RÉPONSE DE SCGM À UNE DEMANDE D'INFORMATION

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CANADIAN HYDROCARBON MARKETS

AND PRICES

March 1, 1998

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The natural gas price forecasts remain the same as Sproule's previous price forecast with the exception of the B.C. plantgate and spot prices which have minor adjustments to the transportation differentials. As new pipeline capacity becomes available throughout 1998, the Henry Hub price is expected to dip as indicated by Sproule's 1998 forecast price of $2.09 US per MMbtu. Although a slight reduction is expected in the US price of natural gas, a price increase is anticipated in Western Canada as the differential between US and Canadian prices more closely resembles the cost of transportation between the two countries. The average plantgate price of natural gas in Alberta is forecast to be $1.80 per MMbtu. This price is capped at $2.20 per MMbtu in 1998 dollars.

The exchange rate ($U.S. per $Canadian) was assumed to increase from the 1998 forecast of 0.71 to 0.73 over the next 2 years, and then remain constant at 0.73.

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 -									At Plant Gate						
Year	1 WTI Cushing Oklahom $US/Bbl	Edmonton Par Price 40 API $/Bbl	2 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 $/Mcf	Sask. $/MMBtu	Ethane $/Bbl	Propane $/Bbl	Butanes $/Bbl	Pentanes Plus $/Bbl	Sulphur $/LT	Inflation Rate %/Yr	Exchange Rate $US/$Cdn
1989 Act	19.58	22.20		13.67	18.29		1.38	1.39	1.64	6.05	8.13	9.82	21.25	71.45	5.3	0.845
1990 Act	24.53	27.65		16.00	22.75	21.40	1.47	1.41	1.60	6.05	13.15	15.64	26.62	61.12	4.9	0.857
1991 Act	21.50	23.42		9.06	16.82	15.07	1.26	1.24	1.37	6.00	11.89	15.25	22.30	54.77	5.8	0.873
1992 Act	20.56	23.76	22.83	12.90	18.39	17.47	1.29	1.13	1.13	6.00	10.03	14.04	22.34	23.05	1.9	0.829
1993 Act	18.46	21.87	22.39	13.56	17.60	16.72	1.60	1.33	2.08	6.00	14.23	13.26	21.49	-2.23	1.8	0.776
1994 Act	17.18	22.25	21.49	15.02	19.26	18.42	1.81	1.50	1.87	5.31	12.52	13.45	21.25	16.57	0.2	0.732
1995 Act	18.42	24.28	22.93	17.26	21.69	20.80	1.23	0.97	1.35	5.80	13.91	13.79	24.21	30.65	2.0	0.729
1996 Act	22.13	29.43	26.26	20.05	26.07	25.11	1.63	1.18	1.28	5.83	22.16	17.12	29.50	14.44	1.6	0.731
1997 Act	20.60	27.89	26.89	14.35	23.71	21.16	1.85	1.42	1.75	5.83	18.56	19.05	29.21	12.26	1.5	0.722
1998	18.00	24.45	23.45	10.45	20.20	17.45	1.79	1.28	1.79	5.84	15.14	16.40	25.04	12.00	2.0	0.710
1999	19.38	25.74	24.74	13.76	21.49	19.49	1.92	1.47	1.92	6.15	15.61	16.88	26.12	15.00	2.0	0.720
2000	20.81	27.31	26.31	17.30	23.06	21.81	2.02	1.60	2.02	6.52	16.20	17.51	27.46	17.17	2.0	0.730
2001	21.22	27.87	26.87	17.82	23.59	22.34	2.09	1.66	2.09	6.66	16.16	17.45	27.87	18.04	2.0	0.730
2002	21.65	28.44	27.44	18.36	24.13	22.88	2.18	1.75	2.18	6.79	16.49	17.38	28.44	18.94	2.0	0.730
2003	22.08	29.02	28.02	18.91	24.68	23.43	2.25	1.81	2.25	6.93	16.83	17.73	29.02	19.87	2.0	0.730
2004	22.52	29.61	28.61	19.47	25.24	23.99	2.32	1.87	2.32	7.07	17.17	18.10	29.61	20.83	2.0	0.730
2005	22.97	30.21	29.21	20.04	25.82	24.57	2.41	1.95	2.41	7.21	17.52	18.46	30.21	21.83	2.0	0.730
2006	23.43	30.83	29.83	20.62	26.40	25.15	2.48	2.01	2.48	7.36	17.88	18.84	30.83	22.85	2.0	0.730
2007	23.90	31.45	30.45	21.21	27.00	25.75	2.57	2.09	2.57	7.51	18.24	19.22	31.45	23.90	2.0	0.730
2008	24.38	32.09	31.09	21.82	27.60	26.35	2.65	2.17	2.65	7.66	18.61	19.61	32.09	24.99	2.0	0.730
2009	24.87	32.74	31.74	22.43	28.23	26.98	2.75	2.25	2.75	7.82	18.99	20.01	32.74	26.11	2.0	0.730
2010	25.36	33.41	32.41	23.06	28.86	27.61	2.79	2.28	2.79	7.98	19.37	20.42	33.41	27.27	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 March 1, 1998

TABLE 2
NATURAL GAS PRICE FORECASTS - VARIOUS SHIPPERS
$Cdn/MMBtu
****

Year	Alberta Gas Reference Price	TCGSL	PanAlberta	Progas	Alberta Direct** Sales	Alberta Spot Sales	Sask Direct Sales	Canwest Wellhead $/Mcf	B.C. Spot Plantgate	B.C. Spot Wellhead	Huntingdon/ Sumas 30 d Spot	Henry Hub Price $US/MMBtu
1989 Act	1.61	1.38	1.45	1.66	1.40	1.28	1.64	1.39				1.66
1990 Act	1.64	1.47	1.46	1.71	1.32	1.14	1.60	1.41				1.62
1991 Act	1.44	1.26	1.31	1.36	0.99	0.96	1.37	1.24				1.45
1992 Act	1.38	1.29	1.43	1.54	0.97	1.03	1.13	1.13				1.76
1993 Act	1.67	1.60	1.74	1.91	1.91	2.17	2.08	1.33				2.12
1994 Act	1.81	1.81	1.73	1.90	1.97	1.89	1.87	1.50	1.81	1.46	1.97	1.88
1995 Act	1.31	1.23	1.25	1.52	1.17	1.03	1.35	0.97	1.12	0.77	1.39	1.59
1996 Act	1.63	1.63	1.88	1.78	1.28	1.26	1.28	1.18	1.47	1.12	1.80	2.62
1997 Act	1.91	1.85	2.21	1.94	1.69	1.70	1.75	1.42	1.98	1.58	2.37	2.59
1998	1.80	1.79	1.84	1.90	1.79	1.68	1.79	1.28	1.73	1.33	2.08	2.19
1999	1.92	1.92	1.92	1.96	1.92	1.87	1.92	1.47	1.92	1.52	2.28	2.08
2000	2.00	2.02	2.02	2.02	2.02	1.96	2.02	1.60	2.07	1.65	2.43	2.12
2001	2.08	2.09	2.09	2.09	2.09	2.04	2.09	1.66	2.14	1.72	2.51	2.19
2002	2.17	2.18	2.18	2.18	2.18	2.12	2.18	1.75	2.23	1.80	2.61	2.26
2003	2.24	2.25	2.25	2.25	2.25	2.19	2.25	1.81	2.31	1.86	2.69	2.34
2004	2.30	2.32	2.32	2.32	2.32	2.26	2.32	1.87	2.37	1.92	2.77	2.41
2005	2.40	2.41	2.41	2.41	2.41	2.35	2.41	1.95	2.47	2.01	2.87	2.49
2006	2.47	2.48	2.48	2.48	2.48	2.42	2.48	2.01	2.54	2.07	2.95	2.57
2007	2.55	2.57	2.57	2.57	2.57	2.51	2.57	2.09	2.63	2.15	3.05	2.65
2008	2.64	2.65	2.65	2.65	2.65	2.59	2.65	2.17	2.72	2.23	3.14	2.73
2009	2.73	2.75	2.75	2.75	2.75	2.68	2.75	2.25	2.81	2.31	3.24	2.82
2010	2.77	2.79	2.79	2.79	2.79	2.73	2.79	2.28	2.85	2.35	3.30	2.90

Escalation Rate of 2.0% thereafter.

