EXHIBIT NO. _______ (WAG-47)
DOCKET NO. UE-031725
2003 POWER COST ONLY RATE CASE
WITNESS: WILLIAM A. GAINES

BEFORE THE

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION, Complainant, v. PUGET SOUND ENERGY, INC., Respondent.	Docket No. UE-031725

REBUTTAL TESTIMONY OF
WILLIAM A. GAINES
ON BEHALF OF PUGET SOUND ENERGY, INC.

FEBRUARY 13, 2004

PIRA ENERGY GROUP

March 26, 2001

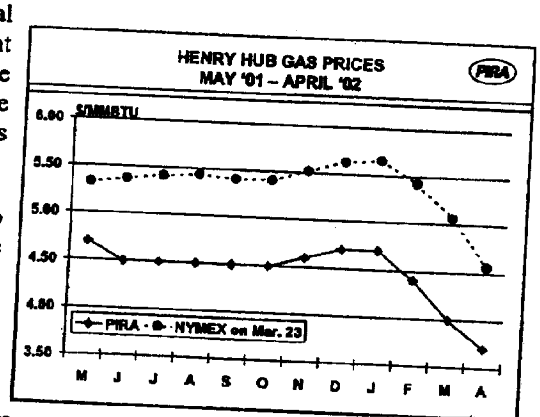
PIRA

NATURAL GAS

U.S. Gas Market Forecast

THE GREAT DEBATE

Spring is the natural gas market's transitional time because storage becomes a major element of demand, instead of supply. The great debate between gas bulls and bears now centers on the impact of this transition on gas prices in the months ahead.



In the bulls' corner, a typical starting point will be to emphasize extremely depleted gas storage at the conclusion of the 00/01 heating season. Consequently, a substantial year-on-year hike in refills will be mandatory to reach *minimum* end-of-injection season targets. Bears will counter that last year's abnormally small refills (1.6 TCF versus a 1.9 TCF prior six-year average) stemmed from vastly different fundamentals then facing the industry. In short, bears (including PIRA) see three factors — the economic slowdown (recession?), stronger domestic production, and higher gas prices — providing the foundation for incremental storage refills without exerting upward pressure on prices. The winner of this debate could be declared before the end of the second quarter, if storage refills begin with a bang relative to a year ago.

Recent gas balances favor the bearish price outlook. Over the past several weeks, storage withdrawals have been running slightly below the year-earlier pace despite about 5 BCF/D higher gas space heating load. Looking ahead, the electric generation (EG) sector will be moving to center stage of the U.S. gas market, and this *Forecast* thus takes an especially close look at the mix of factors that, on balance, point to modest gas demand growth within the sector.

00/01 HEATING SEASON'S LEGACY

From PIRA's perspective, the 00/01 heating season's legacy will be that gas prices indeed matter, not weather alone. For the first time since the 95/96 heating season, gas weighted heating degree days (GWHDDs) will climb above the 30-year average. Following the prior heating season's record-breaking mild temperatures, the year-on-year comparison is truly striking.

Strictly based on GWHDDs, gas demand for residential/commercial (R/C) space heating *alone* would have risen above year-earlier levels by about 5 BCF/D or 750 BCF. Yet, *total* gas demand is on track to increase by about 3 BCF/D over the November through March period. For the most part, the difference can be attributed to price-driven "demand destruction," a market-balancing factor that became highly visible and essential as the heating season progressed.

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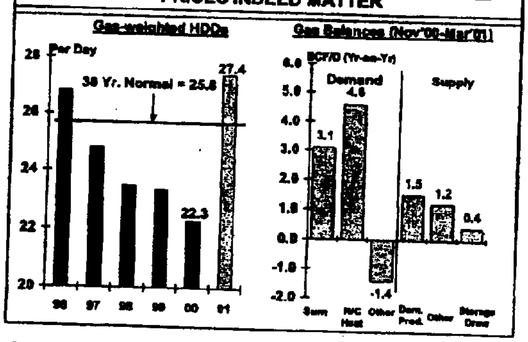
The indicated growth of overall gas demand was made possible by the expansion of disposable gas supply from both domestic production and imports. Storage withdrawals are projected to climb only slightly above the year-earlier pace.

On the supply side, the heating season saw 1.5 BCF/D growth of domestic output heavily oriented toward independent producers that fall outside the coverage of PIRA's quarterly survey. Despite only minimal gas output gains reflected by large producers in fourth-quarter corporate reports, PIRA's analysis of state and federal production data points toward faster output growth than earlier estimated. Industry-wide gains in 4Q00 now appear in the 0.8-1.2 BCF/D area. Given the sharply accelerated pace of gas-oriented drilling in late'00, our projected output levels for 2001 could turn out to be conservative.

Rising Canadian gas exports, coupled with an approximate doubling of LNG shipments, boosted supply by an estimated 1.2 BCF/D. Canadian increases stem from Sable Island and sizable incremental net draws from storage. Western Canadian production exhibited only modest expansion (see page 9, *Table 10*). Higher LNG shipments are attributable to the CMS facility in Lake Charles, Louisiana.

HEATING SEASON RETROSPECTIVE: PRICES INDEED MATTER



On the demand side, a portion of the "destruction" that resulted from this winter's astonishing gas prices appears to have occurred in the R/C heating sector. In Jan/Feb'01, gas price increases at major city gate markets ranged from 40% to 110%. Although evidence so far is essentially anecdotal, PIRA estimates that conservation efforts by R/C consumers in response to price hikes will reduce the sector's gas heating by 4-6% in 1Q01. On balance, R/C gas heating would rise nevertheless by 4.6 BCF/D from the impact of incremental GWHDDs.

In the non-core sectors, the projected 1.5 BCF/D decline underscores the intensity of demand destruction in the traditional industrial and gas-fired electric generation (EG) areas[1]. Within those sectors, the flexibility (i.e. fuel switching capability) and/or "willingness" of consumers (i.e. other economic considerations) to cut gas consumption precluded further gas price gains.

To a large extent those demand reductions were needed, given the bullish mix of lagging supply gains, abnormally low storage, and burgeoning R/C gas heating requirements. Now, with the heating season almost over and thus the evaporation of R/C heating looming, the future strength of U.S. gas demand soon will fall squarely upon the shoulders of the non-core sectors. Consequently, the extent of those end-users' flexibility to use gas will be crucial with respect to gas prices going forward.

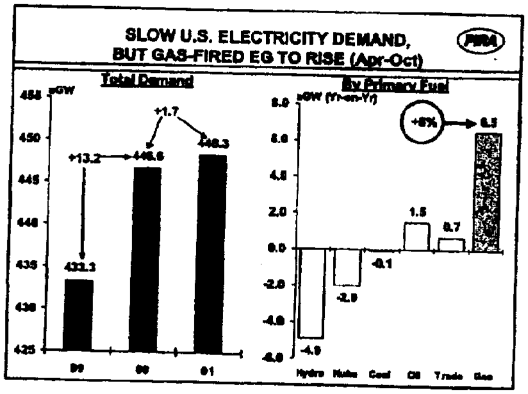
THE EG SECTOR TO CENTER STAGE

Almost as soon as the heating season ends, the EG sector will move to center stage of the U.S. gas market. *Owing to EG's crucial importance to near-term gas demand prospects, PIRA, is attaching a Special Supplement, which provides a regional analysis of the outlook for gas in the EG sector.*

In the recent past, the broad shoulders of the power sector have played a pivotal role in U.S. gas demand growth. PIRA's expanded electric power database reveals that total gas demand for EG soared from

[1] *Those end-uses comprise the overwhelming majority of PIRA's non-core gas demand.*

14.4 BCF/D to 17.6 BCF/D between 1997 and 2000, an annual growth rate of 7%[2].



SLOW U.S. ELECTRICITY DEMAND, BUT GAS-FIRED EG TO RISE (Apr-Oct)

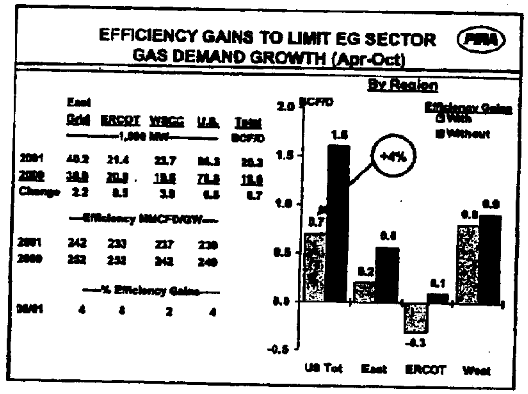
The former unrelenting U.S. economic engine's need for an increasing amount of electricity was driving this powerful trend. 2001, however, is shaping up to be a different story. The hotly debated issue of the U.S. economy's health calls into serious question the near-term strength of national electricity requirements. Largely as a result, ***incremental gas demand within the power sector is now at risk.***

Specifically, U.S. electricity demand is projected to rise by less than 2,000 aMW (average megawatts), or 0.4%, over the upcoming injection season. This modest growth would pale in comparison to the more than 13,000 aMW, or 3%, gain registered a year ago, but at that time the economy was growing at a 5% rate.

Weather comparisons also could turn out to be a restraining influence on electricity load growth. During the key months of May through September'00, the U.S was about 6% warmer than normal based on air-conditioned weighted cooling degree days (CDDs). Relative to normal, temperature deviations varied considerably across regions, but the Western U.S. and Texas experienced significantly more CDDs (i.e. both about 14% more than the NWS 30-year normal).

EG SECTOR GAS DEMAND PROSPECTS

Despite our expectation of slow electricity load growth, PIRA projects that gas-fired electric *generation* will rise by 6,000-7,000 aMW, or about 8%, over the 2001 injection season relative to a year ago. On a volumetric basis, however, total gas *demand* for EG is forecast to rise by only 4%, or 0.7 BCF/D. Even slower growth of 0.3 BCF/D is anticipated during 2Q01.



EFFICIENCY GAINS TO LIMIT EG SECTOR GAS DEMAND GROWTH (Apr-Oct)

The wide differential between gas-fired *generation* growth and gas *demand* growth stems from improvement in the nation's average heat rate of operating gas-fired units. The higher-efficiency of new combined-cycle electric plants stands to constrain gas consumption where these units are run in lieu of older, less efficient gas-fired plants. However, this is a double-edged sword in that stronger electricity demand could translate into magnified gas demand growth if more of the older, less efficient gas-fired EG units are called into service.

In addition to the economy, the weather and EG efficiency, PIRA's gas demand outlook reflects robust oil-fired EG but lower nuclear and hydro generation.

[2] *PIRA's new database includes all operating units — traditional utility, utility divested, new merchant plants as well as industrial cogeneration. In Tables 5 and 6, forecast and historical details are provided by primary energy source and by regional power grid.*

Oil-fired EG: Gas prices in general are not expected to be competitive with 1% sulfur (and above) heavy fuel oil (HFO), thereby limiting gas-fired EG, particularly in the Eastern U.S. A year ago gas held a price advantage over HFO until the third quarter. However, gas is assumed to be competitively priced against distillate (#2 heating oil), unlike the gas-to-distillate premiums in evidence during 1Q01. For details, please refer to page 10, *Table 11*.

Reduced Nuclear: Declines in nuclear generation around the nation will aid gas-fired EG requirements. The decline is due to the stepped up pace of maintenance and refueling outages planned between April and October relative to a year ago.

Reduced Hydro: Weak hydro will be concentrated in the Pacific Northwest, resulting in strong regional gas demand growth, particularly during the second quarter. However, hydro gains are anticipated in the Eastern Grid.

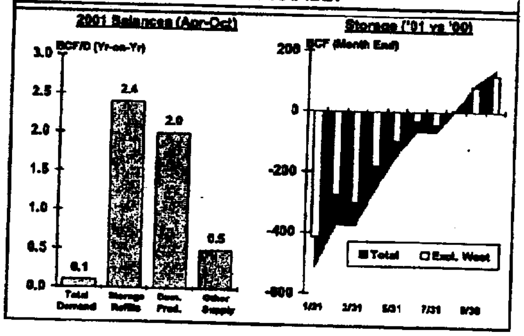
LET THE REFILLS BEGIN

In just a few weeks, storage refills should be moving into high gear, barring a continuation of much colder-than-normal weather. All eyes will be turning to early indications of the difficulty of reducing end-of-March storage deficits. Absent abnormal weather, a fast start to storage refills will send a strong signal of ongoing weak demand and/or escalating supply growth. PIRA's Reference Case indeed envisions spring refills beginning with a bang relative to a year ago.

Alternatively, if storage deficits prove to be resilient, the stage would be set for another summer of head-to-head competition for scarce supplies between non-discretionary storage injections and electric power generators. March is shaping up to be 7-9% colder-than-normal and if this usual weather pattern persists through April storage refills would be constrained. Under slow refill conditions, PIRA would envision gas prices capped by fuel substitution and thus, generally remaining within striking distance of distillate heating oil.

At this juncture, market fundamentals point to robust storage refills throughout the 2001 injection season. Modest demand growth in the EG sector (discussed above) and extremely weak U.S. factory output (particularly in energy-intensive industries) spells lingering gas demand weakness, irrespective of an improvement in the broader economy.

REFILLS EXPECTED TO REDUCE STORAGE DEFICITS RAPIDLY



Consequently, total demand growth is expected to be negligible, particularly in 2Q01. Moreover, a slower-than-anticipated economic recovery could lead to a significant further markdown of 3Q01 gas demand as well. Meager demand growth, coupled with 2.5 BCF/D supply additions (as detailed in PIRA's *Special Supply Supplement*, 2/23/01), should accommodate fast refills and thus exert downward pressure on gas prices.

The required hike in refills is indisputable. But PIRA's outlook breaks with the current market consensus that views a difficult reduction of storage deficits standing in the way of lower gas prices.

For additional information, please contact
Greg Shuttlesworth, Tom Howard, Richard Redash, Nobu Tarui, or Jane Hsu

TABLE 1: GAS PRICES AT HENRY HUB (DOLLARS PER MMBTU)

2.27	2.27	4.31	3.88			5.02	5.84	3.83	4.73
1.81	1.75	2.62	2.53		7.08	6.27	7.09	4.37	5.38
2.23	2.16	3.63	3.45			4.70	5.33	3.63	4.49
2.55	2.60	4.48	4.27			4.50	5.42	3.60	4.48
2.48	2.58	6.48	5.27			4.60	5.63	3.70	4.56
1.85	1.80	2.42	2.36	8.14	9.98	8.14	9.98	4.70	5.66
1.78	1.81	2.66	2.62	5.56	6.21	5.56	6.29	4.40	5.43
1.79	1.63	2.79	2.61		5.05	5.10	5.00	4.00	5.07
2.15	1.88	3.03	2.88			4.90	5.27	3.70	4.57
2.25	2.36	3.58	3.08			4.70	5.33	3.60	4.45
2.30	2.23	4.29	4.38			4.50	5.38	3.60	4.46
2.30	2.27	3.97	4.36			4.50	5.42	3.60	4.49
2.79	2.62	4.42	3.84			4.50	5.44	3.60	4.49
2.55	2.90	5.06	4.62			4.50	5.41	3.60	4.47
2.73	2.55	5.02	5.28			4.50	5.41	3.60	4.46
2.36	3.05	5.52	4.50			4.60	5.52	3.70	4.57
2.36	2.14	8.90	6.03			4.70	5.63	3.80	4.67

TABLE 2: GAS STORAGE (BCF, END OF MONTH)

842	528	260	1630	666	290	160	1116
542	394	218	1154	410	250	120	780
441	376	205	1022	270	245	130	645
460	384	227	1071	363	300	155	818
646	413	249	1308	572	390	200	1162
865	468	273	1606	832	470	240	1542
1096	510	293	1898	1052	510	270	1832
1294	513	289	2096	1271	540	290	2101
1512	573	303	2388	1519	650	310	2479
1673	638	312	2623	1713	720	330	2763
1495	607	262	2364	1673	700	330	2703
991	385	231	1607	1338	610	280	2228

__Gas Prices__. Cash prices are daily averages through 3/23 and Bidweek prices are index values through March'01. PIRA projections represent cash prices. NYMEX actuals are closing gas contract values through March'01.

__Gas Storage__. PIRA's U.S. Total is a hybrid of the AGA's Consuming East through 2/01 and PIRA's estimates of the Producing Region and Consuming West using DOE/EIA data through 12/00 as the starting point.

