RÉPONSE DE SCGM À UNE DEMANDE D'INFORMATION

Origine : Lettre du 27 octobre 1999

Demandeur : ACIG

Question : 4.1.2 Référence : SCGM-4, doc. 1, p. 5, tableau 2 (hypothèses énergétiques) :

Demandes :

a) Veuillez produire l'analyse des prévisions fondamentales effectuée par différents organismes à laquelle il est fait référence à la note 1.

b) Veuillez préciser les sources de référence au soutien des ratios historiques des prix du mazout lourd à Montréal par rapport aux prix du pétrole brut.

Réponse :

a) Vous trouverez ci-joint l'analyse des prévisions fondamentales effectuée par différents organismes à laquelle il est fait référence à la note 1.

b) Les sources de référence utilisées pour le calcul des ratios historiques des prix du mazout à Montréal par rapport au prix du pétrole brut sont :

- Prix des mazouts : Oil Buyers Guide (janvier 1993 à décembre 1998)
- Prix du WTI : Canadian Natural Gas Focus (janvier 1993 à décembre 1998)
- Taux de change : Statistiques Canada, Banque de données CANSIM

Les ratios utilisés pour la prévision du prix des différentes catégories de mazout sont :

Prix de l'huile # 2/ Prix du WTI :	1,27
Prix de l'huile # 6 (1,5% soufre) / Prix du WTI :	0,90
Prix de l'huile # 6 (2,0% soufre) / Prix du WTI :	0,85

Il s'agit de moyennes historiques calculées sur la période de janvier 1993 à décembre 1998.

Canadian Hydrocarbon Prices

July 15, 1999

Sproule
ASSOCIATES
LIMITED

Geological and Petroleum Engineering Consultants

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Canadian Hydrocarbon Prices

Executive Summary

Sproule Associates Limited has revised its energy forecast effective July 15, 1999.

The implementation of the March 12, 1999 Hague Accord confirms the crucial roll that the OPEC nations play in establishing crude oil prices throughout the world. This accord marked the resolution of several disputes between OPEC members and led to the implementation of significant production cuts. In total, a commitment from non-OPEC, as well as OPEC countries could lead to a reduction of 2.1 million barrels per day. By far the largest single reduction comes from Saudi Arabia, which will reduce its country's production quota by 0.6 million barrels per day to 7.4 million barrels per day. These cuts should allow for the gradual reduction of global crude oil inventories and lead to an increase in the price of crude. Reasonable compliance with these production cuts has led to an increase from the February price of $12.02 US per barrel for West Texas Intermediate (WTI) to a July price of approximately $20.00 US per barrel.

Assuming the current supply/demand balance is sustained for the balance of the year, the West Texas Intermediate (WTI) crude oil forecast has been increased to $18.00 US per barrel for the remainder of 1999. Thereafter, the WTI is forecast at $17.00 in the year 2000, $18.00 in 2001, and is capped at $19.00 US per barrel (1999 dollars.)

In Western Canada, the prices of heavy and medium crude have suffered, not only from a depressed world oil price, but also from the local market constraints in heavy oil refining capacity. The abundant supply of heavy oil in Western Canada minimizes the exploration risk and the oil prices received by producers throughout 1996 and 1997 encouraged development that exceeded the downstream infrastructure. With the price reductions of 1998, heavy oil development was constrained and heavy oil price differentials improved. Price differentials for heavy and medium crude at the end of 1998 were approximately half the price differentials at the beginning of the year. Construction of new pipeline and upgrader facilities will help to stabilize heavy oil prices in the long term.

The differential for Hardisty heavy oil has been forecast at $8.00 per barrel for the remainder of 1999, and Sproule forecasts that the long-term differential will stabilize at $8.50 per barrel. This forecast for the long-term differential reflects the improved market for heavy oil due to expansions at various upgraders and

refineries. The differentials for Hardisty medium and Cromer medium are forecast in 1999 at $5.00 per barrel and $3.25 per barrel, respectively.

The 1999 price for natural gas sold in Alberta has increased from the 1998 annual average of $1.87 CDN per MMBtu to an unprecedented summertime high of $2.65 CDN per MMBtu at the Alberta plantgate. This surge in the local market price surpasses Sproule's long-term outlook for natural gas that caps the average price at the Alberta plantgate at $2.35 CDN per MMBtu in real 1999 dollars. Additional natural gas production is required to fill the 1 Bcf per day of new export capacity that was added this past winter. The requirement for incremental supply, and the support of a high gas price, will encourage the natural gas industry to focus on exploration activity rather than the development drilling which, in previous years, has served to increase the overall productive capacity from Western Canada. In the United States, the average 1999 price of $2.20 US per MMBtu for the balance of the year is forecast to increase to a cap of $2.30 US per MMBtu, in 1999 dollars.

The exchange rate ($U.S. per $Canadian) was revised to more closely reflect the current position. It has been forecast at 0.69 for the remainder of 1999, increasing to 0.73 over the next 4 years, and then remain constant at 0.73.

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TABLE 1
SUMMARY OF PRICE FORECASTS, INFLATION and EXCHANGE RATES

	Light Crude Oil			Heavy & Medium Oil			Western Canada Natural Gas			Natural Gas Liquids and Sulphur						
	- Prices in Canadian Dollars -															
	1		2				Plant Gate									
Year	WTI Cushing Oklahom $US/Bbl	Edmonton Par Price 40 API $/Bbl	Alberta Royalty Par Price $/Bbl	Hardisty Heavy 12 API $/Bbl	Cromer Medium 29.3 API $/Bbl	Hardisty Medium 25.7 API $/Bbl	Alberta $/MMbtu	British Columbia $/MMbtu	Sask. $/MMBtu	Ethane $/Bbl	Propane $/Bbl	Butanes $/Bbl	Pentanes Plus $/Bbl	Sulphur $/LT	Inflation Rate %/Yr	Exchange Rate $US/$Cdn
1994 Act	17.18	22.25	21.49	15.02	19.26	18.42	1.97	1.81	1.74	5.51	12.52	13.45	21.25	16.57	0.2	0.732
1995 Act	18.42	24.26	22.93	17.26	21.69	20.80	1.17	1.12	1.35	3.19	13.91	13.79	24.21	30.65	2.2	0.729
1996 Act	22.13	29.43	26.26	20.05	26.07	25.11	1.26	1.47	1.52	3.85	22.16	17.12	29.58	14.44	1.4	0.731
1997 Act	20.60	27.78	26.78	14.35	23.71	21.16	1.69	1.98	1.85	5.13	18.56	19.05	29.11	12.26	1.6	0.722
1998 Act	14.36	20.36	19.36	9.41	16.95	14.63	1.87	2.00	2.05	5.63	10.94	11.88	20.89	8.76	0.9	0.675
1999 6mo.	15.34	21.87	20.87	14.69	19.28	17.33	2.42	2.46	2.54	7.18	11.14	11.56	21.75	4.00	1.0	0.670
1999 6mo.	18.00	25.05	24.05	17.05	21.80	20.05	2.35	2.25	2.40	7.90	13.53	14.56	25.65	5.00	2.0	0.690
2000	17.34	23.73	22.73	15.72	20.48	18.73	2.40	2.35	2.45	7.77	12.82	13.79	24.30	10.00	2.0	0.700
2001	18.73	24.96	23.96	16.96	20.96	19.96	2.44	2.60	2.49	7.64	13.49	14.51	25.56	13.00	2.0	0.720
2002	20.16	26.55	25.55	18.03	22.53	21.55	2.49	2.55	2.54	7.50	14.35	15.44	27.19	15.92	2.0	0.730
2003	20.57	27.09	26.09	18.53	23.04	22.06	2.54	2.60	2.59	7.65	14.64	15.75	27.74	18.94	2.0	0.730
2004	20.98	27.64	26.64	19.05	23.56	22.58	2.59	2.65	2.64	7.80	14.93	16.07	28.30	22.06	2.0	0.730
2005	21.40	28.19	27.19	19.58	24.09	23.11	2.65	2.70	2.70	7.96	15.24	16.39	28.88	22.52	2.0	0.730
2006	21.83	28.76	27.76	20.11	24.63	23.65	2.70	2.76	2.75	8.12	15.54	16.72	29.46	22.97	2.0	0.730
2007	22.26	29.35	28.35	20.67	25.19	24.21	2.75	2.81	2.80	8.28	15.86	17.06	30.06	23.43	2.0	0.730
2008	22.71	29.94	28.94	21.23	25.75	24.77	2.81	2.87	2.86	8.44	16.18	17.41	30.67	23.90	2.0	0.730
2009	23.16	30.55	29.55	21.81	26.33	25.36	2.86	2.93	2.91	8.61	16.51	17.76	31.29	24.38	2.0	0.730
2010	23.62	31.17	30.17	22.40	26.93	25.95	2.92	2.98	2.97	8.79	16.84	18.12	31.92	24.87	2.0	0.730
2011	24.10	31.80	30.80	23.00	27.53	26.55	2.98	3.04	3.03	8.96	17.18	18.49	32.57	25.36	2.0	0.730

Escalation Rate of 2.0% thereafter.

1. 40 Deg API, 0.4% sulphur
2. Edmonton Par less $1.00 per barrel

As of July 16, 1999

TABLE 2

NATURAL GAS PRICE FORECASTS - VARIOUS SHIPPERS

($Cdn/MMBtu)

Year	Alberta Gas Reference Price Plantgate	Alberta 30 day Spot AECO	Alberta 30 day Spot Plantgate	Alberta Average Plantgate	Sask 30 day Spot Plantgate	B.C. 30 day Spot Plantgate	B.C. Average Wellhead	Huntingdon/ Sumas 30 d Spot	Henry Hub Price $US/MMBtu
1994 Act	1.81	1.99	1.86	1.81	1.87	1.81	1.46	1.97	1.90
1995 Act	1.31	1.15	1.04	1.26	1.35	1.12	0.77	1.39	1.64
1996 Act	1.63	1.39	1.26	1.67	1.28	1.47	1.12	1.80	2.59
1997 Act	1.97	1.85	1.70	1.92	1.75	1.98	1.58	2.36	2.59
1998 Act	1.94	2.03	1.87	1.90	2.13	2.00	1.61	2.38	2.11
1999 6mo.	2.01	2.59	2.42	1.98	2.15	2.46	1.97	2.87	1.96
1999 6mo.	2.40	2.85	2.70	2.35	2.75	2.25	1.85	2.60	2.20
2000	2.44	2.81	2.65	2.40	2.70	2.35	1.94	2.70	2.19
2001	2.47	2.76	2.60	2.44	2.65	2.60	2.18	2.97	2.24
2002	2.50	2.71	2.55	2.49	2.60	2.55	2.12	2.92	2.33
2003	2.55	2.76	2.60	2.54	2.65	2.60	2.16	2.98	2.41
2004	2.60	2.82	2.65	2.59	2.70	2.65	2.21	3.04	2.48
2005	2.65	2.87	2.70	2.65	2.76	2.70	2.25	3.10	2.57
2006	2.71	2.93	2.76	2.70	2.81	2.76	2.30	3.16	2.64
2007	2.76	2.99	2.81	2.75	2.87	2.81	2.34	3.22	2.69
2008	2.82	3.05	2.87	2.81	2.93	2.87	2.39	3.29	2.75
2009	2.87	3.11	2.93	2.86	2.99	2.93	2.44	3.35	2.80
2010	2.93	3.17	2.98	2.92	3.05	2.98	2.49	3.42	2.86
2011	2.99	3.23	3.04	2.98	3.11	3.04	2.54	3.49	2.92

Escalation Rate of 2.0% thereafter

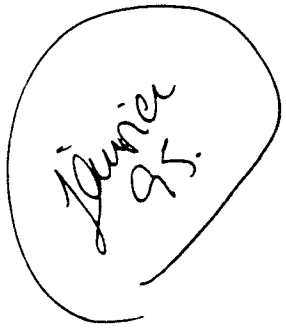
As of July 15, 1999

Gilbert Laustsen Jung Associates Ltd. Petroleum Consultants

403-266-9500

PRODUCT PRICE AND MARKET FORECASTS FOR THE CANADIAN OIL AND GAS INDUSTRY

Quarterly Update
July 1, 1999



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July 1, 1999

Gilbert Laustsen Jung Associates Ltd. has prepared the enclosed price and market forecasts after a comprehensive review of information available through to June 1999. Information sources include numerous government agencies, industry publications, Canadian oil refiners and natural gas marketers. The accuracy of all factual data, from all sources has been accepted as represented without detailed investigation by Gilbert Laustsen Jung Associates Ltd. The forecasts presented herein are based on an informed interpretation of currently available data. While they are considered reasonable at this time, users of these forecasts should understand the inherent high uncertainty in forecasting any commodity or market. These forecasts will be revised periodically as market and economic conditions change. These future revisions may be significant.

GILBERT LAUSTSEN JUNG ASSOCIATES LTD.
PRODUCT PRICE AND MARKET FORECASTS
FOR THE CANADIAN OIL AND GAS INDUSTRY
JULY 1, 1999

Gilbert Laustsen Jung Associates Ltd. has completed a quarterly update of our commodity price forecasts as presented on the attachments. Revisions in near-term forecasts reflective of current market conditions have been incorporated. A summary of near-term forecasts follows:

NATURAL GAS PRICES

	April 1, 1999 Calendar Year	July 1, 1999 Calendar Year	July 1, 1999 Q3-Q4
Henry Hub Gas Price - ($US/MMBTU)			
1999	1.95	2.20	2.40
2000	2.20	2.40	2.40
Average Alberta Gas Price - ($Cdn/MMBTU)			
1999	2.25	2.45	2.65
2000	2.45	2.65	2.65
TCGS Gas Price - ($Cdn/MMBTU)			
1999	2.10	2.25	2.45
2000	2.45	2.55	2.55
Pan-Alberta Gas Price - ($Cdn/MMBTU)			
1999	2.10	2.25	2.45
2000	2.45	2.55	2.55
ProGas Gas Price - ($Cdn/MMBTU)			
1999	2.15	2.35	2.50
2000	2.45	2.55	2.55
Canwest Plant-Gate Gas Price - ($Cdn/MMBTU)			
1999	2.20	2.25	2.45
2000	2.30	2.55	2.55

CRUDE OIL PRICES

	April 1, 1999 Calendar Year	July 1, 1999 Calendar Year	July 1, 1999 Q3-Q4
WTI @ Cushing Price - ($US/BBL)			
1999	15.00	16.50	17.50
2000	17.00	17.00	17.00
Light, Sweet @ Edmonton Price - ($Cdn/BBL)			
1999	21.50	23.25	24.50
2000	23.50	23.50	23.50

Table 1
Gilbert Laustsen Jung Associates Ltd.
Crude Oil and Natural Gas Liquids
Base Case Price Forecast
Effective July 1, 1999

Year	Inflation %	Exchange Rate $US/$Cdn	West Texas Intermediate Crude Oil at Cushing Oklahoma Constant 1999 $ $US/bbl	West Texas Intermediate Crude Oil at Cushing Oklahoma Then Current $US/bbl	Brent Blend Crude Oil FOB North Sea Constant 1999 $ $US/bbl	Brent Blend Crude Oil FOB North Sea Then Current $US/bbl	Light, Sweet Crude Oil (40 API, 0.3%S) at Edmonton Constant 1999 $ $Cdn/bbl	Light, Sweet Crude Oil (40 API, 0.3%S) at Edmonton Then Current $Cdn/bbl	Medium Crude Oil (25.6 API, 2.1%S) at Hardisty Constant 1999 $ $Cdn/bbl	Medium Crude Oil (25.6 API, 2.1%S) at Hardisty Then Current $Cdn/bbl	Heavy Crude Oil (12 API) at Hardisty Constant 1999 $ $Cdn/bbl	Heavy Crude Oil (12 API) at Hardisty Then Current $Cdn/bbl	Medium Crude Oil (29 API, 2.0%S) at Cromer Constant 1999 $ $Cdn/bbl	Medium Crude Oil (29 API, 2.0%S) at Cromer Then Current $Cdn/bbl	Alberta Natural Gas Liquids (Then Current Dollars) Spec Ethane $Cdn/bbl	Alberta Natural Gas Liquids (Then Current Dollars) Edmonton Propane $Cdn/bbl	Alberta Natural Gas Liquids (Then Current Dollars) Edmonton Butane $Cdn/bbl	Alberta Natural Gas Liquids (Then Current Dollars) Edmonton Pentanes Plus $Cdn/bbl
1989	5.0	0.845	25.07	19.58	23.31	18.21	28.40	22.18	23.48	18.34	17.50	13.67	23.42	18.29	n/a	7.64	9.87	n/a
1990	4.8	0.857	29.83	24.46	28.89	23.69	33.74	27.66	26.03	21.34	19.51	16.00	27.77	22.77	n/a	13.18	15.67	n/a
1991	5.6	0.873	24.96	21.45	23.17	19.91	27.22	23.39	17.57	15.10	10.51	9.03	19.59	16.84	n/a	11.92	15.26	n/a
1992	1.5	0.830	22.74	20.64	21.31	19.34	26.02	23.62	19.33	17.54	14.28	12.96	20.33	18.45	n/a	10.58	14.04	n/a
1993	1.8	0.775	20.04	18.46	18.48	17.03	23.81	21.94	18.16	16.73	14.39	13.26	19.09	17.59	n/a	14.10	13.64	21.17
1994	0.2	0.730	18.32	17.18	16.87	15.82	23.69	22.22	19.69	18.47	16.02	15.02	20.58	19.30	n/a	12.53	13.45	21.69
1995	2.2	0.729	19.57	18.39	18.13	17.04	25.78	24.23	22.13	20.80	18.39	17.28	23.08	21.69	n/a	13.90	13.79	24.11
1996	1.5	0.733	22.90	21.99	21.28	20.43	30.61	29.39	26.17	25.13	20.89	20.06	27.18	26.10	n/a	22.31	17.15	30.06
1997	1.6	0.722	21.15	20.61	19.68	19.18	28.58	27.85	21.72	21.17	14.79	14.41	24.34	23.72	n/a	18.62	18.73	30.91
1998	1.0	0.672	14.56	14.42	12.96	12.83	20.56	20.36	14.79	14.64	9.54	9.45	17.12	16.95	n/a	11.73	12.68	21.83
1999 Q1	0.8	0.663	13.06	13.06	11.23	11.23	18.75	18.75	16.43	16.43	13.42	13.42	17.28	17.28	n/a	10.57	10.89	18.45
1999 Q2 (e)	1.5	0.680	17.50	17.50	15.21	15.21	24.81	24.81	20.00	20.00	16.50	16.50	22.30	22.30	n/a	13.50	15.00	24.75
1999 Q3	1.5	0.680	17.50	17.50	16.00	16.00	24.50	24.50	22.00	22.00	18.50	18.50	22.75	22.75	8.75	13.50	14.50	24.50
1999 Q4	1.5	0.680	17.50	17.50	16.00	16.00	24.50	24.50	20.50	20.50	17.50	17.50	22.00	22.00	9.50	13.50	14.50	24.50
1999 Full Year	1.3	0.680	16.50	16.50	14.50	14.50	23.25	23.25	19.75	19.75	16.50	16.50	21.00	21.00	9.25	12.75	13.75	23.00
1999 Q3-Q4	0.0	0.680	17.50	17.50	16.00	16.00	24.50	24.50	21.25	21.25	18.00	18.00	22.25	22.25	9.25	13.50	14.50	24.50
2000	1.5	0.690	16.75	17.00	15.25	15.50	23.25	23.50	19.75	20.00	16.25	16.50	20.75	21.00	9.25	12.50	13.50	23.50
2001	1.5	0.700	17.50	18.00	16.00	16.50	23.75	24.50	20.00	20.50	16.50	17.00	20.75	21.50	9.25	13.50	14.50	24.50
2002	1.5	0.710	18.25	19.00	16.75	17.50	24.50	25.50	20.00	21.00	17.25	18.00	21.50	22.50	8.75	14.50	15.50	25.50
2003	1.5	0.720	18.75	20.00	17.50	18.50	25.00	26.50	20.75	22.00	18.00	19.00	22.25	23.50	8.75	15.50	16.50	26.50
2004	1.5	0.730	19.00	20.50	17.75	19.00	25.00	27.00	21.00	22.50	18.00	19.50	22.25	24.00	8.75	16.00	17.00	27.00
2005	1.5	0.730	19.00	20.75	17.50	19.25	25.00	27.25	20.75	22.75	18.00	19.75	22.25	24.25	8.75	16.25	17.25	27.25
2006	1.5	0.730	19.00	21.25	17.75	19.75	25.00	27.75	21.00	23.25	18.25	20.25	22.25	24.75	8.75	16.75	17.75	27.75
2007	1.5	0.730	19.00	21.50	17.75	20.00	25.00	28.25	21.00	23.75	18.50	20.75	22.50	25.25	9.00	17.25	18.25	28.25
2008	1.5	0.730	19.00	21.75	17.75	20.25	25.00	28.50	21.00	24.00	18.25	21.00	22.25	25.50	9.25	17.50	18.50	28.50
2009	1.5	0.730	19.00	22.00	17.75	20.50	25.00	29.00	21.00	24.50	18.50	21.50	22.50	26.00	9.50	18.00	19.00	29.00
2010+	1.5	0.730	19.00	+1.5%/yr	17.75	+1.5%/yr	25.00	+1.5%/yr	21.00	+1.5%/yr	18.50	+1.5%/yr	22.50	+1.5%/yr	Escalate at 1.5 % per year			

Revised June 23, 1999

Table 2
Gilbert Laustsen Jung Associates Ltd.
Natural Gas and Sulphur
Base Case Price Forecast
Effective July 1, 1999

	US Gulf Coast Gas Price @ Henry Hub			Alberta Plant Gate						Saskatchewan Plant Gate			British Columbia			
	Constant 1999 $	Then Current	AECO-C Spot Then Current	Average Price Constant 1999 $	Average Price Then Current	Spot	TCGS	Pan-Alberta	ProGas	SaskEnergy	Spot	Sumas Spot	CanWest Plant Gate	Spot Plant Gate	Sulphur FOB Vancouver	Alberta Sulphur at Plant Gate
Year	$US/mmbtu	$US/mmbtu	$Cdn/mmbtu	$/mmbtu	$/mmbtu	$/mmbtu	$/mmbtu	$/mmbtu	$/mmbtu	$/mmbtu	$/mmbtu	$US/mmbtu	$/mmbtu	$/mmbtu	$US/LT	$Cdn/LT
1989	2.18	1.69	1.37	2.06	1.61	1.28	1.37	1.44	1.66	1.60	1.46	1.26	1.65	n/a	n/a	72.05
1990	2.10	1.71	1.29	1.91	1.57	1.20	1.46	1.46	1.71	1.67	1.58	1.32	1.67	n/a	n/a	58.01
1991	1.80	1.53	1.09	1.50	1.29	0.95	1.27	1.30	1.41	1.61	1.41	1.21	1.61	n/a	n/a	53.45
1992	1.96	1.73	1.15	1.51	1.37	1.04	1.30	1.45	1.60	1.48	1.17	1.16	1.47	n/a	53.72	19.77
1993	2.33	2.11	2.26	1.86	1.71	2.16	1.59	1.77	1.94	1.48	2.07	1.89	1.73	2.10	30.22	-9.68
1994	2.09	1.94	1.98	1.93	1.81	1.86	1.81	1.73	1.93	1.88	1.87	1.59	1.81	1.87	44.96	16.57
1995	1.82	1.70	1.15	1.39	1.31	1.02	1.22	1.26	1.55	1.35	0.98	1.03	1.29	1.12	54.99	30.07
1996	2.62	2.52	1.39	1.70	1.63	1.26	1.63	1.88	1.78	1.52	1.28	1.32	1.50	1.47	36.28	14.44
1997	2.53	2.47	1.84	2.01	1.96	1.69	1.77	2.24	1.98	1.84	1.74	1.70	1.80	1.98	34.75	11.50
1998	2.18	2.16	2.03	1.96	1.94	1.88	1.87	2.01	1.99	2.05	2.13	1.60	1.94	2.00	24.59	-6.51
1999 Q1	1.80	1.80	2.46	2.02	2.02	2.30	1.91	1.91	2.13	2.45	2.46	2.06	2.39	2.46	27.09	-2.11
1999 Q2 (e)	2.22	2.22	2.85	2.45	2.45	2.70	2.15	2.15	2.24	2.60	2.85	1.78	1.80	2.00	29.75	0.75
1999 Q3	2.30	2.30	2.80	2.50	2.50	2.65	2.30	2.35	2.45	2.65	2.80	1.90	2.30	2.45	32.00	4.00
1999 Q4	2.50	2.50	3.10	2.75	2.75	2.95	2.55	2.55	2.55	2.90	3.10	2.30	2.60	3.05	33.00	6.00
1999 Full Year	2.20	2.20	2.80	2.45	2.45	2.65	2.25	2.25	2.35	2.65	2.80	2.00	2.25	2.50	30.50	2.00
1999 Q3-Q4	2.40	2.40	2.95	2.65	2.65	2.80	2.45	2.45	2.50	2.80	2.95	2.10	2.45	2.75	32.50	5.00
2000	2.35	2.40	2.90	2.60	2.65	2.75	2.55	2.55	2.55	2.80	2.90	2.05	2.55	2.70	40.00	14.50
2001	2.35	2.40	2.80	2.60	2.65	2.65	2.65	2.65	2.65	2.80	2.80	2.05	2.65	2.65	45.00	21.00
2002	2.30	2.40	2.70	2.45	2.55	2.55	2.55	2.55	2.55	2.70	2.70	2.05	2.55	2.55	51.00	28.50
2003	2.30	2.45	2.70	2.40	2.55	2.55	2.55	2.55	2.55	2.70	2.70	2.05	2.55	2.55	52.00	28.50
2004	2.30	2.50	2.70	2.40	2.55	2.55	2.55	2.55	2.55	2.70	2.70	2.10	2.55	2.55	53.00	29.00
2005	2.30	2.55	2.70	2.30	2.55	2.55	2.55	2.55	2.55	2.70	2.70	2.10	2.55	2.55	54.00	30.50
2006	2.30	2.60	2.70	2.30	2.55	2.55	2.55	2.55	2.55	2.70	2.70	2.10	2.55	2.55	55.00	32.00
2007	2.30	2.60	2.75	2.30	2.60	2.60	2.60	2.60	2.60	2.75	2.75	2.15	2.60	2.60	56.00	33.50
2008	2.30	2.65	2.80	2.30	2.65	2.65	2.65	2.65	2.65	2.80	2.80	2.20	2.65	2.65	57.00	35.00
2009	2.30	2.70	2.85	2.30	2.70	2.70	2.70	2.70	2.70	2.85	2.85	2.20	2.70	2.70	58.00	36.00
2010+	2.30	+1.5%/yr	+1.5%/yr	2.30	+1.5%/yr					Escalate at 1.5 % per year					+1.5%/yr	

Unless otherwise stated, the gas price reference point is the receipt point on the applicable provincial gas transmission system known as the plant gate.
The plant gate price represents the price before raw gas gathering and processing charges are deducted.
Spot refers to weighted average one month price.

Revised June 23, 1999

CANADIAN DOLLAR

The Canadian dollar averaged over $US/$CDN 0.68 for each week in May 1999 but came under pressure in the first week of June 1999 due to market sentiment that there will soon be an interest rate increase in the U.S. The currency's recent strength reflects an improved outlook for commodity prices based on the relative calm in Asian economies and strong crude oil prices due to production cuts of approximately 2 million barrels per day. Positive market sentiments as a result of the 1999 Federal budget and continued low inflation are also supporting the Canadian dollar. The strong U.S. economic growth has also contributed to the stronger than expected momentum in Canadian economic activity.

The short-term risk to the continued strengthening of the Canadian dollar is the expectation that the U.S. Federal Reserve will tighten monetary policy this summer. U.S. economic growth continues to outperform the Canadian economy, thereby encouraging capital to move towards better opportunities in the U.S. rather than into Canada. The political uncertainty regarding the Quebec situation also is believed to be responsible for the ongoing weakness in the Canadian dollar.

Despite the risks, the long-term fundamentals for the value of Canadian currency look promising, making a return to the all-time low of $US/$CDN 0.631 unlikely. We continue to hold the view that the value of Canadian currency will continue to improve over time relative to U.S. currency. Surveys of the economic literature indicate that, although there are many views on the main factors which determine exchange rates, there is general consensus that a few key variables account for the broad movements in the value of the Canadian dollar relative to the U.S. dollar. Studies have found that a small number of factors were significant in explaining the major movements in the Canadian exchange rate relative to the U.S. dollar over the last twenty years. Swings in commodity prices, including energy, and the interest rate differential account for much of the movement in exchange rates. Other factors that may affect the short-term movement in the exchange rate are fiscal policy variables, international indebtedness, political uncertainty and investor sentiments. Although there is no guarantee that the implied relationships surmised from the historical data will hold in the future, we believe that commodity prices, and in particular energy commodity prices, will have a potential importance in the determination of the Canadian exchange rate over the long-term. Therefore, as we continue to forecast real growth in the value of energy commodities until 2003, we also continue to strengthen the value of the Canadian dollar versus the U.S. dollar. The near-term value of the Canadian dollar has been increased relative to the April 1, 1999 forecast to $US/$CDN 0.68, reflecting the current market value. The long-term exchange rate has been lowered from $US/$CDN 0.74 to $US/$CDN 0.73.

INFLATION FACTORS

Gilbert Laustsen Jung has revised the operating and capital inflation factors utilized in our evaluations from 2.0 percent to 1.5 percent. This revised factor is also utilized in the long-term price escalations. It is our view that operating and capital costs will not experience increases greater than 1.5 percent over the long-term due to technological advances and the continued desire by this industry to remain low cost providers of crude oil and natural gas. The impact of the change in price escalations in the long-term is minimal.

WORLD OIL PRICES

Crude oil prices continue to experience considerable volatility since the rapid improvement experienced during April 1999. During the first quarter of 1999, West Texas Intermediate prices averaged approximately $US 13.01/BBL, while April and May 1999 averaged $US 17.23/BBL and $US 17.77/BBL, respectively. The latest round of cuts by OPEC and non-OPEC countries has strengthened the crude oil price, despite compliance averaging between 65-85 percent for April 1999. Preliminary May 1999 compliance appears to be averaging around 90 percent. The U.S. Energy Information Administration (EIA) predicts compliance will peak in May or June. Non-OPEC production is forecast to remain essentially flat for the remainder of 1999 as historically low prices in 1998 delayed the development of some oil projects as well as causing some production to be shut-in. Higher prices during 1999 will provide incentives for both OPEC and non-OPEC producers to increase production by late 1999 and into 2000.

The EIA predicts world demand to increase by 1.1 million barrels per day in 1999 and by 1.6 million barrels per day in 2000. This forecast assumes the continued recovery of demand in Asian imports, although growth rates are not expected to return to levels experienced before the economic crisis.

The combination of the aforementioned supply and demand changes will likely prevent even a normal seasonal increase in world oil inventories for the remainder of 1999. The EIA estimates a net withdrawal of about 1 million barrels per day for full year 1999, which if realized, is good news for prices. In years where OECD crude oil stock levels have been high, world oil prices have fallen. During the period between 1990 and 1994, OECD stock levels increased and world crude oil prices fell by over $US 6.00/BBL. In 1995 and 1996, OECD inventories were drawn

The Henry Hub natural gas price forecast has been increased for the next four years relative to the April 1, 1999 forecast, which assumes a balanced to tight supply/demand equilibrium while industry investment grows and technology advancements enable additional reserves to be found and produced economically.

CANADIAN GAS PRICES

The addition of approximately 1.1 BCFD of incremental export pipeline capacity in late 1998 heading mainly for Chicago has contributed to strong Alberta AECO-C gas prices, averaging $CDN 2.55/MMBTU for the first five months of 1999. The basis differential between the U.S. Gulf Coast and AECO-C was below $US 0.20/MMBTU for the first quarter of 1999 when the U.S. Gulf Coast natural gas prices were below $US 2.00/MMBTU. Since the recovery in U.S. prices, the basis differentials between these two locations have widened, averaging $US 0.38/MMBTU for April and May 1999. The AECO-C spot price, like the US Henry Hub spot price, is particularly strong over the coming winter months due to concerns of deliverability shortfalls. The market expectation is for minimal production growth for 1999 due to lower exploration and production budgets, reduced capital spending and normal production declines. The spot prices in the WCSB are anticipated to be stronger than border prices for 1999 and 2000 due to a tight supply/demand balance in the Alberta market.

Load factors on pipelines at the major export points operated near capacity during January 1999 despite the increase in capacity. The pipeline load factor at Monchy, which is the export point onto the Northern Boarder pipeline, operated at approximately 95% for January 1999. The 1998 average load factor at this export point was just over 100 percent of operating capacity. The major eastern export points all averaged 100 percent or greater load factors for January 1999, similar to levels experienced in 1998. The western export points both saw a drop in load factors in January 1999 with Sumas operating at 83 percent and Kingsgate at 86 percent. Both of these load factors are below 1998 averages.