** All direct sales forecasts will be adjusted by a differential to reflect the actual direct sales prices for each company
This differential will be phased out over a one to three year period in recognition of the contract terms specific to the company

As of March 1, 1998

Sproule

HISTORY OF OIL AND GAS IN CANADA

The Leduc discovery in 1947 signaled the birth of the Canadian petroleum industry. Prior to this time, activity in this sector of the economy was erratic and lacked any sustained growth. Over the next 15 years, the exploration for and development of petroleum resources evolved into a major industry in Western Canada, particularly in the Province of Alberta. By 1960, oil production had reached 520,000 barrels per day, more than an order of magnitude greater than the 20,000 barrels per day recorded in 1947.

Although the growth of the Canadian petroleum industry was significant over the period from 1947 to 1960, it certainly was not spectacular, as hydrocarbon prices were essentially flat and relatively low; however, much of the transportation infrastructure which is in place today was constructed during this time. Interprovincial Pipeline was started in 1950 to transport oil from Alberta to markets east of the province, and major natural gas transmission lines were brought into service late in the 1950's. In 1957, the first natural gas deliveries were made to the Alberta Gas Trunk Line and to TransCanada. By 1960, deliveries of natural gas were also being made to Westcoast Transmission and Alberta and Southern. The large investments in transmission facilities made during this time were predicated upon the significant reserve base developed since the Leduc discovery and stable hydrocarbon prices.

In 1960, to promote the development of the petroleum industry, the Canadian government reserved markets west of the Ottawa Valley for domestic oil supplies. Canada also began to export oil to the U.S. after 1960 and, by 1970, production had increased to 1,200,000 barrels per day. The Canadian federal policy embodied in the National Oil Policy, together with the special status accorded to Canadian oil imports by the U.S. government, combined to insulate Canadian producers from the general decline in world oil prices that occurred during the sixties. Even though production levels more than doubled in this decade, oil reserve additions continued to out pace production for most of the sixties. Canada's remaining reserves of conventional oil peaked in 1969 at some 10.5 billion barrels.

Natural gas prices remained depressed through the sixties although prices did increase from $0.10 per thousand cubic feet ("Mcf") to some $0.15 per Mcf towards the end of the decade. The price increase was largely due to gas purchase programs instituted by major interstate transmission companies as U.S. domestic supplies tightened. The U.S. gas shortages of the late sixties and early seventies were primarily a result of gas price controls in that country.

Energy prices, security of supply, and revenue sharing became key national issues in the seventies. During this period, there were two major price shocks orchestrated by OPEC. In Canada,

governments at the provincial and federal levels and their regulatory agencies began playing expanded roles within the petroleum sector, often adopting conflicting positions with one another. Industry was the victim of these confrontations. Regulation of oil and gas prices was introduced in the seventies. With governments looking for a larger share of industry revenues, Crown royalty levies and the provisions of the Canadian Income Tax Act were drastically altered. Although these changes in government policy had a negative impact on the industry in the short-term, by the end of the seventies industry activity was at record levels, mainly due to dramatic and unexpected price increases.

During the seventies, natural gas prices increased by more than tenfold, benefiting from increasing crude oil prices as well as increasing in value relative to crude oil. Consequently, in Canada, natural gas reserves and productive capacity increased significantly. In the early seventies, it appeared that natural gas shortages were developing and government policies and industry strategic plans based on this assumption led to the development of the large surplus capacity which still exists today. Just as regulating prices at artificially low levels will serve to reduce supply, the converse is true as well and price regulation was a prime contributor to the development of the major gas surplus during the seventies.

The National Energy Program ("NEP") was introduced on October 28, 1980, as a result of the inability of the Alberta and federal governments to agree on oil and gas prices. The NEP was essentially a replay of the confrontation politics of the mid-seventies; however, in the eighties, hydrocarbon prices were beginning to soften and markets were being affected by the economic downturn in both Canada and the U.S. Consequently, the industry was not able to rebound from the imposition of new taxes in the way it had been able to in the late seventies. The NEP seriously weakened the Canadian oil industry.

Late in 1984, the federal government began the laborious task of dismantling the NEP; and by March 1985, the federal government along with the governments of British Columbia, Alberta and Saskatchewan formally agreed to a program of price deregulation. The agreement was referred to as "The Western Accord". Oil prices were deregulated soon afterwards, in June 1985. The deregulation of gas prices formally took effect in November 1986.

Oil prices are now "market-derived" and consequently the dramatic decline in world prices in early 1986 were felt immediately. Since the implementation of deregulation, light oil prices in Edmonton reached a maximum level of $38.55 per barrel late in 1985 and a minimum level of $15.85 per barrel in mid-1986.

Deregulation of natural gas prices actually began in 1984 as the federal government began allowing exporters some greater degree of freedom in negotiating prices with their American buyers. The formal deregulation of gas prices for volumes destined for interprovincial markets took effect late in 1986. Recognizing the large surplus productive capacity which has existed for the last several years, it was not surprising that deregulation caused a precipitous decline in gas prices.

Figure 1 prices provide the history of the average wellhead oil and gas price for Alberta.

There was a resurgence in the natural gas price in 1993 as new export pipeline capacity provided access to the U.S. marketplace and released much of the Canadian pent-up supplies. Natural gas prices remained strong through most of 1994, but plummeted in 1995 due to surplus supply resulting from record drilling activity during 1994 and lack of available pipeline capacity. Prices recovered in 1996 due to a severe winter, and have remained strong in 1997 despite the warmer than normal weather.

TRANSMISSION SYSTEMS

Canadian oil and gas production moves to its North American markets through a web of pipelines which cross international, provincial and state borders.

Oil Pipelines

Interprovincial Pipeline ("IPL") operates the major oil pipeline in Canada which extends from Edmonton to Sarnia. The section between Gretna, Manitoba and Sarnia, Ontario is located in the U.S. (owned and operated by the Lakehead Pipeline, an IPL subsidiary). Construction of this system began in 1950, and it moves crude oil, refined oil and natural gas liquids at a rate of some 1,500,000 barrels per day (deliveries averaged 1,497,000 barrels per day in 1993). The pipeline is operated under the jurisdiction of the NEB.

Prior to 1991, the Interprovincial Pipeline extended beyond Sarnia to Montreal. But in July of 1991, the line east of Sarnia was purged. Volumes transported through the pipeline to Montreal had declined from a peak of 300,000 barrels per day in 1980 to 105,000 barrels per day in 1989. The pipeline was originally installed 14 years ago in order to ensure security of supply in Eastern Canada and it has been heavily subsidized by the Federal Government. Montreal has access to alternate supplies from the North Sea which have been slightly cheaper than the western crude.

TransMountain Pipe Line operates a line moving crude oil from Edmonton to Vancouver and into Washington State. The line was completed in 1953 and has a capacity of 200,000 barrels per day. In 1991, deliveries averaged 195,000 barrels per day.

There are regional pipelines in Manitoba, Saskatchewan, British Columbia, Alberta and the Northwest Territories delivering crude oil to major transmission lines in Canada and the U.S. A pipeline also moves oil from Portland, Maine to Montreal.

Gas Pipelines

The first significant Canadian gas pipeline was built in 1912 to move gas from Bow Island (near Medicine Hat) to Calgary; however, it was not until 1955 that sufficient gas reserves had been delineated in Alberta to justify large gas transmission lines to connect new markets.

