007	12/11/2007	86.50	$ 89,881	$ 7,774,724
10/1/2007	10/31/2007	10/16/2007	12/11/2007	56.00	$ 90,337	$ 5,058,883
11/1/2007	11/30/2007	11/15/2007	12/11/2007	25.50	$ 92,313	$ 2,353,987
12/1/2007	12/31/2007	12/16/2007	12/27/2007	11.00	$ 91,857	$ 1,010,429
	TOTAL			37.24	$ 1,064,511	$ 39,640,743
Blue Rx						
1/1/2007	1/31/2007	1/16/2007	3/8/2007	51.00	$ 16,108	$ 821,521
2/1/2007	2/28/2007	2/14/2007	3/8/2007	21.50	$ 17,052	$ 366,624
3/1/2007	3/31/2007	3/16/2007	6/12/2007	88.00	$ 16,136	$ 1,419,938
4/1/2007	4/30/2007	4/15/2007	6/12/2007	57.50	$ 17,074	$ 981,766
5/1/2007	5/31/2007	5/16/2007	6/12/2007	27.00	$ 17,106	$ 461,866
6/1/2007	6/30/2007	6/15/2007	6/12/2007	(3.50)	$ 17,495	$ (61,233)
7/1/2007	7/31/2007	7/16/2007	8/7/2007	22.00	$ 14,727	$ 323,984
8/1/2007	8/31/2007	8/16/2007	9/6/2007	21.00	$ 14,089	$ 295,866
9/1/2007	9/30/2007	9/15/2007	12/11/2007	86.50	$ 14,834	$ 1,283,144
10/1/2007	10/31/2007	10/16/2007	12/11/2007	56.00	$ 15,043	$ 842,409
11/1/2007	11/30/2007	11/15/2007	12/11/2007	25.50	$ 15,970	$ 407,243
12/1/2007	12/31/2007	12/16/2007	12/27/2007	11.00	$ 15,888	$ 174,763
	TOTAL			38.21	$ 191,522	$ 7,317,892
Retiree Vision						
1/1/2007	1/31/2007	1/16/2007	3/8/2007	51.00	$ 1,723	$ 87,863
2/1/2007	2/28/2007	2/14/2007	3/8/2007	21.50	$ 1,638	$ 35,220
3/1/2007	3/31/2007	3/16/2007	6/21/2007	97.00	$ 1,636	$ 158,689
4/1/2007	4/30/2007	4/15/2007	6/21/2007	66.50	$ 1,641	$ 109,153
5/1/2007	5/31/2007	5/16/2007	6/21/2007	36.00	$ 1,619	$ 58,270
6/1/2007	6/30/2007	6/15/2007	6/21/2007	5.50	$ 1,594	$ 8,765
7/1/2007	7/31/2007	7/16/2007	8/21/2007	36.00	$ 1,590	$ 57,254
8/1/2007	8/31/2007	8/16/2007	8/21/2007	5.00	$ 1,537	$ 7,686
9/1/2007	9/30/2007	9/15/2007	12/4/2007	79.50	$ 1,512	$ 120,222
10/1/2007	10/31/2007	10/16/2007	12/4/2007	49.00	$ 1,505	$ 73,726
11/1/2007	11/30/2007	11/15/2007	12/4/2007	18.50	$ 1,494	$ 27,635
12/1/2007	12/31/2007	12/16/2007	12/20/2007	4.00	$ 1,428	$ 5,710
	TOTAL			39.66	$ 18,916	$ 750,194
Retiree Life						
1/1/2007	1/31/2007	1/16/2007	3/8/2007	51.00	$ 17,090	$ 871,581
2/1/2007	2/28/2007	2/14/2007	3/8/2007	21.50	$ 17,090	$ 367,431
3/1/2007	3/31/2007	3/16/2007	6/21/2007	97.00	$ 17,088	$ 1,657,549
4/1/2007	4/30/2007	4/15/2007	6/21/2007	66.50	$ 17,087	$ 1,136,294
5/1/2007	5/31/2007	5/16/2007	6/21/2007	36.00	$ 17,015	$ 612,530
6/1/2007	6/30/2007	6/15/2007	6/21/2007	5.50	$ 17,080	$ 93,940
7/1/2007	7/31/2007	7/16/2007	8/21/2007	36.00	$ 16,731	$ 602,300
8/1/2007	8/31/2007	8/16/2007	8/21/2007	5.00	$ 16,667	$ 83,337
9/1/2007	9/30/2007	9/15/2007	12/4/2007	79.50	$ 16,952	$ 1,347,679
10/1/2007	10/31/2007	10/16/2007	12/4/2007	49.00	$ 16,853	$ 825,774
11/1/2007	11/30/2007	11/15/2007	12/4/2007	18.50	$ 16,809	$ 310,971
12/1/2007	12/31/2007	12/16/2007	12/20/2007	4.00	$ 17,003	$ 68,012
	TOTAL			39.21	$ 203,464	$ 7,977,399

Equitable Gas Company

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Period Covered From (A)	To (B)	Mid-Point of Period (C)	Date Paid (D)	Days Lag (D-C) (E)		Amount of Expense (F)		Dollar Days (E*F) (G)
Retiree Dental								
1/1/2007	1/31/2007	1/16/2007	3/8/2007	51.00	$	14,118	$	720,034
2/1/2007	2/28/2007	2/14/2007	3/8/2007	21.50	$	14,118	$	303,544
3/1/2007	3/31/2007	3/16/2007	6/12/2007	88.00	$	14,274	$	1,256,073
4/1/2007	4/30/2007	4/15/2007	6/12/2007	57.50	$	14,274	$	820,730
5/1/2007	5/31/2007	5/16/2007	6/12/2007	27.00	$	15,080	$	407,153
6/1/2007	6/30/2007	6/15/2007	6/12/2007	(3.50)	$	15,545	$	(54,409)
7/1/2007	7/31/2007	7/16/2007	8/7/2007	22.00	$	14,291	$	314,409
8/1/2007	8/31/2007	8/16/2007	10/4/2007	49.00	$	14,081	$	689,964
9/1/2007	9/30/2007	9/15/2007	10/4/2007	18.50	$	14,080	$	260,473
10/1/2007	10/31/2007	10/16/2007	11/8/2007	23.00	$	14,161	$	325,707
11/1/2007	11/30/2007	11/15/2007	12/4/2007	18.50	$	13,948	$	258,031
12/1/2007	12/31/2007	12/16/2007	12/20/2007	4.00	$	14,254	$	57,017
TOTAL				31.11	$	172,224	$	5,358,727
Aon - Legacy Retiree							$	-
1/1/2007	1/31/2007	1/16/2007	4/17/2007	91.00	$	16,470	$	1,498,808
2/1/2007	2/28/2007	2/14/2007	6/12/2007	117.50	$	12,112	$	1,423,112
3/1/2007	3/31/2007	3/16/2007	6/12/2007	88.00	$	10,886	$	957,932
4/1/2007	4/30/2007	4/15/2007	8/21/2007	127.50	$	14,145	$	1,803,498
5/1/2007	5/31/2007	5/16/2007	8/21/2007	97.00	$	12,015	$	1,165,452
6/1/2007	6/30/2007	6/15/2007	8/30/2007	75.50	$	17,137	$	1,293,831
7/1/2007	7/31/2007	7/16/2007	11/13/2007	120.00	$	12,705	$	1,524,558
8/1/2007	8/31/2007	8/16/2007	11/13/2007	89.00	$	17,237	$	1,534,090
9/1/2007	9/30/2007	9/15/2007	12/11/2007	86.50	$	10,891	$	942,067
10/1/2007	10/31/2007	10/16/2007	12/18/2007	63.00	$	11,184	$	704,612
11/1/2007	11/30/2007	11/15/2007	12/27/2007	41.50	$	13,535	$	561,720
12/1/2007	12/31/2007	12/16/2007	12/27/2007	11.00	$	16,680	$	183,480
TOTAL				82.38	$	164,997	$	13,593,161
Watson Wyatt - Legacy Retiree								
1/1/2007	1/31/2007	1/16/2007	3/15/2007	58.00	$	12,667	$	734,706
2/1/2007	2/28/2007	2/14/2007	4/3/2007	47.50	$	4,465	$	212,066
3/1/2007	3/31/2007	3/16/2007	6/12/2007	88.00	$	12,484	$	1,098,606
4/1/2007	4/30/2007	4/15/2007	6/12/2007	57.50	$	4,402	$	253,129
6/1/2007	7/31/2007	7/1/2007	8/30/2007	60.00	$	6,316	$	378,987
8/1/2007	8/31/2007	8/16/2007	10/4/2007	49.00	$	6,510	$	318,974
9/1/2007	9/30/2007	9/15/2007	11/8/2007	53.50	$	8,490	$	454,211
10/1/2007	10/31/2007	10/16/2007	12/6/2007	51.00	$	1,867	$	95,230
11/1/2007	11/30/2007	11/15/2007	12/20/2007	34.50	$	1,869	$	64,467
12/1/2007	12/31/2007	12/16/2007	12/27/2007	11.00	$	16,680	$	183,480
TOTAL				50.08	$	75,750	$	3,793,857
RETIREE BENEFITS					$	3,446,372	$	92,426,848
WEIGHTED AVERAGE DAYS				26.82				

Equitable Gas Company

Income Taxes
For The Twelve Months Ended December 31, 2007

Period Covered From (A)	To (B)	Mid-Point of Period (C)	Date of Statutory Payment (D)	Days Lag (D-C) (E)	Percent Due (F)	Dollar Days (E*F) (G)
FEDERAL INCOME TAXES						
1/1/2007	12/31/2007	7/2/2007	4/15/2007	(78.00)	25.0	(1,950.00)
1/1/2007	12/31/2007	7/2/2007	6/15/2007	(17.00)	25.0	(425.00)
1/1/2007	12/31/2007	7/2/2007	9/15/2007	75.00	25.0	1,875.00
1/1/2007	12/31/2007	7/2/2007	12/15/2007	166.00	25.0	4,150.00
		TOTAL			100.0	3,650.0
		WEIGHTED AVERAGE DAYS		36.50		
STATE INCOME TAXES						
1/1/2007	12/31/2007	7/2/2007	3/15/2007	(109.00)	22.5	(2,452.50)
1/1/2007	12/31/2007	7/2/2007	6/15/2007	(17.00)	22.5	(382.50)
1/1/2007	12/31/2007	7/2/2007	9/15/2007	75.00	22.5	1,687.50
1/1/2007	12/31/2007	7/2/2007	12/15/2007	166.00	22.5	3,735.00
1/1/2007	12/31/2007	7/2/2007	3/15/2008	257.00	10.0	2,570.00
		Total			100.00	5,157.50
		WEIGHTED AVERAGE DAYS		51.58		

Equitable Gas Company

PA Sales and Use Taxes
For The Twelve Months Ended December 31, 2007

Period Covered From (A)	To (B)	Mid-Point of Period (C)	Date of Payment (D)	Days Lag (D-C) (E)	Dollar Amount (F)	Dollar Days (E*F) (G)
12/1/2006	12/31/2006	12/16/2006	1/22/2007	37.00	$ 580,725	$ 21,486,835
1/1/2007	1/31/2007	1/16/2007	2/23/2007	38.00	$ 751,466	$ 28,555,693
2/1/2007	2/28/2007	2/14/2007	3/20/2007	33.50	$ 1,214,939	$ 40,700,461
3/1/2007	3/31/2007	3/16/2007	4/20/2007	35.00	$ 1,003,936	$ 35,137,759
4/1/2007	4/30/2007	4/15/2007	5/21/2007	35.50	$ 572,288	$ 20,316,231
5/1/2007	5/31/2007	5/16/2007	6/20/2007	35.00	$ 331,004	$ 11,585,125
6/1/2007	6/30/2007	6/15/2007	7/20/2007	34.50	$ 184,055	$ 6,349,906
7/1/2007	7/31/2007	7/16/2007	8/20/2007	35.00	$ 158,426	$ 5,544,911
8/1/2007	8/31/2007	8/16/2007	9/20/2007	35.00	$ 158,635	$ 5,552,222
9/1/2007	9/30/2007	9/15/2007	10/22/2007	36.50	$ 150,475	$ 5,492,332
10/1/2007	10/31/2007	10/16/2007	11/20/2007	35.00	$ 171,093	$ 5,988,272
11/1/2007	11/30/2007	11/15/2007	12/20/2007	34.50	$ 352,322	$ 12,155,126
TOTAL					$ 5,629,365	$ 198,864,872
WEIGHTED AVERAGE DAYS				35.33		

Equitable Gas Company

Taxes Other Than Income
For The Twelve Months Ended December 31, 2007

Period Covered From (A)	To (B)	Mid-Point of Period (C)	Date Paid (D)	Days Lag (D-C) (E)	Amount of Expense (F)		Dollar Days (E*F) (G)
MONONGAHELA MERCANTILE LICENSE TAX							
1/1/2007	12/31/2007	7/2/2007	11/26/2007	147.00	300	$	44,100
PITTSBURGH BUSINESS PRIVILEGE TAX							
1/1/2006	12/31/2006	7/2/2006	4/17/2007	289.00	1,925	$	556,438
PENNSYLVANA PUC ASSESSMENT							
6/1/06	6/30/07	12/15/2006	6/1/07	168.00	16,217	$	2,724,456
7/1/07	6/30/08	12/30/2007	9/18/07	(103.50)	987,304	$	(102,185,964)
QUARTERLY FEDERAL EXCISE TAX							
1/16/07	1/31/07	1/23/2007	2/14/07	21.50	50	$	1,075
2/16/07	2/28/07	2/22/2007	3/14/07	20.00	50	$	1,000
4/16/07	4/30/07	4/23/2007	5/14/07	21.00	50	$	1,050
6/16/07	6/30/07	6/23/2007	7/13/07	20.00	53	$	1,068
7/1/07	7/15/07	7/8/2007	7/27/07	19.00	50	$	950
7/16/07	7/31/07	7/23/2007	8/14/07	21.50	50	$	1,075
8/16/07	8/31/07	8/23/2007	9/14/07	21.50	50	$	1,075
10/1/07	10/15/07	10/8/2007	10/29/07	21.00	50	$	1,050
FEDERAL HEAVY VEHICLE USE TAX							
7/1/07	6/30/08	12/30/2007	8/17/07	(135.50)	1,168	$	(158,264)
PA PURTA							
1/1/07	12/31/07	7/2/2007	5/1/07	(62.00)	71,193	$	(4,413,961)

Equitable Gas Company

Taxes Other Than Income
For The Twelve Months Ended December 31, 2007

Period Covered From (A)	To (B)	Mid-Point of Period (C)	Date Paid (D)	Days Lag (D-C) (E)	Amount of Expense (F)		Dollar Days (E*F) (G)
PA Boro and Township Real Estate							
1/1/2007	12/31/2007	7/2/2007	01/31/07	(152.00)	7,378	$	(1,121,521)
1/1/2006	12/31/2006	7/2/2006	02/28/07	241.00	1	$	222
1/1/2007	12/31/2007	7/2/2007	02/28/07	(124.00)	8	$	(1,013)
1/1/2007	12/31/2007	7/2/2007	03/31/07	(93.00)	40	$	(3,686)
1/1/2007	12/31/2007	7/2/2007	03/31/07	(93.00)	31	$	(2,846)
1/1/2007	12/31/2007	7/2/2007	03/31/07	(93.00)	1,400	$	(130,188)
1/1/2007	12/31/2007	7/2/2007	04/30/07	(63.00)	301	$	(18,948)
1/1/2007	12/31/2007	7/2/2007	04/30/07	(63.00)	544	$	(34,268)
1/1/2007	12/31/2007	7/2/2007	04/30/07	(63.00)	247	$	(15,534)
1/1/2007	12/31/2007	7/2/2007	05/31/07	(32.00)	218	$	(6,977)
1/1/2007	12/31/2007	7/2/2007	05/31/07	(32.00)	2	$	(66)
1/1/2007	12/31/2007	7/2/2007	05/31/07	(32.00)	38	$	(1,200)
1/1/2007	12/31/2007	7/2/2007	08/31/07	60.00	9	$	557
1/1/2007	12/31/2007	7/2/2007	08/31/07	60.00	2,695	$	161,674
1/1/2007	12/31/2007	7/2/2007	08/31/07	60.00	83	$	4,966
1/1/2007	12/31/2007	7/2/2007	08/31/07	60.00	172	$	10,300
1/1/2007	12/31/2007	7/2/2007	08/31/07	60.00	8	$	455
1/1/2007	12/31/2007	7/2/2007	08/31/07	60.00	1,459	$	87,561
1/1/2007	12/31/2007	7/2/2007	08/31/07	60.00	50	$	2,975
1/1/2007	12/31/2007	7/2/2007	08/31/07	60.00	20,162	$	1,209,740
1/1/2007	12/31/2007	7/2/2007	08/31/07	60.00	1,080	$	64,816
1/1/2007	12/31/2007	7/2/2007	08/31/07	60.00	3,246	$	194,772
1/1/2007	12/31/2007	7/2/2007	08/31/07	60.00	9	$	521
1/1/2007	12/31/2007	7/2/2007	08/31/07	60.00	3,246	$	194,772
1/1/2007	12/31/2007	7/2/2007	08/31/07	60.00	175	$	10,510
1/1/2007	12/31/2007	7/2/2007	08/31/07	60.00	2	$	118
1/1/2006	12/31/2006	7/2/2006	08/31/07	425.00	6,168	$	2,621,268
1/1/2006	12/31/2006	7/2/2006	08/31/07	425.00	5	$	2,087
1/1/2006	12/31/2006	7/2/2006	09/30/07	455.00	(175)	$	(79,698)
1/1/2006	12/31/2006	7/2/2006	11/30/07	516.00	1,000	$	516,000
CAPITAL STOCK							
1/1/2007	12/31/2007	7/2/2007	3/15/07	(109.00)	66,589	$	(7,258,201)
1/1/2007	12/31/2007	7/2/2007	6/15/07	(17.00)	66,589	$	(1,132,013)
1/1/2007	12/31/2007	7/2/2007	9/15/07	75.00	66,589	$	4,994,175
1/1/2007	12/31/2007	7/2/2007	12/15/07	166.00	66,589	$	11,053,774
TOTAL					1,394,466		(92,099,751)
WEIGHTED AVERAGE DAYS				(66.05)			

Equitable Gas Company

Interest on Debt
For The Twelve Months Ended December 31, 2007

Debt Instrument	Days Lag	Interest Charges	Dollar Weighted
Long-Term	91.25	$ 13,511,680	$ 1,232,940,830
Short-Term	45.63	$ 9,356,204	$ 426,876,787
TOTAL		$ 22,867,884	$ 1,659,817,617
Weighted Average	72.58		

Equitable Gas Company
Response to Standard Data Requests
REVENUE REQUIREMENT INTERROGATORIES

Item 19: Please provide the payroll distribution showing the percentage of wages charged to O&M and other categories for each of the preceding three calendar years and the most recent annual period available.

Response: See attached.

Equitable Gas Company
Response to Standard Data Requests
REVENUE REQUIREMENT INTERROGATORIES

Item 19:

	Calendar Year Ended							
	December 31, 2007		December 31, 2006		December 31, 2005		December 31, 2004	
	$	%	$	%	$	%	$	%
Labor Charged to Operating Accounts								
Distribution	$11,409,277	44.71%	$11,544,335	45.12%	$11,036,772	44.69%	$13,227,329	52.03%
Customer Accounting	745,591	2.92%	651,505	2.55%	606,137	2.45%	581,675	2.29%
Customer Service & Info.	3,916,898	15.35%	4,241,408	16.58%	4,947,924	20.04%	3,604,719	14.18%
Other Gas Supply	518,900	2.03%	429,016	1.68%	526,266	2.13%	646,590	2.54%
Sales	1,008,540	3.95%	1,010,717	3.95%	1,071,461	4.34%	1,125,977	4.43%
Administrative & General (1) (2)	3,935,919	15.42%	3,032,771	11.85%	1,310,516	5.31%	1,392,138	5.48%
Total Operation & Maintenance Labor	21,535,125	84.40%	20,909,752	81.73%	19,499,076	78.96%	20,578,428	80.95%
Labor Charged to Other Accounts								
Capital	3,981,390	15.60%	4,673,812	18.27%	5,196,916	21.04%	4,843,856	19.05%
Total Labor Charged to Other Accounts	3,981,390	15.60%	4,673,812	18.27%	5,196,916	21.04%	4,843,856	19.05%
Total Labor Charged	$25,516,515	100.00%	$25,583,564	100.00%	$24,695,992	100.00%	$25,422,284	100.00%

(1) 2007 and 2006 amounts include charges related to the acquisition of Dominion Peoples of approximately $1.5 million in both years. Note that the charges included in 2007 have been excluded as part of the annualization and normalization of account 920 included in schedule III-A-17, historical test year.

(2) 2007 amounts include charges of approximately $1.2 million that relate to labor costs that have been subsequently reassigned to other divisions within Equitable Resources due to a reorganization within the first quarter 2008. These charges have been excluded as part of the annualization and normalization of account 920 included in schedule III-A-17, historical test year.

Item 20: Please state whether the future test year budgeted labor includes any increases or decreases in the number of employees during the future test year. If increases have been budgeted, please state whether the future test year includes budgeted positions which have not been filled.

Response: The future test year budgeted labor includes an increase of 12 employees during the future test year. As of May 2008, all positions have been filled.

Item 21: Please explain how the company has treated routine or normal position vacancies which occur as a result of terminations or retirements in its budgeted labor projections.

Response: Routine and/or normal open positions related to terminations or retirements were assumed to be filled with employees with equal pay amounts. The associated amounts are included in the annualized adjustments for both the Historic and Future Test Years. Refer to Exhibit III, Item III-A-17.

Equitable Gas Company
Response to Standard Data Requests
REVENUE REQUIREMENT INTERROGATORIES

Item 22: Please provide the most recent insurance premiums for each type of insurance coverage (i.e., employee benefit and those purchased by the Company) reflected in the Company's filing. If available, please provide estimated premiums for the subsequent calendar year.

Response: Following is a list of insurance premiums reflected in the Company's filing for the year ended December 31, 2007.

Automotive Insurance	$	49,758
Blanket Crime Insurance		765
Property Insurance		191,953
Directors & Officers Liability Insurance		177,970
Excess Liability Insurance		1,141,942
Excess Worker's Compensation		100,511
General Liability Insurance		2,807,052
Fiduciary Liability Insurance		42,729
Total Premiums	$	4,512,680

Equitable Gas Company
Response to Standard Data Requests
REVENUE REQUIREMENT INTERROGATORIES

Item 23: Please provide a copy of the Company's two most recent FERC Form 2.

Response: See attached copies of 2007 and 2006 FERC Form 2.

GAS ANNUAL REPORT
OF

EQUITABLE GAS COMPANY, A DIVISION OF EQUITABLE RESOURCES, INC.

Exact legal name of reporting gas company or corporation

(If name was changed during year, show also the previous name and date of change)

225 NORTH SHORE DRIVE, PITTSBURGH, PENNSYLVANIA 15212-5861

(Address of principal business office at end of year)

FOR THE

YEAR ENDED DECEMBER 31, 2007

TO THE

COMMONWEALTH OF PENNSYLVANIA

PUBLIC UTILITY COMMISSION

Name, title, address and telephone number (including the area code), E-Mail Address, and Web Site Address of the person to be contacted concerning this report:

Jeffery C. Mitchell

jmitchell@eqt.com

Vice President and Controller

225 North Shore Drive, Pittsburgh, Pennsylvania 15212-5861

412-395-3179

www.eqt.com

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GENERAL INSTRUCTIONS

1. The completed original and an electronic (e-mail) copy of this report shall be filed with the Pennsylvania Public Utility Commission, P.O. Box 3265, Harrisburg, Pennsylvania, 17105-3265 on or before the 30th of April following the end of the year to which the report applies.

2. All Natural Gas Distribution Companies subject to the jurisdiction of the Pennsylvania Public Utility Commission, upon which this report is served are required by statute to complete and file this report. The statute further provides that when any such report is defective or believed to be erroneous, the reporting corporation shall be duly notified and given a reasonable time within which to make the necessary amendments or corrections. All data comprising this report shall be submitted in electronic and permanent form.

3. All accounting terms and phrases used in this form are to be interpreted in accordance with the effective applicable Uniform System of Accounts prescribed by the Federal Energy Regulatory Commission Title 18 under "Part 201-Uniform System of Accounts Prescribed for Natural Gas Companies Subject to the Provisions of the Natural Gas Act", (18 CFR Part 201). Whenever the term respondent is used, it shall mean the reporting company.

4. Standard accounting procedures will apply in determining the nature of any entry (e.g., Uncollectibles, a revenue item, is normally a debit entry, and should be entered as a "positive" number unless the reported balance is a credit). Entries of a reverse or contrary character shall be indicated by parenthesis around the number.

5. If the report is made for a period less than the calendar year, the period covered must be clearly stated on the front cover and elsewhere throughout the report where the period covered is shown. When operations cease during the year because of the disposition of property, the balance sheet and supporting schedules should consist of balances and items immediately prior to transfer (for accounting purposes). If the books are not closed as of that date, the data in the report should nevertheless be complete, and the amounts reported should be supported by information set forth in, or as part of, the books of account.

6. All instructions shall be followed and each question shall be answered fully and accurately. Sufficient answers shall appear to show that no question or schedule has been overlooked. The expression "none" or "not applicable" shall be given as the answer to any particular inquiry or schedule where it truly and completely states the fact. Unless otherwise indicated, no information will be accepted which incorporates by reference information from another document or report. Where information called for herein is not given, state fully the reason for its omission.

7. Extra copies of any page will be furnished upon request. If it is necessary or desirable to insert additional statements for the purpose of further explanation of accounts or schedules, they shall be legibly made on paper of durable quality and shall correspond to this form in size of page and width of margin. Additional sheets, ruled either vertically or horizontally, will be furnished on request. Inserts, if any, should be appropriately identified with the schedules to which they relate.

8. If the gas distribution service provider conducts operations both within and outside the Commonwealth of Pennsylvania, data should be reported so that there will be shown the number of subscribers within this state, and (separately by accounts) the operating revenues from sources within this state, and the plant investment as of the end of the year within the state.

9. Whenever schedules call for comparison of figures of a previous year, the figures reported must be based upon those shown by the annual report of the previous year or an appropriate explanation given why different figures were used.

10. Throughout the report, money items shall be shown in units of dollars adjusted to accord with footings. Omitting cents does not apply, however, to items in which cents are of significance, as for instance, in averages and in unit costs.

11. If this report is not completed electronically, the name of the respondent and the year to which the report relates shall be inserted on the top of each page.

GENERAL INFORMATION

1. Name and title of officer having custody of the general books of account and address of the office where such books are kept.

Jeffery C. Mitchell
Vice President & Controller
225 North Shore Drive, Pittsburgh, Pennsylvania 15212-5861

2. Name of State under the laws of which respondent is incorporated and the date of incorporation. If incorporated under a special law, give reference to such law. If not incorporated, state that fact and give the type of organization and date organized.

Pennsylvania, March 31, 1926

3. If at any time during the year the property of respondent was held by a receiver or trustee, give (a) name of receiver or trustee (b) date such receiver or trustee took possession, (c) the authority by which the receivership or trusteeship was created, (d) date when possession by receiver or trustee ceased.

None.

4. State the classes of utility and other services furnished by respondent during the year in each state in which the respondent operated.

Equitable Gas Company operates as a local distribution company in Pennsylvania and West Virginia. The Company also operates a small gathering system in Pennsylvania. In Kentucky, Equitable Gas Company provides exclusively "farm-tap" service under the provisions of KRS 278.485.

IMPORTANT CHANGES DURING YEAR

Hereunder give particulars concerning the matters indicated below. Make the statements explicit and precise, and number them in accordance with the inquiries. Each inquiry must be answered. However, if the word "None" states the fact, it may be used in answering any inquiry.

1. Changes in, and additions to franchise rights; describing (a) the actual consideration given therefor, and (b) from whom acquired. If acquired without the payment of any consideration, state that fact.
2. Acquisition of other companies, reorganization, merger or consolidation with other companies: give names of companies involved, particulars concerning the transactions, and references to Commission authorization, if any.
3. Purchase or sale of substantial operating units, such as generating stations, transmission lines or distribution lines, specifying items, parties, effective dates and also reference to Commission authorization, if any.
4. Important leaseholds (other than leaseholds for natural gas lands) acquired, given, assigned, or surrendered, giving effective dates, lengths of terms, names of parties, rents, Commission authorization, if any, and other conditions.
5. Important extensions of system, giving location, new territory covered by distribution systems, and dates of beginning operations. Give, also, the number of new customers of each class, and for each class of customers the estimated annual revenues.
6. Estimated increase or decrease in annual revenues due to important rate changes, and the approximate extent to which such increase or decrease is reflected in revenues for the reporting year.
7. Important wage scale changes, showing dates of changes, effect on operating expenses for the year, and estimated annual effect of such wage scale changes on operating expenses.
8. Obligations incurred or assumed by respondent as guantantor for the performance by another of any agreement for the performance by another of any agreement or obligation, excluding ordinary commercial paper maturing on demand or not later than one year after date of issue, and giving Commission authorization, if any.
9. Changes in articles of incorporation or amendments to charter: explain the nature and purpose of such changes or amendments.
10. Other important changes not elsewhere provided for.

Item 1: None.

Item 2: None.

Items 3 & 4: None.

Item 5: No important extension of distribution system territory.

Item 6: Purchased Gas Cost Changes

PENNSYLVANIA:

On December 29, 2006, the Company filed an increase in purchased Gas costs effective January 1, 2007 in compliance with the Pennsylvania Public Utility Commission's quarterly gas cost filing regulations.

On June 29, 2007, the Company filed an increase in purchased gas costs effective July 1, 2007 in compliance with the Pennsylvania Public Utility Commission's quarterly gas cost filing regulations.

On September 28, 2007, the Company filed an increase in purchased gas costs effective October 1, 2007 in compliance with the Pennsylvania Public Utility Commission's quarterly gas cost filing regulations.

On October 6, 2006, the Company filed for an increase in its Rider D (Universal Service and Energy Conservation) surcharge, and obtained approval from the Pennsylvania Public Utility Commission to be effective October 2, 2007.

As a result of the rate changes, the net impact on revenues for 2007 was an increase of $14,979,065.

The number of sales customers as of December 31, 2007 was 226,086.

IMPORTANT CHANGES DURING YEAR (Continued)

WEST VIRGINIA:

Effective November 1, 2007, Case No. 07-1436-G-30C, the West Virginia Public Service Commission approved a decrease in the gas cost recovery rates.

As a result of this rate change, the net impact on revenues for 2007 was a decrease of $560,414.

The number of sales customers as of December 31, 2007 was 13,290.

KENTUCKY:

Effective February 1, 2007, Case No. 2006-00560, the Kentucky Public Service Commission approved a decrease in the gas cost recovery rates.

Effective May 1, 2007, Case No. 2007-00130, the Kentucky Public Service Commission approved an increase in the gas cost recovery rates.

Effective August 1, 2007, Case No. 2007-00261, the Kentucky Public Service Commission approved an increase in the gas cost recovery rates.

Effective November 1, 2007 Case No. 2007-00417, the Kentucky Public Service Commission approved a decrease in the gas cost recovery rates.

As a result of these rate changes, the net impact on revenues for 2007 was a decrease of $137,574.

The number of customers as of December 31, 2007 was 3,455.

Item 7: Important Wage Scale Changes

Certain nonunion, nonexempt and exempt employees (excluding officers) received an average wage increase of 3.0% effective February 26, 2007.

Wage increases for employees represented by unions were as follows:

(a) Employees of Equitable Gas Company represented by Local 1935, International Brotherhood of Electrical Workers, received a 2% lump sum payment in lieu of a general wage increase.

(b) Employees of Equitable Gas Company represented by Local 12050, United Steelworkers of America, received a 2.0% general wage increase effective September 24 2007.

(c) Employees of Equitable Gas Company represented by Local 1956, International Brotherhood of Electrical Workers, received a 2.5% general Wage increase effective February 22, 2007.

Item 8: None.

IMPORTANT CHANGES DURING YEAR (Continued)

Item 9: The Company has filed applications with the PA PUC and WV PSC to reorganize into a holding company. The Company is pursuing a holding company reorganization because the Company believes that the separation of its state-regulated distribution operations into a new subsidiary will better segregate its regulated and unregulated businesses and improve overall financing flexibility. To effect the reorganization, the Company intends to merge with a second tier subsidiary (MergerSub), which will result in a first tier subsidiary (New EQT) becoming the new publicly traded parent company of the Equitable Resources family of companies. Following the merger, the Company will transfer to New EQT all of the assets and liabilities of the Company other than those associated with the Company's existing Equitable Gas Company division and New EQT and its subsidiaries will continue to conduct the business and operations that the Company and its subsidiaries conducted immediately before the effective time of the reorganization.

The Company successfully completed a request for direction to holders of notes under the indentures governing its long-term debt. The Company has also received a no-action letter from the SEC satisfactorily addressing certain elements of the proposed reorganization. The Company expects to complete the reorganization upon receipt of PA PUC and WV PSC approvals.

Item 10: None.

DEFINITIONS

"Accounts" means the accounts prescribed in the Federal Code Regulations Title 18, Part 201.

"Amortization" means the gradual extinguishment of an amount in an account by distributing such amount over a fixed period, which may be over the life of the asset or liability to which it applies, or over the period during which it is anticipated the benefit will be realized.

"Book Cost" means the amount at which property is recorded in the applicable account without deduction of related provisions for accrued depreciation, amortization, or for other purposes.

"Control" (including the terms; "controlling," "controlled by," and "under common control with") means the possession, directly or indirectly, of the power to direct or cause the direction of the management and policies of a company, whether such power is exercised through one or more intermediary companies, or alone, or in conjunction with, or pursuant to an agreement, and whether such power is established through a majority or minority ownership or voting of securities, common directors, officers, or stockholders, voting trusts, holding trusts, affiliated companies, contract or any other direct or indirect means.

"Cost" means the amount of money actually paid for property or service. When the consideration given is other than cash, the value of such consideration shall be determined on a cash basis.

"Debt Expense" means all expenses in connection with the issuance and initial sale of evidences of debt, such as fees for drafting mortgages and trust deeds; fees and taxes for issuing or recording evidences of debt; cost of engraving and printing bonds and certificates of indebtedness; fees paid trustees; specific costs of obtaining governmental authority; fees for legal services; fees and commissions paid underwriters, brokers, and salesmen or marketing such evidences of debt; fees and expenses of listing on exchanges; and other like costs.

"Depreciation", as applied to depreciable utility plant, means the loss in service value not restored by current maintenance, incurred in connection with the consumption or prospective retirement of the utility plant in the course of providing service. This includes causes which are known to be in current operation and against which the utility is not protected by insurance. Among the causes to be given consideration are wear and tear, decay, action of the elements, inadequacy, obsolescence, changes in the art, changes in demand, and requirements of regulatory bodies.

"Distribution Service Line", A distribution line that transports gas from a common source of supply to a customer meter or the connection to a customer's piping, whichever is further downstream, or the connection to a customer's piping if there is no customer meter.

DEFINITIONS
(Continued)

"Investment Advances" means advances, represented by notes or by book accounts only, with respect to which it is mutually agreed or intended between the creditor and debtor that they shall be settled by the issuance of securities or shall not be subject to current settlement.

"Minor Items of Property" means the associated parts or items of which retirement units are composed.

"Net Salvage Value" means the salvage value of property retired less the cost of removal.

"Nominally Issued", as applied to securities issued or assumed by the utility means those which have been signed, certified, or otherwise executed, and placed with the proper officer for sale and delivery, or pledged, or otherwise placed in some special fund of the utility, but which have not been sold, or issued directly to trustees of sinking funds in accordance with contractual requirements.

"Original Cost", as applied to utility plant, means the cost of such property to the person first devoting it to public service.

"Property Retired", as applied to utility plant, means property which has been removed, sold, abandoned, destroyed, or which for any cause has been permanently withdrawn from service.

"Replacing or Replacement", when not otherwise indicated in the context, means the construction or installation of utility plant in place of property retired, together with the removal of the property retired.

"Retained Earnings" means the accumulated net income of the utility less distributions to stockholders and transfers to other capital accounts, and other adjustments.

"Salvage Value" means the amount received for property retired, less any expenses incurred in connection with the sale or in preparing the property for sale, or, if retained, the amount at which the material recoverable is chargeable to materials and supplies, or other appropriate account.

"Straight-Line Remaining Life Method", as applied to depreciation accounting, means the plan under which the service value of property is charged to operating expenses (and to clearing accounts if used), and credited to the accumulated depreciation account through equal annual changes during its service life. "Remaining Life" implies that estimates of the future life and salvage shall be reexamined periodically and that depreciation rates will be corrected to reflect any changes in these estimates.

100. VOTING POWERS AND ELECTIONS

1. Has each share of stock the right to one vote? Yes/No
   Yes
2. Are voting rights attached only to stock? Yes/No (If the answer to either query 1 or 2 is "No," give particulars on a separate sheet.)
   Yes

3. Give date of the latest closing of the stock book prior to end of year and state the purpose of such closing.
   N/A

4. Is cumulative voting permitted? Yes/No
   See # 9 below

6. State the date and place of the latest general meeting held prior to the end of the year for the election of directors?
   April 11, 2007

7. State the total number of votes cast at the latest general meeting and the total number cast by proxy.
   Total - 106,572,133 **By Proxy - 106,572,133**

8. State the total number of voting security holders and the total of all voting securities as of such date.
   Voting Securities as of 12/31/2007: Total Number of Security Holders - 3,806
   Total of all Voting Securities - 122,152,999
9. *If any security has preferences, special privileges, or restrictions in the election of directors, trustees or managers, or in the determination of any* corporate action, give details.
   Common Stock has cumulative voting rights of election of directors.

10. State the number of votes controlled by management, other than officers of the Corporation.
   -

101 SECURITY HOLDER INFORMATION AND VOTING POWERS

1. Report the requested information for each holder of one percent or more of the voting securities or if there are fewer than ten such holders, the ten who hold the highest voting powers. Data should be the latest available nearest the end of the year. When the holder of record is a trustee, or other intermediate agency (except a corporation), the data should be reported opposite the names of the beneficial owners, designated as such, under a general heading identifying the trustee or other agency. Securities with contingent voting rights may be disregarded.
2. Attach hereto a certified copy of every effective voting trust established and a certified copy of every other agreement (trustee or otherwise) under which voting securities are held for beneficial owners. If any such agreement has been filed with a previous report, reference to the earlier report will be sufficient provided changes or modification since filing are shown.

Line No	Last Name (a)	First Name (b)	Street Address (c)	City (d)	State (e)	Zip (f)	Total Votes (g)	Common Stock (h)	Preferred Stock (i)	Other (j)	Nonvoting Securities (see instruction 2) Principal, Par Value, or Stated Value (Specify issue-omit cents) (k)	Nonvoting Securities (see instruction 2) Principal, Par Value, or Stated Value (Specify issue-omit cents) (k)	Nonvoting Securities (see instruction 2) Principal, Par Value, or Stated Value (Specify issue-omit cent (k)
1	Total votes of all voting securities						122,152,999	122,152,999			7 3/4% Debentures-due 7/15/2026	5.15% Note-due 03/01/2018	5.15% Note-due 11/15/2012
2	Total number of security holders						3,806	3,806					
3	Total votes of security holders listed below						115,944,377	115,944,377					
4													
5	Cede & Company		18301 Bermuda Green Drive	Tampa	FL	33647	114,688,439				115,000,000	200,000,000	200,000,0
6	Equitable Resources, Inc. Restricted Stock Acct.		225 North Shore Drive	Pittsburgh	PA	15212	281,252						
7	Moritz (all shares held jointly with wife)	Donald	75 Woodland Road	Pittsburgh	PA	15232	236,086						
8	Porges	David	5725 Aylesboro Ave	Pittsburgh	PA	15217	370,920						
9	Ader	Richard	3250 Sandown Park Rd	Keswick	VA	22947	80,000						
10	Glassell, Jr.	Alfred	1021 Main Street, Suite 2300	Houston	TX	77002	76,270						
11	DiBenedetto	Anthony	P.O. Box 419	Bridgewater	CT	06752	69,692						
12	Moritz	Janet	75 Woodland Road	Pittsburgh	PA	15232	57,300						
13	Bagnato	Joseph	209 Valley View Drive	McDonald	PA	15057	47,248						
14	Moeller	Audrey	1003 Cherry Hill Drive	Presto	PA	15142	37,170						

102. COMPANIES CONTROLLED BY RESPONDENT

1. Show below the names of all corporations, business trusts, and similar organizations, controlled directly or indirectly by respondent at any time during the year. If control ceased prior to end of the year, give particulars in a footnote.
2. *If control was by other means than a direct holding of voting rights, state in a footnote the manner in which control was held, naming any intermediates involved.*
3. If control was held jointly with one or more other interests, state the fact in a footnote and name the other interests.

Line No.	Name of Company Controlled (a)	Kind of Business (b)	Street Address (c)	City (d)	State (e)	Zip (f)	Voting % of Stock (g)	Footnote Ref. (h)
1	*Appalachian Drilling LLC*	*Oil and natural gas production*					100%	Note A
2	Appalachian Natural Gas Trust	Oil and natural gas production					100%	Note B
3	Eastern Four, LLC	Oil and natural gas exploration and production					100%	Note C
4	Eastern Series 1997 Trust	Oil and natural gas exploration and production					100%	Note D
5	Eastern Seven Partners, L.P.	Oil and natural gas exploration and production					100%	Note E
6	EPC Investments, Inc.	Holding company					100%	Note E
7	EQT Capital Corporation	Finance company					100%	Note F
8	EQT Holdings Company, LLC	Holding company					100%	Note H
9	EQT Holdings Management Company, LLC	Holding company					100%	Note I
10	EQT International Holdings Corporation	Holding company					100%	Note J
11	EQT Investments Holdings, LLC	Holding company					100%	Note G
12	EQT Investments, LLC	Holding company					100%	Note F
13	*EQT IP Ventures, LLC*	*Intellectual property holding company*					100%	Note K
14	Equitable Energy, LLC	Energy marketing and services					100%	Note L
15	Equitable Energy Holdings Corporation	Holding company					100%	Note J
16	Equitable Gathering Equity, LLC	Natural gas gathering operations					100%	Note M
17	Equitable Gathering, Inc.	Natural gas gathering operations					100%	Note J
18	Equitable Gathering, LLC	Pipeline operations					100%	Note M
19	Equitable HomeWorks, LLC	Sales of energy related products and services					100%	Note A
20	Equitable Production Company	Oil and natural gas exploration and production					100%	Note J
21	Equitable Production Services, LP	Oil and natural gas production					100%	Note N
22	Equitable Resources Foundation, Inc.	Non-profit, charitable, scientific, and educational					100%	Note G
23	Equitable Resources Insurance Company, Ltd.	Captive insurance company					100%	Note G
24	Equitable Utilities Investments, Inc.	Holding company					100%	Note I
25	*Equitrans, LP*	*Interstate pipeline operations*					100%	*Note O*
26	ERI Group LDC	Foreign holding company					100%	Note P
27	ERI Holdings	Foreign holding company					100%	Note Q
28	ERI International	Foreign holding company					100%	Note R
29	ET Blue Grass Clearing, LLC	Land company					100%	Note A
30	ET Blue Grass Company	Oil and natural gas exploration and production					100%	Note J
31	Kentucky West Virginia Gas Company, LLC	Natural gas gathering operations					100%	Note S
32	PEP Finance Company	Foreign holding company					100%	Note T
33	Petroelectrica de Panama LDC	Foreign holding company					100%	Note R
34	Equitable Distribution, LLC	Finance holding company					100%	Note F
35	Nora Gathering LLC	Natural gas gathering operations					50%	Note U

102. COMPANIES CONTROLLED BY RESPONDENT (Continued)
FOOTNOTES

1. Direct control is that which is exercised without interposition of an intermediary.
2. Indirect control is that which is exercised without interposition of an intermediary which exercises direct control. Control may exist by mutual agreement or understanding between two or more parties who together have control within the meaning of the definition of control in the Uniform System of Accounts, regardless of the relative voting rights of each party.
3. Joint control may exist by mutual agreement or understanding between two or more parties who together have control within the meaning of the definition of control in the Uniform System of Accounts, regardless of the relative voting rights of each party.

Note A. Directly controlled by ET Blue Grass Company.
Note B. Directly controlled by EPC Investments, Inc.
Note C. Directly controlled by Eastern Series 1997 Trust.
Note D. Directly controlled by Eastern Seven Partners, L.P.
Note E. Directly controlled by Equitable Production Company.
Note F. Directly controlled by EQT Investments Holdings, LLC.
Note G. Directly controlled by Respondent.
Note H. Directly controlled by EQT Holdings Management Company, LLC (99%) and Equitable Utilities Investments (1%).
Note I. Directly controlled by EQT Capital Corporation.
Note J. Directly controlled by EQT Investments, LLC.
Note K. Directly controlled by EPC Investments, Inc. (49.5%) and Equitable Utilities Investments, Inc. (50.5%).
Note L. Directly controlled by Equitable Energy Holdings Corporation.
Note M. Directly controlled by Equitable Gathering, Inc.
Note N. Directly controlled by Equitable Production Company (50%) and ET Blue Grass (50%).
Note O. Directly controlled by Respondent (85%), Equitable Gathering, Inc. (14%) and ET Blue Grass (1%).
Note P. Directly controlled by ERI Holdings (99%) and ERI International (1%).
Note Q Directly controlled by EQT International Holdings Corporation.
Note R. Directly controlled by ERI Holdings.
Note S. Directly controlled by Respondent (99%) and ET Blue Grass Company (1%).
Note T. Directly controlled by Petroelectrica de Panama LDC
Note U. Directly controlled by Equitable Gathering Equity, LLC (50%) and Pine Mountain Oil and Gas (50%)

103. Directors

1. Report below the information called for concerning each director of the respondent who held office at any time during the year. Include in column (a) abbreviated titles of the directors who are officers of respondent.
2. Designate by an asterisk names of members of Executive Committee, and by double asterisk the Chairman of the Executive Committee.

		Principal Business Address					Term	Term	Meetings	Fees
	Directors Name and Title	Street Address	City	State	Zip	Telephone	Began	Email	Attended	Paid
	(a)	(b)	(c)	(d)	(e)	(h)	(i)	(j)	(k)	(l)
	EQUITABLE RESOURCES,							(A)		
1	Murry S. Gerber *, Chief Executive Officer and Director	225 North Shore Drive	Pittsburgh	PA	15212		6/1/1998	(D)	9	None
2	David L. Porges, President, Chief Operating Officer and Director	225 North Shore Drive	Pittsburgh	PA	15212		5/16/2002	(B)	9	None
3	Phyllis A. Domm*, Director	6038 SE Horseshoe Point Road	Stuart	FL	34997		5/16/2002	(B)	9	$51,250
4	Thomas A. McConomy, Director	413 Woodland Road	Sewickley	PA	15143		5/17/2000	(C)	9	$51,000
5	George L. Miles, Jr.*, Director	4802 Fifth Avenue	Pittsburgh	PA	15213		7/19/2000	(D)	8	$50,500
6	James E. Rohr **, Director	One PNC Plaza, 249 Fifth Avenue	Pittsburgh	PA	15222		5/16/2002	(B)	9	$48,750
7	David S. Shapira, Director	101 Kappa Drive	Pittsburgh	PA	15238		5/16/2002	(B)	9	$48,750
8	James W. Whalen*, Director	150 Gessner - 6E	Houston	TX	77024		7/15/2003	(D)	8	$62,250
9	Lee T. Todd, Jr., Director	101 Main Building	Lexington	KY	40506		11/17/2003	(C)	9	$48,750
10	Barbara S. Jeremiah, Director	201 Isabella Street	Pittsburgh	PA	15212		2/1/2003	(C)	8	$53,250
11	Vicky A. Bailey, Director	3101 New Mexico Avenue NW #249	Washington	DC	20016		6/14/2004	(D)	8	$51,750
	EQUITABLE GAS									
1	M. Elise Hyland, President and Director	225 North Shore Drive	Pittsburgh	PA	15212		11/8/2007	(E)	(F)	None
2	Randall L. Crawford, Director	225 North Shore Drive	Pittsburgh	PA	15212		1/1/2003	(E)	(F)	None
3	Johanna G. O'Loughlin, Corporate Secretary and Director	225 North Shore Drive	Pittsburgh	PA	15212		12/21/2000	(E)	(F)	None

(A) Includes Committee meetings of Board.
(B) Elected April 13, 2005, to continue in office until Annual Meeting of Shareholders in 2008.
(C) Elected April 12, 2006, to continue in office until Annual Meeting of Shareholders in 2009.
(D) Elected April 11, 2007, to continue in office until Annual Meeting of Shareholders in 2010.
(E) Terms are continuous or until appointment of replacement.
(F) Conducted via Unanimous Written Consents in lieu of meetings.