Unlike the dramatic reduction in natural gas completions in the U.S. in 1998, natural gas completions recorded for the first four months of 1999 for the three Western provinces were higher than those recorded for the same period in 1998. Stated in percentage terms, natural gas well completions comprised 66.5 percent of all completions for January to April 1999 compared to 37.4 percent over the 1998 comparable time period. With the improvement in crude oil prices, the percentage of natural gas completions is anticipated to drop slightly as producers return to crude oil drilling. The number of gas well completions is not expected to suffer any significant drop, however, due to the very attractive market prices for natural gas and the fact that 1.3 BCF/D of additional pipeline capacity to export markets is expected to be available in late 2000.

We anticipate that strong demand from Eastern Canada and the U.S. markets will continue to keep Canadian natural gas prices strong, which will encourage natural gas producers to locate and produce additional supplies. We believe that Canadian producers will be extremely challenged to increase deliverability over the next few years in light of steep initial decline rates and low reserve to production ratios. The next two to three years will likely see a shift towards exploratory drilling and a move in activity west and north as producers look deeper for larger finds.

A memorandum of understanding was reached between industry and TCPL/Nova regarding mileage based tolls in late March 1999. The agreement for toll structure maintains the distinction of receipt and delivery service. The receipt point specific toll design is based on distance and size of pipe. Delivery services are differentiated by intra-provincial or export destination. Full export tolls will range from a floor of $CDN 0.199/MMBTU to a ceiling of $CDN 0.359/MMBTU. Intra-Alberta receipt tolls will range from $CDN 0.073/MMBTU to $CDN 0.233/MMBTU. In order to implement competitive tolls and to allow shippers whose tolls are increasing to adjust their investment decisions, the new receipt point specific tolls will be phased in. The ceiling tolls will be phased in at a rate of $CDN 0.002/MMBTU per year from 1999 to 2003. The floor tolls will be phased in at a rate of $CDN 0.004/MMBTU per year from 1999 to 2001. Renewal notice will be 12 months with a financial incentive to provide renewal information at 24 months and the minimum renewal term is one year. It is assumed the Alberta Energy and Utilities Board (AEUB) will approve the revised application without major modifications by the fall of 1999.

The National Energy Board (NEB) approved the Alliance Pipeline Ltd. application in late November. The pipeline is anticipated to ship 1.3 BCF/D of rich natural gas from British Columbia and Alberta to the Chicago market in late 2000. Both U.S. and Canadian regulatory agencies have approved the Vector Pipeline, jointly owned by Enbridge and MCN Energy. The Vector Pipeline would ship approximately 1 BCF/D from the Chicago area to Dawn, Ontario and the planned completion date is October 1, 2000. The Millennium Pipeline proposal plans to pick up gas at Dawn for delivery to New York City as well as the New England area. Other pipelines have also been proposed with the same objective of moving excess gas out of the Chicago market and into other markets. Significant projected demand growth along the East Coast has stimulated the numerous pipeline proposals to continue to move gas into this market area. ANR's Supply Link Pipeline proposal plans to move 750 MMCFD from Illinois to Ohio by November 1999. The Independence Pipeline, a joint venture between Williams Gas Pipeline, Transco, ANR and National Fuel will have capacity of 900 MMCFD with an interconnect to the Supply Link Pipeline and will offer shippers a choice of markets in Ohio and Western Pennsylvania. Completion of this pipeline is scheduled for November 2000.

Production from the Sable Island Offshore Energy Project will be shipped on the Maritimes & Northeast Pipeline (M&NE) into Dracut, Massachusetts where it will interconnect with the Tennessee Gas Pipeline. Pipeline capacity on the M&NE will be 530 MMCFD and is scheduled to begin shipping November 1999.

Gas flows into the Pacific Northwest will likely be affected by the large amount of Western Canada Sedimentary Basin (WCSB) supply moving into the U.S. Midwest market area in late 2000. The aforementioned load factors at both Kingsgate and Sumas for January 1999 are lower than historic January capacities for these export points, perhaps due to some offloading onto eastern flowing lines. The Kingsgate and Sumas prices are anticipated to be strong during times of high demand in the Pacific Northwest and California. Two pipeline projects have currently been proposed to provide additional capacity to Vancouver and the Pacific Northwest. Williams Gas Pipeline's Columbia Gorge Pipeline proposal involves expanding Northwest Pipeline's facilities from Stanfield, Oregon to Sumas, Washington. The expansion is planned in phases, with the first phase to be completed in November 1999 with capacity of 50 MMCFD. A second phase of the same capacity is planned for 2002.

The second project is the Southern Crossing Pipeline, proposed by BC Gas, which will run parallel to their existing inland pipeline. Planned capacity is 250 MMCFD and has been approved by the British Columbia Utilities Commission in May 1999 with the option of completing the new pipeline over the winter of 2000-2001 or the winter of 2001-2002.

The Canadian natural gas industry, like their U.S. counterparts, will be challenged to meet predictions of demand growth over the next few years. Although natural gas drilling did not decline as dramatically as in the U.S. during 1998, the Canadian industry is also experiencing low reserve to production ratios and steep initial decline rates. While we are confident this industry will continue to find reserves and grow production while maintaining a competitive cost structure, the supply/demand balance for the next few years is expected to be tight. Caution is required, however, in assuming that this will translate into long-term high prices. Demand will only continue to grow, particularly in the power generation sector, if natural gas prices remain competitive between supply basins and more importantly, between competing sources of feedstock, such as coal. While we believe the natural gas industry is entering an era of supply/demand balance due to just-in-time inventory management and a highly competitive marketplace, this does not automatically translate into continued long-term real growth of natural gas prices. The market will determine prices and the marginal cost supplier sets the price in that market. Gilbert Laustsen Jung has increased the near-term average Alberta natural gas prices relative to the April 1, 1999 forecast. This price forecast is slightly below current market

expectations due to our belief that the highly competitive nature of the industry will keep natural gas prices flat in the long-term.

NATURAL GAS LIQUIDS AND SULPHUR

As of the end of April 1999, U.S. propane inventories stood at an estimated 38.9 million barrels, a level that is now much closer to 1998 inventory levels. Inventories in the Midwest and Gulf Coast regions still remain slightly above their respective normal ranges for this time of year, while inventories in the East Coast continued within the normal range during this same period last year.

Spot prices for propane at Edmonton averaged approximately $CDN 11.70/BBL for the first five months of 1999, relative to $CDN 12.74/BBL for the same time period in 1998. Propane and butane prices experienced a strong recovery in May 1999 due to increasing petrochemical demand. The May 1999 propane price averaged $CDN 14.05/BBL versus CDN 9.28/BBL recorded in January 1999. Spot prices for normal butane at Edmonton averaged $CDN 16.25/BBL for May 1999, and started out the year at $CDN 9.87/BBL.

Gilbert Laustsen Jung has increased the propane and butane price forecast at Edmonton relative to the April 1, 1999 forecast due to the recovery in crude oil prices.

World sulphur trade recorded a strong performance in the first quarter of 1999 relative to the first quarter of 1998. Canada was the major shipper for the quarter with a nine percent increase from the first quarter of 1998. The increase in sales volume was mostly attributed to the U.S. market as offshore sales continue to be mostly flat. The offshore markets for Canadian sulphur have changed, however, as the first quarter of 1999 recorded large sulphur volumes being sold to China at the expense of the Mediterranean. Canadian sulphur producers are hopeful that the strong export performance to China will continue. Canadian production of sulphur for the first quarter of 1999 did not change significantly from the first quarter of 1998. The average Vancouver FOB sulphur price has increased slightly to be in the range of $US 27-35/tonne. At these export prices, Canadian producers continue to realize netback prices close to zero or possibly negative.

Gilbert Laustsen Jung has not revised the FOB Vancouver sulphur price forecast relative to the April 1, 1999 forecast.

THE OIL & GAS REPORT

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Volume 4 No. 8

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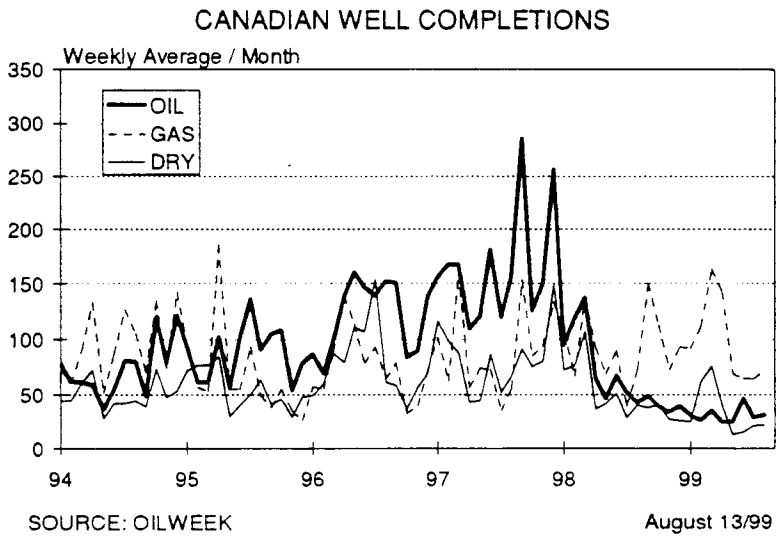
Drilling for Crude Oil and Natural Gas at a Slow Pace in Canada So Far This Year



In This Issue

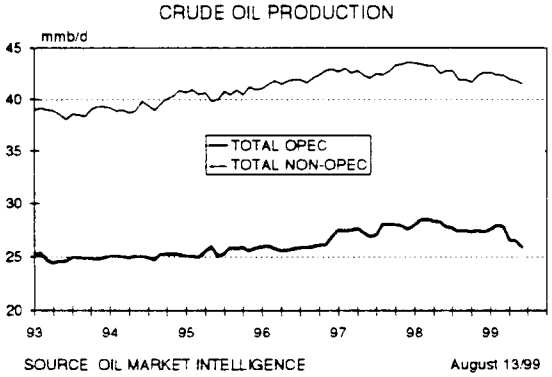
Stock Rating System: 5 = Most Attractive Selection Within Industry Group; 1 = Least Attractive Selection

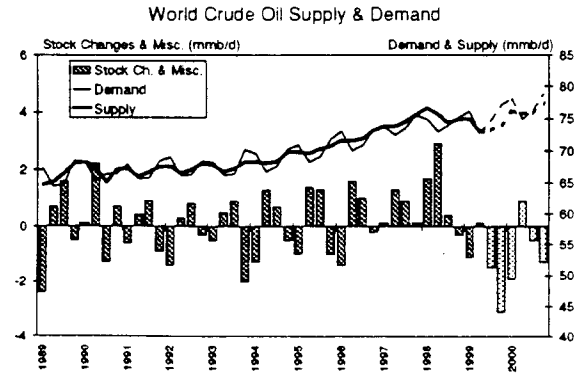
World Crude Oil Outlook

Crude Oil Price Will Reach US$25/b in Absence of OPEC Production Increases This Fall

PRODUCTION (mmb/d)	1997	1998	1999E	2000E	2001E
OPEC	29.9	30.7	29.3	31.2	32.6
OECD	22.1	21.9	21.4	21.9	22.5
Former USSR	7.2	7.3	7.4	7.2	7.3
China	3.2	3.2	3.2	3.1	3.1
Other Non-OPEC	10.4	10.6	10.9	11.3	11.9
Processing Gains	1.6	1.7	1.7	1.7	1.7
TOTAL	**74.4**	**75.4**	**73.8**	**76.4**	**79.1**
% Change	3.1	1.3	(2.2)	3.4	3.4
CONSUMPTION (mmb/d)					
OECD	46.7	46.9	47.7	48.7	49.7
Non-OECD	27.1	27.4	27.5	28.4	29.4
TOTAL	**73.8**	**74.3**	**75.2**	**77.1**	**79.1**
% Change	2.7	0.7	1.2	2.5	2.5
Change in Stock & Adj.	0.9	1.3	(1.4)	(0.7)	0.0

Source: IEA Oil Market Report and NB Forecasts





Crude oil production is in a modest recovery outside OPEC. OPEC production is down to about 26.0 million b/d, and non-OPEC production is expected to recover to 44.4 million b/d in Q3/99 versus 44.1 million b/d in Q3/98. The recent decision by Russia to cut exports of products to rebuild domestic inventories in anticipation of the winter demand is also positive for the price of crude oil.

Global production is estimated at 73.2 million b/d in Q3/99, with expectations of an increase to 74.1 million b/d in Q4/99 as a result of a recovery in production in the North Sea. OPEC production is estimated to be flat at 26.0 million b/d for the time being.

Inventories are estimated to decline by 1.5 million b/d in Q3/99, followed by an even more significant decline of 3.1 million b/d in Q4/99. Altogether, this represents a decline of about 400 million barrels. With excess inventories eliminated by Q4/99 and prospects of another decline of 3.9 million b/d in Q1/00, OPEC will likely have to increase production before year end.

The current demand forecast for Q3/99 is 74.7 million b/d, up 1.1% from Q3/98. Demand in Q4/99 is expected to be 77.2 million b/d, up 2.5% from Q4/98. Demand is in an accelerating recovery trend in Asia.

With prospects of a massive inventory decline for the future, we expect that OPEC will have to increase production by at least 2 million b/d by Q1/00. Any delay in the decision making process will result in an increase in prices beyond the level suggested by OPEC members at recent meetings. In the short term, the price of crude could easily reach US$25.00/b.

U.S. Crude Oil Outlook

Inventories in Line With Historical Averages

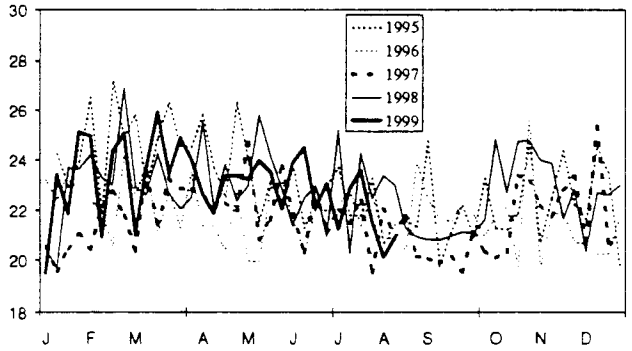
U.S. Oil Ending Stocks (mmb)	Aug 6/99	Aug 7/98	% Chg.
Crude Oil Stocks	323.1	344.7	(6.3)
Motor Gasoline Stocks	206.6	215.4	(4.1)
Light Fuel Stocks	139.1	144.4	(3.7)
Heavy Fuel Oil Stocks	42.6	38.5	10.7
Jet Fuel Oil Stocks	45.5	41.0	10.9

By the beginning of August 1999, crude oil inventories were down 6.3% year over year to 323.1 million barrels. This represented about 20.9 days of refinery throughput. Refineries were operating at 95.0% of capacity.

At 206.6 million barrels, motor gasoline inventories were down 4.1% year over year and represent approximately 23.6 days of consumption, in line with the historical average. U.S. consumption is estimated to have been up 2.5% in the first half of 1999. At 139.1 million barrels, middle distillate inventories were down 3.7% and represent 37.4 days of consumption, also in line with the historical average.

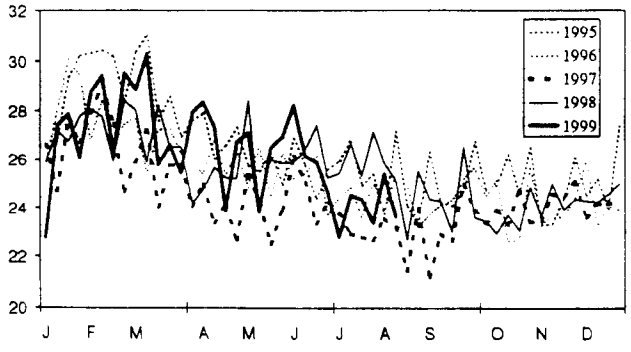
The 3-2-1 crack spread is in a strong recovery trend, reaching close to US$5.00/b.

US Crude Oil - Days of Inventories



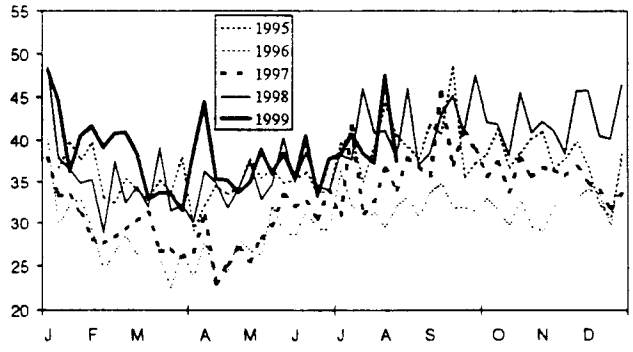
Source: American Petroleum Institute

US Motor Gasoline - Days of Inventories



Source: American Petroleum Institute

US Middle Distillate - Days of Inventories



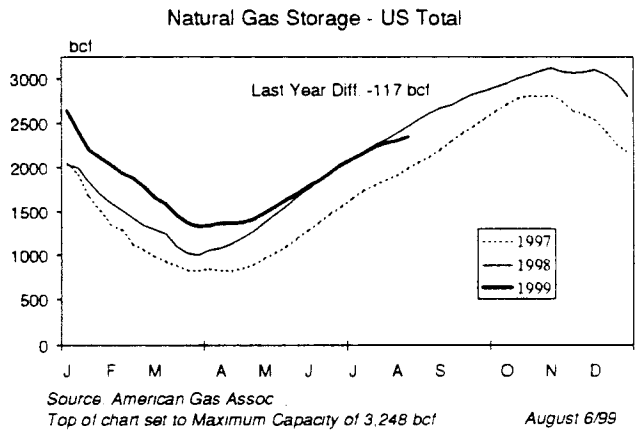
Source: American Petroleum Institute

North American Natural Gas Outlook — U.S.

A Favourable Inventory Outlook for This Winter

U.S. Natural Gas Storage (bcf)							
	Week Ended		Weekly	Previous	Yearly	% of Max.	Maximum
	Aug. 6/99	Jul. 30/99	% Chg.	Year	% Chg.	Cap. Used	Capacity
Producing Region	724	725	(0.1)	751	(3.6)	76	949
Consuming East	1,247	1,209	3.1	1,373	(9.2)	69	1,809
Consuming West	380	372	2.2	344	10.5	78	490
Total U.S.	**2,351**	**2,306**	**2.0**	**2,468**	**(4.7)**	**72**	**3,248**

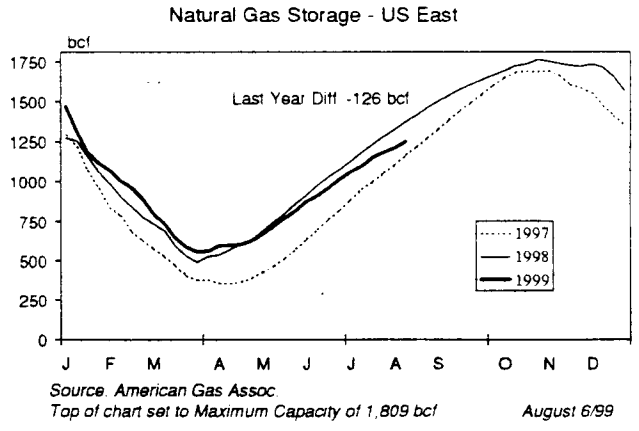
Inventories are building, but at a slow pace, reflecting increased demand this summer and reduced supply as drilling has been weak until recently. As of August 6, U.S. natural gas storage was 2,351 bcf, down 4.7% from last year. Storage is down 9.2% in the Consuming East region.



Source American Gas Assoc
Top of chart set to Maximum Capacity of 3,248 bcf *August 6/99*

The following table presents forecast storage levels at the beginning of the heating season, based on various injection assumptions for a period of eight weeks.

Injection Per Week (bcf)	Total Injection (bcf)	Total Gas in Storage at the Beginning of the Heating Season (bcf)	Percentage of Max. Capacity (%)
60	480	2,831	87.2
65	520	2,871	88.4
70	560	2,921	89.9



Source American Gas Assoc
Top of chart set to Maximum Capacity of 1,809 bcf *August 6/99*

Overall, inventories are about normal for this time of the year and should continue to be as the heating season starts in October. The drilling activity, stimulated by the high price level, has resumed in recent weeks. However, the impact of new production volume will not be seen before early 2000. As a result, prices should stay firm and increase during the heating season.

North American Natural Gas Outlook — Canada

Inventories Increasing at a Fast Pace

Canadian Natural Gas Storage (bcf)						
	Week Ended			Weekly	% of Max.	Maximum
	Aug. 6/99	Jul. 30/99	Change	% Chg.	Cap. Used	Capacity
East	179	172	6	3.5	71	252
West	213	205	9	4.2	77	278
Total Canada	**392**	**377**	**15**	**3.9**	**74**	**529**

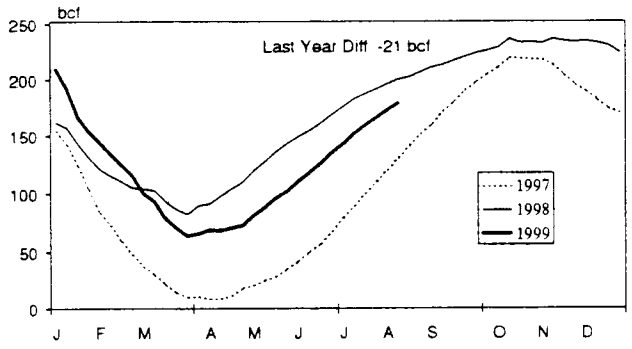
Inventories are building up at a rapid rate. Current inventories remain lower than last year in eastern Canada (71% of capacity) but higher than last year in western Canada (77% of capacity).

The following table shows forecast storage levels at the beginning of the heating season, based on various injection assumptions for a period of eight weeks.

Injection Per Week (bcf)	Total Injection (bcf)	Total Gas in Storage at the Beginning of the Heating Season (bcf)	Percentage of Max. Capacity (%)
8	64	256	86.2
9	72	464	87.7
10	80	472	89.2

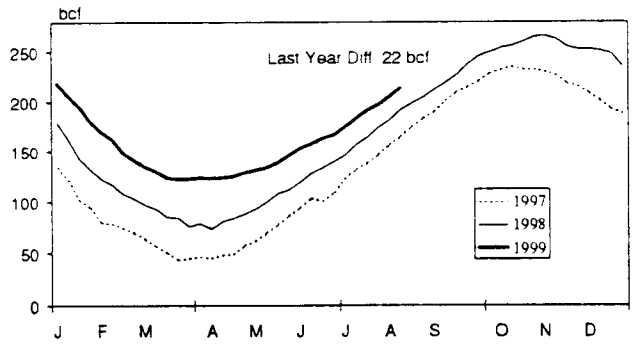
Natural gas prices have firmed up significantly in recent weeks, as a result of the strong demand south of the border and the slow drilling recovery so far this summer. Some weakness is likely this fall, but a normal or colder than normal heating season could bring the price to new highs on a spot basis. We remain optimistic on the price of natural gas this fall and winter.

Natural Gas Storage - Cdn East



Source Canadian Gas Assoc
Top of chart set to Maximum Capacity of 252 bcf *August 6/99*

Natural Gas Storage - Cdn West



Source: Canadian Gas Assoc.
Top of chart set to Maximum Capacity of 278 bcf *August 6/99*

Natural Gas Market in Canada

Some Improvement in Marketable Production, But a Tight Market Ahead

(mmcf/d)	May 1999	May 1998	% Chg.	January - May 1999	January - May 1998	% Chg.
Marketable Production (1)	15,455.6	14,684.3	5.3	15,984.2	15,837.1	0.9
Exports (2)	8,676.4	8,079.3	7.4	9,168.3	8,608.5	6.5
Canadian Sales (3)	4,998.9	4,671.6	7.0	7,835.7	7,344.7	6.7
Sum: Exports + Sales	13,675.3	12,750.8	7.3	17,004.0	15,953.1	6.6
[(2) + (3)] / (1) (%)	88.5	86.8	1.9	106.4	100.7	5.6

The level of marketable production increased by 5.3% in May 1999 versus May 1998; and increased by 0.9% for the first five months of 1999 compared with the same period last year. In absolute terms, the increases were 771.3 mmcf/d and 147.1 mmcf/d, respectively.

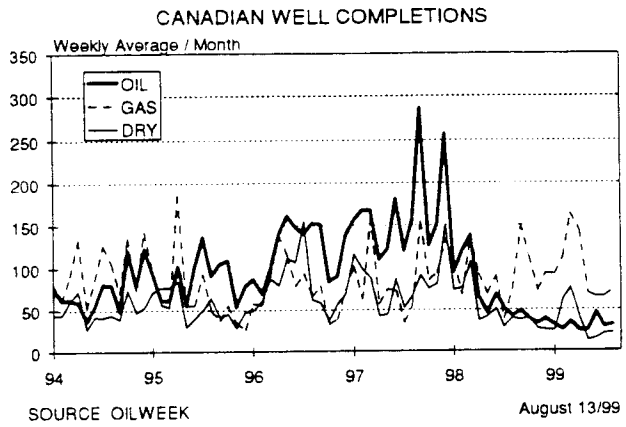
Exports were up 7.4% or 597.1 mmcf/d in May 1999, and up 6.5% or 559.8 mmcf/d for the first five months of 1999. Year-over-year Canadian sales were up 7.0% or 327.3 mmcf/d in May 1999, and increased by 6.7% or 491.0 mmcf/d for the first five months of 1999.

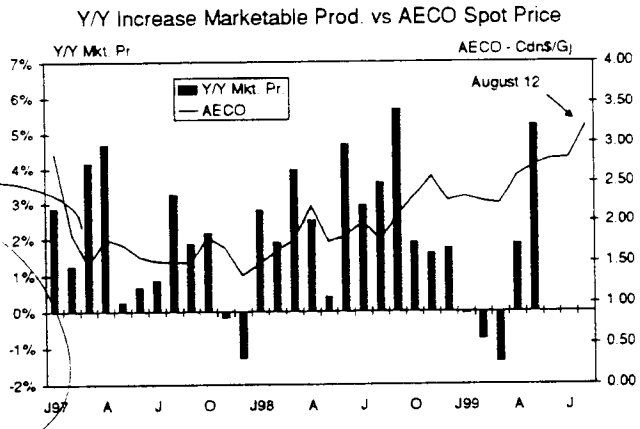
Year over year, exports and Canadian sales as a percentage of marketable production were up 1.9% in May and 5.6% for the first five months of 1999.

For the first 32 weeks of 1999, the number of natural gas wells drilled represented 60.7% of total wells drilled versus 37.9% in 1998. In absolute terms, the number of wells drilled increased by 18.3%. In the second week of August 1999, about 70.1% of all wells drilled were natural gas; 20.5% were crude oil and 9.4% were dry.

Drilling for crude oil is down 62.6% year to date. The absolute number of wells drilled is still low and we expect a turnaround in drilling in late Q3/99 and Q4/99. However, any short-term increase will have a limited impact on production over the next six months.

We continue to believe that there will not be enough production added before next winter, leading to a steady increase in the price of natural gas this year and in early 2000.

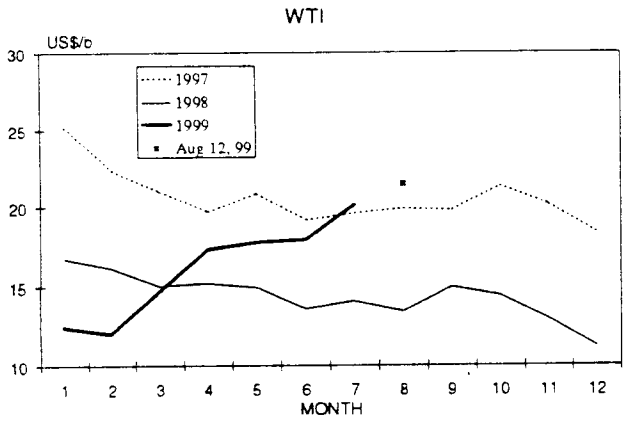


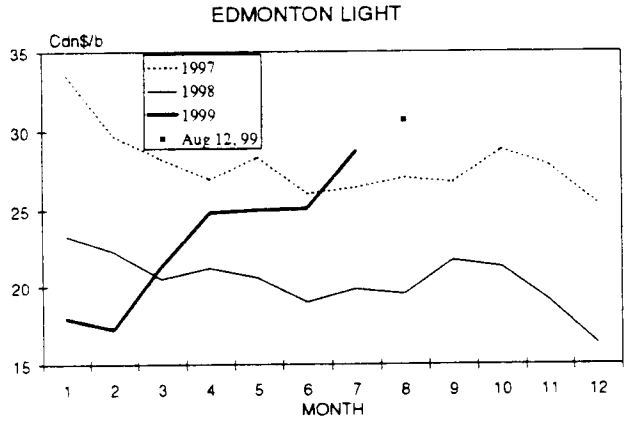


Commodity Prices

Natural Gas Price Forecast Increased; Crude Oil Should Follow

	WTI (US$ / b)	Avg Can$	Equivalent WTI (Can$ / b)	Edmonton Light (Can$ / b)	Differential (Can$ / b)	Wellhead Natural Gas (Can$ / mcf)
1995	18.41	1.3717	25.25	24.28	0.97	1.44
96Q1	19.76	1.3685	27.05	25.95	1.09	1.76
96Q2	21.78	1.3646	29.72	29.02	0.71	1.60
96Q3	22.35	1.3700	30.63	30.07	0.56	1.53
96Q4	24.72	1.3504	33.39	32.60	0.78	2.05
1996	22.16	1.3635	30.22	29.43	0.79	1.74
97Q1	22.88	1.3591	31.10	30.49	0.60	2.39
97Q2	19.92	1.3864	27.62	27.14	0.48	1.73
97Q3	19.77	1.3844	27.36	26.74	0.64	1.72
97Q4	19.87	1.4086	28.00	27.22	0.78	2.22
1997	20.60	1.3649	28.53	27.86	0.65	2.02
98Q1	15.96	1.4298	22.82	22.03	0.78	2.00
98Q2	14.58	1.4485	21.08	20.26	0.83	2.00
98Q3	14.15	1.5133	21.41	20.36	1.06	1.93
98Q4	12.85	1.5420	19.82	18.88	0.94	2.41
1998	14.36	1.4833	21.33	20.37	0.96	2.09
99Q1	13.09	1.5117	19.79	18.90	0.89	2.27
99Q2	17.64	1.4728	25.98	24.95	1.03	2.32E
July	20.10	1.4868	29.89	28.66	1.23	na
Aug 12	21.48	1.4843	31.88	30.68	1.20	na
Yr To Date	16.33	1.4917	24.36	23.31	1.05	na

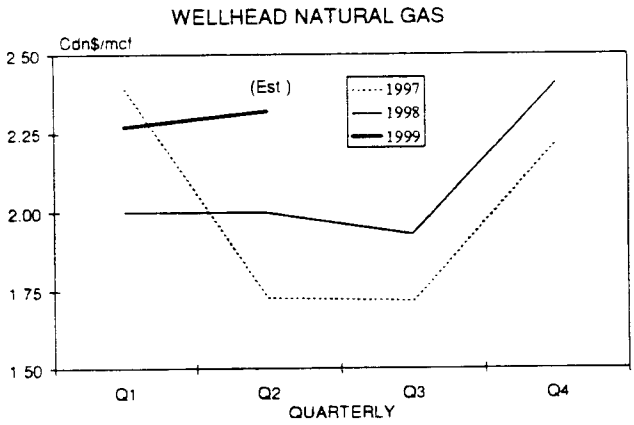




The WTI crude oil price surpassed the US$21.00/b mark as of mid-August, as inventories keep coming down. Demand is expected to be in a significant uptrend over the next 18 months.

For the time being we are maintaining our WTI crude oil price forecast at US$17.00/b for 1999 and US$19.00/b for 2000. Our C$/US$ exchange rate forecast is also unchanged at $0.68 and $0.70, respectively. The WTI/Edmonton light differential forecast continues to be $1.00/b for both years.

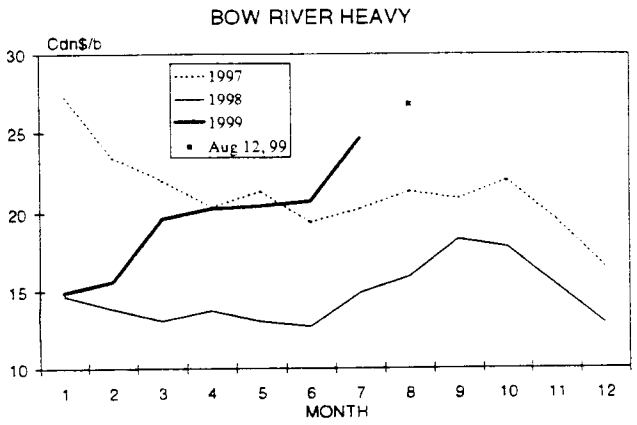
We are increasing our natural gas price forecast from $2.40/mcf to $2.50/mcf for 1999 and from $2.75/mcf to $3.00/mcf for 2000. Our forecast for the price of crude oil (WTI) could be increased further. Prices for both commodities will remain significantly higher year over year until Q1/00.