With surplus deliverability continuing to hang over the western provinces, a number of new pipeline proposals are in various stages of development. Northern Border has begun the regulatory process for a 700 MMcf per day expansion with an on stream date of November 1, 1998; the TransCanada Pipelines TransVoyageur transmission line plans to add 2 Bcf per day of additional capacity in 1999; and in competition to TransCanada, a producer group is supporting the Alliance pipeline which intends to transport 1,250 MMcf per day from Fort St. John to Chicago.

The transportation systems installed over the last 30 years now move Western Canadian production to Montreal, to Vancouver and the U.S. Pacific Northwest, to California and to the U.S. Midwest. These include:

(1) **TransCanada PipeLines** ("TCPL") which has been moving gas east of Alberta since 1957 and now has 8,900 miles of pipeline moving gas as far east as Montreal. In 1991, gas began to flow through a new connection in Ontario with the 370 mile Iroquois pipeline, which now has the capacity to move 980 MMcf per day to market in the Northeastern United States. The current capacity of the TransCanada Pipelines mainline is 7.8 Bcf per day (1997).

(2) **Westcoast Transmission** which moves gas from northeast British Columbia to Vancouver and the U.S. Pacific Northwest through 1,500 miles of pipeline. Westcoast is operating at a capacity of 1,900 MMcf per day as a result of a 1996 mainline expansion. In the Peace River area, the Westcoast system is connected to NOVA and approximately 60 MMcf per day flows from B.C. into Alberta's NOVA system.

(3) **Foothills Pipeline** which was completed in 1982 as the southern portion of the system designed to move Alaskan North Slope gas to U.S. markets. It consists of an East Leg and West Leg, the first serving the U.S. Midwest and the second serving California. Current capacity through the eastern leg is approximately 1,500 MMcf per day. Incremental capacity of 690 MMcf per day is expected to be available as of November 1, 1998, as the result of a facilities expansion approved by the NEB in January 1997. The western leg is operated by Alberta Natural Gas under the terms of an operating agreement.

(4) **Alberta Natural Gas** ("ANG") which delivers Alberta gas to the Pacific Gas Transmission ("PGT") pipeline serving the northern California market. It was completed in 1961, and in 1996 moved 2,288 MMcf per day; total capacity is 2,500 MMcf per day.

(5) **TransQuebec and Maritime Pipeline** ("TQM") is a subsidiary of TCPL and Gaz Metropolitain which presently moves gas from Montreal to Quebec City. All costs incurred in the operation of TQM are currently included in TCPL's cost of service. TQM, in conjunction with TransMaritime Gas Transmission, is proposing expansion from the Quebec/New Brunswick border to Nova Scotia, for access to the Sable Island offshore supply basin, competing with Maritimes and Northeast Pipeline who propose to transport the gas from offshore Nova Scotia to the Boston area market via Maine.

In addition to these interprovincial and international gas transmission systems, there are significant intra provincial systems. The two largest systems are in Alberta and include:

(1) **NOVA Gas Transmission Ltd.** which has the exclusive right to collect and move gas for removal from Alberta. NOVA operates 13,300 miles of trunkline and also moves gas to markets within the province. It started gas deliveries in 1957. The NOVA System has a maximum receipt capacity of 13,500 MMcf per day, with the capacity to deliver a total of 12,800 MMcf per day. The delivery capacity at the border points is 10,700 MMcf per day with the balance of the delivery capacity serving the intra-Alberta market.

(2) **Canadian Utilities** which operates two utilities, one serving Alberta south of Red Deer and the other serving the area north of Red Deer. They have been operating since 1912 and now have 20,000 miles of transmission and distribution lines.

NGL/LPG and Products Pipelines

Ethane, propane, butane and pentanes plus are moved to Sarnia, Ontario through the Interprovincial and the Cochin pipelines. Some liquids are also moved by rail. In Alberta, there are several pipelines moving liquids to Edmonton and other points for consumption or for delivery to transmission systems.

OIL, GAS AND BY-PRODUCT PRICES

Sproule has developed a hydrocarbon pricing model which treats world oil prices, general inflation rates, and exchange rates as input variables. The model calculates transportation costs and the prices of competing fuels in major Canadian and U.S. markets. Once the various market prices have been determined, intervening transportation costs are deducted which results in forecasts of wellhead and plant gate prices for Western Canadian oil, natural gas, and natural gas by-product production.

The price of oil will be governed by supply and demand, and the degree that OPEC is able to limit supply will be a major determinant in establishing oil prices for the next 10 years. Sproule's oil price forecast for the balance of the nineties is based upon a supply forecast which falls in between a fully competitive market and a market controlled by an effective OPEC production quota system.

Natural gas prices, which have declined continuously since deregulation with the exception of a peak in 1993/94, have begun to recover. Prices have been reasonably strong throughout the 1997/1998 winter despite the warmer than normal winter and, although high storage levels may soften the price throughout the summer injection season, the price of natural gas is expected to continue to grow, in real terms. Excess productive capacity within Alberta, in combination with limited transportation capacity leaving the province, continues to suppress the price of natural gas. New pipeline facilities will likely provide new market opportunities in the future and assist in the firming of future natural gas prices.

Transmission costs, a significant item in forecasting Canadian wellhead prices, are expected to increase at rates which are generally less than the rate of inflation. The exchange rate ($U.S. per $Canadian) was assumed to increase from the 1998 forecast of 0.71 to 0.73 over the next 2 years, and then remain constant at 0.73. Sproule's inflation assumptions are set out in Table 1. Schedules of prices for oil and gas in nominal dollars are set out in Tables 1 and 2.

Oil Prices

The oil price forecasts set out in Table 1 were based on a forecast of prices for West Texas Intermediate crude at Cushing, Oklahoma, which is expected to directly reflect world oil prices. The Edmonton oil price is for 40-45 degree API crude with less than 0.5 percent sulphur.

Gas Prices

The gas market is highly competitive and prices vary widely between buyers, reflecting the markets served. To recognize these variations, price models have been developed to forecast prices for the different buyers and the various classifications of producers contracted to these buyers. Detailed gas price schedules are set out in Table 2.

TransCanada Gas Services Limited ("TCGS")

The price for TCGS suppliers is expected to mainly reflect recent pricing arrangements that TCGS has negotiated with the Eastern Canadian utilities, as well as the continuation of gas-on-gas competition. Export gas prices, netted back to the Alberta border, were forecast to be competitive with U.S. indigenous supplies in the marketplace.

Progas

The Progas prices assume that Progas will continue to almost exclusively sell to U.S. markets. The wellhead prices reflect various market prices in the U.S. Northeast and North Central States less intervening transmission costs.

Pan-Alberta Gas Ltd. ("Pan-Alberta")

Prices paid by Pan-Alberta reflect the netback prices attributable to its various export and domestic market in the north-central United States, with other markets in California, Quebec and the northeastern United States.

Alberta Intra provincial Sales

Separate forecasts are prepared for direct sales which are usually for terms of one to two years, and for spot sales which are usually for excess volumes offered for 30 to 60 days. As the markets

for Alberta gas develop, excess capacity is expected to diminish and the prices for direct and spot sales are expected to approach long term market prices.

B.C. and Saskatchewan

The prices forecast for Canwest Gas Supply Inc.'s purchases in British Columbia reflect the Pacific Northwest prices which are expected to continue to be very competitive. In Table 2, Sproule provides a Canwest wellhead price to reflect their traditionally contract structure. Since a number of producers have negotiated for sales at the plantgate, where marketable natural gas after gathering and processing is delivered into the Westcoast transportation system, a B.C. spot plantgate price and a 30-day Huntingdon/Sumas price have also been derived. The B.C. spot wellhead price reflects an average unit cost of gathering and processing charges. Saskatchewan Energy in Saskatchewan is expected to pay a price that is comparable with Alberta netback prices.