104. Officers

Line No.	Official Title & Name (a)	Principal Business Address Street Address (b)	City (c)	State (d)	Zip (e)	Telephone (h)	Fax (i)	Email (j)
1	***EQUITABLE RESOURCES, INC.***							
2	Chief Executive Officer: Murry S. Gerber	225 North Shore Drive	Pittsburgh	PA	15212			
3	President and Chief Operating Officer: David L. Porges	225 North Shore Drive	Pittsburgh	PA	15212			
4	Senior Vice President and Chief Financial Officer: Philip P. Conti	225 North Shore Drive	Pittsburgh	PA	15212			
5	Senior Vice President, General Counsel and Corporate Secretary: Johanna G. O'Loughlin	225 North Shore Drive	Pittsburgh	PA	15212			
6	*Senior Vice President and President, Utilities:* Randall L. Crawford	225 North Shore Drive	Pittsburgh	PA	15212			
7	Senior Vice President and President, Supply/Midstream: Joseph E. O'Brien	225 North Shore Drive	Pittsburgh	PA	15212			
8	Vice President and Chief Administrative Officer: Martin A. Fritz	225 North Shore Drive	Pittsburgh	PA	15212			
9	Vice President & Corporate Controller: Theresa Z. Bone	225 North Shore Drive	Pittsburgh	PA	15212			
10	Vice President and Chief Human Resources Officer: Charlene Petrelli	225 North Shore Drive	Pittsburgh	PA	15212			
11								
12	**EQUITABLE GAS COMPANY**							
13	*President: M. Elise Hyland*	*225 North Shore Drive*	*Pittsburgh*	PA	15212			
14	Senior Vice President and General Counsel: Daniel L. Frutchey	225 North Shore Drive	Pittsburgh	PA	15212			
15	Senior Vice President: Fredrick K. Dalena	225 North Shore Drive	Pittsburgh	PA	15212			
16	Corporate Secretary: Johanna G. O'Loughlin	225 North Shore Drive	Pittsburgh	PA	15212			
17	Treasurer: James E. Crockard, III	225 North Shore Drive	Pittsburgh	PA	15212			
18	Assistant Corporate Secretary: Jean F. Marks	225 North Shore Drive	Pittsburgh	PA	15212			
19	*Assistant Treasurer: Theresa Z. Bone*	*225 North Shore Drive*	Pittsburgh	PA	15212			
20	Assistant Treasurer: Thomas E. Quinlan	225 North Shore Drive	Pittsburgh	PA	15212			

200. COMPARATIVE BALANCE SHEET
ASSETS AND OTHER DEBITS

Balances at Beginning of Year must be consistent with balances at end of previous year

Line No.	Account Number and Title (a)	Schedule Page No. (b)	Balance Beginning of Year (c)	Balance End of Year (d)	Increase/ Decrease (e)
1	**UTILITY PLANT**				
2	101.0 Utility Plant in Service	205	746,817,640	815,310,804	68,493,164
3	101.1 Property Under Capital Leases		4,362,883	4,362,883	0
4	102.0 Gas Plant Purchased or Sold				0
5	103.0 Experimental Gas Plant Unclassified				0
6	104.0 Gas Plant Leased to Others				0
7	105.0 Gas Plant Held for Future Use		156,946	156,946	0
8	105.1 Production Properties Held For Future Use				0
9	106.0 Completed Construction Not Classified-Gas		89,012,871	59,108,393	(29,904,478)
10	107.0 Construction Work in Progress-Gas	208	21,124,506	13,701,521	(7,422,985)
11	108.0 Accumulated Provision for Depreciation of Gas Utility Plant	206	(278,255,058)	(283,282,528)	(5,027,470)
12	111.0 Accumulated Prov. For Amortization & Depletion of Gas Utility Pl.	206	(12,548,318)	(12,938,755)	(390,437)
13	114.0 Gas Plant Acquisition Adjustments	207			0
14	115.0 Accumulated Prov. For Amortization & Depletion of Gas Plant				0
15	Acquisition Adjustments	206			0
16	116.0 Other Gas Plant Adjustments				0
17	117.1 Gas Stored-Base Gas				0
18	117.2 System Balancing Gas				0
19	117.3 Gas Stored in Reservoirs and Pipelines-Noncurrent				0
20	117.4 Gas Owed to System Gas				0
21	118.0 Other Utility Plant Adjustments				0
22	119.0 Accumulated Provision for Depreciation and Amortization of Other				0
23	Utility Plant	206			0
24	**TOTAL UTILITY PLANT**		570,671,470	596,419,264	25,747,794
25	**OTHER PROPERTY AND INVESTMENTS**				
26	121.0 Non-Utility Property		30,386,221	27,335,230	(3,050,991)
27	122.0 Accumulated Depreciation & Amortization of Non-Utility Property		(16,718,597)	(16,918,167)	(199,570)
28	123.0 Investments in Associated Companies	210			0
29	123.1 Other Investments	210	3,164,679,674	3,600,527,662	435,847,98[illegible]
30	124.0 Other Investments	210			0
31	125.0 Sinking Funds				0
32	126.0 Depreciation Fund				0
33	128.0 Other Special Funds		3,929,758	5,117,291	1,187,533
34	**TOTAL OTHER PROPERTY AND INVESTMENTS**		3,182,277,056	3,616,062,016	433,784,960

200. COMPARATIVE BALANCE SHEET
ASSETS AND OTHER DEBITS

Balances at Beginning of Year must be consistent with balances at end of previous year

Line No.	Account Number and Title (a)	Schedule Page No. (b)	Balance Beginning of Year (c)	Balance End of Year (d)	Increase/ Decrease (e)
1	**CURRENT AND ACCRUED ASSETS**				
2	131.0 Cash				0
3	132.0 Interest Special Deposits				0
4	133.0 Dividend Special Deposits				0
5	134.0 Other Special Deposits				0
6	135.0 Working Funds		107,908	74,105	(33,803)
7	136.0 Temporary Cash Investments	210	0	0	0
8	141.0 Notes Receivable	211	628,268	490,541	(137,727)
9	142.0 Customer Accounts Receivable		40,797,246	44,995,730	4,198,484
10	143.0 Other Accounts Receivable	211	820,021	8,635	(811,386)
11	144.0 Accumulated Provision for Uncollectible Accounts-Cr.		(18,402,842)	(17,741,752)	661,090
12	145.0 Notes Receivable from Associated Companies	212			0
13	146.0 Accounts Receivable for Associated Companies	213	15,897,439	372,494,257	356,596,818
14	151.0 Fuel Stock				0
15	152.0 Fuel Stock Expenses Undistributed				0
16	153.0 Residuals and Extracted Products				0
17	154.0 Plant Materials and Operating Supplies	215	1,556,229	1,015,253	(540,976)
18	155.0 Merchandise				0
19	156.0 Other Materials and Supplies				0
20	163.0 Stores Expense-Undistributed		0	0	0
21	164.1 Gas Stored-Current		92,208,035	96,517,392	4,309,357
22	164.2 Liquefied Natural Gas Stored				0
23	164.3 Liquefied Natural Gas Held for Processing				0
24	165.0 Prepayments		16,514,685	14,828,024	(1,686,661)
25	166.0 Advances for Gas Exploration, Development and Production				0
26	167.0 Other Advances for Gas				0
27	171.0 Interest and Dividends Receivable		21,282	21,988	706
28	172.0 Rents Receivable				0
29	173.0 Accrued Utility Revenues		40,626,856	48,744,063	8,117,207
30	174.0 Miscellaneous Current and Accrued Assets		2,875,568	6,615,070	3,739,502
31	**TOTAL CURRENT & ACCRUED ASSETS**		193,650,695	568,063,306	374,412,611
32	**DEFERRED DEBITS**				
33	181.0 Unamortized Debt Expense	216	17,444,691	15,744,670	(1,700,021)
34	182.1 Extraordinary Property Losses	217			0
35	182.2 Unrecovered Plant and Regulatory Study Costs	217			0
36	182.3 Other Regulatory Assets		54,612,240	49,728,762	(4,883,478)
37	183.1 Preliminary Natural Gas Survey and Investigation Charges				0
38	183.2 Other Preliminary Survey and Investigation Charges				0
39	184.0 Clearing Accounts				0
40	185.0 Temporary Facilities				0
41	186.0 Miscellaneous Deferred Debits		8,235,359	5,425,009	(2,810,350)
42	187.0 Deferred Loses from Disposition of Utility Plant				0
43	188.0 Research, Development and Demonstration Expenditures				0
44	189.0 Unamortized Loss on Reacquired Debt		2,756,973	2,511,700	(245,273)
45	190.0 Accumulated Deferred Income Taxes		31,045,623	41,897,297	10,851,674
46	191.0 Unrecovered Purchased Gas Costs		54,062,496	39,081,044	(14,981,452)
47	**TOTAL DEFERRED DEBITS**		168,157,382	154,388,482	(13,768,900)
48	**TOTAL ASSETS & TOTAL DEBITS**		4,114,756,603	4,934,933,068	820,176,465

200. COMPARATIVE BALANCE SHEET
LIABILITIES AND OTHER CREDITS

Balances at Beginning of Year must be consistent with balances at end of previous year

Line No.	Account Number and Title (a)	Schedule Page No. (b)	Balance Beginning of Year (c)	Balance End of Year (d)	Increase/ Decrease (e)
1	**LIABILITIES AND OTHER CREDITS**				
2	**PROPRIETARY CAPITAL**				
3	201.0 Common Stock Issued		268,166,980	268,166,980	0
4	202.0 Common Stock Subscribed				0
5	203.0 Common Stock Liability for Conversion				0
6	204.0 Preferred Stock Issued				0
7	205.0 Preferred Stock Subscribed				0
8	206.0 Preferred Stock Liability for Conversion				0
9	207.0 Premium on Capital Stock				0
10	208.0 Donations Received from Stockholders				0
11	209.0 Reduction in Par or Stated Value of Capital Stock				0
12	210.0 Gain on Resale or Cancellation of Reacquired				0
13	Capital Stock				0
14	211.0 Miscellaneous Paid-In Capital		46,223,521	61,557,973	15,334,452
15	212.0 Installments Received on Capital Stock				0
16	213.0 Discount on Capital Stock				0
17	214.0 Capital Stock Expense				0
18	215.0 Appropriated Retained Earnings				0
19	216.0 Unappropriated Retained Earnings		(665,412,076)	(930,688,553)	(265,276,477)
20	216.1 Unappropriated Undistributed Subsidiary Earnings		2,036,730,020	2,452,333,279	415,603,259
21	217.0 Reacquired Capital Stock		(469,583,476)	(485,050,937)	(15,467,461)
22	219.0 Accumulated Other Comprehensive Income		(19,474,383)	(16,589,792)	2,884,591
23	**TOTAL PROPRIETARY CAPITAL**		1,196,650,586	1,349,728,950	(153,078,36
24					
25	**LONG-TERM DEBT**				
26	221.0 Bonds	231	763,500,000	753,500,000	(10,000,000)
27	222.0 Reacquired Bonds	231			0
28	223.0 Advances from Associated Companies				0
29	224.0 Other Long-term Debt	231			0
30	225.0 Unamortized Premium on Long-Term Debt				0
31	226.0 Unamortized Discount on Long-Term Debt-Debit				0
32	**TOTAL LONG TERM DEBT**		763,500,000	753,500,000	(10,000,000)
33					
34	**OTHER NONCURRENT LIABILITIES**				
35	227 Obligation Under Capital Leases-NonCurrent				0
36	228.1 Accumulated Provision for Property Insurance				0
37	228.2 Accumulated Provision for Injuries and Damages		1,731,131	2,492,837	761,706
38	228.3 Accumulated Provision for Pensions and Benefits		40,563,160	35,571,596	(4,991,564)
39	228.4 Accumulated Miscellaneous Operating Provisions		3,048,375	900,745	(2,147,630)
40	229 Accumulated Provision for Rate Refunds				0
41	**TOTAL OTHER NONCURRENT LIABILITIES**		45,342,666	38,965,178	(6,377,488)
42					

200. COMPARATIVE BALANCE SHEET
LIABILITIES AND OTHER CREDITS

Balances at Beginning of Year must be consistent with balances at end of previous year

Line No.	Account Number and Title (a)	Schedule Page No. (b)	Balance Beginning of Year (c)	Balance End of Year (d)	Increase/ Decrease (e)
1	**CURRENT AND ACCRUED LIABILITIES**				
2	231.00 Notes Payable		136,116,270	450,084,429	313,968,159
3	232.00 Accounts Payable		284,634,797	219,075,395	(65,559,402)
4	233.00 Notes Payable to Associated Companies		1,479,804,202	1,835,014,879	355,210,677
5	234.00 Accounts Payable to Affiliated Companies				0
6	235.00 Customers' Deposits-Billing		4,153,198	3,484,804	(668,394)
7	236.10 Accrued Taxes, Taxes Other Than Income		(5,501,938)	(5,501,938)	0
8	236.20 Accrued Taxes, Income Taxes		(35,672,802)	(32,807,806)	2,864,996
9	237.10 Accrued Interest on Long-term Debt		13,067,160	13,713,941	646,781
10	237.20 Accrued Interest on Other Liabilities		554,089	554,089	0
11	238.00 Dividends Declared				0
12	239.00 Matured Long-term Debt				0
13	240.00 Matured Interest				0
14	241.00 Tax Collections Payable		599,031	820,075	221,044
15	242.00 Miscellaneous Current and Accrued Liabilities		59,467,224	126,115,078	66,647,854
16	243.00 Obligations Under Capital Leases-Current				0
17	**TOTAL CURRENT AND ACCRUED LIABILITIES**		1,937,221,231	2,610,552,946	673,331,715
18					
19	**DEFERRED CREDITS**				0
20	252.00 Customer Advances for Construction				0
21	253.00 Other Deferred Credits		3,103,268	14,631,358	11,528,090
22	254.00 Other Regulatory Liabilities				0
23	255.00 Accumulated Deferred Investment Tax Credits		6,500,816	5,799,217	(701,599)
24	256.00 Deferred Gains from Disposition of Utility Plant				0
25	257.00 Unamortized Gain on Reacquired Debt				0
26	281.00 Accum. Deferred Income Taxes-Assume. Amortization Property				0
27	282.00 Accum. Deferred Income Taxes-Other Property		123,788,957	125,836,873	2,047,916
28	283.00 Accum. Deferred Income Taxes-Other		38,649,079	35,918,546	(2,730,533)
26	**TOTAL DEFERRED CREDITS**		172,042,120	182,185,994	10,143,874
27					
28	**TOTAL LIABILITIES & OTHER CREDITS**		4,114,756,603	4,934,933,068	820,176,465

201. NOTES TO BALANCE SHEET

1. The space below is provided for important notes regarding the balance sheet or any account thereof..
2. Furnish particulars as to any contingent assets or liabilities existing at end of year. Minor items may be grouped by classes. For any dividends in arrears at the end of the year on cumulative preferred stock, state the date of the last dividend, the arrearage per share, and the total amount of the arrearage.
3. For Other Plant Adjustments, Account 116, explain the origin of such amount, debits and credits during the year and plan of disposition contemplated, giving references to Commission orders or to other authorizations repeating classification of amounts as plant adjustments and requirements as to disposition thereof.
4. If the notes to balance sheet, appearing in the annual report to the stockholders are applicable in every respect and furnish the data required by instructions 2 and 3 above, such notes may be attached hereto.

A. Summary of Significant Accounting Policies

BUSINESS: Equitable Resources, Inc., through the Equitable Gas Company division, engages in the purchase, storage, distribution, marketing and transportation of natural gas.

RECLASSIFICATION: Certain previously reported amounts have been reclassified to conform to the current year presentation.

UTILITY REGULATION: Accounting records are maintained in accordance with the Uniform System of Accounts prescribed by the Federal Energy Regulatory Commission (FERC) and applicable state commissions.

INVESTMENT IN SUBSIDIARY COMPANIES: The Respondent's investment in subsidiaries is accounted for on the equity method.

PROPERTIES, DEPRECIATION AND DEPLETION: The cost of property additions, replacements and improvements capitalized includes labor, material and overhead. The cost of property retired, plus removal costs less salvage, is charged to accumulated depreciation.

Depreciation for financial reporting purposes is provided on the straight-line method at composite rates based on estimated service lives. Depreciation rates are based on periodic studies.

201. NOTES TO BALANCE SHEET (Continued)

PROVISION FOR DOUBTFUL ACCOUNTS: Judgment is required to assess the ultimate realization of the Respondent's accounts receivable, including assessing the probability of collection and the credit-worthiness of certain customers. The reserve is based on historical experience, current and expected economic trends and specific information about customer accounts. Accordingly, actual results may differ from these estimates under different assumptions or conditions.

ALLOWANCE FOR FUNDS USED DURING CONSTRUCTION: The FERC prescribes a formula to be used for computing overhead allowances for funds used during construction (AFC). AFC applicable to equity funds capitalized is included in other income and amounted to $405,218 in 2007. AFC applicable to borrowed funds is included as a reduction of interest charges and amounted to $237,126 in 2007.

INVENTORIES: The Respondent's inventory balance consists of natural gas stored underground and materials and supplies. Gas stored underground - - current inventory is stated at cost under the average cost method. Materials and supplies are stated generally at average cost.

REVENUE RECOGNITION: Sales of natural gas to utility customers are billed on a monthly cycle basis; however, the billing cycle periods for certain customers do not necessarily coincide with accounting periods used for financial reporting purposes. The Respondent follows the revenue accrual method of accounting for utility segment revenue whereby revenues applicable to gas delivered to customers but not yet billed under the cycle billing method are estimated and accrued and the related costs are charged to expense.

INCOME TAXES: The Respondent utilizes the asset and liability method to account for income taxes. The provision for income taxes represents amounts paid or estimated to be payable, net of amounts refunded or estimated to be refunded, for the current year and the change in deferred taxes. Any refinements to prior years' taxes made due to subsequent information are reflected as adjustments in the current period. Deferred income tax assets and liabilities are determined based on temporary differences between financial reporting and tax bases of assets and liabilities. Where deferred tax liabilities will be passed through to customers in regulated rates, the Respondent establishes a corresponding regulatory asset for the increase in future revenues that will result when the temporary differences reverse.

Investment tax credits realized in prior years were deferred and are being amortized over the estimated service lives of the related properties where required by ratemaking rules.

DEFERRED PURCHASED GAS COST: Where permitted by regulatory authority under purchased gas adjustment clauses or similar tariff provisions, the Respondent defers the difference between purchased gas cost, less refunds, and the billing of such cost and amortizes the deferral over subsequent periods in which billings either recover or repay such amounts.

CASH FLOWS: The Respondent considers all highly liquid investments with a maturity of three months or less when purchased to be cash equivalents. These investments are accounted for at cost. Interest earned on cash equivalents is included as a reduction of interest charges.

A reconciliation of cash and cash equivalents shown in the statement of cash flows is as follows:

Account Number	Description	Amount
136	Temporary Cash Investments	$ -0-
135	Working Funds	74
		$ 74

REGULATORY ACCOUNTING: The Respondent's distribution rates, terms of service, and contracts with affiliates are subject to comprehensive regulation by the Pennsylvania Public Utilities Commission (PA PUC) and the Public Service Commission of West Virginia (WV PSC) and the issuance of securities is subject to regulation by the PA PUC. The Respondent also provides field line service (also referred to as "farm tap" service as the customer is served directly from a well or gathering pipeline) in Kentucky which is subject only to rate regulation by the Kentucky Public Service Commission. Accounting for the Respondent's regulated operations is performed in accordance with the provisions of Statement of Financial Accounting Standards (SFAS) No. 71, "Accounting for the Effects of Certain Types of Regulation." The application of this accounting policy allows the Respondent to defer expenses and income on its Consolidated Balance Sheets as regulatory assets and liabilities when it is probable that those expenses and income will be allowed in the rate setting process in a period different from the period in which they would have been reflected in the Statements of Consolidated Income for a non-regulated Respondent. The deferred regulatory assets and liabilities are then recognized in the Statements of Consolidated Income in the period in which the same amounts are reflected in rates. Such amounts are reflected on the Respondent's Consolidated Balance Sheets as other current assets or liabilities. The Respondent believes that it will continue to be subject to the rate regulation that will provide for the recovery of deferred costs.

SELF INSURANCE: The Respondent is self-insured for certain losses related to workers' compensation. The Respondent maintains stop loss coverage with third-party insurers to limit the total exposure for general liability, automobile liability, environmental liability and workers' compensation. The recorded reserves represent estimates of the ultimate cost of claims incurred as of the balance sheet date. The estimated liabilities are based on analyses of historical data and actuarial estimates and are not discounted. The liabilities are reviewed by management quarterly, and by independent actuaries annually, to ensure that they are appropriate. While the Respondent believes these estimates are reasonable based on the information available, financial results could be impacted if actual trends, including the severity or frequency of claims or fluctuations in premiums, differ from estimates.

201. NOTES TO BALANCE SHEET (Continued)

ASSET RETIREMENT OBLIGATION: SFAS No. 143 requires that the Respondent accrue a liability for legal asset retirement obligations based on an estimate of the timing and amount of their settlement. For gas wells, the fair value of the Respondent's plugging and abandonment obligations is required to be recorded at the time the obligations are incurred, which is typically at the time the wells are drilled. The Respondent is required to operate and maintain its natural gas pipelines and intends to do so as long as supply and demand for natural gas exists, which the Respondent expects for the foreseeable future. Therefore, the Respondent believes that the substantial majority of its natural gas pipelines have indeterminate lives.

B. Income Taxes

The Respondent files a consolidated federal income tax return including its subsidiaries. Current federal tax balances of all subsidiary companies are settled with the Respondent which makes consolidated tax payments. The consolidated federal income tax provision is allocated among the group's members on a separate return basis with tax credits allocated to those members which generate the credits. The consolidated Federal income tax liability of the Respondent has been settled with the IRS through 1997. The IRS has completed its review of the Respondent's Federal income tax filings for the 1998 through 2000 years. The audit results for these periods generated a tax refund for the Respondent that is in excess of $2 million which requires review and approval by the Joint Committee on Taxation (JCT). During the review process, the JCT questioned an issue that the Respondent had previously agreed upon with the IRS through the Fast Track Appeals process. The Respondent is currently working with the Settlement Agent and the IRS Manager to try to resolve the questions raised by the JCT.

The IRS has surveyed the 2001 and 2002 Federal income tax filings and is currently reviewing the research and experimentation tax credits claim for such years. During the second quarter of 2007, the IRS began an examination of the Respondent's Federal income tax filings for 2003 through 2005. The Respondent also is the subject of various routine state income tax examinations. The Respondent believes that it is appropriately reserved for any uncertain tax positions claimed during these periods.

C. Short-Term Loans

On October 27, 2006, the Respondent entered into a $1.5 billion, five-year revolving credit agreement, which replaced the Respondent's previous $1 billion, five-year revolving credit agreement. On December 15, 2006, the maturity date was extended to October 26, 2011 pursuant to its terms. Additionally, the Respondent may request two one-year extensions of the stated maturity date. The revolving credit agreement may be used for working capital, capital expenditures, share repurchases and other purposes including support of the Respondent's commercial paper program. Subject to certain terms and conditions, the Respondent may, on a one time basis; request that the lender's commitments be increased to an aggregate amount of up to $2.0 billion.

The Respondent is not required to maintain compensating bank balances. The Respondent's debt issuer credit ratings, as determined by either Standard & Poor's or Moody's on its non-credit-enhanced, senior unsecured long-term debt, determine the level of fees associated with its lines of credit in addition to the interest rate charged by the counterparties on any amounts borrowed against the lines of credit; the lower the Company's debt credit rating, the higher the level of fees and borrowing rate.

Due to the volatility in the short-term debt markets during the second half of 2007, the Respondent determined that its lowest cost of short term borrowings would be obtained by utilizing its revolving credit facility. As of December 31, 2007, the Respondent had outstanding short-term loans under the revolving credit facility of $450.0 million and no commercial paper balances. Commitment fees averaging one-seventeenth of one percent in 2007 were paid to maintain credit availability under the revolving credit facility.

The weighted average interest rate for short-term loans outstanding as of December 31, 2007 was 5.26%. The maximum amount of outstanding short-term loans at any time during the year was $450.0 million in 2007. The average daily balance of short-term loans outstanding over the course of the year was approximately $199.5 million at weighted average annual interest rates of 5.84% during 2007.

D. Long-Term Debt

Aggregate maturities of long-term debt $0 in 2008, $4.3 million in 2009, $0 in 2010, $6.0 million in 2011 and $200.0 million in 2012.

E. Pension and Other Postretirement Benefit Plans

During 2007, the Respondent recognized a settlement expense of $0.5 million due to a plan design change for a specific union.

In September 2006, the FASB issued SFAS No. 158, which requires an employer to recognize a benefit plan's funded status in its statement of financial position, measure a benefit plan's assets and obligations as of the end of the employer's fiscal year and recognize the changes in the benefit plan's funded status in other comprehensive income in the year in which the changes occur. The Respondent adopted SFAS No. 158 as of December 31, 2006.

201. NOTES TO BALANCE SHEET (Continued)

The following table sets forth the defined benefit pension and other postretirement benefit plans' funded status, as attributed to the Respondent, and amounts recognized in the Respondent's balance sheet at December 31, 2007:

	Pension Benefits	Other Benefits
Change in benefit obligation:		
Benefit obligation at beginning of year	$51,673,682	$21,606,386
Service cost	77,104	198,427
Interest cost	2,939,692	1,156,294
Amendments	--	789,561
Actuarial gain	(1,289,172)	(2,841,175)
Benefits paid	(5,019,053)	(1,941,627)
Curtailments	--	--
Settlements and special termination benefits	(841,209)	--
Benefit obligation at end of year	$47,541,044	$18,967,866

	Pension Benefits	Other Benefits
Change in plan assets:		
Fair value of plan assets at beginning of year	$47,439,366	$ --
Gain recognized at beginning of year	293,896	--
Actual gain on plan assets	2,967,518	--
Employer contributions	38,765	--
Benefits paid	(5,019,053)	--
Settlements	(848,349)	--
Fair value of plan assets at end of year	$44,872,143	$ --
Funded status at end of year	$ (2,668,901)	$(18,967,866)
Amounts recognized in the statement of financial position consist of:		
Current liabilities	$ --	$ (2,251,067)
Noncurrent liabilities	(2,668,901)	(16,716,799)
Net amount recognized	$ (2,668,901)	$(18,967,866)
Amounts recognized in accumulated other comprehensive loss consist of, net of tax:		
Net loss	$ 9,906,608	$ 8,764,588
Net prior service cost (credit)	47,391	(2,128,795)
Net amount recognized	$ 9,953,999	$ 6,635,793

The accumulated benefit obligation for the defined benefit pension plans was $47,541,044 at December 31, 2007. The Respondent uses a December 31 measurement date for its defined benefit pension and other postretirement plans.

The costs, as attributed to the Respondent, related to defined benefit pension and other postretirement benefit plans comprised the following:

	Pension Benefits	Other Benefits
Components of net periodic benefit cost:		
Service cost	$ 77,104	$ 198,427
Interest cost	2,939,692	1,156,294
Expected return on plan assets	(3,874,527)	--
Amortization of prior service cost	55,079	(340,501)
Recognized net actuarial loss	961,150	991,844
Settlement loss and special termination benefits	335,089	--
Curtailment loss	528,305	--
Net periodic benefit cost	$ 1,021,892	$2,006,064
Other changes in plan assets and benefit obligations recognized in other comprehensive loss, net of tax:		
Net (gain) loss	$ (981,977)	$(2,212,037)
Net prior service cost (credit)	(347,556)	656,979
Total recognized in other comprehensive income, net of tax	$ (1,329,533)	$(1,555,058)
Total recognized in net periodic benefit cost and other comprehensive income, net of tax	$ (307,641)	$ 451,006

201. NOTES TO BALANCE SHEET (Continued)

The estimated net loss and net prior service cost for the defined benefit pension plans that will be amortized from accumulated other comprehensive income into net periodic benefit cost over the next fiscal year are $812,289 and $23,990, respectively. The estimated net loss and net prior service credit for the other postretirement benefit plans that will be amortized from accumulated other comprehensive income into net periodic benefit cost over the next fiscal year are $770,208 and ($272,669), respectively.

The following weighted average assumptions were used to determine the benefit obligations for the Respondent's defined benefit pension and other postretirement benefit plans at December 31, 2007:

	Pension Benefits	Other Benefits
Discount rate	6.25%	6.25%
Rate of compensation increase	N/A	N/A

The following weighted average assumptions were used to determine the net periodic benefit cost for the Respondent's defined benefit pension and other postretirement benefit plans at December 31, 2007:

	Pension Benefits	Other Benefits
Discount rate	5.75%	5.75%
Expected return on plan assets	8.25%	N/A
Rate of compensation increase	N/A	N/A

The expected rate of return is established at the beginning of the fiscal year that it relates to based upon information available to the Respondent at that time, including the plans' investment mix and the forecasted rates of return on these types of securities. The Respondent considered the historical rates of return earned on plan assets, an expected return percentage by asset class based upon a survey of investment managers and the Respondent's actual and targeted investment mix. Any differences between actual experience and assumed experience are deferred as an unrecognized actuarial gain or loss. The unrecognized actuarial gains or losses are amortized into the Respondent's net periodic benefit cost. The expected rate of return determined as of January 1, 2008 totaled 8.25%. This assumption will be used to derive the Respondent's 2008 net periodic benefit cost. The rate of compensation increase is not applicable in determining future benefit obligations as a result of the plan design. Pension expense increases as the expected long-term rate of rate of return decreases or if the discount rate is lowered. Lowering the expected long-term rate of return by 0.5% or lowering the discount rate by 0.5% as of December 31, 2007, would not have a significant impact on pension expense for 2007.

For measurement purposes, the annual rate of increase in the per capita cost of covered health care benefits in 2008 is 10.5% for both the Pre-65 and Post-65 medical charges. The rates were assumed to decrease gradually to ultimate rates of 5.5% in 2013.

Assumed health care cost trend rates have an effect on the amounts reported for the health care plans. A one-percentage-point change in assumed health care cost trend rates would have the following effects:

	One Percentage Point Increase	One Percentage Point Decrease
Increase (decrease) to total of service and interest cost components	$ 28,545	$ (27,735)
Increase (decrease) to postretirement benefit obligation	$ 379,873	$ (360,130)

The Respondent's pension asset allocation at December 31, 2007 and target allocation for 2008 by asset category are as follows:

Asset Category	Target Allocation 2008	Percentage of Plan Assets at December 31, 2007
Domestic broadly diversified equity securities	40% - 60%	46%
Fixed income securities and inflation hedge securities	20% - 50%	40%
International broadly diversified equity securities	5% - 15%	13%
Other	0% - 15%	1%
		100%

201. NOTES TO BALANCE SHEET (Continued)

The investment activities of the Respondent's pension plan are supervised and monitored by the Respondent's Benefits Investment Committee. The Benefits Investment Committee has developed an investment strategy that focuses on asset allocation, diversification and quality guidelines. The investment goals of the Benefits Investment Committee are to minimize high levels of risk at the total pension investment fund level. The Benefits Investment Committee monitors the actual asset allocation on a quarterly basis and adjustments are made, as needed, to rebalance the assets within the prescribed target ranges. Comparative market and peer group benchmarks are utilized to ensure that each of the firm's investment managers is performing satisfactorily.

Cash contributions of $ 38,765 were made to the pension plan during 2007. The Respondent does not expect to make a cash contribution to its pension plan during 2008.

The following benefit payments, which reflect expected future service, are expected to be paid during each of the next five years and the five years thereafter: $5,220,424 in 2008; $5,273,901 in 2009; $4,770,063 in 2010; $5,001,318 in 2011; $4,515,915 in 2012; and $21,917,275 in the five years thereafter.

The following benefit payments for postretirement benefits, which reflect expected future service, are expected to be paid during each of the next five years and the five years thereafter: $2,321,413 in 2008; $2,216,984 in 2009; $2,139,916 in 2010; $2,085,440 in 2011; $1,948,967 in 2012; and $8,426,144 in the five years thereafter.

Expense recognized by the Respondent related to its 401(k) employee savings plans totaled $2,506,718 in 2007.

F. Share-Based Compensation Plans

The Respondent adopted SFAS No. 123R effective January 1, 2006, using the modified prospective method. Under the modified prospective method, compensation cost is recognized beginning with the effective date and prior period results are not restated. As such, compensation cost related to all share-based awards, including non-qualified stock options was recognized in the Respondent's Consolidated Financial Statement for the years ended December 31, 2006 and 2007.

Cash received from exercises under all share-based payment arrangements for employees and directors for the year ended December 31, 2007 was $3.2 million. The actual tax benefits realized for tax deductions from share-based payment arrangements for the year ended December 31, 2007 was $19.4 million.

The Respondent typically funds restricted share obligations from treasury stock at the date of grant and has a policy of issuing shares from treasury stock to satisfy option exercises.

Executive Performance Incentive Programs

In February 2005, the Compensation Committee of the Board of Directors adopted the 2005 Executive Performance Incentive Program (2005 Program) under the 1999 Long-Term Incentive Plan. The 2005 Program was established to provide additional incentive benefits to retain executive officers and certain other employees of the Respondent to further align the interests of the persons primarily responsible for the success of the Respondent with the interests of the shareholders. A total of 1,001,600 stock units granted under the 2005 Program are outstanding as of December 31, 2007. No additional units may be granted. The vesting of these stock units will occur on December 31, 2008, contingent upon a combination of the level of total shareholder return relative to the Respondent's 29 peer companies and the Respondent's average absolute return on total capital during the four-year performance period. As a result, zero to 2,504,000 units (250% of the units outstanding) may be distributed upon vesting. Payment of awards is expected to be made in cash and stock based on the price of the Respondent's common stock at the end of the performance period, December 31, 2008. The Respondent accounts for these awards as liability awards and as such records compensation expense for the remeasurement of the fair value of the awards at the end of each reporting period. The Respondent continually monitors its stock price and performance in order to assess the impact on the ultimate payout under the 2005 Program. The Respondent modified its assumptions during 2007 and increased both the ultimate share price and the payout multiple at the vesting date to $60.00 and 225% of the units awarded, respectively. As a result, the Respondent recognized an increase in long-term incentive plan expense associated with the 2005 Program of $42.3 million for the year ended December 31, 2007. The 2005 Program expense for the year ended December 31, 2007 was classified as selling, general and administrative expense in the Statements of Consolidated Income. The Company has recorded a total accrual for the 2005 Program of $107.1 million as of December 31, 2007.

Restricted Stock Awards

The Respondent granted 77,540 restricted stock awards during the year ended December 31, 2007 to key employees of the Respondent. The shares granted will be fully vested at the end of the three-year period commencing with the date of grant. The weighted average fair value of these restricted stock grants, based on the grant date fair value of the Company's stock, was $44.11 for the year ended December 31, 2007. The total fair value of restricted stock awards vested during the year ended December 31, 2007 was $6.7 million.

As of December 31, 2007, there was $4.6 million of total unrecognized compensation cost related to nonvested restricted stock awards. That cost is expected to be recognized over a remaining weighted average vesting term of approximately 19 months.

201. NOTES TO BALANCE SHEET (Continued)

Non-Qualified Stock Options

The fair value of the Respondent's option grants was estimated at the dates of grant using a Black-Scholes option-pricing model with the assumptions indicated in the table below for the year ended December 31, 2007. The risk-free rate for periods within the contractual life of the option is based on the U.S. Treasury yield curve in effect at the time of grant. The dividend yield is based on the historical dividend yield of the Respondent's stock. Expected volatilities are based on historical volatility of the Respondent's stock. The expected term of options granted represents the period of time that options granted are expected to be outstanding based on historical option exercise experience.

The fair value for these option grants was estimated at the dates of grant using a Black-Scholes option pricing model with the following assumptions for 2007:

Risk-free interest rate (range)	3.99% to 4.97%
Dividend yield	1.77% to 2.29%
Volatility factor	.148 to .183
Weighted average expected life of options	3-6 years
Options granted	27,421
Weighted average fair market value of options granted during the year	$ 7.33

The following schedule summarizes the stock option activity for the year ended December 31, 2007:

Options outstanding January 1	2,961,674
Granted	27,421
Forfeitures	-0-
Exercised	(1,359,173)
Options outstanding December 31	1,629,922

Options outstanding at December 31, 2007 include 1,629,922 exercisable at that date.

Nonemployee Directors' Share-Based Awards

At December 31, 2007, 101,500 options were outstanding under the 1999 Nonemployee Directors' Stock Incentive Plan at prices ranging from $7.66 to $19.56 per share. The exercise price for each award is equal to the market price of the Respondent's common stock on the date of grant. Each option is subject to time-based vesting provisions and expires 5 to 10 years after date of grant.

The Respondent has also historically granted to non-employee directors stock units which vested upon award. The value of the stock units will be paid in cash on the earlier of the director's death or retirement from the Respondent's Board of Directors. A total of 88,530 non-employee director stock units were outstanding as of December 31, 2007. A total of 15,570 stock units were granted to non-employee directors during the year ended December 31, 2007.

G. Commitments and Contingencies

The Respondent has annual commitments of approximately $39.0 million for demand charges under existing long-term contracts with pipeline suppliers for periods extending up to ten years as of December 31, 2007, which relate to natural gas distribution and production operations. However, the Respondent believes that approximately $25.5 million of these costs are recoverable in customer rates.

In the ordinary course of business, various legal claims and proceedings are pending or threatened against the Respondent. While the amounts claimed may be substantial, the Respondent is unable to predict with certainty the ultimate outcome of such claims and proceedings. The Respondent has established reserves for pending litigation, which it believes are adequate, and after consultation with counsel and giving appropriate consideration to available insurance, the Respondent believes that the ultimate outcome of any matter currently pending against the Respondent will not materially affect the financial position of the Respondent.

The Respondent is subject to various federal, state and local environmental and environmentally related laws and regulations. These laws and regulations, which are constantly changing, can require expenditures for remediation and may in certain instances result in assessment of fines. The Respondent has established procedures for ongoing evaluation of its operations to identify potential environmental exposures and to assure compliance with regulatory policies and procedures. The estimated costs associated with identified situations that require remedial action are accrued. However, certain costs are deferred as regulatory assets when recoverable through regulated rates. Ongoing expenditures for compliance with environmental laws and regulations, including investments in plant and facilities to meet environmental requirements, have not been material. Management believes that any such required expenditures will not be significantly different in either their nature or amount in the future and does not know of any environmental liabilities that will have a material effect on the Respondent's financial position or results of operations.

201. NOTES TO BALANCE SHEET (Continued)

H. Office Consolidation/Impairment Charges

In May 2005, the Respondent completed the relocation of its corporate headquarters and other operations to a newly constructed office building located at the North Shore in Pittsburgh. The relocation resulted in the early termination of several operating leases and the early retirement of assets and leasehold improvements at several locations. In accordance with SFAS No.146, the Respondent recognized a loss of $5.3 million on the early termination of operating leases during 2005 for facilities deemed to have no economic benefit to the Respondent. The Respondent also recognized a loss on the impairment of assets of $2.5 million during 2005 in accordance with SFAS No. 144 associated with the office consolidations.

During the second quarter of 2006, the Respondent began to utilize certain of the leased space previously deemed to have no economic benefit to the Respondent. The Respondent reversed approximately $2.4 million of the associated early termination liability for these leases during the second quarter of 2006. Additionally, the Respondent recorded a $0.5 million reduction in the early termination liability during the second quarter of 2006 resulting from a revision of the amount of estimated cash flows for one of its operating leases.

I. Acquisition

On March 1, 2006, the Company entered into a definitive agreement to acquire Dominion's natural gas distribution assets in Pennsylvania and in West Virginia for approximately $970 million, subject to adjustments, in a cash transaction for the stock of Peoples and Hope. In light of the continued delay in achieving the final legal approvals for this transaction, the Company and Dominion mutually agreed to terminate the definitive agreement pursuant to a mutual termination agreement entered into on January 15, 2008. As a result of this termination, the Respondent recognized $9.8 million of deferred acquisition costs and $0.3 million of impairment charges as expense in the 2007 Statements of Consolidated Income.

205. UTILITY PLANT IN SERVICE - Account No. 101.0
TOTAL COMPANY

1. Report by prescribed accounts the original cost of utility plant in service and the additions and retirements of such plant during the year.
2. Do not include as adjustments, corrections to additions and retirements for the current or preceding year. Such items should be included in appropriate Column (c) or (d).
3. Credit adjustments in Column (e) should be shown in red, or in black enclosed in parenthesis. State in a footnote the general character of any adjustments in Column (e).
4. Submit, in a footnote, an explanation of amounts included in Columns (e) and/or (f), Line 34, for lowering or changing the location of mains.

Line No.	Account Number and Title (a)		Balance Previous Year (b)	Additions (c)	Retirements (d)	Adjustments +/- (e)	Balance End of Year (f)
1		**INTANGIBLE PLANT**	XXX	XXX	XXX	XXX	XXX
2	301	Organization	49,770				49,770
3	302	Franchises & Consents	0				0
4	303	Other Plant and Miscellaneous Equipment	11,725,070	17,891,900	3,077,940		26,539,030
5		Total Intangible Plant	11,774,840	17,891,900	3,077,940	0	26,588,800
6		**MANUFACTURED GAS PRODUCTION PLANT**	XXX	XXX	XXX	XXX	XXX
7	304	Land and Land Rights					0
8	305	Structures and Improvements					0
9	306	Boiler Plant Equipment					0
10	307	Other Power Equipment					0
11	308	Coke Ovens					0
12	309	Infiltration Galleries and Tunnels					0
13	310	Producer Gas Equipment					0
14	311	Liquefied Petroleum Gas Equipment					0
15	312	Oil Gas Generating Equipment					0
16	313	Generating Equipment-Other Processes					0
17	314	Coal, Coke and Ash Handling Equipment					0
18	315	Catalytic Cracking Equipment					0
19	316	Other Reforming Equipment					0
20	317	Purification Equipment					0
21	318	Residential Refining Equipment					0
22	319	Gas Mixing Equipment					0
23	320	Other Equipment					0
23		Total Gas Manufacturing Plant	0	0	0	0	0
24		**NATURAL GAS PRODUCTION & GATHERING PLANT**	XXX	XXX	XXX	XXX	XXX
25	325.1	Producing Lands					0
26	325.2	Producing Leaseholds	16,356			0	16,356
27	325.3	Gas Rights	0				0
28	325.4	Rights of Way	2,422				2,42[illegible]
29	325.5	Other Land and Land Rights	0				0
30	326	Other Plant and Miscellaneous Equipment	0				0
31	327	Field Compressor Station Structures	0				0
32	328	Field Measuring & Regulating Station Structures	101				101
33	329	Other Structures	0				0
34	330	Producing Gas Wells-Well Construction	654,658				654,658
35	331	Producing Gas Wells-Well Equipment	257,931				257,931
36	332	Field Lines	177,520	0	6,963	0	170,557
37	333	Field Compressor Station Equipment	0				0
38	334	Field Measuring & Regulating Station Equipment	91,787	0		0	91,787
39	335	Drilling & Cleaning Equipment	0				0
40	336	Purification Equipment	0				0
41	337	Other Equipment	0				0
42	338	Unsuccessful Exploration & Development Costs	0				0
43		Total Natural Gas Production & Gathering Plant	1,200,775	0	6,963	0	1,193,812
44		**PRODUCTS EXTRACTION PLANT**	XXX	XXX	XXX	XXX	XXX
45	340	Land and Land Rights					0
46	341	Other Plant and Miscellaneous Equipment					0
47	342	Extraction & Refining Equipment					0
48	343	Pipe Lines					0
49	344	Extracted Product Storage Equipment					0
50	345	Compressor Equipment					0
51	346	Gas Measuring and Regulating Equipment					0
52	347	Other Equipment					0
		Total Products Extraction Plant	0	0	0	0	0
53		**NATURAL GAS PRODUCTION & PROCESSING PLANT**	XXX	XXX	XXX	XXX	XXX
54	350.1	Land					0
55	350.2	Rights of Way					0
56	351	Structures and Improvements					0
57	352	Wells					0
58	352.1	Storage Leaseholds and Rights					0
59	352.2	Reservoirs					0
60	352.3	Nonrecoverable Natural Gas					[illegible]
61	353	Lines					[illegible]

3. The adjustments in Column (e) relate to the reclassification of assets into the proper account (s).

205. UTILITY PLANT IN SERVICE - Account No. 101.0
TOTAL COMPANY

Line No.	Account Number and Title (a)		Balance Previous Year (b)	Additions (c)	Retirements (d)	Adjustments +/- (e)	Balance End of Year (f)
62	354	Compressor Station Equipment					0
63	355	Measuring and Regulating Equipment					0
64	356	Purification Equipment					0
65	357	Other Equipment					0
66		Total Natural Gas Production and Processing Plant	0	0	0	0	0
67		**OTHER STORAGE PLANT**	XXX	XXX	XXX	XXX	XXX
68	360	Land & Land Rights					0
69	361	Structures and Improvements					0
70	362	Gas Holders					0
71	363	Purification Equipment					0
72	363.1	Liquefaction Equipment					0
73	363.2	Vaporizing Equipment					0
74	363.3	Compressor Equipment					0
75	363.4	Measuring and Regulating Equipment					0
76	363.5	Other Equipment					0
77		Total Other Storage Plant	0	0	0	0	0
78		**BASE LOAD LIQUEFIED NATURAL GAS**					0
79		**TERMINATING AND PROCESSING PLANT**	XXX	XXX	XXX	XXX	XXX
80	364.1	Land and Land Rights					0
81	364.2	Structures and Improvements					0
82	364.3	LNG Processing Terminal Equipment					0
83	364.4	LNG Transportation Equipment					0
84	364.5	Measuring and Regulating Equipment					0
85	364.6	Compressor Station Equipment					0
86	364.7	Communication Equipment					0
87	364.8	Other Equipment					0
88		Total Base Load Liquefied Natural Gas Term. & Proc. Plant	0	0	0	0	0
89		**TRANSMISSION PLANT**	XXX	XXX	XXX	XXX	XXX
90	365.1	Land and Land Rights	0				0
91	365.2	Rights of Way	0				0
92	366	Structures and Improvements	0				0
93	367	Mains	4,744,698	69,180	4,128		4,809,750
94	368	Compressor Station Equipment	0				0
95	369	Measuring and Regulating Station Equipment	268,428				268,428
96	370	Communication Equipment	109,969				109,969
97	371	Other Equipment	0				0
98		Total Transmission Plant	5,123,095	69,180	4,128	0	5,188,147
99		**DISTRIBUTION PLANT**	XXX	XXX	XXX	XXX	XXX
100	374	Land & Land Rights	2,530,672	6,679	26,321		2,511,030
101	375	Structures and Improvements	2,655,256	52,604	329,147		2,378,713
102	376	Mains	422,644,309	29,891,801	2,383,054		450,153,056
103	377	Compressor Station Equipment	0				0
104	378	Measuring & Regulating Station Equipment-General	14,347,621	380,788	44,098		14,684,311
105	379	Measuring & Regulating Station Equipment-City Gate C. St.	0				0
106	380	Services	201,258,817	21,591,313	1,461,701		221,388,429
107	381	Meters	18,920,379	692,649	2,143,438		17,469,590
108	382	Meter Installations	8,800,871	1,087,170	118		9,887,923
109	383	House Regulators	6,379,859	171,826	3,066		6,548,619
110	384	House Regulatory Installations	1,602,789	64,477	117		1,667,149
111	385	Industrial Measuring and Regulating Station Equipment	356,376		2,974		353,402
112	386	Other Property on Customers' Premises	6,606,390				6,606,390
113	387	Other Equipment	2,797,164		1,297,856		1,499,308
114	388	Asset Retirement Costs for Distribution Plant	0				0
115		Total Distribution Plant	688,900,503	53,939,307	7,691,890	0	735,147,920
116		**GENERAL PLANT**	XXX	XXX	XXX	XXX	XXX
117	389	Land & Land Rights	102,364				102,364
118	390	Structures and Improvements	7,777,056	1,388,788	399,662		8,766,182
119	391	Office Furniture & Equipment	11,347,288	4,781,875	1,236,230		14,892,933
120	392	Transportation Equipment	6,321,324	4,823,915	2,165,041		8,980,198
121	393	Stores Equipment	75,115		12,579		62,536
122	394	Tools & Garage Equipment	4,509,375	513,823	369,486		4,653,712
123	395	Laboratory Equipment	26,059				26,059
124	396	Power Operated Equipment	3,328,794	963,998	984,225		3,308,567
125	397	Communication Equipment	10,431,266	103,364	31,444		10,503,186
126	398	Miscellaneous Equipment	262,669		3,398		259,271
127	399	Other Tangible Property	0				0
128		Total General Plant	44,181,310	12,575,763	5,202,065	0	51,555,008
129		Total Plant	751,180,523	84,476,150	15,982,986	0	819,673,687

205. UTILITY PLANT IN SERVICE - Account No. 101.0
PENNSYLVANIA DIVISION

1. Report by prescribed accounts the original cost of utility plant in service and the additions and retirements of such plant during the year.
2. Do not include as adjustments, corrections to additions and retirements for the current or preceding year. Such items should be included in appropriate Column (c) or (d).
3 Credit adjustments in Column (e) should be shown in red, or in black enclosed in parenthesis. State in a footnote the general character of any adjustments in Column (e).
4. Submit, in a footnote, an explanation of amounts included in Columns (e) and/or (f), Line 34, for lowering or changing the location of mains.