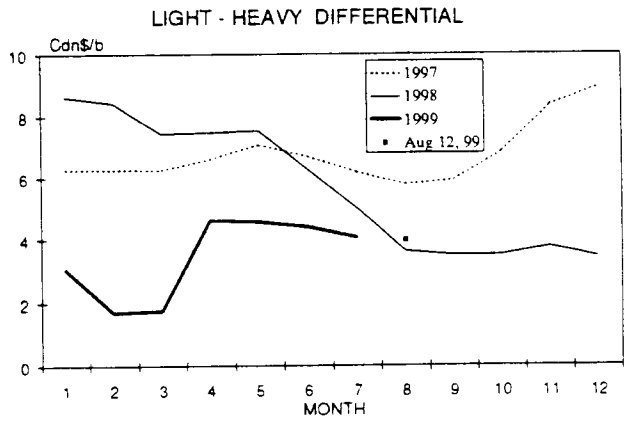


Commodity Prices

Light/Heavy Spread Has Narrowed Short Term

	Edmonton Light (Cdn$ / b)	Bow River Heavy (Cdn$ / b)	Differential (Cdn$ / b)
1995	24.28	20.83	3.45
95Q1	25.95	21.23	4.72
95Q2	29.02	25.58	3.44
95Q3	30.07	26.49	3.58
95Q4	32.60	27.13	5.48
1996	29.43	25.12	4.31
97Q1	30.49	24.23	6.26
97Q2	27.14	20.36	6.78
97Q3	26.74	20.77	5.97
97Q4	27.22	19.18	8.04
1997	27.88	21.12	6.76
98Q1	22.03	13.88	8.15
98Q2	20.26	13.17	7.09
98Q3	20.36	16.31	4.05
98Q4	18.88	15.32	3.56
1998	20.37	14.68	5.69
99Q1	18.90	16.72	2.18
99Q2	24.95	20.43	4.52
July	28.66	24.60	4.06
Aug 12	30.68	26.71	3.97
Yr To Date	23.31	19.82	3.49





Year to Date

The differential between light and heavy crude oil is currently at $3.97/b. Demand for heavy crude oil remains strong, but increases to export pipeline capacity will not come onstream before the fall. As a result, the differential could end up being higher than expected this year. For the time being, we are maintaining our light/heavy spread estimates at $3.50/b for this year and $5.00/b for the year 2000.

Commodity Price Forecast

	Crude Oil Price ($/bbl)					Natural Gas Corp. Avg. Reference Price C$/mcf
	WTI US$/b	CDN$ US$/C$	Diff. C$/b	Edm. Lt. C$/b	Bow River Heavy C$/b	
1995	18.42	0.729	0.99	24.28	20.82	1.44
1996	22.15	0.733	0.80	29.42	25.12	1.74
1997	20.61	0.722	0.64	27.90	21.14	2.02
1998	14.38	0.674	0.96	20.37	14.68	2.09
1999E	17.00	0.680	1.00	24.00	20.50	2.50
2000E	19.00	0.700	1.00	26.14	21.14	3.00

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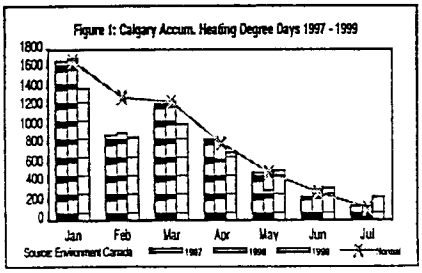
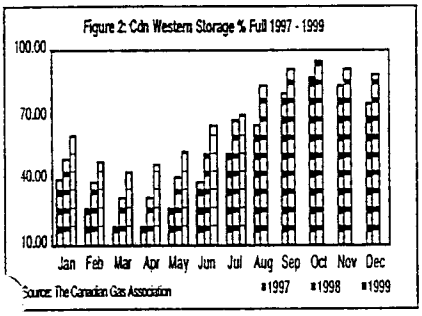
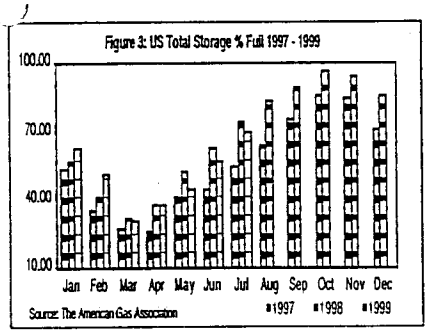
The Natural Gas Lookout™

Monthly Canadian and US Market Analysis and Price Forecasts

August 1999 Volume 2, Number 9







Inside this Month ...

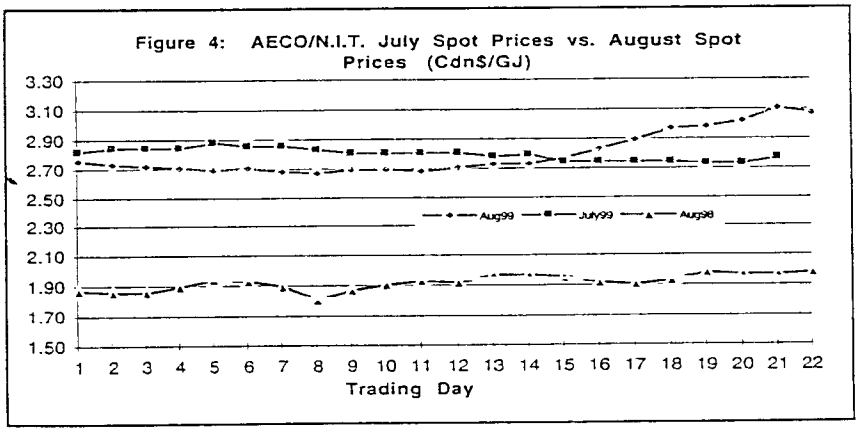
Market Summary

Canadian Market Overview

August Prices Flat in Alberta

August spot prices continued to increase relative to their July prices following continued strong forward prices for AECO/N.I.T. (see Figure 6, page 6) which tracked upward NYMEX Henry Hub August contract prices very closely. U.S. prices dramatically increased throughout July mainly due to above normal levels of cooling demand which fueled natural gas demand for power generation, particularly along the Westcoast and in the Northeast. As a result, Alberta prices increased slightly for August delivery but did not increase as much as other Canadian prices due to offsetting Western Canada weather and less maintenance outages compared to July. The only major July work outages that occurred in Alberta were the NOVA scheduled outages at their Clearwater #5 and Vetchland #1 compressor stations between July 12 and July 21.

August AECO/N.I.T. prices averaged $2.82/GJ representing only a 1 cent increase over July's average price of $2.81/GJ and up 88 cents over August 1998s average price of $1.94/GJ. Overall, 1999 prices are still maintaining significant strength over their 1998 levels due to continued expectation of inadequate supply for the 1999/00 heating season (see Figure 6, page 6 for forward price strength).



September Prices Forecast to Increase Alberta

Market sentiments for August reflect those of recent months. Lower drilling activity across North America continues to fuel supply concerns for the 1999/00 heating season. Coupling this fact with the anticipation of the Alliance Pipeline project late next year, forward prices continue to remain strong following projections of inadequate supply. As well, hot summer temperatures in the U.S. have increased cooling demand through power generation resulting in increased natural gas demand. As a result, according to TD Securities, as of August 4, AECO/N.I.T. forward prices for the balance of the injection season averaged $3.19/GJ; Nov/99-Mar/00 averaged $3.82/GJ; Nov/99-Oct/00 averaged $3.06/GJ. AECO/N.I.T. Forward prices have dramatically increased from prices quoted just one-month prior: the balance of the injection season averaged $2.75/GJ; Nov/99-Mar/00 averaged $3.06/GJ; Nov/99-Oct/00 averaged $2.82/GJ. In general, market prices over the short to medium term are expected to remain strong when compared to last year.

September AECO/N.I.T. prices are forecast to average $3.01/GJ representing a 19 cent

Table 1
AECO/N.I.T. Historical Prices (C$/GJ)

	1997	1998	1999
Jan	2.16	1.40	2.46
Feb	2.69	1.47	2.31
Mar	1.68	1.65	2.25
Apr	1.45	1.78	2.26
May	1.76	2.15	2.59
Jun	1.66	1.82	2.72
Jul	1.55	1.80	2.81
Aug	1.46	1.94	2.82
Sep	1.48	1.63	-
Oct	1.73	2.13	-
Nov	1.98	2.64	-
Dec	1.71	2.80	-
Winter	1.99	1.64	2.49
Summer	1.58	1.89	-
One-Year	1.78	1.93	-

Table 2
AECO/N.I.T. Forecast Scenarios (C$/GJ)

	Most Likely	High	Low
Sep-99	3.01	3.16	2.86
Oct-99	3.03	3.18	2.88
Nov-99	3.01	3.16	2.86
Dec-99	3.00	3.15	2.85
Jan-00	3.16	3.32	3.01
Feb-00	3.30	3.47	3.14
Mar-00	3.22	3.38	3.06
Apr-00	2.93	3.08	2.78
May-00	2.82	2.96	2.68
Jun-00	2.64	2.78	2.51
Jul-00	2.53	2.65	2.40
Aug-00	2.69	2.83	2.56
Sep-00	2.86	3.00	2.72
Oct-00	2.98	3.13	2.83
Nov-00	2.98	3.12	2.83
Dec-00	2.99	3.14	2.84
Jan-01	3.15	3.31	3.00
Feb-01	3.20	3.36	3.04
Mar-01	3.15	3.31	3.00
Apr-01	2.87	3.01	2.72
May-01	2.78	2.92	2.65
Jun-01	2.62	2.75	2.49
Jul-01	2.51	2.64	2.39
Aug-01	2.68	2.82	2.55
Win 99	2.42	2.42	2.42
Sum 99	2.75	2.79	2.71
Win 00	3.14	3.30	2.98
Sum 00	1.96	2.05	1.86
1998	1.93	1.93	1.93
1999	2.69	2.74	2.64

Table 3
Gulf Coast Historical Prices (US$/MMBtu)

	1997	1998	1999
Jan	4.14	2.21	1.79
Feb	2.90	2.04	1.83
Mar	1.67	2.20	1.66
Apr	1.77	2.30	1.88
May	2.14	2.29	2.35
Jun	2.30	2.02	2.26
Jul	2.10	2.35	2.29
Aug	2.13	1.93	2.60
Sep	2.54	1.63	-
Oct	3.17	2.06	-
Nov	3.29	2.00	-
Dec	2.47	2.12	-
Winter	3.05	2.44	1.88
Summer	2.31	2.08	-
One-Year	2.55	2.10	-

Table 4
Gulf Coast Forecast Scenarios (US$/MMBtu)

	Most Likely	High	Low
Sep-99	2.56	2.64	2.48
Oct-99	2.62	2.69	2.54
Nov-99	2.72	2.80	2.64
Dec-99	2.87	2.96	2.79
Jan-00	2.93	3.01	2.84
Feb-00	2.87	2.96	2.79
Mar-00	2.77	2.85	2.69
Apr-00	2.67	2.75	2.59
May-00	2.56	2.64	2.48
Jun-00	2.41	2.48	2.33
Jul-00	2.30	2.38	2.23
Aug-00	2.32	2.40	2.25
Sep-00	2.32	2.40	2.25
Oct-00	2.32	2.40	2.25
Nov-00	2.32	2.40	2.25
Dec-00	2.36	2.43	2.28
Jan-01	2.51	2.59	2.43
Feb-01	2.67	2.75	2.59
Mar-01	2.72	2.80	2.64
Apr-01	2.63	2.70	2.55
May-01	2.52	2.60	2.44
Jun-01	2.41	2.48	2.33
Jul-01	2.38	2.45	2.30
Aug-01	2.38	2.45	2.30
Win 99	1.86	1.86	1.86
Sum 99	2.37	2.39	2.34
Win 00	2.83	2.92	2.75
Sum 00	1.67	1.72	1.62
1998	2.10	2.10	2.10
1999	2.29	2.31	2.26

increase from their August average price of $2.82/GJ and up 38 cents from September 1998s average price of $1.63/GJ.

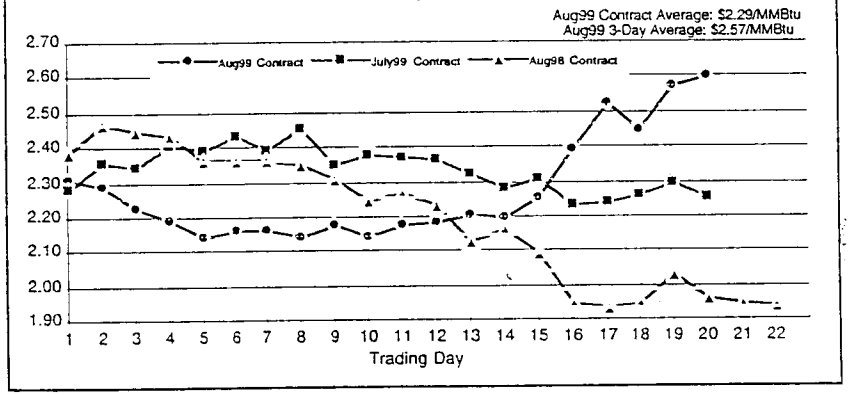
U.S. Market Overview

August Gulf Coast Prices Post Strength due to Hot Temperatures

August prices across the U.S. continued to increase over their July prices following above normal temperatures mainly during the last 10 days of July. Above normal temperatures, predominantly in the New England (July cooling degree day, CDD, totaled 256) and the Middle Atlantic (July CDD totaled 258) regions were enough to raise cooling demand in these census populated areas. Above normal summer temperatures put significant pressure on natural gas demand for power generation. Hot temperatures, plant outages, and increased fund buying on the NYMEX caused August spot prices to display continual upward pressure throughout July.

August Gulf Coast prices averaged $2.60/MMBtu representing a 31 cent increase from their July average price of $2.29/MMBtu and up 67 cents from August 1998s average price of $1.93/MMBtu.

Figure 5: NYMEX Henry Hub July Contract Prices vs. August Contract Prices (US$/MMBtu)



September Prices Forecast to Slightly Decrease

The NYMEX Henry Hub August contract closed at $2.60/MMBtu and September contract prices have been maintaining similar strength. Spot prices for the remainder of the injection season should continue to post relative strength over last year's price levels due to the following:

(i) Drilling statistics continue to show relative weakness when compared to last year's numbers.

(ii) The likelihood of more unplanned outages is still high as many generating plants continued to be pushed by above normal temperatures.

(iii) According to the National Climatic Data Center, again (as compared to last month's forecast) with the exception of the central parts of the Midwest, virtually all of the U.S. is forecast to experience above normal temperatures.

Prices still have an even more volatile upside given that the hurricane season has just begun. Typically most accumulations that result in hurricanes begin in late July and could last until mid-September. Therefore, prices (especially in the Gulf Coast) could experience significant upward price spikes over the next several weeks. Conversely, if no hurricanes were to occur and summer temperatures remain normal, prices should flatten out over the next several weeks.

However, September Gulf Coast prices are forecast to decrease slightly with price maintaining relative strength over last year's levels. September Gulf Coast prices are forecast to average $2.56/MMBtu representing only a 4 cent decrease from August's average price of $2.60/MMBtu but up 93 cents from September 1998s average price of $1.63/MMBtu.

Table 5: One-Month Spot Price Forecasts, Most Likely Case*

Month	Alberta (C$/GJ)			B.C. Stn 2	Export (US$/MMBtu)				U.S. (US$/MMBtu)			(US$/MMBtu)	
	Field Price	AECO/NIT	Empress	(C$/GJ)	Sumas	Kingsgate	Ventura	Niagara	Gulf Coast	Rockies	California	KCBT Waha 3-day	NYMEX HH 3-day
Actual Series													
Sep-98	1.56	1.63	1.66	1.98	1.46	1.42	1.55	1.69	1.63	1.57	1.99	1.67	1.75
Oct-98	1.86	2.13	2.40	2.31	1.67	1.61	1.91	2.08	2.06	1.65	2.07	1.98	2.13
Nov-98	2.19	2.64	2.80	2.77	2.15	1.98	2.02	2.22	2.00	1.99	2.32	2.03	2.13
Dec-98	2.22	2.80	2.80	2.82	2.14	1.96	2.13	2.45	2.12	2.00	2.30	2.07	2.14
Jan-99	2.04	2.46	2.53	2.87	3.02	1.97	1.85	1.91	1.79	1.75	2.06	1.78	1.81
Feb-99	1.90	2.31	2.33	2.33	1.77	1.60	1.80	1.99	1.83	1.63	1.82	1.69	1.75
Mar-99	1.80	2.25	2.25	2.00	1.50	1.50	1.63	1.77	1.66	1.51	1.68	1.62	1.69
Apr-99	1.90	2.26	2.37	2.04	1.52	1.50	1.71	2.06	1.88	1.54	1.78	1.74	1.85
May-99	2.21	2.59	2.72	2.63	1.95	2.03	2.20	2.35	2.35	1.99	2.21	2.26	2.33
Jun-99	2.10	2.72	2.76	2.57	1.90	2.01	2.12	2.32	2.26	1.94	2.21	2.12	2.20
Jul-99	2.02	2.81	2.76	2.62	1.95	2.02	2.18	2.33	2.29	1.99	2.38	2.19	2.27
Aug-99	2.02	2.82	2.93	3.03	2.20	2.14	2.51	2.70	2.60	2.17	2.59	2.50	2.57
Forecast Series												*Projected Series***	
Sep-99	2.19	3.01	3.06	2.72	2.10	2.12	2.42	2.74	2.56	2.10	2.35	2.40	2.55
Oct-99	2.21	3.03	3.08	2.75	2.15	2.17	2.47	2.80	2.62	2.02	2.38	2.45	2.60
Nov-99	2.25	3.01	3.11	2.75	2.20	2.22	2.53	2.91	2.72	2.08	2.44	2.50	2.70
Dec-99	2.30	3.00	3.13	2.79	2.30	2.32	2.64	3.08	2.87	2.19	2.54	2.60	2.85
Jan-00	2.34	3.16	3.29	2.87	2.25	2.27	2.58	3.13	2.93	2.17	2.53	2.55	2.90
Feb-00	2.35	3.30	3.43	2.93	2.21	2.23	2.54	3.08	2.87	2.13	2.49	2.51	2.85
Mar-00	2.34	3.22	3.35	2.92	2.31	2.33	2.54	2.97	2.77	2.12	2.47	2.51	2.75
Apr-00	2.24	2.93	3.06	2.74	2.27	2.29	2.50	2.85	2.67	2.08	2.44	2.47	2.65
May-00	2.16	2.82	2.95	2.62	2.14	2.16	2.35	2.74	2.56	1.94	2.31	2.34	2.55
Jun-00	2.06	2.64	2.77	2.48	2.04	2.06	2.25	2.58	2.41	1.80	2.19	2.24	2.40
Jul-00	2.00	2.53	2.66	2.38	1.98	2.00	2.18	2.47	2.30	1.70	2.10	2.18	2.30
Aug-00	2.08	2.69	2.82	2.53	2.10	2.12	2.20	2.49	2.32	1.69	2.09	2.20	2.32
Sep-00	2.07	2.86	2.99	2.57	1.95	1.97	2.04	2.49	2.32	1.55	1.96	2.21	2.32
Oct-00	2.10	2.98	3.11	2.64	1.95	1.97	2.04	2.49	2.32	1.50	1.92	2.20	2.32
Nov-00	2.10	2.98	3.11	2.64	1.95	1.97	2.04	2.49	2.32	1.49	1.91	2.21	2.32
Dec-00	2.12	2.99	3.12	2.65	1.98	2.00	2.07	2.52	2.36	1.51	1.93	2.24	2.35
Jan-01	2.22	3.15	3.28	2.80	2.11	2.13	2.21	2.69	2.51	1.64	2.06	2.37	2.50
Feb-01	2.29	3.20	3.33	2.88	2.24	2.26	2.36	2.85	2.67	1.81	2.21	2.50	2.65
Mar-01	2.30	3.15	3.28	2.87	2.29	2.31	2.40	2.91	2.72	1.90	2.29	2.55	2.70
Apr-01	2.19	2.87	3.00	2.67	2.21	2.23	2.32	2.81	2.63	1.86	2.24	2.48	2.61
May-01	2.13	2.78	2.91	2.59	2.12	2.14	2.22	2.70	2.52	1.76	2.15	2.37	2.51
Jun-01	2.04	2.62	2.75	2.46	2.02	2.04	2.12	2.58	2.41	1.63	2.04	2.27	2.40
Jul-01	2.00	2.51	2.64	2.38	2.00	2.02	2.09	2.54	2.38	1.57	1.98	2.27	2.37
Aug-01	2.05	2.68	2.81	2.48	2.00	2.02	2.09	2.54	2.38	1.55	1.97	2.28	2.37
Avg. Season^													
Winter 1999	1.91	2.42	2.46	2.41	1.99	1.71	1.82	2.04	1.86	1.69	1.93	1.78	1.85
Summer 1999	2.09	2.75	2.81	2.62	1.97	2.00	2.23	2.47	2.37	1.96	2.27	2.24	2.34
Winter 2000	2.32	3.14	3.26	2.85	2.25	2.27	2.56	3.03	2.83	2.14	2.49	2.53	2.81
Summer 2000	1.47	1.96	2.05	1.80	1.43	1.45	1.53	1.79	1.67	1.18	1.46	1.58	1.67
Avg. Annual													
1997	1.83	1.78	1.87	1.78	1.71	1.75	2.48	2.88	2.55	2.01	2.50	2.44	2.63
1998	1.93	1.93	2.12	2.03	1.62	1.64	2.02	2.24	2.10	1.80	2.21	2.05	2.14
1999	2.08	2.69	2.75	2.59	2.05	1.97	2.17	2.41	2.29	1.91	2.20	2.15	2.26
2000	2.16	2.93	3.06	2.66	2.09	2.11	2.28	2.69	2.51	1.81	2.19	2.32	2.50
2001	2.05	2.90	3.02	2.95	1.59	1.61	2.10	2.55	2.39	1.63	2.03	2.10	2.38
2002	2.03	2.88	3.00	2.93	1.49	1.47	2.14	2.60	2.43	1.61	2.02	2.14	2.42

* Assumes normal storage and Southern Alberta Heating Degree Days.

** Calculated average based on most current futures prices posted by NYMEX and KCBT and internal & external projections.

^ Summer term April to October. Winter term November to March.

Feature Article:
Canadian Natural Gas: Review of 1998 & Outlook to 2005

The article below summarizes the key points contained in the *Canadian Natural Gas: Review of 1998 & Outlook to 2005* produced by the Natural Gas Division, Energy Resources Branch, Energy Sector, Natural Resources Canada. For further information regarding the content of the highlights below, contact John Foran at 613-992-0287.

1998 In Review

Entering 1998, the outlook for North American oil and gas producers was promising. Prices were fairly high; natural gas was at $2.58/MMBtu (December NYMEX close), and crude oil was $18.30/barrel (West Texas Intermediate). While the 1997/98 winter had been a warmer than normal "El Nino" event, the upcoming winter was predicted to be a colder "La Nina" winter.

Gas demand was forecast to rise by 2% per year, mainly due to growing demand for gas for electric power generation. Gas prices were expected to remain strong, and gas-directed drilling was high as a result. In Canada, natural gas prices, at $1.24/MMBtu, were still much lower than NYMEX prices, but it was widely expected that new export pipeline capacity would narrow the price spread.

By the end of 1998, only the last prediction - of a narrowing Canada-US price differential - had materialized. Events combined to bring lower prices, lower demand, and lower gas drilling in 1998 than in 1997.

The first major event was the loss of over 500 Bcf of heating load, caused by another warm winter. Compounding this was marked drop in industrial demand. US industrial demand fell 81 Bcf, while Canadian industrial demand fell 87 Bcf. In total, US gas demand fell by 683 Bcf, while Canadian demand fell by 192 Bcf.

Another key event in 1998 was the fall in world crude prices, and the dawning realization that they would remain low for some time. West Texas Intermediate (WTI) tested the $10/bbl level but averaged $14.40/bbl, 30% less than in 1997.

The crude oil price collapse had several effects: petroleum products became more competitive with gas in certain industrial markets, reducing gas demand; North American gas prices were dragged down; and cash flows were reduced for natural gas producers (most of whom have considerable oil production), causing reduced 1998 gas drilling and development activity.

A major background factor in gas markets in 1998 was the buildup of wellhead productive capacity that had occurred over 1996-98, particularly in the US Gulf Coast. High levels of gas drilling from 1996 through the first half of 1998 created wellhead capacity that was surplus to market needs.

Storage inventories swelled to reflect weak demand and production over capacity. US gas in storage by January 1st, 1999 was 2,645 Bcf, 587 Bcf higher than the previous year. Canadian storage volumes also swelled, reaching 427 Bcf on January 1st, 1999, compared to 341 Bcf a year previous.

Surplus gas, weak demand, high storage levels, and low oil prices pulled US gas prices down in 1998. Average NYMEX gas prices in 1998 were 19% lower than in 1997. While the peak NYMEX settlement price in 1997 (in January) was $4.00/MMBtu, the 1998 peak, (in July) was only $2.36/MMBtu.

With weaker prices, US gas drilling fell dramatically. By the end of 1998, Gulf offshore gas drilling was down 36% from peak levels reached in 1997. As in other periods of weak gas prices and low drilling, production was flat or falling in the high-cost areas of the US Gulf Coast and Midcontinent (rising 1 Bcf and falling 132 Bcf, respectively), while production in the low-cost Rockies and Western Canada areas increased by 172 and 110 Bcf, respectively.

Canadian gas prices (i.e. the AECO spot price) entered 1998 at $1.24/MMBtu (Cdn$1.68 per Gigajoule), which was less than half of the December 1997 NYMEX price. This changed in late 1998 with the completion of the 690 Mmcf/d expansion of the Northern Border pipeline and the 320 Mmcf/d expansion of TransCanada PipeLines Ltd. (TCPL).

The Canadian gas market situation switched from one of a known surplus to a perception that domestic gas buyers would have to compete with US buyers for limited Canadian supplies. Canadian gas prices began to be determined in the US, in US dollar terms, rather than in Canada.

The NYMEX/AECO gas price differential reflected this, narrowing dramatically over the year. In Decem-

ber 1997, the AECO price was $1.34 lower than the NYMEX price. By December 1998, AECO was only $0.23 lower than NYMEX.

Ordinarily, this would have implied a sharp increase in Canadian prices, but the "re-linking" of Canadian and US gas prices occurred at a time of falling US prices. The net effect was that Canadian prices were only 2% higher in 1998 than in 1997 on a US$/MMBtu basis. The weakening Canadian dollar however, meant that in $Cdn/GJ (the basis for most domestic gas purchases), Canadian prices rose 9%, from Cdn$1.75 to Cdn$1.92.

The tightening of gas supply in Alberta in late 1998 may have been as much a matter of perception as reality. In 1998, Alberta gas storage was full, and gas supplies were sufficient to meet domestic demand and fill export pipeline capacity. For example, despite the large increase in Northern Border's capacity, the pipeline's load factor has remained at about 97% since its expansion.

In addition, measurements of gas well productive capacity by the Alberta Energy & Utilities Board show that the large margin between productive capacity and demand is being maintained.

Unlike their US counterparts, Canadian producers continued to drill large numbers of gas wells in 1998. Total Canadian gas completions in 1998 were 4,600 wells, similar to 1997. That number would probably have been higher except that producer cash flows fell due to lower oil prices, which put a drag on gas activity.

In 1998, Canadian gas export volumes to the US rose 6% or 188 Bcf. Although export pipeline capacity increased by 1 Bcf/day in 1998, this capacity did not come on-line until late in the year. Exports increased primarily by using existing capacity throughout the year at even higher load factors than in 1997. Exports now represent 54% of Canadian gas production, the highest percentage in history.

Although domestic Canadian gas prices rose in 1998 to meet US price levels, the US price decline meant falling prices and netbacks for Canadian exporters. Average export prices at the international border fell to $1.91/MMBtu, a drop of 10% from 1997. Netbacks likewise fell 10% to $1.58/MMBtu.

On average in 1998, export netbacks remained well above netbacks for gas sales within Canada, which were $1.26/MMBtu. This year, the US Northeast provided the highest netbacks to Canadian producers, averaging $1.67/MMBtu. However, with the narrowing of the Canada-US price differential, by November 1998 domestic netbacks reached parity with export netbacks.

Overall, the impact of higher volumes and rising domestic prices overwhelmed the impact of lower export prices, and plant gate revenues to Canadian producers rose slightly to Cdn$12.3 billion in 1998, from $12.1 billion in 1997.

Near Term Outlook (to 2000)

In the near term, a rapid change in market conditions is possible. The recent lows in US oil and gas prices have drastically reduced gas drilling and excess productive capacity. US gas prices are now vulnerable to a sharp upward shift. A return to normal winter weather would add about 180 Bcf to North American demand — colder than normal weather would add even more. Finally, increases in world oil prices (which appear to be happening) could lead to certain industrial consumers switching back to gas.

This price spike scenario could be intensified if US gas storage operator decide to fill storage to lower levels than last year. Operators were stung last year by receiving prices for gas withdrawn from storage that were lower than original purchase prices.

Medium Term Outlook (to 2005)

Our medium term outlook (to 2005) has changed only slightly from last year. Our working hypothesis — shared by many in the gas industry — is that demand will continue to rise by about 2% per year, driven mainly by increases in the Utility Electric Generation (UEG) and industrial sectors. The largest increases in annual demand will occur in the US Gulf Coast, Canada, US Northeast, Midwest, South Atlantic, and West.

Most of the additional supply is expected to come from three areas: the Gulf Coast (annual production rising 1,858 Bcf over the 1998-2005 period), Canada (increasing 1,553 Bcf), and the Rockies (increasing 780 Bcf). Regarding gas flows along pipelines, our base scenario is as follows:

Increased **Rockies** production will satisfy most incremental demand in the US West (520 Bcf) and in the Rockies itself (166 Bcf). Canadian pipeline capacity to the US West is already relatively full, and no new ca-

continued on page 12...

Table 6
Station 2 Historical Prices (C$/GJ)

	1997	1998	1999
Jan	2.45	1.45	2.87
Feb	2.65	1.60	2.29
Mar	1.33	1.57	2.00
Apr	1.41	1.88	2.04
May	1.70	2.17	2.63
Jun	1.59	1.79	2.57
Jul	1.54	1.95	2.62
Aug	1.37	2.09	3.03
Sep	1.51	1.98	-
Oct	1.80	2.31	-
Nov	2.31	2.77	-
Dec	1.68	2.82	-
Winter	2.35	1.72	2.56
Summer	1.56	2.03	-
One-Year	1.78	2.03	-

Table 7
Station 2 Forecast Scenarios (C$/GJ)

	Most Likely	High	Low
Sep-99	2.72	2.90	2.65
Oct-99	2.75	2.84	2.66
Nov-99	2.75	2.84	2.66
Dec-99	2.79	2.88	2.70
Jan-00	2.87	2.96	2.78
Feb-00	2.93	3.02	2.84
Mar-00	2.92	3.01	2.83
Apr-00	2.74	2.83	2.65
May-00	2.62	2.71	2.53
Jun-00	2.48	2.57	2.39
Jul-00	2.38	2.47	2.29
Aug-00	2.53	2.62	2.44
Sep-00	2.57	2.66	2.48
Oct-00	2.64	2.73	2.55
Nov-00	2.64	2.73	2.55
Dec-00	2.65	2.74	2.56
Jan-01	2.80	2.89	2.71
Feb-01	2.88	2.97	2.79
Mar-01	2.87	2.96	2.78
Apr-01	2.67	2.76	2.58
May-01	2.59	2.68	2.50
Jun-01	2.46	2.55	2.37
Jul-01	2.38	2.47	2.29
Aug-01	2.48	2.57	2.39
Win 99	2.41	2.41	2.41
Sum 99	2.62	2.66	2.60
Win 00	2.85	2.94	2.76
Sum 00	1.80	1.86	1.74
1998	2.03	2.03	2.03
1999	2.59	2.63	2.56

Table 8
Sumas Historical Prices (US$/MMBtu)

	1997	1998	1999
Jan	4.10	1.85	3.02
Feb	2.32	1.46	1.77
Mar	1.06	1.16	1.50
Apr	1.13	1.41	1.52
May	1.34	1.70	1.95
Jun	1.32	1.39	1.90
Jul	1.23	1.44	1.95
Aug	1.09	1.56	2.20
Sep	1.19	1.46	-
Oct	1.51	1.67	-
Nov	2.86	2.15	-
Dec	1.40	2.14	-
Winter	2.60	1.75	2.12
Summer	1.26	1.52	-
One-Year	1.71	1.62	-

Table 9
Sumas Forecast Scenarios (US$/MMBtu)

	Most Likely	High	Low
Sep-99	2.10	2.19	2.01
Oct-99	2.15	2.24	2.06
Nov-99	2.20	2.29	2.11
Dec-99	2.30	2.39	2.21
Jan-00	2.25	2.34	2.16
Feb-00	2.21	2.30	2.12
Mar-00	2.31	2.40	2.22
Apr-00	2.27	2.36	2.18
May-00	2.14	2.23	2.05
Jun-00	2.04	2.13	1.95
Jul-00	1.98	2.07	1.89
Aug-00	2.10	2.19	2.01
Sep-00	1.95	2.04	1.86
Oct-00	1.95	2.04	1.86
Nov-00	1.95	2.04	1.86
Dec-00	1.98	2.07	1.89
Jan-01	2.11	2.20	2.02
Feb-01	2.24	2.33	2.15
Mar-01	2.29	2.38	2.20
Apr-01	2.21	2.30	2.12
May-01	2.12	2.21	2.03
Jun-01	2.02	2.11	1.93
Jul-01	2.00	2.09	1.91
Aug-01	2.00	2.09	1.91
Win 99	1.99	1.99	1.99
Sum 99	1.97	1.99	1.94
Win 00	2.25	2.34	2.16
Sum 00	1.43	1.50	1.37
1998	1.62	1.62	1.62
1999	2.05	2.08	2.02

Canadian Market Analysis

August Prices Flat in Alberta and Increase Significantly

August spot prices continued to increase relative to their July prices following continued strong forward prices for AECO/N.I.T. and Sumas (see Figure 6, page 6 which tracked upward NYMEX Henry Hub August contract prices very closely. U.S. prices dramatically increased throughout July mainly due to above normal levels of cooling demand which fueled natural gas demand for power generation, particularly along the Westcoast and in the Northeast. As a result, Alberta prices increased slightly for August delivery but did not increase as much as other Canadian prices due to offsetting Western Canada weather and less maintenance outages compared to July. The only major July work outages that occurred in Alberta were the NOVA scheduled outages at their Clearwater #5 and Vetchland #1 compressor stations between July 12 and July 21.