By-Product Prices

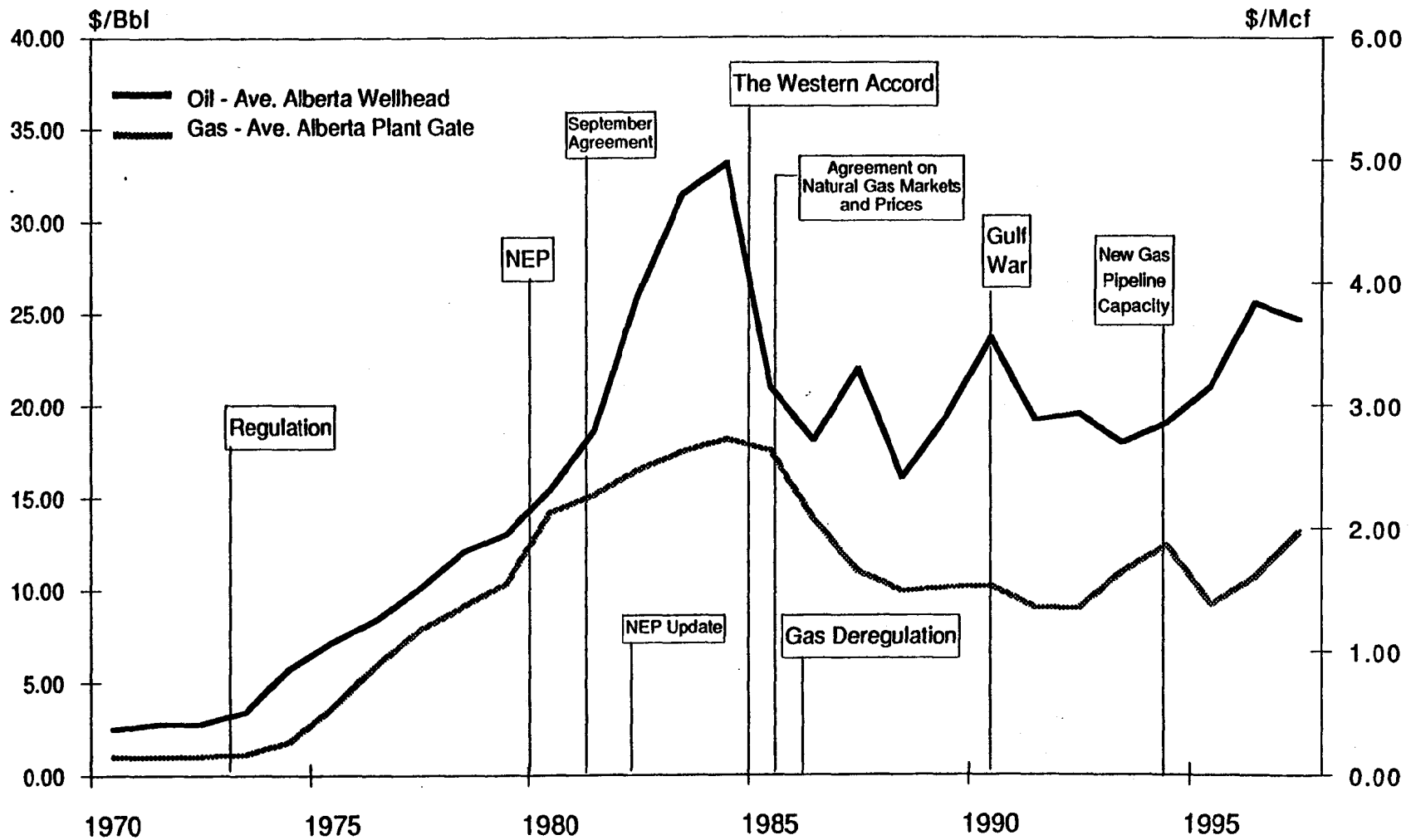
For the most part, propane, butane, and pentanes plus prices are forecast to continue their historic relationships with crude oil prices in major market areas. Propane prices have surpassed butane prices in Alberta due to suppressed butane markets and an increased demand for propane. This trend is expected to revert to normal in the next year or two. Ethane prices are expected to increase from present levels at a rate related to propane price changes. Sulphur prices are expected to remain soft for the next three years before realizing slight growth. The price forecasts for by-products are set out in Table 1.

GAS PURCHASE TAKES

The market allocation, which was expressed as a percentage of Daily Contract Demand ("DCQ"), was used to apportion the available market to producers which were capable of productive capacity in excess of market requirements. This apportionment is no longer necessary. New pipeline capacity into the American northeast, the American mid-west, and California marketplace has provided new market opportunities for Canadian producers and served to reduce the surplus natural gas productive capacity in Western Canada. Sproule forecasts that all shippers will operate at 100 percent of DCQ or 85 percent of the maximum deliverability.

The evaluation of uncontracted shut-in gas reserves in Western Canada considers the proximity to exiting infrastructure and the production start date varies with the magnitude of the reserves and the development plans of the operator. To the extent that plant and gathering facilities of sufficient capacity are currently available, the connection of unconnected supplies is forecast at the deliverability of the well within the year the well is completed. If the reserves are located in moderately remote areas or are of moderate quality, the production start date is deferred a year or two and the economics of plant development may curtail the production of the reserves to an average daily rate of 1.0 MMcf per day per 3.5 Bcf of reserves. For reserves located in remote areas, or reserves that are considered of poor quality, the production start date is no earlier than 2001.

Canadian Energy Prices



Source: CPA Statistics Handbook

FIGURE 1

Sproule

Gilbert Laustsen Jung Associates Ltd. Petroleum Consultants

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

Quarterly Update
April 1, 1998

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April 1, 1998

Gilbert Laustsen Jung Associates Ltd. have prepared the enclosed price and market forecasts after a comprehensive review of information available through to March 1998. 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
APRIL 1, 1998

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

	January 1, 1998 Calendar Year	April 1, 1998 Calendar Year	April 1, 1998 Q2-Q4
Henry Hub Gas Price - ($US/MMBTU)			
1998	2.20	2.25	2.30
1999	2.15	2.30	2.30
Average Alberta Gas Price - ($Cdn/MMBTU)			
1998	1.60	1.80	1.85
1999	1.85	2.00	2.00
TCGS Gas Price - ($Cdn/MMBTU)			
1998	1.70	1.80	1.80
1999	1.85	2.00	2.00
Pan-Alberta Gas Price - ($Cdn/MMBTU)			
1998	1.80	2.05	2.00
1999	1.85	2.00	2.00
ProGas Gas Price - ($Cdn/MMBTU)			
1998	1.80	1.90	1.90
1999	1.85	2.00	2.00
Canwest Field Gas Price - ($Cdn/MCF)			
1998	1.05	1.20	1.15
1999	1.25	1.40	1.40

CRUDE OIL PRICES

	January 1, 1998 Calendar Year	April 1, 1998 Calendar Year	April 1, 1998 Q2-Q4
WTI @ Cushing Price - ($US/BBL)			
1998	19.00	16.75	17.00
1999	20.00	19.00	19.00
Light, Sweet @ Edmonton Price - ($Cdn/BBL)			
1998	25.75	22.75	23.00
1999	26.75	25.25	25.25

Table 1
Gilbert Laustsen Jung Associates Ltd.
Crude Oil and Natural Gas Liquids
Base Case Price Forecast
Effective April 1, 1998