Line No.		Account Number and Title (a)	Balance Previous Year (b)	Additions (c)	Retirements (d)	Adjustments +/- (e)	Balance End of Year (f)
1		**INTANGIBLE PLANT**	XXX	XXX	XXX	XXX	XXX
2	301	Organization	49,770				49,770
3	302	Franchises & Consents	0				0
4	303	Other Plant and Miscellaneous Equipment	11,725,070	17,891,900	3,077,940		26,539,030
5		Total Intangible Plant	11,774,840	17,891,900	3,077,940	0	26,588,800
6		**MANUFACTURED GAS PRODUCTION PLANT**	XXX	XXX	XXX	XXX	XXX
7	304	Land and Land Rights					0
8	305	Structures and Improvements					0
9	306	Boiler Plant Equipment					0
10	307	Other Power Equipment					0
11	308	Coke Ovens					0
12	309	Infiltration Galleries and Tunnels					0
13	310	Producer Gas Equipment					0
14	311	Liquefied Petroleum Gas Equipment					0
15	312	Oil Gas Generating Equipment					0
16	313	Generating Equipment-Other Processes					0
17	314	Coal, Coke and Ash Handling Equipment					0
18	315	Catalytic Cracking Equipment					0
19	316	Other Reforming Equipment					0
20	317	Purification Equipment					0
21	318	Residential Refining Equipment					0
22	319	Gas Mixing Equipment					0
23	320	Other Equipment					0
23		Total Gas Manufacturing Plant	0	0	0	0	0
24		**NATURAL GAS PRODUCTION & GATHERING PLANT**	XXX	XXX	XXX	XXX	XXX
25	325.1	Producing Lands					0
26	325.2	Producing Leaseholds	16,356				16,356
27	325.3	Gas Rights	0				0
28	325.4	Rights of Way	0				0
29	325.5	Other Land and Land Rights	0				0
30	326	Other Plant and Miscellaneous Equipment	0				0
31	327	Field Compressor Station Structures	0				0
32	328	Field Measuring & Regulating Station Structures	0				0
33	329	Other Structures	0				0
34	330	Producing Gas Wells-Well Construction	598,329				598,329
35	331	Producing Gas Wells-Well Equipment	228,454				228,454
36	332	Field Lines	0				0
37	333	Field Compressor Station Equipment	0				0
38	334	Field Measuring & Regulating Station Equipment	0				0
39	335	Drilling & Cleaning Equipment	0				0
40	336	Purification Equipment	0				0
41	337	Other Equipment	0				0
42	338	Unsuccessful Exploration & Development Costs	0				0
43		Total Natural Gas Production & Gathering Plant	843,139	0	0	0	843,139
44		**PRODUCTS EXTRACTION PLANT**	XXX	XXX	XXX	XXX	XXX
45	340	Land and Land Rights					0
46	341	Other Plant and Miscellaneous Equipment					0
47	342	Extraction & Refining Equipment					0
48	343	Pipe Lines					0
49	344	Extracted Product Storage Equipment					0
50	345	Compressor Equipment					0
51	346	Gas Measuring and Regulating Equipment					0
52	347	Other Equipment					0
		Total Products Extraction Plant	0	0	0	0	0
53		**NATURAL GAS PRODUCTION & PROCESSING PLANT**	XXX	XXX	XXX	XXX	XXX
54	350.1	Land					0
55	350.2	Rights of Way					0
56	351	Structures and Improvements					0
57	352	Wells					0
58	352.1	Storage Leaseholds and Rights					0
59	352.2	Reservoirs					0
60	352.3	Nonrecoverable Natural Gas					0
61	353	Lines					0

3. The adjustments in Column (e) relate to the reclassification of assets into the proper account (s).

205. UTILITY PLANT IN SERVICE - Account No. 101.0
PENNSYLVANIA DIVISION

Line No.	Account Number and Title (a)		Balance Previous Year (b)	Additions (c)	Retirements (d)	Adjustments +/- (e)	Balance End of Year (f)
62	354	Compressor Station Equipment					0
63	355	Measuring and Regulating Equipment					0
64	356	Purification Equipment					0
65	357	Other Equipment					0
66		Total Natural Gas Production and Processing Plant	0	0	0	0	0
67		**OTHER STORAGE PLANT**	XXX	XXX	XXX	XXX	XXX
68	360	Land & Land Rights					0
69	361	Structures and Improvements					0
70	362	Gas Holders					0
71	363	Purification Equipment					0
72	363.1	Liquefaction Equipment					0
73	363.2	Vaporizing Equipment					0
74	363.3	Compressor Equipment					0
75	363.4	Measuring and Regulating Equipment					0
76	363.5	Other Equipment					0
77		Total Other Storage Plant	0	0	0	0	0
78		**BASE LOAD LIQUEFIED NATURAL GAS**					0
79		**TERMINATING AND PROCESSING PLANT**	XXX	XXX	XXX	XXX	XXX
80	364.1	Land and Land Rights					0
81	364.2	Structures and Improvements					0
82	364.3	LNG Processing Terminal Equipment					0
83	364.4	LNG Transportation Equipment					0
84	364.5	Measuring and Regulating Equipment					0
85	364.6	Compressor Station Equipment					0
86	364.7	Communication Equipment					0
87	364.8	Other Equipment					0
88		Total Base Load Liquefied Natural Gas Term. & Proc. Plant	0	0	0	0	0
89		**TRANSMISSION PLANT**	XXX	XXX	XXX	XXX	XXX
90	365.1	Land and Land Rights	0				0
91	365.2	Rights of Way	0				0
92	366	Structures and Improvements	0				0
93	367	Mains	4,744,698	69,180	4,128		4,809,750
94	368	Compressor Station Equipment	0				0
95	369	Measuring and Regulating Station Equipment	266,420				266,420
96	370	Communication Equipment	109,969				109,969
97	371	Other Equipment	0				0
98		Total Transmission Plant	5,121,087	69,180	4,128	0	5,186,139
99		**DISTRIBUTION PLANT**	XXX	XXX	XXX	XXX	XXX
100	374	Land & Land Rights	2,250,181	6,679	26,321		2,230,539
101	375	Structures and Improvements	2,439,270	51,507	329,147		2,161,630
102	376	Mains	396,459,296	29,211,599	2,316,470		423,354,425
103	377	Compressor Station Equipment	0				0
104	378	Measuring & Regulating Station Equipment-General	12,991,818	374,085	44,099		13,321,804
105	379	Measuring & Regulating Station Equipment-City Gate C. St.	0				0
106	380	Services	195,467,384	21,064,277	1,382,471		215,149,190
107	381	Meters	17,752,007	550,734	1,996,288		16,306,453
108	382	Meter Installations	7,491,809	1,032,161			8,523,970
109	383	House Regulators	5,476,338	105,641	460		5,581,519
110	384	House Regulatory Installations	1,443,600	55,480			1,499,080
111	385	Industrial Measuring and Regulating Station Equipment	356,376		2,974		353,402
112	386	Other Property on Customers' Premises	6,586,942				6,586,942
113	387	Other Equipment	2,525,438		1,297,856		1,227,582
114	388	Asset Retirement Costs for Distribution Plant	0				0
115		Total Distribution Plant	651,240,459	52,452,163	7,396,086	0	696,296,536
116		**GENERAL PLANT**	XXX	XXX	XXX	XXX	XXX
117	389	Land & Land Rights	67,166				67,166
118	390	Structures and Improvements	7,637,804	1,388,788	399,662		8,626,930
119	391	Office Furniture & Equipment	11,335,867	4,773,084	1,236,230		14,872,721
120	392	Transportation Equipment	5,476,779	4,503,773	2,068,927		7,911,625
121	393	Stores Equipment	74,518		12,579		61,939
122	394	Tools & Garage Equipment	4,030,682	507,459	369,486		4,168,655
123	395	Laboratory Equipment	26,059				26,059
124	396	Power Operated Equipment	3,088,663	908,944	914,199		3,083,408
125	397	Communication Equipment	10,236,042	88,490	31,444		10,293,088
126	398	Miscellaneous Equipment	258,763		3,398		255,365
127	399	Other Tangible Property	0				0
128		Total General Plant	42,232,343	12,170,538	5,035,925	0	49,366,956
129		Total Plant	711,211,868	82,583,781	15,514,079	0	778,281,570

206. ACCUMULATED DEPRECIATION OF UTILITY PLANT - Account Nos. 108, 111, 115 and 119

1. Report below an analysis of the changes in accumulated depreciation during the year and the amounts applicable to prescribed functional classifications.
2. Explain and give particulars of important adjustments during the year.

Line No.	Item (a)	Total (b)	101 Utility Plant In Service (c)	104 Utility Plant Leased to Others (d)	105 Property Held for Future Use (e)	107.0 Construction Work In Progress (f)
1	**Balance Beginning of Year**	290,803,376	290,803,376	0	0	0
2	Credits During Year	XXXXX	XXXXX	XXXXX	XXXXX	XXXXX
3	Depreciation Provisions charged to:	XXXXX	XXXXX	XXXXX	XXXXX	XXXXX
4	403. Depreciation	17,496,571	17,496,571			
5	413. Income from Utility Plant Leased to Others	0				
6	404. Amortization & Depletion	3,443,006	3,443,006			
7	184. Clearing Accounts	1,339,991	1,339,991			
8		0				
9		0				
10	**Total Depreciation Provisions**	22,279,568	22,279,568	0	0	0
11	Recoveries from Insurance	0				
12	Salvage Realized from Retirements	276,770	276,770			
13	Other Credits (Describe)					
14	Depreciation charged to Affiliates	0				
15	Other Misc Adjustments	0				
16		0				
17		0				
18	**Total Credits During Year**	276,770	276,770	0	0	0
19	**Total Credits**	22,556,338	22,556,338	0	0	0
20	Debits During Year	XXXXX	XXXXX	XXXXX	XXXXX	XXXXX
21	Retirement of Utility Plant	16,934,685	16,934,685			
22	Cost of Removal	645,844	645,844			
23	Other Debits (Describe)					
24	Prior Year RWIP Adjustment	0				
25	*Current Year RWIP*	*(442,098)*	*(442,098)*			
26	Transferred Property	0	0			
27		0				
28	**Total Debits During Year**	17,138,431	17,138,431	0	0	0
29	**Balance at End of Year**	296,221,283	296,221,283	0	0	0

Describe the basis upon which depreciation provisions for the year were determined and attach worksheets showing the computations made in arriving at the annual provisions.

207. GAS PLANT ACQUISITIONS ADJUSTMENTS - Account No. 114.0

Line No.	Item (a)	Project No. 1 Amount (b)	Project No. 2 Amount (c)	Project No. 3 Amount (d)	Project No. 4 Amount (e)	Totals (f)
1	Book Plant - Net					0
2	PUC Difference (Ratemaking)					0
3	Less Contributions (Net)					0
4	*Net Utility Plant Acquired*					0
5	Purchase Price					0
6	Acquisition Adjustment					0
7						
8						

206. ACCUMULATED DEPRECIATION OF UTILITY PLANT - (Continued)

Describe the basis upon which depreciation provisions for the year were determined and attach worksheets showing the computations made in arriving at the annual provisions.

DEPRECIATION EXPENSE - ACCOUNT 403

The Respondent uses a straight-line method of depreciation by individual plant account. Depreciation is calculated monthly by applying the appropriate rate to the current month end balance in each account. The rates applied were as follows:

Intangible Plant	PA Rate	WV Rate	KY Rate
301	0 00%		
303	19 48%		
303.02	22.17%		
303.1	6 67%		
Production Plant			
325.2	0.37%		
325.4	0 29%	1.54%	
325.51	0.00%		
327	1.94%		
328	4.73%		
330	0 35%	1.14%	
331	0 45%	4.69%	
332	1.53%	1.53%	
333	2 22%		
334	0.67%	2.92%	
Transmission Plant			
365.1	0.00%		
365.2	0 94%		
366.1	1.65%		
366 2	2.23%		
367	0.74%		
368	1.72%		
369	2 40%	3 15%	
370	7.62%		
Distribution Plant			
374 1	0 00%	0 00%	
374.2	1.12%	1.75%	
375	2.12%	2 16%	
376	1.51%	1.94%	
376.02	0.76%		
378.1	2.07%	2.85%	
378.2	4.57%	5.01%	
380	2.22%	3.36%	
381	3 11%	3 49%	6.67%
382	1.35%	3.12%	3 45%
383	1.68%	3.33%	
384	1.59%	3 09%	
385	1.71%		
386.1	2.50%	10.00%	
386.2	5 67%	10 00%	
386.3	13 30%		
387	0.38%	4.00%	
387.1	10.83%	7.94%	
General Plant			
389.1	0 00%	0 00%	
389.2	0 46%		
390	2 96%	2.88%	
390 02	8.17%		
390 03	5 00%		
391	8.45%	3.71%	
391 02	0.00%		
391.1	12.88%		12.88%
391.12	0.00%		
392.1	13.43%	16 67%	
392.2	4.68%	3 21%	
393	4.94%	3.73%	
393.02	0.00%		
394	3.74%	1.28%	
394 02	0 00%		
395	16.54%		
396	9.40%	3.97%	
397.1	13.15%	7.73%	
397.12	0.00%		
397.2	4.62%	2 40%	
397.2 - 101.1	10.00%		
397.3	11.22%	7.31%	
397.4	9.79%	10 08%	
397.42	0 00%		
397.5	9 25%	14.29%	
397 6	10.51%		
397.7	8.73%		
398	6 26%	9.12%	
398.02	0 00%		

208. CONSTRUCTION WORK IN PROGRESS - Account No. 107

1. Describe the particulars concerning utility plant in process of construction but not ready for service at end of the Calendar Year.

2. Describe separately each work order that exceeds the lesser of an estimated expenditure of $300,000 or 10% of the book cost of utility plant at the beginning of the year. All other work orders may be grouped by nature of project.

Line No.	Description of Work (a)	Balance End of Year (b)	Estimate Total Cost of Construction (c)	Projected In-Service Date (d)
1	Distribution Plant	3,269,310	24,493,279	2008 - 2009
2	General Plant	5,960,046	6,044,895	2008
3	Intangible Plant			2008 - 2009
4	Production Plant	2,850,681	3,782,294	2008
5	Transmission Plant	1,621,484	2,301,404	2008
6				
7				
8				
9				
10				
11				
12				
13				
14				
15				
16				
17				
18				
19				
20				
21				
22				
23				
24				
25	TOTALS	13,701,521	36,621,872	

210. INVESTMENTS (Accounts 123 - 123.1 - 124 - 136)

1. Report below investments in Accounts 123, Investments in Associated Companies 123.1, Investments in Subsidiary Companies, 124, Other Investments and 136, Temporary Cash Investments.
2. Provide a subheading for each account and list thereunder the information called for, observing the instructions below.
3. Investments in Securities - List and describe each security owned giving name of issuer. For bonds give also principal amount, date of issue, maturity, and interest rate. For capital stock state number of shares, class and series of stock. Minor investments may be grouped by classes.
4. Investment Advances - Report separately for each person or company the amounts of loans or investment advances which are subject to repayment but which are not subject to current settlement. With respect to each advance show whether the advance is a note or open account. Each note should be listed giving date of issuance, maturity date, and specifying whether note is a renewal. Designate any advances due from officers, directors, stockholders, or employees.
5. For any securities, notes, or accounts that were pledged, designate such securities acquired. designate such fact and in a footnote state the name of pledges and purpose of the pledge.
6. If Commission approval was required for any advance made or security acquired, designate such fact and in a footnote give date of authorization and case or docket number.
7. Interest and dividend revenues from investments should be reported in column (g), including such revenues from securities disposed of during the year.
8. In column (h) report for each investment disposed of during the year the gain or loss represented by the difference between cost of the investment (or the other amount at which carried in the books of account if different from cost) and the selling price therefor, not including any dividend or interest adjustment incredible in column (g).

Line No.	Description of Investment (a)	Date Acquired (b)	Date of Maturity (c)	Book Costs* Beginning of Year (d)	Principal Amount or No. of Shares (e)	Book Cost End of Year (f)	Revenues For Year (g)	Gain or Loss From Invest Disposed of (h)
1	Investments in Subsidiary Companies (123.1):							
2	Kentucky West Virginia Gas Company, LLC							
3	Membership Capital	11/1/95		(135,389,547)		(58,169,547)	77,220,000	
4	Equity in Undistributed Earnings			70,648,555		71,396,161		
5	TOTAL			(64,740,992)		13,226,614	77,220,000	
6	Equitrans, L.P.							
7	Partnership Capital	11/1/95		(50,745,634)		(96,008,134)	(45,262,500)	
8	Equity in Undistributed Earnings			152,613,553		160,700,485		
9	TOTAL			101,867,919		64,692,351	(45,262,500)	
10	Equitable Resources Capital Trust I							
11	Paid in Capital			0		0		
12	Equity in Undistributed Earnings			(3)		(3)		
13	TOTAL			(3)		(3)	0	
14	Carnegie Pipeline	12/15/99						
15	Paid in Capital			19,650,278		19,650,278	0	
16	Equity in Undistributed Earnings			1,924,050		1,924,050	0	
17	TOTAL			21,574,328		21,574,328	0	
18	EQT Investment Holdings							
19	Membership Capital			3,104,084,706		3,108,346,126		
20	Equity in Undistributed Earnings			(2,139,240)		385,263,409		
21	TOTAL			3,101,945,466		3,493,609,535	0	
22	Equitable Resouraces Ins Ltd.							
23	Membership Capital			2,700,000		2,700,000		
24	Equity in Undistributed Earnings			1,332,956		4,724,837		
25	TOTAL			4,032,956		7,424,837	0	
26								
27	TOTAL COST ACCT. 123.1:			3,164,679,674		3,600,527,662	31,957,500	
28								
29								
30								
31								
32								
33	Temporary Cash Investments Account 136							
34	Commercial Paper			0		0		
35	TOTAL Acct. 136			0		0		

* If book cost is different from cost to respondent, give cost to respondent in a footnote and explain difference.

Refer to Item J of the Notes to Balance Sheet for further discussion of Investments in Subsidiaries.

211. NOTES AND OTHER ACCOUNTS RECEIVABLE (Accounts 141, and 143)

If interest was derived during year from notes liquidated before the end of the year, include such interest revenue in column (d).

		Notes Receivable			Other Accounts Receivable	
Line No.	Item (a)	1/1/2007 (b)	12/31/2007 (c)	Interest Revenue (d)	1/1/2007 (e)	12/31/07 (f)
1	Note Receivable-Allegheny Center Mall	628,268	490,541	39,616		
2	Reimbursable Construction Orders				819,832	8,428
3	Other Accounts Receivable				189	207
4						
5						
6						
7	Total	628,268	490,541	39,616	820,021	8,635

212. NOTES RECEIVABLE FROM ASSOCIATED COMPANIES (Account 145)

1. Furnish below the particulars indicated concerning notes receivable from associated companies at end of year.
2. If any note was received in satisfaction of an open account indebtedness, state the period covered by such open account.
3. Include in column (f) the amount of any interest revenue during the year on notes that were paid off before the end of year.
4. Give particulars of any notes pledged or discounted. This schedule shall include all transactions during the year with each affiliated interest affecting account 145 and account 233.

Line No.	Name of Associated Company (a)	Date of Issue (b)	Date of Maturity (c)	Amount End of Year (d)	Interest Rate (e)	Amount (f)
1	**NONE**					
2						
3						
4						
5						
6						
7						
8						

213. ACCOUNTS RECEIVABLE FROM ASSOCIATED COMPANIES (ACCOUNT 146) AND ACCOUNTS PAYABLE TO ASSOCIATED COMPANIES (ACCOUNT 234)

1. Furnish below the particulars called for concerning Account Receivables and Payables from Associated Companies.
2. The term "Services Received" set forth on line 21 of this schedule means the Management, Construction, Engineering, Purchasing Legal, Accounting or other similar service which has been rendered to respondent under written, oral or implied contracts.
3. The term "Joint Expenses Transferred" set forth on lines 6 and 22 means Central office and/or other expenses continuously assessed against respondent covering all locations of common operating costs.
4. This schedule shall include all transactions during the year with each affiliated interest affecting Account 146.

Line No.	Item (a)	Entries During Year (b)
1	**Debits During Year**	
2	Cash Dispensed	709,946,399
3	Materials and Supplies Sold	
4	Services Rendered	
5	Joint Expense Transferred	1,134,348,553
6	Interest and Dividends Receivable	
7	Rents Receivable	
8	Securities Sold	
9	Other Debits (Specify) - Balance Beginning of Year	15,897,439
10		
11		
12		
13	**Total Debits During Year**	1,860,192,391
14		
15	**Credits During Year**	
16	Cash Received	352,755,713
17	Gas Purchased	69,003,733
18	Fuel Purchased	
19	Materials and Supplies Purchased	
20	Services Received	
21	Joint Expense Transferred	1,065,938,688
22	Interest and Dividends Payable	
23	Rents Payable	
24	Securities Purchased	
25	Transferred to Account "145"	
26	Other Credits (Specify)	
27		
28		
29		
30	**Total Credits During Year**	1,487,698,134
31	**Balance at End of Year**	372,494,257

215. PLANT MATERIALS AND OPERATING SUPPLIES (Account 154)

1. Summarize below by character of materials and supplies, the balances in account 154 at the beginning and end of the year.
2. Account entries totaling $300,000 or 1% of gross revenues, (whichever is less), during the year shall be explained, showing the class of materials affected and the various classes of accounts (operating expenses, clearing accounts, plant accounts, etc.) debited or credited.

Line No.	Classification of Materials And Supplies (a)	Balance Beginning of Year (b)	Balance End of Year (c)	Increase /Decrease (d)
1	General Supplies	1,556,229	1,015,253	(540,976)
2				0
3				0
4				0
5				0
6				0
7				0
8				0
9				0
10				0
11				0
12				0
13				0
14				0
15				0
16				0
17	**Total**	1,556,229	1,015,253	(540,976)

216. UNAMORTIZED DEBT DISCOUNT AND EXPENSE AND UNAMORTIZED PREMIUM ON DEBT (Accounts 181, 225)

1. Report under separate subheadings for Unamortized Debt Discount and Unamortized Premium on Debt, particulars of discount and expense or premium applicable to each class and series of long-term debt.
2. Show premium amounts in red or by enclosure in parenthesis
3. In column (b) show the principal amount of bonds or other long-term debt originally issued.
4. In column (c) show the discount and expense or premium with respect to the amount of bonds or other long-term debt originally issued.
5. Furnish particulars regarding the treatment of unamortized debt discount and expense or premium, redemption premium, and redemption expenses associated with issues redeemed during the year, also, date of the Commission's authorization of treatment other than by debit or credit to Surplus.
6. Set out separately and identify amounts applicable to issues which have been redeemed, although those amounts, prior to the effective date of the Uniform System of Accounts may have prior to the effective date of the Uniform System of Accounts may have been combined with the discount and expense on the refunding issue.
7. Explain any debits and credits other than amortization debited to Account 428, Amortization of Debt Discount and Expense, or credited to Account 429, Amortization of Premium on Debt.

Line No.	Designation of Long-Term Debt (a)	PRINCIPAL AMOUNT OF SECURITIES TO WHICH OR PREMIUM RELATES (b)	TOTAL DISCOUNT AND EXPENSE OR NET PREMIUM (c)	Amortization Period From (d)	To (e)	Balance Beginning of Year (f)	Debits During Year (g)	Credits During Year (h)	Balance End of Year (i)
1	Account 181								
2	Unamortized Debt Expense:								
3	7.75% Debentures Due 7/15/26	150,000,000	6,319,649	7/29/1996	7/15/2026	9,714,418		471,956	9,242,462
4	Medium-Term Notes -- Series A	100,000,000	1,004,911	9/4/1991	10/1/2021	228,029		25,732	202,297
5	Medium-Term Notes -- Series B	75,500,000	823,766	7/20/1992	3/2/2023	104,687		40,041	64,646
6	Medium-Term Notes -- Series C	18,000,000	164,038	5/26/1995	1/15/2018	100,110		19,376	80,734
7	Medium Term Notes -- 5.00%	150,000,000	1,732,520	9/22/2005	10/1/2015	1,574,416		179,934	1,394,482
8	Medium-Term Notes -- 5.15%	200,000,000	1,583,716	11/15/2002	11/15/2012	1,171,916		193,534	978,382
9	Credit Revolver	1,500,000,000	1,251,890	10/27/2006	10/26/2011	2,955,353		625,018	2,330,335
10	Medium Term Notes – 5.15%	200,000,000	2,119,380	2/1/2003	3/1/2018	1,595,762		144,430	1,451,332
11									0
12									0
13									0
14									0
15	Total	2,393,500,000	14,999,870			17,444,691	0	1,700,021	15,744,670

217. EXTRAORDINARY PROPERTY LOSSES (Account 182)

1. Report below the information indicated concerning this account, grouping the items by departments, and showing totals for each department.
2. Include in the description the date property was abandoned or other extraordinary loss incurred.

Line No.	Description of Property Loss Or Damage (a)	Comm. Auth. No. (b)	Amortization Period (Give Years Only) From (c)	To (d)	Total Amount of Loss (e)	Previously Written off (f)	Written off During Year Account Charged (g)	Amount (h)	Balances At End of Year (i)
1	NONE								
2									
3									
4									
5									
6									
7									
8	Total								0

231. LONG-TERM DEBT (Accounts 221,222,224)

(Excluding Advances from Affiliated Companies)

1. Give below the particulars indicated of the long-term debt at end of year represented by unmatured obligations issued or assumed by the respondent, exclusive of advances from affiliated companies.
2. Group entries according to accounts and show the total for each account.
3. For obligations assumed by the respondent show in column (a) the name of the issuing company and the class and series of such obligations.
4. For Receivers' Certificates show the name of the court and date of court order under which such certificates were issued.
5. If respondent has pledged any of its long-term debt securities give particulars in a footnote, including name of the pledge name of the pledge and purpose of pledge.
6. *If interest expense was incurred during the year on any obligations retired or reacquired before end of year include such interest expense in column (g).*
7. If interest was matured but unpaid on any obligation, state in a footnote the class and series and principal amount of such obligation and the amount of interest matured thereon.

Line No.	Class and Series of Obligations (a)	Nominal Date of Issue (b)	Date of Maturity (c)	Principal Amount Authorized (d)	Outstanding Per Balance Sheet (e)	Interest For Year: Rate (f)	Interest For Year: Amount (g)	Held By Respondent: As Reacquired. Lg.-Term Debt (h)	Held By Respondent: In Sinking & Other Funds (i)
1	Account 221								
2	7-3/4% Debentures	07/29/96	07/15/26		115,000,000	7.75	8,912,500		
3	Medium-Term Notes -- Series A	09/04/91	10/01/21		50,500,000	9.00	4,469,770		
4	Medium-Term Notes -- Series B	07/20/92	03/02/23		30,000,000	7.60	2,227,000		
5	Medium-Term Notes -- Series C	05/26/95	01/15/18		8,000,000	7.60	947,000		
6	Medium-Term Notes -- 5.15%	11/15/02	11/15/12		200,000,000	5.15	10,300,000		
7	Medium-Term Notes -- 5.15%	2/1/03	3/1/18		200,000,000	5.15	10,415,361		
8	Medium-Term Notes -- 5.00%	9/22/05	10/1/15		150,000,000	5.00	7,500,000		
9									
10									
11									
12									
13									
14									
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21									
22									
23									
24									
25									
26									
27									
28	TOTAL			0	753,500,000		44,771,631	0	0

*Total amount outstanding without reduction for amount held by respondent.

400. INCOME STATEMENT
REVENUES AND EXPENSES - TOTAL COMPANY

Balances at Beginning of Year must be consistent with balances at end of previous year

Line No.	Account Number and Title (a)	Schedule Page No. (b)	Balance End of Current Year (c)	Balance End of Previous Year (d)	Increase/ Decrease (e)
1	**SALES OF GAS**				
2	480.0 Residential Sales	600	322,592,114	309,532,124	13,059,990
3	481.0 Commercial and Industrial Sales	600	69,668,554	68,763,677	904,877
4	482.0 Other Sales to Public Authorities	600			0
5	483.0 Sales for Resale	501			0
6	484.0 Indepartmental Sales	600			0
7	485.0 Intracompany Transfers	600			0
8	**TOTAL SALES OF GAS**		392,260,668	378,295,801	13,964,867
9					
10	**OTHER OPERATING REVENUES**				
11	487.0 Forfeited Discounts	600	1,632,434	1,577,062	55,372
12	488.0 Miscellaneous Service Revenues	600	2,474,441	1,164,789	1,309,652
13	489.1 Revenues from Transportation of Gas of Others Through				0
14	Gathering Facilities				0
15	489.2 Revenues from Transportation of Gas of Others Through				0
16	Transmission Facilities				0
17	489.3 Revenues from Transportation of Gas of Others Through		62,483,853	64,055,443	(1,571,590)
18	Distribution Facilities				0
19	489.4 Revenues from Storing Gas of Others				0
20	490.0 Sales of Products Extracted from Natural Gas				0
21	491.0 Revenues from Natural Gas Processed by Others				0
22	492.0 Incidental Gasoline and Oil Sales				0
23	493.0 Rent from Gas Property	600	1,588	5,311	(3,723)
24	494.0 Interdepartmental Rents	600			[illegible]
25	495.0 Other Gas Revenues	600	55,742	236,194	(180,45[illegible]
26	496.0 Provision for Rate Refunds				0
27	**TOTAL OTHER OPERATING REVENUES**		66,648,058	67,038,799	(390,741)
28					
29	**TOTAL REVENUES**		458,908,726	445,334,600	13,574,126
30					

400. INCOME STATEMENT
REVENUES AND EXPENSES - TOTAL COMPANY

Balances at Beginning of Year must be consistent with balances at end of previous year

Line No.	Account Number and Title (a)	Schedule Page No. (b)	Balance Current Year (c)	Balance Previous Year (d)	Increase/ Decrease (e)
1	**OPERATING EXPENSES**				
2	401 Operation Expenses		408,137,683	375,070,419	33,067,264
3	402 Maintenance Expenses		11,592,147	11,680,372	(88,225)
4	403 Depreciation Expenses		17,496,571	16,690,666	805,905
5	404.1 Amort. & Depletion of Prod. Natural Gas Land & Rights				0
6	404.2 Amort. Of Underground Storage Land & Land Rights				0
7	404.3 Amort. Of Other Limited-Term Gas Plant		3,443,006	3,643,716	(200,710)
8	405.0 Amortization of Other Gas Plant				0
9	406.0 Amortization of Gas Plant Acquisition Adjustments				0
10	407.1 Amort. Of Prop. Losses, Unrec. Plant & Reg. Study C.				0
11	407.2 Amortization of Conversion Expense				0
12	407.3 Regulatory Debits				0
13	407.4 Regulatory Credits				0
14	408.1 Taxes Other Than Income Taxes, Utility Opr. Income	408	2,215,719	3,708,795	(1,493,076)
15	409.1 Income Taxes, Utility Operating Income	409	3,169,415	27,280,510	(24,111,095)
16	410.1 Provision for Deferred Income Taxes, Ut. Opr. Income	411	2,459,979	(16,171,405)	18,631,384
17	411.1 Prov. For Def. Income Taxes-Credit, Ut. Opr. Income	412			0
18	411.4 Investment Tax Credit Adjustments, Ut. Operations		(9,114)	(240,030)	230,916
19	411.6 Gains from Disposition of Utility Plant				0
20	411.7 Losses from Disp. of Utility Plant				0
21	Total Utility Operating Expenses		448,505,406	421,663,043	26,842,363
22	**OTHER OPERATING INCOME**				
23	412.0 Revenues from Gas Plant Leased to Others				0
24	413.0 Expenses of Gas Plant Leased to Others				0
25	414.0 Other Utility Operating Income				0
26	Total Other Operating Income		0	0	0
27	**OTHER INCOME**				
28	415.0 Rev. from Merchandising, Jobbing and Contract Work				0
29	416.0 Costs and Exp. of Merchandising Jobbing & Contract Wk				0
30	417.0 Revenue from Non-Utility Operations				0
31	418.0 Non Operating Rental Income				0
32	418.1 Equity in Earnings of Subsidiary Companies		415,603,259	316,823,618	98,779,641
33	419.0 Interest & Dividend Income		5,047,383	6,809,081	(1,761,698)
34	419.1 Allowance for Other Funds Used During Construction		405,218	303,842	101,376
35	421.0 Miscellaneous Non Operating Income		(35,450,055)	(25,977,512)	(9,472,543)
36	421.1 Gain on Disposition of Property, Total Other Income				0
37	Total Other Income		385,605,805	297,959,029	87,646,776
38	**OTHER INCOME DEDUCTIONS**				
39	421.2 Loss on Disposition of Property				0
40	425.0 Miscellaneous Amortization				0
41	426.1 Donations		5,966	14,129	(8,163)
42	426.2 Life Insurance				0
43	426.3 Penalties				0
44	426.4 Exp. for Certain Civic, Political & Related Activities		1,061	2,551	(1,490)
45	426.5 Other Deductions		60,588,920	21,875,980	38,712,940
46	Total Other Income Deductions		60,595,947	21,892,660	38,703,287
47	**TAXES APPLICABLE TO OTHER INCOME & DED.**				
48	408.2 Taxes Other Than Income Taxes, Otr. Income & Ded.				0
49	409.2 Income Taxes, Other Income & Deductions		(49,980,000)	(64,198,943)	14,218,943
50	410.2 Prov. for Deferred Income Taxes, Otr. Income & Ded.			2,456,647	(2,456,647)
51	411.2 Prov. for Def. Income Taxes, Credit, Otr Income & Ded.		(17,113,000)		(17,113,000)
52	411.5 Investment Tax Cr. Adjustments, Nonutility Operations				0
53	420.0 Investment Tax Credits		(417,180)	(7,210)	(409,970)
54	Total Taxes on Other Income and Deductions		(67,510,180)	(61,749,506)	(5,760,674)
55	Net Other Income and Deductions		392,520,038	337,815,875	54,704,163

400. INCOME STATEMENT
REVENUES AND EXPENSES - TOTAL COMPANY

Balances at Beginning of Year must be consistent with balances at end of previous year

Line No.	Account Number and Title (a)	Schedule Page No. (b)	Balance Current Year (c)	Balance Previous Year (d)	Increase/ Decrease (e)
1	**INTEREST CHARGES**				
2	427 Interest on Long-Term Debt		72,269,159	57,315,005	14,954,154
3	428 Amortization of Debt Discount and Expense		1,077,348	1,074,581	2,767
4	428.1 Amortization of Loss on Reacquired Debt		245,272	245,272	0
5	429 Amortization of Premium on Debt-Credit				0
6	429.1 Amortization of Gain on Reacquired Debt-Credit				0
7	430 Interest on Debt to Associated Companies		57,802,989	74,168,367	(16,365,378)
8	431 Other Interest Expense		14,282,910	8,155,930	6,126,980
9	432 Allowance for Borrowed Funds Used During Construction-Cr		(237,126)	(166,420)	(70,706)
10	Net Interest Charges		145,440,552	140,792,735	4,647,817
11	**EXTRAORDINARY ITEMS**				
12	434 Extraordinary Income				0
13	435 Extraordinary Deductions			3,654,557	(3,654,557)
14	409.3 Income Taxes-Extraordinary Items			(3,246,355)	3,246,355
15	Net Income		257,482,806	220,286,495	37,196,311
16					
17					
18					
19					
20					
21					
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400. INCOME STATEMENT
REVENUES AND EXPENSES - PENNSYLVANIA DIVISION

Balances at Beginning of Year must be consistent with balances at end of previous year

Line No.	Account Number and Title (a)	Schedule Page No. (b)	Balance End of Current Year (c)	Balance End of Previous Year (d)	Increase/ Decrease (e)
1	**SALES OF GAS**				
2	480.0 Residential Sales	600	306,414,732	292,579,331	13,835,401
3	481.0 Commercial and Industrial Sales	600	64,917,300	63,754,351	1,162,949
4	482.0 Other Sales to Public Authorities	600			0
5	483.0 Sales for Resale	501			0
6	484.0 Indepartmental Sales	600			0
7	485.0 Intracompany Transfers	600			0
8	**TOTAL SALES OF GAS**		371,332,032	356,333,682	14,998,350
9					
10	**OTHER OPERATING REVENUES**				
11	487.0 Forfeited Discounts	600	1,557,851	1,512,240	45,611
12	488.0 Miscellaneous Service Revenues	600	2,474,441	1,164,789	1,309,652
13	489.1 Revenues from Transportation of Gas of Others Through				0
14	Gathering Facilities				0
15	489.2 Revenues from Transportation of Gas of Others Through				0
16	Transmission Facilities				0
17	489.3 Revenues from Transportation of Gas of Others Through				0
18	Distribution Facilities		61,853,829	63,457,558	(1,603,729)
19	*489.4 Revenues from Storing Gas of Others*				0
20	490.0 Sales of Products Extracted from Natural Gas				0
21	491.0 Revenues from Natural Gas Processed by Others				0
22	492.0 Incidental Gasoline and Oil Sales				0
23	493.0 Rent from Gas Property	600	1,588	5,311	(3,723)
24	494.0 Interdepartmental Rents	600			
25	495.0 Other Gas Revenues	600	55,742	236,194	(180,452)
26	496.0 Provision for Rate Refunds				0
27	**TOTAL OTHER OPERATING REVENUES**		65,943,451	66,376,092	(432,641)
28					
29	**TOTAL REVENUES**		437,275,483	422,709,774	14,565,709
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400. INCOME STATEMENT
REVENUES AND EXPENSES - PENNSYLVANIA DIVISION

Balances at Beginning of Year must be consistent with balances at end of previous year

Line No.	Account Number and Title (a)	Schedule Page No. (b)	Balance Current Year (c)	Balance Previous Year (d)	Increase/ Decrease (e)
1	**OPERATING EXPENSES**				
2	401 Operation Expenses		389,448,285	355,408,475	34,039,810
3	402 Maintenance Expenses		11,048,733	11,146,010	(97,277)
4	403 Depreciation Expenses		16,541,917	15,743,994	797,923
5	404.1 Amort. & Depletion of Prod. Natural Gas Land & Rights				0
6	404.2 Amort. Of Underground Storage Land & Land Rights				0
7	404.3 Amort. Of Other Limited-Term Gas Plant		3,443,006	3,638,452	(195,446)
8	405.0 Amortization of Other Gas Plant				0
9	406.0 Amortization of Gas Plant Acquisition Adjustments				0
10	407.1 Amort. Of Prop. Losses, Unrec. Plant & Reg. Study C.				0
11	407.2 Amortization of Conversion Expense				0
12	407.3 Regulatory Debits				0
13	407.4 Regulatory Credits				0
14	408.1 Taxes Other Than Income Taxes, Utility Opr. Income	408	418,256	2,043,010	(1,624,754)
15	409.1 Income Taxes, Utility Operating Income	409	3,169,415	27,280,510	(24,111,095)
16	409.3 Income Taxes, Discontinued Operations				0
17	410.1 Provision for Deferred Income Taxes, Ut. Opr. Income	411	2,459,979	(16,171,405)	18,631,384
18	411.1 Prov. For Def. Income Taxes-Credit, Ut. Opr. Income	412			0
19	411.4 Investment Tax Credit Adjustments, Ut. Operations		(9,114)	(240,030)	230,916
20	411.6 Gains from Disposition of Utility Plant				0
21	411.7 Losses from Disp. of Utility Plant				0
22	Total Utility Operating Expenses		426,520,477	398,849,016	27,671,461
23	**OTHER OPERATING INCOME**				
24	412.0 Revenues from Gas Plant Leased to Others				0
25	413.0 Expenses of Gas Plant Leased to Others				0
26	414.0 Other Utility Operating Income				0
27	Total Other Operating Income		0	0	0
28	**OTHER INCOME**				0
29	415.0 Rev. from Merchandising, Jobbing and Contract Work				0
30	416.0 Costs and Exp. of Merchandising Jobbing & Contract Wk				0
31	417.0 Revenue from Non-Utility Operations				0
32	418.0 Non Operating Rental Income				0
33	418.1 Equity in Earnings of Subsidiary Companies		415,416,633	316,636,992	98,779,641
34	419.0 Interest & Dividend Income		4,910,288	6,809,081	(1,898,793)
35	419.1 Allowance for Other Funds Used During Construction		404,775	302,157	102,618
36	421.0 Miscellaneous Non Operating Income		(35,477,325)	(25,977,512)	(9,499,813)
37	421.1 Gain on Disposition of Property, Total Other Income				0
38	Total Other Income		385,254,371	297,770,718	87,483,653
39	**OTHER INCOME DEDUCTIONS**				0
40	421.2 Loss on Disposition of Property				0
41	425.0 Miscellaneous Amortization				0
42	426.1 Donations		5,966	14,129	(8,163)
43	426.2 Life Insurance				0
44	426.3 Penalties				0
45	426.4 Exp. for Certain Civic, Political & Related Activities		1,061	2,551	(1,490)
46	426.5 Other Deductions		60,588,920	21,875,980	38,712,940
47	Total Other Income Deductions		60,595,947	21,892,660	38,703,287
48	**TAXES APPLICABLE TO OTHER INCOME & DED.**				0
49	408.2 Taxes Other Than Income Taxes, Otr. Income & Ded.				0
50	409.2 Income Taxes, Other Income & Deductions		(49,980,000)	(64,198,943)	14,218,943
51	410.2 Prov. for Deferred Income Taxes, Otr. Income & Ded.			2,456,647	(2,456,647)
52	411.2 Prov. for Def. Income Taxes, Credit, Otr Income & Ded.		(17,113,000)		(17,113,000)
53	411.5 Investment Tax Cr. Adjustments, Nonutility Operations				0
54	420.0 Investment Tax Credits		(417,180)	(7,210)	(409,970)
55	Total Taxes on Other Income and Deductions		(67,510,180)	(61,749,506)	(5,760,674)
56	Net Other Income and Deductions		392,168,604	337,627,564	54,541,040

400. INCOME STATEMENT
REVENUES AND EXPENSES - PENNSYLVANIA DIVISION

Balances at Beginning of Year must be consistent with balances at end of previous year

Line No.		Account Number and Title (a)	Schedule Page No. (b)	Balance Current Year (c)	Balance Previous Year (d)	Increase/ Decrease (e)
1		**INTEREST CHARGES**				
2	427	Interest on Long-Term Debt		72,269,159	57,315,005	14,954,154
3	428	Amortization of Debt Discount and Expense		1,077,348	1,074,581	2,767
4	428.1	Amortization of Loss on Reacquired Debt		245,272	245,272	0
5	429	Amortization of Premium on Debt-Credit				0
6	429.1	Amortization of Gain on Reacquired Debt-Credit				0
7	430	Interest on Debt to Associated Companies		57,802,989	74,168,367	(16,365,378)
8	431	Other Interest Expense		14,282,910	8,155,930	6,126,980
9	432	Allowance for Borrowed Funds Used During Construction-Cr		(236,874)	(165,510)	(71,364)
10		Net Interest Charges		145,440,804	140,793,645	4,647,159
11		**EXTRAORDINARY ITEMS**				0
12	434	Extraordinary Income			3,654,557	(3,654,557)
13	435	Extraordinary Deductions			(3,246,335)	3,246,335
14	409.3	Income Taxes-Extraordinary Items				0
15		Net Income		257,482,806	220,286,455	37,196,351
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405. OPERATION AND MAINTENANCE EXPENSES - TOTAL COMPANY

Balances at Beginning of Year must be consistent with balances at end of previous year

Line No.	Account Number and Title (a)	Schedule Page No. (b)	Balance Current Year (c)	Balance Previous Year (d)	Increase/ Decrease (e)
1	**MANUFACTURED GAS PRODUCTION EXPENSES**		XXX	XXX	XXX
2	**Steam Production Expenses**				
3	**Operation**				
4	700.0 Operation Supervision and Engineering				0
5	701.0 Operating Labor				0
6	702.0 Boiler Fuel				0
7	703.0 Miscellaneous Steam Expenses				0
8	**Total Steam Production Operation Expenses**		0	0	0
9	**Maintenance**				
10	704.0 Steam Transferred-Credit				0
11	705.0 Maintenance, Supervision and Engineering				0
12	706.0 Maintenance of Structures and Improvements				0
13	707.0 Maintenance of Boiler Plant Improvement				0
14	708.0 Maintenance of Other Steam Production Plant				0
	Total Steam Production Maintenance Expenses		0		0
15	**Manufactured Gas Production**				
16	710.0 Operation Supervision and Engineering				0
17	**Production Labor and Expenses**				
18	711.0 Steam Expenses				0
19	712.0 Other Power Expenses				0
20	713.0 Coke Oven Expenses				0
21	714.0 Producer Gas Expenses				0
22	715.0 Water Gas Generating Expenses				0
23	716.0 Oil Gas Generating Expenses				0
24	717.0 Liquefied Petroleum Gas Expenses				0
25	718.0 Other Process Production Expenses				0
	Total Production Labor and Expenses		0	0	0
26	**Gas Fuels**				
27	719.0 Fuel Under Coke Ovens				0
28	720.0 Producer Gas Fuel				0
29	721.0 Water Gas Generator Fuel				0
30	722.0 Fuel for Oil Gas				0
31	723.0 Fuel for Liquefied Petroleum Gas Process				0
32	724.0 Other Gas Fuels				0
	Total Gas Fuels Expenses		0	0	0
33	**Gas Raw Materials**				
34	725.0 Coal Carbonized in Coke Ovens				0
35	726.0 Oil for Water Gas				0
36	727.0 Oil for Oil Gas				0
37	728.0 Liquefied Petroleum Gas Expenses				0
38	729.0 Raw Materials for Other Gas Processes				0
39	730.0 Residuals Expenses				0
40	731.0 Residuals Produced-Credit				0
41	732.0 Purification Expenses				0
42	733.0 Gas Mixing Expenses				0
43	734.0 Duplicate Charges-Credit				0
44	735.0 Miscellaneous Production Expenses				0
45	736.0 Rents				0
	Total Gas Raw Materials Expenses		0	0	0
46	**Maintenance**				
47	740.0 Maintenance Supervision and Engineering				0
48	741.0 Maintenance of Structures and Improvements				0
49	742.0 Maintenance of Production Equipment				0
	Total Maintenance Expenses		0	0	0
	Total Manufactured Gas Production Expenses		0	0	0
50	NATURAL GAS PRODUCTION EXPENSES		XXX	XXX	XXX
51	**Production and Gathering**				
52	**Operation**				
53	750.0 Operating Supervision and Engineering		213	3,120	(2,907)
53	751.0 Production Maps and Records				0
54	752.0 Gas Wells Expenses		1,361	807	554

405. OPERATION AND MAINTENANCE EXPENSES (Continue) - TOTAL COMPANY

Balances at Beginning of Year must be consistent with balances at end of previous year

Line No.	Account Number and Title (a)	Schedule Page No. (b)	Balance Current Year (c)	Balance Previous Year (d)	Increase/ Decrease (e)
1	753.0 Field Lines Expenses				0
2	754.0 Field Compressor Station Expenses				0
3	755.0 Field Compressor Station Fuel and Power				0
4	756.0 Field Measuring and Regulating Station Expenses				0
5	757.0 Purification Expenses				0
6	758.0 Gas Well Royalties				0
7	759.0 Other Expenses				0
8	760.0 Rents				0
	Total Production & Gathering Operation Expenses		1,574	3,927	(2,353)
9	**Maintenance**				
10	761.0 Maintenance Supervision and Engineering		76		76
11	762.0 Maintenance of Structures and Improvements				0
12	763.0 Maintenance of Producing Gas Wells				0
13	764.0 Maintenance of Field Lines		88		88
14	765.0 Maintenance of Field Compressor Station Equipment		125		125
15	766.0 Maintenance of Field Measuring and Reg. Station Equip				0
16	767.0 Maintenance of Purification Equipment				0
17	768.0 Maintenance of Drilling and Cleaning Equipment				0
18	769.0 Maintenance of Other Equipment				0
	Total Production & Gathering Maintenance Expenses		289	0	289
19	**Products Extraction**				
20	**Operation**				
21	770.0 Operation Supervision and Engineering				0
22	771.0 Operating Labor				0
23	772.0 Gas Shrinkage				0
24	773.0 Fuel				0
25	774.0 Power				0
26	775.0 Materials				0
27	776.0 Operation Supplies and Expenses				0
28	777.0 Gas Processed by Others				0
29	778.0 Royalties on Products Extracted				0
30	779.0 Marketing Expenses				0
31	780.0 Products Purchased for Resale				0
32	781.0 Variation in Products Inventory				0
33	782.0 Extracted Products Used by the Utility-Credit				0
34	783.0 Rents				0
	Total Products Extraction Operation Expenses		0	0	0
35	**Maintenance**				
36	784.0 Maintenance Supervision and Engineering				0
37	785.0 Maintenance of Structures and Improvements				0
38	786.0 Maintenance of Extraction and Refining Equipment				0
39	787.0 Maintenance of Pipe Lines				0
40	788.0 Maintenance of Extracted Products Storage Equipment				0
41	789.0 Maintenance of Compressor Equipment				0
42	790.0 Maintenance of Gas Measuring & Regulating Equipment				0
43	791.0 Maintenance of Other Equipment				0
	Total Products Extraction Maintenance Expenses		0	0	0
	Total Natural Gas Production Expenses		1,863	3,927	(2,064)
44	**EXPLORATION AND DEVELOPMENT EXPENSES**		XXX	XXX	XXX
45	**Operation**				
46	795.0 Delay Rentals				0
47	796.0 Nonproductive Well Drilling				0
48	797.0 Abandoned Leases				0
49	798.0 Other Exploration				0
	Total Exploration and Development Operation Exp.		0	0	0
50	**OTHER GAS SUPPLY EXPENSES**		XXX	XXX	XXX
51	**Operation**				
52	800.0 Natural Gas Well Head Purchases				0
53	801.0 Natural Gas Well Head Purchases, Intercompany Trans.		105,127,584	106,373,081	(1,245,497)
54	802.0 Natural Gas Gasoline Plant Outlet Purchases				0
55	803.0 Natural Gas Transmission Line Purchases		130,700,663	146,363,970	(15,663,307)
56	804.0 Natural Gas City Gate Purchases				0

405. OPERATION AND MAINTENANCE EXPENSES (Continued) - TOTAL COMPANY

Balances at Beginning of Year must be consistent with balances at end of previous year

Line No.	Account Number and Title (a)	Schedule Page No. (b)	Balance Current Year (c)	Balance Previous Year (d)	Increase/ Decrease (e)
1	804.1 Liquefied Natural Gas Purchases				0
2	805.0 Other Gas Purchases				0
3	805.1 Purchases Gas Cost Adjustments		19,800,072	2,654,700	17,145,372
4	806.0 Exchange Gas				0
5	807.0 Purchased Gas Expenses		402,000	48,560	353,440
6	808.1 Gas Withdrawn from Storage-Debit		82,786,831	65,537,555	17,249,276
7	808.2 Gas Delivered to Storage-Credit		(90,484,407)	(82,926,900)	(7,557,507)
8	809.1 Withdrawals of Liquefied Nat. Gas Held for Processing				0
9	809.2 Deliveries of Natural Gas for Processing				0
10	810.0 Gas Used for Compressor Station Fuel-Credit				0
11	811.0 Gas Used for Products Extraction-Credit				0
12	812.0 Gas Used for Other Utility Operations-Credit				0
13	813.0 Other Gas Supply Expenses		57,013,472	62,152,706	(5,139,234)
	Total Gas Supply Operation Expenses		305,346,215	300,203,672	5,142,543
14	**Natural Gas Storage, Terminating & Processing Exp.**				
15	**Underground Storage Expenses**				
16	814.0 Operation Supervision and Engineering				
17	815.0 Maps and Records				0
18	816.0 Wells Expenses				0
19	817.0 Lines Expenses				0
20	818.0 Compressor Station Expenses				0
21	819.0 Compressor Station Fuel and Power				0
22	820.0 Measuring and Regulating Station Expenses				0
23	821.0 Purification Expenses				0
24	822.0 Exploration and Development				0
25	823.0 Gas Losses				0
26	824.0 Other Expenses				0
27	825.0 Storage Well Royalties				0
28	826.0 Rents				0
	Total Underground Storage Expenses		0	0	0
29	**Maintenance**				0
30	830.0 Maintenance Supervision and Engineering				
31	831.0 Maintenance of Structures and Improvements				0
32	832.0 Maintenance of Reservoirs and Wells				0
33	833.0 Maintenance of Lines				0
34	834.0 Maintenance of Compressor Station Equipment				0
35	835.0 Maintenance of Measuring & Regulating Station Equip.				0
36	836.0 Maintenance of Purification Equipment				0
37	837.0 Maintenance of Other Equipment				0
	Total Maintenance Expenses		0	0	0
38	**Other Storage Expenses**				0
39	**Operation**				
40	840.0 Operating Supervision and Engineering				
41	841.0 Operation Labor and Expenses				0
42	842.0 Rents				0
43	842.1 Fuel				0
44	842.2 Power				0
45	842.3 Gas Losses				0
	Total Operation Expenses		0	0	0
46	**Maintenance**				0
47	843.1 Maintenance Supervision and Engineering				0
48	843.2 Maintenance of Structures and Improvements				0
49	843.3 Maintenance of Gas Holders				0
50	843.4 Maintenance of Purification Equipment				0
51	843.5 Maintenance of Liquefaction Equipment				0
52	843.6 Maintenance of Vaporizing Equipment				0
53	843.7 Maintenance of Compressor Equipment				0
54	843.8 Maintenance of Measuring and Regulatory Equipment				0
55	843.9 Maintenance of Other Equipment				0
	Total Maintenance Expenses		0	0	0