August AECO/N.I.T. prices averaged $2.82/GJ representing only a 1 cent increase over July's average price of $2.81/GJ and up 88 cents over August 1998s average price of $1.94/GJ. Overall, 1999 prices are still maintaining significant strength over their 1998 levels due to continued expectation of inadequate supply for the 1999/00 heating season (see Figure 6, page 6 for forward price strength).

Figure 6: TD Securities Energy Risk Management

3-Aug-99	NATURAL GAS SWAP PRICES					
	SWAP PRICE C$/GJ				FIXED PRICE SWAP US$/MMBtu	
Term	AECO		Empress		Sumas	
	Bid	Offer	Bid	Offer	Bid	Offer
Sep/99-Mar/00	3.120	3.145	3.130	3.175	2.200	2.220
Nov/99-Mar/00	3.335	3.355	3.415	3.465	2.595	2.615
Apr/00-Oct/00	2.820	2.840	2.890	2.930	1.960	1.980
Nov/99-Oct/00	3.030	3.055	3.120	3.165	2.225	2.245
Nov/00-Oct/01	3.025	3.050	3.135	3.180	2.145	2.165
Nov/01-Oct/02	3.045	3.090	3.165	3.240		

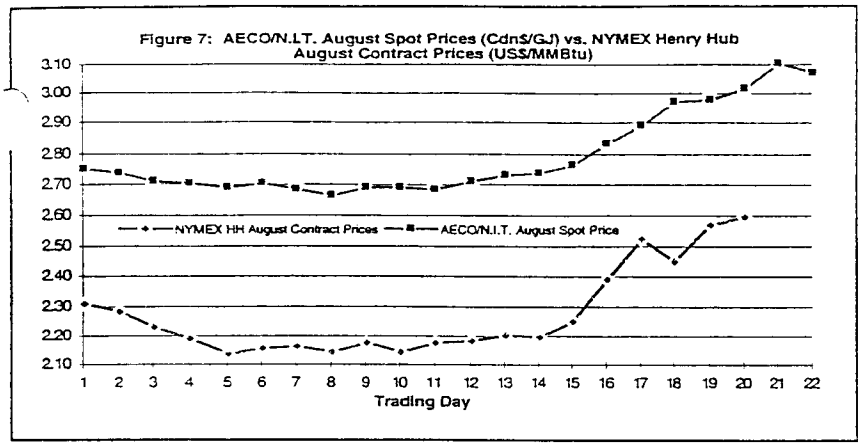
August Empress prices averaged $2.93/GJ posting a 17 cent increase over their July average price of $2.76/GJ and were up 90 cents over their August 1998s average price of $2.03/GJ. Higher demand at the Eastern gate due to power generation demand in Eastern Canada and the Northeastern U.S. coupled with the scheduled outage at the Crawling Valley compressor station that reduced capacity flow to 9.159 Bcf/d compared to its normal level of 9.258 Bcf/d caused Empress spot prices to jump higher.

The average Empress-AECO/N.I.T. one-month differential as reported in the *Canadian Gas Price Reporter* for July trading was 1.91 cents/GJ and fell to 1.64 cents/GJ for late August trading. In general, the differential has been decreasing since the early spring — the April differential was 8.02 cents/GJ.

August Station 2 prices averaged $3.03/GJ representing a 41 cent increase from July's average price of $2.62/GJ and up 94 cents from August 1998s average price of $2.09/GJ. August Station 2 prices dramatically increased due to higher Pacific Northwest prices at Sumas and Kingsgate, but mainly received upward pressure from an announced plant turnaround at the Pine Ridge gas plant, located in B.C., that is scheduled to take place beginning on August 25 and lasting until September 26. Curtailments at the 400 Mcf/d plant are expected to range from 20 to 40% during the 33-day outage.

August Sumas prices averaged $2.20/MMBtu representing a 25 cent increase over their July average price of $1.95/MMBtu and up 64 cents from their August 1998 average price of $1.56/MMBtu. Similarly, August Kingsgate prices averaged $2.14/MMBtu, up 12 cent from July's average price of $2.02/MMBtu and up 55 cents from August 1998s average price of $1.59/MMBtu. Demand for natural gas in the Pacific Northwest was noticeably higher last month due to significant cooling demand.

Niagara spot prices for August delivery averaged $2.70/MMBtu representing a 37 cent increase over their July average price of $2.33/MMBtu and up 75 cents from



August 1998s average price of $1.95/MMBtu. Eastern Canadian export prices traded higher following stronger Gulf Coast prices.

September Prices Forecast to Increase Alberta and Remain Flat Elsewhere Except at Station 2

Market sentiments for August reflect those of recent months. Lower drilling activity across North America continues to fuel supply concerns for the 1999/00 heating season. Coupling this fact with the anticipation of the Alliance Pipeline project late next year, forward prices continue to remain strong following projections of inadequate supply. As well, hot summer temperatures in the U.S. have increased cooling demand through power generation resulting in increased natural gas demand. As a result, according to TD Securities, as of August 4, AECO/N.I.T. forward prices for the balance of the injection season averaged $3.19/GJ; Nov/99-Mar/00 averaged $3.82/GJ; Nov/99-Oct/00 averaged $3.06/GJ. AECO/N.I.T. Forward prices have dramatically increased from prices quoted just one-month prior: the balance of the injection season averaged $2.75/GJ; Nov/99-Mar/00 averaged $3.06/GJ; Nov/99-Oct/00 averaged $2.82/GJ. In general, market prices over the short to medium term are expected to remain strong when compared to last year.

September AECO/N.I.T. prices are forecast to average $3.01/GJ representing a 19 cent increase from their August average price of $2.82/GJ and up 38 cents from September 1998s average price of $1.63/GJ.

Empress prices for September delivery are forecast to average $3.06/GJ representing a 13 cent increase over their August average price of $2.93/GJ and up $1.40/GJ from September 1998s average price of $1.66/GJ.

September Station 2 prices are forecast to average $2.72/GJ representing a 31 cent decrease from August's average price of $3.03/GJ but up 74 cents from September

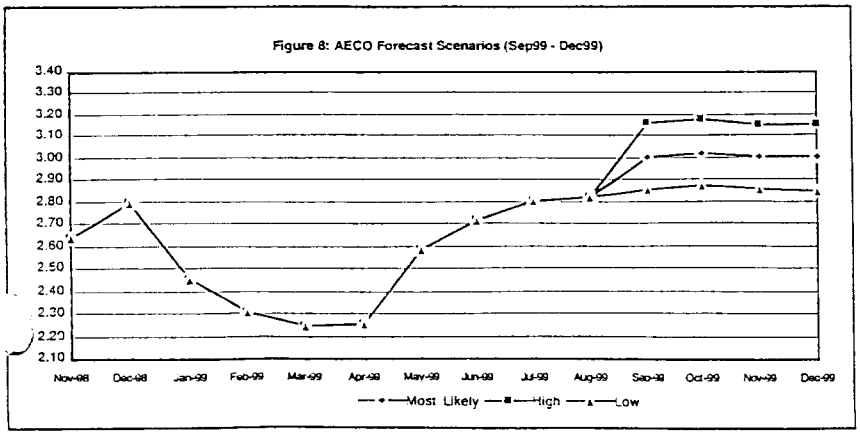


Table 10
Niagara Historical Prices (US$/MMBtu)

	1997	1998	1999
Jan	5.13	2.43	1.91
Feb	3.31	2.19	1.99
Mar	2.01	2.42	1.77
Apr	2.04	2.47	2.06
May	2.33	2.40	2.35
Jun	2.54	2.14	2.32
Jul	2.32	2.41	2.33
Aug	2.33	1.95	2.70
Sep	2.70	1.69	-
Oct	3.35	2.08	-
Nov	3.66	2.22	-
Dec	2.87	2.45	-
Winter	3.62	2.71	2.07
Summer	2.52	2.16	-
One-Year	2.88	2.24	-

Table 11
Niagara Forecast Scenarios (US$/MMBtu)

	Most Likely	High	Low
Sep-99	2.74	2.83	2.66
Oct-99	2.80	2.88	2.71
Nov-99	2.91	3.00	2.82
Dec-99	3.08	3.17	2.99
Jan-00	3.13	3.22	3.04
Feb-00	3.08	3.17	2.99
Mar-00	2.97	3.05	2.88
Apr-00	2.85	2.94	2.77
May-00	2.74	2.83	2.66
Jun-00	2.58	2.66	2.50
Jul-00	2.47	2.55	2.39
Aug-00	2.49	2.57	2.41
Sep-00	2.49	2.57	2.41
Oct-00	2.49	2.57	2.41
Nov-00	2.49	2.57	2.41
Dec-00	2.52	2.60	2.44
Jan-01	2.69	2.77	2.61
Feb-01	2.85	2.94	2.77
Mar-01	2.91	3.00	2.82
Apr-01	2.81	2.90	2.73
May-01	2.70	2.78	2.62
Jun-01	2.58	2.66	2.50
Jul-01	2.54	2.62	2.46
Aug-01	2.54	2.62	2.46
Win 99	2.04	2.04	2.04
Sum 99	2.47	2.50	2.45
Win 00	3.03	3.12	2.94
Sum 00	1.79	1.84	1.73
1998	2.24	2.24	2.24
1999	2.41	2.44	2.38

Table 12
Empress Historical Prices (C$/GJ)

	1997	1998	1999
Jan	2.27	1.91	2.53
Feb	2.85	1.70	2.33
Mar	1.79	1.99	2.25
Apr	1.56	1.99	2.37
May	1.83	2.28	2.72
Jun	1.70	1.86	2.76
Jul	1.60	1.99	2.76
Aug	1.47	2.03	2.93
Sep	1.51	1.66	-
Oct	1.82	2.40	-
Nov	2.13	2.80	-
Dec	1.92	2.80	-
Winter	2.11	1.93	2.54
Summer	1.64	2.03	-
One-Year	1.87	2.12	-

Table 13
Empress Forecast Scenarios (C$/GJ)

	Most Likely	High	Low
Sep-99	3.06	3.21	2.91
Oct-99	3.06	3.23	2.92
Nov-99	3.11	3.26	2.95
Dec-99	3.13	3.29	2.98
Jan-00	3.29	3.46	3.13
Feb-00	3.43	3.61	3.26
Mar-00	3.35	3.52	3.18
Apr-00	3.06	3.21	2.91
May-00	2.95	3.10	2.80
Jun-00	2.77	2.91	2.64
Jul-00	2.66	2.79	2.52
Aug-00	2.82	2.96	2.68
Sep-00	2.99	3.14	2.84
Oct-00	3.11	3.26	2.95
Nov-00	3.11	3.26	2.95
Dec-00	3.12	3.27	2.96
Jan-01	3.28	3.45	3.12
Feb-01	3.33	3.49	3.16
Mar-01	3.28	3.45	3.12
Apr-01	3.00	3.15	2.85
May-01	2.91	3.06	2.77
Jun-01	2.75	2.89	2.61
Jul-01	2.64	2.78	2.51
Aug-01	2.81	2.95	2.67
Win 99	2.46	2.46	2.46
Sum 99	2.81	2.86	2.77
Win 00	3.26	3.43	3.10
Sum 00	2.05	2.15	1.95
1998	2.12	2.12	2.12
1999	2.75	2.80	2.70

Table 14 NYMEX HH 3-day Historical Pr. (US$/MMBtu)			
	1997	1998	1999
Jan	4.25	2.27	1.81
Feb	2.87	2.04	1.75
Mar	1.88	2.23	1.69
Apr	1.85	2.33	1.85
May	2.10	2.29	2.33
Jun	2.33	2.07	2.20
Jul	2.22	2.35	2.27
Aug	2.15	1.95	2.57
Sep	2.51	1.75	-
Oct	3.22	2.13	-
Nov	3.51	2.13	-
Dec	2.68	2.14	-
Winter	3.04	2.55	1.90
Summer	2.34	2.12	
One-Year	2.63	2.14	-

Table 15 NYMEX HH 3-day Projected Scen. (US$/MMBtu)			
	Most Likely	High	Low
Sep-99	2.55	2.62	2.46
Oct-99	2.60	2.67	2.51
Nov-99	2.70	2.77	2.61
Dec-99	2.85	2.93	2.77
Jan-00	2.90	2.98	2.82
Feb-00	2.85	2.93	2.77
Mar-00	2.75	2.83	2.66
Apr-00	2.65	2.72	2.56
May-00	2.55	2.62	2.46
Jun-00	2.40	2.46	2.31
Jul-00	2.30	2.36	2.21
Aug-00	2.32	2.38	2.23
Sep-00	2.32	2.38	2.23
Oct-00	2.32	2.38	2.23
Nov-00	2.32	2.38	2.23
Dec-00	2.35	2.41	2.26
Jan-01	2.50	2.57	2.41
Feb-01	2.65	2.72	2.56
Mar-01	2.70	2.77	2.61
Apr-01	2.61	2.68	2.52
May-01	2.51	2.58	2.42
Jun-01	2.40	2.46	2.31
Jul-01	2.37	2.43	2.28
Aug-01	2.37	2.43	2.28
Win 99	1.85	1.85	1.85
Sum 99	2.34	2.36	2.31
Win 00	2.81	2.89	2.73
Sum 00	1.67	1.71	1.60
1998	2.14	2.14	2.14
1999	2.26	2.29	2.24

Table 16 Ventura Historical Prices (US$/MMBtu)			
	1997	1998	1999
Jan	4.22	2.13	1.85
Feb	2.87	1.96	1.80
Mar	1.64	2.14	1.63
Apr	1.72	2.20	1.71
May	1.94	2.16	2.20
Jun	2.14	1.90	2.12
Jul	2.01	2.25	2.18
Aug	2.03	1.84	2.51
Sep	2.40	1.55	-
Oct	3.02	1.91	-
Nov	3.28	2.02	-
Dec	2.46	2.13	-
Winter	3.00	2.39	1.89
Summer	2.18	1.97	-
One-Year	2.48	2.02	-

Table 17 Ventura Forecast Scenarios (US$/MMBtu)			
	Most Likely	High	Low
Sep-99	2.42	2.52	2.32
Oct-99	2.47	2.58	2.37
Nov-99	2.53	2.64	2.42
Dec-99	2.64	2.75	2.52
Jan-00	2.58	2.69	2.47
Feb-00	2.54	2.65	2.43
Mar-00	2.54	2.65	2.43
Apr-00	2.50	2.60	2.39
May-00	2.35	2.46	2.25
Jun-00	2.25	2.34	2.15
Jul-00	2.18	2.28	2.09
Aug-00	2.20	2.30	2.11
Sep-00	2.04	2.13	1.95
Oct-00	2.04	2.13	1.95
Nov-00	2.04	2.13	1.95
Dec-00	2.07	2.16	1.98
Jan-01	2.21	2.31	2.12
Feb-01	2.36	2.46	2.26
Mar-01	2.40	2.51	2.30
Apr-01	2.32	2.42	2.22
May-01	2.22	2.32	2.13
Jun-01	2.12	2.21	2.03
Jul-01	2.09	2.18	2.00
Aug-01	2.09	2.18	2.00
Win 99	1.82	1.82	1.82
Sum 99	2.23	2.26	2.20
Win 00	2.56	2.67	2.45
Sum 00	1.53	1.60	1.46
1998	2.02	2.02	2.02
1999	2.17	2.21	2.14

1998s average price of $1.98/GJ.

September export prices along the westcoast are projected to slightly decrease following lower forecast U.S. cash prices. As a result, Sumas prices are forecast to average $2.10/MMBtu, down 10 cents from August's average price of $2.20/MMBtu but up 64 cents from September 1998s average price of $1.46/MMBtu. Similarly, Kingsgate prices are forecast to average $2.12/MMBtu, down 2 cents from August's average price of $2.14/MMBtu but up 70 cents from September 1998s average price of $1.42/MMBtu.

Niagara prices for September delivery are forecast to slightly increase following projected strong prices in the Gulf Coast over the next four weeks (see U.S. Market Analysis for further details). As a result, Niagara prices are forecast to average $2.74/MMBtu representing a 4 cent increase over their August average price of $2.70/MMBtu and up $1.05/MMBtu over their September 1998 average price of $1.69/MMBtu.

U.S. Market Analysis

August Prices Post Strength Over July Prices due to Hot Temperatures

August prices across the U.S. continued to increase over their July prices following above normal temperatures mainly during the last 10 days of July. Above normal temperatures, predominantly in the New England (July cooling degree day, CDD, totaled 256) and the Middle Atlantic (July CDD totaled 258) regions were enough to raise cooling demand in these census populated areas. Above normal summer temperatures put significant pressure on natural gas demand for power generation. As well, numerous plant outages in the Southern U.S. occurred: El Paso shut its Chaco gas processing plant in New Mexico in mid-July; El Paso also reported that their White Rock #2 turbine was down which caused San Juan basin capacity to be reduced by 220 Mmcf/d; and, the South Texas 2 1,250 MW nuclear unit was down mid-July. Coupled hot temperatures and plant outages along with increased fuel buying on the NYMEX, August spot prices displayed continual upward pressure throughout July.

August Gulf Coast prices averaged $2.60/MMBtu representing a 31 cent increase from their July average price of $2.29/MMBtu and up 67 cents from August 1998s average price of $1.93/MMBtu.

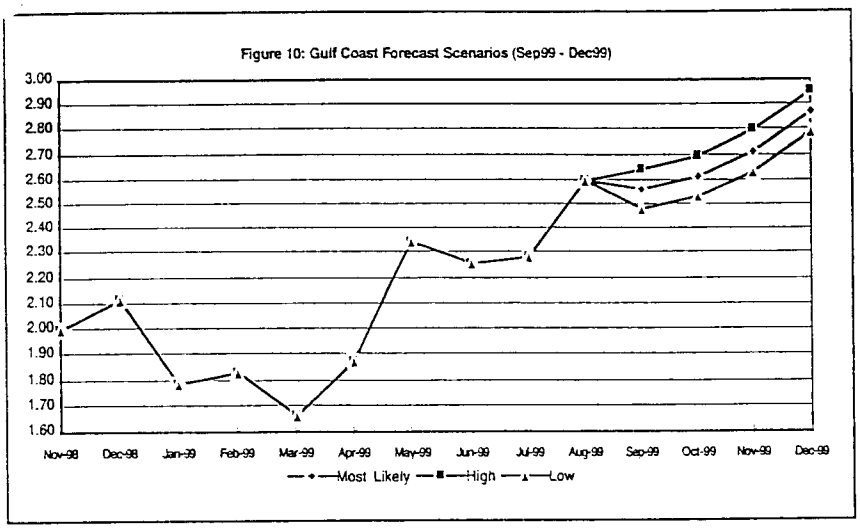
Figure 9: July 1999 U.S. Regional Cooling Degree Days (CDD)

Region	July	Difference from Last Year	Percentage Change	Difference from Normal	Percentage Change
New England	256	74	28.9	77	30.1
Middle Atlantic	358	117	32.7	111	31.0
EN Central	351	117	33.3	102	29.1
WN Central	390	69	17.7	65	16.7
South Atlantic	459	16	3.5	47	10.2
ES Central	462	28	6.1	59	12.8
WS Central	540	-120	-22.2	-3	-0.6
Mountain	322	-39	-12.1	-15	-4.7
Pacific	171	-30	-17.5	-19	-11.1
United Sates	367	31	8.4	51	13.9

Ventura prices for August delivery averaged $2.51/MMBtu, up 33 cents from July's average price of $2.18/MMBtu and up 67 cents from August 1998s average price of $1.84/MMBtu.

August Rockies prices averaged $2.17/MMBtu representing an 18 cent increase over July's average price of $1.99/MMBtu and up 44 cents from August 1998s average price of $1.73/MMBtu. Rockies prices still maintain strength over their last year's levels following similar pricing dynamics in Western Canada. Rockies prices have been historically influenced by Western Canadian prices.

August prices in California increased 21 cents over July's average price of $2.38/MMBtu. As a result, California prices averaged $2.59/MMBtu which posted a 32 cent gain over August 1998s average price of $2.27/MMBtu.



September Prices Forecast to Slightly Decrease

The NYMEX Henry Hub August contract closed at $2.60/MMBtu and September contract prices have been maintaining similar strength. Spot prices for the remainder of the injection season should continue to post relative strength over last year's price levels due to the following:

(i) Drilling statistics continue to show relative weakness when compared to last year's numbers.

(ii) The likelihood of more unplanned outages is still high as many generating plants continued to be pushed by above normal temperatures.

(iii) According to the National Climatic Data Center, again (as compared to last month's forecast) with the exception of the central parts of the Midwest, virtually all of the U.S. is forecast to experience above normal temperatures.

Prices still have an even more volatile upside given that the hurricane season has just begun. Typically most accumulations that result in hurricanes begin in late July and could last until mid-September. Therefore, prices (especially in the Gulf Coast) could experience significant upward price spikes over the next several weeks. Conversely, if no hurricanes were to occur and summer temperatures remain normal, prices should flatten out over the next several weeks.

However, September Gulf Coast prices are forecast to decrease slightly with prices maintaining relative strength over last year's levels. September Gulf Coast prices are forecast to average $2.56/MMBtu representing only a 4 cent decrease from August's average price of $2.60/MMBtu but up 93 cents from September 1998s average price of $1.63/MMBtu.

All other cash prices across the U.S. delivery are expected to show similar price mechanics as the projected Gulf Coast prices.

Table 18
Rockies Historical Prices (US$/MMBtu)

	1997	1998	1999
Jan	4.30	2.04	1.75
Feb	2.51	1.68	1.63
Mar	1.40	1.86	1.51
Apr	1.45	1.90	1.54
May	1.63	1.96	1.99
Jun	1.53	1.64	1.94
Jul	1.44	1.62	1.99
Aug	1.39	1.73	2.17
Sep	1.47	1.57	-
Oct	2.06	1.65	-
Nov	3.06	1.99	-
Dec	1.92	2.00	-
Winter	2.77	2.11	1.78
Summer	1.57	1.72	-
One-Year	2.01	1.80	-

Table 19
Rockies Forecast Scenarios (US$/MMBtu)

	Most Likely	High	Low
Sep-99	2.10	2.20	1.98
Oct-99	2.02	2.13	1.91
Nov-99	2.08	2.19	1.97
Dec-99	2.19	2.30	2.08
Jan-00	2.17	2.28	2.06
Feb-00	2.13	2.24	2.02
Mar-00	2.12	2.23	2.01
Apr-00	2.08	2.19	1.97
May-00	1.94	2.05	1.83
Jun-00	1.80	1.91	1.69
Jul-00	1.70	1.81	1.59
Aug-00	1.69	1.80	1.58
Sep-00	1.55	1.66	1.44
Oct-00	1.50	1.61	1.39
Nov-00	1.49	1.60	1.38
Dec-00	1.51	1.62	1.40
Jan-01	1.64	1.75	1.53
Feb-01	1.81	1.92	1.70
Mar-01	1.90	2.01	1.79
Apr-01	1.86	1.97	1.75
May-01	1.76	1.87	1.65
Jun-01	1.63	1.74	1.52
Jul-01	1.57	1.68	1.46
Aug-01	1.55	1.66	1.44
Win 99	1.69	1.69	1.69
Sum 99	1.96	1.99	1.93
Win 00	2.14	2.25	2.03
Sum 00	1.18	1.26	1.10
1998	1.80	1.80	1.80
1999	1.91	1.94	1.87

Table 20
California Historical Prices (US$/MMBtu)

	1997	1998	1999
Jan	4.35	2.24	2.06
Feb	2.58	2.07	1.82
Mar	1.59	2.24	1.88
Apr	1.74	2.37	1.78
May	2.03	2.35	2.21
Jun	2.16	2.09	2.21
Jul	2.15	2.21	2.38
Aug	2.19	2.27	2.59
Sep	2.50	1.99	-
Oct	3.00	2.07	-
Nov	3.37	2.32	-
Dec	2.35	2.30	-
Winter	2.93	2.45	2.04
Summer	2.25	2.19	-
One-Year	2.50	2.21	-

Table 21
California Forecast Scenarios (US$/MMBtu)

	Most Likely	High	Low
Sep-99	2.35	2.44	2.27
Oct-99	2.38	2.50	2.27
Nov-99	2.44	2.56	2.32
Dec-99	2.54	2.67	2.42
Jan-00	2.53	2.65	2.40
Feb-00	2.49	2.61	2.36
Mar-00	2.47	2.60	2.35
Apr-00	2.44	2.56	2.31
May-00	2.31	2.43	2.19
Jun-00	2.19	2.30	2.07
Jul-00	2.10	2.21	1.99
Aug-00	2.09	2.20	1.98
Sep-00	1.96	2.06	1.85
Oct-00	1.92	2.02	1.82
Nov-00	1.91	2.01	1.81
Dec-00	1.93	2.03	1.83
Jan-01	2.06	2.16	1.95
Feb-01	2.21	2.32	2.10
Mar-01	2.29	2.41	2.17
Apr-01	2.24	2.35	2.13
May-01	2.15	2.26	2.04
Jun-01	2.04	2.14	1.93
Jul-01	1.98	2.09	1.88
Aug-01	1.97	2.07	1.86
Win 99	1.93	1.93	1.93
Sum 99	2.27	2.30	2.24
Win 00	2.49	2.62	2.37
Sum 00	1.46	1.54	1.39
1998	2.21	2.21	2.21
1999	2.20	2.24	2.17

Table 22: One-Month Spot Price Forecasts, High Case*

Month	Alberta (C$/GJ) Field Price	AECO/NIT	Empress	B.C. Stn 2 (C$/GJ)	Export (US$/MMBtu) Sumas	Kingsgate	Ventura	Niagara	U.S. (US$/MMBtu) Gulf Coast	Rockies	California	(US$/MMBtu) KCBT Waha 3-day	NYMEX HH 3-day
Actual Series													
Sep-98	1.56	1.63	1.66	1.98	1.46	1.42	1.55	1.69	1.63	1.57	1.99	1.67	1.75
Oct-98	1.86	2.13	2.40	2.31	1.67	1.61	1.91	2.08	2.06	1.65	2.07	1.98	2.13
Nov-98	2.19	2.64	2.80	2.77	2.15	1.98	2.02	2.22	2.00	1.99	2.32	2.03	2.13
Dec-98	2.22	2.80	2.80	2.82	2.14	1.96	2.13	2.45	2.12	2.00	2.30	2.07	2.14
Jan-99	2.04	2.46	2.53	2.87	3.02	1.97	1.85	1.91	1.79	1.75	2.06	1.78	1.81
Feb-99	1.90	2.31	2.33	2.33	1.77	1.60	1.80	1.99	1.83	1.63	1.82	1.69	1.75
Mar-99	1.80	2.25	2.25	2.00	1.50	1.50	1.63	1.77	1.66	1.51	1.68	1.62	1.69
Apr-99	1.90	2.26	2.37	2.04	1.52	1.50	1.71	2.06	1.88	1.54	1.78	1.74	1.85
May-99	2.21	2.59	2.72	2.63	1.95	2.03	2.20	2.35	2.35	1.99	2.21	2.26	2.33
Jun-99	2.10	2.72	2.76	2.57	1.90	2.01	2.12	2.32	2.26	1.94	2.21	2.12	2.20
Jul-99	2.02	2.81	2.76	2.62	1.95	2.02	2.18	2.33	2.29	1.99	2.38	2.19	2.27
Aug-99	2.02	2.82	2.93	3.03	2.20	2.14	2.51	2.70	2.60	2.17	2.59	2.50	2.57
Forecast Series												*Projected Series***	
Sep-99	2.32	3.16	3.21	2.90	2.19	2.21	2.52	2.83	2.64	2.20	2.44	2.50	2.62
Oct-99	2.34	3.18	3.23	2.84	2.24	2.26	2.58	2.88	2.69	2.13	2.50	2.55	2.67
Nov-99	2.38	3.16	3.26	2.84	2.29	2.31	2.64	3.00	2.80	2.19	2.56	2.60	2.77
Dec-99	2.44	3.15	3.29	2.88	2.39	2.41	2.75	3.17	2.96	2.30	2.67	2.70	2.93
Jan-00	2.47	3.32	3.46	2.96	2.34	2.36	2.69	3.22	3.01	2.28	2.65	2.65	2.98
Feb-00	2.49	3.47	3.61	3.02	2.30	2.32	2.65	3.17	2.96	2.24	2.61	2.61	2.93
Mar-00	2.48	3.38	3.52	3.01	2.40	2.42	2.65	3.05	2.85	2.23	2.60	2.61	2.83
Apr-00	2.37	3.08	3.21	2.83	2.36	2.38	2.60	2.94	2.75	2.19	2.56	2.57	2.72
May-00	2.29	2.96	3.10	2.71	2.23	2.25	2.46	2.83	2.64	2.05	2.43	2.43	2.62
Jun-00	2.19	2.78	2.91	2.57	2.13	2.15	2.34	2.66	2.48	1.91	2.30	2.33	2.46
Jul-00	2.12	2.65	2.79	2.47	2.07	2.09	2.28	2.55	2.38	1.81	2.21	2.27	2.36
Aug-00	2.20	2.83	2.96	2.62	2.19	2.21	2.30	2.57	2.40	1.80	2.20	2.29	2.38
Sep-00	2.20	3.00	3.14	2.66	2.04	2.06	2.13	2.57	2.40	1.66	2.06	2.30	2.38
Oct-00	2.23	3.13	3.26	2.73	2.04	2.06	2.13	2.57	2.40	1.61	2.02	2.29	2.38
Nov-00	2.23	3.12	3.26	2.73	2.04	2.06	2.13	2.57	2.40	1.60	2.01	2.30	2.38
Dec-00	2.25	3.14	3.27	2.74	2.07	2.09	2.16	2.60	2.43	1.62	2.03	2.33	2.41
Jan-01	2.35	3.31	3.45	2.89	2.20	2.22	2.31	2.77	2.59	1.75	2.16	2.46	2.57
Feb-01	2.43	3.36	3.49	2.97	2.33	2.35	2.46	2.94	2.75	1.92	2.32	2.60	2.72
Mar-01	2.44	3.31	3.45	2.96	2.38	2.40	2.51	3.00	2.80	2.01	2.41	2.65	2.77
Apr-01	2.32	3.01	3.15	2.76	2.30	2.32	2.42	2.90	2.70	1.97	2.35	2.58	2.68
May-01	2.25	2.92	3.06	2.68	2.21	2.23	2.32	2.78	2.60	1.87	2.26	2.46	2.58
Jun-01	2.16	2.75	2.89	2.55	2.11	2.13	2.21	2.66	2.48	1.74	2.14	2.36	2.46
Jul-01	2.12	2.64	2.78	2.47	2.09	2.11	2.18	2.62	2.45	1.68	2.09	2.36	2.43
Aug-01	2.17	2.82	2.95	2.57	2.09	2.11	2.18	2.62	2.45	1.66	2.07	2.37	2.43
Avg. Season^													
Winter 1999	1.91	2.42	2.46	2.41	1.99	1.71	1.82	2.04	1.86	1.69	1.93	1.78	1.85
Summer 1999	2.13	2.79	2.86	2.66	1.99	2.02	2.26	2.50	2.39	1.99	2.30	2.26	2.36
Winter 2000	2.45	3.30	3.43	2.94	2.34	2.36	2.67	3.12	2.92	2.25	2.62	2.64	2.89
Summer 2000	1.56	2.05	2.15	1.86	1.50	1.51	1.60	1.84	1.72	1.26	1.54	1.64	1.71
Avg. Annual													
1997	1.83	1.78	1.87	1.78	1.71	1.75	2.48	2.88	2.55	2.01	2.50	2.44	2.63
1998	1.93	1.93	2.12	2.03	1.62	1.64	2.02	2.24	2.10	1.80	2.21	2.05	2.14
1999	2.12	2.74	2.80	2.63	2.08	2.00	2.21	2.44	2.31	1.94	2.24	2.19	2.29
2000	2.29	3.07	3.21	2.75	2.18	2.20	2.38	2.77	2.59	1.92	2.31	2.41	2.57
2001	2.11	3.05	3.17	2.56	1.65	1.66	2.13	2.59	2.42	1.69	2.09	2.13	2.41
2002	2.10	3.02	3.14	2.51	1.57	1.55	2.21	2.69	2.51	1.70	2.10	2.21	2.50

* Assumes a 10.0% increase in the most likely heating degree day scenario for the Canadian domestic market and higher standard deviations for all other prices.