TABLE 3: DOMESTIC GAS DEMAND (BCF/D)

21.92	7.10	10.58	17.68	15.90	5.11	2.01	62.62
22.14	8.16	9.41	17.57	17.04	5.10	2.01	63.86
21.30	8.40	7.94	16.34	16.72	4.97	2.20	61.53
20.50	6.22	9.12	15.34	16.40	5.10	-0.20	57.14
13.90	8.10	10.40	18.50	15.00	4.90	0.04	52.35
10.14	9.28	11.51	20.79	14.00	4.87	1.35	51.14
8.91	11.43	13.64	25.07	12.90	5.06	2.79	54.73
9.02	11.18	13.98	25.16	14.60	4.97	1.77	55.51
21.40	7.03	7.92	14.95	17.80	5.10	-0.20	59.05
13.01	9.81	8.88	18.69	16.20	4.90	0.04	52.84
10.01	10.08	10.02	20.10	14.90	4.87	1.35	51.22
8.88	11.85	10.43	22.28	13.40	5.06	2.79	52.42
8.90	13.02	11.78	24.80	15.20	4.97	1.77	55.63

TABLE 4: RESIDENTIAL/COMMERCIAL GAS DEMAND (BCF/D)

9.23	3.88	13.12	13.28	8.63	21.92	4749
9.39	3.95	13.34	13.44	8.70	22.14	4700
8.93	3.76	12.68	12.95	8.36	21.30	4457
8.24	3.47	11.70	12.29	8.22	20.50	361
3.59	1.51	5.10	7.64	6.26	13.90	161
0.94	0.40	1.34	4.99	5.15	10.14	38
0.07	0.03	0.11	4.12	4.78	8.91	6
0.15	0.06	0.22	4.20	4.81	9.02	13
8.87	3.73	12.60	12.92	8.48	21.40	363
2.96	1.25	4.21	7.01	6.00	13.01	125
0.85	0.36	1.21	4.90	5.11	10.01	34
0.06	0.02	0.08	4.11	4.77	8.88	5
0.07	0.03	0.10	4.12	4.78	8.90	6

Domestic Demand. *Electric Generation (EG) includes gas-fired electricity from traditional utility, utility divested, new merchant plants as well as industrial cogeneration. Other demand also includes lease and plant fuel, pipeline fuel, and changes in base gas storage. The "Balancing Item" represents the difference between the sum of the components of gas supply and the sum of the components of gas demand, after taking into account net changes of working gas storage.*

Residential/Commercial Demand. *Monthly R/C heating equals monthly Heating Degree Days (HDDs) weighted by gas multiplied by Heating Load Factor (annual R/C heating load divided by annual GWHDDs). Total R/C demand includes Base Load, partly estimated from the DOE's reported total R/C demand in July/August. Heating degree days equal the extent to which daily mean temperatures (a simple arithmetic average of the daily high and low readings) fall below 65°F.*

TABLE 5: ELECTRIC GENERATION SECTOR PRIMARY ENERGY (GW)

[illegible]	[illegible]	Coal	[illegible]	[illegible]	[illegible]	CDD
74.5	13.4	226.4	84.0	41.0	439.1	1432
70.7	11.3	226.0	85.8	44.5	438.2	1497
64.0	12.5	214.5	83.1	48.0	422.3	1460
64.1	9.8	195.5	74.7	42.7	386.8	43
76.7	11.2	206.0	76.4	42.6	413.0	122
86.6	13.4	229.9	90.0	42.4	462.3	250
104.4	16.8	249.2	90.5	42.3	503.3	361
105.3	16.6	252.3	90.1	41.0	505.3	330
59.8	6.2	194.7	78.1	53.8	392.6	42
74.4	9.9	207.3	82.6	49.3	423.5	165
80.8	13.2	234.6	89.7	47.2	465.5	255
89.5	12.2	242.1	93.0	47.3	484.1	340
98.7	15.7	251.5	91.3	43.8	501.1	349

TABLE 6: ELECTRIC GENERATION SECTOR GAS DEMAND BY REGION

74.5	34.5	18.4	21.3	17.68	8.28	4.28	5.12
70.7	34.5	18.2	18.0	17.57	8.65	4.57	4.35
64.0	33.8	16.1	14.1	16.34	8.67	4.13	3.54
64.1	27.1	17.1	19.6	15.34	6.41	4.03	4.89
76.7	35.1	20.3	20.7	18.50	8.53	4.75	5.21
86.6	40.2	22.3	24.4	20.79	9.76	5.17	5.85
104.4	50.9	26.0	27.0	25.07	12.53	6.06	6.48
105.3	51.6	25.5	27.7	25.16	12.62	5.96	6.58
59.8	32.0	16.1	11.7	14.95	8.02	4.11	2.83
74.4	37.7	21.0	15.7	18.69	9.60	5.32	3.78
80.8	39.6	20.7	20.5	20.10	9.93	5.17	5.00
89.5	43.6	24.4	21.4	22.28	10.93	6.15	5.20
98.7	47.5	25.4	25.7	24.80	12.12	6.39	6.28

EG Sector. ***Total U.S electric generation by primary energy source includes traditional utility, utility divested, new merchant plants, as well as industrial cogeneration. Cooling degree days (CDD) equal the extent to which daily mean temperatures average more than 65°F. For 2001, NWS 30-year "normals" are used. A GW (gigawatt) equals 1,000 megawatts (MW) of electricity. Heat rates for traditional gas-fired steam units are 10,000-11,000 Btus per kilowatt-hour, requiring 240-260 MMCF/D per GW. Alternatively, gas-fired combined cycle units have heat rates of around7,000 Btus per kilowatt-hour, requiring about 160 MMCF/D per GW.***

Regional EG Sector. ***Total U.S. gas demand for EG is divided into three regions. ERCOT primarily overlays the state of Texas. The WSCC represents the Western U.S. region that is comprised of 11 states including CA, WA, OR, ID, WY, MT, CO, NV, AZ, UT and NM. The East (i.e. Eastern Grid) accounts for the remaining U.S.***

TABLE 7: GAS SUPPLY (BCF/D)

3.44	12.07	8.53	4.23	12.76	25.39	53.66	10.66	-1.70
2.96	11.77	8.28	4.07	12.35	24.58	51.66	10.06	2.15
2.50	12.45	7.99	4.27	12.25	24.16	51.36	9.65	0.51
3.30	12.00	8.45	4.20	12.65	25.22	53.17	9.73	-5.76
3.35	12.05	8.50	4.20	12.70	25.22	53.32	10.13	-11.10
3.40	12.05	8.55	4.20	12.75	25.22	53.42	10.38	-12.65
3.45	12.10	8.60	4.25	12.85	25.42	53.82	10.29	-9.37
3.50	12.10	8.60	4.25	12.85	25.42	53.87	10.31	-8.67
2.70	11.60	8.35	4.03	12.38	24.74	51.42	9.24	-1.62
2.88	11.71	8.35	4.04	12.39	24.31	51.29	9.20	-7.65
3.00	11.80	8.44	4.00	12.44	24.26	51.50	9.65	-9.93
3.10	11.85	8.36	4.04	12.40	24.52	51.87	9.99	-9.44
3.10	11.85	8.29	4.05	12.34	24.73	52.02	9.98	-6.37

TABLE 8: NON-GULF GAS PRODUCTION (BCF/D)

4.72	7.26	11.97	3.72	4.64	2.80	2.25	25.39
4.65	6.98	11.62	3.77	4.37	2.60	2.21	24.58
4.69	7.03	11.72	3.82	3.97	2.45	2.19	24.16
4.70	7.25	11.95	3.70	4.60	2.80	2.17	25.22
4.70	7.25	11.95	3.70	4.60	2.80	2.17	25.22
4.70	7.25	11.95	3.70	4.60	2.80	2.17	25.22
4.75	7.30	12.05	3.70	4.65	2.85	2.17	25.42
4.75	7.30	12.05	3.70	4.65	2.85	2.17	25.42
4.64	7.23	11.87	3.72	4.36	2.55	2.24	24.74
4.66	6.97	11.63	3.77	4.27	2.55	2.09	24.31
4.66	6.97	11.63	3.67	4.34	2.55	2.07	24.26
4.69	7.01	11.70	3.74	4.33	2.63	2.12	24.52
4.67	7.11	11.78	3.76	4.39	2.63	2.17	24.73

Gas Supply. *Other Supply includes net imports from Canada, Mexico, and LNG plus supplemental gaseous fuels. Negative storage denotes net injections; if positive net withdrawals.*

U.S. Regional Production. *Gulf of Mexico (GOM) DW (Deepwater) and SW (Shallow Water) refer to offshore Gulf of Mexico production in greater or less than 1,000 feet water depths. Gulf Coast Offshore includes Gulf of Mexico Federal plus state offshore portions of Alabama, Louisiana, and Texas. Other Onshore GOM includes Alabama, Louisiana and Mississippi. Other Permian/Mid-Continent includes Arkansas, Kansas, Oklahoma, and East New Mexico. San Juan includes West New Mexico and Southwest Colorado. Rocky Mountain consists of all states in the Mountain census region plus North Dakota but excludes East New Mexico. Pacific includes California, Oregon and Alaska production. Midwest/East includes all remaining gas producing states.*

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TABLE 9: NET OTHER SUPPLY (BCF/D)

3.56	6.78	0.45	0.87	9.91	-0.40	0.87	0.28	10.66
3.26	6.18	0.33	0.27	9.49	-0.21	0.50	0.28	10.06
3.31	5.92	0.00	0.11	9.12	-0.01	0.27	0.27	9.65
3.50	5.90	0.45	0.80	9.05	-0.40	0.83	0.25	9.73
3.50	6.30	0.45	0.80	9.45	-0.40	0.83	0.25	10.13
3.50	6.55	0.45	0.80	9.70	-0.40	0.83	0.25	10.38
3.50	6.57	0.45	0.80	9.72	-0.50	0.82	0.25	10.29
3.50	6.59	0.45	0.80	9.74	-0.50	0.82	0.25	10.31
2.87	5.80	0.32	0.10	8.89	-0.24	0.36	0.23	9.24
3.02	5.67	0.34	0.12	8.90	-0.30	0.37	0.23	9.20
3.18	5.90	0.35	0.14	9.29	-0.26	0.42	0.20	9.65
3.24	5.87	0.39	0.14	9.36	-0.25	0.62	0.26	9.99
3.11	5.95	0.43	0.14	9.36	-0.25	0.62	0.26	9.98

TABLE 10: CANADIAN GAS BALANCES (BCF/D)

2.65	4.32	9.91	13.09	3.26	0.51	16.86	0.01	
2.50	4.47	9.49	12.97	2.84	0.33	16.15	0.32	
2.38	4.31	9.08	13.02	2.67	0.00	15.69	0.08	
3.10	4.11	9.05	12.80	3.20	0.50	16.50	-0.24	67
1.70	3.21	9.45	12.60	3.20	0.50	16.30	-1.94	127
1.10	2.98	9.70	12.40	3.20	0.50	16.10	-2.32	197
0.80	2.93	9.72	12.60	3.25	0.55	16.40	-2.95	288
0.80	3.51	9.74	12.60	3.25	0.55	16.40	-2.35	361
2.65	4.17	8.89	12.74	2.88	0.31	15.93	-0.22	162
1.59	3.45	8.90	12.30	2.89	0.33	15.52	-1.57	210
1.05	3.18	9.29	12.30	2.85	0.36	15.52	-2.00	270
0.84	3.13	9.36	12.51	2.50	0.39	15.41	-2.08	335
0.82	3.65	9.36	12.42	2.82	0.42	15.67	-1.85	392

***Net Other Supply.** In 2001, incremental Canadian exports to the U.S. reflect shipments on the Alliance pipeline. The growth of Canadian imports form the U.S. largely reflects those Alliance shipments that are destined for eastern Canada on the Vector pipeline. Both Alliance and Vector started in 12/00. Liquefied Natural Gas (LNG) imports consists of shipments into two terminals (Everett, Mass., and Lake Charles, LA.). Supplemental fuels consist of synthetic natural gas, propane-air, refinery gas, biomass gas and commingled manufactured gas.*

***Canadian Gas Balances.** Canadian net exports are based on National Energy Board data (1999 net exports do not match data in Table 9, which are based on DOE data). Negative storage equals net injections. Positive storage equals net withdrawals. Storage figures (BCF) in the final column are end-of-period levels. Following Statistics Canada's definition, PIRA excludes lease and plant fuel from domestic demand.*

TABLE 11: U.S. GAS/FUEL OIL COMPETITIVE PRICES

4.90	23.65	3.75	71.40	5.17	1.15	-0.27
4.70	24.20	3.84	73.80	5.34	0.86	-0.64
4.50	24.60	3.90	75.40	5.46	0.60	-0.96
4.50	25.10	3.98	76.30	5.53	0.52	-1.03
4.50	25.30	4.02	78.10	5.66	0.48	-1.16
3.03	22.20	3.52	68.50	4.96	-0.49	-1.93
3.58	24.70	3.92	72.80	5.27	-0.34	-1.69
4.29	27.65	4.39	76.00	5.50	-0.10	-1.21
3.97	26.25	4.17	76.50	5.54	-0.20	-1.57
4.42	27.45	4.36	86.80	6.29	0.06	-1.87

TABLE 12: U.S. MACROECONOMIC ASSUMPTIONS

8875.7	139.2	126.0
9318.6	147.0	129.3
9493.1	147.0	127.0
9191.8	144.4	128.8
9318.9	147.1	130.3
9369.5	148.4	129.7
9394.2	148.2	128.4
9410.6	146.2	126.2
	Percentage Change	
5.0	5.6	2.6
1.9	0.0	-1.8

Gas/Fuel Oil Prices. *Differentials equal gas prices minus residual and #2 f.o. prices. Resid is converted at 6.3 MMBtu per barrel; #2 oil is converted at 5.8 MMBtu per barrel. Oil prices are from PIRA's World Oil Market Forecast (02/28/01). Gas prices are daily averages through 3/23/01 and PIRA projections.*

Macroeconomic. *GDP through 4Q00 preliminary estimate. Industrial Production Index through Feb. 2001.*

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PIRA ENERGY GROUP

PIRA

March 26, 2001

NATURAL GAS

Special EG Sector Supplement

Last month's *Forecast* included a *Special Supplement* covering PIRA's near-term regional outlook for U.S. gas production. Equally important in terms of near-term gas price implications is the outlook for demand in the electric generation (EG) sector. In this *Supplement* we provide special in-depth coverage of the key factors behind PIRA's outlook for gas demand in the EG sector over the upcoming April-October injection season.

EG SECTOR PROSPECTS

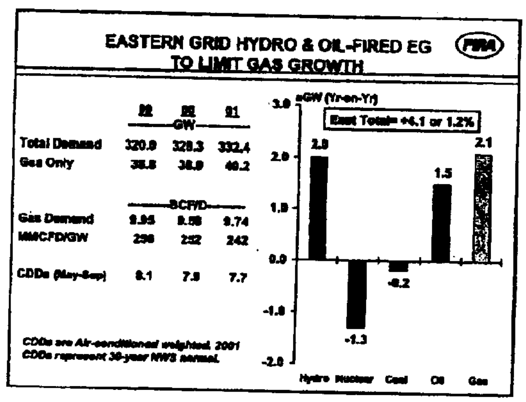
For the 2001 injection season, PIRA projects total U.S. gas-fired EG to rise about 0.7 BCF/D relative to last year. Slower growth of 0.3 BCF/D is anticipated during 2Q01, but in 3Q01 demand growth is seen accelerating to 1.1 BCF/D. The outlook hinges on multiple factors that affect electricity demand, the fuel mix of electric generation, and ultimately gas consumption. However, the overriding concern is the rate of electricity demand growth, given that gas-fired EG is at the margin in many regional U.S. markets.

In many electricity markets around the country, gas represents the marginal fuel for EG, and thus is highly dependent on the pace of electricity load growth. While there can be no argument about the sizable quantities of new gas-fired capacity being added to the EG sector, gas demand will be hard-pressed to maintain its trend-line expansion in the face of modest overall electricity demand growth reflecting a slumping U.S. economy. A more detailed discussion of the regional specifics is provided below.

THE EAST

The Eastern grid (east of the Rockies) accounts for approximately 75% of total U.S. electricity demand, but less than half to the U.S. power sector's gas consumption. Eastern U.S. electricity demand is forecast to rise more than 4,000 aMW (average megawatts), or about 1%, between April and October relative to the year-ago period. This gain accounts for the overwhelming majority of the projected total U.S. electricity demand increase. However, this region's gas demand most likely will not show the largest gains due in part to gas and oil prices, increased hydro, and gas-fired EG efficiency gains.

The Eastern grid is home to the largest concentration of dual-fuel facilities. As a result of natural gas forward prices that are well above heavy fuel oil (HFO) and at parity with distillates, oil-fired EG should increase its market share by providing roughly 1,500 aMW of additional electricity supplies. However, that will come at the expense of both coal (-200 aMW) and nuclear (-1,300 aMW) generation. Since all but 14 of the total U.S. nuclear generation units are located in the Eastern grid, the year-on-year increase in planned outages will hit this region the hardest.



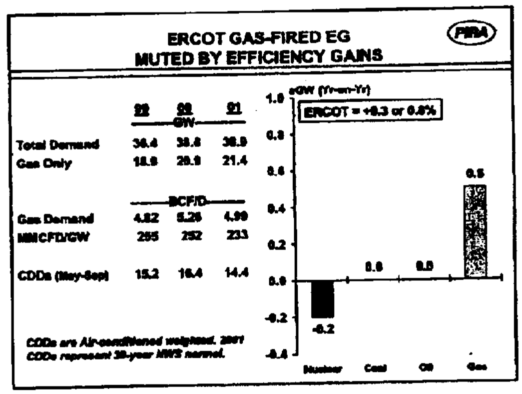
In spite of the competitive disadvantage natural gas prices are likely to be in relation to oil, stronger gas-fired EG (along with more hydro) will be required to meet the anticipated increase in this region's electricity demand. Specifically, gas-fired EG is seen rising by more than 2,000 aMW during the injection period. The related gas demand growth, though, is limited to 0.1-0.2 BCF/D, or less than 2%. An approximate 4% improvement in the average heat rate of Eastern gas-fired EG units lowers gas demand growth by roughly 0.4-0.5 BCF/D in this market.

It is noteworthy to point out the impact of normal weather on electricity demand and, thus, on gas consumption within the Eastern grid's power sector. This region includes the Northeast, Midwest, the South Atlantic and Gulf states, excluding Texas. While the Northeast and Midwest were largely spared from 90 degree-plus weather throughout the peak 2000 summer months, hot conditions elsewhere in the Eastern grid resulted in nearly a 3% increase in air-condition-weighted cooling degree days (CDDs) through the April-October'00 period relative to normal. Consequently, the occurrence of normal temperatures in the Eastern grid this summer would not necessarily result in a significant year-on-year hike in weather-related gas cooling demand.