405. OPERATION AND MAINTENANCE EXPENSES (Continued) - TOTAL COMPANY

Balances at Beginning of Year must be consistent with balances at end of previous year

Line No.	Account Number and Title (a)	Schedule Page No (b)	Balance Current Year (c)	Balance Previous Year (d)	Increase/ Decrease (e)
1					
2	**LIQUEFIED NATURAL GAS TERMINATING AND**				
3	**PROCESSING EXPENSES**		XXX	XXX	XXX
4	**Operation**				
5	844.1 Operation Supervision and Engineering				0
6	844.2 LNG Processing Terminal Labor and Expenses				0
7	844.3 Liquefaction Processing Labor and Expenses				0
8	844.4 LNG Transportation Labor and Expenses				0
9	844.5 Measuring and Regulating Labor and Expenses				0
10	844.6 Compressor Station Labor and Expenses				0
11	844.7 Communication System Expenses				0
12	844.8 System Control and Load Dispatching				0
13	845.1 Fuel				0
14	845.2 Power				0
15	845.3 Rents				0
16	845.4 Demurrage Charges				0
17	845.5 Warfare Receipts-Credit				0
18	845.6 Processing Liquefied or Vaporized Gas by Others				0
19	846.1 Gas Losses				0
20	846.2 Other Expenses				0
	Total Liq. N.G. Term & Proc. Operation Expenses		0	0	0
21	**Maintenance**				
22	847.1 Maintenance Supervision and Engineering				0
23	847.2 Maintenance of Structures and Improvements				0
24	847.3 Maintenance of LNG Processing Terminal Equipment				0
25	847.4 Maintenance of LNG Transportation Equipment				0
26	847.5 Maintenance of Measuring and Regulating Equipment				0
27	847.6 Maintenance of Compressor Station Equipment				0
28	847.7 Maintenance of Communication Equipment				0
29	847.8 Maintenance of Other Equipment				0
	Total Liq. N.G. Term. Proc. Maintenance Expenses		0	0	0
30	**TRANSMISSION EXPENSES**		XXX	XXX	XXX
31	**Operation**				
32	850.0 Operating Supervision and Engineering				0
33	851.0 System Control and Load Dispatching				0
34	852.0 Communication System Expenses				0
35	853.0 Compressor Station Labor and Expenses				0
36	854.0 Gas for Compressor Station Fuel				0
37	855.0 Other Fuel and Power for Compressor Stations				0
38	856.0 Mains Expenses				0
39	857.0 Measuring and Regulating Station Expenses				0
40	858.0 Transmission and Compression of gas by Others				0
41	859.0 Other Expenses				0
42	860.0 Rents				0
	Total Transmission Operation Expenses		0	0	0
43	**Maintenance**				
44	861.0 Maintenance Supervision and Engineering				0
45	862.0 Maintenance of Structures and Improvements				0
46	863.0 Maintenance of Mains				0
47	864.0 Maintenance of Compressor Station Equipment				0
48	865.0 Maintenance of Measuring and Regulating Station Equip.				0
49	866.0 Maintenance of Communication Equipment				0
50	867.0 Maintenance of Other Equipment				0
51	**Total Transmission Maintenance Expenses**		0	0	0
52	**DISTRIBUTION EXPENSES**		XXX	XXX	XXX
53	**Operation**				
54	870.0 Operation Supervision and Engineering		1,530,136	1,308,060	222,076
55	871.0 Distribution Load Dispatching		127,195	463,547	(336,352)
56	872.0 Compressor Station Labor and Expenses				0
57	873.0 Compressor Station Fuel and Power (Major Only)		(66)	670	(736)
58	874.0 Mains and Services Expenses		5,530,541	4,780,986	749,555
59	875.0 Measuring and Regulating Station Expenses-General		125,069	162,861	(37,792)

405. OPERATION AND MAINTENANCE EXPENSES (Continued) - TOTAL COMPANY

Balances at Beginning of Year must be consistent with balances at end of previous year

Line No.	Account Number and Title (a)		Schedule Page No. (b)	Balance Current Year (c)	Balance Previous Year (d)	Increase/ Decrease (e)
1	876.0	Measuring and Regulating Station Expenses-Industrial		114	1,293	(1,179)
2	877.0	Measuring and Regulating Station Expenses-City Gate				0
3	878.0	Meter and House Regulator Expenses		7,397,870	6,739,671	658,199
4	879.0	Customer Installations Expenses		74,425	47,955	26,470
5	880.0	Other Expenses		1,345,842	1,515,557	(169,715)
6	881.0	Rents		667,545	729,041	(61,496)
7		**Total Distribution Operation Expenses**		16,798,671	15,749,641	1,049,030
7		**Maintenance**				
8	885.0	Maintenance Supervision and Engineering		900,455	819,931	80,524
9	886.0	Maintenance of Structures and Improvements		502,536	337,834	164,702
10	887.0	Maintenance of Mains		5,667,082	5,997,684	(330,602)
11	888.0	Maintenance of Compressor Station Equipment				0
12	889.0	Maintenance of Measuring & Reg. Station Equip.-Genl.		1,159,221	1,416,598	(257,377)
13	890.0	Maintenance of Measuring & Reg. Station Equip.-Indtrl.		2,031	3,300	(1,269)
14	891.0	Maintenance of Measuring & Reg. Station Equip.-City G		10,085	2,731	7,354
15	892.0	Maintenance of Services		660,479	528,999	131,480
16	893.0	Maintenance of Meters & House Regulators		106,536	101,030	5,506
17	894.0	Maintenance of Other Equipment		65,961	57,191	8,770
		Total Maintenance Expenses		9,074,386	9,265,298	(190,912)
18		**CUSTOMER ACCOUNTS EXPENSES**		XXX	XXX	XXX
19		**Operations**				
20	901.0	Supervision		260,505	229,537	30,968
21	902.0	Meter Reading Expenses		1,082,930	1,189,993	(107,063)
22	903.0	Customer Records & Collection Expenses		9,808,782	9,520,923	287,859
23	904.0	Uncollectable Accounts		8,719,290	6,624,888	2,094,402
24	905.0	Miscellaneous Customer Accounts Expenses		405	51	354
		Total Customer Account Operations Expenses		19,871,912	17,565,392	2,306,520
25		**CUSTOMER SERVICE & INFORM. EXPENSES**		XXX	XXX	XXX
26		**Operations**				0
27	907.0	Supervision				0
28	908.0	Customer Assistance Expenses		446,984	588,310	(141,326)
29	909.0	Informational & Instructional Advertising Expenses				0
30	910.0	Miscellaneous Customer Service & Informational Exp.		635,700	635,700	0
		Total Cust. Service & Inform. Operations Expenses		1,082,684	1,224,010	(141,326)
31		**SALES EXPENSES**		XXX	XXX	XXX
32		**Operation**				
33	911.0	Supervision		60,028	56,356	3,672
34	912.0	Demonstrating and Selling Expenses		756,174	809,050	(52,876)
35	913.0	Advertising Expenses		24,121	35,845	(11,724)
36	914.0	(Reserved)				0
37	915.0	(Reserved)				0
38	916.0	Miscellaneous Sales Expenses				0
		Total Operation Sales Expenses		840,323	901,251	(60,928)
39		**ADMINISTRATIVE AND GENERAL EXPENSES**		XXX	XXX	XXX
40		**Operation**				
41	920.0	Administrative and General Salaries		15,082,322	12,309,262	2,773,060
42	921.0	Office Supplies and Expenses		9,133,072	4,952,861	4,180,211
43	922.0	Administrative Expenses Transferred-Credit		(15,231,859)	(18,828,799)	3,596,940
44	923.0	Outside Service Employed		28,538,765	16,421,457	12,117,308
45	924.0	Property Insurance		(2,532,394)	(88,815)	(2,443,579)
46	925.0	Injuries and Damages		4,249,714	3,180,632	1,069,082
47	926.0	Employee Pensions and Benefits		16,851,203	15,111,654	1,739,549
48	927.0	Franchise Requirements				0
49	928.0	Regulatory Commission Expenses		20,609	37,033	(16,424)
50	929.0	Duplicate Charges-Credit				0
51	930.1	General Advertising Expenses		54,602	63,859	(9,257)
52	930.2	Miscellaneous General Expenses		2,987,601	2,322,613	664,988
53	931.0	Rents		5,042,669	3,940,769	1,101,900
54		**Total Adminstrative and General Operation Expeness**		64,196,304	39,422,526	24,773,778
54		**Maintenance**				
55	932.0	Maintenance of General Plant		2,517,472	2,415,074	102,398
57		**Total Gas Operation and Maintenance Expenses**		66,713,776	41,837,600	24,876,176
58						
59		**Total Gas Operation Expenses**		408,137,683	375,070,419	33,067,264
60		**Total Maintenance Expenses**		11,592,147	11,680,372	(88,225)

405. OPERATION AND MAINTENANCE EXPENSES - PENNSYLVANIA DIVISION

Balances at Beginning of Year must be consistent with balances at end of previous year

Line No.	Account Number and Title (a)	Schedule Page No. (b)	Balance Current Year (c)	Balance Previous Year (d)	Increase/ Decrease (e)
1	**MANUFACTURED GAS PRODUCTION EXPENSES**		XXX	XXX	XXX
2	**Steam Production Expenses**				
3	**Operation**				
4	700.0 Operation Supervision and Engineering				0
5	701.0 Operating Labor				0
6	702.0 Boiler Fuel				0
7	703.0 Miscellaneous Steam Expenses				0
8	**Total Steam Production Operation Expenses**		0	0	0
9	**Maintenance**				
10	704.0 Steam Transferred-Credit				0
11	705.0 Maintenance, Supervision and Engineering				0
12	706.0 Maintenance of Structures and Improvements				0
13	707.0 Maintenance of Boiler Plant Improvement				0
14	708 0 Maintenance of Other Steam Production Plant				0
	Total Steam Production Maintenance Expenses			0	0
15	**Manufactured Gas Production**				
16	710.0 Operation Supervision and Engineering				0
17	**Production Labor and Expenses**				
18	711.0 Steam Expenses				0
19	712.0 Other Power Expenses				0
20	713.0 Coke Oven Expenses				0
21	714.0 Producer Gas Expenses				0
22	715.0 Water Gas Generating Expenses				0
23	716.0 Oil Gas Generating Expenses				0
24	717.0 Liquefied Petroleum Gas Expenses				0
25	718.0 Other Process Production Expenses				0
	Total Production Labor and Expenses		0	0	0
26	**Gas Fuels**				
27	719.0 Fuel Under Coke Ovens				0
28	720.0 Producer Gas Fuel				0
29	721.0 Water Gas Generator Fuel				0
30	722.0 Fuel for Oil Gas				0
31	723.0 Fuel for Liquefied Petroleum Gas Process				0
32	724.0 Other Gas Fuels				0
	Total Gas Fuels Expenses		0	0	0
33	**Gas Raw Materials**				
34	725.0 Coal Carbonized in Coke Ovens				0
35	726.0 Oil for Water Gas				0
36	727.0 Oil for Oil Gas				0
37	728.0 Liquefied Petroleum Gas Expenses				0
38	729.0 Raw Materials for Other Gas Processes				0
39	730.0 Residuals Expenses				0
40	731.0 Residuals Produced-Credit				0
41	732.0 Purification Expenses				0
42	733.0 Gas Mixing Expenses				0
43	734.0 Duplicate Charges-Credit				0
44	735.0 Miscellaneous Production Expenses				0
45	736.0 Rents				0
	Total Gas Raw Materials Expenses		0	0	0
46	**Maintenance**				
47	740.0 Maintenance Supervision and Engineering				0
48	741.0 Maintenance of Structures and Improvements				0
49	742.0 Maintenance of Production Equipment				0
	Total Maintenance Expenses		0	0	0
	Total Manufactured Gas Production Expenses		0	0	0
50	NATURAL GAS PRODUCTION EXPENSES		XXX	XXX	XXX
51	**Production and Gathering**				
52	**Operation**				
53	750.0 Operating Supervision and Engineering		213	3,120	(2,907)
53	751.0 Production Maps and Records				0
54	752.0 Gas Wells Expenses		1,361	859	502

405. OPERATION AND MAINTENANCE EXPENSES (Continue) - PENNSYLVANIA DIVISION

Balances at Beginning of Year must be consistent with balances at end of previous year

Line No.	Account Number and Title (a)	Schedule Page No. (b)	Balance Current Year (c)	Balance Previous Year (d)	Increase/ Decrease (e)
1	753.0 Field Lines Expenses				0
2	754.0 Field Compressor Station Expenses				0
3	755.0 Field Compressor Station Fuel and Power				0
4	756.0 Field Measuring and Regulating Station Expenses				0
5	757.0 Purification Expenses				0
6	758.0 Gas Well Royalties				0
7	759.0 Other Expenses				0
8	760.0 Rents				0
	Total Production & Gathering Operation Expenses		1,574	3,979	(2,405)
9	**Maintenance**				
10	761.0 Maintenance Supervision and Engineering		76		76
11	762.0 Maintenance of Structures and Improvements				0
12	763.0 Maintenance of Producing Gas Wells				0
13	764.0 Maintenance of Field Lines		(1)		(1)
14	765.0 Maintenance of Field Compressor Station Equipment		125	0	125
15	766.0 Maintenance of Field Measuring and Reg. Station Equip.				0
16	767.0 Maintenance of Purification Equipment				0
17	768.0 Maintenance of Drilling and Cleaning Equipment				0
18	769.0 Maintenance of Other Equipment				0
	Total Production & Gathering Maintenance Expenses		200	0	200
19	**Products Extraction**				
20	**Operation**				
21	770.0 Operation Supervision and Engineering				0
22	771.0 Operating Labor				0
23	772.0 Gas Shrinkage				0
24	773.0 Fuel				0
25	774.0 Power				0
26	775.0 Materials				0
27	776.0 Operation Supplies and Expenses				0
28	777.0 Gas Processed by Others				0
29	778.0 Royalties on Products Extracted				0
30	779.0 Marketing Expenses				0
31	780.0 Products Purchased for Resale				0
32	781.0 Variation in Products Inventory				0
33	782.0 Extracted Products Used by the Utility-Credit				0
34	783.0 Rents				0
	Total Products Extraction Operation Expenses		0	0	0
35	**Maintenance**				
36	784.0 Maintenance Supervision and Engineering				0
37	785.0 Maintenance of Structures and Improvements				0
38	786.0 Maintenance of Extraction and Refining Equipment				0
39	787.0 Maintenance of Pipe Lines				0
40	788.0 Maintenance of Extracted Products Storage Equipment				0
41	789.0 Maintenance of Compressor Equipment				0
42	790.0 Maintenance of Gas Measuring & Regulating Equipment				0
43	791.0 Maintenance of Other Equipment				0
	Total Products Extraction Maintenance Expenses		0	0	0
	Total Natural Gas Production Expenses		1,774	3,979	(2,205)
44	EXPLORATION AND DEVELOPMENT EXPENSES		XXX	XXX	XXX
45	**Operation**				
46	795.0 Delay Rentals				0
47	796.0 Nonproductive Well Drilling				0
48	797.0 Abandoned Leases				0
49	798.0 Other Exploration				0
	Total Exploration and Development Operation Exp.		0	0	0
50	OTHER GAS SUPPLY EXPENSES		XXX	XXX	XXX
51	**Operation**				
52	800.0 Natural Gas Well Head Purchases				0
53	801.0 Natural Gas Well Head Purchases, Intercompany Trans.		100,011,705	101,588,429	(1,576,724)
54	802.0 Natural Gas Gasoline Plant Outlet Purchases				0
55	803.0 Natural Gas Transmission Line Purchases		125,031,493	140,759,516	(15,728,023)
56	804.0 Natural Gas City Gate Purchases			-	0

405. OPERATION AND MAINTENANCE EXPENSES (Continued) - PENNSYLVANIA DIVISION

Balances at Beginning of Year must be consistent with balances at end of previous year

Line No.	Account Number and Title (a)	Schedule Page No. (b)	Balance Current Year (c)	Balance Previous Year (d)	Increase/ Decrease (e)
1	804.1 Liquefied Natural Gas Purchases				0
2	805.0 Other Gas Purchases				0
3	805.1 Purchases Gas Cost Adjustments		18,047,867	(1,628,290)	19,676,157
4	806.0 Exchange Gas				0
5	807.0 Purchased Gas Expenses		174,108	22,425	151,683
6	808.1 Gas Withdrawn from Storage-Debit		79,416,051	63,589,443	15,826,608
7	808.2 Gas Delivered to Storage-Credit		(86,777,591)	(79,825,092)	(6,952,499)
8	809.1 Withdrawals of Liquefied Nat. Gas Held for Processing				0
9	809.2 Deliveries of Natural Gas for Processing				0
10	810.0 Gas Used for Compressor Station Fuel-Credit				0
11	811.0 Gas Used for Products Extraction-Credit				0
12	812.0 Gas Used for Other Utility Operations-Credit				0
13	813.0 Other Gas Supply Expenses		55,283,600	60,314,110	(5,030,510)
	Total Gas Supply Operation Expenses		291,187,233	284,820,541	6,366,692
14	**Natural Gas Storage, Terminating & Processing Exp.**				
15	**Underground Storage Expenses**				
16	814.0 Operation Supervision and Engineering				0
17	815.0 Maps and Records				0
18	816.0 Wells Expenses				0
19	817.0 Lines Expenses				0
20	818.0 Compressor Station Expenses				0
21	819.0 Compressor Station Fuel and Power				0
22	820.0 Measuring and Regulating Station Expenses				0
23	821.0 Purification Expenses				0
24	822.0 Exploration and Development				0
25	823.0 Gas Losses				0
26	824.0 Other Expenses				0
27	825.0 Storage Well Royalties				0
28	826.0 Rents				0
	Total Underground Storage Expenses		0	0	0
29	**Maintenance**				
30	830.0 Maintenance Supervision and Engineering				0
31	831.0 Maintenance of Structures and Improvements				0
32	832.0 Maintenance of Reservoirs and Wells				0
33	833.0 Maintenance of Lines				0
34	834.0 Maintenance of Compressor Station Equipment				0
35	835.0 Maintenance of Measuring & Regulating Station Equip.				0
36	836.0 Maintenance of Purification Equipment				0
37	837.0 Maintenance of Other Equipment				0
	Total Maintenance Expenses		0	0	0
38	**Other Storage Expenses**				0
39	**Operation**				
40	840.0 Operating Supervision and Engineering				0
41	841.0 Operation Labor and Expenses				0
42	842.0 Rents				0
43	842.1 Fuel				0
44	842.2 Power				0
45	842.3 Gas Losses				0
	Total Operation Expenses		0	0	0
46	**Maintenance**				
47	843.1 Maintenance Supervision and Engineering				0
48	843.2 Maintenance of Structures and Improvements				0
49	843.3 Maintenance of Gas Holders				0
50	843.4 Maintenance of Purification Equipment				0
51	843.5 Maintenance of Liquefaction Equipment				0
52	843.6 Maintenance of Vaporizing Equipment				0
53	843.7 Maintenance of Compressor Equipment				0
54	843.8 Maintenance of Measuring and Regulatory Equipment				0
55	843.9 Maintenance of Other Equipment				0
	Total Maintenance Expenses		0	0	0

405. OPERATION AND MAINTENANCE EXPENSES (Continued) - PENNSYLVANIA DIVISION

Balances at Beginning of Year must be consistent with balances at end of previous year

Line No.	Account Number and Title (a)		Schedule Page No. (b)	Balance Current Year (c)	Balance Previous Year (d)	Increase/ Decrease (e)
1						
2		**LIQUEFIED NATURAL GAS TERMINATING AND**				
3		**PROCESSING EXPENSES**		XXX	XXX	XXX
4		**Operation**				
5	844.1	Operation Supervision and Engineering				0
6	844.2	LNG Processing Terminal Labor and Expenses				0
7	844.3	Liquefaction Processing Labor and Expenses				0
8	844.4	LNG Transportation Labor and Expenses				0
9	844.5	Measuring and Regulating Labor and Expenses				0
10	844.6	Compressor Station Labor and Expenses				0
11	844.7	Communication System Expenses				0
12	844.8	System Control and Load Dispatching				0
13	845.1	Fuel				0
14	845.2	Power				0
15	845.3	Rents				0
16	845.4	Demurrage Charges				0
17	845.5	Warfare Receipts-Credit				0
18	845.6	Processing Liquefied or Vaporized Gas by Others				0
19	846.1	Gas Losses				0
20	846.2	Other Expenses				0
		Total Liq. N.G. Term & Proc. Operation Expenses		0	0	0
21		**Maintenance**				
22	847.1	Maintenance Supervision and Engineering				0
23	847.2	Maintenance of Structures and Improvements				0
24	847.3	Maintenance of LNG Processing Terminal Equipment				0
25	847.4	Maintenance of LNG Transportation Equipment				0
26	847.5	Maintenance of Measuring and Regulating Equipment				0
27	847.6	Maintenance of Compressor Station Equipment				0
28	847.7	Maintenance of Communication Equipment				0
29	847.8	Maintenance of Other Equipment				0
		Total Liq. N.G. Term. Proc. Maintenance Expenses		0	0	0
30		**TRANSMISSION EXPENSES**		XXX	XXX	XXX
31		**Operation**				
32	850.0	Operating Supervision and Engineering				0
33	851.0	System Control and Load Dispatching				0
34	852.0	Communication System Expenses				0
35	853.0	Compressor Station Labor and Expenses				0
36	854.0	Gas for Compressor Station Fuel				0
37	855.0	Other Fuel and Power for Compressor Stations				0
38	856.0	Mains Expenses				0
39	857.0	Measuring and Regulating Station Expenses				0
40	858.0	Transmission and Compression of gas by Others				0
41	859.0	Other Expenses				0
42	860.0	Rents				0
		Total Transmission Operation Expenses		0	0	0
43		**Maintenance**				
44	861.0	Maintenance Supervision and Engineering				0
45	862.0	Maintenance of Structures and Improvements				0
46	863.0	Maintenance of Mains				0
47	864.0	Maintenance of Compressor Station Equipment				0
48	865.0	Maintenance of Measuring and Regulating Station Equip.				0
49	866.0	Maintenance of Communication Equipment				0
50	867.0	Maintenance of Other Equipment				0
51		**Total Transmission Maintenance Expenses**		0	0	0
52		**DISTRIBUTION EXPENSES**		XXX	XXX	XXX
53		**Operation**				
54	870.0	Operation Supervision and Engineering		1,270,634	1,086,404	184,230
55	871.0	Distribution Load Dispatching		109,598	372,882	(263,284)
56	872.0	Compressor Station Labor and Expenses				0
57	873.0	Compressor Station Fuel and Power (Major Only)		(66)	670	(736)
58	874.0	Mains and Services Expenses		5,430,587	4,685,227	745,360
59	875.0	Measuring and Regulating Station Expenses-General		98,543	116,472	(17,929)

405. OPERATION AND MAINTENANCE EXPENSES (Continued) - PENNSYLVANIA DIVISION

Balances at Beginning of Year must be consistent with balances at end of previous year

Line No.	Account Number and Title (a)	Schedule Page No. (b)	Balance Current Year (c)	Balance Previous Year (d)	Increase/ Decrease (e)
1	876.0 Measuring and Regulating Station Expenses-Industrial		114	1,293	(1,179)
2	877.0 Measuring and Regulating Station Expenses-City Gate				0
3	878.0 Meter and House Regulator Expenses		5,911,479	5,542,608	368,871
4	879.0 Customer Installations Expenses		61,892	38,381	23,511
5	880.0 Other Expenses		1,288,739	1,162,843	125,896
6	881.0 Rents		601,663	676,463	(74,800)
7	**Total Distribution Operation Expenses**		14,773,183	13,683,243	1,089,940
7	**Maintenance**				
8	885.0 Maintenance Supervision and Engineering		859,352	779,311	80,041
9	886.0 Maintenance of Structures and Improvements		500,985	336,665	164,320
10	887.0 Maintenance of Mains		5,389,511	5,739,931	(350,420)
11	888.0 Maintenance of Compressor Station Equipment				0
12	889.0 Maintenance of Measuring & Reg. Station Equip.-Genl.		973,651	1,243,304	(269,653)
13	890.0 Maintenance of Measuring & Reg. Station Equip.-Indtrl.				0
14	891.0 Maintenance of Measuring & Reg. Station Equip.-City G		10,085	2,731	7,354
15	892.0 Maintenance of Services		643,444	505,789	137,655
16	893.0 Maintenance of Meters & House Regulators		105,975	101,030	4,945
17	894.0 Maintenance of Other Equipment		65,961	57,191	8,770
	Total Maintenance Expenses		8,548,964	8,765,952	(216,988)
18	CUSTOMER ACCOUNTS EXPENSES		XXX	XXX	XXX
19	**Operations**				
20	901.0 Supervision		225,221	195,339	29,882
21	902.0 Meter Reading Expenses		586,933	679,565	(92,632)
22	903.0 Customer Records & Collection Expenses		9,500,849	9,297,537	203,312
23	904.0 Uncollectable Accounts		8,559,290	6,182,394	2,376,896
24	905.0 Miscellaneous Customer Accounts Expenses		405	51	354
	Total Customer Account Operations Expenses		18,872,698	16,354,886	2,517,812
25	**CUSTOMER SERVICE & INFORM. EXPENSES**		XXX	XXX	XXX
26	**Operations**				
27	907.0 Supervision				0
28	908.0 Customer Assistance Expenses		446,984	588,310	(141,326)
29	909.0 Informational & Instructional Advertising Expenses				0
30	910.0 Miscellaneous Customer Service & Informational Exp.		635,700	635,700	0
	Total Cust. Service & Inform. Operations Expenses		1,082,684	1,224,010	(141,326)
31	SALES EXPENSES		XXX	XXX	XXX
32	**Operation**				
33	911.0 Supervision		60,028	56,356	3,672
34	912.0 Demonstrating and Selling Expenses		755,844	808,992	(53,148)
35	913.0 Advertising Expenses		24,121	35,845	(11,724)
36	914.0 (Reserved)				0
37	915.0 (Reserved)				0
38	916.0 Miscellaneous Sales Expenses				0
	Total Operation Sales Expenses		839,993	901,193	(61,200)
39	**ADMINISTRATIVE AND GENERAL EXPENSES**		XXX	XXX	XXX
40	**Operation**				
41	920.0 Administrative and General Salaries		14,715,411	11,992,369	2,723,042
42	921.0 Office Supplies and Expenses		9,121,024	4,945,524	4,175,500
43	922.0 Administrative Expenses Transferred-Credit		(15,438,480)	(19,177,799)	3,739,319
44	923.0 Outside Service Employed		28,039,675	16,361,003	11,678,672
45	924.0 Property Insurance		(2,597,070)	(88,815)	(2,508,255)
46	925.0 Injuries and Damages		4,197,695	3,083,764	1,113,931
47	926.0 Employee Pensions and Benefits		16,575,235	15,017,668	1,557,567
48	927.0 Franchise Requirements				0
49	928.0 Regulatory Commission Expenses		18,887	25,699	(6,812)
50	929.0 Duplicate Charges-Credit				0
51	930.1 General Advertising Expenses		54,602	63,859	(9,257)
52	930.2 Miscellaneous General Expenses		2,980,851	2,309,883	670,968
53	931.0 Rents		5,023,090	3,887,469	1,135,621
54	**Total Adminstrative and General Operation Expeness**		62,690,920	38,420,624	24,270,296
54	**Maintenance**				
55	932.0 Maintenance of General Plant		2,499,569	2,380,057	119,512
57	**Total Gas Operation and Maintenance Expenses**		65,190,489	40,800,681	24,389,808
58					
59	**Total Gas Operation Expenses**		389,448,285	355,408,476	34,039,809
60	**Total Maintenance Expenses**		11,048,733	11,146,009	(97,276)

408. TAXES OTHER THAN INCOME TAXES, UTILITY OPERATING INCOME (Account 408.1)

This schedule shall include a breakdown of the various tax expenses that constitute the ending balance in Account No. 408.1-Taxes Other Than Income Taxes Utility Operating Income. The information should also reflect related entries to Account No. 165-Prepayments; and Account No. 236-Taxes Accrued.

Line No.	Type of Tax (a)	Account 165 Prepayments (b)	Account 236 Taxes Accrued (c)	Account 408.1 Taxes Other Than Income (d)
1	**Social Security**			
2	**Federal Unemployment**			
3	**Pennsylvania Unemployment**			
4	**Utility Regulatory Assessment**		1,088,293	1,088,293
5	**Local Property / Real Estate Taxes**		55,523	55,523
6	***Public Utility Realty Tax***		1,077,265	1,077,265
7	**State Capital Stock Tax**		(725,815)	(725,815)
8	**Other Taxes (specify)**			
9	**Miscellaneous**		12,251	12,251
10	**Business Privilege & Occupation Tax**		708,202	708,202
11	**TOTAL**	0	2,215,719	2,215,719

409. INCOME TAXES, UTILITY OPERATING INCOME (Account 409.1)

This schedule shall include a breakdown of the various tax expenses that constitute the ending balance in Account No. 409.1-Income Taxes, Ut. Operating Income. The information should also reflect related entries to Account No. 165-Prepayments; Account No. 190-Accumulated Deferred Income Taxes and Account No. 236-Accrued Utility Operating Income.

Line No.	Type of Tax (a)	Account 165 Prepayments (b)	Account 190 Accumulated Def. Income Taxes (c)	Account 236 Accrued Taxes (d)	Account 409.1 Income Taxes Opr Income (e)
1	**Federal Income Taxes**			2,574,000	2,574,000
2	**State Income Taxes**			595,415	595,415
3	**Local Income Taxes**				
4					
5					
6					
7					
8	**Other Taxes (specify)**				
9					
10					
11	**TOTAL**	0	0	3,169,415	3,169,415

410. CALCULATION OF FEDERAL INCOME TAXES - CURRENT PERIOD

1. The totals as reported on this schedule should conform with amounts reported on corresponding Schedules.

Line No.	Item (a)	Total (b)	Current (c)	Deferred Property Related (d)	Deferred Other (e)
1	Operating Revenues	458,908,726	458,908,726		
2	Operating Expenses	440,659,994	440,659,994		
3	Operating Taxes (Non-Income)	2,215,719	2,215,719		
4	Interest & Other Expense	123,994,536	123,994,536		
5	Pre-Tax Operating Income				
	Total Line 1 Minus Lines 2-3-4	(107,961,523)	(107,961,523)	-	-
6	Other Income (Expense)	(112,048,830)	(112,048,830)		
7	Pre Tax Book Income	-			
	Total Lines 5+6	(220,010,353)	(220,010,353)	-	-
8	Permanent and Flow-Through Differ.	14,266,061	14,266,061		
9	Temporary Differences	(19,872,216)	16,155,669	(36,027,885)	
10	State Only Differences	-			
11	Subtotal	(225,616,508)	(189,588,623)	(36,027,885)	-
12	State Tax at Current Rate	(5,417,697)	(2,274,218)	(3,143,479)	
13	Adjustments to State Tax	-			
14	Adjustments for St. Tax Rate Changes	-			
15	State Tax Accrual	-			
	Total Lines 12+13+14	(5,417,697)	(2,274,218)	(3,143,479)	-
16	Federal Taxable Income	-			
	Total Line 11 Minus Lines 10-12-13	(220,198,811)	(187,314,405)	(32,884,406)	-
17	Federal Tax at Current Rate	(77,069,584)	(65,560,042)	(11,509,542)	
18	ITC Authorization	(426,294)	(426,294)		
19	Adjustment for Fed. Tax Rate Change	-			
20	R & D Credits	(610,854)	(610,854)		
21	IRS Audit Settlement	-			
22	Tax Rate Change on Extraord. Activity	-			
23	Other	-			
24	Federal Tax Accrual	-			
	Total Lines 17 through 23	(78,106,732)	(66,597,190)	(11,509,542)	-

411. PROVISION FOR DEFERRED INCOME TAXES, UTILITY OPERATING INCOME (Account 410.1)

This schedule shall include a breakdown of the various tax expenses that constitute the ending balance in Account No. 410.1-Provision for Deferred Income Taxes, Utility Operating Income. The information should also reflect related entries to Account No. 165-Prepayments; Account No. 190-Accumulated Deferred Income Taxes & Account No. 236-Accrued Taxes, Utility Operating Income.

Line No.	DEBITS Type of Tax (a)	Account 165 Prepayments (b)	Account 190 Accumulated Deferred Income Taxes (c)	Account 236 Accrued Taxes (d)	Account 410.1 Provision for Deferred Income Taxes (e)
1	Federal				(675,000)
2	State				3,134,979
3	Other				
4					
5					
6					
7	Total	0	0	0	2,459,979

412. PROVISION FOR DEFERRED INCOME TAXES UTILITY OPR. INCOME, CREDIT (Account 411.1)

This schedule shall include a breakdown of the various tax expenses that constitute the ending balance in Account No. 411.1-Provision for Deferred Income Taxes-Credit. The information should also reflect related entries to Account No. 165-Prepayments; Account No. 190-Accumulated Deferred Income Taxes & Account No. 236-Accrued Taxes.

Line No.	DEBITS Type of Tax (a)	Account 165 Prepayments (b)	Account 190 Accumulated Deferred Income Taxes (c)	Account 236 Accrued Taxes (d)	Account 411.1 Provision for Deferred Income Taxes (e)
1	Federal				
2	State				
3	Other				
4					
5					
6					
7	Total	0	0	0	0

Utility Operating Income (Account 410.1) column e: Account 283 and intercompany account receivable.

500. GAS PURCHASED

1. Report below the information called for concerning gas purchased for resale during year.
2. *Purchases from independent natural gas producers shall be grouped on one line and columns (a), (d), (g) and (h) only shall be reported with respect to such purchase.*
3. The quantities reported should be those shown by the bills rendered by the vendor. Indicate MCF, CCF or Therms
4. Report separately non-interruptible and interruptible purchases from the same company. Designate purchases from affiliated interest by an asterisk following the name in column (d).

Line No.	Purchased From (a)	Point of Delivery (b)	B.T.U. Per Cu. Ft. (c)	Mcf (d)	Commodity Charges (e)	Other Charges (f)	Total (g)	Cost Per Unit (h)
1	801 Field Purchases							
2	Independent Group Purchases	Various Locations		14,418,967	105,127,584		105,127,584	729.09
3							0	
4							0	
5							0	
6	803 Pipeline Purchase						0	
7	Independent Group Purchases	Various Locations		16,660,627	125,774,368		125,774,368	754.92
8	Equitable Energy *	Various Locations		732,250	4,926,295		4,926,295	672.76
9							0	
10	805.1 Purchase Gas Cost Adjustment				19,800,072		19,800,072	
Totals			0	31,811,844	255,628,319	0	255,628,319	803.56

501. SALES FOR RESALE

1. Report below the information called for concerning gas sold during year to other gas utilities or to public authorities for resale.
2. The quantities shown should be those shown by the bills rendered to the purchasers. Indicate MCF, CCF or Therms.
3. Report separately non-interruptible and interruptible sales to the same company. Designate sales to affiliated interest by an asterisk following the name in column (a)
4. Designate any sales which are other than firm sales.

Line No.	Sold To (a)	Point of Delivery (b)	BTU Per Cu. Ft. (c)	MCF CCF or Therms (d)	Commodity Charges (e)	Other Charges (f)	Total (g)	Revenue Per Unit (h)
1	**N/A**							
2								
3								
4								
5								
6								
7								
8								
9								
10								
Totals			0	0	0	0	0	

505. GAS ACCOUNT-NATURAL GAS

1 The purpose of this schedule is to account for the quantity of natural gas received and delivered by the respondent adjusted for any differences in pressure bases used in measuring MCF of natural gas received and delivered.

2 If the respondent operates two or more systems which are not interconnected, separate schedules should be submitted. Insert pages should be used for this purpose.

No.	Item (a)	MCF as Reported (b)
1	**GAS RECEIVED**	
2	Natural Gas Produced	178,968
3	L.P.G. Gas Produced and Mixed with Natural Gas	
4	Manufactured Gas Produced and Mixed with Natural Gas	
5	Purchased Gas	31,811,854
6	Gas of Others Received for Transportation	24,594,805
7	Receipts of Respondent's Gas Transported or Compressed by Others	
8	Exchange Gas Received	
9	Gas Received from Underground Storage	10,876,232
10	Other Receipts	
11		
12		
13		
14	**Total Receipts:**	67,461,859
15	**GAS DELIVERED**	
16	Natural Gas Sales:	
17	Local Distribution by Respondent	24,900,740
18	Main Line Industrial Sales	
19	Sales for Resale	
20	Interdepartmental Sales	
21		
21		
22	**Total Sales**	24,900,740
23	Deliveries of Gas Transported or Compressed for Others	24,564,606
24	Deliveries of Respondent's Gas for Trans. Or Compressed by Others	
25	Exchange Gas Delivered	
26	Natural Gas used by Respondent	14,473
27	Natural Gas Delivered to Storage	11,697,593
28	Natural Gas for Franchise Requirements	
29	Other Deliveries: Specify	
30	**Total Deliveries**	61,177,412
31	**UNACCOUNTED FOR**	
32	Production System Losses	
33	Storage Losses	
34	Transmission System Losses	
35	Distribution System Losses	5,123,053
36	Other Losses: Calculated Effect of Temperature and Pressure	
37	Variations on Outside Metering	1,161,394
38	**Total Unaccounted For**	6,284,447
38	**Total Deliveries and Unaccounted For**	67,461,859

510. UNDERGROUND GAS STORAGE - TOTAL COMPANY

1. Report particulars for each underground gas storage project.
2. Give particulars of any gas stored for the benefit of another company under a gas exchange arrangement or on a basis of purchase and resale to another company. Designate if other company is an associated company.
3. Pressure base of gas volumes reported below.

Line No.	Month (a)	Total (b)	Project Location (c)	Dominion Transmission (d)	Equitrans, L.P. (e)
1	**Storage Operations**	MCF	MCF	MCF	MCF
2	**Gas Delivered to Storage**				
1	January	219,340		0	219,340
2	February	0		0	0
3	March	0		0	0
4	April	129,098		0	129,098
5	May	1,074,861		671,009	403,852
6	June	1,804,857		203,668	1,601,189
7	July	2,383,270		488,090	1,895,180
8	August	1,622,202		464,584	1,157,618
9	September	2,046,657		417,943	1,628,714
10	October	1,901,780		424,013	1,477,767
11	November	279,679		82,730	196,949
12	December	0		0	0
13	Totals	11,461,744	0	2,752,037	8,709,707
14	**Gas Withdrawn From Storage**				
15	January	2,898,945		553,906	2,345,039
16	February	3,106,136		292,453	2,813,683
17	March	1,783,312		703,828	1,079,484
18	April	1,302,845		0	1,302,84[illegible]
19	May	45,316		0	45,316
20	June	0		0	0
21	July	0		0	0
22	August	0		0	0
23	September	0		0	0
24	October	402,170		402,170	0
25	November	541,312		534,368	6,944
26	December	560,347		552,180	8,167
27	Totals	10,640,383	0	3,038,905	7,601,478
28	Stored Gas End of Year-MCF	12,686,081			
29	Est. Native Gas in Storage Reservoir-MCF	Footnote A			
30	Total Gas in Reservoir-MCF (Lines 28 plus 29)	Footnote A			
31	Storage Capacity (Escl. Native Gas)-MCF	Footnote A			
32	Reservoir Pressure at which Storage Cap.-Computed	Footnote A			
33	Number of Storage Wells in Project	Footnote A			
34	Number of Acres of Storage Area	Footnote A			
35	Maximum Day's Withdrawal from Storage	Footnote A			
36	Date of Maximum Day's Withdrawal	Footnote A			
37	Year Storage Operations Commenced	Footnote A			

A. Gas was stored by Dominion Transmission (Column d) and Equitrans, L.P. (Column e), an affiliate, under a gas storage and transportion agreement.

510. UNDERGROUND GAS STORAGE - PA OPERATIONS

1. Report particulars for each underground gas storage project.
2. Give particulars of any gas stored for the benefit of another company under a gas exchange arrangement or on a basis of purchase and resale to another company. Designate if other company is an associated company.
3. Pressure base of gas volumes reported below.

Line No.	Month (a)	Total (b)	Project Location (c)	Dominion Transmission (d)	Equitrans (e)
1	**Storage Operations**	MCF	MCF	MCF	MCF
2	**Gas Delivered to Storage**				
1	January	219,340		0	219,340
2	February	0		0	0
3	March	0		0	0
4	April	129,098		0	129,098
5	May	987,574		671,009	316,565
6	June	1,717,357		203,668	1,513,689
7	July	2,295,780		488,090	1,807,690
8	August	1,534,713		464,584	1,070,129
9	September	1,928,213		417,943	1,510,270
10	October	1,810,735		424,013	1,386,722
11	November	279,679		82,730	196,949
12	December	0		0	0
13	Totals	10,902,489	0	2,752,037	8,150,452
14	**Gas Withdrawn From Storage**				
15	January	2,827,849		553,906	2,273,943
16	February	2,855,899		292,453	2,563,446
17	March	1,647,229		703,828	943,401
18	April	1,302,845		0	1,302,845
19	May	0		0	0
20	June	0		0	0
21	July	0		0	0
22	August	0		0	0
23	September	0		0	0
24	October	402,170		402,170	0
25	November	534,368		534,368	0
26	December	552,180		552,180	0
27	Totals	10,122,540	0	3,038,905	7,083,635
28	Stored Gas End of Year-MCF	12,005,931			
29	Est. Native Gas in Storage Reservoir-MCF	Footnote A			
30	Total Gas in Reservoir-MCF (Lines 28 plus 29)	Footnote A			
31	Storage Capacity (Escl. Native Gas)-MCF	Footnote A			
32	Reservoir Pressure at which Storage Cap.-Computed	Footnote A			
33	Number of Storage Wells in Project	Footnote A			
34	Number of Acres of Storage Area	Footnote A			
35	Maximum Day's Withdrawal from Storage	Footnote A			
36	Date of Maximum Day's Withdrawal	Footnote A			
37	Year Storage Operations Commenced	Footnote A			

A. Gas was stored by Dominion Transmission (Column d) and Equitrans, L.P. (Column e), an affiliate, under a gas storage and transportion agreement.

511. MANUFACTURED GAS PRODUCTION PLANT

1 Kind or Type of Plant________ Location________
2 Maximum Daily Capacity of Plant________ MCF________
3 Maximum Daily MCF of Gas Produced During Year________ Date________
4 Maximum Daily MCF of Gas Produced During Life of Plant________ Date________
5 Number of Days Plant was Commercially Operated During Year________
6 Date Plant was last Commercially Operated________
7 MCF of Gas Produced During the Year________
8 Average BTU Content of Gas Produced________
0

NONE

512. LIQUEFIED PETROLEUM GAS OPERATIONS

1 Location of Plant________
2 MCF of Gas Produced During Year________
3 Gallons of L.P.G. Used During Year________
4 Function of Plant________
5 Storage Capacity for L.P.G. (Gallons)________

NONE

515. GAS AND OIL WELLS

Line No.			
1	**GAS WELLS**		
2	Productive Wells at Beginning of Year	54	
3	Productive Wells Drilled During the Year		
4	Oil Wells Restored to Productive Basis During Year		
5	Wells Purchased During the Year		
6	Wells Abandoned During the Year		
7	Wells Sold During the Year		
8			
9	**Productive Wells at End of Year**	54	
10	Number of Wells Drilled Deeper During the Year	NONE	
11	Dry Holes Drilled During the Year	NONE	
12			
13	**NATURAL GAS ACREAGE**	**Operative**	**Non Operative**
14	Number of Acres Owned at End of Year	NONE	NONE
15	Number of Acres Leased at End of Year		
16			
17	**OIL WELLS**		
18	Productive Wells at Beginning of Year	NONE	
19	Productive Wells Drilled During the Year		
20	Wells Abandoned and Sold During the Year		
21			
22	**Productive Wells at End of Year**		

516. GAS LINES, METERS AND SERVICES

Line No.	Size of Pipe Inches	Field Lines M. Ft.	Prod. Ext. Lines M. Ft.	Storage Lines M. Ft.	Distr. Mains M. Ft.	Transmission M. Ft.
28	01"				394	
29	02"	4			3,588	
30	03"	26			4,757	
31	04"	16			4,169	2
32	05"	2			95	
33	06"	23			3,179	
34	08"	1			1,458	1
35	10"	10			428	
36	12"				917	99
37	14"				1	
38	16"				436	13
39	20"				390	38
40	24"				195	
41	30"				87	1
42	36"				25	

Meters in Service at End of Year 259,757 Services at End of Year, Company Owned

Meters in Stock or Shop at End of Year 500 Services at End of Year, Customer Owned

517. CUSTOMER GAS METERS

Line No.	(a)	Size (b)	Number of Meters: First of Year (c)	Added During Year (d)	Removed Or Disconnected During Year (e)	End of Year (e)
1	**In residential use**					0
2	N/A					0
3						0
4						0
5						0
6						0
7						0
8						0
9						0
10	**Total in residential use**		0	0	0	0
11	**In commercial use**					0
12	N/A					0
13						0
14						0
15						0
16						0
17						0
18						0
19						0
20	**Total in commercial use**		0	0	0	0
21	**In industrial use**					0
22	N/A					0
23						0
24						0
25						[illegible]
26						[illegible]
27						0
28						0
29						0
30	**Total in industrial use**		0	0	0	0
31	**In public (municipal or government) use**					0
32	N/A					0
33						0
34						0
35						0
36						0
37						0
38						0
39						0
40	**Total in public (municipal or government) use**		0	0	0	0
41	**Total in use**		0	0	0	0
42	**In Stock**					0
43	N/A					0
44						0
45						0
46						0
47						0
48						0
49						0
50	**Total in stock**		0	0	0	0
51	**Total all meters**		0	0	0	0

METERS TESTED BY SIZES

	(a)	(a)	1/2 (a)	5/8 (b)	3/4 (c)	1 (d)	(e)	(f)	(g)	Total (h)
52	Numbe	Number tested during the year								

600. CLASSIFICATION OF CUSTOMERS, UNITS SOLD AND OPERATING REVENUES BY TARIFF SCHEDULE

1. Report below the details called for concerning Customers, MCF, CCF or Therms (Indicate Unit Used) Sold, and Opr. Revenues by Tariff Schedule.
2. Customers should be reported on the basis of number of meters, plus number of unmetered accounts, except that where separate meter readings are added for billing purposes, one customer shall be counted for each group of meters so added.
3. Quantities of gas sold to flat-rate customers shown in column (e), should explain in a footnote the basis upon which quantities were determined.
4. Respondent should use additional sheets if necessary.

Line No.	Account (a)	Number of Customers: Beginning of Year (b)	End of Year (c)	Average During Year (d)	Sales During Year: Total MCF (e)	Total Operating Revenue (f)	MCF Per Customer (g)	Revenues: Per Customer (h)	Per Unit (i)
2	**Metered Sales by Tariff Schedule**								
3	**Residential**								
4	PA Retail - Billed	210,578	211,710	209,685	18,713,883	298,919,585	88	$ 1,411.93	$ 15.97
5	- Unbilled				273,638	7,495,147			
6	WV Retail - Billed	12,370	12,305	12,234	896,875	13,233,738	73	$ 1,075.48	$ 14.76
7	- Unbilled				4,130	(81,552)			
8	KY Retail - Billed	3,535	3,452	3,478	215,045	3,025,196	62	$ 876.36	$ 14.07
9									
10	Transportation - Billed	28,945	28,888	28,769	3,360,936	28,567,285	116	$ 988.90	$ 8.50
11	- Unbilled				29,575	592,196			
12									
13	**Total Residential Metered Sales**	255,428	256,355	254,166	23,494,082	351,751,595			
14	**Commercial**								
15	PA Retail - Billed	14,205	14,333	14,194	4,316,022	62,535,666	301	$ 4,363.05	$ 14.49
16	- Unbilled				70,003	1,538,263			
17	WV Retail - Billed	969	976	963	321,128	4,367,127	329	$ 4,474.52	$ 13.60
18	- Unbilled				329	(10,208)			
19	KY Retail - Billed	3	3	3	1,378	18,146	459	$ 6,048.67	$ 13.17
20									
21	Transportation - Billed	3,193	3,069	3,138	8,133,355	23,332,279	2,650	$ 7,602.57	$ 2.87
22									
23									
24	**Total Commercial Metered Sales**	18,370	18,381	18,298	12,842,215	91,781,273			
25	**Industrial**								
26	PA Retail - Billed	39	43	38	60,205	843,140	1,400	$19,607.91	$ 14.00
27	- Unbilled				(14)	231			
28	WV Retail - Billed	9	9	9	28,118	376,189	3,124	$41,798.78	$ 13.38
29	- Unbilled								
30	Transportation - Billed	117	117	119	13,040,740	9,992,093	111,459	$85,402.50	$ 0.77
31									
32	**Total Industrial Metered Sales**	165	169	166	13,129,049	11,211,653			
33	Public								
34	Interdepartmental								
35	Other								
36	**Total Metered Sales**	273,963	274,905	272,630	49,465,346	454,744,521			
37	**Unmetered Sales-All Categories**								
38	Other								
39	**Total Unmetered Sales**	-	-	-	-				
40	**Total Sales of Gas**	273,963	274,905	272,630	49,465,346	454,744,521			
41	Other Gas Revenues:								
42	Rent from Gas Property					1,588			
43	Interdepartmental Rents								
44	Operating Revenue Other Than Gas Sales					2,474,441			
45	Allowance to Customers								
46	Customers Forfeited Discounts & Penalties					1,632,434			
47	Miscellaneous Gas Revenues					55,742			
48	**Total Other Gas Revenues**	-	-	-	-	4,164,205			
49	**Total Gas Operating Revenues**	273,963	274,905	272,630	49,465,346	458,908,726			

605. NUMBER OF EMPLOYEES

Report the requested information concerning the number of employees on respondent's payrolls at end of year.