Year	Inflation %	Exchange Rate $US/$Cdn	West Texas Intermediate Crude Oil at Cushing Oklahoma Constant 1998 $ $US/bbl	West Texas Intermediate Crude Oil at Cushing Oklahoma Then Current $US/bbl	Brent Blend Crude Oil FOB North Sea Constant 1998 $ $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 1998 $ $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 1998 $ $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 1998 $ $Cdn/bbl	Heavy Crude Oil (12 API) at Hardisty Then Current $Cdn/bbl	Medium Crude Oil (29 API, 2.0%S) at Cromer Constant 1998 $ $Cdn/bbl	Medium Crude Oil (29 API, 2.0%S) at Cromer Then Current $Cdn/bbl	Alberta Natural Gas Liquids (Then Current Dollars) Field 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	24.82	19.58	18.95	14.95	28.12	22.18	23.25	18.34	17.33	13.67	23.19	18.29	n/a	7.64	9.87	n/a
1990	4.8	0.857	29.54	24.46	21.99	18.21	33.40	27.66	25.77	21.34	19.32	16.00	27.50	22.77	n/a	13.18	15.67	n/a
1991	5.6	0.873	24.71	21.45	27.29	23.69	26.95	23.39	17.40	15.10	10.40	9.03	19.40	16.84	n/a	11.92	15.26	n/a
1992	1.5	0.830	22.52	20.64	21.72	19.91	25.77	23.62	19.13	17.54	14.14	12.96	20.13	18.45	n/a	10.58	14.04	n/a
1993	1.8	0.775	19.84	18.46	20.78	19.34	23.58	21.94	17.98	16.73	14.25	13.26	18.90	17.59	n/a	14.10	13.64	21.17
1994	0.2	0.730	18.14	17.18	17.98	17.03	23.46	22.22	19.50	18.47	15.86	15.02	20.38	19.30	n/a	12.53	13.45	21.69
1995	2.2	0.729	19.38	18.39	16.67	15.82	25.53	24.23	21.92	20.80	18.21	17.28	22.85	21.69	n/a	13.90	13.79	24.11
1996	1.5	0.733	22.68	21.99	21.07	20.43	30.31	29.39	25.92	25.13	20.69	20.06	26.92	26.10	n/a	22.31	17.15	30.06
1997	1.6	0.722	20.94	20.61	19.49	19.18	28.30	27.85	21.51	21.17	14.64	14.41	24.10	23.72	n/a	18.62	18.73	30.91
1998 Q1 (e)	1.1	0.700	15.93	15.93	14.13	14.13	21.97	21.97	14.38	14.38	5.78	5.78	18.63	18.63	n/a	13.11	15.16	27.61
1998 Q2	2.0	0.710	16.50	16.50	15.00	15.00	22.25	22.25	15.25	15.25	9.25	9.25	18.25	18.25	5.75	12.25	14.25	25.25
1998 Q3	2.0	0.710	17.00	17.00	15.50	15.50	23.00	23.00	16.00	16.00	10.00	10.00	19.00	19.00	6.00	13.00	15.00	26.00
1998 Q4	2.0	0.710	17.50	17.50	16.00	16.00	23.50	23.50	16.50	16.50	10.50	10.50	19.50	19.50	7.25	14.50	15.50	26.50
1998 Full Year	1.8	0.708	16.75	16.75	15.25	15.25	22.75	22.75	15.50	15.50	9.00	9.00	18.75	18.75	6.50	13.25	15.00	26.25
1998 Q2-Q4	2.0	0.710	17.00	17.00	15.50	15.50	23.00	23.00	16.00	16.00	10.00	10.00	19.00	19.00	6.50	13.25	15.00	26.00
1999	2.0	0.720	18.75	19.00	17.25	17.50	24.75	25.25	19.75	20.25	15.00	15.25	21.25	21.75	7.00	14.25	15.25	26.25
2000	2.0	0.730	19.25	20.00	17.75	18.50	25.25	26.25	21.00	21.75	17.50	18.25	21.75	22.75	7.00	15.25	16.25	26.75
2001	2.0	0.740	20.25	21.50	18.75	20.00	26.50	28.00	22.25	23.50	19.25	20.50	23.00	24.50	7.50	17.00	18.00	28.00
2002	2.0	0.740	20.25	22.00	19.00	20.50	26.50	28.75	22.50	24.25	19.75	21.25	23.25	25.25	8.00	17.75	18.75	28.75
2003	2.0	0.740	20.50	22.50	19.00	21.00	26.50	29.50	22.75	25.00	20.00	22.00	23.50	26.00	8.50	18.50	19.50	29.50
2004	2.0	0.740	20.50	23.00	19.00	21.50	26.75	30.00	22.75	25.50	20.00	22.50	23.50	26.50	9.00	19.00	20.00	30.00
2005	2.0	0.740	20.50	23.50	19.25	22.00	26.75	30.75	22.75	26.25	20.25	23.25	23.75	27.25	9.50	19.75	20.75	30.75
2006	2.0	0.740	20.50	24.00	19.25	22.50	26.75	31.25	22.75	26.75	20.25	23.75	23.75	27.75	9.50	20.00	21.25	31.25
2007	2.0	0.740	20.50	24.50	19.25	23.00	26.75	32.00	23.00	27.50	20.50	24.50	23.75	28.50	9.75	20.50	22.00	32.00
2008	2.0	0.740	20.50	25.00	19.25	23.50	26.75	32.75	23.25	28.25	20.75	25.25	24.00	29.25	10.00	21.00	22.75	32.75
2009+	2.0	0.740	20.50	+2.0%/yr	19.25	+2.0%/yr	26.75	+2.0%/yr	23.25	+2.0%/yr	20.75	+2.0%/yr	24.00	+2.0%/yr		Escalate at 2.0 % per year		

Revised March 27, 1998

Table 2
Gilbert Laustsen Jung Associates Ltd.
Natural Gas and Sulphur
Base Case Price Forecast
Effective April 1, 1998