ERCOT (TEXAS)

ERCOT only accounts for about 8% of the total summer U.S. electricity market, but fully 25% of total gas demand within the EG sector. Looking forward, difficult year-on-year weather comparisons, coupled with higher energy prices and slower economic growth, are expected to limited ERCOT electricity demand growth. ERCOT power demand should rise by only 300 aMW, or less than 1%, this summer. However, because of changes in the fuel mix, gas-fired EG should register larger gains.

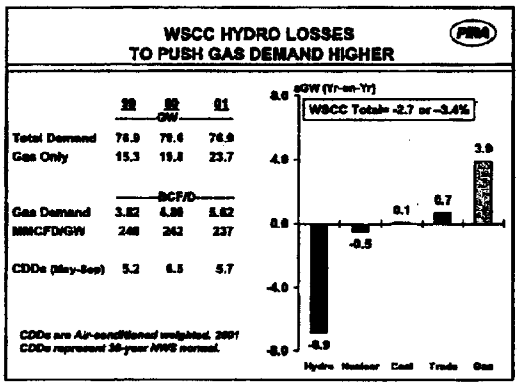
In contrast to the East and West, the make up of this power market is relatively simple in that the role of oil and hydro is meager in contrast to the dominance of coal, nuclear and gas-fired EG. Incremental coal-fired EG will be limited this summer by available capacity limitations. Additionally, nuclear EG should be down by about 200 aMW on-average during the Apr-Oct'01 period versus last year. The net effect of these changes, when combined with regional electricity demand growth, gas-fired EG requirements by about 500 aMW.



The plant efficiency improvements associated with new combined-cycle and combustion turbines will be most dramatic in ERCOT in terms of this region's average heat rate of employed gas-fired EG units. Due to the ongoing influx of more-efficient plant capacity additions, PIRA estimates that the average heat rate of gas-fired power plants will decline by more than 8% relative to a year ago. That equates to a savings of 0.4 BCF/D of gas demand within the power sector. As a result of this striking improvement, ERCOT will be able to provide the additional 500 aMW of gas-fired EG with less gas than was used a year ago. Specifically, gas demand is projected to decline 0.3 BCF/D during the 2001 injection season. Those losses exceed the expected increase in the Eastern Grid, but the demand growth in the West should still lift the overall U.S. results.

WSCC (THE WEST)

The WSCC electricity market represents about 17% of the total U.S., but a larger 25% of total gas use within the power sector. The region, or more specifically, California, has been the center of attention as talk of a U.S. energy crisis mounts. Highlighted by episodes of rolling blackouts, concerns are growing regarding the adequacy and price of electricity and gas supplies needed by California and the surrounding states. Numerous issues are behind the unfolding energy problem, but the situation has been worsened by unusually dry conditions in the Pacific Northwest limiting hydrogenation and strengthening demand for gas-fired generation. Even weaker electricity demand is unlikely to substantially alleviate the problem.



In addition to more difficult weather comparison, high energy prices and the associated slowdown of economic activity is behind PIRA's projected WSCC electric demand decrease. Regional electricity demand is seen declining by almost 3,000 aMW, or more than 3%, during the injection season. In normal years when hydropower is more bountiful, a reduction in electricity demand would typically cut gas use within the power sector. Reduced electricity demand would result in a lower reliance on the high heat rate gas-fired steam generators that are plentiful in California and the WSCC. Such a development would lead to lower gas demand, especially when more efficient units are being added to the regional generation mix.

The year-on-year growth of the WSCC gas-fired EG should approach 4,000 aMW on average during the Apr.-Oct.'01 period. The gains are solely attributable to the enormous shortfall in hydroelectric generation, which could eclipse 7,000 aMW. The current outlook for Pacific Northwest hydro is still on track to be one of the worst in many years due to low rain and snowfall and the related reductions in reservoir levels. The higher gas-fired EG needed to offset the declines in hydro will require a healthy 0.8 BCF/D increase in gas supplies during the injection season versus a year ago.

Clearly, the particulars of the electric sector and the role of gas are dynamic and complex. For even greater details, contact Victoria Watkins at PIRA Energy Group (i.e., vwatkins@pira.com) and inquire about the monthly Eastern and Western Grid Market Forecast reports.

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PIRA ENERGY GROUP

PIRA

May 24, 2001

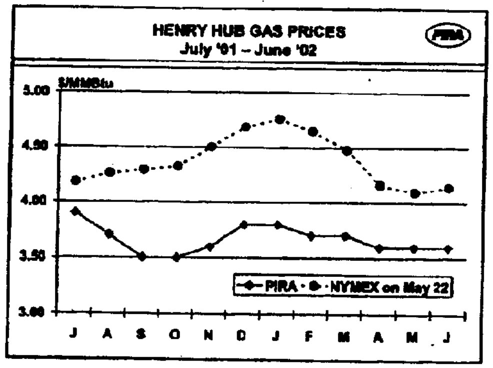
NATURAL GAS

U.S. Gas Market Forecast

BEAR MARKET RISING

To date, 2Q01 gas balances reveal a monumental mismatch between supply and demand. The resulting record-breaking pace of storage injections has re-built spring storage with lightning speed and exerted downward pressure on gas prices. From PIRA's perspective, these trends appear to represent only the beginning of a protracted bear market.

A year ago, the gas market confronted exactly the opposite situation. Upward price pressures underscored the need to curtail end-use consumption to accommodate ***non-discretionary storage refills***, as gas balances reflected competition for scarce supplies between electric power generation and those required storage refills. Despite looming supply scarcity, the market was slow to recognize the extent to which Henry Hub gas prices, by necessity, were headed into record high territory.



This year's gas market expectations appear no less biased, but in reverse. In the face of an ***intensive need for discretionary storage refills***, the market remains reluctant to recognize the extent to which near-term Henry Hub prices are at a risk of plunging below current levels. A key factor is the general perception that domestic gas deliverability is expanding at only a modest pace, at best, a perception not based on reality, but largely on corporate reports of major U.S. gas producers. Lower demand is thus seen almost entirely behind faster storage refills, with demand recovery led by a stronger economy providing a potential "quick fix" to the market's imbalance. However, PIRA sees independent producers (outside the scope of corporate surveys) as the potential linchpin for accelerating domestic gas deliverability. If so, downside price risks are indicated beyond our already bearish Reference Case, owing to the specter of running out of storage capacity to absorb discretionary refills.

SHADES OF SUMMER 1998

In the summer ahead, PIRA anticipates the development of gas storage conditions that could bear a striking resemblance to the summer of 1998. Prior to that summer, El Niño conditions had produced one of the mildest winters in history. Largely as a result, working gas storage stood at an abnormally high 1.1 TCF on March 31st, almost 0.2 TCF above the year-earlier level. By June 30th, storage had reached 2.08 TCF, fully 0.4 TCF above the prior year's level.

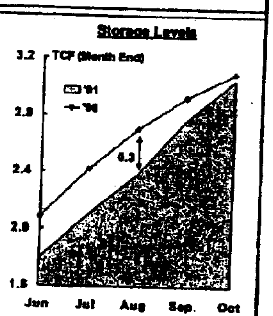
Despite a strong economy and cheap gas (July '98 Bidweek Henry Hub prices were about $2.10/MMBTU), it was difficult to see how gas demand would be strong enough to limit storage injections to roughly 1.0 TCF (8 BCF/D) over the final four months (123 days) of the injection season. Yet, something would have to give, since injections significantly in excess of 1.0 TCF were not feasible given the 3.1-3.2 TCF upper limits of total U.S. working gas storage.

SUMMER 2001: SHADES OF SUMMER 1998

Gas Balances, July/October

	1998	2001
	—BCF/D—	
Supply	59.5	64.6
Dom. Prod.	50.9	54.2
Other	8.6	10.4
Demand	51.2	54.4
Storage Refills	8.3	10.2
Storage Levels	—TCF—	
June 30	2.08	1.79
October 31	3.09	3.04

Excluding Hurricane Impact, 1998 Dom. Prod. 51.6 BCF/D.



For September '98, the Henry Hub Bidweek index fell to only $1.57/MMBtu. This critically low price reflected: 1) the protracted supply/demand mismatch generating discretionary storage refills, and 2) the increasingly visible specter of running out of storage capacity to absorb those refills.

During September '98, an astonishing mix of hurricanes and tropical storms wrought havoc in the offshore Gulf of Mexico (GOM). Those unprecedented disruptions curtailed offshore GOM output by upwards of 90 BCF (3 BCF/D) during the month. The hurricane losses spared U.S. gas producers the likely prospect of sub-$1.50 gas over the final three months of the injection season.

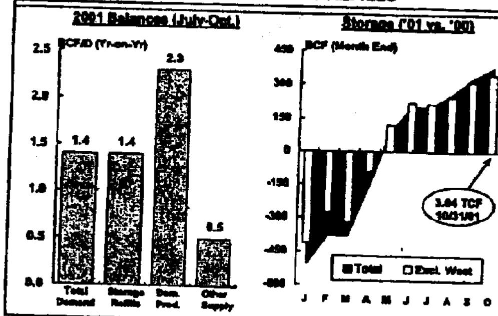
SUMMER 2001 GAS BALANCES

In July/August 2001, PIRA's Reference Case gas prices ($3.90/MMBtu at Henry Hub) should make gas generally competitive against distillate fuel oil. However, gas prices closer to $3.50 would appear necessary to dominate the 2.0-2.5 BCF/D (gas equivalent) dual-fueled steam boiler markets where gas competes with heavy fuel oil (HFO).

In September/October, PIRA's Reference Case gas prices ($3.50-3.60/MMBTU at Henry Hub) should be low enough to compete with HFO. However, the primary energy demand of those gas/HFO boiler markets drops closer to 1.0 BCF/D after the conclusion of the summer air conditioning season.

From the above gas prices, the assumption of normal cooling degree days, and the absence of major hurricane supply losses, PIRA anticipates that storage injections will continue to surpass the year-earlier pace by a wide margin over the July/October period. We expect that July will be the exception, because incremental gas-fired electric generation (2.5-3.0 BCF/D) should limit storage refills (see tables 5 and 6 on page 7 for details).

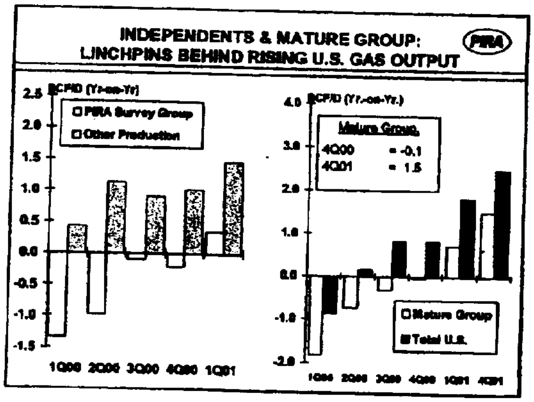
THE SPECTER OF NEARLY FULL STORAGE LIMITING DISCRETIONARY REFILLS



In the late stages of the 2001 storage refill season, gas balances point to downside price pressures similar to the summer of 1998, before the hurricane onslaught. Especially if domestic production turns out to surpass PIRA's Reference Case, the specter of nearly full storage limiting discretionary refills once again would become highly visible. The major supply-side wildcard will be rig productivity in the Shallow-Water Gulf of Mexico (SWGOM), of which more later.

SUPPLY GROWTH PRICE RISKS

The perception that domestic gas deliverability is expanding at only a modest pace, if at all, continues to have broad acceptance. This perception is not based on reality, but instead is largely attributable to the first quarter E&P results from major U.S. producers. By comparison, PIRA's assessment is that expanding domestic output in response to rising prices began in mid-2000 (with no contribution from major producers) and is now accelerating due to the success of independent producers and the improving production performance of the Mature Group[1].

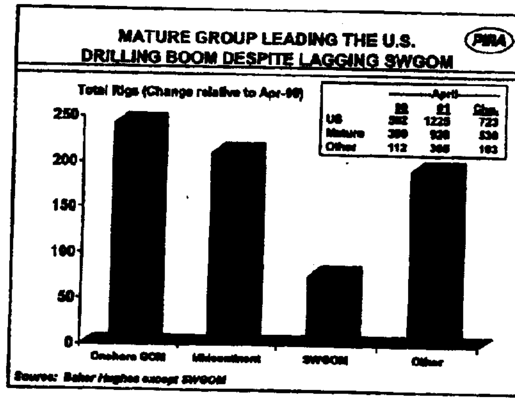


Looking back over the past two months, no accounting of Gross Demand Destruction (GDD, defined as supply growth plus demand losses) is possible to determine the precise basis for incremental storage refills. Looking forward, supply growth poses greater downside gas price risks. Forward gas prices (i.e. the 12-month strip) low enough to curtail gas-oriented drilling are likely to be below prices low enough for gas to capture gas/HFO boiler markets, as well as stimulate other price-sensitive demand growth. Consequently, PIRA sees the shadow over gas prices cast by supply growth looming larger than demand weakness.

Through 3Q00, production data are sufficiently complete to provide definitive evidence of rising U.S. gas output. Moreover, when storage injections are considered in the context of the past two month's slide in gas prices, the implication is that supply growth is becoming responsible for a greater portion of GDD (*Gas Flash*, 5/16/01).

GAS DRILLING OVERVIEW

Few should be surprised to see some gas output growth occur eventually, especially since rig counts have been climbing now for a full two years. The gas-drilling boom is readily visible across the country, but the intensity has varied regionally, and those differences have affected the timing of the supply turnaround.



Despite steady increases in SWGOM rig counts, drilling activity has yet to match late-1996/early-1997 peaks. In contrast, the national rig count, in addition to the Onshore GOM and Midcontinent tallies, have long since moved into new high ground. In spite of the lagged recovery in the SWGOM, the gas-oriented drilling boom is now heavily concentrated in the Mature Group regions. The anticipated impact on gas production from those rig counts is discussed below.

REGIONAL PRODUCTION OUTLOOK

In the <u>SWGOM</u>, drilling activity gains have been both slower and smaller when viewed in relation to most other areas and the U.S. as a whole. Even though the rig count is now at 181, up significantly relative to the April'99 low (104), the region's all-time high (193) has proven elusive thus far.

For the 12 months ending 9/30/01, we are projecting that SWGOM rigs will reach 180-185, as compared to the year-ago average of 151. Even when allowing rig productivity[2] to rival the former all-time lows (which

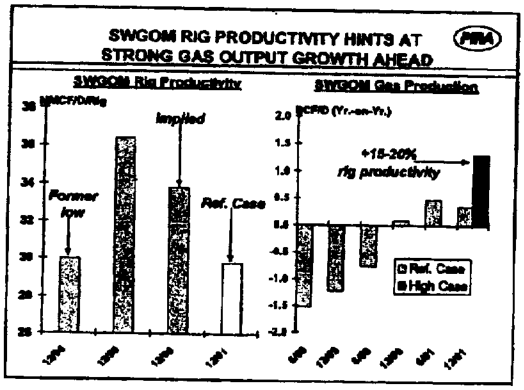
[1] *Mature Group consists of the SWGOM, Onshore GOM, and the Midcontinent/Permian basin areas.*

[2] *PIRA measures "rig productivity" as the volume of first-year gas output in relation to the number of active rigs (mobile and platform) operating in the region. We allow a three-month time lag between drilling and new production. For December, rig productivity would reflect first-year gas well production divided by the 12-month average rig count ending September.*

were realized with comparable rig counts), gas deliverability from first-year wells should be sufficient to expand production.

SWGOM gas production remains about 2.5 BCF/D below its 14.4 BCF/D peak. As a result, even with 40-45% average annual decline rates of wells beyond their first year of operation, lost production due to depletion should not be large enough to offset the new gas deliverability. Annual production losses from older wells have been trimmed from more than 6 BCF/D to around 5 BCF/D, owing to the erosion of the production base.

For December '00, PIRA has estimated SWGOM rig productivity based on three factors: (1) actual rig counts (12-months average ending 9/30/00); (2) "vintage analysis" of preliminary gas production data, which indicate the region's total output trends into late last year[3]; and (3) annual declines from older gas wells in line with recent experience[4].



For December '00, the SWGOM's implied rig productivity was 15-20% greater than in earlier periods with comparable levels of rig activity. This apparent rig productivity improvement is reinforced by anecdotal evidence of independent producers' success in the area. If similar rig productivity extends into the current year, incremental SWGOM gas output in late-2001 has the potential to exceed our Reference Case by 0.5-1.0 BCF/D.

The **Onshore GOM** is leading the Mature Group and the U.S. in terms of gas drilling activity. The total rig count eclipsed the 400 mark in April'01, with gas-oriented drilling accounting for about 80% of the total. The Onshore GOM's gas drilling leadership fostered a quicker turnaround in gas production. Indeed, year-on-year gains first materialized in mid-2000, particularly within east Texas.

Even after factoring into our Reference Case all-time low gas-rig productivity, the region's gas production growth should reach upwards of 0.5 BCF/D by late 2001. This projection is based on a 12-month average gas-rig count ending 9/30/01 of 320-325. Simply put, the increase in drilling should overwhelm declining gas-rig productivity.

In the **Midcontinent**, gas production has been dogged by weakness in oil-oriented drilling, owing to the greater role of associated gas in this region. Nevertheless, the region's rig counts have managed to explode to the upside in recent months. In west Texas and in states like Oklahoma and Kansas, the number of active rigs has increased exponentially relative to the 1999 lows.

Here, too, the intensity of the region's current drilling effort should begin to dwarf the negative effect of lower gas-rig productivity. For late 2001, PIRA's Reference Case gas output increase of 0.5 BCF/D is associated with a 12-month average oil and gas rig count ending 9/30/01 of 315-320, nearly 50% higher than the year-earlier average. Gas-oriented rigs make up close to 60% of that total.