Line No.	Classification According to Occupation (a)	Number at Year End (b)
1	Total Officials and Senior Manager Employees	18
2	Total Professional and Semiprofessional Employees	54
3	Total Business Office, Sales And Professional Employees	113
4	Total Clerical Employees	38
5	Total Operators	
6	Total Construction, Installation and Maintenance Employees	192
7	Total Building, Supplies and Motor Vehicle Employees	
8	All Other Employees Not Elsewhere Classified	
9	Total All Employees	415

Line 1 includes Officers and Department Heads
Line 2 includes Managers and Supervisors
Line 3 includes Technical, Professional and Administrative Employees

610. Territory Served - PENNSYLVANIA

Report below the number of customers at the end of the year in respondent's distribution system in which service is furnished setting forth by counties the number of customers and the average number of customers during the year. Respondent should place an X in the box in column (b) if that county is served and supply related customer information in columns (d) and (e).

County Code (a)	Serves County (b)	Name of Pennsylvania County (c)	Number Of Customers At End Of Year (d)	Average Number Of Customers During Year (e)
01		Adams		
02	X	Allegheny	227,112	226,754
03	X	Armstrong	2,801	2,810
04		Beaver		
05		Bedford		
06		Berks		
07		Blair		
08		Bradford		
09		Bucks		
10	X	Butler	1,842	1,798
11		Cambria		
12		Cameron		
13		Carbon		
14		Centre		
15		Chester		
16	X	Clarion	233	235
17		Clearfield		
18		Clinton		
19		Columbia		
20		Crawford		
21		Cumberland		
22		Dauphin		
23		Delaware		
24		Elk		
25		Erie		
26	X	Fayette	26	26
27		Forest		
28		Franklin		
29		Fulton		
30	X	Greene	6,350	6,356
31		Huntingdon		
32	X	Indiana	77	76
33	X	Jefferson	46	46
34		Juniata		
35		Lackawanna		
36		Lancaster		
37		Lawrence		
38		Lebanon		
39		Lehigh		
40		Luzerne		
41		Lycoming		
42		McKean		
43		Mercer		
44		Mifflin		
45		Monroe		
46		Montgomery		
47		Montour		
48		Northampton		
49		Northumberland		
50		Perry		
51		Philadelphia		
52		Pike		
53		Potter		
54		Schuylkill		
55		Snyder		
56		Somerset		
57		Sullivan		
58		Susquehanna		
59		Tioga		
60		Union		
61		Venango		
62		Warren		
63	X	Washington	12,882	12,805
64		Wayne		
65	X	Westmoreland	6,767	6,726
66		Wyoming		
67		York		
Totals			258,136	257,630
Total Population of Territory Served (Estimated)			2,409,816	2,416,686

610. Territory Served - WEST VIRGINIA

Report below the number of customers at the end of the year in respondent's distribution system in which service is furnished setting forth by counties the number of customers and the average number of customers during the year. Respondent should place an X in the box in column (b) if that county is served and supply related customer information in columns (d) and (e).

County Code (a)	Serves County (b)	Name of West Virginia County (c)	Number Of Customers At End Of Year (d)	Average Number Of Customers During Year (e)
01		Barbour		
02		Berkeley		
03		Boone		
04	X	Braxton	248	250
05		Brooke		
06		Cabell		
07		Calhoun		
08	X	Clay	98	98
09	X	Doddridge	860	869
10		Fayette		
11	X	Gilmer	458	458
12		Grant		
13		Geenbrier		
14		Hampshire		
15		Hancock		
16		Hardy		
17	X	Harrison	912	914
18		Jackson		
19		Jefferson		
20		Kanawha		
21	X	Lewis	437	436
22		Lincoln		
23		Logan		
24		McDowell		
25	X	Marion	5,426	5,424
26	X	Marshall	1	1
27		Mason		
28		Mercer		
29		Mineral		
30		Mingo		
31	X	Monongalia	551	559
32		Monroe		
33		Morgan		
34		Nicholas		
35		Ohio		
36		Pendleton		
37		Pleasants		
38		Pocahontas		
39		Preston		
40		Putnam		
41		Raleigh		
42		Randolph		
43	X	Ritchie	202	205
44		Roane		
45		Summers		
46	X	Taylor	3,250	3,258
47		Tucker		
48	X	Tyler	67	68
49	X	Upshur	175	176
50		Wayne		
51		Webster		
52	X	Wetzel	620	623
53		Wirt		
54		Wood		
55		Wyoming		
56				
57				
58				
59				
60				
61				
62				
63				
64				
65				
66				
67				
Totals			13,305	13,335
Total Population of Territory Served (Estimated)			377,284	377,359

610. Territory Served - KENTUCKY

Report below the number of customers at the end of the year in respondent's distribution system in which service is furnished setting forth by counties the number of customers and the average number of customers during the year. Respondent should place an X in the box in column (b) if that county is served and supply related customer information in columns (d) and (e)

County Code (a)	Serves County (b)	Name of Kentucky County (c)	Number Of Customers At End Of Year (d)	Average Number Of Customers During Year (e)
01		Adair		
02		Allen		
03		Anderson		
04		Ballard		
05		Barren		
06		Bath		
07		Bell		
08		Boone		
09		Bourbon		
10		Boyd		
11		Boyle		
12		Bracken		
13		Breathitt		
14		Breckinridge		
15		Bullitt		
16		Butler		
17		Caldwell		
18		Calloway		
19		Campbell		
20		Carlisle		
21		Carroll		
22		Carter		
23		Casey		
24		Christian		
25		Clark		
26		Clay		
27		Clinton		
28		Crittenden		
29		Cumberland		
30		Daviess		
31		Edmonson		
32		Elliott		
33		Estill		
34		Fayette		
35		Fleming		
36	X	Floyd	1,327	1,341
37		Franklin		
38		Fulton		
39		Gallatin		
40		Garrard		
41		Grant		
42		Graves		
43		Grayson		
44		Green		
45		Greenup		
46		Hancock		
47		Hardin		
48		Harlan		
49		Harrison		
50		Hart		
51		Henderson		
52		Henry		
53		Hickman		
54		Hopkins		
55		Jackson		
56		Jefferson		
57		Jessamine		
58	X	Johnson	92	94
59		Kenton		
60	X	Knott	781	789
61		Knox		
62		Larue		
63		Laurel		
64	X	Lawrence	30	29
65		Lee		
66	X	Leslie	13	14
67	X	Letcher	93	94
68		Lewis		
69		Lincoln		
70		Livingston		
71		Logan		
72		Lyon		
73		McCracken		
74		McCreary		
75		McLean		
76		Madison		

610. Territory Served - KENTUCKY

Report below the number of customers at the end of the year in respondent's distribution system in which service is furnished setting forth by counties the number of customers and the average number of customers during the year. Respondent should place an X in the box in column (b) if that county is served and supply related customer information in columns (d) and (e)

County Code (a)	Serves County (b)	Name of Kentucky County (c)	Number Of Customers At End Of Year (d)	Average Number Of Customers During Year (e)
77	X	Magoffin	23	24
78		Marion		
79		Marshall		
80	X	Martin	74	75
81		Mason		
82		Meade		
83		Menifee		
84		Mercer		
85		Metcalfe		
86		Monroe		
87		Montgomery		
88		Morgan		
89		Muhlenberg		
90		Nelson		
91		Nicholas		
92		Ohio		
93		Oldham		
94		Owen		
95		Owsley		
96		Pendleton		
97	X	Perry	170	173
98	X	Pike	850	864
99		Powell		
100		Pulaski		
101		Robertson		
102		Rockcastle		
103		Rowan		
104		Russell		
105		Scott		
106		Shelby		
107		Simpson		
108		Spencer		
109		Taylor		
110		Todd		
111		Trigg		
112		Trimble		
113		Union		
114		Warren		
115		Washington		
116		Wayne		
117		Webster		
118		Whitley		
119		Wolfe		
120		Woodford		
Totals			3,453	3,495
Total Population of Territory Served (Estimated)			258,975	258,705

VERIFICATION

The foregoing report must be verified by the oath of the officer having control of the accounting of the respondent. It shall be verified, also, by the oath of the president or other chief officer of the respondent. The oaths required may be taken before any person authorized to administer an oath by the laws of the State in which the same is taken.

OATH

(To be made by the officer having control of the accounting of the respondent)

State of Pennsylvania

as:

County of Allegheny

Jeffery C. Mitchell makes oath and says that he/she is Vice President & Controller
(Name of affiant) (Official title of affiant)

of Equitable Gas Company, a Division of Equitable Resources, Inc.
(Exact legal title or name of the respondent)

The signed offier has reviewed the report.

Based on the officer's knowledge, the report does not contain any unture statements of a material fact or omit to state a material fact necessary in order to make the statements made, in light of the circumstances under which such statements were made, not misleading.

Based on such officer's knowledge, the financial statements, and other financial information included in the report, fairly present in all material respects the financial condition and results of operations of the issuer as of, and for, the periods presented in the report.

He/she believes that all other statements contained in the said report are true, and that the said report is a correct and complete statement of the business and affairs of the above-named respondent during the period of time from and including January 1, 2007 to and including December 31, 2007.

J C Mitchell
(Signature of affiant)

Subscribed and sworn to and before me, a NOTARY
in and for the State and County above-named, this 29th day of MAY, 2008

My commission expires July 25, 2009 Linda M. Dayak
(Signature of officer authorized to administer oaths)

COMMONWEALTH OF PENNSYLVANIA
Notarial Seal
Linda M. Dayak, Notary Public
City Of Pittsburgh, Allegheny County
My Commission Expires July 25, 2009
Member, Pennsylvania Association of Notaries

SUPPLEMENTAL OATH

(By the president or other chief officer of the respondent)

State of Pennsylvania

as:

County of Allegheny

Randall L. Crawford makes oath and says that he/she is President
(Name of affiant) (Official title of affiant)

of *Equitable Gas Company, a Division of Equitable Resources, Inc.*
(Exact legal title or name of the respondent)

that he has carefully examined the foregoing report; that he believes that all statements of fact contained in the said report are true, and that the said report is a correct and complete statement of the business and affairs of the above named respondent during the period of time from and including January 1, 2007, to and including December 31, 2007

Randall L. Crawford
(Signature of affiant)

Subscribed and sworn to before me, a NOTARY
in and for the State and County above-named, this 29th day of May, 2008

My commission expires July 25, 2009 Linda M. Dayak
(Signature of officer authorized to administer oaths)

COMMONWEALTH OF PENNSYLVANIA
Notarial Seal
Linda M. Dayak, Notary Public
City Of Pittsburgh, Allegheny County
My Commission Expires July 25, 2009
Member, Pennsylvania Association of Notaries

GAS ANNUAL REPORT
OF

EQUITABLE GAS COMPANY, A DIVISION OF EQUITABLE RESOURCES, INC.

Exact legal name of reporting gas company or corporation

(If name was changed during year, show also the previous name and date of change)

225 NORTH SHORE DRIVE, PITTSBURGH, PENNSYLVANIA 15212-5861

(Address of principal business office at end of year)

FOR THE

YEAR ENDED DECEMBER 31, 2006

TO THE

COMMONWEALTH OF PENNSYLVANIA

PUBLIC UTILITY COMMISSION

Name, title, address and telephone number (including the area code), E-Mail Address, and Web Site Address of the person to be contacted concerning this report:

Theresa Z. Bone

Vice President and Controller

225 North Shore Drive, Pittsburgh, Pennsylvania 15212-5861

412-395-3000

www.eqt.com

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GENERAL INSTRUCTIONS

1. The completed original and an electronic (e-mail) copy of this report shall be filed with the Pennsylvania Public Utility Commission, P.O. Box 3265, Harrisburg, Pennsylvania, 17105-3265 on or before the 30th of April following the end of the year to which the report applies.

2. All Natural Gas Distribution Companies subject to the jurisdiction of the Pennsylvania Public Utility Commission, upon which this report is served are required by statute to complete and file this report. The statute further provides that when any such report is defective or believed to be erroneous, the reporting corporation shall be duly notified and given a reasonable time within which to make the necessary amendments or corrections. All data comprising this report shall be submitted in electronic and permanent form.

3. All accounting terms and phrases used in this form are to be interpreted in accordance with the effective applicable Uniform System of Accounts prescribed by the Federal Energy Regulatory Commission Title 18 under "Part 201-Uniform System of Accounts Prescribed for Natural Gas Companies Subject to the Provisions of the Natural Gas Act", (18 CFR Part 201). Whenever the term respondent is used, it shall mean the reporting company.

4. Standard accounting procedures will apply in determining the nature of any entry (e.g., Uncollectibles, a revenue item, is normally a debit entry, and should be entered as a "positive" number unless the reported balance is a credit). Entries of a reverse or contrary character shall be indicated by parenthesis around the number.

5. If the report is made for a period less than the calendar year, the period covered must be clearly stated on the front cover and elsewhere throughout the report where the period covered is shown. When operations cease during the year because of the disposition of property, the balance sheet and supporting schedules should consist of balances and items immediately prior to transfer (for accounting purposes). If the books are not closed as of that date, the data in the report should nevertheless be complete, and the amounts reported should be supported by information set forth in, or as part of, the books of account.

6. All instructions shall be followed and each question shall be answered fully and accurately. Sufficient answers shall appear to show that no question or schedule has been overlooked. The expression "none" or "not applicable" shall be given as the answer to any particular inquiry or schedule where it truly and completely states the fact. Unless otherwise indicated, no information will be accepted which incorporates by reference information from another document or report. Where information called for herein is not given, state fully the reason for its omission.

7. Extra copies of any page will be furnished upon request. If it is necessary or desirable to insert additional statements for the purpose of further explanation of accounts or schedules, they shall be legibly made on paper of durable quality and shall correspond to this form in size of page and width of margin. Additional sheets, ruled either vertically or horizontally, will be furnished on request. Inserts, if any, should be appropriately identified with the schedules to which they relate.

8. If the gas distribution service provider conducts operations both within and outside the Commonwealth of Pennsylvania, data should be reported so that there will be shown the number of subscribers within this state, and (separately by accounts) the operating revenues from sources within this state, and the plant investment as of the end of the year within the state.

9. Whenever schedules call for comparison of figures of a previous year, the figures reported must be based upon those shown by the annual report of the previous year or an appropriate explanation given why different figures were used.

10. Throughout the report, money items shall be shown in units of dollars adjusted to accord with footings. Omitting cents does not apply, however, to items in which cents are of significance, as for instance, in averages and in unit costs.

11. If this report is not completed electronically, the name of the respondent and the year to which the report relates shall be inserted on the top of each page.

GENERAL INFORMATION

Name and title of officer having custody of the general books of account and address of the office where such books are kept.

Theresa Z. Bone
Vice President & Controller
225 North Shore Drive, Pittsburgh, Pennsylvania 15212-5861

2. Name of State under the laws of which respondent is incorporated and the date of incorporation. If incorporated under a special law, give reference to such law. If not incorporated, state that fact and give the type of organization and date organized.

Pennsylvania, March 31, 1926

3. If at any time during the year the property of respondent was held by a receiver or trustee, give (a) name of receiver or trustee (b) date such receiver or trustee took possession, (c) the authority by which the receivership or trusteeship was created, (d) date when possession by receiver or trustee ceased.

None.

4. State the classes of utility and other services furnished by respondent during the year in each state in which the respondent operated.

Equitable Gas Company operates as a local distribution company in Pennsylvania and West Virginia. The Company also operates small gathering system in Pennsylvania. In Kentucky, Equitable Gas Company provides exclusively "farm-tap" service under the provisions of KRS 278.485.

IMPORTANT CHANGES DURING YEAR

Hereunder give particulars concerning the matters indicated below. Make the statements explicit and precise, and number them in accordance with the inquiries. Each inquiry must be answered. However, if the word "None" states the fact, it may be used in answering any inquiry.

1. Changes in, and additions to franchise rights; describing (a) the actual consideration given therefor, and (b) from whom acquired. If acquired without the payment of any consideration, state that fact.
2. Acquisition of other companies, reorganization, merger or consolidation with other companies: give names of companies involved, particulars concerning the transactions, and references to Commission authorization, if any.
3. Purchase or sale of substantial operating units, such as generating stations, transmission lines or distribution lines, specifying items, parties, effective dates and also reference to Commission authorization, if any.
4. Important leaseholds (other than leaseholds for natural gas lands) acquired, given, assigned, or surrendered, giving effective dates, lengths of terms, names of parties, rents, Commission authorization, if any, and other conditions.
5. Important extensions of system, giving location, new territory covered by distribution systems, and dates of beginning operations. Give, also, the number of new customers of each class, and for each class of customers the estimated annual revenues.
6. Estimated increase or decrease in annual revenues due to important rate changes, and the approximate extent to which such increase or decrease is reflected in revenues for the reporting year.
7. Important wage scale changes, showing dates of changes, effect on operating expenses for the year, and estimated annual effect of such wage scale changes on operating expenses.
8. Obligations incurred or assumed by respondent as guantantor for the performance by another of any agreement for the performance by another of any agreement or obligation, excluding ordinary commercial paper maturing on demand or not later than one year after date of issue, and giving Commission authorization, if any.
9. Changes in articles of incorporation or amendments to charter: explain the nature and purpose of such changes or amendments.
10. Other important changes not elsewhere provided for.

Item 1: None

Item 2: Refer to Item I of the Notes to Balance Sheet for further discussion of the Respondent's pending acquisition of Dominion Resources, Inc.'s natural gas distribution assets in Pennsylvania and in West Virginia for approximately $970 million, subject to adjustments, in a cash transaction for the stock of The Peoples Natural Gas Company and Hope Gas, Inc.

Items 3 & 4: None

Item 5: No important extension of distribution system territory.

Item 6: Purchased Gas Cost Changes

PENNSYLVANIA:

On December 30, 2005, the Company filed an increase in purchased Gas costs effective January 1, 2006 in compliance with the Pennsylvania Public Utility Commission's quarterly gas cost filing regulations.

On March 31, 2006, the Company filed a decrease in purchased gas costs effective April 1, 2006 in compliance with the Pennsylvania Public Utility Commission's quarterly gas cost filing regulations.

On June 30, 2006, the Company filed a decrease in purchased gas costs effective July 1, 2006 in compliance with the Pennsylvania Public Utility Commission's quarterly gas cost filing regulations.

On September 29, 2006, the Company filed a decrease in purchased gas costs effective October 1, 2006 in compliance with the Pennsylvania Public Utility Commission's quarterly gas cost filing regulations.

As a result of the rate changes, the net impact on revenues for 2006 was a decrease of $11,965,733.

The number of sales customers as of December 31, 2006 was 224,822.

IMPORTANT CHANGES DURING YEAR (Continued)

WEST VIRGINIA:

Effective April 1, 2006, Case No. 05-1138-G-30C, the West Virginia Public Service Commission approved an increase in the gas cost recovery rates.

Effective November 1, 2006, Case No. 06-0998-G-30C, the West Virginia Public Service Commission approved a decrease in the gas cost recovery rates.

As a result of these rate changes, the net impact on revenues for 2006 was an increase of $206,900.

The number of sales customers as of December 31, 2006 was 13,348.

KENTUCKY:

Effective February 2, 2006, Case No. 2006-00004, the Kentucky Public Service Commission approved an increase in the gas cost recovery rates.

Effective May 1, 2006, Case No. 2006-00127, the Kentucky Public Service Commission approved a decrease in the gas cost recovery rates.

Effective August 1, 2006, Case No. 2006-00319, the Kentucky Public Service Commission approved a decrease in the gas cost recovery rates.

Effective November 1, 2006 Case No. 2006-00421, the Kentucky Public Service Commission approved an increase in the gas cost recovery rates.

As a result of these rate changes, the net impact on revenues for 2006 was an increase of $53,769.

The number of customers as of December 31, 2006 was 3,538.

Item 7: Important Wage Scale Changes

Certain nonunion, nonexempt and exempt employees (excluding officers) received an average wage increase of 1.94% effective February 27, 2006.

Wage increases for employees represented by unions were as follows:

(a) Employees of Equitable Gas Company represented by Local 1935, International Brotherhood of Electrical Workers, received a 2% general wage increase Effective May 22, 2006.

(b) Employees of Equitable Gas Company represented by Local 12050, United Steelworkers of America, received a 2.5% general wage increase effective September 25, 2006.

(c) Employees of Equitable Gas Company represented by Local 1956, International Brotherhood of Electrical Workers, received a 3% general Wage increase effective January 2, 2006.

Items 8 & None.

Item 10: None.

DEFINITIONS

"Accounts" means the accounts prescribed in the Federal Code Regulations Title 18, Part 201.

"Amortization" means the gradual extinguishment of an amount in an account by distributing such amount over a fixed period, which may be over the life of the asset or liability to which it applies, or over the period during which it is anticipated the benefit will be realized.

"Book Cost" means the amount at which property is recorded in the applicable account without deduction of related provisions for accrued depreciation, amortization, or for other purposes.

"Control" (including the terms; "controlling," "controlled by," and "under common control with") means the possession, directly or indirectly, of the power to direct or cause the direction of the management and policies of a company, whether such power is exercised through one or more intermediary companies, or alone, or in conjunction with, or pursuant to an agreement, and whether such power is established through a majority or minority ownership or voting of securities, common directors, officers, or stockholders, voting trusts, holding trusts, affiliated companies, contract or any other direct or indirect means.

"Cost" means the amount of money actually paid for property or service. When the consideration given is other than cash, the value of such consideration shall be determined on a cash basis.

"Debt Expense" means all expenses in connection with the issuance and initial sale of evidences of debt, such as fees for drafting mortgages and trust deeds; fees and taxes for issuing or recording evidences of debt; cost of engraving and printing bonds and certificates of indebtedness; fees paid trustees; specific costs of obtaining governmental authority; fees for legal services; fees and commissions paid underwriters, brokers, and salesmen or marketing such evidences of debt; fees and expenses of listing on exchanges; and other like costs.

"Depreciation", as applied to depreciable utility plant, means the loss in service value not restored by current maintenance, incurred in connection with the consumption or prospective retirement of the utility plant in the course of providing service. This includes causes which are known to be in current operation and against which the utility is not protected by insurance. Among the causes to be given consideration are wear and tear, decay, action of the elements, inadequacy, obsolescence, changes in the art, changes in demand, and requirements of regulatory bodies.

"Distribution Service Line", A distribution line that transports gas from a common source of supply to a customer meter or the connection to a customer's piping, whichever is further downstream, or the connection to a customer's piping if there is no customer meter.

DEFINITIONS
(Continued)

"Investment Advances" means advances, represented by notes or by book accounts only, with respect to which it is mutually agreed or intended between the creditor and debtor that they shall be settled by the issuance of securities or shall not be subject to current settlement.

"Minor Items of Property" means the associated parts or items of which retirement units are composed.

"Net Salvage Value" means the salvage value of property retired less the cost of removal.

"Nominally Issued", as applied to securities issued or assumed by the utility means those which have been signed, certified, or otherwise executed, and placed with the proper officer for sale and delivery, or pledged, or otherwise placed in some special fund of the utility, but which have not been sold, or issued directly to trustees of sinking funds in accordance with contractual requirements.

"Original Cost", as applied to utility plant, means the cost of such property to the person first devoting it to public service.

"Property Retired", as applied to utility plant, means property which has been removed, sold, abandoned, destroyed, or which for any cause has been permanently withdrawn from service.

"Replacing or Replacement", when not otherwise indicated in the context, means the construction or installation of utility plant in place of property retired, together with the removal of the property retired.

"Retained Earnings" means the accumulated net income of the utility less distributions to stockholders and transfers to other capital accounts, and other adjustments.

"Salvage Value" means the amount received for property retired, less any expenses incurred in connection with the sale or in preparing the property for sale, or, if retained, the amount at which the material recoverable is chargeable to materials and supplies, or other appropriate account.

"Straight-Line Remaining Life Method", as applied to depreciation accounting, means the plan under which the service value of property is charged to operating expenses (and to clearing accounts if used), and credited to the accumulated depreciation account through equal annual changes during its service life. "Remaining Life" implies that estimates of the future life and salvage shall be reexamined periodically and that depreciation rates will be corrected to reflect any changes in these estimates.

100. VOTING POWERS AND ELECTIONS

1. Has each share of stock the right to one vote? Yes/No
   Yes
2. Are voting rights attached only to stock? Yes/No (If the answer to either query 1 or 2 is "No," give particulars on a separate sheet.)
   Yes

3. Give date of the latest closing of the stock book prior to end of year and state the purpose of such closing.
   N/A

4. Is cumulative voting permitted? Yes/No
   See # 9 below

6. State the date and place of the latest general meeting held prior to the end of the year for the election of directors?
   April 12, 2006

7. State the total number of votes cast at the latest general meeting and the total number cast by proxy.
   Total - 99,322,710 **By Proxy - 99,322,710**

8. State the total number of voting security holders and the total of all voting securities as of such date.
   Voting Securities as of 12/31/2006: Total Number of Security Holders - 4,012
   Total of all Voting Securities - 119,871,576
9. If any security has preferences, special privileges, or restrictions in the election of directors, trustees or managers, or in the determination of any corporate action, give details.
   Common Stock has cumulative voting rights of election of directors.

10. State the number of votes controlled by management, other than officers of the Corporation.
   -

101 SECURITY HOLDER INFORMATION AND VOTING POWERS

1. Report the requested information for each holder of one percent or more of the voting securities or if there are fewer than ten such holders, the ten who hold the highest voting powers. Data should be the latest available nearest the end of the year. When the holder of record is a trustee, or other intermediate agency (except a corporation), the data should be reported opposite the names of the beneficial owners, designated as such, under a general heading identifying the trustee or other agency. Securities with contingent voting rights may be disregarded.
2. Attach hereto a certified copy of every effective voting trust established and a certified copy of every other agreement (trustee or otherwise) under which voting securities are held for beneficial owners. If any such agreement has been filed with a previous report, reference to the earlier report will be sufficient provided changes or modification since filing are shown.

Line No.	Last Name (a)	First Name (b)	Street Address (c)	City (d)	State (e)	Zip (f)	Total Votes (g)	Common Stock (h)	Preferred Stock (i)	Other (j)	Nonvoting Securities (see instruction 2) Principal, Par Value, or Stated Value (Specify issue-omit cents) (k)	Nonvoting Securities (see instruction 2) Principal, Par Value, or Stated Value (Specify issue-omit cents) (k)	Nonvoting Securities (see instruction 2) Principal, Par Value, or Stated Value (Specify issue-omit cents) (k)
1	Total votes of all voting securities						119,871,576	119,871,576			7 3/4% Debentures-due 7/15/2026	5.15% Note- due 03/01/2018	5.15% Note- due 11/15/2012
2	Total number of security holders						4,012	4,012					
3	Total votes of security holders listed below						114,828,177	114,828,177					
4													
5	Cede & Company		18301 Bermuda Green Drive	Tampa	FL	33647	113,466,430	113,466,430			115,000,000	200,000,000	200,000,000
6	Equitable Resources, Inc. Restricted Stock Acct.		225 North Shore Drive	Pittsburgh	PA	15212	576,281	576,281					
7	Moritz (all shares held jointly with wife)	Donald	75 Woodland Road	Pittsburgh	PA	15232	236,086	236,086					
8	Porges	David	5725 Aylesboro Ave	Pittsburgh	PA	15217	181,670	181,670					
9	Ader	Richard	3250 Sandown Park Rd	Keswick	VA	22947	80,000	80,000					
10	Glassell, Jr.	Alfred	1021 Main Street, Suite 2300	Houston	TX	77002	76,270	76,270					
11	DiBenedetto	Anthony	P.O. Box 419	Bridgewater	CT	06752	69,692	69,692					
12	Moritz	Janet	75 Woodland Road	Pittsburgh	PA	15232	57,300	57,300					
13	Bagnato	Joseph	209 Valley View Drive	McDonald	PA	15057	47,248	47,248					
14	Moeller	Audrey	1003 Cherry Hill Drive	Presto	PA	15142	37,200	37,200					
1													
2													
3													
4													
5													
6													
7													
8													
9													
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12													
13													
14													

102. COMPANIES CONTROLLED BY RESPONDENT

1. Show below the names of all corporations, business trusts, and similar organizations, controlled directly or indirectly by respondent at any time during the year. If control ceased prior to end of the year, give particulars in a footnote.
2. If control was by other means than a direct holding of voting rights, state in a footnote the manner in which control was held, naming any intermediates involved.
3. If control was held jointly with one or more other interests, state the fact in a footnote and name the other interests.

Line No.	Name of Company Controlled (a)	Kind of Business (b)	Street Address (c)	City (d)	State (e)	Zip (f)	Voting % of Stock (g)	Footnote Ref. (h)
1	Appalachian Drilling LLC	Oil and natural gas production					100%	Note A
2	Appalachian Natural Gas Trust	Oil and natural gas production					100%	Note B
3	Eastern Four, LLC	Oil and natural gas exploration and production					100%	Note C
4	Eastern Series 1997 Trust	Oil and natural gas exploration and production					100%	Note D
5	Eastern Seven Partners, L.P.	Oil and natural gas exploration and production					100%	Note E
6	EPC Investments, Inc.	Holding company					100%	Note E
7	EQT Capital Corporation	Finance company					100%	Note F
8	EQT Holdings Company, LLC	Holding company					100%	Note H
9	EQT Holdings Management Company, LLC	Holding company					100%	Note I
10	EQT International Holdings Corporation	Holding company					100%	Note J
11	EQT Investments Holdings, LLC	Holding company					100%	Note G
12	EQT Investments, LLC	Holding company					100%	Note F
13	EQT IP Ventures, LLC	Intellectual property holding company					100%	Note K
14	Equitable Energy, LLC	Energy marketing and services					100%	Note L
15	Equitable Energy Holdings Corporation	Holding company					100%	Note J
16	Equitable Gathering Equity, LLC	Natural gas gathering operations					100%	Note M
17	Equitable Gathering, Inc.	Natural gas gathering operations					100%	Note J
18	Equitable Gathering, LLC	Pipeline operations					100%	Note M
19	Equitable HomeWorks, LLC	Sales of energy related products and services					100%	Note A
20	Equitable Production Company	Oil and natural gas exploration and production					100%	Note J
21	Equitable Production Services, LP	Oil and natural gas production					100%	Note N
22	Equitable Resources Foundation, Inc.	Non-profit, charitable, scientific, and educational					100%	Note G
23	Equitable Resources Insurance Company, Ltd.	Captive insurance company					100%	Note G
24	Equitable Utilities Investments, Inc.	Holding company					100%	Note I
25	Equitrans, LP	Interstate pipeline operations					100%	Note O
26	ERI Group LDC	Foreign holding company					100%	Note P
27	ERI Holdings	Foreign holding company					100%	Note Q
28	ERI International	Foreign holding company					100%	Note R
29	ET Blue Grass Clearing, LLC	Land company					100%	Note A
30	ET Blue Grass Company	Oil and natural gas exploration and production					100%	Note J
31	Kentucky West Virginia Gas Company, LLC	Natural gas gathering operations					100%	Note S
32	PEP Finance Company	Foreign holding company					100%	Note T
33	Petroelectrica de Panama LDC	Foreign holding company					100%	Note R

102. COMPANIES CONTROLLED BY RESPONDENT (Continued)
FOOTNOTES

1. Direct control is that which is exercised without interposition of an intermediary.
2. Indirect control is that which is exercised without interposition of an intermediary which exercises direct control. Control may exist by mutual agreement or understanding between two or more parties who together have control within the meaning of the definition of control in the Uniform System of Accounts, regardless of the relative voting rights of each party.
3. Joint control may exist by mutual agreement or understanding between two or more parties who together have control withi the meaning of the definition of control in the Uniform System of Accounts, regardless of the relative voting rights of each

Note A. Directly controlled by ET Blue Grass Company.
Note B. Directly controlled by EPC Investments, Inc.
Note C. Directly controlled by Eastern Series 1997 Trust.
Note D. Directly controlled by Eastern Seven Partners, L.P.
Note E. Directly controlled by Equitable Production Company.
Note F. Directly controlled by EQT Investments Holdings, LLC.
Note G. Directly controlled by Respondent.
Note H. Directly controlled by EQT Holdings Management Company, LLC (99%) and Equitable Utilities Investments (1%).
Note I. Directly controlled by EQT Capital Corporation.
Note J. Directly controlled by EQT Investments, LLC.
Note K. Directly controlled by EPC Investments, Inc. (49.5%) and Equitable Utilities Investments, Inc. (50.5%).
Note L. Directly controlled by Equitable Energy Holdings Corporation.
Note M. Directly controlled by Equitable Gathering, Inc.
Note N. Directly controlled by Equitable Production Company (50%) and ET Blue Grass (50%).
Note O. Directly controlled by Respondent (85%), Equitable Gathering, Inc. (14%) and ET Blue Grass (1%).
Note P. Directly controlled by ERI Holdings (99%) and ERI International (1%).
Note Q Directly controlled by EQT International Holdings Corporation.
Note R. Directly controlled by ERI Holdings.
Note S. Directly controlled by Respondent (99%) and ET Blue Grass Company (1%).
Note T. Directly controlled by Petroelectrica de Panama LDC

103. Directors

1. Report below the information called for concerning each director of the respondent who held office at any time during the year. Include in column (a) abbreviated titles of the directors who are officers of respondent.
2. Designate by an asterisk names of members of Executive Committee, and by double asterisk the Chairman of the Executive Committee.

		Principal Business Address					Term	Term	Meetings	Fees
	Directors Name and Title	Street Address	City	State	Zip	Telephone	Began		Attended	Paid
	(a)	(b)	(c)	(d)	(e)	(h)	(i)	(j)	(k)	(l)
	EQUITABLE RESOURCES, INC.							(A)		
1	Murry S. Gerber *, Chairman, President and Chief Executive Officer and Director	225 North Shore Drive	Pittsburgh	PA	15212		6/1/1998	(D)	7	None
2	David L. Porges, Vice Chairman, Executive Vice President - Finance & Administration and Director	225 North Shore Drive	Pittsburgh	PA	15212		5/16/2002	(B)	7	None
3	Phyllis A. Domm*, Director	6038 SE Horseshoe Point Road	Stuart	FL	34997		5/16/2002	(B)	16	$51,250
4	Thomas A. McConomy, Director	413 Woodland Road	Sewickley	PA	15143		5/17/2000	(C)	14	$49,500
5	George L. Miles, Jr.*, Director	4802 Fifth Avenue	Pittsburgh	PA	15213		7/19/2000	(D)	12	$48,250
6	James E. Rohr **, Director	One PNC Plaza 249 Fifth Avenue	Pittsburgh	PA	15222		5/16/2002	(B)	12	$45,750
7	David S. Shapira, Director	101 Kappa Drive	Pittsburgh	PA	15238		5/16/2002	(B)	11	$42,750
8	James W. Whalen*, Director	150 Gessner - 6E	Houston	TX	77024		7/15/2003	(D)	17	$65,250
9	Lee T. Todd, Jr., Director	101 Main Building	Lexington	KY	40506		11/17/2003	(C)	15	$46,500
10	Barbara S. Jeremiah, Director	201 Isabella Street	Pittsburgh	PA	15212		2/1/2003	(C)	17	$50,250
11	Vicky A. Bailey, Director	3101 New Mexico Avenue NW #249	Washington	DC	20016		6/14/2004	(E)	15	$49,500
	EQUITABLE GAS COMPANY DIVISION									
1	Randall L. Crawford, President and Director	225 North Shore Drive	Pittsburgh	PA	15212		12/21/2000	(F)	(G)	None
2	Edward M. Nolan, Jr., Senior Vice President and Director	225 North Shore Drive	Pittsburgh	PA	15212		12/29/1995	(F)	(G)	None
3	Johanna G. O'Loughlin, Corporate Secretary and Director	225 North Shore Drive	Pittsburgh	PA	15212		12/21/2000	(F)	(G)	None

(A) Includes Committee meetings of Board.
(B) Elected April 13, 2005, to continue in office until Annual Meeting of Shareholders in 2008.
(C) Elected April 12, 2006, to continue in office until Annual Meeting of Shareholders in 2009.
(D) Elected April 14, 2004, to continue in office until Annual Meeting of Shareholders in 2007.
(E) Elected April 13, 2005, to continue in office until Annual Meeting of Shareholders in 2007.
(F) Terms are continuous or until appointment of replacement.
(G) Conducted via Unanimous Written Consents in lieu of meetings.

104. Officers

Line No.	Official Title & Name (a)	Principal Business Address: Street Address (b)	City (c)	State (d)	Zip (e)	Telephone (h)	Fax (i)	Email (j)
1	**EQUITABLE RESOURCES, INC.**							
2	Chairman, President and Chief Executive Officer: Murry S. Gerber	225 North Shore Drive	Pittsburgh	PA	15212			
3	Vice Chairman and Executive Vice President, Finance & Administration: David L. Porges	225 North Shore Drive	Pittsburgh	PA	15212			
4	Vice President and Chief Financial Officer: Philip P. Conti	225 North Shore Drive	Pittsburgh	PA	15212			
5	Senior Vice President, General Counsel and Corporate Secretary: Johanna G. O'Loughlin	225 North Shore Drive	Pittsburgh	PA	15212			
6	Vice President & Corporate Controller: John A. Bergonzi	225 North Shore Drive	Pittsburgh	PA	15212			
7	Vice President, Human Resources: Charlene Petrelli	225 North Shore Drive	Pittsburgh	PA	15212			
8	Vice President: Randall L. Crawford	225 North Shore Drive	Pittsburgh	PA	15212			
9	Vice President: Joseph E. O'Brien	225 North Shore Drive	Pittsburgh	PA	15212			
10	Vice President & Chief Information Officer: Martin A. Fritz	225 North Shore Drive	Pittsburgh	PA	15212			
11								
12	**EQUITABLE GAS COMPANY**							
13	President: Randall L. Crawford	225 North Shore Drive	Pittsburgh	PA	15212			
14	Senior Vice President and General Counsel: Daniel L. Frutchey	225 North Shore Drive	Pittsburgh	PA	15212			
15	Senior Vice President: Edward M. Nolan, Jr.	225 North Shore Drive	Pittsburgh	PA	15212			
16	Senior Vice President: Fredrick K. Dalena	225 North Shore Drive	Pittsburgh	PA	15212			
17	Senior Vice President: Elise H. Hyland	225 North Shore Drive	Pittsburgh	PA	15212			
18	Vice President: Stephen Rafferty	225 North Shore Drive	Pittsburgh	PA	15212			
19	Corporate Secretary: Johanna G. O'Loughlin	225 North Shore Drive	Pittsburgh	PA	15212			
20	Vice President and Controller: Theresa Z. Bone	225 North Shore Drive	Pittsburgh	PA	15212			
21	Treasurer: James E. Crockard, III	225 North Shore Drive	Pittsburgh	PA	15212			
22	Assistant Corporate Secretary: Carol B. Gras	225 North Shore Drive	Pittsburgh	PA	15212			
23	Assistant Corporate Secretary: Jean F. Marks	225 North Shore Drive	Pittsburgh	PA	15212			
24	Assistant Treasurer: John A. Bergonzi	225 North Shore Drive	Pittsburgh	PA	15212			
25	Assistant Treasurer: Thomas E. Quinlan	225 North Shore Drive	Pittsburgh	PA	15212			

200. COMPARATIVE BALANCE SHEET
ASSETS AND OTHER DEBITS

Balances at Beginning of Year must be consistent with balances at end of previous year

Line No.	Account Number and Title (a)	Schedule Page No. (b)	Balance Beginning of Year (c)	Balance End of Year (d)	Increase/ Decrease (e)
1	**UTILITY PLANT**				
2	101.0 Utility Plant in Service	205	722,173,009	746,817,640	24,644,631
3	101.1 Property Under Capital Leases		4,362,883	4,362,883	0
4	*102.0 Gas Plant Purchased or Sold*				0
5	103.0 Experimental Gas Plant Unclassified				0
6	104.0 Gas Plant Leased to Others				0
7	105.0 Gas Plant Held for Future Use		156,946	156,946	0
8	105.1 Production Properties Held For Future Use				0
9	106.0 Completed Construction Not Classified-Gas		81,978,363	89,012,871	7,034,508
10	107.0 Construction Work in Progress-Gas	208	11,198,539	21,124,506	9,925,967
11	108.0 Accumulated Provision for Depreciation of Gas Utility Plant	206	(270,479,515)	(278,255,058)	(7,775,543)
12	111.0 Accumulated Prov. For Amortization & Depletion of Gas Utility Pl.	206	(8,902,746)	(12,548,318)	(3,645,572)
13	114.0 Gas Plant Acquisition Adjustments	207			0
14	115.0 Accumulated Prov. For Amortization & Depletion of Gas Plant				0
15	Acquisition Adjustments	206			0
16	116.0 Other Gas Plant Adjustments				0
17	117.1 Gas Stored-Base Gas				0
18	117.2 System Balancing Gas				0
19	117.3 Gas Stored in Reservoirs and Pipelines-Noncurrent				0
20	117.4 Gas Owed to System Gas				0
21	118.0 Other Utility Plant Adjustments				0
22	119.0 Accumulated Provision for Depreciation and Amortization of Other				0
23	Utility Plant	206			0
24	**TOTAL UTILITY PLANT**		540,487,479	570,671,470	30,183,991
25	**OTHER PROPERTY AND INVESTMENTS**				
26	121.0 Non-Utility Property		28,956,744	30,386,221	1,429,477
27	122.0 Accumulated Depreciation & Amortization of Non-Utility Property		(15,179,530)	(16,718,597)	(1,539,067)
28	123.0 Investments in Associated Companies	210			0
29	*123.1 Other Investments*	210	2,927,082,992	3,164,679,674	237,596,682
30	124.0 Other Investments	210			0
31	125.0 Sinking Funds				0
32	126.0 Depreciation Fund				0
33	128.0 Other Special Funds		3,727,173	3,929,758	202,585
34	**TOTAL OTHER PROPERTY AND INVESTMENTS**		2,944,587,379	3,182,277,056	237,689,677

200. COMPARATIVE BALANCE SHEET
ASSETS AND OTHER DEBITS

Balances at Beginning of Year must be consistent with balances at end of previous year

Line No.	Account Number and Title (a)	Schedule Page No. (b)	Balance Beginning of Year (c)	Balance End of Year (d)	Increase/ Decrease (e)
1	**CURRENT AND ACCRUED ASSETS**				
2	131.0 Cash				0
3	132.0 Interest Special Deposits				0
4	133.0 Dividend Special Deposits				0
5	134.0 Other Special Deposits				0
6	135.0 Working Funds		99,437	107,908	8,471
7	136.0 Temporary Cash Investments	210	80,000,000	0	(80,000,000)
8	141.0 Notes Receivable	211	756,710	628,268	(128,442)
9	142.0 Customer Accounts Receivable		64,172,809	40,797,246	(23,375,563)
10	143.0 Other Accounts Receivable	211	502,123	820,021	317,898
11	144.0 Accumulated Provision for Uncollectible Accounts-Cr.		(20,510,710)	(18,402,842)	2,107,868
12	145.0 Notes Receivable from Associated Companies	212			0
13	146.0 Accounts Receivable for Associated Companies	213	(80,794,376)	15,897,439	96,691,815
14	151.0 Fuel Stock				0
15	152.0 Fuel Stock Expenses Undistributed				0
16	153.0 Residuals and Extracted Products				0
17	154.0 Plant Materials and Operating Supplies	215	2,250,898	1,556,229	(694,669)
18	155.0 Merchandise				0
19	156.0 Other Materials and Supplies				0
20	163.0 Stores Expense-Undistributed		1,026	0	(1,026)
21	164.1 Gas Stored-Current		74,818,690	92,208,035	17,389,345
22	164.2 Liquefied Natural Gas Stored				0
23	164.3 Liquefied Natural Gas Held for Processing				0
24	165.0 Prepayments		14,779,525	16,514,685	1,735,160
25	166.0 Advances for Gas Exploration, Development and Production				0
26	167.0 Other Advances for Gas				0
27	171.0 Interest and Dividends Receivable		141,319	21,282	(120,037)
28	172.0 Rents Receivable				0
29	173.0 Accrued Utility Revenues		58,957,920	40,626,856	(18,331,064)
30	174.0 Miscellaneous Current and Accrued Assets		3,435,282	2,875,568	(559,714)
31	**TOTAL CURRENT & ACCRUED ASSETS**		198,610,653	193,650,695	(4,959,958)
32	**DEFERRED DEBITS**				
33	181.0 Unamortized Debt Expense	216	18,024,174	17,444,691	(579,483)
34	182.1 Extraordinary Property Losses	217			0
35	182.2 Unrecovered Plant and Regulatory Study Costs	217			0
36	182.3 Other Regulatory Assets		52,544,547	54,612,240	2,067,693
37	183.1 Preliminary Natural Gas Survey and Investigation Charges				0
38	183.2 Other Preliminary Survey and Investigation Charges				0
39	184.0 Clearing Accounts				0
40	185.0 Temporary Facilities				0
41	186.0 Miscellaneous Deferred Debits		5,367,535	8,235,359	2,867,824
42	187.0 Deferred Loses from Disposition of Utility Plant				0
43	188.0 Research, Development and Demonstration Expenditures				0
44	189.0 Unamortized Loss on Reacquired Debt		3,002,245	2,756,973	(245,272)
45	190.0 Accumulated Deferred Income Taxes		20,224,967	31,045,623	10,820,656
46	191.0 Unrecovered Purchased Gas Costs		50,471,991	54,062,496	3,590,505
47	**TOTAL DEFERRED DEBITS**		149,635,459	168,157,382	18,521,923
48	**TOTAL ASSETS & TOTAL DEBITS**		3,833,320,970	4,114,756,603	281,435,633

200. COMPARATIVE BALANCE SHEET
LIABILITIES AND OTHER CREDITS

Balances at Beginning of Year must be consistent with balances at end of previous year

Line No.	Account Number and Title (a)	Schedule Page No. (b)	Balance Beginning of Year (c)	Balance End of Year (d)	Increase/ Decrease (e)
1	**LIABILITIES AND OTHER CREDITS**				
2	**PROPRIETARY CAPITAL**				
3	201.0 Common Stock Issued		268,166,980	268,166,980	0
4	202.0 Common Stock Subscribed				0
5	203.0 Common Stock Liability for Conversion				0
6	204.0 Preferred Stock Issued				0
7	205.0 Preferred Stock Subscribed				0
8	206.0 Preferred Stock Liability for Conversion				0
9	207.0 Premium on Capital Stock				0
10	208.0 Donations Received from Stockholders				0
11	209.0 Reduction in Par or Stated Value of Capital Stock				0
12	210.0 Gain on Resale or Cancellation of Reacquired				0
13	Capital Stock				0
14	211.0 Miscellaneous Paid-In Capital		38,051,720	46,223,521	8,171,801
15	212.0 Installments Received on Capital Stock				0
16	213.0 Discount on Capital Stock				0
17	214.0 Capital Stock Expense				0
18	215.0 Appropriated Retained Earnings				0
19	216.0 Unappropriated Retained Earnings		(542,030,105)	(665,412,076)	(123,381,971)
20	216.1 Unappropriated Undistributed Subsidiary Earnings		1,798,112,791	2,036,730,020	238,617,229
21	217.0 Reacquired Capital Stock		(496,511,262)	(469,583,476)	26,927,786
22	219.0 Accumulated Other Comprehensive Income		(9,635,234)	(19,474,383)	(9,839,149)
23	**TOTAL PROPRIETARY CAPITAL**		1,056,154,890	1,196,650,586	(140,495,696
24					
25	**LONG-TERM DEBT**				
26	221.0 Bonds	231	766,434,244	763,500,000	(2,934,244)
27	222.0 Reacquired Bonds	231			0
28	223.0 Advances from Associated Companies				0
29	224.0 Other Long-term Debt	231			0
30	225.0 Unamortized Premium on Long-Term Debt				0
31	226.0 Unamortized Discount on Long-Term Debt-Debit				0
32	**TOTAL LONG TERM DEBT**		766,434,244	763,500,000	(2,934,244)
33					
34	**OTHER NONCURRENT LIABILITIES**				
35	227 Obligation Under Capital Leases-NonCurrent				0
36	228.1 Accumulated Provision for Property Insurance			0	0
37	228.2 Accumulated Provision for Injuries and Damages		1,632,076	1,881,131	249,055
38	228.3 Accumulated Provision for Pensions and Benefits		25,806,249	40,563,160	14,756,911
39	228.4 Accumulated Miscellaneous Operating Provisions		2,364,740	3,048,375	683,635
40	229 Accumulated Provision for Rate Refunds				0
41	**TOTAL OTHER NONCURRENT LIABILITIES**		29,803,065	45,492,666	15,689,601
42					

200. COMPARATIVE BALANCE SHEET
LIABILITIES AND OTHER CREDITS

Balances at Beginning of Year must be consistent with balances at end of previous year

Line No.	Account Number and Title (a)	Schedule Page No. (b)	Balance Beginning of Year (c)	Balance End of Year (d)	Increase/ Decrease (e)
1	**CURRENT AND ACCRUED LIABILITIES**				
2	231.00 Notes Payable		365,447,690	136,116,270	(229,331,420)
3	232.00 Accounts Payable		158,986,312	284,634,797	125,648,485
4	233.00 Notes Payable to Associated Companies		1,326,091,522	1,479,804,202	153,712,680
5	234.00 Accounts Payable to Affiliated Companies				0
6	235.00 Customers' Deposits-Billing		4,508,005	4,153,198	(354,807)
7	236.10 Accrued Taxes, Taxes Other Than Income		(5,501,938)	(5,501,938)	0
8	236.20 Accrued Taxes, Income Taxes		(85,315,018)	(35,672,802)	49,642,216
9	237.10 Accrued Interest on Long-term Debt		13,276,379	13,067,160	(209,219)
10	237.20 Accrued Interest on Other Liabilities		554,089	554,089	0
11	238.00 Dividends Declared				0
12	239.00 Matured Long-term Debt				0
13	240.00 Matured Interest				0
14	241.00 Tax Collections Payable		1,292,813	599,031	(693,782)
15	242.00 Miscellaneous Current and Accrued Liabilities		42,024,767	59,467,224	17,442,457
16	243.00 Obligations Under Capital Leases-Current				0
17	**TOTAL CURRENT AND ACCRUED LIABILITIES**		1,821,364,621	1,937,221,231	115,856,610
18					
19	**DEFERRED CREDITS**				0
20	252.00 Customer Advances for Construction				0
21	253.00 Other Deferred Credits		6,052,296	3,103,268	(2,949,028)
22	254.00 Other Regulatory Liabilities				0
23	255.00 Accumulated Deferred Investment Tax Credits		7,207,208	6,500,816	(706,392)
24	256.00 Deferred Gains from Disposition of Utility Plant				0
25	257.00 Unamortized Gain on Reacquired Debt				0
26	281.00 Accum. Deferred Income Taxes-Assume. Amortization Property				0
27	282.00 Accum. Deferred Income Taxes-Other Property		119,292,429	123,788,957	4,496,528
28	283.00 Accum. Deferred Income Taxes-Other		27,012,217	38,649,079	11,636,862
26	**TOTAL DEFERRED CREDITS**		159,564,150	172,042,120	12,477,970
27					
28	**TOTAL LIABILITIES & OTHER CREDITS**		3,833,320,970	4,114,906,603	281,585,633

201. NOTES TO BALANCE SHEET

1. The space below is provided for important notes regarding the balance sheet or any account thereof.,
2. Furnish particulars as to any contingent assets or liabilities existing at end of year. Minor items may be grouped by classes. For any dividends in arrears at the end of the year on cumulative preferred stock, state the date of the last dividend, the arrearage per share, and the total amount of the arrearage.
3. For Other Plant Adjustments, Account 116, explain the origin of such amount, debits and credits during the year and plan of disposition contemplated, giving references to Commission orders or to other authorizations repealing classification of amounts as plant adjustments and requirements as to disposition thereof.
4. If the notes to balance sheet, appearing in the annual report to the stockholders are applicable in every respect and furnish the data required by instructions 2 and 3 above, such notes may be attached hereto.