	US Gulf Coast Gas Price @ Henry Hub			Alberta Plant Gate						Saskatchewan Plant Gate			British Columbia					
Year	Constant 1998 $ $US/mmbtu	Then Current $US/mmbtu	Empress Spot Then Current $Cdn/mmbtu	Average Price Constant 1998 $ $/mmbtu	Then Current $/mmbtu	Spot $/mmbtu	TCGS $/mmbtu	Pan-Alberta $/mmbtu	ProGas $/mmbtu	SaskEnergy $/mmbtu	Spot $/mmbtu	Sumas Spot $US/mmbtu	CanWest Plant Gate $/mcf	CanWest Field Gate $/mcf	Spot Plant Gate $/mmbtu	Spot Field Gate $/mmbtu	Sulphur FOB Vancouver $US/LT	Alberta Sulphur at Plant Gate $Cdn/LT
1989	2.15	1.69	1.61	2.04	1.61	1.28	1.37	1.44	1.66	1.60	1.46	1.26	1.75	1.36	n/a	1.19	n/a	72.05
1990	2.08	1.71	1.44	1.90	1.57	1.20	1.46	1.46	1.71	1.67	1.58	1.32	1.76	1.36	n/a	1.06	n/a	58.01
1991	1.78	1.53	1.21	1.49	1.29	0.95	1.27	1.30	1.41	1.61	1.41	1.21	1.63	1.22	n/a	0.74	n/a	53.45
1992	1.94	1.73	1.33	1.49	1.37	1.04	1.30	1.45	1.60	1.48	1.17	1.16	1.64	1.17	n/a	0.70	53.72	19.77
1993	2.30	2.11	2.23	1.84	1.71	2.16	1.59	1.77	1.94	1.48	2.07	1.89	1.87	1.41	2.10	1.67	30.22	-9.68
1994	2.07	1.94	2.07	1.91	1.81	1.86	1.81	1.73	1.93	1.88	1.87	1.59	1.92	1.52	1.87	1.49	44.96	16.57
1995	1.81	1.70	1.19	1.38	1.31	1.02	1.22	1.26	1.55	1.35	0.98	1.03	1.36	0.95	1.12	0.73	54.99	30.07
1996	2.60	2.52	1.50	1.68	1.63	1.26	1.63	1.88	1.78	1.52	1.28	1.32	1.58	1.15	1.47	1.06	36.28	14.44
1997	2.51	2.47	1.97	1.99	1.96	1.69	1.76	2.24	1.98	1.84	1.74	1.70	1.88	1.45	1.95	1.56	34.75	11.50
1998 Q1 (e)	2.19	2.19	1.97	1.65	1.65	1.45	1.74	2.18	1.90	1.65	1.50	1.49	1.68	1.27	1.61	1.24	31.24	1.63
1998 Q2	2.20	2.20	1.85	1.65	1.65	1.60	1.65	1.90	1.80	1.65	1.60	1.20	1.40	1.00	1.35	1.00	31.00	0.50
1998 Q3	2.30	2.30	1.95	1.75	1.75	1.70	1.80	1.90	1.80	1.75	1.70	1.20	1.40	1.00	1.35	1.00	31.00	0.50
1998 Q4	2.40	2.40	2.40	2.10	2.10	2.15	2.00	2.20	2.10	2.10	2.15	1.70	1.90	1.50	2.05	1.70	31.00	0.50
1998 Full Year	2.25	2.25	2.05	1.80	1.80	1.75	1.80	2.05	1.90	1.80	1.75	1.40	1.60	1.20	1.60	1.25	31.00	0.75
1998 Q2-Q4	2.30	2.30	2.07	1.85	1.85	1.80	1.80	2.00	1.90	1.85	1.80	1.35	1.55	1.15	1.60	1.20	31.00	0.50
1999	2.25	2.30	2.25	1.95	2.00	2.00	2.00	2.00	2.00	2.00	2.00	1.65	1.90	1.40	2.00	1.50	35.00	5.00
2000	2.20	2.30	2.25	1.95	2.00	2.00	2.00	2.00	2.00	2.00	2.00	1.70	2.00	1.50	2.00	1.50	40.00	11.50
2001	2.20	2.35	2.45	2.05	2.15	2.15	2.15	2.15	2.15	2.15	2.15	1.80	2.15	1.65	2.15	1.65	45.00	17.50
2002	2.25	2.45	2.55	2.15	2.30	2.30	2.30	2.30	2.30	2.30	2.30	1.90	2.30	1.80	2.30	1.80	51.00	25.50
2003	2.30	2.55	2.70	2.20	2.45	2.45	2.45	2.45	2.45	2.45	2.45	2.00	2.45	1.95	2.45	1.95	52.00	27.00
2004	2.35	2.65	2.90	2.35	2.60	2.60	2.60	2.60	2.60	2.60	2.60	2.15	2.60	2.10	2.60	2.10	53.00	28.00
2005	2.35	2.70	2.95	2.35	2.70	2.70	2.70	2.70	2.70	2.70	2.70	2.20	2.70	2.20	2.70	2.20	54.00	29.50
2006	2.35	2.75	3.05	2.35	2.75	2.75	2.75	2.75	2.75	2.75	2.75	2.25	2.75	2.25	2.75	2.25	55.00	31.00
2007	2.35	2.80	3.10	2.35	2.80	2.80	2.80	2.80	2.80	2.80	2.80	2.30	2.80	2.35	2.80	2.35	56.00	32.50
2008	2.35	2.85	3.20	2.35	2.90	2.90	2.90	2.90	2.90	2.90	2.90	2.35	2.90	2.45	2.90	2.45	57.00	34.00
2009+	2.35	+2.0%/yr	+2.0%/yr	2.35	+2.0%/yr	Escalate at 2.0 % per year											+2.0%/yr	

Unless otherwise stated, the gas price reference point is the receipt point on the applicable provincial gas transmission system. The CanWest price in British Columbia is presented at both the plant gate and field gate reference points. The plant gate price represents the price before raw gas gathering and processing charges which is comparable to the Nova inlet point in Alberta; the field gate price represents the price actually received by the producer and is net of raw gas gathering and processing charges incurred on the Westcoast system but before deduction of field gathering and compression costs. In Alberta, the prices are at the Nova receipt point and are subject to all gathering, processing and compression costs incurred by the operator. The Saskatchewan prices are at the Provincial Gas receipt point and are subject to minor additional field gathering, compression and processing costs. The Pan-Alberta Gas Ltd. prices include the settlement payments. Spot refers to weighted average one month price.

Revised March 27, 1998

CANADIAN DOLLAR

The Canadian dollar has gained strength relative to the U.S. dollar over the past few weeks, primarily due to political factors affecting the Federalist movement within Quebec which international investors consider positive for the Canadian dollar.

Looking ahead, there are a number of factors pointing to a sustained recovery in the value of the Canadian dollar. The Bank of Canada appears set to continue the commitment of protecting the dollar through interest rate increases and buying the dollar. Additionally, Canada's economy is strong, enjoying minimal inflation and the reduction or elimination of deficits. Political uncertainty, as noted, has also diminished due to the possibility of a new Quebec provincial Liberal leader who could possibly win an election over the current ruling separatist party.

The forecast of exchange rates utilized in the January 1, 1998 price forecast remains reasonable in our view.

WORLD OIL PRICES

A combination of events during the last quarter of 1997 has led to a severe drop in crude oil prices. In the first two months of 1998, WTI averaged $US 16.41/BBL, down 31 percent from the same period in 1997. It is the lowest year-to-date average since 1994, when the price averaged $US 14.91/BBL. The average price recorded for the first half of March 1998 for WTI is approximately $US 14.86/BBL. At the 103rd OPEC Conference in late November 1997, member countries agreed to raise their crude oil production ceiling by approximately 10 percent, from 25.033 million barrels per day to 27.5 million barrels per day. Actual OPEC crude oil production for February 1998 was approximately 28.7 million barrels per day, just over 1 million barrels per day in excess of the new quota. Coinciding with the increased OPEC quotas is the UN agreement to double the allowable export revenues Iraq may receive in each 180-day period through the sale of crude oil. Iraq has publicly stated that $US 300 million in infrastructure repairs are required to push production levels upwards. It is unclear just how much additional oil Iraq will be able to export in the short-term due to the condition of the oil production plants and other infrastructure.

Thirteen large crude oil producing countries recently announced an agreement to cut production which, if successful, will remove approximately 2 million barrels per day of crude oil production from the global market. Saudi Arabia, Venezuela and Mexico were the main signatories to the production agreement. The inclusion of a non-OPEC member is perhaps a sign of new cooperation between all crude oil producing countries and may well be a deciding factor in the success of the

cutback agreement. It is unclear whether the successful implementation of the agreement will be enough to bring supply and demand into balance, and the market is experiencing enormous volatility due to the uncertainty surrounding the agreement.

Coincident with the increase in world crude oil supply is a drop in global crude oil demand. Weak heating demand in the Atlantic Basin as well as relatively weak overall demand in Asia due to the Asian monetary crisis kept international oil markets in a condition of relative oversupply from November 1997 until March 1998. The slowdown in Asian demand and the warm winter in North America have been estimated to reduce global oil demand by approximately 800 thousand barrels per day. The combined increase in OPEC production since November 1997 and the reduction in demand have led to a global crude oil surplus of approximately 2 million barrels per day. As storage facilities become full, the downward pressure on price will become more intense unless there is a reduction in supply.

The near-term WTI crude oil price forecast has been lowered relative to the January 1, 1998 price forecast for the remainder of 1998. This reflects the lower Asian demand and incorporates the possibility that not all oil exporters will honor production-cutting commitments or, if they do, that the production cutbacks will not be adequate. The forecast has been slightly lowered for 1999 and 2000 relative to the January 1, 1998 forecast.