For additional information, please contact Greg Shuttlesworth, Tom Howard, Richard Redash, Nobu Tarui, or Jane Hsu

3 *"Vintage analysis" relates to PIRA's experience in monitoring both pre and post-95% complete MMS data in terms of the sequential pattern of revisions over time.*

4 *Decline rates vary over time and across regions. For example, in the SWGOM, gas wells beyond their first year of production, collectively exhibited decline rates in the 50-55% are. In contrast, wells producing for two or more year's show decline rates of only 20-30%.*

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TABLE 1: GAS PRICES AT HENRY HUB (DOLLARS PER MMBTU)

	1999 Actual		2000 Actual		2001 Actual		2001 Act/Proj		2002 Projection	
	Cash	Bidweek	Cash	Bidweek	Cash	Bidweek	PIRA	NYMEX	PIRA	NYMEX
Yr	2.27	2.27	4.31	3.88			4.52	5.15	3.74	4.34
1Q	1.81	1.75	2.62	2.53	6.29	7.08	6.29	7.08	3.73	4.63
2Q	2.23	2.16	3.63	3.45			4.48	4.78	3.60	4.13
3Q	2.55	2.60	4.48	4.27			3.70	4.29	3.70	4.21
[illegible]	2.48	2.58	6.48	5.27			3.63	4.69	3.93	4.38
Jan	1.85	1.80	2.42	2.36	8.14	9.98	8.14	9.98	3.80	4.76
Feb	1.78	1.81	2.66	2.62	5.56	6.21	5.56	6.21	3.70	4.65
Mar	1.79	1.63	2.79	2.61	5.16	5.05	5.16	5.05	3.70	4.48
Apr	2.15	1.88	3.03	2.88	5.18	5.34	5.18	5.34	3.60	4.16
May	2.25	2.36	3.58	3.08		4.87	4.25	4.87	3.60	4.10
Jun	2.30	2.23	4.29	4.38			4.00	4.12	3.60	4.14
[illegible]	2.30	2.27	3.97	4.36			3.90	4.18	3.70	4.19
[illegible]	2.79	2.62	4.42	3.84			3.70	4.26	3.70	4.21
[illegible]	2.55	2.90	5.06	4.62			3.50	4.29	3.70	4.23
[illegible]	2.73	2.55	5.02	5.28			3.50	4.32	3.70	4.24
[illegible]	2.36	3.05	5.52	4.50			3.60	4.50	3.90	4.38
[illegible]	2.36	2.14	8.90	6.03			3.80	4.69	4.20	4.51

TABLE 2: GAS STORAGE (BCF, END OF MONTH)

[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
[illegible]	842	516	260	1618	666	280	163	1109
[illegible]	542	384	218	1144	410	237	118	765
[illegible]	441	343	205	989	253	212	142	607
[illegible]	460	345	227	1032	406	305	171	882
[illegible]	646	385	249	1279	690	460	220	1370
[illegible]	865	446	273	1584	940	590	255	1785
[illegible]	1096	504	293	1893	1155	660	280	2095
[illegible]	1294	532	289	2115	1351	720	305	2376
[illegible]	1512	613	303	2427	1609	830	320	2759
[illegible]	1673	681	312	2666	1773	930	340	3043
[illegible]	1495	611	262	2368	1722	880	325	2927
[illegible]	991	384	231	1606	1426	760	280	2466

Gas Prices. ***Cash is the average of daily prices during the month. Bidweek prices are index values through May'01. PIRA projections represent cash prices. For Janary'01 – May'01 NYMEX prices are Henry Hub bidweek index.***

Gas Storage. ***PIRA's U.S. storage totals are a combination of a) AGA's Consuming East and the Producing Region and b) PIRA's latest estimates of the Consuming West using the latest DOE/EIA data (2/28/01) as the starting point.***

TABLE 3: DOMESTIC GAS DEMAND (BCF/D)

[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
[illegible]	22.27	7.55	10.34	17.89	16.78	5.10	62.04
[illegible]	22.54	8.29	9.39	17.68	18.36	5.10	63.68
[illegible]	21.30	8.53	7.94	16.47	18.91	4.97	61.65
[illegible]							
[illegible]	9.98	9.88	10.88	20.76	14.80	4.87	50.40
[illegible]	8.96	12.22	13.00	25.22	15.09	5.06	54.33
[illegible]	9.07	12.02	13.50	25.52	15.72	4.97	55.28
[illegible]	11.49	9.12	12.07	21.19	14.38	4.57	51.63
[illegible]	18.71	7.06	10.33	17.38	15.48	4.65	56.22
[illegible]							
[illegible]	9.97	10.21	10.02	20.23	15.90	4.87	50.96
[illegible]	8.93	12.01	10.43	22.43	15.49	5.06	51.92
[illegible]	8.95	13.20	11.78	24.98	15.82	4.97	54.72
[illegible]	12.05	9.42	10.68	20.10	14.38	4.57	51.09
[illegible]	17.67	6.86	9.81	16.67	15.28	4.65	54.27

TABLE 4: RESIDENTIAL/COMMERCIAL GAS DEMAND (BCF/D)

[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
[illegible]	9.28	4.14	13.42	13.28	8.99	22.27	4749
[illegible]	9.47	4.22	13.69	13.47	9.07	22.54	4700
[illegible]	8.95	3.66	12.60	12.95	8.36	21.30	4457
[illegible]							
[illegible]	0.78	0.35	1.13	4.78	5.20	9.98	38
[illegible]	0.08	0.03	0.11	4.08	4.88	8.96	6
[illegible]	0.15	0.07	0.22	4.15	4.92	9.07	13
[illegible]	1.83	0.81	2.64	5.83	5.66	11.49	73
[illegible]	6.82	3.04	9.86	10.82	7.89	18.71	285
[illegible]							
[illegible]	0.77	0.34	1.12	4.77	5.19	9.97	31
[illegible]	0.06	0.03	0.08	4.06	4.88	8.93	5
[illegible]	0.07	0.03	0.10	4.07	4.88	8.95	6
[illegible]	2.21	0.99	3.20	6.21	5.84	12.05	89
[illegible]	6.10	2.72	8.82	10.10	7.57	17.67	255

Domestic Demand. *Electric Generation (EG) includes gas-fired electricity from traditional utility, utility divested, new merchant plants as well as industrial cogeneration. Miscellaneous demand includes lease and plant fuel, pipeline fuel, and changes in base gas storage. Industrial demand includes a balancing item which represents the difference between the sum of the components of gas supply and the sum of the components of reported gas demand, after taking into account net changes of working gas storage.*

Residential/Commercial Demand. *Monthly R/C heating equals monthly Gas Weighted Heating Degree Days (GWHDDs) multiplied by Heating Load Factor (annual R/C heating load divided by annual GWHDDs). Total R/C demand includes Base Load, partly estimated from the DOE's reported total R/C demand in July/August. Heating degree days equal the extent to which daily mean temperatures (a simple arithmetic average of the daily high and low readings) fall below 65°F.*

TABLE 5: ELECTRIC GENERATION SECTOR PRIMARY ENERGY (GW)

	Gas	Oil	Coal	Nuke	Other	Total	CDD
2001	74.5	12.6	227.0	85.1	40.5	439.6	1448
2000	70.6	11.4	225.9	85.8	44.9	438.6	1497
1999	64.0	12.5	214.5	83.1	48.4	422.6	1460
2001							
[illegible]	85.6	12.3	235.1	90.5	41.9	465.4	250
[illegible]	104.1	15.0	249.7	90.5	42.8	502.1	361
[illegible]	106.1	15.1	252.8	90.1	41.4	505.4	330
[illegible]	89.7	12.0	230.1	83.8	35.6	451.2	187
[illegible]	73.8	10.2	218.3	75.8	34.9	413.0	68
[illegible]							
[illegible]	80.8	13.2	234.6	89.7	48.3	466.6	255
[illegible]	89.5	12.2	242.1	93.0	48.2	485.0	340
[illegible]	98.7	15.7	251.5	91.3	45.4	502.7	349
[illegible]	80.7	13.5	232.2	85.5	38.9	450.8	200
Oct	67.7	11.5	220.6	74.2	35.4	409.4	71

TABLE 6: ELECTRIC GENERATION SECTOR GAS DEMAND BY REGION

	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	ERCOT	WSCC
[illegible]	74.5	34.9	18.3	21.3	17.89	8.49	4.26	5.15
[illegible]	70.6	34.5	18.2	18.0	17.68	8.65	4.56	4.47
[illegible]	64.0	33.8	16.1	14.1	16.47	8.70	4.13	3.64
[illegible]								
[illegible]	85.6	39.9	22.3	23.4	20.76	9.89	5.17	5.70
[illegible]	104.1	53.5	26.0	24.6	25.22	13.23	6.06	5.93
[illegible]	106.1	54.3	25.5	26.3	25.52	13.34	5.96	6.22
[illegible]	89.7	44.1	21.7	23.8	21.19	10.55	5.04	5.60
[illegible]	73.8	36.5	16.8	20.6	17.38	8.66	3.85	4.88
[illegible]								
[illegible]	80.8	39.6	20.7	20.5	20.23	9.95	5.16	5.12
[illegible]	89.5	43.6	24.4	21.4	22.43	10.96	6.15	5.33
[illegible]	98.7	47.5	25.4	25.7	24.98	12.16	6.40	6.42
[illegible]	80.7	36.2	21.5	23.0	20.10	9.09	5.34	5.67
[illegible]	67.7	29.7	17.1	20.9	16.67	7.32	4.27	5.08

EG Sector. *Total U.S electric generation by primary energy source includes traditional utility, utility divested, new merchant plants, as well as industrial cogeneration. Cooling degree days (CDD) equal the extent to which daily mean temperatures average more than 65°F. For 2001, NWS 30-year "normals" are used. A GW (gigawatt) equals 1,000 megawatts (MW) of electricity. Heat rates for traditional gas-fired steam units are 10,000-11,000 Btus per kilowatt-hour, requiring 240-260 MMCF/D per GW. Alternatively, gas-fired combined cycle units have heat rates of around7,000 Btus per kilowatt-hour, requiring about 160 MMCF/D per GW.*

Regional EG Sector. *Total U.S. gas demand for EG is divided into three regions. ERCOT primarily overlays the state of Texas. The WSCC represents the Western U.S. region that is comprised of 11 states including CA, WA, OR, ID, WY, MT, CO, NV, AZ, UT and NM (adjusted to include Alaska). The East (i.e. Eastern Grid) accounts for the remaining U.S.*

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TABLE 7: GAS SUPPLY (BCF/D)

	3.50	12.12	8.57	4.20	25.43	53.82	10.57	-2.36	
	2.97	11.73	8.29	4.05	24.57	51.60	9.96	2.12	
	2.50	12.46	7.99	4.27	24.16	51.37	9.65	0.63	
	3.55	12.15	8.65	4.20	25.45	54.00	10.24	-13.84	1785
	3.55	12.20	8.65	4.20	25.42	54.02	10.29	-9.98	2095
	3.60	12.20	8.65	4.20	25.42	54.07	10.29	-9.08	2376
	3.60	12.20	8.65	4.25	25.42	54.12	10.29	-12.78	2759
Oct	3.60	12.25	8.70	4.25	25.62	54.42	10.95	-9.15	3043
2000									
	3.02	11.68	8.45	4.00	24.26	51.42	9.69	-10.15	1584
	3.10	11.71	8.38	4.04	24.53	51.75	10.13	-9.97	1893
	3.10	11.79	8.32	4.05	24.75	52.00	9.90	-7.18	2115
	3.10	11.80	8.26	4.05	24.59	51.80	9.70	-10.41	2427
	3.10	11.80	8.29	4.05	24.79	52.02	9.95	-7.71	2666

TABLE 8: NON-GULF GAS PRODUCTION (BCF/D)

	4.76	7.20	11.96	3.75	4.67	2.78	2.27	25.43
	4.66	6.98	11.64	3.77	4.36	2.60	2.21	24.57
	4.69	7.03	11.72	3.83	3.97	2.45	2.19	24.16
	4.80	7.25	12.05	3.75	4.70	2.80	2.15	25.45
	4.80	7.25	12.05	3.70	4.70	2.80	2.17	25.42
	4.80	7.25	12.05	3.70	4.70	2.80	2.17	25.42
	4.80	7.25	12.05	3.70	4.70	2.80	2.17	25.42
	4.80	7.25	12.05	3.70	4.70	2.80	2.37	25.62
	4.67	6.96	11.63	3.68	4.34	2.55	2.07	24.26
	4.70	7.02	11.72	3.74	4.33	2.63	2.12	24.53
	4.68	7.12	11.80	3.75	4.39	2.63	2.17	24.75
	4.67	6.93	11.60	3.72	4.44	2.63	2.20	24.59
	4.64	6.95	11.59	3.80	4.45	2.65	2.30	24.79

Gas Supply. *Other Supply includes net imports from Canada, Mexico, and LNG plus supplemental gaseous fuels. Negative storage change denotes net injections; if positive net withdrawals. Storage levels (BCF) are at end of month shown.*

U.S. Regional Production. *Gulf of Mexico (GOM) DW (Deepwater) and SW (Shallow Water) refer to offshore Gulf of Mexico production in greater or less than 1,000 feet water depths. Gulf Coast Offshore includes Gulf of Mexico Federal plus state offshore portions of Alabama, Louisiana, and Texas. Other Onshore GOM includes Alabama, Louisiana and Mississippi. Other Permian/Mid-Continent includes Arkansas, Kansas, Oklahoma, and East New Mexico. San Juan includes West New Mexico and Southwest Colorado. Rocky Mountain consists of all states in the Mountain census region plus North Dakota but excludes East New Mexico. Pacific includes California, Oregon and Alaska production. Midwest/East includes all remaining gas producing states.*

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TABLE 9: NET OTHER SUPPLY (BCF/D)

[illegible]	Canadian Exports to US West	Other	East	From US	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
[illegible]	3.51	6.84	0.44	0.80	9.98	-0.19	0.50	0.28	10.57
[illegible]	3.25	6.15	0.32	0.26	9.46	-0.21	0.43	0.28	9.96
[illegible]	3.31	5.92	0.00	0.11	9.12	-0.01	0.27	0.27	9.65
[illegible]	3.50	6.55	0.45	0.80	9.70	-0.20	0.49	0.25	10.24
[illegible]	3.50	6.65	0.45	0.80	9.80	-0.25	0.49	0.25	10.29
[illegible]	3.50	6.65	0.45	0.80	9.80	-0.25	0.49	0.25	10.29
[illegible]	3.50	6.65	0.45	0.80	9.80	-0.25	0.49	0.25	10.29
[illegible]	3.60	7.05	0.45	0.80	10.30	-0.20	0.55	0.30	10.95
[illegible]	3.18	5.90	0.35	0.14	9.29	-0.26	0.46	0.20	9.69
[illegible]	3.24	5.87	0.39	0.14	9.36	-0.25	0.75	0.26	10.13
[illegible]	3.11	5.92	0.43	0.14	9.33	-0.25	0.56	0.26	9.90
[illegible]	3.14	5.74	0.42	0.14	9.16	-0.23	0.54	0.23	9.70
[illegible]	3.27	5.72	0.42	0.15	9.27	-0.25	0.59	0.35	9.95

TABLE 10: CANADIAN GAS BALANCES (BCF/D)

[illegible]	Domestic Demand Res/Comm	Other	Exports	Domestic Production Alberta	Other West	Atlantic	[illegible]	[illegible]	[illegible]
[illegible]	2.64	4.39	9.98	13.36	3.25	0.51	17.12	-0.11	
[illegible]	2.49	4.55	9.45	13.01	2.84	0.33	16.17	0.32	
[illegible]	2.38	4.31	9.08	13.02	2.67	0.00	15.69	0.08	
[illegible]	1.10	3.10	9.70	12.60	3.20	0.50	16.30	-2.40	275
[illegible]	0.80	3.10	9.80	12.80	3.05	0.55	16.40	-2.70	358
[illegible]	0.80	3.70	9.80	12.80	3.25	0.55	16.60	-2.30	430
[illegible]	1.10	4.00	9.80	12.90	3.25	0.55	16.70	-1.80	484
[illegible]	2.00	5.00	10.30	13.40	3.45	0.55	17.40	-0.10	487
[illegible]	1.05	3.19	9.28	12.30	2.85	0.36	15.52	-2.00	270
[illegible]	0.84	3.13	9.36	12.51	2.50	0.39	15.41	-2.08	335
[illegible]	0.82	3.70	9.30	12.42	2.82	0.42	15.67	-1.85	392
[illegible]	1.06	3.83	9.16	12.57	2.78	0.41	15.76	-1.71	443
[illegible]	1.75	4.80	9.27	13.05	2.99	0.43	16.47	-0.65	463

Net Other Supply. *In 2001, incremental Canadian exports to the U.S. reflect shipments on the Alliance pipeline. The growth of Canadian imports form the U.S. largely reflects those Alliance shipments that are destined for eastern Canada on the Vector pipeline. Both Alliance and Vector started in 12/00. Liquefied Natural Gas (LNG) imports consists of shipments into two terminals (Everett, Mass., and Lake Charles, LA.). Supplemental fuels consist of synthetic natural gas, propane-air, refinery gas, biomass gas and commingled manufactured gas.*

Canadian Gas Balances. *Canadian net exports are based on National Energy Board data (1999 net exports do not match data in Table 9, which are based on DOE data). Negative storage equals net injections. Positive storage equals net withdrawals. Storage figures (BCF) in the final column are end-of-period levels. Following Statistics Canada's definition, PIRA excludes lease and plant fuel from domestic demand.*