A. Summary of Significant Accounting Policies

BUSINESS: Equitable Resources, Inc., through the Equitable Gas Company division, engages in the purchase, storage, distribution, marketing and transportation of natural gas.

UTILITY REGULATION: Accounting records are maintained in accordance with the Uniform System of Accounts prescribed by the Federal Energy Regulatory Commission (FERC) and applicable state commissions.

INVESTMENT IN SUBSIDIARY COMPANIES: The Respondent's investment in subsidiaries is accounted for on the equity method.

PROPERTIES, DEPRECIATION AND DEPLETION: The cost of property additions, replacements and improvements capitalized includes labor, material and overhead. The cost of property retired, plus removal costs less salvage, is charged to accumulated depreciation.

Depreciation for financial reporting purposes is provided on the straight-line method at composite rates based on estimated service lives. Depreciation rates are based on periodic studies.

201. NOTES TO BALANCE SHEET (Continued)

PROVISION FOR DOUBTFUL ACCOUNTS: Judgment is required to assess the ultimate realization of the Respondent's accounts receivable, including assessing the probability of collection and the credit-worthiness of certain customers. The reserve is based on historical experience, current and expected economic trends and specific information about customer accounts. Accordingly, actual results may differ from these estimates under different assumptions or conditions.

ALLOWANCE FOR FUNDS USED DURING CONSTRUCTION: The FERC prescribes a formula to be used for computing overhead allowances for funds used during construction (AFC). AFC applicable to equity funds capitalized is included in other income and amounted to $303,842 in 2006. AFC applicable to borrowed funds is included as a reduction of interest charges and amounted to $166,420 in 2006.

INVENTORIES: The Respondent's inventory balance consists of natural gas stored underground and materials and supplies. Gas stored underground - - current inventory is stated at cost under the average cost method. Materials and supplies are stated generally at average cost.

REVENUE RECOGNITION: Sales of natural gas to utility customers are billed on a monthly cycle basis; however, the billing cycle periods for certain customers do not necessarily coincide with accounting periods used for financial reporting purposes. The Respondent follows the revenue accrual method of accounting for utility segment revenue whereby revenues applicable to gas delivered to customers but not yet billed under the cycle billing method are estimated and accrued and the related costs are charged to expense.

INCOME TAXES: The Respondent utilizes the asset and liability method to account for income taxes. The provision for income taxes represents amounts paid or estimated to be payable, net of amounts refunded or estimated to be refunded, for the current year and the change in deferred taxes. Any refinements to prior years' taxes made due to subsequent information are reflected as adjustments in the current period. Deferred income tax assets and liabilities are determined based on temporary differences between financial reporting and tax bases of assets and liabilities. Where deferred tax liabilities will be passed through to customers in regulated rates, the Respondent establishes a corresponding regulatory asset for the increase in future revenues that will result when the temporary differences reverse.

Investment tax credits realized in prior years were deferred and are being amortized over the estimated service lives of the related properties where required by ratemaking rules.

DEFERRED PURCHASED GAS COST: Where permitted by regulatory authority under purchased gas adjustment clauses or similar tariff provisions, the Respondent defers the difference between purchased gas cost, less refunds, and the billing of such cost and amortizes the deferral over subsequent periods in which billings either recover or repay such amounts.

CASH FLOWS: The Respondent considers all highly liquid investments with a maturity of three months or less when purchased to be cash equivalents. These investments are accounted for at cost. Interest earned on cash equivalents is included as a reduction of interest charges.

A reconciliation of cash and cash equivalents shown in the statement of cash flows is as follows:

Account Number	Description	Amount
136	Temporary Cash Investments	$ -0-
135	Working Funds	107,908
		$ 107,908

REGULATORY ACCOUNTING: The Respondent's distribution operations are subject to comprehensive regulation by the Pennsylvania Public Utilities Commission (PA PUC) and the Public Service Commission of West Virginia (WV PSC). The Respondent also provides field line service (also referred to as "farm tap" service as the customer is served directly from a well or gathering pipeline) in Kentucky which is subject only to rate regulation by the Kentucky Public Service Commission. Accounting for the Respondent's regulated operations is performed in accordance with the provisions of Statement of Financial Accounting Standards (SFAS) No. 71, "Accounting for the Effects of Certain Types of Regulation." The application of this accounting policy allows the Respondent to defer expenses and income on its Consolidated Balance Sheets as regulatory assets and liabilities when it is probable that those expenses and income will be allowed in the rate setting process in a period different from the period in which they would have been reflected in the Statements of Consolidated Income for a non-regulated Respondent. The deferred regulatory assets and liabilities are then recognized in the Statements of Consolidated Income in the period in which the same amounts are reflected in rates. Amounts deferred relate primarily to the accounting for income taxes and *purchased gas cost. The Respondent believes that it will continue to be subject to the rate regulation that* will provide for the recovery of deferred costs.

SELF INSURANCE: The Respondent is self-insured for certain losses related to workers' compensation. The Respondent maintains stop loss coverage with third-party insurers to limit the total exposure for general liability, automobile liability, environmental liability and workers' compensation. The recorded reserves represent estimates of the ultimate cost of claims incurred as of the balance sheet date. The estimated liabilities are based on analyses of historical data and actuarial estimates and are not discounted. The liabilities are reviewed by management quarterly, and by independent actuaries annually, to ensure that they are appropriate. While the Respondent believes these estimates are reasonable based on the information available, financial results could be impacted if actual trends, including the severity or frequency of claims or fluctuations in premiums, differ from estimates.

201. NOTES TO BALANCE SHEET (Continued)

B. Income Taxes

The Respondent files a consolidated federal income tax return including its subsidiaries. Current federal tax balances of all subsidiary companies are settled with the Respondent which makes consolidated tax payments. The consolidated federal income tax provision is allocated among the group's members on a separate return basis with tax credits allocated to those members which generate the credits. The consolidated Federal income tax liability of the Respondent has been settled with the IRS through 1997. The IRS has completed its review of the Respondent's Federal income tax filings for the 1998 through 2000 years and the Respondent believes that only minor issues remain to be resolved. The IRS is expected to survey the 2001 and 2002 Federal income tax filings and audit years 2003 and forward. The Respondent believes that it is appropriately reserved for any tax exposures.

C. Short-Term Loans

On October 27, 2006, the Respondent entered into a $1.5 billion, five-year revolving credit agreement, which replaced the Respondent's previous $1 billion, five-year revolving credit agreement. On December 15, 2006, the maturity date was extended to October 26, 2011 pursuant to its terms. Additionally, the Respondent may request two one-year extensions of the stated maturity date. The revolving credit agreement may be used for working capital, capital expenditures, share repurchases and other purposes including support of the Respondent's commercial paper program. Subject to certain terms and conditions, the Respondent may, on a one time basis, request that the lender's commitments be increased to an aggregate amount of up to $2.0 billion.

Short-term loans were comprised of commercial paper balances of $136.0 million with a weighted average annual interest rate of 5.45% as of December 31, 2006. The maximum amount of outstanding short-term loans at any time during the year was $467.5 million in 2006. The average daily balance of short-term loans outstanding over the course of the year was approximately $126.0 million at a weighted average annual interest rate of 4.63% during 2006.

D. Long-Term Debt

Aggregate maturities of long-term debt are $10.0 million in 2007, $0 in 2008, $4.3 million in 2009, $0 in 2010 and $6.0 million in 2011.

E. Pension and Other Postretirement Benefit Plans

During 2006, the Respondent made certain retiree medical plan design changes, which were accounted for under SFAS No. 106, that decreased the Respondent's other postretirement benefits plan benefits obligation by $5,296,990. These design changes included a decrease in the Respondent's capped contribution per retiree and the elimination of certain retiree benefits.

In September 2006, the FASB issued SFAS No. 158, which requires an employer to recognize a benefit plan's funded status in its statement of financial position, measure a benefit plan's assets and obligations as of the end of the employer's fiscal year and recognize the changes in the benefit plan's funded status in other comprehensive income in the year in which the changes occur. SFAS No. 158's requirement to recognize the funded status of a benefit plan and the new disclosure requirements were effective as of December 31, 2006. The requirement to measure plan assets and benefit obligations as of the date of the employer's fiscal year-end statement of financial position is effective for fiscal years ending after December 15, 2008. The

Incremental effect of applying SFAS No. 158 on individual line items in the statement of financial position:	Before application of SFAS No. 158	Adjustments	After application of SFAS No. 158
Miscellaneous deferred debits	9,341,014	(1,105,655)	8,235,359
Accumulated deferred income taxes	25,198,605	5,847,018	31,045,623
Total deferred debits	163,416,019	4,741,363	168,157,382
Total assets and other debits	4,102,591,785	4,741,363	4,107,333,148
Other current liabilities	56,766,104	2,701,120	59,467,224
Total current and accrued liabilities	1,934,520,111	2,701,120	1,937,221,231
Accumulated provision for pension and benefits	29,937,119	10,626,041	40,563,160
Total other noncurrent liabilities	34,716,625	10,626,041	45,342,666
Accumulated other comprehensive income	(10,888,585)	(8,585,798)	(19,474,383)
Total proprietary capital	1,197,812,929	(8,585,798)	1,189,227,131
Total liabilities and other credits	4,102,591,785	4,741,363	4,107,333,148

201. NOTES TO BALANCE SHEET (Continued)

The following table sets forth the defined benefit pension and other postretirement benefit plans' funded status, as attributed to the Respondent, and amounts recognized in the Respondent's balance sheet at December 31, 2006:

	Pension Benefits	Other Benefits
Change in benefit obligation:		
Benefit obligation at beginning of year	$53,249,583	$25,691,372
Service cost	240,356	235,820
Interest cost	2,954,897	1,351,119
Amendments	--	(5,296,990)
Actuarial loss	3,119,514	1,984,137
Benefits paid	(5,563,338)	(2,359,072)
Curtailments	(101,314)	--
Settlements	(2,226,016)	--
Benefit obligation at end of year	$51,673,682	$21,606,386

	Pension Benefits	Other Benefits
Change in plan assets:		
Fair value of plan assets at beginning of year	$48,928,206	$ --
Gain recognized at beginning of year	495,819	--
Actual gain on plan assets	4,954,902	--
Employer contribution	838,393	--
Benefits paid	(5,563,338)	--
Settlements	(2,214,616)	--
Fair value of plan assets at end of year	$47,439,366	$ --
Funded status at end of year	$ (4,234,316)	$(21,606,386)
Amounts recognized in the statement of financial position consist of:		
Current liabilities	$ --	$ (2,701,120)
Noncurrent liabilities	4,234,316	(18,905,266)
Net amount recognized	$ (4,234,316)	$(21,606,386)
Amounts recognized in accumulated other comprehensive loss consist of, net of tax:		
Net loss	$ 10,888,585	$ 10,976,625
Net prior service cost (credit)	394,947	(2,785,774)
Net amount recognized	$ 11,283,532	$ 8,190,851

The accumulated benefit obligation for the defined benefit pension plans was $51,673,682 at December 31, 2006. The Respondent uses a December 31 measurement date for its defined benefit pension and other postretirement plans.

The costs, as attributed to the Respondent, related to defined benefit pension and other postretirement benefit plans comprised the following:

	Pension Benefits	Other Benefits
Components of net periodic benefit cost:		
Service cost	$ 240,356	$ 235,820
Interest cost	2,954,897	1,351,119
Expected return on plan assets	(4,214,990)	--
Amortization of prior service cost	234,903	28,910
Recognized net actuarial loss	709,742	922,798
Settlement loss and special termination benefits	245,694	--
Curtailment loss	208,134	--
Net periodic benefit cost	$ 378,736	$2,538,647

201. NOTES TO BALANCE SHEET (Continued)

	Pension Benefits	Other Benefits
Other changes in plan assets and benefit obligations recognized in other comprehensive loss, net of tax:		
Net (gain) loss	$ 1,253,351	$10,976,625
Net prior service cost (credit)	394,947	(2,785,774)
Total recognized in other comprehensive income, net of tax	$ 1,648,298	$ 8,190,851
Total recognized in net periodic benefit cost and other comprehensive income, net of tax	$ 2,027,034	$10,729,498

The estimated net loss and net prior service cost for the defined benefit pension plans that will be amortized from accumulated other comprehensive income into net periodic benefit cost over the next fiscal year are $915,066 and $148,952, respectively. The estimated net loss and net prior service credit for the other postretirement benefit plans that will be amortized from accumulated other comprehensive income into net periodic benefit cost over the next fiscal year are $958,115 and ($348,619), respectively.

The following weighted average assumptions were used to determine the benefit obligations and net periodic benefit cost for the Respondent's defined benefit pension and other postretirement benefit plans:

	Pension Benefits	Other Benefits
Discount rate	5.75%	5.75%
Expected return on plan assets	8.25%	N/A
Rate of compensation increase	N/A	N/A

The expected rate of return is established at the beginning of the fiscal year that it relates to based upon information available to the Respondent at that time, including the plans' investment mix and the forecasted rates of return on these types of securities. The Respondent considered the historical rates of return earned on plan assets, an expected return percentage by asset class based upon a survey of investment managers and the Respondent's actual and targeted investment mix. Any differences between actual experience and assumed experience are deferred as an unrecognized actuarial gain or loss. The unrecognized actuarial gains or losses are amortized into the Respondent's net periodic benefit cost in accordance with SFAS No. 87. The expected rate of return determined as of January 1, 2007 totaled 8.25%. This assumption will be used to derive the Respondent's 2007 net periodic benefit cost. The rate of compensation increase is no longer applicable in determining future benefit obligations as a result of the conversion of certain non-represented employees to a defined contribution plan in 2003. Pension expense increases as the expected long-term rate of rate of return decreases or if the discount rate is lowered. Lowering the expected long-term rate of return by 0.5% or lowering the discount rate by 0.5% as of December 31, 2006, would not have a significant impact on pension expense for 2007.

For measurement purposes, the annual rate of increase in the per capita cost of covered health care benefits in 2007 is 10.0% for both the Pre-65 and Post-65 medical charges. The rates were assumed to decrease gradually to ultimate rates of 5.0% in 2012.

Assumed health care cost trend rates have an effect on the amounts reported for the health care plans. A one-percentage-point change in assumed health care cost trend rates would have the following effects:

	One Percentage Point Increase	One Percentage Point Decrease
Increase (decrease) to total of service and interest cost components	$ 54,646	$ (52,281)
Increase (decrease) to postretirement benefit obligation	$ 486,268	$ (458,096)

201. NOTES TO BALANCE SHEET (Continued)

The Respondent's pension asset allocation at December 31, 2006 and target allocation for 2007 by asset category are as follows:

Asset Category	Target Allocation 2007	Percentage of Plan Assets at December 31, 2006
Domestic broadly diversified equity securities	50% - 70%	50%
Fixed income securities and inflation hedge securities	30% - 45%	36%
International broadly diversified equity securities	5% - 15%	11%
Other	0% - 15%	3%
		100%

The investment activities of the Respondent's pension plan are supervised and monitored by the Respondent's Benefits Investment Committee. The Benefits Investment Committee has developed an investment strategy that focuses on asset allocation, diversification and quality guidelines. The investment goals of the Benefits Investment Committee are to minimize high levels of risk at the total pension investment fund level. The Benefits Investment Committee monitors the actual asset allocation on a quarterly basis and adjustments are made, as needed, to rebalance the assets within the prescribed target ranges. Comparative market and peer group benchmarks are utilized to ensure that each of the firm's investment managers is performing satisfactorily.

Cash contributions of $838,393 were made to the pension plan during 2006. The Respondent does not expect to make a cash contribution to its pension plan during 2007.

The following benefit payments, which reflect expected future service, are expected to be paid during each of the next five years and the five years thereafter: $5,345,847 in 2007; $5,234,426 in 2008; $5,267,403 in 2009; $4,791,680 in 2010; $5,038,816 in 2011; and $22,611,701 in the five years thereafter.

Expense recognized by the Respondent related to its 401(k) employee savings plans totaled $2,124,156 in 2006.

F. Share-Based Compensation Plans

The Respondent adopted SFAS No. 123R effective January 1, 2006, using the modified prospective method. Under the modified prospective method, compensation cost is recognized beginning with the effective date and prior period results are not restated. As such, compensation cost related to all share-based awards, including non-qualified stock options, was recorded as selling, general and administrative expense in the Respondent's Statement of Consolidated Income for the year ended December 31, 2006. The compensation cost that has been charged to expense for all of the Respondent's share-based compensation arrangements, described below, was $26.6 million in 2006.

Adoption of SFAS No. 123R had the effect of reducing operating income and income from continuing operations before income taxes by $1.0 million, and net income by $0.6 million or less than $0.01 per basic and diluted share, for the year ended December 31, 2006. Prior to the adoption of SFAS No. 123R, the Respondent presented all tax benefits for deductions resulting from the exercise of share-based awards as cash flows from operating activities in its Statements of Condensed Consolidated Cash Flows. SFAS No. 123R requires the benefits of tax deductions in excess of recognized compensation expense to be reported as a cash flow from financing activities, rather than as a cash flow from operating activities. This requirement reduced cash flows from operating activities and increased cash flows from financing activities by $15.7 million for the year ended December 31, 2006. Total net cash flows were not impacted by the adoption of SFAS No. 123R.

Cash received from exercises under all share-based payment arrangements for employees and directors for the year ended December 31, 2006 was $34.9 million. The actual tax benefits realized for tax deductions from share-based payment arrangements for the year ended December 31, 2006 was $18.9 million.

The Respondent typically funds restricted share obligations from treasury stock at the date of grant and has a policy of issuing shares from treasury stock to satisfy option exercises.

Executive Performance Incentive Programs

In February 2005, the Compensation Committee of the Board of Directors adopted the 2005 Executive Performance Incentive Program (2005 Program) under the 1999 Long-Term Incentive Plan. The 2005 Program was established to provide additional incentive benefits to retain executive officers and certain other employees of the Respondent to further align the interests of the persons primarily responsible for the success of the Respondent with the interests of the shareholders. A total of 1,029,800 stock units granted under the 2005 Program are outstanding as of December 31, 2006. No additional units may be granted. The vesting of these stock units will occur on December 31, 2008, contingent upon a combination of the level of total shareholder return relative to the Respondent's 29 peer companies and the Respondent's average absolute return on total capital during the four-year performance period. As a result, zero to 2,574,500 units (250% of the units outstanding) may be distributed in cash or stock. The Respondent anticipates, based on current estimates, that a certain level of performance will be met and has expensed a ratable estimate of the units accordingly. The 2005 Program expense for the year ended December 31, 2006 was $21.1 million.

201. NOTES TO BALANCE SHEET (Continued)

Restricted Stock Awards

The Respondent granted 112,700, 138,400, and 291,100 restricted stock awards during the years ended December 31, 2006, 2005, and 2004, respectively, to key executives of the Respondent. The majority of these awards will be fully vested at the end of the three-year period commencing the date of grant. The fair value of each share is determined based on the market price of the Respondent's common stock on the date of grant. The weighted average fair value of these restricted stock grants, based on the grant date fair value of the Respondent's stock, was $36.11, $33.07, and $21.88, for the years ended December 31, 2006, 2005, and 2004, respectively. The total fair value of restricted stock awards vested during the years ended December 31, 2006, 2005, and 2004 was $1.5 million, $1.8 million and $0.1 million, respectively. Compensation expense recorded by the Respondent related to restricted stock awards was $3.5 million, $3.4 million and $3.8 million for the years ended December 31, 2006, 2005, and 2004, respectively.

As of December 31, 2006, there was $5.3 million of total unrecognized compensation cost related to nonvested restricted stock awards. That cost is expected to be recognized over a weighted average period of approximately 10.1 months.

Stock Options

The fair value of the Respondent's option grants was estimated at the dates of grant using a Black-Scholes option-pricing model with the assumptions indicated in the table below for the year ended December 31, 2006. The risk-free rate for periods within the contractual life of the option is based on the U.S. Treasury yield curve in effect at the time of grant. The dividend yield is based on the historical dividend yield of the Respondent's stock. Expected volatilities are based on historical volatility of the Respondent's stock. The expected term of options granted represents the period of time that options granted are expected to be outstanding based on historical option exercise experience.

The fair value for these option grants was estimated at the dates of grant using a Black-Scholes option pricing model with the following assumptions for 2006:

Risk-free interest rate (range)	4.51% to 5.04%
Dividend yield	2.34% to 2.38%
Volatility factor	.212 to .226
Weighted average expected life of options	7 years
Options granted	84,935
Weighted average fair market value of options granted during the year	$ 9.43

The following schedule summarizes the stock option activity for the year ended December 31, 2006:

Options outstanding January 1	5,110,421
Granted	84,935
Forfeitures	(4,716)
Exercised	(2,228,966)
Options outstanding December 31	2,961,674

Options outstanding at December 31, 2006 include 2,961,674 exercisable at that date.

Nonemployee Directors' Stock Incentive Plans

At December 31, 2006, 160,904 options were outstanding under the 1999 Nonemployee Directors' Stock Incentive Plan at prices ranging from $6.59 to $29.67 per share, and 537,200 options had been exercised under this plan since plan inception. The exercise price for each award is equal to the market price of the Respondent's common stock on the date of grant. Each option is subject to time-based vesting provisions and expires 5 to 10 years after date of grant.

The Respondent has also historically granted to non-employee directors stock units which vested upon award. The value of the stock units will be paid in cash on the earlier of the director's death or retirement from the Respondent's Board of Directors. A total of 72,960 non-employee director stock units were outstanding as of December 31, 2006. A total of 18,000, 18,000, and 21,120 stock units were granted to non-employee directors during the years ended December 31, 2006, 2005, and 2004, respectively.

201. NOTES TO BALANCE SHEET (Continued)

G. Commitments and Contingencies

The Respondent has annual commitments of approximately $37.8 million for demand charges under existing long-term contracts with pipeline suppliers for periods extending up to ten years as of December 31, 2006, which relate to natural gas distribution and production operations. However, the Respondent believes that approximately $26.4 million of these costs are recoverable in customer rates.

In the ordinary course of business, various legal claims and proceedings are pending or threatened against the Respondent. While the amounts claimed may be substantial, the Respondent is unable to predict with certainty the ultimate outcome of such claims and proceedings. The Respondent has established reserves for pending litigation, which it believes are adequate, and after consultation with counsel and giving appropriate consideration to available insurance, the Respondent believes that the ultimate outcome of any matter currently pending against the Respondent will not materially affect the financial position of the Respondent.

The Respondent is subject to various federal, state and local environmental and environmentally related laws and regulations. These laws and regulations, which are constantly changing, can require expenditures for remediation and may in certain instances result in assessment of fines. The Respondent has established procedures for ongoing evaluation of its operations to identify potential environmental exposures and to assure compliance with regulatory policies and procedures. The estimated costs associated with identified situations that require remedial action are accrued. However, certain costs are deferred as regulatory assets when recoverable through regulated rates. Ongoing expenditures for compliance with environmental laws and regulations, including investments in plant and facilities to meet environmental requirements, have not been material. Management believes that any such required expenditures will not be significantly different in either their nature or amount in the future and does not know of any environmental liabilities that will have a material effect on the Respondent's financial position or results of operations.

H. Office Consolidation/Impairment Charges

In May 2005, the Respondent completed the relocation of its corporate headquarters and other operations to a newly constructed office building located at the North Shore in Pittsburgh. The relocation resulted in the early termination of several operating leases and the early retirement of assets and leasehold improvements at several locations. In accordance with SFAS No. 146, the Respondent recognized a loss of $5.3 million on the early termination of operating leases during 2005 for facilities deemed to have no economic benefit to the Respondent. The Respondent also recognized a loss on the impairment of assets of $2.5 million during 2005 in accordance with SFAS No. 144 associated with the office consolidations.

During the second quarter of 2006, the Respondent began to utilize certain of the leased space previously deemed to have no economic benefit to the Respondent to make space available for the pending acquisition of The Peoples Natural Gas Respondent and Hope Gas, Inc. transition planning activities. The Respondent reversed approximately $2.4 million of the associated early termination liability for these leases during the second quarter of 2006. Additionally, the Respondent recorded a $0.5 million reduction in the early termination liability during the second quarter of 2006 resulting from a revision of the amount of estimated cash flows for one of its operating leases.

I. Acquisition

On March 1, 2006, the Respondent entered into a definitive agreement to acquire Dominion Resources, Inc.'s natural gas distribution assets in Pennsylvania and in West Virginia for approximately $970 million, subject to adjustments, in a cash transaction for the stock of The Peoples Natural Gas Respondent and Hope Gas, Inc. On February 9, 2007, an administrative law judge for the Pennsylvania Public Utility Commission (PA PUC) issued an initial decision approving the stock acquisition, subject to the terms and conditions of a Joint Petition for Settlement filed by the Respondent and a number of the intervening parties. On April 13, 2007, the PA PUC issued an Opinion and Order approving the stock acquisition consistent with the terms and conditions of the Joint Petition for Settlement which includes, among other things, an agreement by the Respondent that Equitable Gas Respondent and The Peoples Natural Gas Respondent will not make base rate case filings prior to January 1, 2009. The transaction also requires approval from the Public Service Commission of West Virginia (WV PSC) and is under review by the Pennsylvania Attorney General. The WV PSC has approved a procedural schedule which calls for hearings to occur in mid-May 2007. Several parties have intervened in the West Virginia regulatory case. The Respondent continues to engage in settlement negotiations with the interveners. On March 14, 2007, the Federal Trade Commission (FTC) issued an administrative complaint challenging the Respondent's acquisition of The Peoples Natural Gas Respondent. On April 13, 2007, the FTC filed a complaint in the U.S. District Court for the Western District of Pennsylvania seeking a preliminary injunction to enjoin the proposed acquisition. The U.S. District Court has approved a procedural order in this case designed to achieve resolution of the issues raised in the FTC's U.S. District Court complaint by June 30, 2007. The Respondent's acquisition agreement had an expiration date of March 31, 2007, unless the closing had not occurred due to a failure to obtain a required governmental consent or authorization when such is being diligently pursued, in which case the expiration date is automatically extended to June 30, 2007. Pursuant to these terms, the expiration date of the acquisition agreement automatically extended to June 30, 2007. No assurance can be given that the remaining regulatory issues will be resolved within this timeframe. The agreement will terminate if no closing occurs by June 30, 2007, unless the parties agree to an extension. The assets to be acquired will increase: customers in the distribution operations by 475,000 or 173%; total storage capacity by 33 Bcf or 60%; miles of gathering pipelines by 936 miles; gathered volumes by 40%; and miles of high pressure transmission by 466 miles or 42%.

J. Investments in Subsidiaries

In 2006 EQT Capital distributed its interest in EQTI to EQT Investments Holdings LLC, which was formed as a limited liability company by the Respondent and to which the Respondent contributed its interest in EQT Capital.

K. The opening balances for account 186 have been restated to reflect accumulated other comprehensive incomes separately (in Account 219).

205. UTILITY PLANT IN SERVICE - Account No. 101.0
TOTAL COMPANY

1. *Report by prescribed accounts the original cost of utility plant in service and the additions and retirements of such plant during the year.*
2. Do not include as adjustments, corrections to additions and retirements for the current or preceding year. Such items should be included in appropriate Column (c) or (d).
3. Credit adjustments in Column (e) should be shown in red, or in black enclosed in parenthesis. State in a footnote the general character of any adjustments in Column (e).
4. Submit, in a footnote, an explanation of amounts included in Columns (e) and/or (f), Line 34, for lowering or changing the location of mains.

Line No.		Account Number and Title (a)	Balance Previous Year (b)	Additions (c)	Retirements (d)	Adjustments +/- (e)	Balance End of Year (f)
1		**INTANGIBLE PLANT**	XXX	XXX	XXX	XXX	XXX
2	301	Organization	49,770				49,770
3	302	*Franchises & Consents*					0
4	303	Other Plant and Miscellaneous Equipment	9,784,177	1,940,893			11,725,070
5		Total Intangible Plant	9,833,947	1,940,893	0	0	11,774,840
6		**MANUFACTURED GAS PRODUCTION PLANT**	XXX	XXX	XXX	XXX	XXX
7	304	Land and Land Rights					0
8	305	Structures and Improvements					0
9	306	Boiler Plant Equipment					0
10	307	Other Power Equipment					0
11	308	Coke Ovens					0
12	309	Infiltration Galleries and Tunnels					0
13	310	Producer Gas Equipment					0
14	311	Liquefied Petroleum Gas Equipment					0
15	312	Oil Gas Generating Equipment					0
16	313	Generating Equipment-Other Processes					0
17	314	Coal, Coke and Ash Handling Equipment					0
18	315	Catalytic Cracking Equipment					0
19	316	Other Reforming Equipment					0
20	317	Purification Equipment					0
21	318	Residential Refining Equipment					0
22	319	Gas Mixing Equipment					0
23	320	Other Equipment					0
23		Total Gas Manufacturing Plant	0	0	0	0	0
24		**NATURAL GAS PRODUCTION & GATHERING PLANT**	XXX	XXX	XXX	XXX	XXX
25	325.1	Producing Lands					0
26	325.2	Producing Leaseholds	16,356			0	16,356
27	325.3	Gas Rights					0
28	325.4	Rights of Way	2,422				2,422
29	325.5	Other Land and Land Rights	0				0
30	326	*Other Plant and Miscellaneous Equipment*					0
31	327	Field Compressor Station Structures	0				0
32	328	Field Measuring & Regulating Station Structures	101				101
33	329	Other Structures					0
34	330	Producing Gas Wells-Well Construction	654,658				654,658
35	331	Producing Gas Wells-Well Equipment	257,931				257,931
36	332	Field Lines	177,520	0	0	0	177,520
37	333	Field Compressor Station Equipment	0				0
38	334	Field Measuring & Regulating Station Equipment	91,787	0		0	91,787
39	335	Drilling & Cleaning Equipment					0
40	336	Purification Equipment					0
41	337	Other Equipment					0
42	338	Unsuccessful Exploration & Development Costs					0
43		Total Natural Gas Production & Gathering Plant	1,200,775	0	0	0	1,200,775
44		**PRODUCTS EXTRACTION PLANT**	XXX	XXX	XXX	XXX	XXX
45	340	Land and Land Rights					0
46	341	Other Plant and Miscellaneous Equipment					0
47	342	Extraction & Refining Equipment					0
48	343	Pipe Lines					0
49	344	Extracted Product Storage Equipment					0
50	345	Compressor Equipment					0
51	346	Gas Measuring and Regulating Equipment					0
52	347	Other Equipment					0
		Total Products Extraction Plant	0	0	0	0	0
53		**NATURAL GAS PRODUCTION & PROCESSING PLANT**	XXX	XXX	XXX	XXX	XXX
54	350.1	Land					0
55	350.2	Rights of Way					0
56	351	Structures and Improvements					0
57	352	*Wells*					0
58	352.1	Storage Leaseholds and Rights					0
59	352.2	Reservoirs					0
60	352.3	Nonrecoverable Natural Gas					0
61	353	Lines					

3. The adjustments in Column (e) relate to the reclassification of assets into the proper account (s).

205. UTILITY PLANT IN SERVICE - Account No. 101.0
TOTAL COMPANY

Line No.	Account Number and Title (a)		Balance Previous Year (b)	Additions (c)	Retirements (d)	Adjustments +/- (e)	Balance End of Year (f)
62	354	Compressor Station Equipment					0
63	355	Measuring and Regulating Equipment					0
64	356	Purification Equipment					0
65	357	Other Equipment					0
66		Total Natural Gas Production and Processing Plant	0	0	0	0	0
67		OTHER STORAGE PLANT	XXX	XXX	XXX	XXX	XXX
68	360	Land & Land Rights					0
69	361	Structures and Improvements					0
70	362	Gas Holders					0
71	363	Purification Equipment					0
72	363.1	Liquefaction Equipment					0
73	363.2	Vaporizing Equipment					0
74	363.3	Compressor Equipment					0
75	363.4	Measuring and Regulating Equipment					0
76	363.5	Other Equipment					0
77		Total Other Storage Plant	0	0	0	0	0
78		BASE LOAD LIQUEFIED NATURAL GAS					0
79		TERMINATING AND PROCESSING PLANT	XXX	XXX	XXX	XXX	XXX
80	364.1	Land and Land Rights					0
81	364.2	Structures and Improvements					0
82	364.3	LNG Processing Terminal Equipment					0
83	364.4	LNG Transportation Equipment					0
84	364.5	Measuring and Regulating Equipment					0
85	364.6	Compressor Station Equipment					0
86	364.7	Communication Equipment					0
87	364.8	Other Equipment					0
88		Total Base Load Liquefied Natural Gas Term. & Proc. Plant	0	0	0	0	0
89		TRANSMISSION PLANT	XXX	XXX	XXX	XXX	XXX
90	365.1	Land and Land Rights	0				0
91	365.2	Rights of Way	0				0
92	366	Structures and Improvements	0				0
93	367	Mains	4,747,993		3,295		4,744,698
94	368	Compressor Station Equipment	0				0
95	369	Measuring and Regulating Station Equipment	268,428				268,428
96	370	Communication Equipment	110,165		196		109,969
97	371	Other Equipment	0				0
98		Total Transmission Plant	5,126,586	0	3,491	0	5,123,095
99		DISTRIBUTION PLANT	XXX	XXX	XXX	XXX	XXX
100	374	Land & Land Rights	3,184,914	19,340	673,582		2,530,672
101	375	Structures and Improvements	2,900,821	404,127	649,692		2,655,256
102	376	Mains	402,797,448	21,818,189	1,971,328		422,644,309
103	377	Compressor Station Equipment	0				0
104	378	Measuring & Regulating Station Equipment-General	14,006,961	256,035	65,375	150,000	14,347,621
105	379	Measuring & Regulating Station Equipment-City Gate C. St.	0				0
106	380	Services	196,522,524	5,755,180	1,018,887		201,258,817
107	381	Meters	18,744,034	195,251	18,906		18,920,379
108	382	Meter Installations	8,800,871				8,800,871
109	383	House Regulators	6,141,070	238,789			6,379,859
110	384	House Regulatory Installations	1,544,196	58,602	9		1,602,789
111	385	Industrial Measuring and Regulating Station Equipment	356,376				356,376
112	386	Other Property on Customers' Premises	6,704,056		97,666		6,606,390
113	387	Other Equipment	3,555,473	8,776	767,085		2,797,164
114	388	Asset Retirement Costs for Distribution Plant	150,000			(150,000)	0
115		Total Distribution Plant	665,408,744	28,754,289	5,262,530	0	688,900,503
116		GENERAL PLANT	XXX	XXX	XXX	XXX	XXX
117	389	Land & Land Rights	102,364				102,364
118	390	Structures and Improvements	9,538,035	13,406	1,774,385		7,777,056
119	391	Office Furniture & Equipment	10,171,843	2,272,040	1,096,595		11,347,288
120	392	Transportation Equipment	6,035,679	514,857	229,212		6,321,324
121	393	Stores Equipment	115,760		40,645		75,115
122	394	Tools & Garage Equipment	4,432,587	190,507	113,719		4,509,375
123	395	Laboratory Equipment	26,059				26,059
124	396	Power Operated Equipment	3,364,091	4,787	40,084		3,328,794
125	397	Communication Equipment	10,656,124	235,660	460,518		10,431,266
126	398	Miscellaneous Equipment	523,298		260,629		262,669
127	399	Other Tangible Property	0				0
128		Total General Plant	44,965,840	3,231,257	4,015,787	0	44,181,310
129		Total Plant	726,535,892	33,926,439	9,281,808	0	751,180,523

205. UTILITY PLANT IN SERVICE - Account No. 101.0
PENNSYLVANIA DIVISION

1. Report by prescribed accounts the original cost of utility plant in service and the additions and retirements of such plant during the year.
2. Do not include as adjustments, corrections to additions and retirements for the current or preceding year. Such items should be included in appropriate Column (c) or (d).
3. Credit adjustments in Column (e) should be shown in red, or in black enclosed in parenthesis. State in a footnote the general character of any adjustments in Column (e).
4. Submit, in a footnote, an explanation of amounts included in Columns (e) and/or (f), Line 34, for lowering or changing the location of mains.

Line No.		Account Number and Title (a)	Balance Previous Year (b)	Additions (c)	Retirements (d)	Adjustments +/- (e)	Balance End of Year (f)
1		**INTANGIBLE PLANT**	XXX	XXX	XXX	XXX	XXX
2	301	Organization	49,770				49,770
3	302	Franchises & Consents	0				0
4	303	Other Plant and Miscellaneous Equipment	9,784,177	1,940,893			11,725,070
5		*Total Intangible Plant*	9,833,947	1,940,893	0	0	11,774,840
6		**MANUFACTURED GAS PRODUCTION PLANT**	XXX	XXX	XXX	XXX	XXX
7	304	Land and Land Rights					0
8	305	Structures and Improvements					0
9	306	Boiler Plant Equipment					0
10	307	Other Power Equipment					0
11	308	Coke Ovens					0
12	309	Infiltration Galleries and Tunnels					0
13	310	Producer Gas Equipment					0
14	311	Liquefied Petroleum Gas Equipment					0
15	312	Oil Gas Generating Equipment					0
16	313	Generating Equipment-Other Processes					0
17	314	Coal, Coke and Ash Handling Equipment					0
18	315	Catalytic Cracking Equipment					0
19	316	Other Reforming Equipment					0
20	317	Purification Equipment					0
21	318	Residential Refining Equipment					0
22	319	Gas Mixing Equipment					0
23	320	Other Equipment					0
23		Total Gas Manufacturing Plant	0	0	0	0	0
24		**NATURAL GAS PRODUCTION & GATHERING PLANT**	XXX	XXX	XXX	XXX	XXX
25	325.1	Producing Lands					0
26	325.2	Producing Leaseholds	16,356				16,356
27	325.3	Gas Rights	0				0
28	325.4	Rights of Way	0				0
29	325.5	Other Land and Land Rights	0				0
30	326	Other Plant and Miscellaneous Equipment	0				0
31	327	Field Compressor Station Structures	0				0
32	328	Field Measuring & Regulating Station Structures	0				0
33	329	Other Structures	0				0
34	330	Producing Gas Wells-Well Construction	598,329				598,329
35	331	Producing Gas Wells-Well Equipment	228,454				228,454
36	332	Field Lines	0				0
37	333	Field Compressor Station Equipment	0				0
38	334	Field Measuring & Regulating Station Equipment	0				0
39	335	Drilling & Cleaning Equipment	0				0
40	336	Purification Equipment	0				0
41	337	Other Equipment	0				0
42	338	Unsuccessful Exploration & Development Costs	0				0
43		Total Natural Gas Production & Gathering Plant	843,139	0	0	0	843,139
44		**PRODUCTS EXTRACTION PLANT**	XXX	XXX	XXX	XXX	XXX
45	340	Land and Land Rights					0
46	341	Other Plant and Miscellaneous Equipment					0
47	342	Extraction & Refining Equipment					0
48	343	Pipe Lines					0
49	344	Extracted Product Storage Equipment					0
50	345	Compressor Equipment					0
51	346	Gas Measuring and Regulating Equipment					0
52	347	Other Equipment					0
		Total Products Extraction Plant	0	0	0	0	0
53		**NATURAL GAS PRODUCTION & PROCESSING PLANT**	XXX	XXX	XXX	XXX	XXX
54	350.1	Land					0
55	350.2	Rights of Way					0
56	351	Structures and Improvements					0
57	352	Wells					0
58	352.1	Storage Leaseholds and Rights					0
59	352.2	Reservoirs					[illegible]
60	352.3	Nonrecoverable Natural Gas					0
61	353	Lines					0

3. The adjustments in Column (e) relate to the reclassification of assets into the proper account (s).

205. UTILITY PLANT IN SERVICE - Account No. 101.0
PENNSYLVANIA DIVISION

Line No.	Account Number and Title (a)		Balance Previous Year (b)	Additions (c)	Retirements (d)	Adjustments +/- (e)	Balance End of Year (f)
62	354	Compressor Station Equipment					0
63	355	Measuring and Regulating Equipment					0
64	356	Purification Equipment					0
65	357	Other Equipment					0
66		Total Natural Gas Production and Processing Plant	0	0	0	0	0
67		**OTHER STORAGE PLANT**	XXX	XXX	XXX	XXX	XXX
68	360	Land & Land Rights					0
69	361	Structures and Improvements					0
70	362	Gas Holders					0
71	363	Purification Equipment					0
72	363.1	Liquefaction Equipment					0
73	363.2	Vaporizing Equipment					0
74	363.3	Compressor Equipment					0
75	363.4	Measuring and Regulating Equipment					0
76	363.5	Other Equipment					0
77		Total Other Storage Plant	0	0	0	0	0
78		**BASE LOAD LIQUEFIED NATURAL GAS**					0
79		**TERMINATING AND PROCESSING PLANT**	XXX	XXX	XXX	XXX	XXX
80	364.1	Land and Land Rights					0
81	364.2	Structures and Improvements					0
82	364.3	LNG Processing Terminal Equipment					0
83	364.4	LNG Transportation Equipment					0
84	364.5	Measuring and Regulating Equipment					0
85	364.6	Compressor Station Equipment					0
86	364.7	Communication Equipment					0
87	364.8	Other Equipment					0
88		Total Base Load Liquefied Natural Gas Term. & Proc. Plant	0	0	0	0	0
89		**TRANSMISSION PLANT**	XXX	XXX	XXX	XXX	XXX
90	365.1	Land and Land Rights	0				0
91	365.2	Rights of Way	0				0
92	366	Structures and Improvements	0				0
93	367	Mains	4,747,993		3,296		4,744,697
94	368	Compressor Station Equipment	0				0
95	369	Measuring and Regulating Station Equipment	266,420				266,420
96	370	Communication Equipment	110,165		196		109,969
97	371	Other Equipment	0				0
98		Total Transmission Plant	5,124,578	0	3,492	0	5,121,086
99		**DISTRIBUTION PLANT**	XXX	XXX	XXX	XXX	XXX
100	374	Land & Land Rights	2,904,544	19,219	673,582		2,250,181
101	375	Structures and Improvements	2,684,835	404,127	649,692		2,439,270
102	376	Mains	376,949,063	21,198,238	1,688,005		396,459,296
103	377	Compressor Station Equipment	0				0
104	378	Measuring & Regulating Station Equipment-General	12,696,708	179,016	33,906	150,000	12,991,818
105	379	Measuring & Regulating Station Equipment-City Gate C. St.	0				0
106	380	Services	190,731,928	5,752,843	1,017,387		195,467,384
107	381	Meters	17,663,378	88,629			17,752,007
108	382	Meter Installations	7,491,809				7,491,809
109	383	House Regulators	5,352,933	123,405			5,476,338
110	384	House Regulatory Installations	1,385,007	58,601	8		1,443,600
111	385	Industrial Measuring and Regulating Station Equipment	356,376				356,376
112	386	Other Property on Customers' Premises	6,684,608		97,666		6,586,942
113	387	Other Equipment	3,283,698	8,776	767,036		2,525,438
114	388	Asset Retirement Costs for Distribution Plant	150,000			(150,000)	0
115		Total Distribution Plant	628,334,887	27,832,854	4,927,282	0	651,240,459
116		**GENERAL PLANT**	XXX	XXX	XXX	XXX	XXX
117	389	Land & Land Rights	67,166				67,166
118	390	Structures and Improvements	9,401,078	11,110	1,774,384		7,637,804
119	391	Office Furniture & Equipment	10,160,422	2,272,040	1,096,595		11,335,867
120	392	Transportation Equipment	5,407,280	142,086	72,587		5,476,779
121	393	Stores Equipment	115,163		40,645		74,518
122	394	Tools & Garage Equipment	3,967,448	162,908	99,674		4,030,682
123	395	Laboratory Equipment	26,059				26,059
124	396	Power Operated Equipment	3,105,966	4,787	22,090		3,088,663
125	397	Communication Equipment	10,506,166	190,394	460,518		10,236,042
126	398	Miscellaneous Equipment	519,392		260,629		258,763
127	399	Other Tangible Property	0				0
128		Total General Plant	43,276,140	2,783,325	3,827,122	0	42,232,343
129		Total Plant	687,412,691	32,557,072	8,757,896	0	711,211,867

206. ACCUMULATED DEPRECIATION OF UTILITY PLANT - Account Nos. 108, 111, 115 and 119

1. Report below an analysis of the changes in accumulated depreciation during the year and the amounts applicable to prescribed functional classifications.
2. Explain and give particulars of important adjustments during the year.

Line No.	Item (a)	Total (b)	101 Utility Plant In Service (c)	104 Utility Plant Leased to Others (d)	105 Property Held for Future Use (e)	107.0 Construction Work In Progress (f)
1	**Balance Beginning of Year**	279,382,261	279,382,261	0	0	0
2	Credits During Year	XXXXX	XXXXX	XXXXX	XXXXX	XXXXX
3	Depreciation Provisions charged to:	XXXXX	XXXXX	XXXXX	XXXXX	XXXXX
4	403. Depreciation	16,690,666	16,690,666			
5	413. Income from Utility Plant Leased to Others	0				
6	404. Amortization & Depletion	3,643,716	3,643,716			
7	184. Clearing Accounts	1,005,506	1,005,506			
8		0				
9		0				
10	**Total Depreciation Provisions**	21,339,888	21,339,888	0	0	0
11	Recoveries from Insurance	0				
12	Salvage Realized from Retirements	3,466,651	3,466,651			
13	Other Credits (Describe)					
14	Depreciation charged to Affiliates	0				
15	Other Misc Adjustments	0				
16		0				
17		0				
18	**Total Credits During Year**	3,466,651	3,466,651	0	0	0
19	**Total Credits**	24,806,539	24,806,539	0	0	0
20	Debits During Year	XXXXX	XXXXX	XXXXX	XXXXX	XXXXX
21	Retirement of Utility Plant	8,608,223	8,608,223			
22	Cost of Removal	1,153,518	1,153,518			
23	Other Debits (Describe)					
24	Prior Year RWIP Adjustment	0				
25	Current Year RWIP	936,881	936,881			
26	Transferred Property	2,697,629	2,697,629			
27		(10,827)	(10,827)			
28	**Total Debits During Year**	13,385,424	13,385,424	0	0	0
29	**Balance at End of Year**	290,803,376	290,803,376	0	0	0

Describe the basis upon which depreciation provisions for the year were determined and attach worksheets showing the computations made in arriving at the annual provisions.

207. GAS PLANT ACQUISITIONS ADJUSTMENTS - Account No. 114.0

Line No.	Item (a)	Project No. 1 Amount (b)	Project No. 2 Amount (c)	Project No. 3 Amount (d)	Project No. 4 Amount (e)	Totals (f)
1	Book Plant - Net					0
2	PUC Difference (Ratemaking)					0
3	Less Contributions (Net)					0
4	Net Utility Plant Acquired					0
5	Purchase Price					0
6	Acquisition Adjustment					0
7						
8						

206. ACCUMULATED DEPRECIATION OF UTILITY PLANT - (Continued)

Describe the basis upon which depreciation provisions for the year were determined and attach worksheets showing the computations made in arriving at the annual provisions

DEPRECIATION EXPENSE - ACCOUNT 403

The Respondent uses a straight-line method of depreciation by individual plant account. Depreciation is calculated monthly by applying the appropriate rate to the current month end balance in each account. The rates applied were as follows:

Intangible Plant	PA Rate	WV Rate	KY Rate
301	0 00%		
303	19.48%		
303.02	22.17%		
303.1	6 67%		
Production Plant			
325 2	0 37%		
325 4	0.29%	1 54%	
325.51	0 00%		
327	1.94%		
328	4.73%		
330	0.35%	1.14%	
331	0 45%	4.69%	
332	1.53%	1.53%	
333	2 22%		
334	0 67%	2 92%	
Transmission Plant			
365.1	0.00%		
365.2	0.94%		
366.1	1.65%		
366.2	2.23%		
367	0.74%		
368	1.72%		
369	2 40%	3 15%	
370	7.62%		
Distribution Plant			
374.1	0 00%	0.00%	
374 2	1.12%	1.75%	
375	2.12%	2.16%	
376	1.51%	1.94%	
376.02	0.76%		
378.1	2 07%	2 85%	
378.2	4.57%	5.01%	
380	2.22%	3.36%	
381	3.11%	3.49%	6 67%
382	1.35%	3.12%	3 45%
383	1.68%	3.33%	
384	1.59%	3 09%	
385	1.71%		
386 1	2 50%	10 00%	
386 2	5 67%	10 00%	
386.3	13.30%		
387	0 38%	4 00%	
387.1	10 83%	7 94%	
General Plant			
389 1	0 00%	0 00%	
389.2	0.46%		
390	2.96%	2 88%	
390 02	8.17%		
390.03	5.00%		
391	8.45%	3.71%	
391.02	0 00%		
391.1	12 88%		
391.12	0.00%		
392.1	13.43%	16 67%	
392.2	4.68%	3 21%	
393	4 94%	3.73%	
393.02	0 00%		
394	3.74%	1 28%	
394.02	0 00%		
395	16 54%		
396	9.40%	3.97%	
397.1	13.15%	7.73%	
397.12	0 00%		
397.2	4 62%	2 40%	
397.2 - 101.1	10 00%		
397.3	11.22%	7.31%	
397.4	9.79%	10 08%	
397 42	0.00%		
397.5	9.25%	14.29%	
397.6	10.51%		
397.7	8.73%		
398	6.26%	9.12%	
398 02	0 00%		

208. CONSTRUCTION WORK IN PROGRESS - Account No. 107

1. Describe the particulars concerning utility plant in process of construction but not ready for service at end of the Calendar Year.
2. Describe separately each work order that exceeds the lesser of an estimated expenditure of $300,000 or 10% of the book cost of utility plant at the beginning of the year. All other work orders may be grouped by nature of project.