** Calculated average based on most current futures prices posted by NYMEX and KCBT and internal & external projections.

^ Summer term April to October. Winter term November to March.

Methodology/Assumptions

In most cases, in the short-term, the price forecasts in this publication were generated from econometric models using explanatory variables such as degree days, storage levels, NYMEX prices, and lagged prices. All models had significant t-statistics at the 1.0% level and R-squared statistics greater than 80.0%. The following results are noteworthy:

Canadian domestic prices are more related to fundamental inputs such as weather, storage, and one-period lagged prices in short term forecasts (1998/99). Alberta Field prices were generated from Empress prices and an average export price. Station 2 prices are highly correlated with AECO and Sumas, which were used to forecast Station 2 prices. Niagara prices were found to be highly correlated with the U.S. Gulf Coast price. In order to forecast high and low scenarios, various positive and negative deviations around the explanatory variables based on historic averages were used.

With respect to U.S. short term price forecasts (1998/1999), the KCBT Waha 3-day contract average proved very statistically significant in forecasting prices at Ventura, the Rockies, and California. Gulf Coast prices were forecast using the NYMEX Henry Hub 3-day contract average. Variables such as weather and storage are already assumed to be captured within the futures market. High and low scenarios for U.S. prices follow average statistical deviations from the most likely case.

With respect to the long term forecasts (2000 - 2002), quantitative methods are used in conjunction with qualitative market assessments. Long term assumptions such as increased gas-on-gas competition in North America due to Canadian pipeline expansion into the U.S., resulting North American energy market integration, and projections of economic growth, gas supply and demand are taken into account.

Table 23: One-Month Spot Price Forecasts, Low Case*

Month	Alberta (C$/GJ) Field Price	AECO/NIT	Empress	B.C. Stn 2 (C$/GJ)	Export (US$/MMBtu) Sumas	Kingsgate	Ventura	Niagara	U.S. (US$/MMBtu) Gulf Coast	Rockies	California	(US$/MMBtu) KCBT Waha 3-day	NYMEX HH 3-day
Actual Series													
Sep-98	1.56	1.63	1.66	1.98	1.46	1.42	1.55	1.69	1.63	1.57	1.99	1.67	1.75
Oct-98	1.86	2.13	2.40	2.31	1.67	1.61	1.91	2.08	2.06	1.65	2.07	1.98	2.13
Nov-98	2.19	2.64	2.80	2.77	2.15	1.98	2.02	2.22	2.00	1.99	2.32	2.03	2.13
Dec-98	2.22	2.80	2.80	2.82	2.14	1.96	2.13	2.45	2.12	2.00	2.30	2.07	2.14
Jan-99	2.04	2.46	2.53	2.87	3.02	1.97	1.85	1.91	1.79	1.75	2.06	1.78	1.81
Feb-99	1.90	2.31	2.33	2.33	1.77	1.60	1.80	1.99	1.83	1.63	1.82	1.69	1.75
Mar-99	1.80	2.25	2.25	2.00	1.50	1.50	1.63	1.77	1.66	1.51	1.68	1.62	1.69
Apr-99	1.90	2.26	2.37	2.04	1.52	1.50	1.71	2.06	1.88	1.54	1.78	1.74	1.85
May-99	2.21	2.59	2.72	2.63	1.95	2.03	2.20	2.35	2.35	1.99	2.21	2.26	2.33
Jun-99	2.10	2.72	2.76	2.57	1.90	2.01	2.12	2.32	2.26	1.94	2.21	2.12	2.20
Jul-99	2.02	2.81	2.76	2.62	1.95	2.02	2.18	2.33	2.29	1.99	2.38	2.19	2.27
Aug-99	2.02	2.82	2.93	3.03	2.20	2.14	2.51	2.70	2.60	2.17	2.59	2.50	2.57
Forecast Series												*Projected Series***	
Sep-99	2.08	2.86	2.91	2.65	2.01	2.03	2.32	2.66	2.48	1.98	2.27	2.30	2.46
Oct-99	2.10	2.88	2.92	2.66	2.06	2.08	2.37	2.71	2.54	1.91	2.27	2.35	2.51
Nov-99	2.13	2.86	2.95	2.66	2.11	2.13	2.42	2.82	2.64	1.97	2.32	2.40	2.61
Dec-99	2.19	2.85	2.98	2.70	2.21	2.23	2.52	2.99	2.79	2.08	2.42	2.50	2.77
Jan-00	2.22	3.01	3.13	2.78	2.16	2.18	2.47	3.04	2.84	2.06	2.40	2.45	2.82
Feb-00	2.23	3.14	3.26	2.84	2.12	2.14	2.43	2.99	2.79	2.02	2.36	2.41	2.77
Mar-00	2.22	3.06	3.18	2.83	2.22	2.24	2.43	2.88	2.69	2.01	2.35	2.41	2.66
Apr-00	2.13	2.78	2.91	2.65	2.18	2.20	2.39	2.77	2.59	1.97	2.31	2.37	2.56
May-00	2.05	2.68	2.80	2.53	2.05	2.07	2.25	2.66	2.48	1.83	2.19	2.25	2.46
Jun-00	1.96	2.51	2.64	2.39	1.95	1.97	2.15	2.50	2.33	1.69	2.07	2.15	2.31
Jul-00	1.90	2.40	2.52	2.29	1.89	1.91	2.09	2.39	2.23	1.59	1.99	2.09	2.21
Aug-00	1.97	2.56	2.68	2.44	2.01	2.03	2.11	2.41	2.25	1.58	1.98	2.11	2.23
Sep-00	1.97	2.72	2.84	2.48	1.86	1.88	1.95	2.41	2.25	1.44	1.85	2.12	2.23
Oct-00	2.00	2.83	2.95	2.55	1.86	1.88	1.95	2.41	2.25	1.39	1.82	2.11	2.23
Nov-00	2.00	2.83	2.95	2.55	1.86	1.88	1.95	2.41	2.25	1.38	1.81	2.12	2.23
Dec-00	2.01	2.84	2.96	2.56	1.89	1.91	1.98	2.44	2.28	1.40	1.83	2.15	2.26
[illegible]-01	2.11	3.00	3.12	2.71	2.02	2.04	2.12	2.61	2.43	1.53	1.95	2.28	2.41
[illegible]-01	2.17	3.04	3.16	2.79	2.15	2.17	2.26	2.77	2.59	1.70	2.10	2.40	2.56
Mar-01	2.18	3.00	3.12	2.78	2.20	2.22	2.30	2.82	2.64	1.79	2.17	2.45	2.61
Apr-01	2.08	2.72	2.85	2.58	2.12	2.14	2.22	2.73	2.55	1.75	2.13	2.38	2.52
May-01	2.02	2.65	2.77	2.50	2.03	2.05	2.13	2.62	2.44	1.65	2.04	2.28	2.42
Jun-01	1.94	2.49	2.61	2.37	1.93	1.95	2.03	2.50	2.33	1.52	1.93	2.18	2.31
Jul-01	1.90	2.39	2.51	2.29	1.91	1.93	2.00	2.46	2.30	1.46	1.88	2.18	2.28
Aug-01	1.94	2.55	2.67	2.39	1.91	1.93	2.00	2.46	2.30	1.44	1.86	2.19	2.28
Avg. Season^													
Winter 1999	1.91	2.42	2.46	2.41	1.99	1.71	1.82	2.04	1.86	1.69	1.93	1.78	1.85
Summer 1999	2.06	2.71	2.77	2.60	1.94	1.97	2.20	2.45	2.34	1.93	2.24	2.21	2.31
Winter 2000	2.20	2.98	3.10	2.76	2.16	2.18	2.45	2.94	2.75	2.03	2.37	2.43	2.73
Summer 2000	1.40	1.86	1.95	1.74	1.37	1.38	1.46	1.73	1.62	1.10	1.39	1.51	1.60
Avg. Annual													
1997	1.83	1.78	1.87	1.78	1.71	1.75	2.48	2.88	2.55	2.01	2.50	2.44	2.63
1998	1.93	1.93	2.12	2.03	1.62	1.64	2.02	2.24	2.10	1.80	2.21	2.05	2.14
1999	2.04	2.64	2.70	2.56	2.02	1.94	2.14	2.38	2.26	1.87	2.17	2.12	2.24
2000	2.05	2.78	2.90	2.57	2.00	2.02	2.18	2.61	2.44	1.70	2.08	2.23	2.41
2001	1.96	2.75	2.87	2.31	1.47	1.49	1.98	2.42	2.26	1.50	1.91	2.00	2.26
2002	1.94	2.73	2.85	2.26	1.36	1.35	2.03	2.48	2.31	1.48	1.90	2.04	2.31

* Assumes a10.0% decrease in the most likely heating degree day scenario for the Canadian domestic market and lower standard deviations for all other prices.

** Calculated average based on most current futures prices posted by NYMEX and KCBT and internal & external projections.

^ Summer term April to October. Winter term November to March.

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... continued from page 5

pacity is expected. Besides, during 1998 the US West was the lowest netback export market for Canadian gas producers.

Higher production from the **Gulf Coast** will satisfy all incremental demand in the South Atlantic (615 Bcf), in the Gulf Coast itself (748 Bcf), and in the Midcontinent (108 Bcf), and will also replace the loss of 407 Bcf of Midcontinent production. In total, these areas will absorb virtually all of the projected increase in Gulf Coast production.

Higher production in **Canada** will satisfy increased gas demand in the Midwest (795 Bcf), Northeast (791 Bcf), and Canada (785 Bcf). Pipelines from Western Canada to the Midwest, Northeast, and Eastern Canada are being built to capture markets in these areas.

On the price side, the Gulf Coast (NYMEX) is expected to continue to be the benchmark North American gas price. The Gulf Coast is a high-cost supplier, and is the marginal supplier to most North American markets. Gulf coast gas is the last gas that must be purchased to balance the market, and thus sets the marginal price in the market.

As long as a market area requires some supply from the Gulf, the gas price in that market will be linked to the Gulf price. We expect prices in the US West, Midwest, Northeast, Gulf Coast, and South Atlantic to continue to be driven off Gulf Coast pricing.

Canadian supply is expected to be a price taker in Midwest and Northeast markets, as those markets will continue to need some Gulf Coast gas. Depending on supply development, prices in the Canadian market could maintain the linkage to US prices established in late 1998, or could again fall below US prices. This would happen if additions to Canadian supply capacity again result in capacity greater than the sum of all exit pipelines plus Canadian demand.

A sampling of expert gas price forecasts shows US prices (NYMEX or wellhead) rising from an average of $2.11/MMBtu in 1998 to $2.60 (nominal) in 2005. Canadian prices are expected to rise from an average of $1.36/MMBtu (Cdn$1.92/GJ) in 1998 to $2.26/MMBtu (Cdn$2.74/GJ) by 2005.

Canadian gas exports are once again entering a period of sharp growth, due to recent and continuing pipeline construction. We expect reports to reach 3.9 Tcf by 2005.

With higher exports, continued domestic gas demand growth, and stronger US gas prices, the outlook is for strong growth in Canadian producer revenues. Revenue could be lower if domestic prices again become de-linked from US prices.

Producer plant gate revenues from export and domestic gas sales are expected to climb from Cdn$12.3 billion in 1998 to $19.7 billion by 2005.

Similarly, revenues to the Canadian pipeline sector will proportionally increase, due to higher throughput volumes.

SECTION V

NORTH AMERICAN NATURAL GAS MARKET ANALYSIS

FEATURE ARTICLE
PROSPECTS FOR NWT GAS DEVELOPMENT

Over the past few months, certain issues and events have rekindled interest in the potential of Mackenzie Delta/Beaufort Sea gas. New discoveries have been made in the southern NWT near Fort Liard. Plans to extend the gas grid into the NWT to pick up Fort Liard gas have been announced. Finally, Indian and Northern Affairs Canada (INAC) have issued a call for bids in the Mackenzie Delta region.

Bids for four Mackenzie Delta parcels are expected from interested oil and gas interests by September 9, 1999. Spurred on by recent natural gas discoveries at Fort Liard in the southern Northwest Territories, interest in the northern regions appear to be on the increase. Companies are seriously reviewing the potential of picking up a position or expanding their current interests close to the major gas fields at Taglu and Niglintgak and several other gas and oil discoveries onshore the Mackenzie Delta.

Until recently, most analyses and forecasts have tended to discount the need for Mackenzie Delta/Beaufort Sea natural gas prior to 2020. The costs of exploration, development, production, and transportation to market were seen as too high to justify proceeding, given the market and pricing outlook for the North American natural gas industry. Development of these resources for the continental gas grid was therefore considered beyond any reasonable planning horizon. However, recent concerns about future conventional supplies, potentially large incremental demand increases due to environmental considerations and electric industry restructuring, and recent strength in Western Canadian gas prices are all seen as positive indicators to encourage the renewed interest in the gas potential of the NWT.

In late July 1999, TransCanada PipeLines Limited announced plans to build a $100 million pipeline from the Fort Liard region to its Alberta mainline system. It is expected to be completed by the end of 2000. Westcoast's pipeline also reaches close to this area, and Westcoast has plans to extend its pipeline system to this area, and should be able to be completed sooner. Both pipeline systems could be positioning themselves for further extension northward should the Mackenzie Delta reserves commence development.

Buoyed by their recent discovery at Fort Liard, the producer consortium led by Chevron are planning further drilling activities. The recent Fort Liard discovery is expected to have a producing rate of 70 to 100 million cubic feet per day, which is very prolific based on most wells in the Western Canadian Sedimentary Basin.

Based on a recent industry report prepared by Purvin & Gertz, ***"Mackenzie Delta/Beaufort Sea Gas: Development Scenario"***, recent prices in Western Canada are close to the threshold of supporting development of the rich northern gas prospects. The need for this gas could develop sooner than commonly expected if future conventional supply growth does not materialize, or stronger demands in both Canada and the U.S. occur. If major initiatives are undertaken to significantly reduce greenhouse gas emissions in both countries, such northern gas supplies could become very critical within the next decade to meeting the North American market demand.

FIGURE V-1
U.S. NATURAL GAS WORKING INVENTORIES

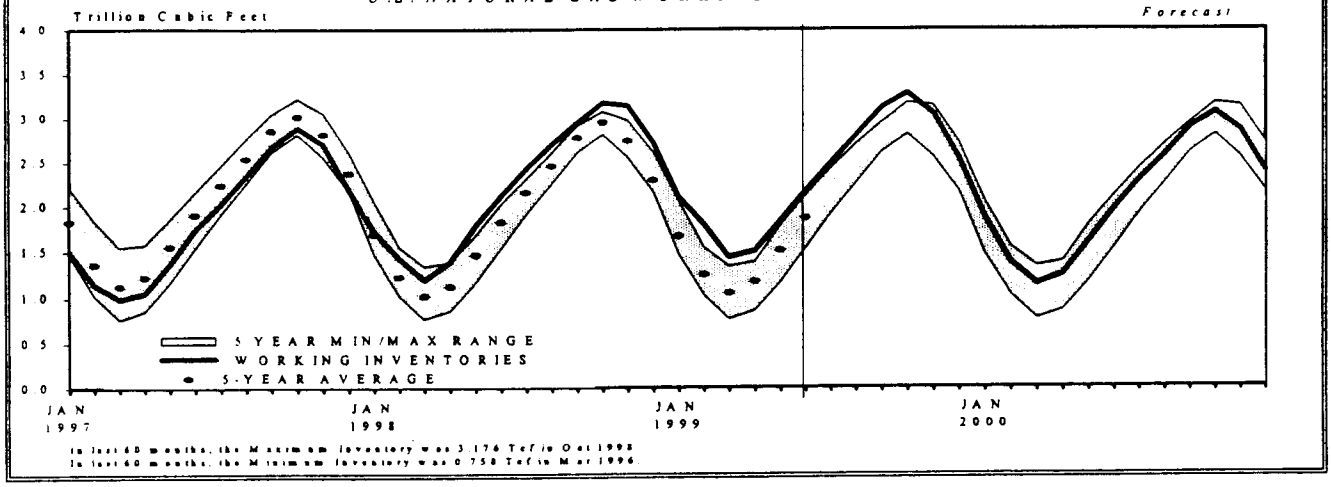


FIGURE V-2
U.S. NATURAL GAS AND LNG IMPORTS BY SOURCE

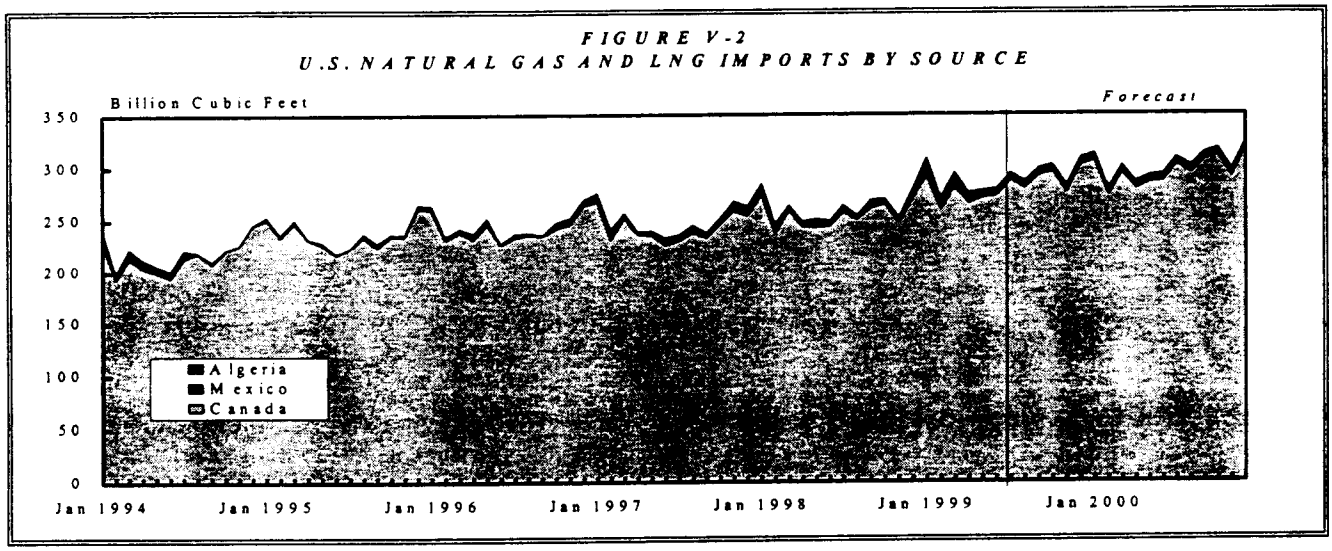
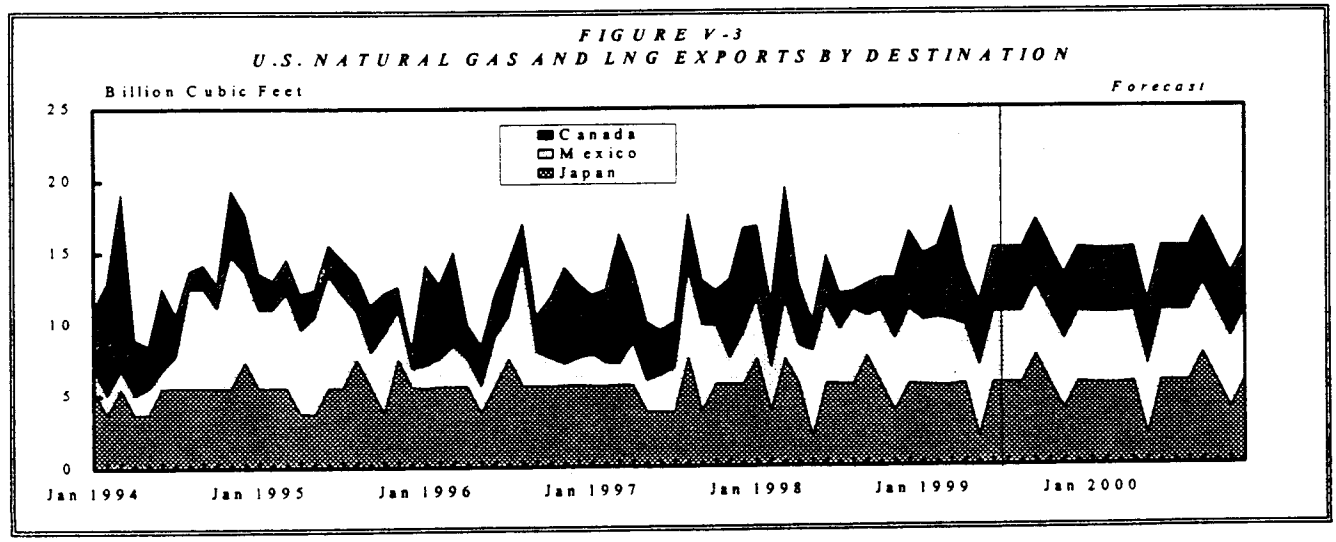


FIGURE V-3
U.S. NATURAL GAS AND LNG EXPORTS BY DESTINATION



U.S. NATURAL GAS MARKET & PRICING ANALYSIS

- NATURAL GAS PRICES SHOULD DIP IN SEPTEMBER.
- DOMESTIC GAS PRODUCTION REMAINED ONLY SLIGHTLY BELOW LAST YEAR.
- IMPORTS FROM CANADA WERE 12% HIGHER THIS JUNE.
- WORKING GAS STORAGE LEVELS WILL LIKELY PEAK FAR ABOVE 3 TCF THIS FALL.

Weekly average spot prices for natural gas in most producing regions declined by about 10-15 cents during the first half of July. Prices then rebounded by about the same amount during the latter part of the month. As has been the case for a couple of months, the primary factors driving prices involved the weather and/or gas storage levels. Whether the actual data were higher or lower than the industry's expectations often had a major effect on prices.

In these difficult times for forecasting when market sentiment rather than fundamental factors is driving prices, we expect that the average pipeline acquisition price for natural gas in the U.S. Gulf Coast region will remain nearly unchanged at $2.20 per MMBtu in July versus to $2.24 in June. We look for prices to dip to a low of $2.15 in September and then rise quickly to $2.60 in December.

In the Mid-Continent, we expect that the average pipeline acquisition price for natural gas will also remain nearly flat at $2.15 per MMBtu in July compared to $2.18 in June. Gas prices in the region should then decline to a low of $2.10 in September and October before peaking at $2.30 in December.

Pipeline acquisition prices for natural gas in the Rocky Mountain region should average about $1.95 per MMBtu in July, and fluctuate near $1.95-$2.00 through October. Prices should peak at $2.40 per MMBtu in December.

In the mix of psychological and fundamental factors currently at work in the gas market, gas inventories would seem to be an important fundamental factor. However, we believe the market is overlooking the most important aspect of this data. For example, data from the American Gas Association show that working gas in storage in the total U.S. rose to 2.161 Tcf as of July 9, which was 17 Bcf less than at the same time in 1998. Although the market seems to think that this was bullish news, we believe it was bearish (or neutral, at best) because last year's storage level was significantly higher than in previous years. Furthermore, data from the EIA show that "official" storage levels totaled 2.169 Tcf at the end of June, compared to the AGA's estimate of slightly above 2.0 Tcf. Thus, as is typical during this time of year, the AGA data tend to under-report gas storage levels. We now estimate that the "official" storage level will build to slightly below 2.5 Tcf at the end of July and peak at 3.25-3.30 Tcf at the end of October. This level is far higher than the industry's typical goal of about 3.0 Tcf.

Another factor at work in the natural gas market is the prevalent opinion that gas production is going to be lower this year because the number of gas drilling rigs in operation is very low. However, we believe that the fewer rigs in operation are likely being used to drill the best prospects and might therefore be much more successful in finding gas. Also, the drilling rig data do not report the rigs that are being used to rework existing wells, which should be an important factor in maintaining or increasing gas production. Furthermore, the drilling rig data do not account for the deepwater Gulf of Mexico projects that are just beginning to come into production. Lastly, the current high prices for both oil and gas should result in a rebound (albeit cautious) in drilling rig utilization.

Recent data from the EIA support our contention that gas production might not be as low as the market is currently expecting. The EIA's data for June show that dry gas production of 1,550 Bcf per month was only slightly lower (99.5%) than during June 1998. This production estimate, if accurate, dispels some of the hype in the market regarding lower gas production this year. In what we believe is a fairly conservative forecast, we expect that dry gas production this year will average only about 1% less than last year.

In addition to U.S. domestic production, natural gas imports from Canada will likely be higher this year due to recent expansions of two western pipelines, and the planned addition of the new Maritimes Pipeline in eastern Canada by year-end. For example, data from the EIA show that net gas imports totaled 264 Bcf this June compared to 236 Bcf last year.

Purvin & Gertz continues to believe that summertime gas demand by electric utilities has been grossly overblown by the market. Market conditions that will likely not be repeated this summer include: 1) last summer was unusually hot, 2) more nuclear power plants were off line last year, and 3) coal deliveries to southern power plants were disrupted by railroad congestion. Furthermore, hydroelectric power production is expected to be much higher this summer due to increased snowmelt. Based on these many factors, we expect that annual utility consumption of natural gas during 1999 will drop by nearly 3% from last year's unusually high demand. For example, in June electric utilities used 2 Bcf less gas this year than during June last year.

FIGURE V-4
NORTHEAST UTILITY FUEL PRICING
DELIVERED RESID VS BURNER TIP GAS PARITY

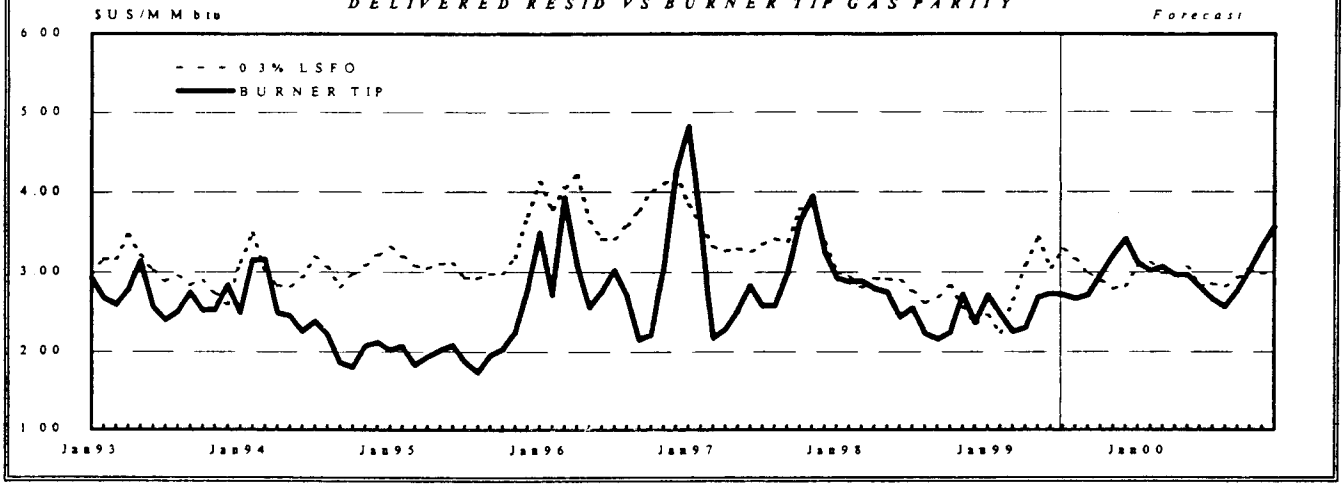


FIGURE V-5
FLORIDA UTILITY FUEL PRICING
DELIVERED RESID VS BURNER TIP GAS PARITY

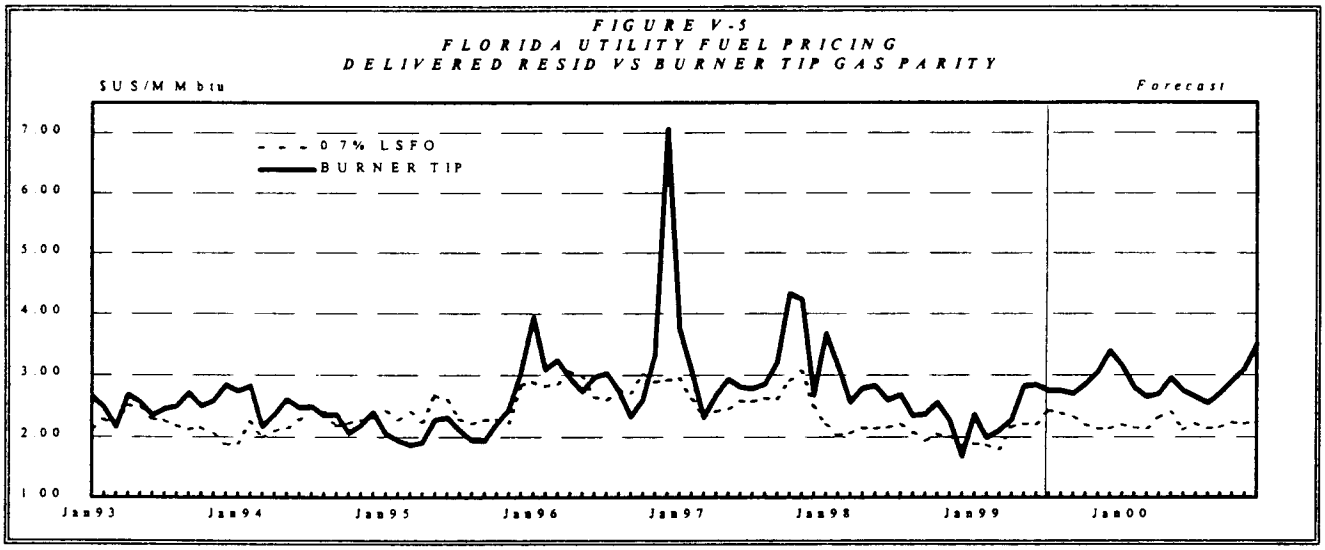
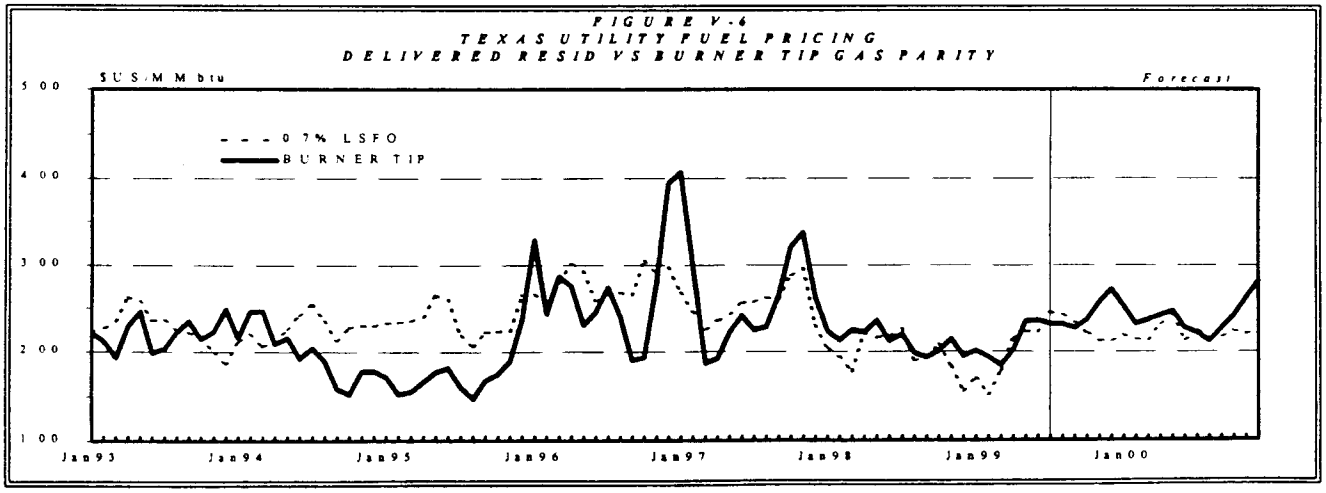


FIGURE V-6
TEXAS UTILITY FUEL PRICING
DELIVERED RESID VS BURNER TIP GAS PARITY



Lastly, the gas market has been concerned about the possibility that increased hurricane activity in the Gulf of Mexico might curtain production this summer and fall. Although this factor cannot be overlooked, particularly as the U.S. becomes increasingly dependent on gas production from offshore platforms, we are concerned that the market may be inflating the magnitude of the possible disruptions.