TABLE 11: U.S. GAS/FUEL OIL COMPETITIVE PRICES

[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
[illegible]							
[illegible]	4.87	23.48	3.73	74.34	5.38	+1.14	-0.51
[illegible]	4.12	23.79	3.78	80.89	5.86	+0.35	-1.73
[illegible]	4.18	24.00	3.81	80.00	5.79	+0.37	-1.61
[illegible]	4.26	24.05	3.82	80.25	5.81	+0.44	-1.55
[illegible]	4.29	23.78	3.78	80.75	5.85	+0.51	-1.56
[illegible]	4.32	23.40	3.71	81.35	5.89	+0.61	-1.57
[illegible]							
[illegible]	3.08	24.45	3.88	73.18	5.30	-0.80	-2.22
[illegible]	4.38	26.95	4.28	73.98	5.36	+0.10	-0.98
[illegible]	4.36	24.21	3.84	84.14	6.09	+0.52	-1.73
[illegible]	3.84	24.36	3.87	77.93	5.64	-0.03	-1.80
[illegible]	4.62	29.29	4.65	98.42	7.13	-0.03	-2.51
[illegible]	5.28	29.31	4.65	92.40	6.69	+0.63	-1.41

TABLE 12: U.S. MACROECONOMIC ASSUMPTIONS

[illegible]	[illegible]	[illegible]	[illegible]
		(1992=100)	(1992=100)
[illegible]	8875.7	139.2	126.0
[illegible]	9318.5	147.0	129.3
[illegible]	9510.4	147.1	127.1
[illegible]	9191.8	144.4	128.8
[illegible]	9318.9	147.1	130.3
[illegible]	9369.5	148.4	129.7
[illegible]	9393.7	148.1	128.4
[illegible]	9439.9	146.3	126.6
[illegible]	9475.1	146.5	126.5
		—Percentage Change—	
[illegible]	4.8	5.3	2.5
[illegible]	2.0	0.0	-1.7
[illegible]	2.7	1.3	-1.7
[illegible]	1.7	-0.4	-2.9

Gas/Fuel Oil Prices. *Historical NYMEX #2 Heating Oil prices are closing futures contract values, and Resid prices are Platts daily averages. Historical gas prices are Henry Hub bidweek index. Differentials equal gas prices minus residual and #2 f.o. prices. Resid is converted at 6.3 MMBtu per barrel; #2 oil is converted at 5.8 MMBtu per barrel. For May'01 – October'01, Resid prices are 80% of WTI NYMEX future contract values. Note that for approximately the last two years, Resid prices have averaged between 70% and 90% of WTI.*

Macroeconomic. *GDP through 1Q01 advance estimate. Industrial Production Index through April 2001.*

PIRA ENERGY GROUP

PIRA

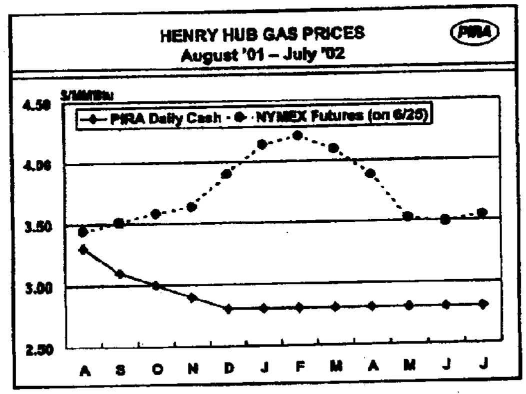
June 26, 2001

NATURAL GAS

U.S. Gas Market Forecast

WARNING: DANGEROUS PRICE CURVE AHEAD

Gas futures reflect a consensus of market expectations. Those expectations typically cause heating season forward prices to command sizable premiums relative to storage injection season prices. Currently, NYMEX prices strengthen in Sep./Oct. relative to the summer '01 peak and then make an even steeper turn upward in Nov./Dec. However, PIRA's market fundamentals indicate that this forward price curve is dangerously misleading. We envision the greatest downside price risks in the Sept/Oct and Nov/Dec periods.



Greater reliance on gas-fired electric generation (EG) is making the summer an increasingly robust period for gas demand. In recent years, EG sector gas demand has risen seasonally by upwards of 5 BCF/D between May/June and July/August, and PIRA anticipates a similar upswing in the months ahead. Seasonally rising demand will slow the pace of storage injections, which in turn should mitigate downward price pressures. Alternatively, if summer Gulf Coast gas prices drop below PIRA's Reference Case, large end-user hedging and the potential recapture of markets from heavy fuel oil (HFO) will tend to provide temporary price support.

PIRA's early-fall (Sept./Oct.) gas balances increasingly point to a potential shortfall between remaining storage capacity and the market's need for discretionary refills. Early-heating season (Nov./Dec.) balances suggest additional downward price pressures. In part, those pressures will stem from the market's incentive to draw storage at a faster pace than needed to satisfy demand. Consequently, high 01/02 winter storage should force daily cash prices to fall substantially below 02/03 winter gas futures prices. Otherwise, the economic incentive to draw storage at an excessive pace relative to demand could require production shut-ins to balance the market.

SUMMER BALANCES

Recent balances underscore bearish price concerns. In May, storage injections soared almost 8 BCF/D above the year-earlier pace, causing the storage deficit at the start of the month to turn into a 71 BCF surplus at the beginning of June.

Despite the steep plunge of bidweek prices ($4.87/May to $3.73/June) and a weather-related strengthening of gas-fired EG, we now expect storage refills to average 4.7 BCF/D above a year ago in June '01. On July 1st, our Reference Case storage moves up to 1.79 TCF, 205-210 BCF above a year ago[1].

[1] *In May'01, gas demand in the EG sector declined year-on-year by an estimated 2.2 BCF/D. Factors behind the reduction included milder weather (fewer CDDs) and gas-to-HFO substitution. In June'01, lower gas prices are recapturing some market share from HFO and weather is shaping up to be hotter than normal but about equal to a year ago. Our current month's Reference Case anticipates that EG sector gas demand will roughly match the year-earlier level.*

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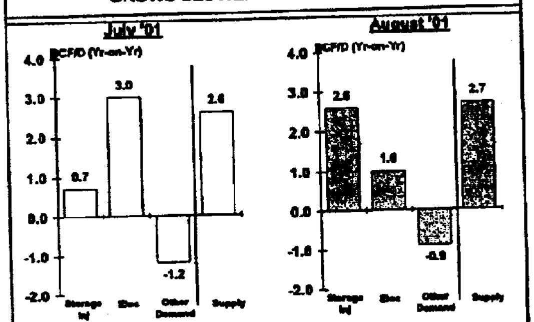
Over the next two months, a similar year-on-year pace of incremental injections (4.5 BCF/D) would raise total storage on September 1st to roughly 2.6 TCF, almost 500 BCF above a year ago. However, our Reference Case envisions a more moderate pace of incremental July/August injections. If cooling degree days are close to normal, we anticipate that gas-fired EG will post a healthy increase in July (3.0-3.5 BCF/D) but much less so in August (0.5-1.0 BCF/D). Reflecting those anticipated EG sector gas demand swings, incremental year-on-year storage refills would average only 0.5-1.0 BCF/D in July before rebounding to 2.5-3.0 BCF/D in August.

IN JULY, STORAGE SURPLUS GROWS SLOWER THAN IN AUGUST



Our July/August balances raise total working gas storage to 2.43 TCF on September 1st, 310-320 BCF above last year. When compared with the low price environment of summer '98, September 1st storage would be about 270 BCF less in 2001.

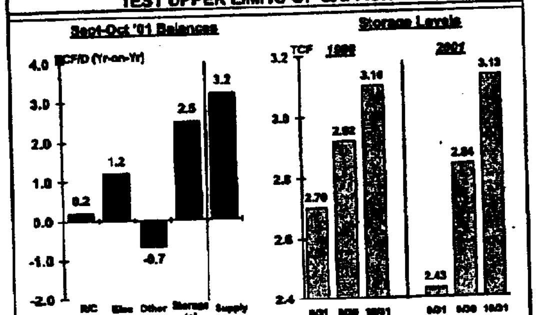
EARLY-FALL BALANCES (SEPT./OCT.)

On the surface, the above comparison fails to signal an imminent storage capacity shortfall in relation to the market's future needs for discretionary refills. On closer examination, however, ***PIRA's outlook for Sept./Oct. gas balances does indeed signal a serious risk of a storage capacity shortfall.*** Demand growth substantially in excess of 1.0 BCF/D in Sept./Oct. appears to be a long shot. PIRA expects that EG sector growth will be offset in part by ongoing losses in the industrial sector. Unless supply side growth weakens markedly (an unlikely prospect without a major assist from hurricanes), storage injections in early-fall should exceed last year's pace by 2.0-2.5 BCF/D.

On the demand side, growth of gas-fired EG will stem largely from gas recapturing year-earlier price-driven losses to HFO. In the Eastern Grid, those HFO year-earlier gains were in the vicinity of 3 gigawatts (GW) or the gas equivalent of 0.7-0.8 BCF/D, based on the standard heat rates of conventional steam generators (240-250 MMCF/D per GW). If degree days are normal, residential/commercial gas heating should also post a modest additional gain of 0.2 BCF/D.

During Sept./Oct. '01, our Reference Case forecasts a jump in working gas storage of 700 BCF, from 2.43 TCF to 3.13 TCF. By comparison, in the record-high storage period of early-fall '98, storage rose in the same period by only 400 BCF (from 2.70 to 3.10 TCF), in part because of unprecedented Gulf of Mexico hurricane-related supply losses.

EARLY-FALL STORAGE REFILLS WILL TEST UPPER LIMITS OF CAPACITY



Finding working gas storage capacity to accommodate 3.1-3.2 TCF will be a challenge. The AGA's benchmark for capacity is 3.29 TCF. However, this total includes 509 BCF in the Consuming West. The highest ever recorded for this region was 420 BCF in fall '95. We are doubtful that more than roughly 400 BCF is feasible in the current year.

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ECONOMIC VULNERABILITY

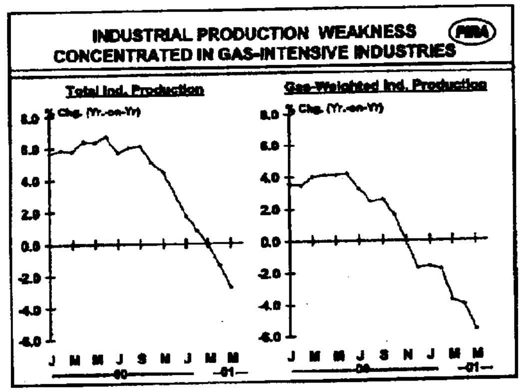
During the next four months, industrial sector gas demand will play a crucial role in determining the strength of discretionary storage injections. As a result, we have paid particularly close attention to the outlook for the U.S. economy as a whole and energy-intensive manufacturing in updating this month's PIRA's gas balances.

Ultimately, lower interest rates and direct fiscal stimulus in the form of a $50 billion upfront tax rebate will provide for stronger economic growth. Yet, the timing of the impact from these measures is not certain. So far, the latest string of data has failed to provide evidence of any economic turnaround, particularly with respect to the nation's factory sector. Indeed, manufacturing remains mired in a lengthy contraction.

Although no economic evidence shows the macro U.S. economy in a recession, the marked slowdown in GDP growth that began in 3Q00 has yet to run its course. Hopes of stronger growth this year, while initially buoyed by the preliminary 1Q01 GDP estimate of 2.0%, were partially quashed by the subsequent downward adjustment to 1.3%, a remarkably similar pace to the low-water mark recorded for 4Q00. Economic data released in recent weeks also cast a pall over the current quarter's performance, causing economists to discuss the increased likelihood of a quarter-to-quarter economic contraction.

While economists, in general, still expect a better performance in the third quarter and beyond, of greater immediate concern for the gas market is industrial production (IP) and more specifically gas-weighted IP.

During 1Q01, total IP's nearly 7% annualized decline should alarm even the most ardent gas market bull. Reflecting this horrible start, the near-term consensus outlook for 2001 IP has been revised sharply lower. Further declines are now expected in 2Q01, and modest growth is bravely projected for 3Q01.



From the gas market's perspective, the state of U.S. manufacturing is especially crucial. For 1Q01, the manufacturing component of total IP declined at nearly an 8% annualized rate. Massive declines in manufacturing employment that continued into May highlight this sector's abysmal performance.

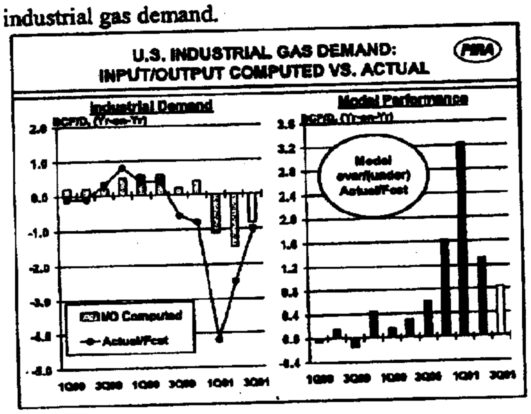
Gas-weighted IP declined by 8% (annualized) in the first quarter, and the second quarter is on track to fall by 6.8% (a 5.2% year-on-year contraction). A quick turnaround seems unlikely, given both weak factory orders and the prolonged sub-50 level of the NAPM index. However, ***PIRA's Reference Case makes an optimistic allowance for gas-weighted IP to begin stabilizing in 3Q01 relative to 2Q01*** (see Table 12, page 10).

HAMSTRUNG INDUSTRIAL DEMAND

PIRA's input/output model is used to aid industrial gas demand analysis[2]. The input/output model's results are not intended to reflect the full impact of gas price swings on demand. Key external factors include inter-fuel competition (gas versus HFO and distillates) and changing gas intensity within each of the major gas-intensive industries themselves.

[2] *Based on historical gas input per unit of output relationships for key gas- consuming industries. Using specific output indices measured by the Federal Reserve Board for each of those industries, quarterly gas usage is compiled and compared with actual and forecast results.*

Massive gas price reductions since 1Q01 are certain to improve gas demand prospects in the manufacturing sector. Nonetheless, those earlier record-high gas prices appear to have been the catalyst to structural gas demand losses perhaps on the order of 1 BCF/D. Our input/output model makes no allowance for those losses and thus should continue to overestimate industrial gas demand.



In 2Q01, industrial gas demand (excluding all gas-fired EG) now appears likely to decline by 2.5 BCF/D. By comparison, the model only projects a reduction of about 1.5 BCF/D. Structural demand losses explain the shortfall between actual demand and the model's projection.

Our Reference Case projects that 3Q01 industrial demand will average 13.6 BCF/D, or 1.0 BCF/D less than a year ago. Relative to the previous quarter, the difference between actual demand and the model's higher projected demand should narrow owing to the positive impact of still lower gas prices.

EARLY-HEATING SEASON (NOV./DEC.)

Heating season forward prices generally reflect market concerns over the potential for an extended cold snap. When such weather does materialize in the early stages of the heating season, a wellhead stampede of spot market purchasing can be ignited owing to the gas industry's strategic need to preserve deliverability from storage for later winter peaks.[3]

In the current year, high winter month premiums relative to injection season gas futures prices reflect a broader mix of factors. First, they incorporate the conventional concerns over the potential for market tightness in the event of another early heating season cold snap. Second, those premiums are being driven by the current market's exceptionally wide gap between disposable gas supply and end-use demand. The related fast pace of discretionary storage injections means that even in the event of major weather wildcards (Gulf of Mexico hurricanes and/or unusually hot summer temperatures), the related supply losses and/or demand gains would not jeopardize meeting minimum industry storage targets.

However, PIRA's early heating season gas balances underscore downside price risks at least as great as those anticipated in the early fall. The extreme cold experienced in Nov.-Dec.'00 required approximately 300 BCF of additional gas supply relative to normal weather. Barring a repeat of such conditions this year, the start of the 01/02 heating season will likely show large heating demand losses and year-end gas storage levels could be about 1.0 TCF above the year ago level (see Table 2, page 5).

Such high 01/02 winter storage should force daily cash prices to fall substantially below 02/03 winter gas futures prices. Otherwise, the economic incentive to draw storage at an excessive pace relative to demand could require production shut-ins to balance the market.

For additional information, please contact Greg Shuttlesworth, Tom Howard, Rich Redash, Nobu Tarui or Jane Hsu.