Line No.	Description of Work (a)	Balance End of Year (b)	Estimate Total Cost of Construction (c)	Projected In-Service Date (d)
1	Distribution Plant	8,425,200	27,196,812	2007 - 2008
2	General Plant	7,084,377	11,178,190	2007
3	Intangible Plant	5,614,929	7,147,736	2007 - 2008
4				
5				
6				
7				
8				
9				
10				
11				
12				
13				
14				
15				
16				
17				
18				
19				
20				
21				
22				
23				
24				
25	TOTALS	21,124,506	45,522,738	

210. INVESTMENTS (Accounts 123 - 123.1 - 124 - 136)

Report below investments in Accounts 123, Investments in Associated Companies 123.1, Investments in Subsidiary Companies, 124, Other Investments and 136, Temporary Cash Investments.

2. Provide a subheading for each account and list thereunder the information called for, observing the instructions below.
3. Investments in Securities - List and describe each security owned giving name of issuer. For bonds give also principal amount, date of issue, maturity, and interest rate. For capital stock state number of shares, class and series of stock. Minor investments may be grouped by classes.
4. Investment Advances - Report separately for each person or company the amounts of loans or investment advances which are subject to repayment but which are not subject to current settlement. With respect to each advance show whether the advance is a note or open account. Each note should be listed giving date of issuance, maturity date, and specifying whether note is a renewal. Designate any advances due from officers, directors, stockholders, or employees.
5. For any securities, notes, or accounts that were pledged, designate such securities acquired, designate such fact and in a footnote state the name of pledges and purpose of the pledge.
6. If Commission approval was required for any advance made or security acquired, designate such fact and in a footnote give date of authorization and case or docket number.
7. Interest and dividend revenues from investments should be reported in column (g), including such revenues from securities disposed of during the year.
8. In column (h) report for each investment disposed of during the year the gain or loss represented by the difference between cost of the investment (or the other amount at which carried in the books of account if different from cost) and the selling price therefor, not including any dividend or interest adjustment incredible in column (g).

Line No.	Description of Investment (a)	Date Acquired (b)	Date of Maturity (c)	Book Costs* Beginning of Year (d)	Principal Amount or No. of Shares (e)	Book Cost End of Year (f)	Revenues For Year (g)	Gain or Loss From Invest Disposed of (h)
1	Investments in Subsidiary Companies (123.1):							
2	Kentucky West Virginia Gas Company, LLC							
3	*Membership Capital*	11/1/95		(75,989,547)		(135,389,547)	(59,400,000)	
4	Equity in Undistributed Earnings			68,105,249		70,648,555		
5	TOTAL			(7,884,298)		(64,740,992)	(59,400,000)	
6	Equitrans, L.P.							
7	*Partnership Capital*	11/1/95		(50,745,634)		(50,745,634)		
8	Equity in Undistributed Earnings			136,945,536		152,613,553		
9	TOTAL			86,199,902		101,867,919	0	
10	EQT Capital Corporation							
11	Common Stock (100 Shares)			2,310,929,896				
12	Equity in Undistributed Earnings			513,627,822			0	
13	TOTAL			2,824,557,718		0	0	
14	Equitable Resources Capital Trust I							
15	Paid in Capital			0		0		
16	Equity in Undistributed Earnings			(3)		(3)		
17	TOTAL			(3)		(3)	0	
18	Carnegie Pipeline	12/15/99						
19	Paid in Capital			19,650,278		19,650,278	0	
20	Equity in Undistributed Earnings			1,924,050		1,924,050	0	
21	TOTAL			21,574,328		21,574,328	0	
22	EQT Investment Holdings							
23	Membership Capital					3,104,084,706	40,000,000	
24	Equity in Undistributed Earnings					(2,139,240)	(40,841,176)	
25	TOTAL			0		3,101,945,466	(841,176)	
26	Equitable Resources Ins Ltd.							
27	Membership Capital			2,700,000		2,700,000		
28	Equity in Undistributed Earnings			(64,655)		1,332,956	(179,372)	
29	TOTAL			2,635,345		4,032,956	(179,372)	
30								
31	TOTAL COST ACCT. 123.1:			2,927,082,992		3,164,679,674	(60,420,548)	
32								
33	Temporary Cash Investments Account 136							
34	Commercial Paper			80,000,000		0		
35	TOTAL Acct. 136			80,000,000		0		

* If book cost is different from cost to respondent, give cost to respondent in a footnote and explain difference.

Refer to Item J of the Notes to Balance Sheet for further discussion of Investments in Subsidiaries.

211. NOTES AND OTHER ACCOUNTS RECEIVABLE (Accounts 141, and 143)

If interest was derived during year from notes liquidated before the end of the year, include such interest revenue in column (d).

Line No.	Item (a)	Notes Receivable 1/1/2006 (b)	Notes Receivable 12/31/2006 (c)	Notes Receivable Interest Revenue (d)	Other Accounts Receivable 1/1/2006 (e)	Other Accounts Receivable 12/31/06 (f)
1	Note Receivable-Allegheny Center Mall	756,710	628,268	48,901		
2	Reimbursable Construction Orders				24,266	819,832
3	Other Accounts Receivable				477,857	189
4						
5						
6						
7	Total	756,710	628,268	48,901	502,123	820,021

212. NOTES RECEIVABLE FROM ASSOCIATED COMPANIES (Account 145)

1. Furnish below the particulars indicated concerning notes receivable from associated companies at end of year.
2. If any note was received in satisfaction of an open account indebtedness, state the period covered by such open account.
3. Include in column (f) the amount of any interest revenue during the year on notes that were paid off before the end of year.
4. Give particulars of any notes pledged or discounted. This schedule shall include all transactions during the year with each affiliated interest affecting account 145 and account 233.

Line No.	Name of Associated Company (a)	Date of Issue (b)	Date of Maturity (c)	Amount End of Year (d)	Interest Rate (e)	Amount (f)
1	**NONE**					
2						
3						
4						
5						
6						
7						
8						

213. ACCOUNTS RECEIVABLE FROM ASSOCIATED COMPANIES (ACCOUNT 146) AND ACCOUNTS PAYABLE TO ASSOCIATED COMPANIES (ACCOUNT 234)

1. Furnish below the particulars called for concerning Account Receivables and Payables from Associated Companies.
2. The term "Services Received" set forth on line 21 of this schedule means the Management, Construction, Engineering, Purchasing Legal, Accounting or other similar service which has been rendered to respondent under written, oral or implied contracts.
3. The term "Joint Expenses Transferred" set forth on lines 6 and 22 means Central office and/or other expenses continuously assessed against respondent covering all locations of common operating costs.
4. This schedule shall include all transactions during the year with each affiliated interest affecting Account 146.

Line No.	Item (a)	Entries During Year (b)
1	**Debits During Year**	
2	Cash Dispensed	287,928,871
3	Materials and Supplies Sold	
4	Services Rendered	
5	Joint Expense Transferred	987,790,520
6	Interest and Dividends Receivable	
7	Rents Receivable	
8	Securities Sold	
9	Other Debits (Specify)	
10		
11		
12		
13	**Total Debits During Year**	1,275,719,391
14		
15	**Credits During Year**	
16	Cash Received	273,317,167
17	Gas Purchased	61,910,018
18	Fuel Purchased	
19	Materials and Supplies Purchased	
20	Services Received	
21	Joint Expense Transferred	843,800,391
22	Interest and Dividends Payable	
23	Rents Payable	
24	Securities Purchased	
25	Transferred to Account "145"	
26	Other Credits (Specify) Balance Beginning of Year	80,794,376
27		
28		
29		
30	**Total Credits During Year**	1,259,821,952
31	**Balance at End of Year**	15,897,439

215. PLANT MATERIALS AND OPERATING SUPPLIES (Account 154)

1. Summarize below by character of materials and supplies, the balances in account 154 at the beginning and end of the year.
2. Account entries totaling $300,000 or 1% of gross revenues, (whichever is less), during the year shall be explained, showing the class of materials affected and the various classes of accounts (operating expenses, clearing accounts, plant accounts, etc.) debited or credited.

Line No.	Classification of Materials And Supplies (a)	Balance Beginning of Year (b)	Balance End of Year (c)	Increase /Decrease (d)
1	General Supplies	2,250,898	1,556,229	(694,669)
2				0
3				0
4				0
5				0
6				0
7				0
8				0
9				0
10				0
11				0
12				0
13				0
14				0
15				0
16				0
17	**Total**	2,250,898	1,556,229	(694,669)

216. UNAMORTIZED DEBT DISCOUNT AND EXPENSE AND UNAMORTIZED PREMIUM ON DEBT (Accounts 181, 225)

1. Report under separate subheadings for Unamortized Debt Discount and Unamortized Premium on Debt, particulars of discount and expense or premium applicable to each class and series of long-term debt.
2. Show premium amounts in red or by enclosure in parenthesis
3. In column (b) show the principal amount of bonds or other long-term debt originally issued.
4. In column (c) show the discount and expense or premium with respect to the amount of bonds or other long-term debt originally issued.
5. Furnish particulars regarding the treatment of unamortized debt discount and expense or premium, redemption premium, and redemption expenses associated with issues redeemed during the year, also, date of the Commission's authorization of treatment other than by debit or credit to Surplus.
6. Set out separately and identify amounts applicable to issues which have been redeemed, although those amounts, prior to the effective date of the Uniform System of Accounts may have prior to the effective date of the Uniform System of Accounts may have been combined with the discount and expense on the refunding issue.
7. Explain any debits and credits other than amortization debited to Account 428, Amortization of Debt Discount and Expense, or credited to Account 429, Amortization of Premium on Debt.

Line No.	Designation of Long-Term Debt (a)	PRINCIPAL AMOUNT OF SECURITIES TO WHICH OR PREMIUM RELATES (b)	TOTAL DISCOUNT AND EXPENSE OR NET PREMIUM (c)	Amortization Period From (d)	To (e)	Balance Beginning of Year (f)	Debits During Year (g)	Credits During Year (h)	Balance End of Year (i)
1	Account 181								
2	Unamortized Debt Expense:								
3	7.75% Debentures Due 7/15/26	150,000,000	6,319,649	7/29/1996	7/15/2026	10,186,374		471,956	9,714,418
4	Medium-Term Notes -- Series A	100,000,000	1,004,911	9/4/1991	10/1/2021	253,760		25,731	228,029
5	Medium-Term Notes -- Series B	75,500,000	823,766	7/20/1992	3/2/2023	144,727		40,040	104,687
6	Medium-Term Notes -- Series C	18,000,000	164,038	5/26/1995	1/15/2018	119,486		19,376	100,110
7	Medium Term Notes -- 5.00%	150,000,000	1,732,520	9/22/2005	10/1/2015	1,670,140	81,443	177,167	1,574,416
8	Medium-Term Notes -- 5.15%	200,000,000	1,583,716	11/15/2002	11/15/2012	1,365,450		193,534	1,171,916
9	Credit Revolver	1,500,000,000	1,251,890	10/27/2006	10/26/2011	2,544,045	985,682	574,374	2,955,353
10	Medium Term Notes -- 5.15%	200,000,000	2,119,380	2/1/2003	3/1/2018	1,740,192		144,430	1,595,762
11									0
12									0
13									0
14									0
15	Total	2,393,500,000	14,999,870			18,024,174	1,067,125	1,646,608	17,444,691

217. EXTRAORDINARY PROPERTY LOSSES (Account 182)

1. Report below the information indicated concerning this account, grouping the items by departments, and showing totals for each department.
2. Include in the description the date property was abandoned or other extraordinary loss incurred.

Line No.	Description of Property Loss Or Damage (a)	Comm. Auth. No. (b)	Amortization Period (Give Years Only) From (c)	To (d)	Total Amount of Loss (e)	Previously Written off (f)	Written off During Year Account Charged (g)	Amount (h)	Balances At End of Year (i)
1	NONE								
2									
3									
4									
5									
6									
7									
8	Total								0

231. LONG-TERM DEBT (Accounts 221,222,224)

(Excluding Advances from Affiliated Companies)

1. Give below the particulars indicated of the long-term debt at end of year represented by unmatured obligations issued or assumed by the respondent, exclusive of advances from affiliated companies.
2. Group entries according to accounts and show the total for each account.
3. For obligations assumed by the respondent show in column (a) the name of the issuing company and the class and series of such obligations.
4. For Receivers' Certificates show the name of the court and date of court order under which such certificates were issued.
5. If respondent has pledged any of its long-term debt securities give particulars in a footnote, including name of the pledge name of the pledge and purpose of pledge.
6. If interest expense was incurred during the year on any obligations retired or reacquired before end of year include such interest expense in column (g).
7. If interest was matured but unpaid on any obligation, state in a footnote the class and series and principal amount of such obligation and the amount of interest matured thereon.

Line No.	Class and Series of Obligations (a)	Nominal Date of Issue (b)	Date of Maturity (c)	Principal Amount Authorized (d)	Outstanding Per Balance Sheet (e)	Interest For Year: Rate (f)	Interest For Year: Amount (g)	Held By Respondent: As Reacquired. Lg.-Term Debt (h)	Held By Respondent: In Sinking & Other Funds (i)
1	Account 221								
2	7-3/4% Debentures	07/29/96	07/15/26		115,000,000	7.75	8,912,500		
3	Medium-Term Notes -- Series A	09/04/91	10/01/21		50,500,000	9.00	4,638,570		
4	Medium-Term Notes -- Series B	07/20/92	03/02/23		30,000,000	7.60	2,227,000		
5	Medium-Term Notes -- Series C	05/26/95	01/15/18		18,000,000	7.60	1,286,000		
6	Medium-Term Notes -- 5.15%	11/15/02	11/15/12		200,000,000	5.15	10,300,000		
7	Medium-Term Notes -- 5.15%	2/1/03	3/1/18		200,000,000	5.15	10,300,000		
8	Medium-Term Notes -- 5.00%	9/22/05	10/1/15		150,000,000	5.00	7,500,000		
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27									
28	TOTAL			0	763,500,000		45,164,070	0	0

*Total amount outstanding without reduction for amount held by respondent.

400. INCOME STATEMENT
REVENUES AND EXPENSES - TOTAL COMPANY
Balances at Beginning of Year must be consistent with balances at end of previous year

Line No.	Account Number and Title (a)	Schedule Page No. (b)	Balance End of Current Year (c)	Balance End of Previous Year (d)	Increase/ Decrease (e)
1	**SALES OF GAS**				
2	480.0 Residential Sales	600	309,532,124	333,895,991	(24,363,867)
3	481.0 Commercial and Industrial Sales	600	68,763,677	67,472,688	1,290,989
4	482.0 Other Sales to Public Authorities	600			0
5	483.0 Sales for Resale	501			0
6	484.0 Indepartmental Sales	600			0
7	485.0 Intracompany Transfers	600			0
8	***TOTAL SALES OF GAS***		*378,295,801*	*401,368,679*	*(23,072,878)*
9					
10	**OTHER OPERATING REVENUES**				
11	487.0 Forfeited Discounts	600	1,577,062	1,731,154	(154,092)
12	488.0 Miscellaneous Service Revenues	600	1,164,789	1,064,305	100,484
13	489.1 Revenues from Transportation of Gas of Others Through				0
14	Gathering Facilities				0
15	*489.2 Revenues from Transportation of Gas of Others Through*				0
16	Transmission Facilities				0
17	489.3 Revenues from Transportation of Gas of Others Through		64,055,443	66,873,412	(2,817,969)
18	Distribution Facilities				0
19	489.4 Revenues from Storing Gas of Others				0
20	490.0 Sales of Products Extracted from Natural Gas				0
21	491.0 Revenues from Natural Gas Processed by Others				0
22	492.0 Incidental Gasoline and Oil Sales				0
23	493.0 Rent from Gas Property	600	5,311	6,348	(1,037)
24	494.0 Interdepartmental Rents	600			0
25	495.0 Other Gas Revenues	600	236,194	183,565	52,62[illegible]
26	496.0 Provision for Rate Refunds				0
27	**TOTAL OTHER OPERATING REVENUES**		67,038,799	69,858,784	(2,819,985)
28					
29	**TOTAL REVENUES**		445,334,600	471,227,463	(25,892,863)
30					

400. INCOME STATEMENT
REVENUES AND EXPENSES - TOTAL COMPANY

Balances at Beginning of Year must be consistent with balances at end of previous year

Line No.	Account Number and Title (a)	Schedule Page No. (b)	Balance Current Year (c)	Balance Previous Year (d)	Increase/ Decrease (e)
1	**OPERATING EXPENSES**				
2	401 Operation Expenses		375,070,419	400,082,638	(25,012,219)
3	402 Maintenance Expenses		11,680,372	13,292,933	(1,612,561)
4	403 Depreciation Expenses		16,690,666	15,900,520	790,146
5	404.1 Amort. & Depletion of Prod. Natural Gas Land & Rights				0
6	404.2 Amort. Of Underground Storage Land & Land Rights				0
7	404.3 Amort. Of Other Limited-Term Gas Plant		3,643,716	3,728,715	(84,999)
8	405.0 Amortization of Other Gas Plant				0
9	406.0 Amortization of Gas Plant Acquisition Adjustments				0
10	407.1 Amort. Of Prop. Losses, Unrec. Plant & Reg. Study C.				0
11	407.2 Amortization of Conversion Expense				0
12	407.3 Regulatory Debits				0
13	407.4 Regulatory Credits				0
14	408.1 Taxes Other Than Income Taxes, Utility Opr. Income	408	3,708,795	2,567,032	1,141,763
15	409.1 Income Taxes, Utility Operating Income	409	(36,918,432)	(26,843,974)	(10,074,458)
16	410.1 Provision for Deferred Income Taxes, Ut. Opr. Income	411	(13,255,599)	(1,056,489)	(12,199,110)
17	411.1 Prov. For Def. Income Taxes-Credit, Ut. Opr. Income	412			0
18	411.4 Investment Tax Credit Adjustments, Ut. Operations		(19,800)	(24,200)	4,400
19	411.6 Gains from Disposition of Utility Plant				0
20	411.7 Losses from Disp. of Utility Plant				0
21	Total Utility Operating Expenses		360,600,137	407,647,175	(47,047,038)
22	**OTHER OPERATING INCOME**				
23	412.0 Revenues from Gas Plant Leased to Others				0
24	413.0 Expenses of Gas Plant Leased to Others				0
25	414.0 Other Utility Operating Income				0
26	Total Other Operating Income		0	0	0
27	**OTHER INCOME**				
28	415.0 Rev. from Merchandising, Jobbing and Contract Work				0
29	416.0 Costs and Exp. of Merchandising Jobbing & Contract Wk				0
30	417.0 Revenue from Non-Utility Operations		(134,897)	(135,446)	549
31	418.0 Non Operating Rental Income				0
32	418.1 Equity in Earnings of Subsidiary Companies		298,017,229	322,485,980	(24,468,751)
33	419.0 Interest & Dividend Income		(22,575,501)	(9,636,489)	(12,939,012)
34	419.1 Allowance for Other Funds Used During Construction		303,842	277,066	26,776
35	421.0 Miscellaneous Non Operating Income		(7,171,123)	(24,587,643)	17,416,520
36	421.1 Gain on Disposition of Property, Total Other Income		93,152	4,006	89,146
37	Total Other Income		268,532,702	288,407,474	(19,874,772)
38	**OTHER INCOME DEDUCTIONS**				
39	421.2 Loss on Disposition of Property				0
40	425.0 Miscellaneous Amortization				0
41	426.1 Donations		14,129	4,050	10,079
42	426.2 Life Insurance				0
43	426.3 Penalties				0
44	426.4 Exp. for Certain Civic, Political & Related Activities		2,551	20,806	(18,255)
45	426.5 Other Deductions		21,834,235	43,210,456	(21,376,221)
46	Total Other Income Deductions		21,850,915	43,235,312	(21,384,397)
47	**TAXES APPLICABLE TO OTHER INCOME & DED.**				
48	408.2 Taxes Other Than Income Taxes, Otr. Income & Ded.				0
49	409.2 Income Taxes, Other Income & Deductions				0
50	410.2 Prov. for Deferred Income Taxes, Otr. Income & Ded.				0
51	411.2 Prov. for Def. Income Taxes, Credit, Otr Income & Ded.				0
52	411.5 Investment Tax Cr. Adjustments, Nonutility Operations				0
53	420.0 Investment Tax Credits		(686,600)	(686,500)	(100)
54	Total Taxes on Other Income and Deductions		(686,600)	(686,500)	(100)
55	Net Other Income and Deductions		247,368,387	245,858,662	1,509,725

400. INCOME STATEMENT
REVENUES AND EXPENSES - TOTAL COMPANY

Balances at Beginning of Year must be consistent with balances at end of previous year

Line No.		Account Number and Title (a)	Schedule Page No. (b)	Balance Current Year (c)	Balance Previous Year (d)	Increase/ Decrease (e)
1		**INTEREST CHARGES**				
2	427	Interest on Long-Term Debt		57,315,005	46,517,920	10,797,085
3	428	Amortization of Debt Discount and Expense		1,074,581	939,484	135,097
4	428.1	Amortization of Loss on Reacquired Debt		245,272	245,272	0
5	429	Amortization of Premium on Debt-Credit				0
6	429.1	Amortization of Gain on Reacquired Debt-Credit				0
7	430	Interest on Debt to Associated Companies		44,783,785	23,458,505	21,325,280
8	431	Other Interest Expense		8,155,930	12,553,638	(4,397,708)
9	432	Allowance for Borrowed Funds Used During Construction-Cr		(166,420)	(151,751)	(14,669)
10		Net Interest Charges		111,408,153	83,563,068	27,845,085
11		**EXTRAORDINARY ITEMS**				
12	434	Extraordinary Income				0
13	435	Extraordinary Deductions		3,654,557	(34,179,290)	37,833,847
14	409.3	Income Taxes-Extraordinary Items		(3,246,355)		(3,246,355)
15		Net Income		220,286,495	260,055,172	(39,768,677)
16						
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400. INCOME STATEMENT
REVENUES AND EXPENSES - PENNSYLVANIA DIVISION

Balances at Beginning of Year must be consistent with balances at end of previous year

Line No.	Account Number and Title (a)	Schedule Page No. (b)	Balance End of Current Year (c)	Balance End of Previous Year (d)	Increase/ Decrease (e)
1	**SALES OF GAS**				
2	480.0 Residential Sales	600	292,579,331	317,483,855	(24,904,524)
3	481.0 Commercial and Industrial Sales	600	63,754,351	63,640,413	113,938
4	482.0 Other Sales to Public Authorities	600			0
5	483.0 Sales for Resale	501			0
6	484.0 Indepartmental Sales	600			0
7	485.0 Intracompany Transfers	600			0
8	**TOTAL SALES OF GAS**		356,333,682	381,124,268	(24,790,586)
9					
10	**OTHER OPERATING REVENUES**				
11	487.0 Forfeited Discounts	600	1,512,240	1,682,516	(170,276)
12	488.0 Miscellaneous Service Revenues	600	1,164,789	1,064,305	100,484
13	489.1 Revenues from Transportation of Gas of Others Through				0
14	Gathering Facilities				0
15	489.2 Revenues from Transportation of Gas of Others Through				0
16	Transmission Facilities				0
17	489.3 Revenues from Transportation of Gas of Others Through				0
18	Distribution Facilities		63,457,558	66,134,966	(2,677,408)
19	489.4 Revenues from Storing Gas of Others				0
20	490.0 Sales of Products Extracted from Natural Gas				0
21	491.0 Revenues from Natural Gas Processed by Others				0
22	492.0 Incidental Gasoline and Oil Sales				0
23	493.0 Rent from Gas Property	600	5,311	6,348	(1,037)
24	494.0 Interdepartmental Rents	600			
25	495.0 Other Gas Revenues	600	236,194	185,489	50,705
26	496.0 Provision for Rate Refunds				0
27	**TOTAL OTHER OPERATING REVENUES**		66,376,092	69,073,624	(2,697,532)
28					
29	**TOTAL REVENUES**		422,709,774	450,197,892	(27,488,118)
30					

400. INCOME STATEMENT
REVENUES AND EXPENSES - PENNSYLVANIA DIVISION

Balances at Beginning of Year must be consistent with balances at end of previous year

Line No.	Account Number and Title (a)	Schedule Page No. (b)	Balance Current Year (c)	Balance Previous Year (d)	Increase/ Decrease (e)
1	**OPERATING EXPENSES**				
2	401 Operation Expenses		355,408,476	383,121,614	(27,713,138)
3	402 Maintenance Expenses		11,146,009	12,610,319	(1,464,310)
4	403 Depreciation Expenses		15,743,994	14,974,691	769,303
5	404.1 Amort. & Depletion of Prod. Natural Gas Land & Rights				0
6	404.2 Amort. Of Underground Storage Land & Land Rights				0
7	404.3 Amort. Of Other Limited-Term Gas Plant		3,638,452	3,728,715	(90,263)
8	405.0 Amortization of Other Gas Plant				0
9	406.0 Amortization of Gas Plant Acquisition Adjustments				0
10	407.1 Amort. Of Prop. Losses, Unrec. Plant & Reg. Study C.				0
11	407.2 Amortization of Conversion Expense				0
12	407.3 Regulatory Debits				0
13	407.4 Regulatory Credits				0
14	408.1 Taxes Other Than Income Taxes, Utility Opr. Income	408	2,043,010	897,543	1,145,467
15	409.1 Income Taxes, Utility Operating Income	409	(36,918,432)	(26,843,974)	(10,074,458)
17	410.1 Provision for Deferred Income Taxes, Ut. Opr. Income	411	(13,255,599)	(1,056,489)	(12,199,110)
18	411.1 Prov. For Def. Income Taxes-Credit, Ut. Opr. Income	412			0
19	411.4 Investment Tax Credit Adjustments, Ut. Operations		(19,800)	(24,200)	4,400
20	411.6 Gains from Disposition of Utility Plant				0
21	411.7 Losses from Disp. of Utility Plant				0
22	Total Utility Operating Expenses		337,786,110	387,408,219	(49,622,109)
23	**OTHER OPERATING INCOME**				
24	412.0 Revenues from Gas Plant Leased to Others				0
25	413.0 Expenses of Gas Plant Leased to Others				0
26	414.0 Other Utility Operating Income				0
27	Total Other Operating Income		0	0	0
28	**OTHER INCOME**				0
29	415.0 Rev. from Merchandising, Jobbing and Contract Work				0
30	416.0 Costs and Exp. of Merchandising Jobbing & Contract Wk				0
31	417.0 Revenue from Non-Utility Operations		(134,881)	(126,072)	(8,809)
32	418.0 Non Operating Rental Income				0
33	418.1 Equity in Earnings of Subsidiary Companies		297,830,607	323,270,234	(25,439,627)
34	*419.0 Interest & Dividend Income*		(22,575,501)	(10,148,167)	(12,427,334)
35	419.1 Allowance for Other Funds Used During Construction		302,157	275,110	27,047
36	421.0 Miscellaneous Non Operating Income		(7,171,123)	(24,587,643)	17,416,520
37	421.1 Gain on Disposition of Property, Total Other Income		93,152	4,006	89,146
38	Total Other Income		268,344,411	288,687,468	(20,343,057)
39	**OTHER INCOME DEDUCTIONS**				0
40	421.2 Loss on Disposition of Property				0
41	425.0 Miscellaneous Amortization				0
42	426.1 Donations		14,129	4,050	10,079
43	426.2 Life Insurance				0
44	426.3 Penalties				0
45	426.4 Exp. for Certain Civic, Political & Related Activities		2,551	20,806	(18,255)
46	426.5 Other Deductions		21,834,235	43,210,456	(21,376,221)
47	Total Other Income Deductions		21,850,915	43,235,312	(21,384,397)
48	**TAXES APPLICABLE TO OTHER INCOME & DED.**				0
49	408.2 Taxes Other Than Income Taxes, Otr. Income & Ded.				0
50	409.2 Income Taxes, Other Income & Deductions				0
51	410.2 Prov. for Deferred Income Taxes, Otr. Income & Ded.				0
52	411.2 Prov. for Def. Income Taxes, Credit, Otr Income & Ded.				0
53	411.5 Investment Tax Cr. Adjustments, Nonutility Operations				0
54	420.0 Investment Tax Credits		(686,600)	(686,500)	(100)
55	Total Taxes on Other Income and Deductions		(686,600)	(686,500)	(100)
56	Net Other Income and Deductions		247,180,096	246,138,656	1,041,440

400. INCOME STATEMENT
REVENUES AND EXPENSES - PENNSYLVANIA DIVISION

Balances at Beginning of Year must be consistent with balances at end of previous year

Line No.	Account Number and Title (a)	Schedule Page No. (b)	Balance Current Year (c)	Balance Previous Year (d)	Increase/ Decrease (e)
1	**INTEREST CHARGES**				
2	427 Interest on Long-Term Debt		57,315,005	46,517,920	10,797,085
3	428 Amortization of Debt Discount and Expense		1,074,581	939,484	135,097
4	428.1 Amortization of Loss on Reacquired Debt		245,272	245,272	0
5	429 Amortization of Premium on Debt-Credit				0
6	429.1 Amortization of Gain on Reacquired Debt-Credit				0
7	430 Interest on Debt to Associated Companies		44,783,785	22,946,827	21,836,958
8	431 Other Interest Expense		8,155,930	12,553,638	(4,397,708)
9	432 Allowance for Borrowed Funds Used During Construction-Cr		(165,510)	(150,694)	(14,816)
10	Net Interest Charges		111,409,063	83,052,447	28,356,616
11	**EXTRAORDINARY ITEMS**				0
12	434 Extraordinary Income		3,654,557	(34,179,290)	37,833,847
13	435 Extraordinary Deductions		(3,246,335)		(3,246,335)
14	409.3 Income Taxes-Extraordinary Items				0
15	Net Income		220,286,475	260,055,172	(39,768,697)
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405. OPERATION AND MAINTENANCE EXPENSES - TOTAL COMPANY

Balances at Beginning of Year must be consistent with balances at end of previous year

Line No.	Account Number and Title (a)	Schedule Page No. (b)	Balance Current Year (c)	Balance Previous Year (d)	Increase/ Decrease (e)
1	**MANUFACTURED GAS PRODUCTION EXPENSES**		XXX	XXX	XXX
2	**Steam Production Expenses**				
3	**Operation**				
4	700.0 Operation Supervision and Engineering				0
5	701.0 Operating Labor				0
6	702.0 Boiler Fuel				0
7	703.0 Miscellaneous Steam Expenses				0
8	**Total Steam Production Operation Expenses**		0	0	0
9	**Maintenance**				
10	704.0 Steam Transferred-Credit				0
11	705.0 Maintenance. Supervision and Engineering				0
12	706.0 Maintenance of Structures and Improvements				0
13	707.0 Maintenance of Boiler Plant Improvement				0
14	708.0 Maintenance of Other Steam Production Plant				0
	Total Steam Production Maintenance Expenses		0		0
15	**Manufactured Gas Production**				
16	710.0 Operation Supervision and Engineering				0
17	**Production Labor and Expenses**				
18	711.0 Steam Expenses				0
19	712.0 Other Power Expenses				0
20	713.0 Coke Oven Expenses				0
21	714.0 Producer Gas Expenses				0
22	715.0 Water Gas Generating Expenses				0
23	716.0 Oil Gas Generating Expenses				0
24	717.0 Liquefied Petroleum Gas Expenses				0
25	718.0 Other Process Production Expenses				0
	Total Production Labor and Expenses		0	0	0
26	**Gas Fuels**				
27	719.0 Fuel Under Coke Ovens				0
28	720.0 Producer Gas Fuel				0
29	721.0 Water Gas Generator Fuel				0
30	722.0 Fuel for Oil Gas				0
31	723.0 Fuel for Liquefied Petroleum Gas Process				0
32	724.0 Other Gas Fuels				0
	Total Gas Fuels Expenses		0	0	0
33	**Gas Raw Materials**				
34	725.0 Coal Carbonized in Coke Ovens				0
35	726.0 Oil for Water Gas				0
36	727.0 Oil for Oil Gas				0
37	728.0 Liquefied Petroleum Gas Expenses				0
38	729.0 Raw Materials for Other Gas Processes				0
39	730.0 Residuals Expenses				0
40	731.0 Residuals Produced-Credit				0
41	732.0 Purification Expenses				0
42	733.0 Gas Mixing Expenses				0
43	734.0 Duplicate Charges-Credit				0
44	735.0 Miscellaneous Production Expenses				0
45	736.0 Rents				0
	Total Gas Raw Materials Expenses		0	0	0
46	**Maintenance**				
47	740.0 Maintenance Supervision and Engineering				0
48	741.0 Maintenance of Structures and Improvements				0
49	742.0 Maintenance of Production Equipment				0
	Total Maintenance Expenses		0	0	0
	Total Manufactured Gas Production Expenses		0	0	0
50	NATURAL GAS PRODUCTION EXPENSES		XXX	XXX	XXX
51	**Production and Gathering**				
52	**Operation**				
53	750.0 Operating Supervision and Engineering		3,120		3,120
53	751.0 Production Maps and Records				0
54	752.0 Gas Wells Expenses		807	1,666	(859)

405. OPERATION AND MAINTENANCE EXPENSES (Continue) - TOTAL COMPANY

Balances at Beginning of Year must be consistent with balances at end of previous year

Line No.	Account Number and Title (a)	Schedule Page No. (b)	Balance Current Year (c)	Balance Previous Year (d)	Increase/ Decrease (e)
1	753.0 Field Lines Expenses				0
2	754.0 Field Compressor Station Expenses				0
3	755.0 Field Compressor Station Fuel and Power				0
4	756.0 Field Measuring and Regulating Station Expenses				0
5	757.0 Purification Expenses				0
6	758.0 Gas Well Royalties				0
7	759.0 Other Expenses				0
8	760.0 Rents				0
	Total Production & Gathering Operation Expenses		3,927	1,666	2,261
9	**Maintenance**				
10	761.0 Maintenance Supervision and Engineering				0
11	762.0 Maintenance of Structures and Improvements				0
12	763.0 Maintenance of Producing Gas Wells				0
13	764.0 Maintenance of Field Lines				0
14	765.0 Maintenance of Field Compressor Station Equipment				0
15	766.0 Maintenance of Field Measuring and Reg. Station Equip.				0
16	767.0 Maintenance of Purification Equipment				0
17	768.0 Maintenance of Drilling and Cleaning Equipment				0
18	769.0 Maintenance of Other Equipment				0
	Total Production & Gathering Maintenance Expenses		0	0	0
19	***Products Extraction***				
20	**Operation**				
21	770.0 Operation Supervision and Engineering				0
22	771.0 Operating Labor				0
23	772.0 Gas Shrinkage				0
24	773.0 Fuel				0
25	774.0 Power				0
26	775.0 Materials				0
27	776.0 Operation Supplies and Expenses				0
28	777.0 Gas Processed by Others				0
29	778.0 Royalties on Products Extracted				0
30	779.0 Marketing Expenses				0
31	780.0 Products Purchased for Resale				0
32	781.0 Variation in Products Inventory				0
33	782.0 Extracted Products Used by the Utility-Credit				0
34	783.0 Rents				0
	Total Products Extraction Operation Expenses		0	0	0
35	**Maintenance**				
36	784.0 Maintenance Supervision and Engineering				0
37	785.0 Maintenance of Structures and Improvements				0
38	786.0 Maintenance of Extraction and Refining Equipment				0
39	787.0 Maintenance of Pipe Lines				0
40	788.0 Maintenance of Extracted Products Storage Equipment				0
41	789.0 Maintenance of Compressor Equipment				0
42	790.0 Maintenance of Gas Measuring & Regulating Equipment				0
43	791.0 Maintenance of Other Equipment				0
	Total Products Extraction Maintenance Expenses		0	0	0
	Total Natural Gas Production Expenses		3,927	1,666	2,261
44	**EXPLORATION AND DEVELOPMENT EXPENSES**		XXX	XXX	XXX
45	**Operation**				
46	795.0 Delay Rentals				0
47	796.0 Nonproductive Well Drilling				0
48	797.0 Abandoned Leases				0
49	798.0 Other Exploration				0
	Total Exploration and Development Operation Exp.		0	0	0
50	**OTHER GAS SUPPLY EXPENSES**		XXX	XXX	XXX
51	**Operation**				
52	800.0 Natural Gas Well Head Purchases				0
53	801.0 Natural Gas Well Head Purchases, Intercompany Trans.		106,373,081	122,401,513	(16,028,432)
54	802.0 Natural Gas Gasoline Plant Outlet Purchases				0
55	803.0 Natural Gas Transmission Line Purchases		146,363,970	152,578,865	(6,214,895)
56	804.0 Natural Gas City Gate Purchases				0

405. OPERATION AND MAINTENANCE EXPENSES (Continued) - TOTAL COMPANY

Balances at Beginning of Year must be consistent with balances at end of previous year

Line No.	Account Number and Title (a)	Schedule Page No. (b)	Balance Current Year (c)	Balance Previous Year (d)	Increase/ Decrease (e)
1	804.1 Liquefied Natural Gas Purchases				0
2	805.0 Other Gas Purchases				0
3	805.1 Purchases Gas Cost Adjustments		2,654,700	(25,189,565)	27,844,265
4	806.0 Exchange Gas				0
5	807.0 Purchased Gas Expenses		48,560	32,425	16,135
6	808.1 Gas Withdrawn from Storage-Debit		65,537,555	89,470,332	(23,932,777)
7	808.2 Gas Delivered to Storage-Credit		(82,926,900)	(99,862,973)	16,936,073
8	809.1 Withdrawals of Liquefied Nat. Gas Held for Processing				0
9	809.2 Deliveries of Natural Gas for Processing				0
10	810.0 Gas Used for Compressor Station Fuel-Credit				0
11	811.0 Gas Used for Products Extraction-Credit				0
12	812.0 Gas Used for Other Utility Operations-Credit				0
13	813.0 Other Gas Supply Expenses		62,152,706	72,834,163	(10,681,457)
	Total Gas Supply Operation Expenses		300,203,672	312,264,760	(12,061,088)
14	**Natural Gas Storage, Terminating & Processing Exp.**				
15	**Underground Storage Expenses**				
16	814.0 Operation Supervision and Engineering				
17	815.0 Maps and Records				0
18	816.0 Wells Expenses				0
19	817.0 Lines Expenses				0
20	818.0 Compressor Station Expenses				0
21	819.0 Compressor Station Fuel and Power				0
22	820.0 Measuring and Regulating Station Expenses				0
23	821.0 Purification Expenses				0
24	822.0 Exploration and Development				0
25	823.0 Gas Losses				0
26	824.0 Other Expenses				0
27	825.0 Storage Well Royalties				0
28	826.0 Rents				0
	Total Underground Storage Expenses		0	0	0
29	**Maintenance**				0
30	830.0 Maintenance Supervision and Engineering				
31	831.0 Maintenance of Structures and Improvements				0
32	832.0 Maintenance of Reservoirs and Wells				0
33	833.0 Maintenance of Lines				0
34	834.0 Maintenance of Compressor Station Equipment				0
35	835.0 Maintenance of Measuring & Regulating Station Equip.				0
36	836.0 Maintenance of Purification Equipment				0
37	837.0 *Maintenance of Other Equipment*				0
	Total Maintenance Expenses		0	0	0
38	**Other Storage Expenses**				0
39	**Operation**				
40	840.0 Operating Supervision and Engineering				
41	841.0 Operation Labor and Expenses				0
42	842.0 Rents				0
43	842.1 Fuel				0
44	842.2 Power				0
45	842.3 Gas Losses				0
	Total Operation Expenses		0	0	0
46	**Maintenance**				0
47	843.1 Maintenance Supervision and Engineering				0
48	843.2 Maintenance of Structures and Improvements				0
49	843.3 Maintenance of Gas Holders				0
50	843.4 Maintenance of Purification Equipment				0
51	843.5 Maintenance of Liquefaction Equipment				0
52	843.6 Maintenance of Vaporizing Equipment				0
53	843.7 Maintenance of Compressor Equipment				0
54	843.8 Maintenance of Measuring and Regulatory Equipment				0
55	843.9 Maintenance of Other Equipment				0
	Total Maintenance Expenses		0	0	0

405. OPERATION AND MAINTENANCE EXPENSES (Continued) - TOTAL COMPANY

Balances at Beginning of Year must be consistent with balances at end of previous year

Line No.		Account Number and Title (a)	Schedule Page No. (b)	Balance Current Year (c)	Balance Previous Year (d)	Increase/ Decrease (e)
1						
2		LIQUEFIED NATURAL GAS TERMINATING AND				
3		PROCESSING EXPENSES		XXX	XXX	XXX
4		Operation				
5	844.1	Operation Supervision and Engineering				0
6	844.2	LNG Processing Terminal Labor and Expenses				0
7	844.3	Liquefaction Processing Labor and Expenses				0
8	844.4	LNG Transportation Labor and Expenses				0
9	844.5	Measuring and Regulating Labor and Expenses				0
10	844.6	Compressor Station Labor and Expenses				0
11	844.7	Communication System Expenses				0
12	844.8	System Control and Load Dispatching				0
13	845.1	Fuel				0
14	845.2	Power				0
15	845.3	Rents				0
16	845.4	Demurrage Charges				0
17	845.5	Warfare Receipts-Credit				0
18	845.6	Processing Liquefied or Vaporized Gas by Others				0
19	846.1	Gas Losses				0
20	846.2	Other Expenses				0
		Total Liq. N.G. Term & Proc. Operation Expenses		0	0	0
21		Maintenance				
22	847.1	Maintenance Supervision and Engineering				0
23	847.2	Maintenance of Structures and Improvements				0
24	847.3	Maintenance of LNG Processing Terminal Equipment				0
25	847.4	Maintenance of LNG Transportation Equipment				0
26	847.5	Maintenance of Measuring and Regulating Equipment				0
27	847.6	Maintenance of Compressor Station Equipment				0
28	847.7	Maintenance of Communication Equipment				0
29	847.8	Maintenance of Other Equipment				0
		Total Liq. N.G. Term. Proc. Maintenance Expenses		0	0	0
30		TRANSMISSION EXPENSES		XXX	XXX	XXX
31		Operation				
32	850.0	Operating Supervision and Engineering				0
33	851.0	System Control and Load Dispatching				0
34	852.0	Communication System Expenses				0
35	853.0	Compressor Station Labor and Expenses				0
36	854.0	Gas for Compressor Station Fuel				0
37	855.0	Other Fuel and Power for Compressor Stations				0
38	856.0	Mains Expenses				0
39	857.0	Measuring and Regulating Station Expenses				0
40	858.0	Transmission and Compression of gas by Others				0
41	859.0	Other Expenses				0
42	860.0	Rents				0
		Total Transmission Operation Expenses		0	0	0
43		Maintenance				
44	861.0	Maintenance Supervision and Engineering				0
45	862.0	Maintenance of Structures and Improvements				0
46	863.0	Maintenance of Mains				0
47	864.0	Maintenance of Compressor Station Equipment				0
48	865.0	Maintenance of Measuring and Regulating Station Equip.				0
49	866.0	Maintenance of Communication Equipment				0
50	867.0	Maintenance of Other Equipment				0
51		**Total Transmission Maintenance Expenses**		0	0	0
52		DISTRIBUTION EXPENSES		XXX	XXX	XXX
53		Operation				
54	870.0	Operation Supervision and Engineering		1,308,060	1,439,035	(130,975)
55	871.0	Distribution Load Dispatching		463,547	589,600	(126,053)
56	872.0	Compressor Station Labor and Expenses				0
57	873.0	Compressor Station Fuel and Power (Major Only)		670	113	557
58	874.0	Mains and Services Expenses		4,780,986	4,227,353	553,633
59	875.0	Measuring and Regulating Station Expenses-General		162,861	221,679	(58,818)

405. OPERATION AND MAINTENANCE EXPENSES (Continued) - TOTAL COMPANY

Balances at Beginning of Year must be consistent with balances at end of previous year

Line No.	Account Number and Title (a)		Schedule Page No. (b)	Balance Current Year (c)	Balance Previous Year (d)	Increase/ Decrease (e)
1	876.0	Measuring and Regulating Station Expenses-Industrial		1,293	18,213	(16,920)
2	877.0	Measuring and Regulating Station Expenses-City Gate			126	(126)
3	878.0	Meter and House Regulator Expenses		6,739,671	7,167,831	(428,160)
4	879.0	Customer Installations Expenses		47,955	134,566	(86,611)
5	880.0	Other Expenses		1,515,557	344,701	1,170,856
6	881.0	Rents		729,041	551,236	177,805
7		**Total Distribution Operation Expenses**		15,749,642	14,694,453	1,055,189
7		**Maintenance**				
8	885.0	Maintenance Supervision and Engineering		819,931	908,365	(88,434)
9	886.0	Maintenance of Structures and Improvements		337,834	541,233	(203,399)
10	887.0	Maintenance of Mains		5,997,684	7,690,623	(1,692,939)
11	888.0	Maintenance of Compressor Station Equipment				0
12	889.0	Maintenance of Measuring & Reg. Station Equip.-Genl.		1,416,598	1,021,084	395,514
13	890.0	Maintenance of Measuring & Reg. Station Equip.-Indtrl.		3,300	5,680	(2,380)
14	891.0	Maintenance of Measuring & Reg. Station Equip.-City G		2,731	4,501	(1,770)
15	892.0	Maintenance of Services		528,999	606,265	(77,266)
16	893.0	Maintenance of Meters & House Regulators		101,030	82,322	18,708
17	894.0	Maintenance of Other Equipment		57,191	70,986	(13,795)
		Total Maintenance Expenses		9,265,298	10,931,059	(1,665,761)
18		CUSTOMER ACCOUNTS EXPENSES		XXX	XXX	XXX
19		**Operations**				
20	901.0	Supervision		229,537	253,448	(23,911)
21	902.0	Meter Reading Expenses		1,189,993	2,157,797	(967,804)
22	903.0	Customer Records & Collection Expenses		9,520,923	10,698,742	(1,177,819)
23	904.0	Uncollectable Accounts		6,624,888	12,418,072	(5,793,184)
24	905.0	Miscellaneous Customer Accounts Expenses		51	303	(252)
		Total Customer Account Operations Expenses		17,565,392	25,528,362	(7,962,970)
25		CUSTOMER SERVICE & INFORM. EXPENSES		XXX	XXX	XXX
26		**Operations**				0
27	907.0	Supervision				0
28	908.0	Customer Assistance Expenses		588,310	632,819	(44,509)
29	909.0	Informational & Instructional Advertising Expenses				0
30	910.0	Miscellaneous Customer Service & Informational Exp.		635,700	635,700	0
		Total Cust. Service & Inform. Operations Expenses		1,224,010	1,268,519	(44,509)
31		SALES EXPENSES		XXX	XXX	XXX
32		**Operation**				
33	911.0	Supervision		56,356	81,260	(24,904)
34	912.0	Demonstrating and Selling Expenses		809,050	1,003,180	(194,130)
35	913.0	Advertising Expenses		35,845	21,905	13,940
36	914.0	(Reserved)				0
37	915.0	(Reserved)				0
38	916.0	Miscellaneous Sales Expenses				0
		Total Operation Sales Expenses		901,251	1,106,345	(205,094)
39		**ADMINISTRATIVE AND GENERAL EXPENSES**		XXX	XXX	XXX
40		**Operation**				
41	920.0	Administrative and General Salaries		12,309,262	10,416,305	1,892,957
42	921.0	Office Supplies and Expenses		4,952,861	14,471,088	(9,518,227)
43	922.0	Administrative Expenses Transferred-Credit		(18,828,799)	(17,048,358)	(1,780,441)
44	923.0	Outside Service Employed		16,421,457	6,869,391	9,552,066
45	924.0	Property Insurance		(88,815)	(1,179,665)	1,090,850
46	925.0	Injuries and Damages		3,180,632	3,533,660	(353,028)
47	926.0	Employee Pensions and Benefits		15,111,654	22,593,690	(7,482,036)
48	927.0	Franchise Requirements				0
49	928.0	Regulatory Commission Expenses		37,033	12,769	24,264
50	929.0	Duplicate Charges-Credit				0
51	930.1	General Advertising Expenses		63,859	61,591	2,268
52	930.2	Miscellaneous General Expenses		2,322,613	2,385,103	(62,490)
53	931.0	Rents		3,940,769	3,102,959	837,810
54		**Total Admiustrative and General Operation Expeness**		39,422,526	45,218,533	(5,796,007)
54		**Maintenance**				
55	932.0	Maintenance of General Plant		2,415,074	2,361,874	53,200
57		**Total Gas Operation and Maintenance Expenses**		41,837,600	47,580,407	(5,742,807)
58						
59		Total Gas Operation Expenses		375,070,419	400,082,638	(25,012,219)
60		Total Maintenance Expenses		11,680,372	13,292,933	(1,612,561)

405. OPERATION AND MAINTENANCE EXPENSES - PENNSYLVANIA DIVISION

Balances at Beginning of Year must be consistent with balances at end of previous year