With the natural gas market being driven more by psychological factors than by fundamentals we believe that there will be two pivotal periods in the near future for gas prices. If gas demand for power generation continues to be lower this summer, gas prices should drop in September. Secondly, if the hurricane season does not significantly disrupt gas production, prices could drop later this year.

AGA data show that working gas in storage in the U.S. rose to 2.161 Tcf as of July 9, which was 17 Bcf less than at the same time in 1998. Although the market seems to think that this was bullish news, we believe it was bearish because last year's storage level was significantly higher than in previous years. This year, gas storage facilities in the U.S. were 66.5% full versus 68.3% last year. The largest excess was in the Producing Region where working gas in storage rose to 721 Bcf of gas (76% full) versus last year's level of 678 Bcf (74% full). Storage facilities in the Western Consuming Region were also higher with 347 Bcf of gas in storage (71% full) compared to 321 Bcf (67% full) at the same time in 1998. The deficit was in the Eastern Consuming Region where working gas in storage rose to 1093 Bcf (60% full) versus 1179 Bcf (66% full) last year.

Data from the EIA show that "official" storage levels totaled 2.169 Tcf at the end of June, compared to the AGA's estimate of slightly above 2.0 Tcf. Thus, we estimate that "official" storage levels will rise to about 2.5 Tcf at the end of July and will peak at 3.25-3.30 Tcf at the end of October.

The EIA's data for June show that dry gas production of 1,550 Bcf per month was only 99.5% lower than during June 1998, which dispels some of the hype regarding lower gas production this year. We expect that dry gas production this year will average about 1% less than last year's monthly rates. Data from the EIA also show that net gas imports rose to 264 Bcf this June compared to 236 Bcf last year due to recent expansions of gas export pipelines from Canada.

U.S. gas consumption totaled 1.502 Tcf this June compared to 1.482 Tcf in June 1998. Residential gas consumption of 144 Bcf was 9 Bcf lower than during June last year. Our forecast calls for residential consumption of natural gas to be about 8.0% higher during 1999 than in 1998 due to the very mild winter last year. Natural gas consumption by the commercial sector was 14 Bcf higher at 157 Bcf this June, and should average 2.5%-3.0% higher than in 1998. The industrial sector used about 27 Bcf more natural gas this June (680 Bcf) and demand should continue to exceed last year's consumption.

At 377 Bcf, electric utility consumption of gas this June was 2 Bcf less than last year. We expect utility demand will drop by nearly 3% in 1999 due to lower summertime demand because: 1) last summer was unusually hot, 2) more nuclear power plants were off line last, and 3) coal deliveries to southern power plants were disrupted by railroad congestion.

NATURAL GAS FUTURES CONTRACT

Since late-June, natural gas futures moved downward, as we predicted. However, there has been a strong rally in prices since late July, as expectations of strong electric demand due to air conditioning hit the futures market. The prompt natural gas contract hit a low of $2.14 per million Btu on July 12 and continued to languish under $2.20 per million Btu until July 21, when the contract rallied to over $2.52, a new high.

In last month's report, we suggested that selling the prompt month natural gas contract was the appropriate course of action, as we felt the market was overbought. We were correct, as the market declined from a near term high of $2.40 per million Btu on June 29 to the low of $2.14 per million Btu on July 12. We feel the market overcorrected in late July and was again in an overbought situation. An imminent correction is due, as the market rose almost 15% in three trading days.

We continue to believe the market has additional downside. While the indicator has not yet triggered a "sell" signal, we are looking for a downward correction in the market. However, we would recommend a neutral stance until there is some evidence of a downward move. We feel that any disappointment, such as lower air conditioning demand as temperatures across the country move lower, could be the trigger for a downward move in gas futures that could be as sharp as the recent upward move. We suggest caution as prices are extremely volatile, but are looking for some downward corrections to appear.

NYMEX FRACT SPREAD

The propane-versus-natural gas fract spread moved upward quite significantly since late June. Since early June, the fract spread has been on an almost continual upward movement, till hitting a peak at $2.02 per million Btu on July 19. Since then, the spread moved downward. As the spread moved downward, it changed signals and moved into "sell" territory after sending a "buy" signal since early June.

In last month's report, we stated that we were in agreement with the indicator, which signaled a "buy" at that time, indicating that purchasing propane contracts and selling natural gas contracts was the preferred course of action. We also stated that we were waiting for an imminent reversal of the signal as we believed the fract spread had reached a near term peak. For the next month, we feel there will be a move into "buy" territory as the natural gas futures contract retreats from its recent highs and the propane market continues to stay firm. Therefore, we feel that the purchase of propane contracts and the sale of natural gas contracts will provide the lowest risk for August.

FIGURE V-7
NYMEX PROMPT MONTH NATURAL GAS FUTURES

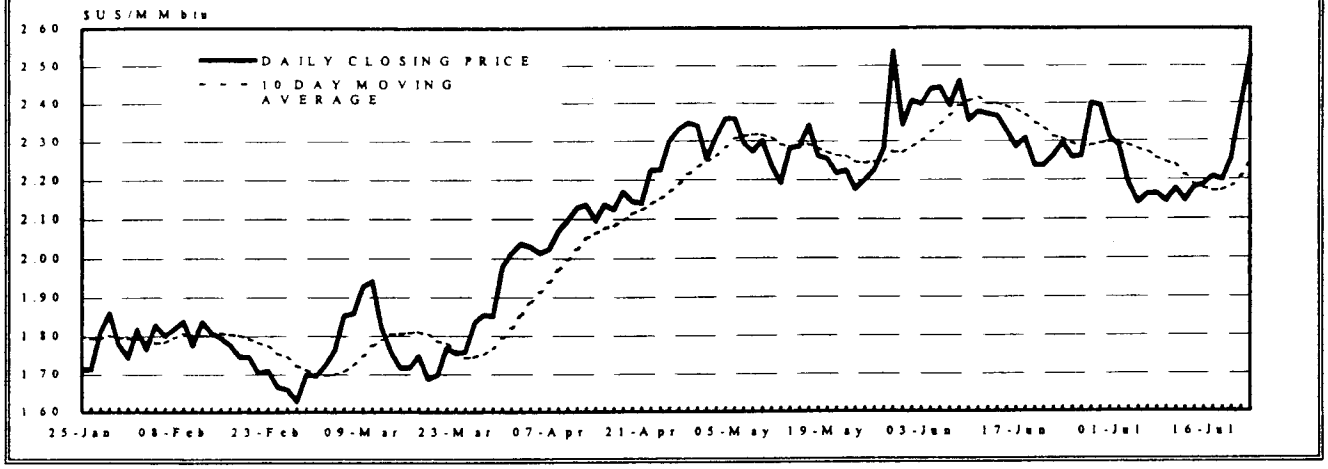


FIGURE V-8
CANADIAN GAS PRICE BASIS DIFFERENTIALS

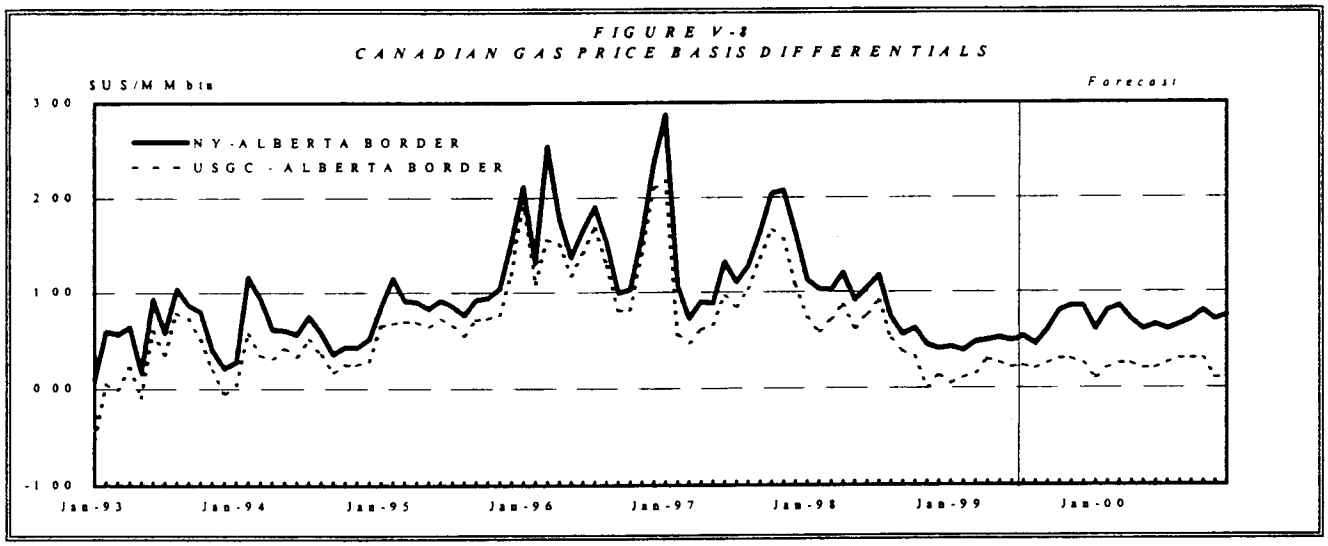
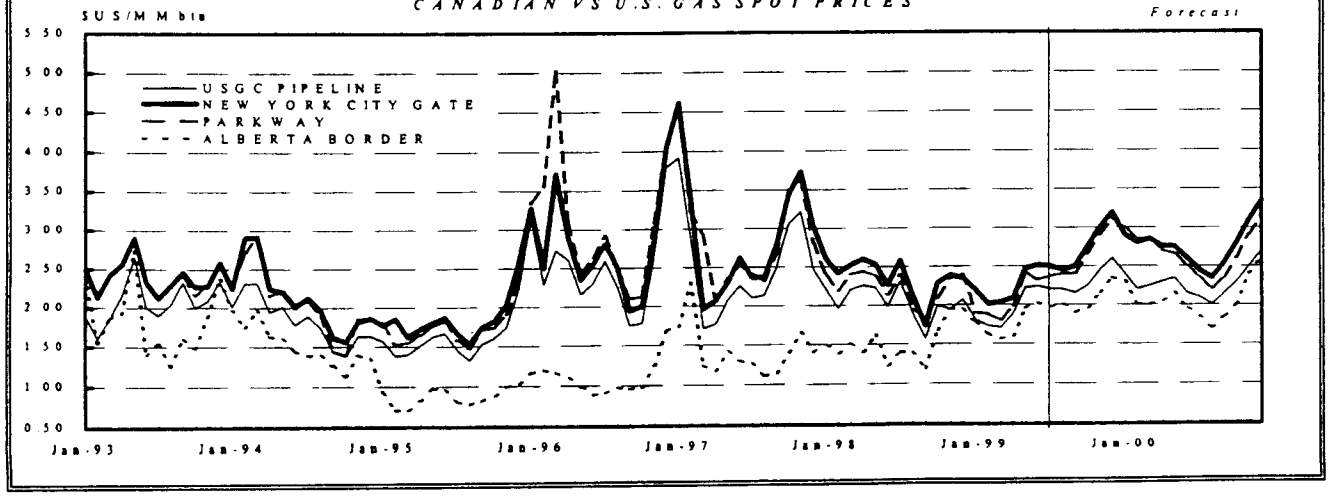


FIGURE V-9
CANADIAN VS U.S. GAS SPOT PRICES



CANADIAN NATURAL GAS PRICING

- PURVIN & GERTZ PRICE FORECAST NUDGED UPWARDS.
- PRICES TO MODERATE IN NEAR TERM.
- MARKET PRICE EXPECTATIONS TOO STRONG.

CANADIAN NATURAL GAS PRICES

Spot prices in Western Canada remained mostly flat during the first half of July. This was certainly not the case for the last two weeks of the month as prices increased dramatically. Market perceptions are still bullish, however, prices are expected to stabilize relative to the increases seen throughout July.

Prices at the end of July for AECO/NIT were 0.36 $Cdn/Mcf higher than at the beginning of the month and have remained well over the 3.00 $Cdn/Mcf mark since the end of July. Prices have not seen these levels in over two years. Most of the increase can be attributed to the rise in prices on the NYMEX. Scorching heat across much of the United States drove up demand for electricity to meet air conditioning requirements. Storage injections in the United States suffered as a result of the increase in power generation demand, making the third week in July the lowest since mid-April. However, inventory remains close to last year's five-year record high. It is expected that prices will not remain at these levels and will begin to trade in a range more in in-line with current market fundamentals.

Although Western Canada is currently a strong natural gas market, the differential between Henry Hub and the Alberta Border throughout July indicated that prices could not support the levels seen in the United States based on Alberta market fundamentals. The basis between Henry Hub and the Alberta border widened from approximately 0.40 $Cdn/Mcf at the beginning of the month to just over 0.70 $Cdn/Mcf by month end.

Futures prices also strengthened during the month to reach their highest levels of the year. Winter 99/00 gas gained approximately 0.25 $Cdn/Mcf over the course of the month.

Despite a short term increase, Purvin & Gertz still believes that the basis between Henry Hub and the Alberta Border will remain in the 0.20-0.30 $U.S./MMBtu range until the end of the year. Prices will decrease slightly in the traditional shoulder months of September and October but will strengthen into the winter heating season.

ALBERTA GAS PRICES

Canadian natural gas storage information released by the Canadian Gas Association continues to show high levels of natural gas in storage, comparable to levels seen last year. The last survey before the end of the month reported that storage was 66% full compared to 70% full in 1998. Western regions are still above last year's volumes while eastern provinces are below. When comparing data between the two years, it should be noted that 1998 was a record year for gas volumes in storage, reaching levels not seen in five years.

The basis between AECO and Empress was narrow throughout the entire month and remained in the 0.01-0.02 $Cdn./Mcf range. The basis indicates the value of transportation between two points. In this case, the value has dropped below the full, regulated transportation cost, indicating seasonal weakness.

Reduced receipts into the Alberta system (formerly Nova), due to lower drilling levels associated with the recent slump in crude oil prices, is another factor lending support to the recent surge in natural gas prices in Alberta.

B.C. PRICES

Prices at Kingsgate for the month of July traded in a narrow band relative to Alberta prices. Kingsgate/Empress differentials rarely deviated more than a couple of cents. The basis between B.C. prices and Alberta prices is expected to remain narrow for the remainder of the year and throughout 2000. Huntingdon prices are forecast to decrease slightly in September to 2.65 $C/GJ before topping out at 3.32 $C/GJ in December.

ONTARIO/NEW YORK PRICES

The New York City-gate price, at 2.50 $U.S./MMBtu, was essentially unchanged from last month's price. Parkway was up slightly, trading at a 0.13 $U.S./MMBtu discount to New York. The basis between these two pricing points is expected to remain between 0.05-0.10 $U.S./MMBtu in the near term. Pipeline developments into these two market areas is sure to have an effect on the differential in the longer term.

TABLE V-1
U.S. NATURAL GAS SUPPLY/DEMAND
(Trillion Cubic Feet)

	Domestic Gas Production				Imports/Exports						
Period	Marketed Wet Prod	Shrink	Dry	Synth. Nat Gas	Imports	Exports	Net	Inventory W/drawals - Additns	Adjust-ments	Net Dry Gas Con-sumption	Work. Gas Ending Inventory
January 1997	1.709	0.083	1.626	0.012	0.278	0.012	0.266	0.685	0.066	2.523	1.496
February	1.549	0.075	1.474	0.010	0.241	0.012	0.228	0.358	(0.183)	2.253	1.139
March	1.720	0.084	1.636	0.009	0.257	0.016	0.241	0.154	(0.075)	2.115	0.990
April	1.639	0.080	1.559	0.008	0.238	0.014	0.224	(0.059)	(0.063)	1.795	1.051
May	1.702	0.083	1.619	0.008	0.242	0.010	0.232	(0.321)	(0.050)	1.588	1.365
June	1.612	0.078	1.534	0.008	0.232	0.010	0.223	(0.365)	(0.053)	1.451	1.731
July	1.674	0.081	1.593	0.007	0.236	0.010	0.225	(0.283)	0.005	1.537	2.017
August	1.671	0.081	1.590	0.008	0.245	0.018	0.227	(0.322)	(0.015)	1.518	2.338
September	1.632	0.079	1.553	0.008	0.239	0.013	0.226	(0.336)	0.009	1.440	2.672
October	1.678	0.081	1.597	0.008	0.252	0.012	0.239	(0.210)	0.100	1.534	2.886
November	1.626	0.079	1.547	0.010	0.272	0.013	0.259	0.189	0.110	1.895	2.699
December	1.655	0.080	1.575	0.011	0.263	0.017	0.246	0.534	0.049	2.317	2.175
January 1998	1.717	0.084	1.633	0.012	0.284	0.017	0.267	0.467	(0.035)	2.414	1.713
February	1.547	0.075	1.472	0.010	0.248	0.011	0.237	0.299	(0.091)	2.109	1.419
March	1.696	0.083	1.613	0.011	0.264	0.019	0.244	0.242	(0.022)	2.132	1.185
April	1.632	0.079	1.553	0.009	0.248	0.013	0.235	(0.199)	(0.123)	1.721	1.382
May	1.682	0.082	1.600	0.008	0.250	0.010	0.240	(0.393)	(0.060)	1.515	1.775
June	1.637	0.079	1.558	0.007	0.251	0.015	0.236	(0.323)	(5.703)	7.181	2.103
July	1.665	0.081	1.584	0.009	0.263	0.012	0.251	(0.314)	(0.058)	1.588	2.417
August	1.681	0.081	1.600	0.009	0.256	0.012	0.244	(0.284)	(0.015)	1.584	2.697
September	1.631	0.079	1.552	0.009	0.268	0.013	0.255	(0.227)	0.121	1.468	2.949
October	1.677	0.082	1.595	0.010	0.270	0.013	0.257	(0.255)	0.117	1.490	3.176
November	1.615	0.079	1.536	0.011	0.256	0.013	0.243	0.034	0.107	1.717	3.143
December	1.674	0.081	1.593	0.012	0.284	0.016	0.267	0.436	0.168	2.140	2.718
January 1999	1.659	0.080	1.579	0.013	0.308	0.015	0.293	0.623	(0.020)	2.528	2.094
February	1.511	0.073	1.438	0.010	0.276	0.015	0.260	0.333	(0.080)	2.121	1.792
March	1.687	0.082	1.605	0.011	0.294	0.018	0.276	0.297	0.054	2.135	1.430
April	1.625	0.079	1.546	0.010	0.275	0.014	0.261	(0.091)	(0.108)	1.834	1.514
May	1.678	0.082	1.596	0.009	0.278	0.011	0.267	(0.325)	(0.026)	1.573	1.839
June	1.593	0.079	1.494	0.009	0.280	0.015	0.264	(0.330)	(0.064)	1.502	2.169
July	1.611	0.081	1.543	0.009	0.295	0.015	0.279	(0.324)	(0.106)	1.613	2.493
* August	1.627	0.081	1.580	0.009	0.287	0.015	0.272	(0.308)	(0.057)	1.609	2.801
* September	1.577	0.079	1.512	0.009	0.299	0.017	0.282	(0.322)	(0.014)	1.495	3.123
* October	1.623	0.082	1.584	0.010	0.303	0.015	0.287	(0.166)	0.170	1.545	3.289
* November	1.561	0.079	1.650	0.011	0.283	0.013	0.270	0.233	0.333	1.831	3.056
* December	1.621	0.081	1.638	0.012	0.309	0.015	0.294	0.514	0.177	2.281	2.542
* January 2000	1.679	0.081	1.598	0.012	0.313	0.015	0.298	0.672	0.014	2.566	1.870
* February	1.529	0.074	1.455	0.010	0.280	0.015	0.265	0.490	(0.055)	2.276	1.380
* March	1.707	0.083	1.624	0.011	0.302	0.015	0.287	0.234	(0.015)	2.171	1.145
* April	1.644	0.080	1.564	0.009	0.287	0.015	0.271	(0.102)	(0.080)	1.823	1.247
* May	1.698	0.083	1.615	0.008	0.292	0.011	0.281	(0.357)	(0.058)	1.604	1.604
* June	1.648	0.080	1.568	0.007	0.294	0.015	0.279	(0.355)	(0.035)	1.534	1.959
* July	1.666	0.082	1.585	0.009	0.309	0.015	0.294	(0.334)	(0.095)	1.649	2.293
* August	1.682	0.082	1.601	0.009	0.301	0.015	0.286	(0.288)	(0.038)	1.646	2.581
* September	1.632	0.080	1.552	0.009	0.314	0.017	0.297	(0.322)	0.009	1.528	2.903
* October	1.678	0.083	1.596	0.010	0.318	0.015	0.303	(0.176)	0.157	1.575	3.079
* November	1.616	0.080	1.536	0.011	0.298	0.013	0.284	0.208	0.177	1.863	2.871
* December	1.675	0.082	1.594	0.012	0.325	0.015	0.310	0.474	0.070	2.319	2.397
1997 Qtr 1	4.978	0.242	4.736	0.031	0.776	0.041	0.735	1.197	(0.192)	6.891	0.990
1997 Qtr 2	4.953	0.241	4.712	0.022	0.712	0.033	0.679	(0.745)	(0.166)	4.834	2.017
1997 Qtr 3	4.977	0.241	4.736	0.021	0.720	0.041	0.679	(0.941)	(0.000)	4.495	2.672
1997 Qtr 4	4.959	0.240	4.719	0.029	0.787	0.042	0.745	0.513	0.260	5.746	2.175
1998 Qtr 1	4.960	0.242	4.718	0.033	0.795	0.048	0.748	1.008	(0.148)	6.655	1.185
1998 Qtr 2	4.951	0.240	4.711	0.024	0.749	0.038	0.712	(0.915)	(5.885)	10.417	2.103
1998 Qtr 3	4.977	0.241	4.736	0.027	0.787	0.037	0.750	(0.825)	0.048	4.640	2.949
1998 Qtr 4	4.966	0.242	4.724	0.033	0.810	0.043	0.767	0.215	0.392	5.347	2.718
1999 Qtr 1	4.857	0.235	4.622	0.034	0.877	0.048	0.829	1.253	(0.048)	6.784	1.430
1999 Qtr 2	4.932	0.240	4.636	0.028	0.833	0.040	0.792	(0.746)	(0.198)	4.909	2.169
* 1999 Qtr 3	4.922	0.240	4.634	0.027	0.881	0.048	0.833	(0.954)	(0.177)	4.717	3.123
* 1999 Qtr 4	4.911	0.241	4.671	0.033	0.895	0.044	0.851	0.581	0.679	5.657	2.542
* 2000 Qtr 1	4.915	0.238	4.677	0.033	0.895	0.045	0.850	1.397	(0.056)	7.012	4.395
* 2000 Qtr 2	4.990	0.243	4.748	0.024	0.873	0.042	0.831	(0.814)	(0.173)	4.962	4.810
* 2000 Qtr 3	4.980	0.243	4.738	0.027	0.925	0.048	0.877	(0.944)	(0.124)	4.823	7.776
* 2000 Qtr 4	4.969	0.244	4.726	0.033	0.940	0.044	0.897	0.506	0.404	5.757	8.346
1996 Year	19.751	0.958	18.793	0.110	2.937	0.153	2.784	0.007	(0.268)	21.962	2.173
1997 Year	19.867	0.964	18.903	0.103	2.994	0.157	2.837	0.024	(0.099)	21.966	2.175
1998 Year	19.854	0.965	18.889	0.117	3.142	0.165	2.977	(0.517)	(5.593)	27.059	2.718
* 1999 Year	19.374	0.956	18.600	0.122	3.488	0.180	3.308	0.134	0.256	22.067	2.542
* 2000 Year	19.855	0.967	18.888	0.117	3.634	0.179	3.454	0.145	0.051	22.554	2.397

* designates forecast

TABLE V-2
NATURAL GAS PRICE OUTLOOK
SPOT AVERAGE - DELIVERED TO PIPELINE
(US Dollars per MMBTU unless noted)

Time Period	Gulf Coast	W Texas N Mexico	Mid-Continent	Rocky Mountains	Alberta Border $US/MMBtu	Alberta Border $C/GJ	Huntingdon $US/MMBtu	Huntingdon $C/GJ
January 1997	3.92	4.10	4.13	4.19	1.74	2.22	3.92	5.01
February	2.85	2.53	2.76	2.47	2.30	2.96	2.43	3.12
March	1.71	1.53	1.62	1.39	1.25	1.62	1.07	1.39
April	1.77	1.62	1.69	1.43	1.17	1.55	1.14	1.51
May	2.07	1.90	1.93	1.63	1.42	1.86	1.36	1.78
June	2.26	2.06	2.11	1.46	1.30	1.71	1.33	1.75
July	2.10	2.00	2.00	1.43	1.26	1.65	1.22	1.59
August	2.14	2.05	2.04	1.38	1.11	1.46	1.11	1.46
September	2.49	2.36	2.39	1.47	1.14	1.50	1.19	1.56
October	3.06	2.87	2.98	2.11	1.40	1.84	1.49	1.96
November	3.22	3.12	3.14	2.99	1.66	2.22	2.76	3.70
December	2.47	2.21	2.33	1.94	1.40	1.90	1.46	1.97
January 1998	2.21	2.09	2.13	2.04	1.49	2.03	1.81	2.47
February	1.96	1.86	1.91	1.69	1.39	1.89	1.43	1.95
March	2.21	2.06	2.15	1.87	1.50	2.02	1.17	1.57
April	2.26	2.14	2.16	1.90	1.40	1.90	1.39	1.88
May	2.23	2.11	2.15	1.97	1.62	2.22	1.68	2.30
June	1.98	1.88	1.92	1.63	1.22	1.70	1.38	1.91
July	2.31	2.18	2.25	1.61	1.40	1.98	1.43	2.02
August	1.89	1.92	1.83	1.73	1.39	2.02	1.55	2.25
September	1.57	1.59	1.55	1.55	1.19	1.71	1.41	2.03
October	1.99	1.83	1.89	1.65	1.67	2.45	1.65	2.42
November	1.95	1.96	1.93	1.97	1.95	2.84	2.15	3.13
December	2.07	1.99	2.04	1.99	1.94	2.84	2.12	3.10
January 1999	1.81	1.75	1.83	1.71	1.77	2.55	2.94	4.24
February	1.73	1.67	1.72	1.63	1.63	2.31	1.76	2.50
March	1.71	1.65	1.66	1.52	1.56	2.25	1.48	2.13
April	1.89	1.90	1.94	1.76	1.59	2.25	1.52	2.14
May	2.22	2.17	2.17	2.01	1.95	2.71	1.92	2.66
June	2.24	2.19	2.18	1.99	2.03	2.82	1.90	2.65
July	2.20	2.15	2.15	1.95	1.97	2.77	1.93	2.69
* August	2.20	2.15	2.15	2.00	2.00	2.80	2.00	2.80
* September	2.15	2.10	2.10	1.95	1.90	2.65	1.90	2.65
* October	2.25	2.20	2.10	2.00	1.95	2.71	2.00	2.78
* November	2.45	2.40	2.20	2.20	2.15	2.98	2.20	3.05
* December	2.60	2.60	2.30	2.40	2.35	3.25	2.40	3.32
* January 2000	2.40	2.35	2.05	2.15	2.30	3.18	2.35	3.25
* February	2.20	2.15	1.95	2.00	2.00	2.77	2.05	2.84
* March	2.25	2.15	2.15	2.05	2.00	2.76	2.00	2.76
* April	2.30	2.20	2.25	2.10	2.05	2.83	2.00	2.76
* May	2.35	2.25	2.20	2.05	2.15	2.97	2.10	2.90
* June	2.15	2.05	2.05	1.95	1.95	2.69	1.95	2.69
* July	2.10	2.00	2.00	1.85	1.85	2.55	1.85	2.55
* August	2.00	1.95	1.90	1.75	1.70	2.34	1.70	2.34
* September	2.15	2.10	2.10	2.00	1.85	2.54	1.85	2.54
* October	2.30	2.25	2.15	2.10	2.00	2.71	2.05	2.78
* November	2.50	2.45	2.25	2.25	2.40	3.25	2.45	3.32
* December	2.70	2.70	2.35	2.45	2.60	3.47	2.65	3.54
1998 Qtr 1	2.13	2.00	2.07	1.87	1.46	1.98	1.47	2.00
1998 Qtr 2	2.16	2.04	2.08	1.83	1.42	1.94	1.48	2.03
1998 Qtr 3	1.92	1.90	1.88	1.63	1.33	1.90	1.46	2.10
1998 Qtr 4	2.00	1.92	1.95	1.87	1.85	2.71	1.97	2.88
1999 Qtr 1	1.75	1.69	1.74	1.62	1.65	2.37	2.06	2.96
1999 Qtr 2	2.12	2.09	2.10	1.92	1.86	2.59	1.78	2.48
* 1999 Qtr 3	2.18	2.13	2.13	1.97	1.96	2.74	1.94	2.71
* 1999 Qtr 4	2.00	1.92	1.95	1.87	1.85	2.71	1.97	2.88
* 2000 Qtr 1	2.28	2.22	2.05	2.07	2.10	2.91	2.13	2.95
* 2000 Qtr 2	2.27	2.17	2.17	2.03	2.05	2.83	2.02	2.79
* 2000 Qtr 3	2.08	2.02	2.00	1.87	1.80	2.48	1.80	2.48
* 2000 Qtr 4	2.50	2.47	2.25	2.27	2.33	3.14	2.38	3.21
1996 Year	2.50	2.05	2.13	1.44	1.10	1.43	1.32	1.71
1997 Year	2.50	2.36	2.43	1.99	1.42	1.87	1.70	2.23
1998 Year	2.05	1.97	2.00	1.80	1.51	2.14	1.60	2.26
* 1999 Year	2.12	2.08	2.04	1.93	1.91	2.67	2.00	2.81
* 2000 Year	2.28	2.22	2.12	2.06	2.07	2.84	2.08	2.86

* designates forecast

TABLE V-3
NATURAL GAS PRICE OUTLOOK
SPOT AVERAGE - DELIVERED TO MARKET
(US Dollars per MMBTU unless noted)