[3] *During the first two months of the 00/01 heating season, those pre-heating season concerns proved highly justified. The wellhead stampede caused bidweek prices to soar from $4.50/MMBtu (Nov.'00) to $6.03/MMBtu (Dec.00), before culminating in January'01 bidweek's index only fractionally under $10/MMBtu.*

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TABLE 1: GAS PRICES AT HENRY HUB (DOLLARS PER MMBTU)

[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible] Bidweek	2001 Act/Proj PIRA	NYMEX	2002 Projection PIRA	NYMEX
2.27	2.27	4.31	3.88			4.21	4.78	2.83	3.72
1.81	1.75	2.62	2.53	6.29	7.08	6.29	7.08	2.80	4.05
2.23	2.16	3.63	3.45			4.37	4.65	2.80	3.49
2.55	2.60	4.48	4.27			3.27	3.58	2.80	3.58
2.48	2.58	6.48	5.27			2.90	4.13	2.90	3.77
1.85	1.80	2.42	2.36	8.14	9.98	8.14	9.98	2.80	4.20
1.78	1.81	2.66	2.62	5.56	6.21	5.56	6.21	2.80	4.08
1.79	1.63	2.79	2.61	5.16	5.05	5.16	5.05	2.80	3.88
2.15	1.88	3.03	2.88	5.18	5.34	5.18	5.34	2.80	3.50
2.25	2.36	3.58	3.08	4.18	4.87	4.18	4.87	2.80	3.46
2.30	2.23	4.29	4.38		3.73	3.75	3.73	2.80	3.51
2.30	2.27	3.97	4.36			3.40	3.45	2.80	3.56
2.79	2.62	4.42	3.84			3.30	3.52	2.80	3.58
2.55	2.90	5.06	4.62			3.10	3.57	2.80	3.59
2.73	2.55	5.02	5.28			3.00	3.64	2.80	3.62
2.36	3.05	5.52	4.50			2.90	3.89	2.90	3.77
2.36	2.14	8.90	6.03			2.80	4.13	3.00	3.91

TABLE 2: GAS STORAGE (BCF, END OF MONTH)

[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
842	516	260	1618	666	280	163	1109
542	384	218	1144	410	237	118	765
441	343	205	989	253	212	130	595
460	345	227	1032	406	305	160	871
646	385	249	1279	694	439	215	1348
865	446	273	1584	967	556	267	1790
1096	504	293	1893	1152	670	300	2122
1294	532	289	2115	1371	740	315	2426
1512	613	303	2427	1671	830	335	2836
1673	681	312	2666	1818	940	370	3128
1495	611	262	2368	1756	910	360	3026
991	384	231	1606	1450	800	320	2570

Gas Prices. *Cash is average of daily prices during the month. Bidweek prices are index values through May'01. PIRA projections represent cash prices. For Janary'01 – June'01 NYMEX prices are Henry Hub bidweek index.*

Gas Storage. *PIRA's U.S. storage totals are a combination of a) AGA's Consuming East and the Producing Region and b) PIRA's latest estimates of the Consuming West using the latest DOE/EIA data (3/31/01) as the starting point.*

TABLE 3: DOMESTIC GAS DEMAND (BCF/D)

22.29	7.60	10.50	18.10	16.38	5.10	61.87
22.54	8.29	9.43	17.71	18.48	5.10	63.83
21.30	8.53	7.94	16.47	18.93	4.97	61.68
8.96	12.34	13.13	25.47	14.35	5.06	53.84
9.07	12.29	13.65	25.94	14.81	4.97	54.79
11.49	9.34	12.18	21.53	13.47	4.57	51.06
18.71	7.25	10.45	17.69	14.59	4.65	55.64
28.82	6.14	9.72	15.86	19.39	4.87	68.93
8.93	12.01	10.43	22.43	15.55	5.06	51.98
8.95	13.20	11.78	24.98	15.81	4.97	54.70
12.05	9.42	10.68	20.10	14.37	4.57	51.09
17.67	6.86	9.81	16.67	15.29	4.65	54.27
31.99	5.98	9.43	15.42	20.19	4.87	72.46

TABLE 4: RESIDENTIAL/COMMERCIAL GAS DEMAND (BCF/D)

9.30	4.14	13.44	13.30	8.99	22.29	4715
9.47	4.22	13.69	13.47	9.07	22.54	4682
8.95	3.66	12.60	12.95	8.36	21.30	4406
0.08	0.03	0.11	4.08	4.88	8.96	6
0.15	0.07	0.22	4.15	4.92	9.07	13
1.83	0.81	2.64	5.83	5.66	11.49	73
6.82	3.04	9.86	10.82	7.89	18.71	285
13.81	6.16	19.97	17.81	11.01	28.82	559
0.06	0.03	0.08	4.06	4.88	8.93	5
0.07	0.03	0.10	4.07	4.88	8.95	6
2.21	0.99	3.20	6.21	5.84	12.05	89
6.10	2.72	8.82	10.10	7.57	17.67	255
16.01	7.13	23.14	20.01	11.98	31.99	648

***Domestic Demand.** Electric Generation (EG) includes gas-fired electricity from traditional utility, utility divested, new merchant plants as well as industrial cogeneration. Miscellaneous demand includes lease and plant fuel, pipeline fuel, and changes in base gas storage. Industrial demand includes a balancing item which represents the difference between the sum of the components of gas supply and the sum of the components of gas demand, after taking into account net changes of working gas storage.*

***Residential/Commercial Demand.** Monthly R/C heating equals monthly Gas Weighted Heating Degree Days (GWHDDs) multiplied by Heating Load Factor (annual R/C heating load divided by annual GWHDDs). Total R/C demand includes Base Load, partly estimated from the DOE's reported total R/C demand in July/August. Heating degree days equal the extent to which daily mean temperatures (a simple arithmetic average of the daily high and low readings) fall below 65°F.*

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TABLE 5: ELECTRIC GENERATION SECTOR PRIMARY ENERGY (GW)

[illegible]	Gas	Oil	Coal	Nuke	Other	Sum	CDD
[illegible]	75.6	12.8	226.3	84.9	39.0	438.6	1465
[illegible]	70.8	11.4	225.9	85.8	44.6	438.6	1497
[illegible]	64.0	12.5	214.5	83.1	48.4	422.6	1460
[illegible]							
[illegible]	105.1	15.0	249.0	91.0	42.4	502.6	361
[illegible]	107.8	14.9	252.3	90.1	40.7	505.9	330
[illegible]	91.1	12.1	231.8	81.3	35.9	452.2	187
[illegible]	75.3	10.0	219.3	74.5	34.5	413.5	68
[illegible]	68.8	8.1	219.2	80.7	38.3	415.2	19
[illegible]							
[illegible]	89.5	12.2	242.1	93.0	48.2	485.0	340
[illegible]	98.7	15.7	251.5	91.3	45.4	502.7	349
[illegible]	80.7	13.5	232.2	85.5	38.9	450.8	200
[illegible]	67.7	11.5	220.6	74.2	35.4	409.4	71
[illegible]	63.6	10.7	225.3	82.7	39.6	421.9	17

TABLE 6: ELECTRIC GENERATION SECTOR GAS DEMAND BY REGION

[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
[illegible]	75.6	35.7	18.2	21.8	18.10	8.63	4.23	5.25
[illegible]	70.8	34.7	18.2	18.0	17.71	8.68	4.56	4.47
[illegible]	64.0	33.8	16.1	14.1	16.47	8.70	4.13	3.64
[illegible]								
[illegible]	105.1	53.6	26.0	25.5	25.47	13.25	6.06	6.15
[illegible]	107.8	55.0	25.5	27.2	25.94	13.53	5.96	6.45
[illegible]	91.1	45.0	21.7	24.3	21.53	10.76	5.04	5.72
[illegible]	75.3	37.4	16.8	21.1	17.69	8.88	3.85	4.97
[illegible]	68.8	32.5	16.0	20.3	15.86	7.59	3.59	4.68
[illegible]								
[illegible]	89.5	43.6	24.4	21.4	22.43	10.96	6.15	5.33
[illegible]	98.7	47.5	25.4	25.7	24.98	12.16	6.40	6.42
[illegible]	80.7	36.2	21.5	23.0	20.10	9.09	5.34	5.67
[illegible]	67.7	29.7	17.1	20.9	16.67	7.32	4.27	5.08
[illegible]	63.6	28.8	15.4	19.4	15.42	6.89	3.77	4.75

EG Sector. *Total U.S electric generation by primary energy source includes traditional utility, utility divested, new merchant plants, as well as industrial cogeneration. Cooling degree days (CDD) equal the extent to which daily mean temperatures average more than 65°F. For 2001, NWS 30-year "normals" are used. A GW (gigawatt) equals 1,000 megawatts (MW) of electricity. Heat rates for traditional gas-fired steam units are 10,000-11,000 Btus per kilowatt-hour, requiring 240-260 MMCF/D per GW. Alternatively, gas-fired combined cycle units have heat rates of around7,000 Btus per kilowatt-hour, requiring about 160 MMCF/D per GW.*

Regional EG Sector. *Total U.S. gas demand for EG is divided into three regions. ERCOT primarily overlays the state of Texas. The WSCC represents the Western U.S. region that is comprised of 11 states including CA, WA, OR, ID, WY, MT, CO, NV, AZ, UT and NM (adjusted to include Alaska). The East (i.e. Eastern Grid) accounts for the remaining U.S.*

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TABLE 7: GAS SUPPLY (BCF/D)

[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
[illegible]	3.49	12.07	8.56	4.25	25.62	54.00	10.51	-2.64	
[illegible]	2.97	11.73	8.30	4.10	24.67	51.76	9.95	2.12	
[illegible]	2.50	12.50	7.99	4.25	24.16	51.39	9.65	0.63	
[illegible]									
[illegible]	3.55	12.10	8.60	4.25	25.75	54.25	10.29	-10.70	2122
[illegible]	3.60	12.10	8.65	4.30	25.75	54.40	10.19	-9.80	2426
[illegible]	3.60	12.10	8.65	4.35	25.80	54.50	10.24	-13.68	2836
Oct	3.60	12.15	8.65	4.35	25.90	54.65	10.40	-9.41	3128
Nov	3.60	12.15	8.65	4.35	25.90	54.65	10.90	3.38	3026
2000									
[illegible]	3.10	11.73	8.38	4.04	24.56	51.82	10.13	-9.97	1893
[illegible]	3.10	11.77	8.32	4.05	24.75	51.99	9.90	-7.18	2115
[illegible]	3.10	11.74	8.26	4.05	24.65	51.80	9.70	-10.41	2427
[illegible]	3.10	11.82	8.31	4.05	24.80	52.07	9.91	-7.71	2666
[illegible]	3.10	11.85	8.26	4.05	24.82	52.07	10.46	9.94	2368

TABLE 8: NON-GULF GAS PRODUCTION (BCF/D)

[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
[illegible]	4.80	7.23	12.03	3.76	4.73	2.82	2.29	25.62
[illegible]	4.66	7.07	11.73	3.77	4.36	2.60	2.22	24.67
[illegible]	4.69	7.03	11.72	3.83	3.97	2.45	2.19	24.16
[illegible]								
[illegible]	4.85	7.30	12.15	3.70	4.80	2.85	2.25	25.75
[illegible]	4.85	7.30	12.15	3.70	4.80	2.85	2.25	25.75
[illegible]	4.85	7.30	12.15	3.70	4.80	2.90	2.25	25.80
[illegible]	4.85	7.30	12.15	3.70	4.80	2.90	2.35	25.90
[illegible]	4.85	7.30	12.15	3.70	4.80	2.90	2.35	25.90
[illegible]								
[illegible]	4.70	7.06	11.76	3.74	4.32	2.63	2.11	24.56
[illegible]	4.68	7.07	11.75	3.75	4.39	2.63	2.22	24.75
[illegible]	4.69	6.98	11.68	3.72	4.44	2.63	2.18	24.65
Oct	4.65	6.95	11.60	3.80	4.45	2.65	2.30	24.80
Nov	4.67	6.95	11.62	3.80	4.45	2.65	2.30	24.82

Gas Supply. *Other Supply includes net imports from Canada, Mexico, and LNG plus supplemental gaseous fuels. Negative storage change denotes net injections; if positive net withdrawals. Storage levels (BCF) are at end of month shown.*

U.S. Regional Production. *Gulf of Mexico (GOM) DW (Deepwater) and SW (Shallow Water) refer to offshore Gulf of Mexico production in greater or less than 1,000 feet water depths. Gulf Coast Offshore includes Gulf of Mexico Federal plus state offshore portions of Alabama, Louisiana, and Texas. Other Onshore GOM includes Alabama, Louisiana and Mississippi. Other Permian/Mid-Continent includes Arkansas, Kansas, Oklahoma, and East New Mexico. San Juan includes West New Mexico and Southwest Colorado. Rocky Mountain consists of all states in the Mountain census region plus North Dakota but excludes East New Mexico. Pacific includes California, Oregon and Alaska production. Midwest/East includes all remaining gas producing states.*

TABLE 9: NET OTHER SUPPLY (BCF/D)

[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
[illegible]	3.40	6.88	0.44	0.78	9.94	-0.21	0.50	0.28	10.51
[illegible]	3.25	6.15	0.32	0.26	9.46	-0.21	0.42	0.28	9.95
[illegible]	3.31	5.92	0.00	0.11	9.12	-0.01	0.27	0.27	9.65
[illegible]	3.40	6.75	0.45	0.80	9.80	-0.25	0.49	0.25	10.29
[illegible]	3.40	6.75	0.45	0.80	9.80	-0.35	0.49	0.25	10.19
[illegible]	3.40	6.75	0.45	0.80	9.80	-0.30	0.49	0.25	10.24
[illegible]	3.50	6.65	0.45	0.80	9.80	-0.25	0.55	0.30	10.40
[illegible]	3.50	7.30	0.45	0.95	10.30	-0.25	0.55	0.30	10.90
[illegible]	3.24	5.87	0.39	0.14	9.36	-0.25	0.75	0.26	10.13
[illegible]	3.11	5.92	0.43	0.14	9.33	-0.25	0.56	0.26	9.90
[illegible]	3.14	5.74	0.42	0.14	9.16	-0.23	0.54	0.23	9.70
[illegible]	3.27	5.72	0.42	0.15	9.27	-0.25	0.55	0.35	9.91
[illegible]	3.30	6.78	0.39	0.58	9.89	-0.23	0.45	0.35	10.46

TABLE 10: CANADIAN GAS BALANCES (BCF/D)

[illegible]	Res/Comm	Other	Net Exports	Alberta	Other West	[illegible]	[illegible]	[illegible]	[illegible]
[illegible]	2.59	4.31	9.94	13.25	3.21	0.51	16.97	-0.12	
[illegible]	2.49	4.55	9.46	13.01	2.84	0.33	16.17	0.32	
[illegible]	2.38	4.31	9.08	13.02	2.67	0.00	15.69	0.08	
[illegible]	0.80	3.10	9.80	12.70	3.25	0.55	16.50	-2.80	373
[illegible]	0.80	3.70	9.80	12.70	3.25	0.55	16.50	-2.20	441
[illegible]	1.10	4.00	9.80	12.75	3.25	0.55	16.55	-1.65	491
[illegible]	2.00	5.10	9.80	13.20	3.30	0.55	17.05	-0.15	496
[illegible]	3.30	5.40	10.30	13.65	3.40	0.55	17.60	1.40	454
[illegible]	0.84	3.13	9.36	12.51	2.50	0.39	15.41	-2.08	335
[illegible]	0.82	3.67	9.33	12.42	2.82	0.42	15.67	-1.85	392
[illegible]	1.06	3.83	9.16	12.57	2.78	0.41	15.76	-1.71	443
[illegible]	1.75	4.80	9.27	13.05	2.99	0.43	16.47	-0.65	463
[illegible]	3.02	5.17	9.89	13.34	3.14	0.44	16.92	1.16	429

Net Other Supply. *In 2001, incremental Canadian exports to the U.S. reflect shipments on the Alliance pipeline. The growth of Canadian imports form the U.S. largely reflects those Alliance shipments that are destined for eastern Canada on the Vector pipeline. Both Alliance and Vector started in 12/00. Liquefied Natural Gas (LNG) imports consists of shipments into two terminals (Everett, Mass., and Lake Charles, LA.). Supplemental fuels consist of synthetic natural gas, propane-air, refinery gas, biomass gas and commingled manufactured gas.*

Canadian Gas Balances. *Canadian net exports are based on National Energy Board data (1999 net exports do not match data in Table 9, which are based on DOE data). Negative storage equals net injections. Positive storage equals net withdrawals. Storage figures (BCF) in the final column are end-of-period levels. Following Statistics Canada's definition, PIRA excludes lease and plant fuel from domestic demand.*

TABLE 11: U.S. GAS/FUEL OIL COMPETITIVE PRICES

[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
[illegible]	3.45	21.20	3.37	73.89	5.35	0.08	-1.90
[illegible]	3.52	21.80	3.46	74.35	5.38	0.06	-1.86
[illegible]	3.57	21.74	3.45	75.05	5.43	0.12	-1.86
[illegible]	3.64	21.60	3.43	75.85	5.49	0.21	-1.85
[illegible]	3.89	21.53	3.42	76.55	5.54	0.47	-1.65
[illegible]	4.13	21.41	3.40	77.10	5.58	0.73	-1.45
[illegible]	4.36	24.21	3.84	84.14	6.09	0.52	-1.73
[illegible]	3.84	24.36	3.87	77.93	5.64	-0.03	-1.80
[illegible]	4.62	29.29	4.65	98.42	7.13	-0.03	-2.51
[illegible]	5.28	29.31	4.65	92.40	6.69	0.63	-1.41
[illegible]	4.50	28.31	4.49	94.10	6.81	0.01	-2.31
[illegible]	6.03	25.37	4.03	105.34	7.63	2.00	-1.60

TABLE 12: U.S. MACROECONOMIC ASSUMPTIONS

[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
[illegible]	9318.5	5.0	147.0	5.6	129.3	2.6
[illegible]	9484.3	1.8	144.5	-1.7	124.6	-3.7
[illegible]	9771.3	3.0	148.4	2.7	127.5	2.4
[illegible]	9191.8	4.8	144.4	6.7	128.8	1.0
[illegible]	9318.9	5.6	147.1	7.9	130.3	4.5
[illegible]	9369.5	2.2	148.4	3.5	129.7	-1.7
[illegible]	9393.7	1.0	148.1	-0.9	128.4	-4.0
[illegible]	9424.5	1.3	145.5	-6.7	125.7	-8.0
[illegible]	9448.0	1.0	143.5	-5.5	123.5	-6.8
[illegible]	9497.2	2.1	144.0	1.4	124.0	1.5
[illegible]	9567.6	3.0	145.0	2.8	125.0	3.3
[illegible]	9647.9	3.4	146.4	3.9	126.5	4.9

Gas/Fuel Oil Prices. *Historical NYMEX #2 Heating Oil prices are closing futures contract values, and Resid prices are Platts daily averages. Historical gas prices are Henry Hub bidweek index. Differentials equal gas prices minus residual and #2 f.o. prices. Resid is converted at 6.3 MMBtu per barrel; #2 oil is converted at 5.8 MMBtu per barrel. For May'01 – October'01, Resid prices are 80% of WTI NYMEX future contract values. Note that for approximately the last two years, Resid prices have averaged between 70% and 90% of WTI.*

Macroeconomic. *GDP through 1Q01 preliminary estimate. Industrial Production Index through May 2001. For full years, percentage changes are year-on-year. For quarters, percentage changes are quarter-to-quarter annualized.*

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PIRA ENERGY GROUP

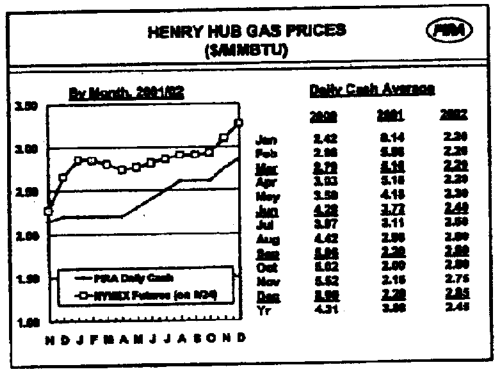
PIRA

September 25, 2001

NATURAL GAS

U.S. Gas Market Forecast

Rapid gas price recovery has become a long shot, with U.S. economic recession imminent. Now, PIRA believes that even an extremely cold 01/02 heating season would only boost Henry Hub prices back near month-earlier levels.