CANADIAN CRUDE OIL PRICES

The Light Sweet crude oil price at Edmonton for the first two months of 1998 averaged approximately $CDN 22.81/BBL, compared to $CDN 31.51 for the same time period in 1997. The average price for the first half of March, 1998 is approximately $CDN 20.26/BBL. Relatively strong crude oil prices during 1996 and 1997 stimulated crude oil drilling which exceeded both export pipeline capacity and market growth. Crude oil pipeline capacity constraints are still apparent with continued high apportionment levels on IPL. IPL's SEP II, slated to be completed for the second half of 1998, will add incremental pipeline capacity out of Western Canada of 120,000 barrels per day and 170,000 barrels per day on the Lakehead Pipeline between Superior and Chicago. As well, IPL has announced a revised time line for the Terrace expansion project. The revised proposal will add 270,000 barrels per day of export capacity and IPL anticipates the line to be completed by late 1999. An additional 370,000 barrels per day can be added in 2002 if required. Although the strong U.S. demand for light crude and refined products is expected to continue in the near-term as the U.S. economy experiences healthy growth rates, global supply is expected to exceed demand for the remainder of 1998. Canadian producers face stiff price

competition with offshore imports to the U.S., putting additional downward pressure on Canadian crude oil prices.

Another area of looming concern for the upstream industry in Western Canada is the IPL Line 9 reversal. Ontario refineries have been interested in obtaining imported crude due to declining North American light crude production. North Sea production is light crude and Sarnia refineries are generally not retrofitted to take heavy crude feedstock. Possibly losing Sarnia market share and therefore pushing the WCSB production into the highly competitive Chicago market will impact light crude production from Western Canada. Initial capacity upon reversal is 140,000 barrels per day with the ability to increase to 260,000 barrels per day by the next year with an in-service date in 1998.

The April 1, 1998 Light, Sweet crude oil price forecast at Edmonton is lower for the remainder of 1998 to 2000 relative to the January 1, 1998 forecast due to the decline in the near-term U.S. WTI price forecast.

The current crude oil glut has hit the heavy crude oil prices particularly hard in Western Canada. The price for Bow River blend at Hardisty for the first two months of 1998 averaged $CDN 14.38/BBL, versus $CDN 25.15/BBL for the same time period in 1997. The differential between the Bow River blend at Hardisty and Light, Sweet crude oil at Edmonton for the first two months of 1998 has reached $CDN 8.43/BBL versus $CDN 6.36/BBL for the first two months of 1997. The diluent cost is also very high as the demand for pentanes plus has grown faster than available supply. Refiners' ability to process heavy crude oil is lagging far behind supply. Therefore, refineries have numerous choices of heavy crude sources which, in turn, bids down feedstock prices. The situation has been exacerbated by the global surplus of all crude oil types. A decrease in supply will be the first result of wide differentials as capital expenditure plans for heavy oil are canceled or postponed based on marginal economics. IPL's announced accelerated expansion of the Terrace project will also help to improve the differentials. IPL's proposal to increase the viscosity limit for 1998 has been approved and the Echo Pipeline, which ships heavy crude from Lindbergh to Hardisty, has evaluated blending options that will eliminate condensate as an additive. Husky has announced an expansion of their upgrader by approximately 23 percent and IPL plans to build a spur line to the BP Toledo refinery which plans to retrofit for 110,000 barrels of incremental heavy crude by the first quarter of 1999. The Mustang Project, jointly proposed by IPL and Mobil, will extend the capability of IPL shippers to reach the Patoka/Wood River heavy crude refining hub with very competitive tolls.

Differentials for heavy crude oil have been increased in the near-term, relative to the January 1, 1998 price forecast to reflect the current supply situation but remain unchanged in later years.

US GULF COAST GAS PRICE

The current New York Mercantile Exchange natural gas futures contract is in contango (current prices lower than outer months), reflecting an abundance of supply exemplified by high storage levels relative to 1997 and the average of the past three years. The market expectation of future higher prices stems from fundamentals including declining production from traditionally important fields, increased demand for power generation and weather related demand due to an expected hot summer and cold winter in 1998/1999.

Despite the optimism the market has for natural gas prices for the summer and next winter, the next three months could well experience significant price weakness due to the storage overhang. The storage surplus compared to last year is 313 BCF and compared to the three-year average it is nearly 200 BCF higher. The recent light demand was illustrated by a recent American Gas Association (AGA) storage report, which showed a net injection into storage in the producing region during the last week in February. Currently, the market has not factored in lower demand for natural gas due to the drastically lower residual fuel oil prices which compete with natural gas in those areas where fuel switching is possible. Lower demand for natural gas for the remainder of 1998 and 1999 will occur if crude oil prices remain low.

The near-term Henry Hub natural gas price forecast has been increased to reflect the current market outlook for the remainder of 1998 and 1999. Without the post-El Nino summer and winter weather expectations, combined with additional Canadian gas entering the Chicago hub late in 1998 and lower demand due to low residual crude oil prices, the Henry Hub price may prove to be unable to maintain current market expectations.

CANADIAN GAS PRICES

Western Canadian producers are hoping natural gas prices will sustain their strength in light of the dramatic fall in crude oil prices. Natural gas in the Western Canada Sedimentary Basin is experiencing surprising price strength for the summer of 1998 considering that the heating season of 1997/1998 was one of the warmest El Nino winters seen in recent years. The lack of winter related heating demand has resulted in gas storage being approximately 20 percent higher than the same period last year. The market psychology contributing to the price strength is the belief that fewer gas wells will be drilled in early 1998 due to an early spring breakup and therefore Nova field receipts will not significantly increase. Additionally, although the California reservoir levels

are very high, the market is anticipating strong summer demand for natural gas based on the belief that the summer of 1998 will be warm and air conditioning demand will be strong. This reasoning also applies to Eastern Canada despite the even higher storage overhang that exists in this demand region, at double the amount in storage compared to this time last year. Finally, the market is anticipating an early startup on the Northern Border capacity expansion for some of the incremental capacity as early as September, 1998 which is hoped to reduce the basis differential between Alberta and the U.S. markets, thereby increasing netbacks in this region.

The AECO-C spot price is currently around $CDN 1.83/MMBTU with the market anticipating significantly stronger prices for the 1998/1999 heating season in the range of $CDN 2.47/MMBTU at AECO-C. The Canadian natural gas aggregators are anticipating healthy netback prices for the 1998/1999 heating season and beyond in light of the relative strength in the U.S. prices, the strong Alberta spot prices and the incremental export capacity. As incremental export pipeline capacity is added, long-term aggregator netback prices and spot prices are forecast to achieve equilibrium.

Gilbert Laustsen Jung has made an upward revision to the Alberta and British Columbia natural gas prices for the remainder of 1998 and 1999 relative to the January 1, 1998 forecast to reflect current market expectations. The revised prices are moderated due to concerns regarding the current high storage levels and the possibility that demand will not be as robust as expected, particularly during the summer months. The long-term price forecast remains unchanged based on the assumption that additional export pipeline capacity will continue to narrow basis differentials and improve netback prices in this basin.

NATURAL GAS LIQUIDS AND SULPHUR

Propane stocks in both Western and Eastern Canada are higher this year compared to the same time period last year. Butane stocks overall are also up this year, although by a smaller amount. Spot prices for propane at Edmonton have fallen from record highs seen last winter to more moderate levels of approximately $CDN 15.20/bbl for the first two months of 1998. The current spot price for butane at Edmonton average $CDN 15.20/BBL for the first two months of 1998.

Gilbert Laustsen Jung has decreased the 1998 propane and butane price forecast at Edmonton relative to the January 1, 1998 forecast to reflect current price levels and the lower crude oil price forecast.

The negotiated sulphur price at Vancouver has fallen for the first quarter of 1998 as the sharp drop in prices in Brazil and lower prices offered in Egypt and Jordon indicate the continued weakness in

the international sulphur market. The price cut in Brazil has resulted in competition among Canadian suppliers and will likely lead to further price erosion, as stocks at Vancouver are high. For Canadian producers, the recent reductions in prices will mean plant-gate netbacks close to zero or possibly negative.