	New York				California	Parkway	
Time Period	Burner Tip	City Gate	Midwest	Florida	Border	US$MMBtu	C$/GJ
January 1997	4.82	4.61	4.63	3.74	3.91	4.60	5.88
February	3.58	3.37	3.24	3.07	2.63	3.22	4.14
March	2.17	1.96	1.95	2.32	1.63	2.93	3.81
April	2.28	2.07	1.96	2.68	1.75	2.06	2.72
May	2.51	2.30	2.08	2.93	2.08	2.36	3.09
June	2.83	2.62	2.35	2.81	2.21	2.51	3.29
July	2.58	2.37	2.23	2.78	2.19	2.41	3.15
August	2.59	2.38	2.22	2.85	2.22	2.32	3.06
September	2.99	2.78	2.67	3.21	2.49	2.67	3.51
October	3.65	3.44	3.26	4.33	3.09	3.50	4.60
November	3.94	3.73	3.67	4.23	3.33	3.63	4.86
December	3.25	3.04	2.86	2.68	2.32	2.81	3.80
January 1998	2.92	2.61	2.36	3.68	2.26	2.40	3.28
February	2.87	2.42	2.11	3.15	2.09	2.19	2.98
March	2.88	2.53	2.30	2.56	2.35	2.40	3.22
April	2.79	2.60	2.39	2.79	2.36	2.45	3.32
May	2.74	2.53	2.36	2.83	2.35	2.38	3.26
June	2.44	2.27	2.13	2.60	2.06	2.13	2.96
July	2.55	2.58	2.42	2.69	2.22	2.40	3.39
August	2.23	2.12	1.98	2.35	2.29	1.94	2.82
September	2.15	1.74	1.67	2.37	2.01	1.83	2.64
October	2.24	2.29	2.15	2.56	2.03	2.09	3.06
November	2.72	2.39	2.16	2.28	2.33	2.33	3.40
December	2.36	2.35	2.27	1.68	2.29	2.40	3.51
January 1999	2.71	2.19	1.93	2.36	1.94	1.90	2.74
February	2.47	2.01	1.77	1.98	1.83	1.88	2.67
March	2.25	2.04	1.77	2.11	1.73	1.80	2.59
April	2.30	2.09	1.82	2.29	1.94	1.98	2.80
May	2.69	2.47	2.27	2.82	2.23	2.41	3.34
June	2.73	2.51	2.29	2.84	2.29	2.32	3.23
July	2.72	2.50	2.30	2.75	2.35	2.37	3.33
* August	2.67	2.45	2.30	2.75	2.30	2.40	3.36
* September	2.72	2.50	2.25	2.70	2.25	2.40	3.35
* October	2.97	2.75	2.35	2.85	2.40	2.65	3.68
* November	3.22	3.00	2.55	3.05	2.60	2.90	4.02
* December	3.42	3.20	2.80	3.40	2.75	3.10	4.29
* January 2000	3.12	2.90	2.55	3.15	2.65	3.00	4.15
* February	3.02	2.80	2.40	2.80	2.40	2.85	3.95
* March	3.07	2.85	2.45	2.85	2.40	2.85	3.94
* April	2.97	2.75	2.45	2.70	2.40	2.70	3.73
* May	2.97	2.75	2.40	2.95	2.45	2.65	3.66
* June	2.82	2.60	2.25	2.75	2.25	2.50	3.45
* July	2.67	2.45	2.15	2.65	2.20	2.35	3.24
* August	2.57	2.35	2.05	2.55	2.15	2.20	3.03
* September	2.77	2.55	2.25	2.70	2.30	2.35	3.23
* October	3.02	2.80	2.40	2.90	2.50	2.60	3.52
* November	3.32	3.10	2.60	3.10	2.70	2.90	3.93
* December	3.57	3.35	2.85	3.50	2.90	3.15	4.21
1998 Qtr 1	2.89	2.52	2.26	3.13	2.23	2.33	3.16
1998 Qtr 2	2.66	2.47	2.29	2.74	2.26	2.32	3.18
1998 Qtr 3	2.31	2.14	2.02	2.47	2.17	2.06	2.95
1998 Qtr 4	2.44	2.34	2.19	2.17	2.22	2.27	3.32
1999 Qtr 1	2.48	2.08	1.82	2.15	1.83	1.86	2.67
1999 Qtr 2	2.57	2.36	2.13	2.65	2.15	2.24	3.12
* 1999 Qtr 3	2.70	2.48	2.28	2.73	2.30	2.39	3.35
* 1999 Qtr 4	3.20	2.98	2.57	3.10	2.58	2.88	4.00
* 2000 Qtr 1	3.07	2.85	2.47	2.87	2.48	2.90	4.01
* 2000 Qtr 2	2.92	2.70	2.37	2.80	2.37	2.62	3.62
* 2000 Qtr 3	2.67	2.45	2.15	2.63	2.22	2.30	3.17
* 2000 Qtr 4	3.30	3.08	2.62	3.17	2.70	2.88	3.89
1996 Year	3.00	2.79	2.65	3.34	1.82	3.07	3.97
1997 Year	3.09	2.88	2.75	3.13	2.48	2.91	3.82
1998 Year	2.57	2.37	2.19	2.62	2.22	2.25	3.16
* 1999 Year	2.74	2.48	2.20	2.66	2.22	2.35	3.29
* 2000 Year	2.99	2.77	2.40	2.87	2.44	2.67	3.67

* designates forecast

TABLE III-1
LIGHT CRUDE OIL PRICES AND TRADING RELATIONSHIPS
(Dollars per Barrel)

	1998				1999		FORECAST 1999		FORECAST 2000												FORECAST	
	1Q	2Q	3Q	4Q	1Q	2Q	3Q	4Q	1Q	2Q	3Q	4Q	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000
Mideast Light Prices																						
Dubai Spot, FOB	12.37	12.23	12.48	11.58	11.08	15.28	17.47	16.43	16.59	15.08	15.09	15.33	16.50	17.10	14.87	14.72	16.67	18.52	18.10	12.14	14.57	15.90
Dubai Spot, USGC	14.34	14.49	14.47	13.34	12.49	16.73	19.40	17.73	18.44	16.73	18.00	17.28	18.94	19.83	16.87	16.28	17.89	20.42	20.33	14.14	16.71	16.80
Brent Prices																						
Brent Dated-Dubai, FOB	1.05	1.07	(0.02)	(0.36)	0.24	0.20	0.06	0.32	0.56	1.10	0.30	0.12	3.45	2.13	2.00	1.07	0.94	2.13	0.97	0.58	0.43	0.81
Brent Dated-Dubai, USGC	1.16	0.37	(0.74)	(0.66)	(0.28)	(0.06)	0.43	(0.20)	0.46	0.83	(0.10)	(0.20)	2.72	1.63	1.74	0.94	0.40	1.68	0.29	(0.05)	(0.05)	0.26
Brent-Dubai, Cracking, USGC	1.04	1.63	1.46	1.42	1.17	1.16	1.40	1.43	1.75	1.68	1.44	1.47	2.00	2.33	2.30	1.65	1.29	1.65	1.66	1.01	1.30	1.51
WTI-Brent Dated, USGC	0.39	(0.17)	0.47	0.44	0.44	1.00	0.51	0.34	0.37	0.65	0.59	0.38	0.38	0.58	0.61	0.38	0.23	0.20	(0.07)	0.28	0.47	0.80
WTI, Cushing-Brent Dated, FOB	1.92	1.33	1.71	1.73	1.77	2.10	1.56	1.57	1.58	1.77	1.58	1.56	1.54	1.25	1.46	1.41	1.40	1.49	1.32	1.67	1.46	1.07
Brent Dated-1st Month, FOB	(0.40)	(0.41)	(0.33)	(0.37)	(0.23)	(0.30)	(0.20)	(0.12)	(0.05)	(0.13)	(0.12)	(0.12)	(0.06)	(0.05)	(0.10)	(0.16)	(0.17)	(0.14)	(0.22)	(0.39)	(0.22)	(0.10)
Brent Dated, FOB	14.02	13.30	12.83	11.14	11.30	15.48	16.83	16.15	16.64	16.47	15.80	15.76	19.84	19.28	16.94	16.79	17.01	20.84	19.07	12.71	16.41	[illegible]
Brent 1st Month, FOB	14.42	13.77	12.83	11.51	11.52	15.82	16.43	16.27	16.68	16.60	16.21	15.88	20.00	19.34	17.06	15.90	17.18	20.70	19.20	13.11	16.63	[illegible]
Brent Dated, USGC	15.51	14.70	13.93	12.38	12.01	16.68	17.43	17.48	20.51	17.06	16.71	17.07	21.40	20.44	18.31	17.12	18.38	22.10	20.41	14.09	16.86	17.06
Light Louisiana Sweet Price																						
LLS-Brent, Cracking, USGC	0.11	0.07	0.09	0.07	0.10	0.16	0.78	0.34	0.23	0.10	0.21	0.30	0.31	0.28	0.20	0.23	0.24	0.27	0.22	0.08	0.17	0.22
LLS-Brent Dated, USGC	0.16	(0.40)	0.30	0.37	(0.09)	0.36	(0.10)	0.19	0.15	0.25	0.21	0.25	0.26	0.43	0.32	0.24	0.29	0.21	0.07	0.08	0.09	0.21
LLS, St. James	15.68	14.38	14.03	12.65	12.53	17.02	18.09	17.63	18.44	17.80	18.11	17.32	21.70	20.74	18.52	17.23	18.50	22.31	20.89	14.17	18.14	17.27
Isthmus Formula Prices																						
LLS-Isthmus, Cracking, USGC	1.73	1.31	1.24	1.27	1.05	0.99	1.27	1.47	1.48	1.43	1.33	1.37	2.53	2.17	2.19	1.54	1.24	1.79	1.72	1.39	1.20	1.11
LLS-Isthmus, USGC	1.60	1.71	1.59	1.81	1.49	1.35	1.26	1.47	1.42	1.43	1.35	1.07	2.72	2.25	2.04	1.27	1.37	1.18	1.79	1.63	1.39	1.44
WTI, Cushing-Isthmus, FOB	2.38	2.39	2.12	2.28	2.46	2.38	1.89	2.04	2.06	2.21	2.09	2.17	7.50	2.55	2.63	1.85	1.69	1.55	2.33	2.29	2.10	2.13
Isthmus Formula, FOB	13.88	12.34	12.02	10.58	10.81	16.27	11.38	[illegible]	[illegible]	11.08	15.10	15.26	18.40	17.80	18.89	15.36	16.72	20.58	18.26	12.10	14.50	15.26
Isthmus Formula, USGC	14.06	12.67	12.43	11.04	11.04	16.07	16.43	16.18	16.33	16.46	16.40	15.74	19.23	18.63	16.50	16.08	17.40	21.10	18.90	12.84	16.35	15.82
West Texas Intermediate Prices																						
WTI, Cushing-LLS, St. James	0.28	0.25	0.11	0.22	0.53	0.93	0.16	0.09	0.17	0.30	0.28	0.10	(0.31)	(0.20)	(0.10)	(0.03)	(0.17)	(0.18)	(0.09)	0.21	0.30	0.27
WTI, Midland-WTI, Cushing	0.29	0.26	0.30	0.31	0.27	0.23	0.17	0.10	0.27	0.16	0.14	0.15	0.05	0.11	0.09	0.10	0.13	0.08	0.28	0.27	0.22	0.19
WTI Spot, Cushing	15.94	14.63	14.14	12.87	13.06	17.88	18.97	17.73	17.72	18.24	17.18	17.42	21.40	20.54	18.43	17.20	18.41	22.13	20.59	14.39	17.10	17.48
WTI Spot, Midland	15.65	14.37	13.84	12.56	12.78	17.41	18.70	17.53	18.02	18.09	17.04	17.10	21.44	20.43	18.33	17.10	18.28	22.07	20.31	14.12	16.98	17.30
WTI Spot, USGC	16.30	14.62	14.10	12.82	13.05	17.07	18.91	17.78	17.10	18.31	17.30	17.48	22.02	21.04	18.92	17.40	18.91	22.30	20.58	14.37	17.12	17.56
WTI Posted, Midland	14.20	12.63	12.03	10.72	10.88	15.66	17.03	16.33	15.69	16.09	16.17	16.34	20.38	19.70	17.40	16.11	17.19	20.89	19.00	12.40	15.16	16.38
WTI Posted, USGC	14.47	12.90	12.31	11.00	11.10	15.83	16.20	16.40	16.88	16.88	16.35	14.22	21.29	20.41	18.01	16.51	17.58	21.19	19.20	12.69	16.43	16.33
WTI Posted, Field (40 API)	13.78	12.24	11.88	10.27	10.43	15.10	17.48	16.60	16.44	16.16	16.22	16.48	20.21	19.31	18.01	16.63	18.74	20.44	18.65	11.95	14.90	16.40
West Texas Sour Prices																						
WTI-WTS, Cracking, USGC	1.39	1.14	1.06	1.06	0.84	0.79	0.97	1.08	1.07	1.10	1.09	1.12	1.94	1.60	1.69	1.17	0.88	1.33	1.31	1.16	0.92	1.09
WTI-WTS Spot, Midland	1.72	1.34	1.00	1.17	0.99	1.28	1.12	1.18	1.08	1.11	1.11	1.22	2.17	1.80	1.51	0.85	0.89	1.18	1.42	1.30	1.16	1.13
WTS-Dubai Spot, USGC	(0.18)	(1.13)	(1.37)	(1.68)	(0.83)	(0.34)	(0.47)	(1.10)	(0.20)	0.41	(0.07)	(1.09)	0.01	0.71	0.84	0.38	(0.16)	0.70	(1.18)	(1.04)	(0.72)	(0.37)
WTI, Cushing-WTS, Midland	2.01	1.60	1.30	1.48	1.26	1.52	1.25	1.37	1.39	1.28	1.28	1.46	2.22	1.62	1.60	0.95	1.02	1.24	1.70	1.57	1.39	1.32
WTS Spot, Midland	13.93	13.03	12.84	11.38	11.80	16.13	16.38	16.44	16.84	16.94	16.06	15.87	19.27	18.92	16.83	16.28	17.31	20.89	18.90	12.81	15.73	16.17
WTS Spot, USGC	14.16	13.28	13.20	11.60	12.06	16.38	16.93	16.69	16.66	17.21	16.39	16.23	19.85	18.54	17.43	16.64	17.73	21.12	19.13	13.08	16.06	16.41
WTS Posted, Midland	11.16	9.54	9.88	7.87	7.73	12.31	14.78	12.98	15.41	13.41	13.12	12.70	18.11	17.34	15.00	13.73	14.78	18.60	18.10	9.28	11.98	12.60
WTS Posted, USGC	11.44	9.82	9.17	7.88	8.02	12.87	16.06	13.28	12.71	13.73	12.41	13.07	18.72	17.88	16.01	14.13	15.16	18.78	16.48	9.54	12.37	13.09
WTS Posted, Field (33 API)	10.71	9.09	9.44	7.12	7.20	11.34	14.33	12.53	11.98	13.09	12.47	12.33	17.84	16.87	14.82	13.28	14.34	18.05	18.74	8.83	11.84	12.33
Average Gulf Coast Light, USGC	14.88	13.83	13.33	11.85	11.78	16.34	18.06	16.89	18.34	17.17	16.29	16.83	20.60	19.76	17.42	16.73	18.04	21.73	19.70	13.36	16.04	16.65

UPDATE

July 1999

ADVISORY

RESEARCH

CAPITAL

FINANCIAL CORPORATION

- Crude oil prices continue to improve
  - $US 20.00/B level in sight
  - prospect for large drawdown in inventories the major driver
  - OPEC quota adherence key to sustaining high prices
  - 1999 WTI forecast raised to $US 16.70/B -- 2000 unchanged at $US 17.50/B

- Natural gas prices remain strong
  - tight supply and demand growth more than offset high storage inventories
  - potential for weather related upside remains very high
  - drilling activity should accelerate due to attractive investment economics
  - 1999 average Alberta plantgate forecast raised to $2.40/Mcf -- 2000 unchanged at $2.60/Mcf

- Canadian oil and gas equities gaining momentum
  - asset valuations now in premium teritory, but still far below 1997 peak
  - adjusted cash flow multiples now slightly above historical averages
  - potential for further strong recovery given positive outlook for commodity prices

WORLD OIL MARKET OUTLOOK

Highlights

- *We have revised our 1999 average WTI and Edmonton Light price forecasts up to $US 16.70/B and $23.50/B respectively.*
  - With better than expected OPEC compliance to-date, we have raised our 2H99 WTI price forecast from $US 17.00/B to $US 18.00/B versus a forward market price as at June 29 of $US 18.40/B and a 1H99 average of $US 15.35/B. This could still prove to be conservative, however, as spot prices were approching the $US 20.00/B level as this report was going to print.
  - Edmonton Light prices have averaged approximately $ 24.90/B and $ 21.70/B in 2Q99 and 1H99, respectively, 25% and 4% above the 1998 comparables. Our 1999 average forecast of $ 23.50/B is 17% above the 1998 average of $20.10/B.
  - Hardisty Heavy prices have averaged approximately $ 20.30/B and $ 18.40/B in 2Q99 and 1H99 respectively, 55% and 37% above the 1998 comparables of $ 13.05/B and $ 13.45/B. Edmonton Light – Hardisty Heavy differentials averaged roughly $ 3.30/B in 1H99 and are expected to remain narrow due to recent pipeline capacity additions. As well, higher returns on gas projects and the large inventory of assets for sale are likely to limit oil-directed capital spending.

- *The recent strength in crude oil prices is due more to supply declines than demand growth.*
  - Our estimate for the 2H99 global stock build now stands at 0.1 MMB/d versus a 1996-98 comparable build of 2.0 MMB/d even though year-over-year oil demand growth in the 1998-1H99 period was only 0.5-1.0 MMB/d, well below the 1995-97 average of 1.7 MMB/d.
  - OPEC's May compliance improved to 75% with estimated production cuts totaling 1.3 MMB/d versus pledges of 1.7 MMB/d. Output, excluding Iraq, averaged 23.4 MMB/d, only 1.8% above the cartel's target of 23.0 MMB/d. Total OPEC production in May was 26.1 MMB/d, the cartel's lowest monthly average since the 1990-91 Gulf war.
  - Non-OPEC supply is expected to decline by 0.3 MMB/d in 1999, due primarily to a substantial drop in U.S. production. This would be the first annual decline in non-OPEC production since 1993. An expectation of cautious spending increases limits our estimate of year 2000 non-OPEC supply growth to a modest 0.2 MMB/d as the recent consolidation in the sector is more focused on profitability than on volume growth.
  - Our 2H99 baseline scenario indicates a 2.1 MMB/d world stock draw versus a 1996-98 average second half build of 0.4 MMB/d. OECD industry stocks are now projected to decrease to 50 days of forward cover by year-end, well below the 4Q96 forward cover of 54 days when WTI averaged $US 24.50/B.
  - Our year 2000 baseline scenario indicates the "call" on OPEC will average 28.2 MMB/d, which would represent an all-time record high for the cartel. If the cartel were to maintain output at current levels, the alternative would be sharply higher prices relative to our baseline forecast of $US 17.50/B. This would be very difficult to manage, however, as the temptation to cheat would be very strong.

Pledged Output Reductions (MMB/d)

	May/99 Output	Target Output	Shortfall	1999 cuts pledged	Compliance
OPEC					
Saudi Arabia	7.50	7.44	(0.06)	0.59	90%
Iran	3.38	3.36	(0.02)	0.26	92%
Venezuela	2.74	2.72	(0.02)	0.13	84%
U.A.E.	2.00	2.00	0.00	0.16	100%
Kuwait	1.81	1.84	0.03	0.14	122%
Nigeri	2.03	1.89	(0.15)	0.15	2%
Libya	1.31	1.23	(0.08)	0.10	14%
Indonesia	1.28	1.19	(0.09)	0.09	0%
Algeria	0.74	0.73	(0.01)	0.06	84%
Qatar	0.63	0.59	(0.04)	0.05	21%
OPEC ex-Iraq	23.41	22.98	(0.43)	1.72	75%
Iraq	2.65	2.66	na	0.00	na
Total OPEC	26.06	25.64	(0.43)	1.72	75%
Non-OPEC					
Russia	2.40	2.96	(0.11)	0.10	-10%
Mexico	3.27	3.37	0.10	0.13	176%
Norway	3.05	3.03	(0.02)	0.10	83%
Oman	0.92	0.84	(0.08)	0.06	-32%
Total non-OPEC	9.64	10.20	(0.11)	0.39	70%
Total	35.70	35.83	(0.55)	2.10	74%

Source: CGES, IEA, ARC Financial.

Notes: Neutral Zone production split evenly between Saudi Arabia and Kuwait. Compliance calculated based upon March 1999 cuts. Targets based upon February 1999 production, except Norway. Russian data is for crude oil and products exports.

◆ OPEC's May compliance improved to 75% with estimated production cuts totaling 1.3 MMB/d versus pledges of 1.7 MMB/d. Output excluding Iraq averaged 23.4 MMB/d, only 1.8% above the cartel's target of 23.0 MMB/d. The four Gulf states, with compliance of 90% or better, are leading by example and setting the tone for other members.

◆ Iraq's May production was 2.65 MMB/d and government production targets of 3.0 MMB/d and 3.5 MMB/d by year end 1999 and mid-2000, respectively, appear aggressive given a shortage of capital and parts. Nonetheless, production estimates have been revised steadily upwards since 1997 and further growth this year cannot be ruled out.

◆ OPEC's current production level of 26.1 MMB/d is the cartel's lowest monthly average since the 1991 Gulf war. Further significant reductions in supply are unlikely in light of strong prices and the potential for "leakage", in particular from the more populous cartel members such as Nigeria and Indonesia.

Non-OPEC Supply Outlook (MMB/d)

						Annual Growth		
	1997	1998E	1999F	2000F	1997/90	1998/97	1999/98	2000/99
OECD								
Canada	2.57	2.67	2.54	2.58	0.10	0.10	-0.13	0.04
U.S.	8.65	8.33	8.00	7.98	-0.06	-0.32	-0.33	-0.02
Mexico	3.41	3.50	3.43	3.44	0.07	0.09	-0.07	0.01
North Sea	6.02	5.99	6.04	6.00	0.39	-0.03	0.05	-0.04
Other	1.42	1.36	1.30	1.30	0.01	-0.06	-0.06	0.00
Total OECD	22.07	21.85	21.31	21.30	0.52	-0.22	-0.54	-0.01
Other Non-OPEC								
South America	3.43	3.69	3.90	4.05	0.21	0.26	0.21	0.15
Africa	2.73	2.72	2.70	2.75	0.13	-0.01	-0.02	0.05
Southeast Asia	2.11	2.13	2.10	2.12	0.07	0.02	-0.03	0.02
Middle East	1.89	1.89	1.90	1.90	0.10	0.00	0.01	0.00
FSU	7.20	7.29	7.30	7.30	-0.71	0.09	0.01	0.00
China	3.19	3.19	3.20	3.20	0.07	0.00	0.01	0.00
Other	0.20	0.19	0.20	0.20	-0.01	-0.01	0.01	0.00
Total Other Non-OPEC	20.75	21.10	21.30	21.52	-0.15	0.35	0.20	0.22
Refinery Gain	1.57	1.64	1.70	1.70	0.05	0.07	0.06	0.00
Total Non-OPEC	44.39	44.59	44.31	44.52	0.42	0.20	-0.28	0.21
Total Ex. FSU	37.19	37.30	37.01	37.22	1.14	0.11	-0.29	0.21

Sources: IEA, ARC Financial estimates.

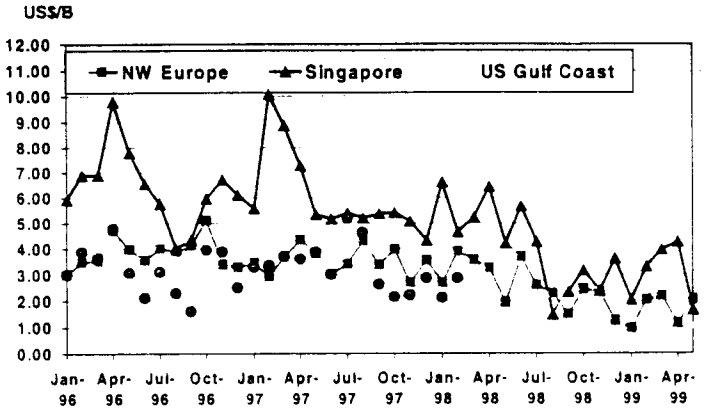
◆ Non-OPEC production is expected to decline by 0.3 MMB/d in 1999, due primarily to a very substantial drop in U.S. production. This would be the first annual decline in non-OPEC production since 1993. Shut-in of high cost production and a significant reduction in capital spending are the major drivers. We believe this is a conservative estimate when compared to the IEA's 1Q99 estimate indicating a 0.7 MMB/d decrease from the year ago comparable.

◆ Year 2000 supply growth is estimated at 0.2 MMB/d driven largely by additions offshore West Africa and in Latin America. With an expectation of cautious spending increases, other regions are expected to maintain 1999 production levels in year 2000 as the recent consolidation in the sector is more focused on profitability rather than volume growth, particularly in Western Canada, the Lower-48 states and the North Sea where capital is essential to sustain production.

◆ Indications of weak demand growth are found in historically low refining margins. Margins have been squeezed as product inventories have remained high while spot crude prices have increased roughly 50% since February. With year-over-year oil demand growth through 1998-1H99 in the range of 0.5-1.0 MMB/d versus the 1995-97 average of 1.7 MMB/d, capacity expansions and high utilization rates have sustained high inventories.

◆ Preliminary estimates indicate OECD products inventories at the end of May were 3% lower than the 1998 comparable, but roughly 7% above the 1995-97 average. Although refiners have cut production runs in response to poor margins, product demand will also need to rise to drive inventories lower in the near-term. A key test of OPEC's compliance commitment will come when margins begin to increase and refiners seek additional crude to boost throughputs.

Global Refining Margins

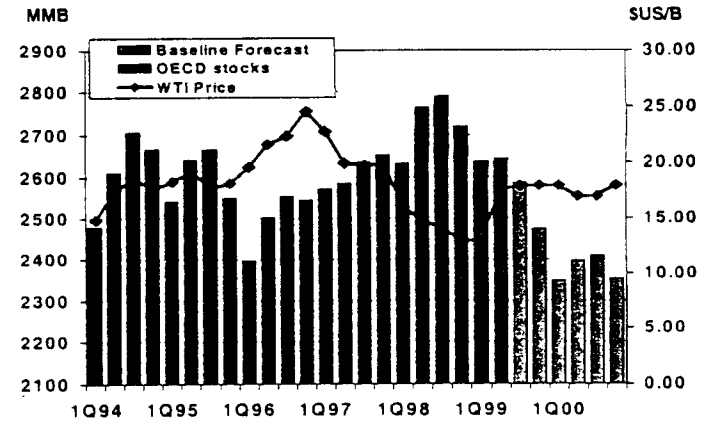


Source: Bloomberg.
Notes: Crack spreads indicate the cash profitability of refining crude oil into various products based upon spot prices. NW Europe is for 2-1-1 cracking of Brent crude, US Gulf Coast is for 3-2-1 cracking of WTI @ Cushing and Singapore is for 3-2-1 cracking of Dubai barrels. All values are month-end.

◆ Our 2H99 baseline scenario forecasts demand growth near 1.3 MMB/d, Iraqi production of 2.7 MMB/d and OPEC compliance in the 60% range, indicating a 2.1 MMB/d world stock draw versus a 1996-98 average second half build of 0.4 MMB/d. OECD industry stocks decrease to 2,470 MMB or 50 days of forward cover by year-end, well below 4Q96 forward cover of 54 days when WTI averaged $US 24.50/B.

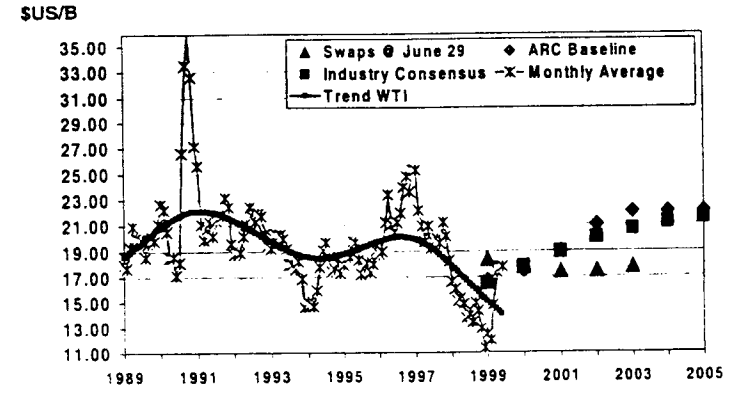
◆ Our year 2000 baseline scenario which calls for demand growth of 1.2 MMB/d (1.6% per annum) and non-OPEC supply growth of 0.2 MMB/d, indicates the "call" on OPEC could average 28.2 MMB/d. This would be an all-time record production level for the cartel. As in the aftermath of the 1986 price collapse, OPEC output will likely increase substantially and quickly to fill any gap between demand growth and non-OPEC supply. The alternative would be sharply higher prices relative to our baseline forecast of $US 17.50/B.

OECD Industry Stocks versus WTI Crude Oil Price



Sources: IEA, Oil Market Intelligence, ARC Financial estimates.
Notes: Stocks are end of period and include crude oil and products. Excludes government strategic reserves and oil at sea. Assumes OPEC ouput averages 26.4 in 2H99 and 28.2 MMB/d in year 2000. WTI price is for spot purchases.

WTI Price Expectations

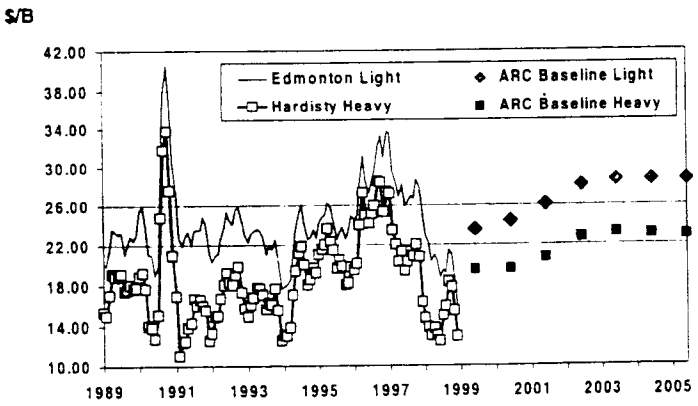


Sources: Historical data from PIW, swap prices from RBC DS. Industry consensus represented by April/99 survey of major brokerage houses and Canadian petroleum consultants.
Notes: Historical prices represent monthly averages. Trend WTI was calculated by smoothing actual WTI prices with a statistical technique called a Hodrick-Prescott filter.

◆ WTI prices have averaged roughly $US 17.60/B in 2Q99 bringing the 1H99 average to $US 15.35/B. Better than anticipated OPEC compliance has caused us to raise our 2H99 WTI price forecast from $US 17.00/B to $US 18.00/B versus a forward market price as at June 29 of $US 18.40/B. Our average 1999 WTI forecast now stands at $US 16.70/B versus a consensus forecast in the range of $US16.50/B.

◆ Our year 2000 forecast is unchanged at $US 17.50/B. This compares to a forward market price as at June 29 of $US 17.75/B and a consensus forecast in the range of $US 17.50-18.25/B. While higher prices remain a very real possibility, we remain cautious given the fact that OPEC is now "managing" surplus capacity in the order of 6.5 MMB/d excluding Iraq.

Canadian Oil Price Expectations



Source: Historical data from CAPP.
Note: Historical prices are monthly averages. Shaded area represents one standard deviation for Edmonton Light oil prices.

◆ Edmonton Light prices have averaged approximately $24.90/B and $21.70/B in 2Q99 and 1H99 respectively, 25% and 4% above the 1998 comparables. Our 2H99 Edmonton Light price forecast has been raised from $24.05/B to $25.30/B which compares to a forward market price as at June 29 of $25.90. Our 1999 forecast average price now stands at $23.50/B, 17% above the 1998 average of $20.10/B.

◆ Hardisty Heavy prices have averaged approximately $20.30/B and $18.40/B in 2Q99 and 1H99 respectively, 55% and 37% above the 1998 comparables of $13.05/B and $13.45/B. Differentials are expected to remain narrow due to recent pipeline capacity additions and what we anticipate to be a relatively gradual aggregate supply response to improved prices. Higher returns on gas projects and a large inventory of assets for sale will limit oil-directed capital spending.