In the aftermath of the September 11th terrorism, PIRA's assessment of inter-relationships between the U.S. economy and gas demand points to substantially weaker demand growth in the electric power and industrial sectors into the first half of next year. On the supply side, a more severe cutback of gas-oriented drilling (especially in the shallow-water GOM) will mitigate the impact of those demand markdowns. Nevertheless, a storage hangover of some 1.3 TCF looms for the start of the 2002 injection season.

For the 01/02 heating season, PIRA's Henry Hub prices have been lowered to about $2.20. For the 2002 injection season, PIRA's 2002 Reference Case is beginning to bear a striking resemblance to 1999. During that period, Henry Hub prices averaged close to $2.40. PIRA's slightly higher 2002 injection season prices, while still bearish, are now much closer to the NYMEX forward price curve.

THE GRIM LANDSCAPE

Prior to September 11th, the U.S. economy was slowing, and the U.S. manufacturing sector was already in a recession. Suddenly, ***the terrorist attack transformed an uncertain economic horizon into a grim near-term landscape***. Temporary disruptions within the economy tied to the attack, e.g. closing of offices, factories, and layoffs, will reduce output and push down an already weak second-half. One positive factor, though, is that fiscal and monetary policymakers are determined to stimulate the economy.

Those intentions notwithstanding, the future course of the economy will be set by elusive factors such as consumer confidence and the willingness of businesses to invest. On balance, near-term optimism associated with those critical factors appears more fragile than ever considering the precipitous decline in equity markets and reduced corporate profits.

PIRA's Reference Case anticipates negative economic activity through the early part of next year (*see Table 12 on page 10*). From a gas demand perspective, PIRA's markdowns of GDP and industrial production (IP) will take a heavy toll on industrial and electric power gas usage.

R/C SECTOR SURPRISE

New data from the DOE/EIA indicate that record-high gas prices had minimal impact on conservation within the residential heating market. This surprising outcome runs counter to PIRA's earlier view that price "shock" (in some regions as much as a doubling of rates) would reduce heating load per gas-weighted heating degree day (GWHDD).

In hindsight, the residential sector's lack of price response can be attributed to such factors as time-lagged utility bills, delayed price signals, and the limited impact of gas cost itself on a residential customer's total bill. Also, the year-on-year contrast in temperatures between the 99/00 and 00/01 heating seasons skewed the results, given the non-linear nature of heating demand under extremely different weather conditions. In 00/01, sharply higher GWHDDs masked any conservation.

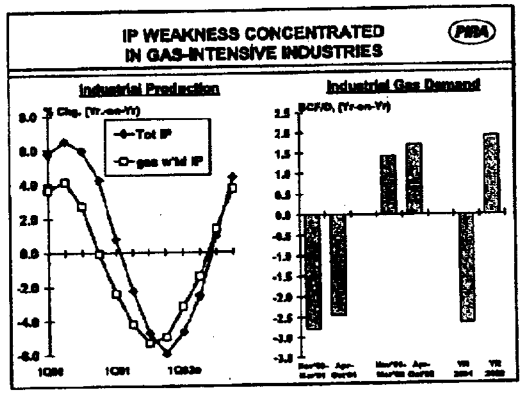
By comparison, the commercial sector results demonstrate a clear price response. This response was expected in light of the commercial sector's greater gas use per consumer and flexibility relative to residential customers to react to higher prices. For Jan-Apr'01, preliminary EIA data indicate a 10% decline in commercial gas heating demand relative to a year ago, despite a 10% increase in GWHDDs. However, residential space heating dwarfs that of the commercial sector, mitigating the net impact of conservation on total R/C gas heating.

Our new R/C sector analysis sheds light on what happened earlier this year when gross demand destruction (GDD) swelled. The allocation of GDD between supply and demand is a zero-sum game. Thus, stronger demand within the overall R/C heating sectors must translate into weaker demand in the non-core markets or stronger gas supply or some combination of each. PIRA's revised gas balances allocate a greater share of GDD to the industrial sector.

INDUSTRIAL SECTOR RECOVERY

For the industrial sector, virtually all economists agree that the aggressive easing of monetary policy will allow manufacturing to increase sequentially, especially given the dire conditions over the past year. Optimism on the timing of IP recovery, however, must be tempered by the events of September 11th. Indeed, the risk of reduced consumer spending in the U.S. and abroad casts a pall over gas-intensive industries such as chemicals, petroleum refining, metal fabrication and paper.

Despite these concerns, ***the beleaguered manufacturing sector remains an integral factor behind the anticipated recovery of gas demand.*** With prices now near $2/MMBtu, the massive year-earlier industrial gas demand losses point to favorable comparisons going forward. Some steps to lessen exposure to natural gas amidst last year's steep price increases will prove permanent (plant closings, efficiency improvements, etc.). However, fuel switching and other temporary measures no longer will be at work.



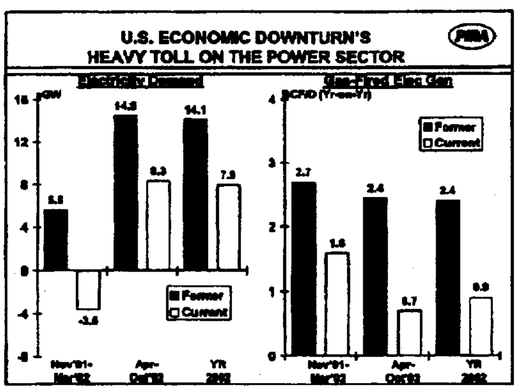
Even still, pitfalls will mitigate gas demand growth. For starters, a repeat of the extreme cold that blanketed the nation during late 2000 cannot be expected. In 4Q00, PIRA calculates the heating load that spilled over into the industrial sector, boosted gas demand by roughly 0.5 BCF/D. And although a recovery in gas-weighted IP underlies our Reference Case macroeconomic assumptions, the anticipated increase is not seen lifting the index back to its former peak until late 2002.

PIRA's industrial gas demand model links projected changes in the output of gas-intensive industries with related gas requirements (exclusive of electricity generation). For an updated assessment of our model's results, see the attached *Special Supplement*. For 4Q01, industrial gas demand should be flat, at best, with a year ago. In 1Q02, an increase upwards to 2 BCF/D is possible. Fuel switching alone reduced demand in 1Q01 by roughly 1 BCF/D. Taking a longer view of the sector's trends, however, our Reference Case sees the sector's 2002 gas demand remaining below 2000 levels throughout the entire year.

POWER SECTOR NOT IMMUNE

A more tenuous economic environment also spells trouble for gas-fired electric generation (EG). Indeed, with a more extended period of weak-to-negative GDP growth now likely, electricity demand will suffer and that will lean heavily on gas-fired EG since this fuel is burned at the margin in many regional electric markets. Moreover, reduced electric demand will magnify the impact of efficiency gains tied to new power plant additions. The 30%-40% efficiency advantage that combined-cycle combustion turbines have in relation to single-cycle units reduces the volume of gas needed for EG when the capacity additions exceed rate of electric demand growth.

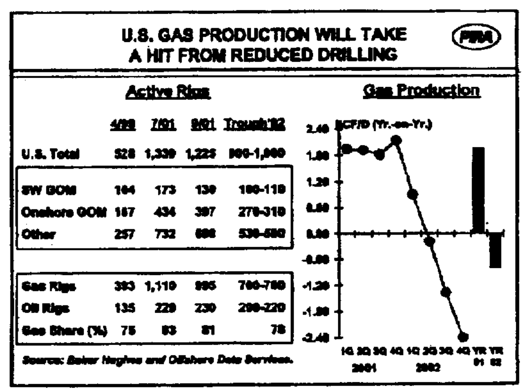
Beyond the macroeconomic situation, hydroelectric is the key factor anticipated to curb gas-fired EG growth in 2002. Total U.S. hydroelectric is forecast to rise by more than 7 average gigawatts (aGW). In the Pacific Northwest alone, more normal precipitation would eliminate about 2 BCF/D of gas-fired EG relative to this year's exceptionally dry conditions.



For full year 2002, gas-fired EG is anticipated to rise by 6 aGW, or slightly less than total electric demand growth of 8 aGW or 1.8% (*see Table 5 on page 7*). ***PIRA projects an EG sector gas demand increase of 0.9 BCF/D, as compared to growth in excess of 2 BCF/D prior to our negatively revised economic outlook.*** We expect less generation from coal and nuclear next year, but not enough to alter gas-fired EG significantly. We also continue to view gas prices remaining highly competitive with heavy fuel oil prices throughout late 2001 and 2002.

GAS DRILLING DOWNTURN

Following the current year's unprecedented boom, ***the downturn in gas-oriented drilling has just begun.*** In July 2001, total U.S. rig counts peaked at 1,339, 2.5 times the April 1999 low.[1] In the most recent weekly period, total active rigs slipped to 1,225, a level already approaching a 10% falloff from the July peak. The standout reductions thus far are concentrated in the shallow-water GOM (SWGOM). The SWGOM's rig counts peaked in April at 181, before slipping to 173 in July, and a week ago to only 130 — almost a 30% cutback from the region's April peak.



The gas price freefall is certain to push gas-oriented drilling considerably under the most recent weekly figures. At the apex of the 2001 cycle, gas-oriented drilling reached a contemporary high of 1,110 rigs. Today, gas rig counts already have declined by 115 from the July peak.

[1] *PIRA's total active rig counts differ from Baker Hughes, owing to the substitution of Offshore Data Services (ODS) rig counts for the Offshore GOM. ODS active rig counts are consistently above those reported by Baker Hughes. ODS counts were above Baker Hughes as follows: 130 vs. 97 rigs in April '99, 213 vs. 151 rigs in July '01, and currently 176 vs. 137 rigs.*

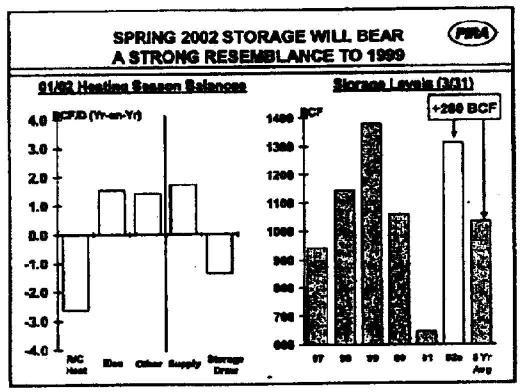
Looking ahead, ***PIRA's 2002 domestic gas production outlook reflects a near-term trough between 700 and 780 gas-oriented rigs.*** In our Reference Case, total active rigs (both gas-and oil-oriented) drop to 900-1,000, with the gas market share slipping from its 83% peak in 2001 to 78% in 2002. However, the SWGOM represents the only region where drilling plunges to within striking distance of April 1999 levels.

In 4Q01, domestic gas production appears likely to post year-on-year increases still in the vicinity of 2 BCF/D. In 1Q02, production is forecast to remain close to late '01 levels, but year-on-year growth will narrow to less than 1 BCF/D. These projections reflect the impressive near-term growth expected from the deepwater GOM (DWGOM) and the time-lags between drilling cutbacks and their impact on new gas well production. Thereafter, the brunt of drilling cutbacks will become much more evident, with year-on-year production declines exceeding 2 BCF/D by late next year.

THE LOOMING STORAGE HANGOVER

Despite the unwinding of GDD owing to the freefall in gas prices, the stage is set for more pronounced economic weakness and tough weather comparisons to undermine gas demand growth during the 01/02 heating season. R/C heating demand, as always, is wed to GWHDDs, but the record cold spell that overlaid late 2000 almost assures large demand losses during the first two-months of the heating season. As for non-core demand, given its close link with economic activity, the negative prognosis is poised to work against gas usage.

On the supply front, growth is expected to slow throughout the 01/02 heating season, before sizable losses materialize during the second half of 2002. In spite of the bullish supply impact on U.S. gas balances, a sizable storage hangover is anticipated at the end of the 01/02 heating season, barring below-normal temperatures. The inventory glut's primary cause will be record high stocks ahead of the winter. U.S. gas storage for March 31st, 2002, is forecast to be slightly in excess of 1.3 TCF, more the twice last year's trough and roughly 280 BCF above the past five-year average. Such storage levels are more akin to the end of May than March.



Despite recent sub-$2/MMBtu readings, the black cloud over the economy, together with the gas storage hangover, make it difficult to envision strong near-term gas price recovery. ***For 2002 as a whole, gas balances in 1999 appear to offer the best insight to possible price direction.*** Back then, Henry Hub prices remained near the $2 mark through the first half, before beginning to rise in response to demand strength (led by economic expansion) and supply weakness (from critically low gas-oriented drilling).

For additional information, please contact
Greg Shuttlesworth, Tom Howard, Rich Redash, Nobu Tarui or Jane Hsu.

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TABLE 1: GAS PRICES AT HENRY HUB (DOLLARS PER MMBTU)

	Daily Cash (Actual/PIRA)			Bidweek(Actual/NYMEX Futures)		
	2000	2001	2002	2000	2001	2002
Yr	[redacted]	3.88	2.45	[redacted]	4.22	2.90
1Q	[redacted]	[redacted]	2.20	[redacted]	[redacted]	2.83
2Q	[redacted]	[redacted]	2.30	[redacted]	[redacted]	2.77
3Q	[redacted]	2.76	2.57	[redacted]	2.88	2.89
4Q	[redacted]	2.12	2.73	[redacted]	2.28	3.09
Jan	[redacted]	[redacted]	2.20	[redacted]	[redacted]	2.85
Feb	[redacted]	[redacted]	2.20	[redacted]	[redacted]	2.85
Mar	[redacted]	[redacted]	2.20	[redacted]	[redacted]	2.80
Apr	[redacted]	[redacted]	2.20	[redacted]	[redacted]	2.74
May	[redacted]	[redacted]	2.30	[redacted]	[redacted]	2.77
Jun	[redacted]	[redacted]	2.40	[redacted]	[redacted]	2.82
Jul	[redacted]	[redacted]	2.50	[redacted]	[redacted]	2.86
Aug	[redacted]	[redacted]	2.60	[redacted]	[redacted]	2.90
Sep	[redacted]	2.20	2.60	[redacted]	[redacted]	2.91
Oct	[redacted]	2.00	2.60	[redacted]	1.91	2.93
Nov	[redacted]	2.15	2.75	[redacted]	2.28	3.09
Dec	[redacted]	2.20	2.85	[redacted]	2.66	3.27

TABLE 2: GAS STORAGE (BCF, END OF MONTH)

	Cons. East	Prod. Region	Cons. West	U.S. Total	Cons. East	Prod. Region	Cons. West	U.S. Total
	2000/2001				2001/2002			
Apr	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
May	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Jun	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Jul	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Aug	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Sep	[redacted]	[redacted]	[redacted]	[redacted]	1675	820	458	2953
Oct	[redacted]	[redacted]	[redacted]	[redacted]	1800	920	490	3210
Nov	[redacted]	[redacted]	[redacted]	[redacted]	1721	895	490	3106
Dec	[redacted]	[redacted]	[redacted]	[redacted]	1373	820	430	2623
Jan	[redacted]	[redacted]	[redacted]	[redacted]	929	660	340	1929
Feb	[redacted]	[redacted]	[redacted]	[redacted]	647	540	280	1467
Mar	[redacted]	[redacted]	[redacted]	[redacted]	550	500	260	1310

Gas Prices. *Shaded areas are actual prices. Daily Cash is the average of daily prices at Henry Hub and PIRA projections from September'01 through December'02. Bidweek prices are actual index values through September'01 and NYMEX gas futures prices for October'01 through December'02 effective September 24, 2001.*
Gas Storage. *Shaded areas are actual storage levels. To obtain end-of-month storage levels, PIRA prorates AGA's weekly storage figures. PIRA projections starting from September'01.*

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TABLE 3: DOMESTIC GAS DEMAND (BCF/D)