Line No.	Account Number and Title (a)	Schedule Page No. (b)	Balance Current Year (c)	Balance Previous Year (d)	Increase/ Decrease (e)
1	MANUFACTURED GAS PRODUCTION EXPENSES		XXX	XXX	XXX
2	**Steam Production Expenses**				
3	**Operation**				
4	700.0 Operation Supervision and Engineering				0
5	701.0 Operating Labor				0
6	702.0 Boiler Fuel				0
7	703.0 Miscellaneous Steam Expenses				0
8	**Total Steam Production Operation Expenses**		0	0	0
9	**Maintenance**				
10	704.0 Steam Transferred-Credit				0
11	705.0 Maintenance, Supervision and Engineering				0
12	706.0 Maintenance of Structures and Improvements				0
13	707.0 Maintenance of Boiler Plant Improvement				0
14	708.0 Maintenance of Other Steam Production Plant				0
	Total Steam Production Maintenance Expenses			0	0
15	**Manufactured Gas Production**				
16	710.0 Operation Supervision and Engineering				0
17	**Production Labor and Expenses**				
18	711.0 Steam Expenses				0
19	712.0 Other Power Expenses				0
20	713.0 Coke Oven Expenses				0
21	714.0 Producer Gas Expenses				0
22	715.0 Water Gas Generating Expenses				0
23	716.0 Oil Gas Generating Expenses				0
24	717.0 Liquefied Petroleum Gas Expenses				0
25	718.0 Other Process Production Expenses				0
	Total Production Labor and Expenses		0	0	0
26	**Gas Fuels**				
27	719.0 Fuel Under Coke Ovens				0
28	720.0 Producer Gas Fuel				0
29	721.0 Water Gas Generator Fuel				0
30	722.0 Fuel for Oil Gas				0
31	723.0 Fuel for Liquefied Petroleum Gas Process				0
32	724.0 Other Gas Fuels				0
	Total Gas Fuels Expenses		0	0	0
33	**Gas Raw Materials**				
34	725.0 Coal Carbonized in Coke Ovens				0
35	726.0 Oil for Water Gas				0
36	727.0 Oil for Oil Gas				0
37	728.0 Liquefied Petroleum Gas Expenses				0
38	729.0 Raw Materials for Other Gas Processes				0
39	730.0 Residuals Expenses				0
40	731.0 Residuals Produced-Credit				0
41	732.0 Purification Expenses				0
42	733.0 Gas Mixing Expenses				0
43	734.0 Duplicate Charges-Credit				0
44	735.0 Miscellaneous Production Expenses				0
45	736.0 Rents				0
	Total Gas Raw Materials Expenses		0	0	0
46	**Maintenance**				
47	740.0 Maintenance Supervision and Engineering				0
48	741.0 Maintenance of Structures and Improvements				0
49	742.0 Maintenance of Production Equipment				0
	Total Maintenance Expenses		0	0	0
	Total Manufactured Gas Production Expenses		0	0	0
50	NATURAL GAS PRODUCTION EXPENSES		XXX	XXX	XXX
51	**Production and Gathering**				
52	**Operation**				
53	750.0 Operating Supervision and Engineering		3,120		3,120
53	751.0 Production Maps and Records				0
54	752.0 Gas Wells Expenses		859	1,484	(625)

405. OPERATION AND MAINTENANCE EXPENSES (Continue) - PENNSYLVANIA DIVISION

Balances at Beginning of Year must be consistent with balances at end of previous year

Line No.	Account Number and Title (a)	Schedule Page No. (b)	Balance Current Year (c)	Balance Previous Year (d)	Increase/ Decrease (e)
1	753.0 Field Lines Expenses				0
2	754.0 Field Compressor Station Expenses				0
3	755.0 Field Compressor Station Fuel and Power				0
4	756.0 Field Measuring and Regulating Station Expenses				0
5	757.0 Purification Expenses				0
6	*758.0 Gas Well Royalties*				*0*
7	759.0 Other Expenses				0
8	760.0 Rents				0
	Total Production & Gathering Operation Expenses		3,979	1,484	2,495
9	**Maintenance**				
10	761.0 Maintenance Supervision and Engineering				0
11	762.0 Maintenance of Structures and Improvements				0
12	763.0 Maintenance of Producing Gas Wells			5,935	(5,935)
13	764.0 Maintenance of Field Lines				0
14	765.0 Maintenance of Field Compressor Station Equipment			0	0
15	766.0 Maintenance of Field Measuring and Reg. Station Equip.				0
16	*767.0 Maintenance of Purification Equipment*				0
17	768.0 Maintenance of Drilling and Cleaning Equipment				0
18	769.0 Maintenance of Other Equipment				0
	Total Production & Gathering Maintenance Expenses		0	5,935	(5,935)
19	**Products Extraction**				
20	**Operation**				
21	770.0 Operation Supervision and Engineering				0
22	771.0 Operating Labor				0
23	772.0 Gas Shrinkage				0
24	773.0 Fuel				0
25	774.0 Power				0
26	775.0 Materials				0
27	776.0 Operation Supplies and Expenses				0
28	777.0 Gas Processed by Others				0
29	778.0 Royalties on Products Extracted				0
30	779.0 Marketing Expenses				0
31	780.0 Products Purchased for Resale				0
32	781.0 Variation in Products Inventory				0
33	782.0 Extracted Products Used by the Utility-Credit				0
34	783.0 Rents				0
	Total Products Extraction Operation Expenses		0	0	0
35	**Maintenance**				
36	784.0 Maintenance Supervision and Engineering				0
37	785.0 Maintenance of Structures and Improvements				0
38	786.0 Maintenance of Extraction and Refining Equipment				0
39	787.0 Maintenance of Pipe Lines				0
40	788.0 Maintenance of Extracted Products Storage Equipment				0
41	789.0 Maintenance of Compressor Equipment				0
42	790.0 Maintenance of Gas Measuring & Regulating Equipment				0
43	791.0 Maintenance of Other Equipment				0
	Total Products Extraction Maintenance Expenses		0	0	0
	Total Natural Gas Production Expenses		3,979	7,419	(3,440)
44	**EXPLORATION AND DEVELOPMENT EXPENSES**		XXX	XXX	XXX
45	**Operation**				
46	*795.0 Delay Rentals*				0
47	796.0 Nonproductive Well Drilling				0
48	797.0 Abandoned Leases				0
49	798.0 Other Exploration				0
	Total Exploration and Development Operation Exp.		0	0	0
50	**OTHER GAS SUPPLY EXPENSES**		XXX	XXX	XXX
51	**Operation**				
52	800.0 Natural Gas Well Head Purchases				0
53	801.0 Natural Gas Well Head Purchases, Intercompany Trans.		101,588,429	113,955,469	(12,367,040)
54	802.0 Natural Gas Gasoline Plant Outlet Purchases				0
55	803.0 Natural Gas Transmission Line Purchases		140,759,516	149,543,360	(8,783,844)
56	804.0 Natural Gas City Gate Purchases				0

405. OPERATION AND MAINTENANCE EXPENSES (Continued) - PENNSYLVANIA DIVISION

Balances at Beginning of Year must be consistent with balances at end of previous year

Line No.	Account Number and Title (a)	Schedule Page No. (b)	Balance Current Year (c)	Balance Previous Year (d)	Increase/ Decrease (e)
1	804.1 Liquefied Natural Gas Purchases				0
2	805.0 Other Gas Purchases				0
3	805.1 Purchases Gas Cost Adjustments		(1,628,290)	(21,965,494)	20,337,204
4	806.0 Exchange Gas				0
5	807.0 Purchased Gas Expenses		22,425	20,295	2,130
6	808.1 Gas Withdrawn from Storage-Debit		63,589,443	86,747,305	(23,157,862)
7	808.2 Gas Delivered to Storage-Credit		(79,825,092)	(96,205,868)	16,380,776
8	809.1 Withdrawals of Liquefied Nat. Gas Held for Processing				0
9	809.2 Deliveries of Natural Gas for Processing				0
10	810.0 Gas Used for Compressor Station Fuel-Credit				0
11	811.0 Gas Used for Products Extraction-Credit				0
12	812.0 Gas Used for Other Utility Operations-Credit				0
13	813.0 Other Gas Supply Expenses		60,314,110	66,825,452	(6,511,342)
	Total Gas Supply Operation Expenses		284,820,541	298,920,519	(14,099,978)
14	**Natural Gas Storage, Terminating & Processing Exp.**				
15	**Underground Storage Expenses**				
16	814.0 Operation Supervision and Engineering				0
17	815.0 Maps and Records				0
18	816.0 Wells Expenses				0
19	817.0 Lines Expenses				0
20	818.0 Compressor Station Expenses				0
21	819.0 Compressor Station Fuel and Power				0
22	820.0 Measuring and Regulating Station Expenses				0
23	821.0 Purification Expenses				0
24	822.0 Exploration and Development				0
25	823.0 Gas Losses				0
26	824.0 Other Expenses				0
27	825.0 Storage Well Royalties				0
28	826.0 Rents				0
	Total Underground Storage Expenses		0	0	0
29	**Maintenance**				
30	830.0 Maintenance Supervision and Engineering				0
31	831.0 Maintenance of Structures and Improvements				0
32	832.0 Maintenance of Reservoirs and Wells				0
33	833.0 Maintenance of Lines				0
34	834.0 Maintenance of Compressor Station Equipment				0
35	835.0 Maintenance of Measuring & Regulating Station Equip.				0
36	836.0 Maintenance of Purification Equipment				0
37	837.0 Maintenance of Other Equipment				0
	Total Maintenance Expenses		0	0	0
38	**Other Storage Expenses**				0
39	**Operation**				
40	840.0 Operating Supervision and Engineering				0
41	841.0 Operation Labor and Expenses				0
42	842.0 Rents				0
43	842.1 Fuel				0
44	842.2 Power				0
45	842.3 Gas Losses				0
	Total Operation Expenses		0	0	0
46	**Maintenance**				
47	843.1 Maintenance Supervision and Engineering				0
48	843.2 Maintenance of Structures and Improvements				0
49	843.3 Maintenance of Gas Holders				0
50	843.4 Maintenance of Purification Equipment				0
51	843.5 Maintenance of Liquefaction Equipment				0
52	843.6 Maintenance of Vaporizing Equipment				0
53	843.7 Maintenance of Compressor Equipment				0
54	843.8 Maintenance of Measuring and Regulatory Equipment				0
55	843.9 Maintenance of Other Equipment				0
	Total Maintenance Expenses		0	0	0

405. OPERATION AND MAINTENANCE EXPENSES (Continued) - PENNSYLVANIA DIVISION

Balances at Beginning of Year must be consistent with balances at end of previous year

Line No.	Account Number and Title (a)		Schedule Page No. (b)	Balance Current Year (c)	Balance Previous Year (d)	Increase/ Decrease (e)
1						
2		LIQUEFIED NATURAL GAS TERMINATING AND				
3		PROCESSING EXPENSES		XXX	XXX	XXX
4		Operation				
5	844.1	Operation Supervision and Engineering				0
6	844.2	LNG Processing Terminal Labor and Expenses				0
7	844.3	Liquefaction Processing Labor and Expenses				0
8	844.4	LNG Transportation Labor and Expenses				0
9	844.5	Measuring and Regulating Labor and Expenses				0
10	844.6	Compressor Station Labor and Expenses				0
11	844.7	Communication System Expenses				0
12	844.8	System Control and Load Dispatching				0
13	845.1	Fuel				0
14	845.2	Power				0
15	845.3	Rents				0
16	845.4	Demurrage Charges				0
17	845.5	Warfare Receipts-Credit				0
18	845.6	Processing Liquefied or Vaporized Gas by Others				0
19	846.1	Gas Losses				0
20	846.2	Other Expenses				0
		Total Liq. N.G. Term & Proc. Operation Expenses		0	0	0
21		Maintenance				
22	847.1	Maintenance Supervision and Engineering				0
23	847.2	Maintenance of Structures and Improvements				0
24	847.3	Maintenance of LNG Processing Terminal Equipment				0
25	847.4	Maintenance of LNG Transportation Equipment				0
26	847.5	Maintenance of Measuring and Regulating Equipment				0
27	847.6	Maintenance of Compressor Station Equipment				0
28	847.7	Maintenance of Communication Equipment				0
29	847.8	Maintenance of Other Equipment				0
		Total Liq. N.G. Term. Proc. Maintenance Expenses		0	0	0
30		TRANSMISSION EXPENSES		XXX	XXX	XXX
31		Operation				
32	850.0	Operating Supervision and Engineering				0
33	851.0	System Control and Load Dispatching				0
34	852.0	Communication System Expenses				0
35	853.0	Compressor Station Labor and Expenses				0
36	854.0	Gas for Compressor Station Fuel				0
37	855.0	Other Fuel and Power for Compressor Stations				0
38	856.0	Mains Expenses				0
39	857.0	Measuring and Regulating Station Expenses				0
40	858.0	Transmission and Compression of gas by Others				0
41	859.0	Other Expenses				0
42	860.0	Rents				0
		Total Transmission Operation Expenses		0	0	0
43		Maintenance				
44	861.0	Maintenance Supervision and Engineering				0
45	862.0	Maintenance of Structures and Improvements				0
46	863.0	Maintenance of Mains				0
47	864.0	Maintenance of Compressor Station Equipment				0
48	865.0	Maintenance of Measuring and Regulating Station Equip.				0
49	866.0	Maintenance of Communication Equipment				0
50	867.0	Maintenance of Other Equipment				0
51		Total Transmission Maintenance Expenses		0	0	0
52		DISTRIBUTION EXPENSES		XXX	XXX	XXX
53		Operation				
54	870.0	Operation Supervision and Engineering		1,086,404	1,225,142	(138,738)
55	871.0	Distribution Load Dispatching		372,882	478,266	(105,384)
56	872.0	Compressor Station Labor and Expenses				0
57	873.0	Compressor Station Fuel and Power (Major Only)		670	113	557
58	874.0	Mains and Services Expenses		4,685,227	4,129,087	556,140
59	875.0	Measuring and Regulating Station Expenses-General		116,472	149,182	(32,710)

405. OPERATION AND MAINTENANCE EXPENSES (Continued) - PENNSYLVANIA DIVISION

Balances at Beginning of Year must be consistent with balances at end of previous year

Line No.		Account Number and Title (a)	Schedule Page No. (b)	Balance Current Year (c)	Balance Previous Year (d)	Increase/ Decrease (e)
1	876.0	Measuring and Regulating Station Expenses-Industrial		1,293	18,213	(16,920)
2	877.0	Measuring and Regulating Station Expenses-City Gate			126	(126)
3	878.0	Meter and House Regulator Expenses		5,542,608	6,008,507	(465,899)
4	879.0	Customer Installations Expenses		38,381	126,833	(88,452)
5	880.0	Other Expenses		1,162,843	270,564	892,279
6	881.0	Rents		676,463	501,000	175,463
7		**Total Distribution Operation Expenses**		13,683,244	12,907,033	776,211
7		**Maintenance**				
8	885.0	Maintenance Supervision and Engineering		779,311	881,709	(102,398)
9	886.0	Maintenance of Structures and Improvements		336,665	538,373	(201,708)
10	887.0	Maintenance of Mains		5,739,931	7,368,216	(1,628,285)
11	888.0	Maintenance of Compressor Station Equipment				0
12	889.0	Maintenance of Measuring & Reg. Station Equip.-Genl.		1,243,304	835,861	407,443
13	890.0	Maintenance of Measuring & Reg. Station Equip.-Indtrl.			670	(670)
14	891.0	Maintenance of Measuring & Reg. Station Equip.-City G		2,731	4,501	(1,770)
15	892.0	Maintenance of Services		505,789	564,271	(58,482)
16	893.0	Maintenance of Meters & House Regulators		101,030	82,255	18,775
17	894.0	Maintenance of Other Equipment		57,191	70,986	(13,795)
		Total Maintenance Expenses		8,765,952	10,346,842	(1,580,890)
18		CUSTOMER ACCOUNTS EXPENSES		XXX	XXX	XXX
19		**Operations**				
20	901.0	Supervision		195,339	214,391	(19,052)
21	902.0	Meter Reading Expenses		679,565	1,619,042	(939,477)
22	903.0	Customer Records & Collection Expenses		9,297,537	10,413,652	(1,116,115)
23	904.0	Uncollectable Accounts		6,182,394	12,264,072	(6,081,678)
24	905.0	Miscellaneous Customer Accounts Expenses		51	303	(252)
		Total Customer Account Operations Expenses		16,354,886	24,511,460	(8,156,574)
25		CUSTOMER SERVICE & INFORM. EXPENSES		XXX	XXX	XXX
26		**Operations**				
27	907.0	Supervision				0
28	908.0	Customer Assistance Expenses		588,310	632,819	(44,509)
29	909.0	Informational & Instructional Advertising Expenses				0
30	910.0	Miscellaneous Customer Service & Informational Exp.		635,700	635,700	0
		Total Cust. Service & Inform. Operations Expenses		1,224,010	1,268,519	(44,509)
31		SALES EXPENSES		XXX	XXX	XXX
32		**Operation**				
33	911.0	Supervision		56,356	81,260	(24,904)
34	912.0	Demonstrating and Selling Expenses		808,992	998,294	(189,302)
35	913.0	Advertising Expenses		35,845	21,905	13,940
36	914.0	(Reserved)				0
37	915.0	(Reserved)				0
38	916.0	Miscellaneous Sales Expenses				0
		Total Operation Sales Expenses		901,193	1,101,459	(200,266)
39		ADMINISTRATIVE AND GENERAL EXPENSES		XXX	XXX	XXX
40		**Operation**				
41	920.0	Administrative and General Salaries		11,992,369	10,032,670	1,959,699
42	921.0	Office Supplies and Expenses		4,945,524	14,450,836	(9,505,312)
43	922.0	Administrative Expenses Transferred-Credit		(19,177,799)	(17,048,358)	(2,129,441)
44	923.0	Outside Service Employed		16,361,003	6,823,521	9,537,482
45	924.0	Property Insurance		(88,815)	(1,179,665)	1,090,850
46	925.0	Injuries and Damages		3,083,764	3,387,434	(303,670)
47	926.0	Employee Pensions and Benefits		15,017,668	22,418,562	(7,400,894)
48	927.0	Franchise Requirements				0
49	928.0	Regulatory Commission Expenses		25,699	10,417	15,282
50	929.0	Duplicate Charges-Credit				0
51	930.1	General Advertising Expenses		63,859	61,591	2,268
52	930.2	Miscellaneous General Expenses		2,309,883	2,376,353	(66,470)
53	931.0	Rents		3,887,469	3,077,779	809,690
54		**Total Adminstrative and General Operation Expeness**		38,420,624	44,411,140	(5,990,516)
54		**Maintenance**				
55	932.0	Maintenance of General Plant		2,380,057	2,257,542	122,515
57		**Total Gas Operation and Maintenance Expenses**		40,800,681	46,668,682	(5,868,001)
58						
59		Total Gas Operation Expenses		355,408,476	383,121,614	(27,713,138)
60		Total Maintenance Expenses		11,146,009	12,610,319	(1,464,310)

408. TAXES OTHER THAN INCOME TAXES, UTILITY OPERATING INCOME (Account 408.1)

This schedule shall include a breakdown of the various tax expenses that constitute the ending balance in Account No. 408.1-Taxes Other Than Income Taxes Utility Operating Income. The information should also reflect related entries to Account No. 165-Prepayments; and Account No. 236-Taxes Accrued.

Line No.	Type of Tax (a)	Account 165 Prepayments (b)	Account 236 Taxes Accrued (c)	Account 408.1 Taxes Other Than Income (d)
1	**Social Security**			
2	**Federal Unemployment**			
3	**Pennsylvania Unemployment**			
4	**Utility Regulatory Assessment**		1,036,173	1,036,173
5	**Local Property / Real Estate Taxes**		673,399	673,399
6	**Public Utility Realty Tax**		903,271	903,271
7	**State Capital Stock Tax**		417,105	417,105
8	**Other Taxes (specify)**			
9	**Miscellaneous**		(51,041)	(51,041)
10	**Business Privilege & Occupation Tax**		729,888	729,888
11	**TOTAL**	0	3,708,795	3,708,795

409. INCOME TAXES, UTILITY OPERATING INCOME (Account 409.1)

This schedule shall include a breakdown of the various tax expenses that constitute the ending balance in Account No. 409.1-Income Taxes, Ut. Operating Income. The information should also reflect related entries to Account No. 165-Prepayments; Account No. 190-Accumulated Deferred Income Taxes and Account No. 236-Accrued Utility Operating Income.

Line No.	Type of Tax (a)	Account 165 Prepayments (b)	Account 190 Accumulated Def. Income Taxes (c)	Account 236 Accrued Taxes (d)	Account 409.1 Income Taxes Opr Income (e)
1	**Federal Income Taxes**			(35,012,213)	(35,012,213)
2	**State Income Taxes**			(1,906,219)	(1,906,219)
3	**Local Income Taxes**				
4					
5					
6					
7					
8	**Other Taxes (specify)**				
9					
10					
11	**TOTAL**	0	0	(36,918,432)	(36,918,432)

410. CALCULATION OF FEDERAL INCOME TAXES - CURRENT PERIOD

1. The totals as reported on this schedule should conform with amounts reported on corresponding Schedules.

Line No.	Item (a)	Total (b)	Current (c)	Deferred Property Related (d)	Deferred Other (e)
1	Operating Revenues	445,334,600	445,334,600		
2	Operating Expenses	407,085,173	407,085,173		
3	Operating Taxes (Non-Income)	3,078,795	3,078,795		
4	*Interest & Other Expense*	162,368,997	162,368,997		
5	Pre-Tax Operating Income				
	Total Line 1 Minus Lines 2-3-4	(127,198,365)	(127,198,365)	-	-
6	Other Income (Expense)	298,017,229	298,017,229		
7	Pre Tax Book Income	-			
	Total Lines 5+6	170,818,864	170,818,864	-	-
8	Permanent and Flow-Through Differ.	(355,031,997)	(355,031,997)		
9	Temporary Differences	60,974,626	86,004,591	(25,029,965)	
10	State Only Differences	-			
11	Subtotal	(123,238,507)	(98,208,542)	(25,029,965)	-
12	State Tax at Current Rate	(8,821,775)	(1,906,219)	(6,915,556)	
13	Adjustments to State Tax	-			
14	Adjustments for St. Tax Rate Changes	-			
15	State Tax Accrual	-			
	Total Lines 12+13+14	(8,821,775)	(1,906,219)	(6,915,556)	-
16	Federal Taxable Income	-			
	Total Line 11 Minus Lines 10-12-13	(114,416,732)	(96,302,323)	(18,114,409)	-
17	Federal Tax at Current Rate	(40,045,856)	(33,705,813)	(6,340,043)	
18	ITC Authorization	(706,400)	(706,400)		
19	Adjustment for Fed. Tax Rate Change	-			
20	R & D Credits	(600,000)	(600,000)		
21	IRS Audit Settlement	-			
22	Tax Rate Change on Extraord. Activit	-			
23	Other	-			
24	Federal Tax Accrual	-			
	Total Lines 17 through 23	(41,352,256)	(35,012,213)	(6,340,043)	-

411. PROVISION FOR DEFERRED INCOME TAXES, UTILITY OPERATING INCOME (Account 410.1)

This schedule shall include a breakdown of the various tax expenses that constitute the ending balance in Account No. 410.1-Provision for Deferred Income Taxes, Utility Operating Income. The information should also reflect related entries to Account No. 165-Prepayments; Account No. 190-Accumulated Deferred Income Taxes & Account No. 236-Accrued Taxes, Utility Operating Income.

Line No.	DEBITS Type of Tax (a)	Account 165 Prepayments (b)	Account 190 Accumulated Deferred Income Taxes (c)	Account 236 Accrued Taxes (d)	Account 410.1 Provision for Deferred Income Taxes (e)
1	Federal				(6,340,043)
2	State				(6,915,556)
3	Other				
4					
5					
6					
7	Total	0	0	0	(13,255,599)

412. PROVISION FOR DEFERRED INCOME TAXES UTILITY OPR. INCOME, CREDIT (Account 411.1)

This schedule shall include a breakdown of the various tax expenses that constitute the ending balance in Account No. 411.1-Provision for Deferred Income Taxes-Credit. The information should also reflect related entries to Account No. 165-Prepayments; Account No. 190-Accumulated Deferred Income Taxes & Account No. 236-Accrued Taxes.

Line No.	DEBITS Type of Tax (a)	Account 165 Prepayments (b)	Account 190 Accumulated Deferred Income Taxes (c)	Account 236 Accrued Taxes (d)	Account 411.1 Provision for Deferred Income Taxes (e)
1	Federal				
2	State				
3	Other				
4					
5					
6					
7	Total	0	0	0	0

Utility Operating Income (Account 410.1) column e: Account 283 and intercompany account receivable.

500. GAS PURCHASED

1. Report below the information called for concerning gas purchased for resale during year.
2. Purchases from independent natural gas producers shall be grouped on one line and columns (a), (d), (g) and (h) only shall be reported with respect to such purchase.
3. The quantities reported should be those shown by the bills rendered by the vendor. Indicate MCF, CCF or Therms
4. Report separately non-interruptible and interruptible purchases from the same company. Designate purchases from affiliated interest by an asterisk following the name in column (d).

Line No.	Purchased From (a)	Point of Delivery (b)	B.T.U. Per Cu. Ft. (c)	Mcf (d)	Commodity Charges (e)	Other Charges (f)	Total (g)	Cost Per Unit (h)
1	801 Field Purchases							
2	Independent Group Purchases	Various Locations		15,088,708	106,373,082		106,373,082	704.98
3							0	
4							0	
5							0	
6	803 Pipeline Purchase						0	
7	Independent Group Purchases	Various Locations		17,936,972	132,263,391		132,263,391	737.38
8	Equitable Energy *	Various Locations		1,275,386	14,100,578		14,100,578	1,105.59
9							0	
10	805.1 Purchase Gas Cost Adjustment				2,654,700		2,654,700	
Totals			0	34,301,066	255,391,751	0	255,391,751	744.56

501. SALES FOR RESALE

1. Report below the information called for concerning gas sold during year to other gas utilities or to public authorities for resale.
2. The quantities shown should be those shown by the bills rendered to the purchasers. Indicate MCF, CCF or Therms.
3. Report separately non-interruptible and interruptible sales to the same company. Designate sales to affiliated interest by an asterisk following the name in column (a)
4. Designate any sales which are other than firm sales.

Line No.	Sold To (a)	Point of Delivery (b)	BTU Per Cu. Ft. (c)	MCF CCF or Therms (d)	Commodity Charges (e)	Other Charges (f)	Total (g)	Revenue Per Unit (h)
1	**N/A**							
2								
3								
4								
5								
6								
7								
8								
9								
10								
Totals			0	0	0	0	0	

505. GAS ACCOUNT-NATURAL GAS

1 *The purpose of this schedule is to account for the quantity of natural gas received and delivered by the respondent* adjusted for any differences in pressure bases used in measuring MCF of natural gas received and delivered.

2 If the respondent operates two or more systems which are not interconnected, separate schedules should be submitted. Insert pages should be used for this purpose.

No.	Item (a)	MCF as Reported (b)
1	**GAS RECEIVED**	
2	Natural Gas Produced	168,126
3	L.P.G. Gas Produced and Mixed with Natural Gas	
4	Manufactured Gas Produced and Mixed with Natural Gas	
5	Purchased Gas	34,301,066
6	Gas of Others Received for Transportation	22,239,368
7	Receipts of Respondent's Gas Transported or Compressed by Others	
8	Exchange Gas Received	
9	Gas Received from Underground Storage	7,390,400
10	Other Receipts	
11		
12		
13		
14	**Total Receipts:**	64,098,960
15	**GAS DELIVERED**	
16	Natural Gas Sales:	
17	Local Distribution by Respondent	22,168,287
18	Main Line Industrial Sales	
19	Sales for Resale	
20	Interdepartmental Sales	
21		
21		
22	**Total Sales**	22,168,287
23	Deliveries of Gas Transported or Compressed for Others	22,686,763
24	Deliveries of Respondent's Gas for Trans. Or Compressed by Others	
25	Exchange Gas Delivered	
26	Natural Gas used by Respondent	14,473
27	Natural Gas Delivered to Storage	11,597,307
28	Natural Gas for Franchise Requirements	
29	Other Deliveries: Specify	
30	**Total Deliveries**	56,466,830
31	**UNACCOUNTED FOR**	
32	Production System Losses	
33	Storage Losses	
34	Transmission System Losses	
35	Distribution System Losses	6,470,736
36	Other Losses: Calculated Effect of Temperature and Pressure	
37	Variations on Outside Metering	1,161,394
38	**Total Unaccounted For**	7,632,130
38	**Total Deliveries and Unaccounted For**	64,098,960

510. UNDERGROUND GAS STORAGE - TOTAL COMPANY

1. Report particulars for each underground gas storage project.
2. Give particulars of any gas stored for the benefit of another company under a gas exchange arrangement or on a basis of purchase and resale to another company. Designate if other company is an associated company.
3. Pressure base of gas volumes reported below.

Line No.	Month (a)	Total (b)	Project Location (c)	Dominion Transmission (d)	Equitrans, L.P. (e)
1	**Storage Operations**	MCF	MCF	MCF	MCF
2	**Gas Delivered to Storage**				
1	January	0		0	0
2	February	0		0	0
3	March	0		0	0
4	April	1,083,959		277,932	806,027
5	May	1,584,130		527,474	1,056,656
6	June	1,658,271		473,548	1,184,723
7	July	1,877,163		364,488	1,512,675
8	August	1,226,930		195,323	1,031,607
9	September	2,206,482		422,663	1,783,819
10	October	1,960,372		416,598	1,543,774
11	November	0		0	0
12	December	0		0	0
13	Totals	11,597,307	0	2,678,026	8,919,281
14	**Gas Withdrawn From Storage**				
15	January	961,699		561,856	399,843
16	February	1,741,703		655,816	1,085,887
17	March	1,654,433		446,457	1,207,976
18	April	848,495		0	848,495
19	May	0		0	0
20	June	0		0	0
21	July	0		0	0
22	August	0		0	0
23	September	0		0	0
24	October	0		0	0
25	November	1,007,523		543,732	463,791
26	December	1,176,547		561,856	614,691
27	Totals	7,390,400	0	2,769,717	4,620,683
28	*Stored Gas End of Year-MCF*	11,864,720			
29	Est. Native Gas in Storage Reservoir-MCF	Footnote A			
30	Total Gas in Reservoir-MCF (Lines 28 plus 29)	Footnote A			
31	Storage Capacity (Escl. Native Gas)-MCF	Footnote A			
32	Reservoir Pressure at which Storage Cap.-Computed	Footnote A			
33	Number of Storage Wells in Project	Footnote A			
34	Number of Acres of Storage Area	Footnote A			
35	Maximum Day's Withdrawal from Storage	Footnote A			
36	Date of Maximum Day's Withdrawal	Footnote A			
37	Year Storage Operations Commenced	Footnote A			

A. Gas was stored by Dominion Transmission (Column d) and Equitrans, L.P. (Column e), an affiliate, under a gas storage and transportion agreement.

510. UNDERGROUND GAS STORAGE - PA OPERATIONS

1. Report particulars for each underground gas storage project.
2. Give particulars of any gas stored for the benefit of another company under a gas exchange arrangement or on a basis of purchase and resale to another company. Designate if other company is an associated company.
3. Pressure base of gas volumes reported below.

Line No.	Month (a)	Total (b)	Project Location (c)	Dominion Transmission (d)	Equitrans (e)
1	**Storage Operations**	MCF	MCF	MCF	MCF
2	**Gas Delivered to Storage**				
1	January	0		0	0
2	February	0		0	0
3	March	0		0	0
4	April	1,083,959		277,932	806,027
5	May	1,486,146		527,474	958,672
6	June	1,457,392		473,548	983,844
7	July	1,805,047		364,488	1,440,559
8	August	1,142,296		195,323	946,973
9	September	2,137,436		422,663	1,714,773
10	October	1,862,009		416,598	1,445,411
11	November	0		0	0
12	December	0		0	0
13	Totals	10,974,285	0	2,678,026	8,296,259
14	**Gas Withdrawn From Storage**				
15	January	902,348		561,856	340,492
16	February	1,680,530		655,816	1,024,714
17	March	1,466,510		446,457	1,020,053
18	April	834,367		0	834,367
19	May	0		0	0
20	June	0		0	0
21	July	0		0	0
22	August	0		0	0
23	September	0		0	0
24	October	0		0	0
25	November	1,007,523		543,732	463,791
26	December	1,118,356		561,856	556,500
27	Totals	7,009,634	0	2,769,717	4,239,917
28	Stored Gas End of Year-MCF	11,225,982			
29	Est. Native Gas in Storage Reservoir-MCF	Footnote A			
30	Total Gas in Reservoir-MCF (Lines 28 plus 29)	Footnote A			
31	Storage Capacity (Escl. Native Gas)-MCF	Footnote A			
32	Reservoir Pressure at which Storage Cap.-Computed	Footnote A			
33	Number of Storage Wells in Project	Footnote A			
34	Number of Acres of Storage Area	Footnote A			
35	Maximum Day's Withdrawal from Storage	Footnote A			
36	Date of Maximum Day's Withdrawal	Footnote A			
37	Year Storage Operations Commenced	Footnote A			

A. Gas was stored by Dominion Transmission (Column d) and Equitrans, L.P. (Column e), an affiliate, under a gas storage and transportion agreement.

511. MANUFACTURED GAS PRODUCTION PLANT

1 Kind or Type of Plant______ Location______
2 Maximum Daily Capacity of Plant______ MCF______
3 Maximum Daily MCF of Gas Produced During Year______ Date______
4 Maximum Daily MCF of Gas Produced During Life of Plant______ Date______
5 Number of Days Plant was Commercially Operated During Year______
6 Date Plant was last Commercially Operated______
7 MCF of Gas Produced During the Year______
8 Average BTU Content of Gas Produced______
0

NONE

512. LIQUEFIED PETROLEUM GAS OPERATIONS

1 Location of Plant______
2 MCF of Gas Produced During Year______
3 Gallons of L.P.G. Used During Year______
4 Function of Plant______
5 *Storage Capacity for L.P.G. (Gallons)*______

NONE

515. GAS AND OIL WELLS

Line No.			
1	**GAS WELLS**		
2	Productive Wells at Beginning of Year	54	
3	Productive Wells Drilled During the Year		
4	Oil Wells Restored to Productive Basis During Year		
5	Wells Purchased During the Year		
6	Wells Abandoned During the Year		
7	Wells Sold During the Year		
8			
9	**Productive Wells at End of Year**	54	
10	Number of Wells Drilled Deeper During the Year	NONE	
11	Dry Holes Drilled During the Year	NONE	
12			
13	**NATURAL GAS ACREAGE**	**Operative**	**Non Operative**
14	Number of Acres Owned at End of Year	NONE	NONE
15	Number of Acres Leased at End of Year		
16			
17	**OIL WELLS**		
18	Productive Wells at Beginning of Year	NONE	
19	Productive Wells Drilled During the Year		
20	Wells Abandoned and Sold During the Year		
21			
22	**Productive Wells at End of Year**		
23			

516. GAS LINES, METERS AND SERVICES

Line No.	Size of Pipe Inches	Field Lines M. Ft.	Prod. Ext. Lines M. Ft.	Storage Lines M. Ft.	Distr. Mains M. Ft.	Transmission M. Ft.
24						
25						
26–27						
28	01"				392	
29	02"	5			3,539	
30	03"	26			4,757	
31	04"	20			4,311	2
32	05"	2			97	
33	06"	30			3,090	1
34	08"	1			1,497	1
35	10"	10			434	
36	12"				929	100
37	14"				1	
38	16"				474	13
39	20"				388	38
40	24"				195	
41	30"				87	1
42	36"				24	

Meters in Service at End of Year 255,871

Services at End of Year, Company Owned

Meters in Stock or Shop at End of Year 800

Services at End of Year, Customer Owned

517. CUSTOMER GAS METERS

Line No.	(a)	Size (b)	Number of Meters: First of Year (c)	Added During Year (d)	Removed Or Disconnected During Year (e)	End of Year (e)
1	**In residential use**					0
2	N/A					0
3						0
4						0
5						0
6						0
7						0
8						0
9						0
10	**Total in residential use**		0	0	0	0
11	**In commercial use**					0
12	N/A					0
13						0
14						0
15						0
16						0
17						0
18						0
19						0
20	**Total in commercial use**		0	0	0	0
21	**In industrial use**					0
22	N/A					0
23						0
24						0
25						0
26						[illegible]
27						0
28						0
29						0
30	**Total in industrial use**		0	0	0	0
31	**In public (municipal or government) use**					0
32	N/A					0
33						0
34						0
35						0
36						0
37						0
38						0
39						0
40	**Total in public (municipal or government) use**		0	0	0	0
41	**Total in use**		0	0	0	0
42	**In Stock**					0
43	N/A					0
44						0
45						0
46						0
47						0
48						0
49						0
50	**Total in stock**		0	0	0	0
51	**Total all meters**		0	0	0	0

METERS TESTED BY SIZES

	(a)	(a)	1/2 (a)	5/8 (b)	3/4 (c)	1 (d)	(e)	(f)	(g)	Total (h)
52	Numbe	Number tested during the year								

600. CLASSIFICATION OF CUSTOMERS, UNITS SOLD AND OPERATING REVENUES BY TARIFF SCHEDULE

1. Report below the details called for concerning Customers, MCF, CCF or Therms (Indicate Unit Used) Sold, and Opr. Revenues by Tariff Schedule.
2. Customers should be reported on the basis of number of meters, plus number of unmetered accounts, except that where separate meter readings are added for billing purposes, one customer shall be counted for each group of meters so added.
3. Quantities of gas sold to flat-rate customers shown in column (e), should explain in a footnote the basis upon which quantities were determined.
4. Respondent should use additional sheets if necessary.

		Number of Customers			Sales During Year			Revenues	
Line No.	Account (a)	Beginning of Year (b)	End of Year (c)	Average During Year (d)	Total MCF (e)	Total Operating Revenue (f)	MCF Per Customer (g)	Per Customer (h)	Per Unit (i)
2	**Metered Sales by Tariff Schedule**								
3	**Residential**								
4	PA Retail - Billed	209,195	210,578	207,559	17,056,507	303,384,677	81	$ 1,440.72	$ 17.79
5	- Unbilled				(304,606)	(10,805,347)			
6	WV Retail - Billed	12,471	12,370	12,304	888,657	13,613,043	72	$ 1,100.49	$ 15.32
7	- Unbilled				(25,967)	(337,394)			
8	KY Retail - Billed	3,699	3,535	3,594	216,162	3,677,143	61	$ 1,040.21	$ 17.01
9									
10	Transportation - Billed	30,283	28,945	30,132	3,257,015	29,662,755	113	$ 1,024.80	$ 9.11
11	- Unbilled				(73,804)	(1,088,659)			
12									
13	**Total Residential Metered Sales**	255,648	255,428	253,589	21,013,964	338,106,218			
14	**Commercial**								
15	PA Retail - Billed	14,303	14,205	14,081	3,960,800	64,538,828	279	$ 4,543.39	$ 16.29
16	- Unbilled				(46,815)	(1,810,523)			
17	WV Retail - Billed	975	969	964	336,884	4,776,346	348	$ 4,929.15	$ 14.18
18	- Unbilled				(1,906)	(24,120)			
19	KY Retail - Billed	3	3	3	1,697	26,216	566	$ 8,738.67	$ 15.45
20									
21	Transportation - Billed	3,300	3,193	3,264	10,221,970	24,582,716	3,201	$ 7,698.94	$ 2.40
22									
23									
24	**Total Commercial Metered Sales**	18,581	18,370	18,312	14,472,630	92,089,463			
25	**Industrial**								
26	PA Retail - Billed	53	39	47	70,809	1,028,182	1,816	$26,363.64	$ 14.52
27	- Unbilled				(75)	(2,136)			
28	WV Retail - Billed	9	9	9	16,141	230,884	1,793	$25,653.78	$ 14.30
29	- Unbilled								
30	Transportation - Billed	121	117	119	9,281,581	10,898,633	79,330	$93,150.71	$ 1.17
31									
32	**Total Industrial Metered Sales**	183	165	175	9,368,456	12,155,563			
33	Public								
34	Interdepartmental								
35	Other								
36	**Total Metered Sales**	274,412	273,963	272,076	44,855,050	442,351,244			
37	**Unmetered Sales-All Categories**								
38	Other								
39	**Total Unmetered Sales**	-	-	-	-				
40	**Total Sales of Gas**	274,412	273,963	272,076	44,855,050	442,351,244			
41	Other Gas Revenues:								
42	Rent from Gas Property					5,311			
43	Interdepartmental Rents								
44	Operating Revenue Other Than Gas Sales					1,164,789			
45	Allowance to Customers								
46	Customers Forfeited Discounts & Penalties					1,577,062			
47	Miscellaneous Gas Revenues					236,194			
48	**Total Other Gas Revenues**	-	-	-	-	2,983,356			
49	**Total Gas Operating Revenues**	274,412	273,963	272,076	44,855,050	445,334,600			

605. NUMBER OF EMPLOYEES

Report the requested information concerning the number of employees on respondent's payrolls at end of year.

Line No.	Classification According to Occupation (a)	Number at Year End (b)
1	Total Officials and Senior Manager Employees	15
2	Total Professional and Semiprofessional Employees	57
3	Total Business Office, Sales And Professional Employees	123
4	Total Clerical Employees	37
5	Total Operators	
6	Total Construction, Installation and Maintenance Employees	212
7	Total Building, Supplies and Motor Vehicle Employees	
8	All Other Employees Not Elsewhere Classified	
9	Total All Employees	444

Line 1 includes Officers and Department Heads
Line 2 includes Managers and Supervisors
Line 3 includes Technical, Professional and Administrative Employees

610. Territory Served - PENNSYLVANIA

Report below the number of customers at the end of the year in respondent's distribution system in which service is furnished setting forth by counties the number of customers and the average number of customers during the year. Respondent should place an X in the box in column (b) if that county is served and supply related customer information in columns (d) and (e).

County Code (a)	Serves County (b)	Name of Pennsylvania County (c)	Number Of Customers At End Of Year (d)	Average Number Of Customers During Year (e)
01		Adams		
02	X	Allegheny	226,396	226,540
03	X	Armstrong	2,819	2,829
04		Beaver		
05		Bedford		
06		Berks		
07		Blair		
08		Bradford		
09		Bucks		
10	X	Butler	1,754	1,709
11		Cambria		
12		Cameron		
13		Carbon		
14		Centre		
15		Chester		
16	X	Clarion	236	238
17		Clearfield		
18		Clinton		
19		Columbia		
20		Crawford		
21		Cumberland		
22		Dauphin		
23		Delaware		
24		Elk		
25		Erie		
26	X	Fayette	26	26
27		Forest		
28		Franklin		
29		Fulton		
30	X	Greene	6,361	6,370
31		Huntingdon		
32	X	Indiana	74	76
33	X	Jefferson	46	47
34		Juniata		
35		Lackawanna		
36		Lancaster		
37		Lawrence		
38		Lebanon		
39		Lehigh		
40		Luzerne		
41		Lycoming		
42		McKean		
43		Mercer		
44		Mifflin		
45		Monroe		
46		Montgomery		
47		Montour		
48		Northampton		
49		Northumberland		
50		Perry		
51		Philadelphia		
52		Pike		
53		Potter		
54		Schuylkill		
55		Snyder		
56		Somerset		
57		Sullivan		
58		Susquehanna		
59		Tioga		
60		Union		
61		Venango		
62		Warren		
63	X	Washington	12,727	12,568
64		Wayne		
65	X	Westmoreland	6,685	6,746
66		Wyoming		
67		York		
Totals			257,124	257,146
Total Population of Territory Served (Estimated)			2,423,556	

610. Territory Served - WEST VIRGINIA

Report below the number of customers at the end of the year in respondent's distribution system in which service is furnished setting forth by counties the number of customers and the average number of customers during the year. Respondent should place an X in the box in column (b) if that county is served and supply related customer information in columns (d) and (e).

County Code (a)	Serves County (b)	Name of West Virginia County (c)	Number Of Customers At End Of Year (d)	Average Number Of Customers During Year (e)
01		Barbour		
02		Berkeley		
03		Boone		
04	X	Braxton	252	253
05		Brooke		
06		Cabell		
07		Calhoun		
08	X	Clay	98	102
09	X	Doddridge	877	883
10		Fayette		
11	X	Gilmer	458	461
12		Grant		
13		Geenbrier		
14		Hampshire		
15		Hancock		
16		Hardy		
17	X	Harrison	915	920
18		Jackson		
19		Jefferson		
20		Kanawha		
21	X	Lewis	434	432
22		Lincoln		
23		Logan		
24		McDowell		
25	X	Marion	5,421	5,419
26	X	Marshall	1	1
27		Mason		
28		Mercer		
29		Mineral		
30		Mingo		
31	X	Monongalia	566	574
32		Monroe		
33		Morgan		
34		Nicholas		
35		Ohio		
36		Pendleton		
37		Pleasants		
38		Pocahontas		
39		Preston		
40		Putnam		
41		Raleigh		
42		Randolph		
43	X	Ritchie	208	208
44		Roane		
45		Summers		
46	X	Taylor	3,266	3,292
47		Tucker		
48	X	Tyler	68	71
49	X	Upshur	176	177
50		Wayne		
51		Webster		
52	X	Wetzel	625	631
53		Wirt		
54		Wood		
55		Wyoming		
56				
57				
58				
59				
60				
61				
62				
63				
64				
65				
66				
67				
Totals			13,365	13,421
Total Population of Territory Served (Estimated)			377,433	

610. Territory Served - KENTUCKY

Report below the number of customers at the end of the year in respondent's distribution system in which service is furnished setting forth by counties the number of customers and the average number of customers during the year. Respondent should place an X in the box in column (b) if that county is served and supply related customer information in columns (d) and (e)

County Code (a)	Serves County (b)	Name of Kentucky County (c)	Number Of Customers At End Of Year (d)	Average Number Of Customers During Year (e)
01		Adair		
02		Allen		
03		Anderson		
04		Ballard		
05		Barren		
06		Bath		
07		Bell		
08		Boone		
09		Bourbon		
10		Boyd		
11		Boyle		
12		Bracken		
13		Breathitt		
14		Breckinridge		
15		Bullitt		
16		Butler		
17		Caldwell		
18		Calloway		
19		Campbell		
20		Carlisle		
21		Carroll		
22		Carter		
23		Casey		
24		Christian		
25		Clark		
26		Clay		
27		Clinton		
28		Crittenden		
29		Cumberland		
30		Daviess		
31		Edmonson		
32		Elliott		
33		Estill		
34		Fayette		
35		Fleming		
36	X	Floyd	1,355	1,385
37		Franklin		
38		Fulton		
39		Gallatin		
40		Garrard		
41		Grant		
42		Graves		
43		Grayson		
44		Green		
45		Greenup		
46		Hancock		
47		Hardin		
48		Harlan		
49		Harrison		
50		Hart		
51		Henderson		
52		Henry		
53		Hickman		
54		Hopkins		
55		Jackson		
56		Jefferson		
57		Jessamine		
58	X	Johnson	95	96
59		Kenton		
60	X	Knott	796	811
61		Knox		
62		Larue		
63		Laurel		
64	X	Lawrence	28	29
65		Lee		
66	X	Leslie	14	14
67	X	Letcher	94	98
68		Lewis		
69		Lincoln		
70		Livingston		
71		Logan		
72		Lyon		
73		McCracken		
74		McCreary		
75		McLean		
76		Madison		

610. Territory Served - KENTUCKY

Report below the number of customers at the end of the year in respondent's distribution system in which service is furnished setting forth by counties the number of customers and the average number of customers during the year. Respondent should place an X in the box in column (b) if that county is served and supply related customer information in columns (d) and (e)

County Code (a)	Serves County (b)	Name of Kentucky County (c)	Number Of Customers At End Of Year (d)	Average Number Of Customers During Year (e)
77	X	Magoffin	24	26
78		Marion		
79		Marshall		
80	X	Martin	76	79
81		Mason		
82		Meade		
83		Menifee		
84		Mercer		
85		Metcalfe		
86		Monroe		
87		Montgomery		
88		Morgan		
89		Muhlenberg		
90		Nelson		
91		Nicholas		
92		Ohio		
93		Oldham		
94		Owen		
95		Owsley		
96		Pendleton		
97	X	Perry	176	185
98	X	Pike	878	898
99		Powell		
100		Pulaski		
101		Robertson		
102		Rockcastle		
103		Rowan		
104		Russell		
105		Scott		
106		Shelby		
107		Simpson		
108		Spencer		
109		Taylor		
110		Todd		
111		Trigg		
112		Trimble		
113		Union		
114		Warren		
115		Washington		
116		Wayne		
117		Webster		
118		Whitley		
119		Wolfe		
120		Woodford		
Totals			3,536	3,618
Total Population of Territory Served (Estimated)			258,434	

VERIFICATION

The foregoing report must be verified by the oath of the officer having control of the accounting of the respondent. It shall be verified, also, by the oath of the president or other chief officer of the respondent. The oaths required may be taken before any person authorized to administer an oath by the laws of the State in which the same is taken.

OATH

(To be made by the officer having control of the accounting of the respondent)

State of Pennsylvania
ss:
County of Allegheny

Theresa Z. Bone makes oath and says that he/she is Vice President & Controller
(Name of affiant) (Official title of affiant)

of Equitable Gas Company, a Division of Equitable Resources, Inc.
(Exact legal title or name of the respondent)

The signed offier has reviewed the report.

Based on the officer's knowledge, the report does not contain any unture statements of a material fact or omit to state a material fact necessary in order to make the statements made, in light of the circumstances under which such statements were made, not misleading.

Based on such officer's knowledge, the financial statements, and other financial information included in the report, fairly present in all material respects the financial condition and results of operations of the issuer as of, and for, the periods presented in the report.

He/she believes that all other statements contained in the said report are true, and that the said report is a correct and complete statement of the business and affairs of the above-named respondent during the period of time from and including January 1, 2006 to and including December 31, 2006.

(Signature of affiant)

Subscribed and sworn to and before me, a Notary in and for the State and County above-named, this 30th day of April, 2007

My commission expires July 25, 2009

Linda Dayak
(Signature of officer authorized to administer oaths)

COMMONWEALTH OF PENNSYLVANIA
Notarial Seal
Linda M. Dayak, Notary Public
City Of Pittsburgh, Allegheny County
My Commission Expires July 25, 2009
Member, Pennsylvania Association of Notaries

SUPPLEMENTAL OATH

(By the president or other chief officer of the respondent)

State of Pennsylvania
ss:
County of Allegheny

Randall L. Crawford makes oath and says that he/she is President
(Name of affiant) (Official title of affiant)

of Equitable Gas Company, a Division of Equitable Resources, Inc.
(Exact legal title or name of the respondent)

that he has carefully examined the foregoing report; that he believes that all statements of fact contained in the said report are true, and that the said report is a correct and complete statement of the business and affairs of the above named respondent during the period of time from and including January 1, 2006, to and including December 31, 2006

Randall L. Crawford
(Signature of affiant)

Subscribed and sworn to before me, a Notary in and for the State and County above-named, this 30th day of April

My commission expires July 25, 2009

Linda Dayak
(Signature of officer authorized to administer oaths)

COMMONWEALTH OF PENNSYLVANIA
Notarial Seal
Linda M. Dayak, Notary Public
City Of Pittsburgh, Allegheny County
My Commission Expires July 25, 2009
Member, Pennsylvania Association of Notaries