ARC Financial World Oil Market Outlook

							ARC Financial Forecast										
	1997	1Q98	2Q98	3Q98	4Q98	1998	1Q99	2Q99	3Q99	4Q99	1999	1Q00	2Q00	3Q00	4Q00	2000	2005
World Oil Prices																	
WTI ($US/B)	20.63	15.90	14.70	14.10	12.85	14.39	13.10	17.60	18.00	18.00	16.70	18.00	17.00	17.00	18.00	17.50	22.00
Brent ($US/B)	19.12	14.10	13.35	12.48	11.07	12.75	11.30	15.40	16.70	16.60	15.00	16.30	15.30	15.30	16.30	15.80	20.10
Canadian Prices ($Cdn/B)																	
Edmonton Light	27.82	21.76	20.00	20.01	18.66	20.11	18.45	24.90	25.30	25.30	23.50	25.40	23.95	23.30	24.75	24.35	28.60
Hardisty Heavy	21.22	13.80	13.05	16.33	15.34	14.63	16.50	20.30	20.60	20.20	19.40	20.60	19.40	18.60	19.55	19.50	22.90
Differential	6.60	7.96	6.95	3.68	3.32	5.48	1.95	4.60	4.70	5.10	4.10	4.80	4.55	4.70	5.20	4.85	5.70
International Prices ($US/B)																	
Dubai Fateh	18.15	12.50	12.10	12.50	11.50	12.15	11.10	15.30	15.60	15.50	14.40	15.45	14.45	14.45	15.45	14.95	19.30
OPEC Basket	18.75	13.69	12.52	12.32	10.98	12.38	11.05	15.45	15.90	16.00	14.60	16.05	15.05	15.05	16.05	15.30	19.70
World Oil Demand (MMB/d)																	
OECD																	
North America	22.7	22.6	23.0	23.5	23.4	23.1	23.6	23.1	23.8	24.1	23.7	24.2	23.4	24.1	24.5	24.0	25.7
Western Europe	15.0	15.4	14.8	15.2	15.9	15.3	15.8	14.8	15.5	16.1	15.5	15.9	14.9	15.7	16.3	15.7	16.1
Pacific OECD	9.0	9.2	7.8	7.9	8.8	8.4	9.4	8.0	8.0	8.9	8.6	9.5	8.1	8.1	9.0	8.7	9.0
Total OECD	46.7	47.2	45.5	46.7	48.1	46.9	48.8	45.9	47.4	49.1	47.8	49.6	46.4	47.9	49.7	48.4	50.8
% Change	1.6%	0.7%	0.0%	0.8%	0.5%	0.5%	3.2%	0.9%	1.5%	2.1%	2.0%	1.7%	1.0%	1.0%	1.2%	1.2%	1.0%
Non-OECD																	
Latin America	4.5	4.4	4.6	4.7	4.6	4.6	4.4	4.6	4.7	4.7	4.6	4.4	4.6	4.7	4.7	4.6	5.3
Asia	10.9	11.2	10.9	10.8	11.0	11.0	11.3	11.2	11.1	11.5	11.3	11.6	11.5	11.4	11.8	11.6	14.1
Middle East	4.0	3.9	4.2	4.3	4.1	4.1	4.0	4.2	4.4	4.2	4.2	4.1	4.3	4.5	4.3	4.3	4.9
Africa	2.3	2.4	2.4	2.3	2.5	2.4	2.4	2.4	2.3	2.5	2.4	2.4	2.5	2.4	2.6	2.5	2.9
Eastern Europe	0.8	0.9	0.8	0.7	0.8	0.8	0.9	0.8	0.8	0.8	0.8	0.9	0.8	0.8	0.9	0.8	1.0
Total LDCs	22.5	22.8	22.9	22.8	23.0	22.9	23.0	23.3	23.2	23.7	23.3	23.5	23.8	23.7	24.2	23.8	28.1
% Change	4.5%	2.7%	3.0%	1.4%	0.5%	1.8%	0.7%	1.7%	1.9%	3.0%	1.8%	2.2%	2.2%	2.2%	2.2%	2.2%	3.4%
FSU	4.3	4.6	4.2	4.1	4.1	4.3	4.2	3.5	3.9	4.1	3.9	4.3	3.6	4.0	4.2	4.0	4.6
% Change	0.9%	7.7%	-1.6%	-4.0%	-9.8%	-1.8%	-9.3%	-17.3%	-4.6%	1.7%	-7.5%	2.6%	2.9%	1.5%	1.7%	2.2%	2.7%
Total World	73.5	74.7	72.6	73.6	75.2	74.0	75.9	72.7	74.5	77.0	75.0	77.4	73.8	75.6	78.2	76.2	83.5
% Change	2.5%	1.7%	0.8%	0.7%	-0.1%	0.8%	1.7%	0.1%	1.3%	2.4%	1.4%	1.9%	1.5%	1.4%	1.6%	1.6%	1.8%
Non-OPEC Supply (MMB/d)																	
OECD																	
Canada	2.6	2.7	2.6	2.7	2.7	2.7	2.5	2.5	2.5	2.6	2.5	2.6	2.5	2.6	2.6	2.6	2.7
Mexico	3.4	3.5	3.5	3.5	3.5	3.5	3.5	3.3	3.4	3.5	3.4	3.4	3.4	3.4	3.4	3.4	3.7
U.S.	8.7	8.6	8.5	8.1	8.0	8.3	8.1	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.1	8.0	7.7
U.K./Norway	6.1	6.3	5.9	5.7	6.1	6.0	6.1	5.8	5.9	6.3	6.0	6.2	6.0	5.9	6.2	6.0	7.0
Other	1.4	1.4	1.3	1.4	1.3	1.4	1.3	1.3	1.3	1.4	1.3	1.3	1.3	1.3	1.3	1.3	1.4
Total OECD	22.1	22.6	22.0	21.3	21.5	21.8	21.5	20.9	21.1	21.8	21.3	21.4	21.2	21.1	21.6	21.3	22.5
Other Non-OPEC																	
South America	3.4	3.6	3.6	3.7	3.8	3.7	3.9	3.9	3.9	3.9	3.9	4.0	4.0	4.1	4.1	4.1	4.2
Africa	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.8	2.8	2.8	2.8	2.8	3.3
Southeast Asia	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.2	2.1	2.1	2.1	2.1	2.1	2.1	2.4
Middle East	1.9	1.9	1.9	1.9	1.9	1.9	1.9	1.9	1.9	1.9	1.9	1.9	1.9	1.9	1.8	1.9	2.2
FSU	7.2	7.3	7.2	7.2	7.4	7.3	7.4	7.3	7.3	7.3	7.3	7.4	7.3	7.3	7.2	7.3	8.0
China	3.2	3.2	3.2	3.2	3.2	3.2	3.2	3.2	3.2	3.1	3.2	3.2	3.2	3.2	3.2	3.2	3.4
Other	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.1	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.3
Total Other Non-OPEC	20.8	21.1	21.0	21.0	21.3	21.1	21.3	21.2	21.2	21.3	21.3	21.6	21.4	21.5	21.4	21.5	23.8
Refinery Gain	1.6	1.7	1.6	1.6	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.6	1.6	1.6	1.6	1.7	1.7
Total Non-OPEC	44.4	45.3	44.6	43.9	44.6	44.6	44.6	43.7	44.0	44.8	44.3	44.7	44.1	44.3	44.6	44.5	48.0
The Call on OPEC (MMB/d)																	
Big Six																	
Saudi Arabia	8.1	8.4	8.2	7.8	8.0	8.1	7.9	7.4	7.5	7.5	7.6	7.5	7.9	8.2	8.4	8.0	8.8
Iraq	1.1	1.6	2.1	2.4	2.4	2.1	2.5	2.6	2.6	2.7	2.6	2.7	2.7	2.7	2.8	2.7	4.0
Iran	3.6	3.6	3.8	3.5	3.6	3.6	3.8	3.4	3.5	3.5	3.6	3.5	3.7	3.8	3.8	3.7	4.0
Venezuela	3.2	3.4	3.2	3.0	3.0	3.1	2.9	2.8	2.8	2.8	2.8	2.9	3.0	3.1	3.3	3.1	4.0
Kuwait	1.8	1.9	1.8	1.7	1.7	1.8	1.7	1.6	1.6	1.6	1.6	1.6	1.9	1.9	1.9	1.8	2.7
UAE	2.3	2.5	2.3	2.2	2.2	2.3	2.2	2.0	2.0	2.0	2.1	2.0	2.3	2.5	2.5	2.2	2.9
Total Crude	27.2	28.5	28.2	27.3	27.4	27.8	27.7	26.3	26.3	26.5	26.7	26.7	28.0	28.7	29.2	28.2	32.4
NGLs	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9	3.1
Market Share	41%	42%	43%	41%	40%	41%	40%	40%	39%	38%	39%	38%	42%	42%	42%	41%	42%
Capacity	31.6	31.9	32.1	32.6	32.6	32.3	32.7	32.8	32.8	32.9	32.8	32.9	32.9	32.9	33.0	32.9	36.0
Capacity Utilization	86%	89%	88%	84%	84%	86%	85%	80%	80%	81%	81%	81%	85%	87%	88%	86%	90%
Inventories																	
Reported Changes (MMB/d)	0.3	-0.3	1.7	0.4	-0.7	0.3	-0.9	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Other Changes (MMB/d)	0.6	2.2	1.3	0.0	0.3	0.9	0.0	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Total Changes (MMB/d)	0.9	1.9	3.0	0.4	-0.4	1.2	-0.9	0.1	-1.4	-2.8	-1.2	-3.1	1.2	0.3	-1.4	-0.7	0.0
OECD Industry Stocks (MMB)	2652	2631	2763	2790	2719	2719	2637	2642	2586	2473	2473	2348	2397	2409	2352	2352	NA
OECD Fwd. Cover (days)	56	58	59	58	56	56	57	56	53	50	50	51	50	48	47	47	NA

Source: B.P. Statistical Review of World Energy, EIA, IEA, Oil and Energy Trends, ARC Financial.

Notes:
1. Year-on-year change is calculated as annual compound average.
2. Totals may not add due to rounding.
3. Reported stock changes are for OECD industry and government stocks from IEA. Other stock changes reflect the difference between world supply and demand.
4. S. Korean demand is included in Pacific OECD. Mexican demand is included in North America for all years shown.
5. Saudi Arabia and Kuwait production data excludes Neutral Zone production of approximately 0.5 MMB/d.
6. Forecast OECD stock level changes based on world S/D balance stock changes.
7. Fwd cover is based on succeeding quarterly demand.
8. Stock levels are at period end.
9. Historical OECD stocks are from IEA and are industry stocks of crude and products, excluding government stocks or stocks held for emergency purposes only.
10. Historical world stockcover, and inventory data from CGES and excludes former centrally planned economies.

Crude Oil Price Forecast Summary

Baseline Scenario

	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
WTI at Cushing																
(40° API, $US/B)	18.40	22.07	20.62	14.40	16.70	17.50	19.00	21.00	22.00	22.00	22.00	22.00	22.00	22.00	22.00	22.00
$ 1999	19.80	23.20	21.40	14.50	16.70	17.20	18.30	19.80	20.30	19.90	19.50	19.20	18.80	18.40	18.00	17.70
Canadian Crude Prices ($Cdn/B)																
Edmonton (40° API)	24.05	29.23	27.64	20.10	23.50	24.35	26.08	28.12	28.65	28.60	28.60	28.60	28.60	28.60	28.60	28.60
$ 1999	24.97	30.77	28.64	20.30	23.50	23.87	25.07	26.50	26.47	25.91	25.39	24.90	24.41	23.93	23.46	23.00
Hardisty Heavy (26° API)	20.63	25.03	21.20	14.63	19.40	19.50	20.58	22.63	23.16	22.97	22.86	22.81	22.81	22.81	22.81	22.82
$ 1999	22.20	26.35	21.97	14.77	19.40	19.12	19.78	21.32	21.39	20.81	20.30	19.86	19.47	19.09	18.71	18.35
Alta Light Wellhead	22.51	27.66	26.32	18.81	21.60	22.44	24.15	26.18	26.70	26.64	26.61	26.60	26.59	26.58	26.56	26.55
Alta Heavy Wellhead	18.86	22.82	18.75	12.38	16.90	17.00	18.08	20.13	20.66	20.47	20.36	20.21	20.21	20.21	20.21	20.22
Alta Bitumen Wellhead	15.47	18.93	13.30	7.64	14.48	14.73	15.74	17.79	18.32	18.09	17.94	17.87	17.87	17.87	17.87	17.88
Synthetic	23.45	28.50	27.50	19.90	22.91	23.74	25.43	27.42	27.94	27.89	27.88	27.88	27.88	27.88	27.88	27.89
Condensates/C5+	24.22	29.23	28.19	19.70	23.97	24.81	26.08	28.12	28.65	28.60	28.60	28.60	28.60	28.60	28.60	28.60
Propane	13.90	22.31	18.62	11.71	13.26	14.15	15.83	17.36	17.97	18.12	18.37	18.30	18.32	18.32	18.32	18.32
Butane	13.79	17.15	18.73	13.25	14.19	15.07	16.77	18.34	18.94	19.07	19.30	19.45	19.66	19.87	19.87	19.87
International Crude Prices ($US/B)																
Brent (38° API)	17.03	20.50	19.10	12.75	15.00	15.80	17.19	19.17	20.15	20.13	20.12	20.10	20.08	20.06	20.04	20.02
$ 1999	18.32	21.58	19.79	12.88	15.00	15.49	16.52	18.07	18.62	18.24	17.86	17.50	17.14	16.78	16.44	16.10
OPEC Basket	16.87	20.13	18.70	12.33	14.60	15.30	16.78	18.76	19.73	19.71	19.69	19.66	19.64	19.62	19.59	19.57
$ 1999	18.15	21.19	19.38	12.45	14.60	15.00	16.13	17.67	18.23	17.85	17.48	17.12	16.76	16.42	16.07	15.74
Dubai Fateh (32° API, 2% S)	16.10	18.54	18.15	12.12	14.40	14.95	16.42	18.40	19.37	19.35	19.32	19.29	19.27	19.24	19.21	19.18
$ 1999	17.32	19.52	18.81	12.24	14.40	14.66	15.79	17.34	17.90	17.52	17.16	16.80	16.44	16.10	15.76	15.43

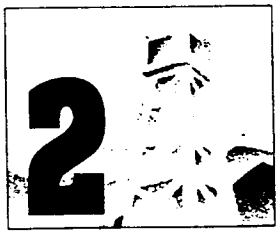
Low Price Scenario

	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
WTI at Cushing																
(40° API, $US/B)	18.40	22.07	20.62	14.40	14.50	14.00	16.00	18.00	18.00	18.00	18.00	18.00	18.00	18.00	18.00	18.00
$ 1999	19.80	23.20	21.40	14.50	14.50	13.73	15.38	16.96	16.63	16.30	15.98	15.67	15.36	15.06	14.77	14.48
Canadian Crude Prices ($Cdn/B)																
Edmonton (40° API)	24.05	29.23	27.64	19.90	20.50	19.60	21.80	24.00	23.30	23.30	23.30	23.20	23.20	23.20	23.20	23.20
$ 1999	24.97	30.77	28.64	20.30	20.50	19.22	20.95	22.62	21.53	21.10	20.69	20.20	19.80	19.41	19.03	18.66
Hardisty Heavy (26° API)	20.63	25.03	21.20	14.63	15.00	13.20	15.90	18.50	18.40	17.80	17.30	17.10	17.70	17.90	18.00	17.90
$ 1999	22.20	26.35	21.97	14.77	15.00	12.94	15.28	17.43	17.00	16.12	15.36	14.89	15.11	14.98	14.77	14.40

High Price Scenario

	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
WTI at Cushing																
(40° API, $US/B)	18.40	22.07	20.62	14.40	18.00	20.00	22.00	25.00	25.00	25.00	25.00	25.00	25.00	25.00	25.00	25.00
$ 1999	19.80	23.20	21.40	14.50	18.00	19.61	21.15	23.56	23.10	22.64	22.20	21.76	21.34	20.92	20.51	20.11
Canadian Crude Prices ($Cdn/B)																
Edmonton (40° API)	24.05	29.23	27.64	20.10	25.60	28.40	30.30	33.60	32.70	32.70	32.70	32.60	32.60	32.60	32.60	32.60
$ 1999	24.97	30.77	28.64	20.30	25.60	27.84	29.12	31.66	30.21	29.62	29.04	28.38	27.82	27.28	26.74	26.22
Hardisty Heavy (26° API)	20.63	25.03	21.20	14.63	20.60	22.00	23.60	27.20	26.90	26.30	25.80	25.60	26.20	26.40	26.50	26.40
$ 1999	22.20	26.35	21.97	14.77	20.60	21.57	22.68	25.63	24.85	23.82	22.91	22.29	22.36	22.09	21.74	21.23

Notes: 1. General inflation assumed flat at 2% per annum.
2. Canadian prices based on $US/Cdn 0.68, 0.69, 0.70, 0.72 exchange rate in 1999/2000/01/02, respectively, $US/Cdn 0.74 in 2003 and beyond.
3. Edmonton Light Sweet prices average of postings by major refiners.
4. Hardisty Heavy prices representative of posted Hardisty Heavy prices by major refiners.
5. International Prices FOB at point of origin.



NORTH AMERICAN NATURAL GAS MARKET OUTLOOK

Highlights

- *Our average 1999 Henry Hub price forecast has been revised upwards to $US 2.20/MMBtu, from $US 2.10/MMBtu.*
  - The likelihood of declining U.S. gas production has caused us to raise our 2H99 Henry Hub price forecast from $US 2.30/MMBtu to $US 2.40/MMBtu versus a forward market price as at June 29 of $US 2.47/MMBtu.
  - As at June 18, U.S. working gas in storage was 60% full at 1.94 Tcf, the same as the 1998 comparable and 25% or 385 Bcf higher than the 1996-98 average. Year-to-date injection rates have averaged 7.2 Bcf/d, 20% below the 1996-98 average of 9.0 Bcf/d. With higher Canadian imports and 2Q99 estimated demand growth of 1.7%, these lower injection rates signal a significant decline in Lower-48 deliverability.
  - Higher prices depend to a large extent on demand growth as we believe excess deliverability has been "wrung out" of the U.S. industry over the last decade as gas markets have been deregulated. Sharply higher prices relative to our baseline forecast of $US 2.40/MMBtu could result from a scenario of steady U.S. economic growth, WTI prices above $US 17.00/B, an abnormally warm summer and/or extended cold winter weather given the current tightness in domestic U.S. gas supply.

- *Our 1999 average Alberta plantgate price forecast has been increased to $2.40/Mcf, from $2.35/Mcf.*
  - Alberta prices should remain firmly linked to U.S. markets over the near-term. Contracted winter delivery capacity on TCPL's Alberta system will increase by 0.5 Bcf/d in November 1999 to 15.1 Bcf/d. Average winter 1999/00 deliverability, including storage withdrawals, is forecast in the range of 14.3-14.7 Bcf/d implying there will be 0.4-0.8 Bcf/d of surplus transportation capacity.
  - Through May, TCPL Alberta System field receipts have averaged 12.56 Bcf/d, 100 MMcf/d (1%) higher than the 1998 comparable of 12.46 Bcf/d while comparable Westcoast (B.C.) and Transgas (Saskatchewan) field receipts remained essentially unchanged at 2.01 Bcf/d and 0.55 Bcf/d respectively. Canadian gas supply should begin to grow at a faster pace over the next twelve months due to higher producer cash flows, accelerating drilling activity, ready access to markets and East Coast development (Sable Island).
  - Gas producers will report favourable 2Q99 quarter-over-quarter results as Alberta 30-day plantgate spot prices averaged $2.50/Mcf, 41% more than the 2Q98 comparable of $1.77/Mcf. Results will vary widely between companies based upon individual marketing portfolios.
  - In this bullish environment very few producers have fixed prices for the upcoming gas year. Based upon discussions with individual companies we estimate less than 20% of 1999/2000 sales are currently under fixed price terms.
  - Longer-term forward market prices continue to set record highs. As at June 29, Alberta spot plantgate prices were $2.86/Mcf in 2001 rising to $2.95/Mcf by 2003.

U.S. Working Gas in Storage

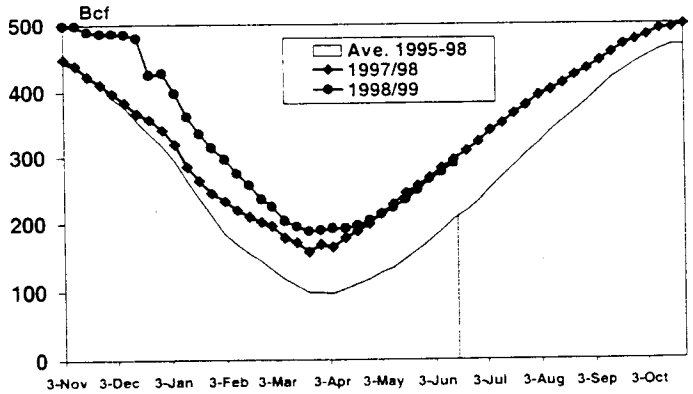
	1999	1998	1997	1996	1995	Ave. 1996-98
Working gas in storage @ 3rd week of June (Bcf)	1,942	1,939	1,483	1,250	1,758	1,557
% full @ 3rd week	60%	60%	47%	39%	55%	49%
YTD average injection rate (Bcf/d)	7.2	11.1	7.8	8.0	6.7	9.0
4 wk. MVA injection rate (Bcf/d)	11.0	13.5	13.4	12.6	13.4	13.2
Ave. injection rate to Oct. 31 (Bcf/d)	9.8	8.7	10.0	11.1	9.0	9.9

Source: American Gas Association.
Note: YTD average injection rate is calculated from April 1st. Average injection rate to Oct. 31/ 99 is calculated for remaining injection period of 19 weeks as at June 18/99 and compared to actual average injection rates for comparable historicals.

◆ As at June 18, U.S. working gas in storage was 1.94 Tcf or 60% full, the same as the 1998 comparable and 25% or 385 Bcf higher than the 1996-98 average. Year-to-date and four week moving average injection rates are 20% and 17% below the 1996-98 comparables. With estimated 2Q99 demand near 4.72 Tcf or 1.7% lower than the 1996-98 average of 4.80 Tcf and higher Canadian imports, these lower injection rates indicate a significant decline in the Lower-48 deliverability.

◆ With 19 weeks remaining in the injection season, the average rate to fill storage by November 1st is 9.8 Bcf/d, 1% below the 1996-98 actual of 9.9 Bcf/d. As we estimate that 1999 domestic supply will decline by at least 2% or roughly 1 Bcf/d, future injection rates will depend largely on weather-related demand. Gas-fired generation should face competition this summer from plentiful hydro generation and cost competitive coal-fired units, but a "normal" winter load is likely to severely stress domestic gas deliverability.

Canadian Working Natural Gas Storage Levels



Source: Canadian Gas Association Weekly Storage Survey
Note: Most recent data is for June 18/99 stock levels.

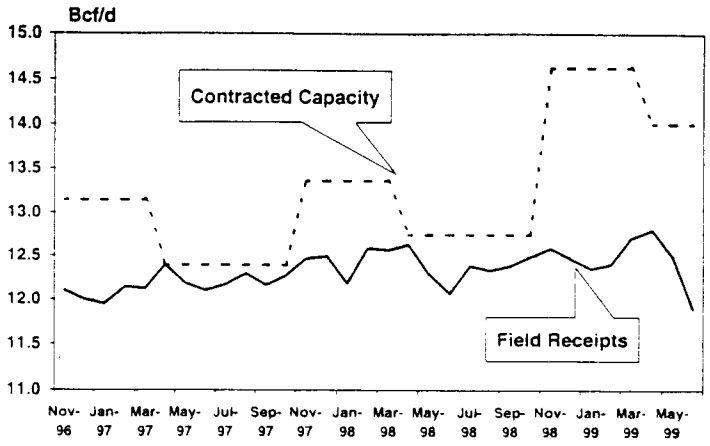
◆ As at June 18, Canadian working gas in storage was 55% full at 290 Bcf, 5 Bcf or 2% below the 1998 comparable of 295 Bcf, but 42% higher than the 1995-98 average of 205 Bcf. Despite these high storage levels, Alberta plantgate daily spot prices remain firmly above $2.70/Mcf, further evidence that Alberta spot prices are now strongly linked to Henry Hub prices for the first time since 1996.

◆ Injection rates have averaged 1.2 Bcf/d since April 1st versus a 1995-98 average of 1.3 Bcf/d. With a major inspection program now complete on the Alberta system, current Western Canada injection rates are in the range of 700-800 MMcf/d. Barring unexpected outages, with 19 weeks remaining in the injection season, Canadian commercial storage is likely to be near capacity of 500 Bcf by November 1st.

◆ TCPL Alberta field receipts decreased below 12 Bcf/d in June due to mainline inspection outages and are currently back above 12.6 Bcf/d. Through May, receipts averaged 12.56 Bcf/d, 100 MMcf/d (1%) higher than the 1998 comparable of 12.46 Bcf/d. NUL (Alberta) field receipts are up 11% over the same period to 0.55 Bcf/d while Westcoast (B.C.) and Transgas (Saskatchewan) field receipts remained essentially unchanged at 2.01 Bcf/d and 0.55 Bcf/d respectively.

◆ Contracted winter delivery capacity on TCPL's Alberta system increases 0.5 Bcf/d in November 1999 to 15.1 Bcf/d with growth split evenly between intra-Alberta and export deliveries. Average winter 1999/00 deliverability, including storage withdrawals, is forecast in the range of 14.3-14.7 Bcf/d implying 0.4-0.8 Bcf/d of surplus transportation. This surplus capacity should keep Alberta prices firmly linked to U.S. markets.

TCPL Alberta System Field Receipts vs. Delivery Capability

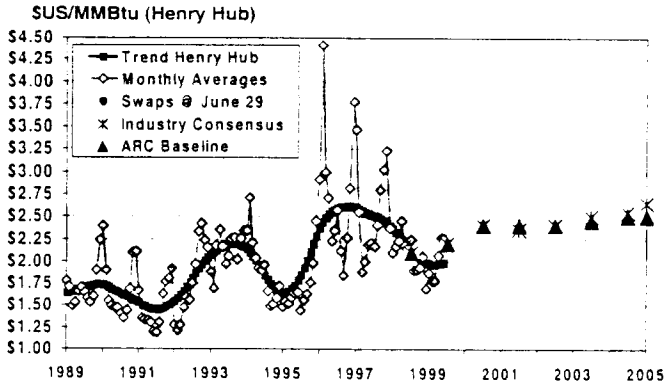


Source: TCPL, Canadian Natural Gas Focus.
Note: Field receipts are Alberta daily average system receipts less deliveries from commercial storage. June 1999 average receipts are estimated from daily reports.

◆ Deliverability concerns have caused us to raise our 2H99 Henry Hub price forecast from $US2.30/MMBtu to $US 2.40/MMBtu versus a forward market price as at June 29 of $US 2.47/MMBtu. Our average 1999 forecast now stands at $US 2.20/MMBtu versus a consensus forecast in the range of $US 2.20-2.30/MMBtu.

◆ Our year 2000 forecast remains unchanged at $US 2.40/MMBtu versus a forward market price as at June 29 of $US 2.46/MMBtu. Our caution is based upon the potential for higher U.S. gas drilling activity and growing Canadian imports to temper prices. As at June 25, the U.S. gas directed rig count had increased 25% to 453 from the low reached in April of 362. Year 2000 East Coast Canadian imports will likely add 0.2-0.4 Bcf/d into the U.S. Northeast. We underscore the potential for sharp price increases next year if U.S. domestic gas production falls short of our expectation.

Henry Hub Price Expectations



Source: Historical data from Natural Gas Week (spot cash). Swap prices from RBC DS. Industry consensus represented by June 1999 survey of brokerage houses and Canadian petroleum consultants.
Note: Trend Henry Hub was calculated by smoothing actual Henry Hub prices with a statistical technique called a Hodrick-Prescott filter. Current year swap price shown is for the remainder of the calendar year.

2H99 Alberta Gas Price Forecast Portfolio Breakdown

	Forward Market @ June 29/99	Baseline Price	Weighting
Henry Hub ($US/MMBtu)	2.47	2.43	
AECo Basis ($US/MMBtu)	0.41	0.34	
Alberta Spot Plantgate ($/Mcf)	2.86	2.90	25%
Alberta Term Plantgate ($/Mcf)	2.65	2.65	20%
Exports @ Ab. Plantgate ($/Mcf)			
California/Pacific N.W.	2.46	2.32	21%
Midwest	2.57	2.42	21%
Northeast	2.43	2.29	13%
Average	2.50	2.35	55%
Wt. Ave. Ab. Plantgate ($/Mcf)	2.62	2.55	100%

Notes: Baseline forecast assumes exchange rate of $US/Cdn 0.69. NOVA cost of $0.26/Mcf and NYMEX- export point basis differentials ranging between $US-0.05/MMBtu for Niagara and $US0.30/MMBtu for Sumas.

◆ Alberta 30-day plantgate spot prices averaged $2.50/Mcf, 41% more than the 2Q98 comparable of $1.77/Mcf. Our estimate of the 2Q99 average Alberta plantgate price is $2.30/Mcf, up 5% and 17% respectively from the 1Q99 and 2Q98 comparables.

◆ Our 2H99 weighted average Alberta plantgate price forecast is $2.55/Mcf. Using forward market prices as at June 29 for Alberta spot plantgate and Henry Hub of $2.86/Mcf and $US 2.47/MMBtu respectively, implies a weighted average Alberta plantgate price in the $2.60/Mcf range.

2000 Alberta Gas Price Forecast Portfolio Breakdown

	Forward Market @ June 29/99	Baseline Price	Weighting
Henry Hub ($US/MMBtu)	2.46	2.40	
AECo Basis ($US/MMBtu)	0.39	0.37	
Alberta Spot Plantgate ($/Mcf)	2.86	2.80	30%
Alberta Term Plantgate ($/Mcf)	2.70	2.70	15%
Exports @ Ab. Plantgate ($/Mcf)			
California/Pacific N.W.	2.51	2.44	21%
Midwest	2.73	2.46	22%
Northeast	2.69	2.43	12%
Average	2.64	2.45	55%
Wt. Ave. Ab. Plantgate ($/Mcf)	2.70	2.60	100%

Notes: Baseline forecast assumes exchange rate of $US/Cdn 0.69, average NOVA receipt charge of $0.14/Mcf and NYMEX- export point basis differentials ranging between $US-0.17/MMBtu for Niagara and $US0.35/MMBtu for Sumas.

◆ Our year 2000 weighted average Alberta plantgate price forecast is $2.60/Mcf. Using forward market prices as at June 29 for Alberta spot plantgate and Henry Hub of $2.86/Mcf and $US 2.46/MMBtu respectively, indicates a modestly higher price of $2.70/Mcf.

◆ High production declines, ready access to markets and cost competitive supplies all bode well for Canadian gas producers entering the year 2000. In this bullish environment very few producers have fixed prices for the upcoming gas year. Based upon discussions with individual companies we estimate less than 20% of 1999/2000 sales are currently under fixed price terms.

◆ Longer term forward market prices continue to set record highs. As at June 29, Alberta spot plantgate prices were $ 2.86/Mcf in 2001 rising to $ 2.95/Mcf by 2003.

North American Natural Gas Price Forecast Summary

Baseline Scenario	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
U.S. Gas Prices ($US/MMBtu)																
Henry Hub	1.71	2.75	2.53	2.09	2.20	2.40	2.40	2.40	2.45	2.50	2.50	2.50	2.50	2.50	2.50	2.50
$ 1999	1.84	2.90	2.62	2.11	2.20	2.35	2.31	2.26	2.26	2.26	2.22	2.18	2.13	2.09	2.05	2.01
Alberta Plantgate Gas Prices ($Cdn/Mcf)																
Domestic Sales																
Spot	1.04	1.27	1.69	1.95	2.72	2.76	2.67	2.58	2.50	2.50	2.50	2.43	2.43	2.42	2.42	2.42
Export Sales																
Average	1.45	2.08	2.30	2.01	2.25	2.45	2.34	2.21	2.20	2.30	2.30	2.30	2.30	2.30	2.30	2.30
Total																
Average	1.37	1.70	1.94	2.00	2.40	2.60	2.50	2.45	2.40	2.40	2.40	2.40	2.40	2.40	2.40	2.40
$ 1999	1.48	1.79	2.02	2.02	2.40	2.55	2.40	2.31	2.22	2.18	2.13	2.09	2.05	2.01	1.97	1.93
Aggregator Prices ($Cdn/Mcf)																
TCGS	1.24	1.63	1.87	1.88	2.23	2.38	2.30	2.22	2.20	2.28	2.28	2.28	2.31	2.31	2.31	2.31
Pan Alberta	1.29	1.90	2.30	2.00	2.33	2.49	2.30	2.22	2.20	2.28	2.28	2.28	2.31	2.31	2.31	2.31
Progas	1.54	1.77	2.00	1.98	2.33	2.46	2.30	2.22	2.20	2.28	2.28	2.28	2.31	2.31	2.31	2.31
CanWest	1.31	1.58	1.87	2.02	2.40	2.45	2.32	2.18	2.21	2.28	2.28	2.28	2.31	2.31	2.31	2.31

Low Price Scenario	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
Henry Hub $US/MMBtu	1.71	2.75	2.53	2.09	1.90	2.00	2.00	2.00	2.00	2.00	2.00	2.10	2.10	2.10	2.10	2.10
$ 1999	1.84	2.90	2.62	2.11	1.86	1.92	1.88	1.85	1.81	1.78	1.74	1.79	1.76	1.72	1.69	1.66
Alberta Spot $Cdn/Mcf	1.04	1.27	1.69	1.95	2.29	1.96	1.90	1.83	1.77	1.84	1.90	2.04	2.03	2.03	2.03	2.02
Ave. Alberta $Cdn/Mcf	1.37	1.70	1.94	2.00	1.99	1.92	1.92	1.82	1.74	1.75	1.80	1.90	1.91	1.90	1.91	1.90
$ 1999	1.48	1.79	2.02	2.02	1.95	1.85	1.81	1.68	1.58	1.55	1.57	1.62	1.60	1.56	1.53	1.50

High Price Scenario	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
Henry Hub $US/MMBtu	1.71	2.75	2.53	2.09	2.45	2.50	2.50	2.50	2.50	2.55	2.60	2.65	2.70	2.70	2.75	2.80
$ 1999	1.84	2.90	2.62	2.11	2.40	2.40	2.36	2.31	2.26	2.26	2.26	2.26	2.26	2.21	2.21	2.21
Alberta Spot $Cdn/Mcf	1.04	1.27	1.69	1.95	2.98	3.00	2.95	2.86	2.71	2.70	2.70	2.70	2.70	2.69	2.76	2.82
Ave. Alberta $Cdn/Mcf	1.37	1.70	1.94	2.00	2.78	2.80	2.80	2.65	2.52	2.58	2.65	2.66	2.67	2.66	2.73	2.80
$ 1999	1.48	1.79	2.02	2.02	2.72	2.70	2.63	2.45	2.28	2.29	2.31	2.27	2.23	2.19	2.20	2.20

Notes:
1. General inflation assumed flat at 2% per annum.
2. Canadian prices based on $US/Cdn 0.68, 0.69, 0.70 ,0.72 exchange rate in 1999/2000/01/02 respectively, $US/Cdn 0.74 in 2003 and thereafter.
3. Alberta gas prices are at the plantgate – ie., before the deduction of field gathering, processing and compression costs.
4. CanWest prices are at the plantgate, before Westcoast gathering and processing charges of roughly $0.41/Mcf.
5. Spot/Short-term represents an average of spot and 1-year prices.
6. Assumes heating content of 1000 MBtu's per Mcf.