22.24	7.37	11.48	18.86	18.51	5.10	64.70
22.13	7.68	10.27	17.95	16.60	5.10	61.78
22.49	8.29	8.93	17.22	19.26	5.10	64.07
11.74	9.37	11.55	20.92	14.11	4.57	51.33
18.45	7.78	10.35	18.13	14.99	4.65	56.22
28.20	6.43	9.44	15.87	20.11	4.87	69.05
37.17	6.26	9.90	16.16	22.81	5.35	81.49
40.85	6.36	10.55	16.91	25.01	5.74	88.51
12.04	9.42	10.08	19.50	15.21	4.57	51.32
17.64	6.86	9.31	16.17	16.29	4.65	54.75
31.92	5.98	8.78	14.77	21.61	4.87	73.17
45.12	6.00	9.08	15.09	22.91	5.35	88.47
40.77	5.20	8.37	13.57	21.11	5.74	81.19

TABLE 4: RESIDENTIAL/COMMERCIAL GAS DEMAND (BCF/D)

9.98	3.41	13.39	13.98	8.26	22.24	4825
9.90	3.38	13.28	13.90	8.23	22.13	4670
9.59	4.05	13.64	13.59	8.90	22.49	4682
2.15	0.74	2.89	6.15	5.59	11.74	83
7.16	2.44	9.60	11.16	7.29	18.45	286
14.42	4.92	19.35	18.42	9.77	28.20	559
21.11	7.21	28.32	25.11	12.06	37.17	846
23.86	8.15	32.00	27.86	13.00	40.85	955
2.24	0.95	3.19	6.24	5.80	12.04	89
6.18	2.61	8.79	10.18	7.46	17.64	255
16.21	6.85	23.07	20.21	11.70	31.92	648
25.49	10.78	36.27	29.49	15.63	45.12	1054
23.80	8.12	31.92	27.80	12.97	40.77	953

Domestic Demand. ***Electric Generation (EG) includes gas-fired electricity from traditional utility, utility divested, new merchant plants as well as industrial cogeneration. Miscellaneous demand includes lease and plant fuel, pipeline fuel, and changes in base gas storage. Industrial demand includes a balancing item which represents the difference between the sum of the components of gas supply and the sum of the components of gas demand, after taking into account net changes of working gas storage.***

Residential/Commercial Demand. ***Monthly R/C heating equals monthly Gas Weighted Heating Degree Days (GWHDDs) multiplied by Heating Load Factor (annual R/C heating load divided by annual GWHDDs). Total R/C demand includes Base Load, partly estimated from the DOE's reported total R/C demand in July/August. Heating degree days equal the extent to which daily mean temperatures (a simple arithmetic average of the daily high and low readings) fall below 65°F.***

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TABLE 5: ELECTRIC GENERATION SECTOR PRIMARY ENERGY (GW)

	80.5	9.3	221.7	84.1	46.8	442.4	1433
	74.5	12.1	222.8	85.6	39.4	434.4	1507
	69.2	11.9	223.7	85.8	45.6	436.2	1497
	87.3	9.8	222.7	84.3	37.8	441.9	187
	76.3	7.6	210.0	74.3	35.5	403.7	68
	67.4	6.3	212.9	79.3	37.9	403.9	19
	68.5	8.4	227.3	86.4	42.6	433.2	10
	72.3	10.6	237.5	89.1	43.3	452.7	11
	79.2	14.0	229.7	85.5	39.9	448.3	200
	66.2	12.0	217.7	74.2	36.4	406.5	71
	60.6	11.2	222.4	82.7	40.6	417.5	17
	62.0	21.1	239.6	91.2	37.8	451.6	6
	56.5	21.6	239.1	92.3	38.9	448.4	3

TABLE 6: ELECTRIC GENERATION SECTOR GAS DEMAND BY REGION

	80.5	44.0	19.4	17.1	18.86	10.34	4.44	4.08
	74.5	35.8	18.0	20.7	17.95	8.60	4.28	5.07
	69.2	33.5	18.2	17.5	17.22	8.39	4.50	4.32
	87.3	43.3	22.0	22.0	20.92	10.32	5.27	5.33
	76.3	39.8	16.8	19.7	18.13	9.37	3.98	4.78
	67.4	33.5	15.0	18.8	15.87	7.88	3.51	4.48
	68.5	34.0	16.0	18.4	16.16	8.05	3.73	4.38
	72.3	39.2	16.0	17.1	16.91	9.18	3.66	4.06
	79.2	35.2	21.5	22.5	19.50	8.74	5.24	5.52
	66.2	28.7	17.1	20.4	16.17	7.07	4.17	4.93
	60.6	26.8	15.4	18.4	14.77	6.59	3.67	4.50
	62.0	28.6	15.4	18.1	15.09	6.96	3.66	4.47
	56.5	23.2	14.0	19.3	13.57	5.50	3.33	4.74

EG Sector. ***Total U.S electric generation by primary energy source includes traditional utility, utility divested, new merchant plants, as well as industrial cogeneration. Cooling degree days (CDD) equal the extent to which daily mean temperatures average more than 65°F. For 2001, NWS 30-year "normals" are used. A GW (gigawatt) equals 1,000 megawatts (MW) of electricity. Heat rates for traditional gas-fired steam units are 10,000-11,000 Btus per kilowatt-hour, requiring 240-260 MMCF/D per GW. Alternatively, gas-fired combined cycle units have heat rates of around7,000 Btus per kilowatt-hour, requiring about 160 MMCF/D per GW.***

Regional EG Sector. ***Total U.S. gas demand for EG is divided into three regions. ERCOT primarily overlays the state of Texas. The WSCC represents the Western U.S. region that is comprised of 11 states including CA, WA, OR, ID, WY, MT, CO, NV, AZ, UT and NM (adjusted to include Alaska). The East (i.e. Eastern Grid) accounts for the remaining U.S.***

PIRA

September 25, 2001

NATURAL GAS

TABLE 7: GAS SUPPLY (BCF/D)

3.90	11.26	8.30	4.22	25.45	53.13	10.68	0.89	
3.45	11.95	8.55	4.39	25.57	53.91	10.47	-2.61	
2.93	11.67	8.31	4.25	24.81	51.96	9.94	2.16	
3.60	11.50	8.60	4.40	25.55	53.65	9.94	-12.26	2953
3.70	11.65	8.65	4.45	25.80	54.25	10.25	-8.28	3210
3.75	12.00	8.65	4.45	25.90	54.75	10.85	3.45	3106
3.80	12.00	8.65	4.45	25.95	54.85	11.05	15.59	2623
3.85	11.90	8.60	4.40	25.85	54.60	11.54	22.38	1929
3.01	11.64	8.26	4.30	24.80	52.01	9.70	-10.39	2512
2.99	11.77	8.32	4.35	25.06	52.49	10.00	-7.74	2752
3.09	11.81	8.26	4.24	25.02	52.42	10.46	10.29	2443
3.14	11.92	8.42	4.21	24.86	52.56	11.02	24.89	1671
3.15	12.01	8.40	4.35	25.54	53.44	11.41	16.34	1165

TABLE 8: NON-GULF GAS PRODUCTION (BCF/D)

4.57	7.24	11.81	3.62	4.93	2.77	2.31	25.45
4.65	7.39	12.04	3.82	4.73	2.71	2.27	25.57
4.67	7.20	11.87	3.82	4.39	2.51	2.21	24.81
4.70	7.35	12.05	3.80	4.70	2.75	2.25	25.55
4.70	7.40	12.10	3.80	4.75	2.75	2.40	25.80
4.70	7.40	12.10	3.80	4.80	2.80	2.40	25.90
4.70	7.40	12.10	3.80	4.85	2.80	2.40	25.95
4.65	7.35	12.00	3.75	4.85	2.80	2.45	25.85
4.73	7.08	11.81	3.81	4.46	2.55	2.18	24.80
4.66	7.15	11.81	3.85	4.57	2.55	2.28	25.06
4.67	7.16	11.83	3.77	4.61	2.55	2.27	25.02
4.58	6.96	11.55	3.66	4.75	2.54	2.36	24.86
4.65	7.29	11.94	3.87	4.74	2.62	2.37	25.54

Gas Supply. *Other Supply includes net imports from Canada, Mexico, and LNG plus supplemental gaseous fuels. Negative storage change denotes net injections; if positive net withdrawals. Storage levels (BCF) are at end of month shown.*

U.S. Regional Production. *Gulf of Mexico (GOM) DW (Deepwater) and SW (Shallow Water) refer to offshore Gulf of Mexico production in greater or less than 1,000 feet water depths. Gulf Coast Offshore includes Gulf of Mexico Federal plus state offshore portions of Alabama, Louisiana, and Texas. Other Onshore GOM includes Alabama, Louisiana and Mississippi. Other Permian/Mid-Continent includes Arkansas, Kansas, Oklahoma, and East New Mexico. San Juan includes West New Mexico and Southwest Colorado. Rocky Mountain consists of all states in the Mountain census region plus North Dakota but excludes East New Mexico. Pacific includes California, Oregon and Alaska production. Midwest/East includes all remaining gas producing states.*

TABLE 9: NET OTHER SUPPLY (BCF/D)

3.41	7.19	0.48	0.87	10.20	-0.35	0.56	0.27	10.68
3.26	6.90	0.42	0.67	9.91	-0.20	0.49	0.28	10.47
3.25	6.13	0.32	0.26	9.44	-0.21	0.43	0.28	9.94
3.50	6.35	0.45	0.80	9.50	-0.30	0.49	0.25	9.94
3.50	6.55	0.45	0.80	9.70	-0.20	0.45	0.30	10.25
3.50	7.30	0.45	0.95	10.30	-0.20	0.45	0.30	10.85
3.50	7.50	0.45	0.95	10.50	-0.20	0.45	0.30	11.05
3.50	8.05	0.45	1.00	11.00	-0.20	0.44	0.30	11.54
3.14	5.74	0.42	0.14	9.16	-0.23	0.54	0.23	9.70
3.27	5.72	0.42	0.15	9.27	-0.25	0.64	0.35	10.00
3.30	6.78	0.39	0.58	9.89	-0.23	0.45	0.35	10.46
3.48	7.29	0.35	0.73	10.40	-0.04	0.31	0.35	11.02
3.35	7.71	0.33	0.59	10.80	-0.09	0.36	0.35	11.41

TABLE 10: CANADIAN GAS BALANCES (BCF/D)

2.78	4.30	10.20	13.58	3.60	0.54	17.71	-0.01	
2.49	4.30	9.91	13.24	3.22	0.46	16.92	-0.22	
2.49	4.57	9.44	13.01	2.84	0.33	16.17	0.32	
1.10	3.65	9.50	12.80	3.30	0.45	16.55	-2.30	461
2.00	4.55	9.70	13.30	3.45	0.45	17.20	-0.95	490
3.30	4.90	10.30	13.60	3.50	0.50	17.60	0.90	463
4.50	6.55	10.50	14.40	3.55	0.50	18.45	3.10	367
5.40	5.95	11.00	14.50	3.40	0.50	18.40	3.95	245
1.06	3.83	9.16	12.57	2.78	0.41	15.76	-1.71	443
1.75	4.80	9.27	13.05	2.99	0.43	16.47	-0.65	463
3.02	5.17	9.89	13.34	3.14	0.44	16.92	1.16	429
4.56	7.27	10.40	14.09	3.12	0.42	17.63	4.60	286
4.44	5.19	10.80	13.99	2.87	0.42	17.28	3.15	188

Net Other Supply. *In 2001, incremental Canadian exports to the U.S. reflect shipments on the Alliance pipeline. The growth of Canadian imports form the U.S. largely reflects those Alliance shipments that are destined for eastern Canada on the Vector pipeline. Both Alliance and Vector started in 12/00. Liquefied Natural Gas (LNG) imports consists of shipments into two terminals (Everett, Mass., and Lake Charles, LA.). Supplemental fuels consist of synthetic natural gas, propane-air, refinery gas, biomass gas and commingled manufactured gas.*

Canadian Gas Balances. *Canadian net exports are based on National Energy Board data (1999 net exports do not match data in Table 9, which are based on DOE data). Negative storage equals net injections. Positive storage equals net withdrawals. Storage figures (BCF) in the final column are end-of-period levels. Following Statistics Canada's definition, PIRA excludes lease and plant fuel from domestic demand.*

TABLE 11: U.S. GAS/FUEL OIL COMPETITIVE PRICES

[illegible]	1.91	21.27	3.38	61.06	4.42	-1.47	-2.51
[illegible]	2.28	17.61	2.79	62.52	4.53	-0.52	-2.25
[illegible]	2.66	17.95	2.85	66.69	4.83	-0.19	-2.17
[illegible]	2.85	18.56	2.95	67.24	4.87	-0.09	-2.02
[illegible]	2.85	18.41	2.92	67.09	4.86	-0.08	-2.01
[illegible]	2.80	18.23	2.89	65.24	4.72	-0.09	-1.92
[illegible]	5.28	29.31	4.65	94.10	6.81	0.63	-1.53
[illegible]	4.50	28.31	4.49	105.34	7.63	0.01	-3.13
[illegible]	6.03	25.37	4.03	90.66	6.57	2.00	-0.54
[illegible]	9.98	25.08	3.98	78.63	5.69	6.00	4.29
[illegible]	6.21	23.18	3.68	73.34	5.31	2.53	0.90
[illegible]	5.05	23.15	3.67	75.67	5.48	1.38	-0.43

TABLE 12: U.S. MACROECONOMIC ASSUMPTIONS

[illegible]	9224.0	4.1	147.0	5.6	129.3	2.6
[illegible]	9308.0	0.9	142.5	-3.1	123.9	-4.1
[illegible]	9358.2	0.5	141.7	-0.5	123.9	0.0
[illegible]	9334.5	1.3	145.5	-6.8	125.7	-8.0
[illegible]	9338.4	0.2	143.9	-4.4	124.8	-3.0
[illegible]	9314.9	-1.0	141.4	-6.7	123.2	-4.9
[illegible]	9244.3	-3.0	139.2	-6.0	122.0	-3.9
[illegible]	9221.1	-1.0	138.7	-1.4	121.8	-0.8
[illegible]	9289.5	3.0	140.2	4.4	123.0	4.2
[illegible]	9403.5	5.0	142.7	7.4	124.5	5.0
[illegible]	9518.9	5.0	145.3	7.2	126.5	6.6

Gas/Fuel Oil Prices. ***Historical NYMEX #2 Heating Oil prices are closing futures contract values, and Resid prices are Platts daily averages. Historical gas prices are Henry Hub bidweek index. Differentials equal gas prices minus residual and #2 f.o. prices. Resid is converted at 6.3 MMBtu per barrel; #2 oil is converted at 5.8 MMBtu per barrel. For October'01 – March'02, Resid prices are 80% of WTI NYMEX future contract values. Note that for approximately the last two years, Resid prices have averaged between 70% and 90% of WTI.***

Macroeconomic. ***GDP through 2Q01 preliminary estimate. Industrial Production Index through August 2001. For full years, percentage changes are year-on-year. For quarters, percentage changes are quarter-to-quarter annualized.***

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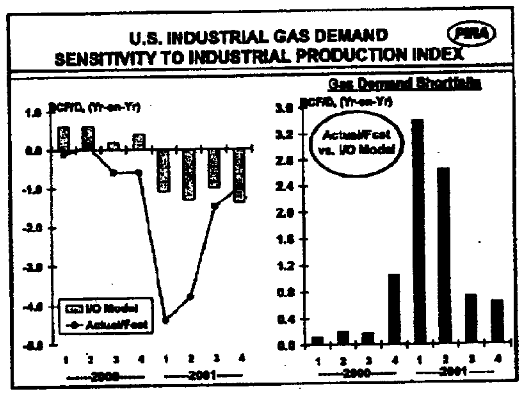
Special Supplement — Industrial Demand

TRADITIONAL INDUSTRIAL GAS DEMAND & PIRA'S INPUT/OUTPUT MODEL

The grim economic landscape applies not only to the U.S., but to the global economy, as well. In such an environment, industrial gas demand is highly vulnerable. As a result, our outlook for this sector during the heating season has been tempered, but demand growth is nonetheless anticipated, given the extremely weak performance of a year ago. Industrial production (IP) is a key driver of gas demand, but other factors also affect this sector's gas use. Indeed, while the impact from the macroeconomic situation is expected to mitigate growth of industrial gas demand, ongoing weakness in natural gas prices offers cost relief for the gas-intensive manufacturers, especially in relation to 1Q01 when prices marched deep into new record-high territory.



Traditional industrial demand is forecast based on historical gas input per unit of output relationships for key gas consuming industries. Using specific output indices measured by the Federal Reserve Board for each of those industries, quarterly gas usage is compiled and compared with actual and forecast results. The results from PIRA's input/output model are primarily driven by our gas-weighted IP estimates, but seasonal tendencies and abnormal weather adjustments are also incorporated.

The model, however, does not reflect the full extent of the traditional industrial sector's gas demand sensitivity to a number of other factors. For example, record high gas prices, cost advantages of oil relative to gas, higher BTU content of gas, and reduced gas intensity within key industries themselves, are not directly considered by the model, yet those factors greatly contributed to demand destruction from late 2000 into early 2001. These influences explain the model's variance relative to imputed industrial demand. Going forward, many of those issues have been reversing this year as gas prices declined in terms of both absolute levels and on a relative basis. Consequently, the model's results should more closely approximate actual industrial demand.

Given the visibility as well as the sizable gas volumes at stake within the ammonia and methanol industry, PIRA analyzes this sector independently of the model. For consistency purposes though, our ammonia analysis is included in the input/output model's final results when compared with actual industrial demand and PIRA's forecast. The highly visible ammonia industry's return to profitability earlier this year proved short-lived as plant returns and weak demand depressed selling prices, which undermined margins. More recently, however, profitability final returned, and thus, we now expect a distinct narrowing of year-on-year gas demand losses.

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