Gilbert Laustsen Jung has lowered the near-term FOB Vancouver sulphur price forecast relative to the January 1, 1998 forecast due to the current supply situation.

Table 1

McDaniel & Associates Consultants Ltd.

Summary of Price Forecasts

April 1, 1998

Year	WTI Crude Oil $US/BBL (1)	Edmonton Light Crude Oil $C/BBL (2)	Medium Crude Oil $C/BBL (3)	Alberta Average Natural Gas $C/Mmbtu (4)	Edmonton Cond. & Natural Gasolines $/Bbl	Edmonton Propane $/Bbl	Edmonton Butanes $/Bbl	Edmonton NGL Mix $/Bbl (5)	Sulphur $/LT	Inflation %	US/CAN Exchange Rate $US/$CAN
History											
1986	15.00	20.50	15.11	2.35	20.10	13.96	17.30	16.40	129.40	4.1	0.719
1987	19.30	24.30	20.79	1.64	23.80	9.98	16.80	15.10	89.20	4.4	0.755
1988	16.00	18.70	14.41	1.44	18.30	8.19	12.95	11.90	75.95	4.1	0.812
1989	19.60	22.20	18.09	1.47	21.80	8.14	10.35	11.60	72.00	5.0	0.844
1990	24.50	27.60	21.06	1.45	27.00	13.67	16.21	17.20	59.60	4.8	0.857
1991	21.40	23.40	15.07	1.18	22.90	11.91	15.25	15.30	54.15	5.6	0.873
1992	20.55	23.50	17.52	1.22	23.00	10.55	14.05	14.30	21.00	1.5	0.828
1993	18.60	21.90	16.70	1.89	21.50	14.10	13.55	15.40	-4.90	1.8	0.775
1994	17.20	22.20	18.43	1.83	21.75	12.50	13.45	14.70	11.65	0.2	0.732
1995	18.45	24.25	20.80	1.18	23.76	13.90	13.80	15.80	24.00	2.0	0.729
1996	22.10	29.35	25.11	1.50	28.75	22.20	17.15	21.70	8.00	2.0	0.733
1997	20.60	27.80	21.75	1.85	27.25	18.90	19.25	20.70	na	2.0	0.722
1998 (3mo)	16.00	22.50	16.00	1.65	22.00	12.70	14.50	15.20	na	2.0	0.700
Forecast											
1998 (9 mo)	18.00	24.00	18.60	1.75	23.50	14.60	14.90	16.50	10.00	2.0	0.720
1999	19.25	25.70	21.38	1.95	25.20	14.70	16.00	17.30	15.00	2.0	0.720
2000	20.40	27.30	23.41	2.15	26.80	15.70	17.00	18.40	20.00	2.0	0.720
2001	21.00	28.10	24.13	2.25	27.50	16.30	17.50	19.00	25.00	2.0	0.720
2002	21.60	28.90	24.85	2.35	28.30	16.80	18.00	19.50	30.00	2.0	0.720
2003	22.20	29.70	25.57	2.40	29.10	17.30	18.50	20.10	31.80	2.0	0.720
2004	22.90	30.70	26.49	2.50	30.10	17.90	19.10	20.80	33.70	2.0	0.720
2005	23.60	31.60	27.31	2.60	31.00	18.50	19.70	21.40	35.70	2.0	0.720
2006	24.30	32.60	28.22	2.70	31.90	19.10	20.30	22.10	37.80	2.0	0.720
2007	25.00	33.50	29.03	2.75	32.80	19.60	20.90	22.70	40.10	2.0	0.720
2008	25.80	34.60	30.04	2.85	33.90	20.20	21.50	23.40	42.50	2.0	0.720
2009	26.60	35.70	31.05	2.95	35.00	20.90	22.20	24.20	45.10	2.0	0.720
2010	27.40	36.80	32.06	3.05	36.10	21.60	22.90	25.00	47.80	2.0	0.720
2011	28.20	37.90	33.07	3.20	37.10	22.40	23.60	25.80	50.70	2.0	0.720
2012	29.00	39.00	34.07	3.30	38.20	23.00	24.30	26.50	53.70	2.0	0.720
2013	29.90	40.20	35.17	3.40	39.40	23.70	25.00	27.30	56.90	2.0	0.720
2014	30.80	41.40	36.27	3.50	40.60	24.40	25.80	28.10	60.30	2.0	0.720
2015	31.70	42.60	37.37	3.65	41.70	25.20	26.50	29.00	63.90	2.0	0.720
2016	32.70	44.00	38.66	3.75	43.10	26.00	27.40	29.90	67.70	2.0	0.720
2017	33.70	45.30	39.86	3.90	44.40	26.90	28.20	30.90	71.80	2.0	0.720
Thereafter	33.70	45.30	39.86	3.90	44.40	26.90	28.20	30.90	71.80	0.0	0.720

(1) West Texas Intermediate at Cushing Oklahoma
(2) Edmonton price for 40 API, 0.5% sulphur crude
(3) Bow River 26 degrees/2.1% sulphur crude oil at Hardisty Alberta
(4) Average Alberta field price
(5) NGL Mix based on 45 percent propane, 35 percent butane and 20 percent natural gasolines.

G980401 - Effective April 1, 1998

McDaniel & Associates Consultants Ltd.

Summary of Natural Gas Plantgate Price Forecasts

April 1, 1998

Year	U.S. Henry Hub Gas Price $US/Mmbtu	Alberta Average $C/Mmbtu (1)	TCGSL $C/Mmbtu (2)	Pagl $C/Mmbtu	Progas $C/Mmbtu	Alberta Spot Sales $C/Mmbtu	Sask. Prov. Gas $C/Mmbtu	British Columbia CanWest $C/Mcf (3)	B.C. Spot Sales $C/Mmbtu	B.C. Direct Sales $C/Mmbtu
History										
1986	1.75	2.35	2.59	2.53	2.48	-	2.51	1.73	-	-
1987	1.50	1.64	1.82	1.53	1.80	-	1.86	1.40	-	-
1988	1.85	1.44	1.66	1.53	1.51	1.21	1.86	1.61	-	-
1989	1.68	1.47	1.57	1.44	1.66	1.28	1.60	1.36	-	-
1990	1.67	1.45	1.64	1.46	1.71	1.20	1.67	1.38	-	-
1991	1.54	1.18	1.31	1.35	1.36	0.97	1.61	1.33	1.13	-
1992	1.79	1.22	1.30	1.43	1.55	1.04	1.51	1.17	1.10	-
1993	2.13	1.89	1.60	1.78	1.91	2.16	2.16	1.40	2.13	-
1994	1.92	1.83	1.81	1.73	1.91	1.86	1.92	1.46	1.87	-
1995	1.62	1.18	1.23	1.26	1.52	1.02	1.35	0.91	1.12	-
1996	2.50	1.50	1.63	1.83	1.78	1.26	1.52	1.14	1.47	-
1997	2.59	1.85	1.87	2.22	1.97	1.70	1.80	1.30	1.98	-
1998 (3mo)	2.20	1.65	1.70	1.90	1.85	1.50	1.65	1.50	1.75	-
Forecast										
1998 (9 mo)	2.17	1.75	1.80	1.80	1.80	1.70	1.75	1.20	1.70	1.75
1999	2.24	1.95	2.00	2.00	2.00	1.90	1.95	1.40	1.90	1.95
2000	2.37	2.15	2.20	2.20	2.20	2.10	2.15	1.60	2.10	2.15
2001	2.44	2.25	2.30	2.30	2.30	2.20	2.25	1.70	2.20	2.25
2002	2.51	2.35	2.40	2.40	2.40	2.30	2.35	1.80	2.30	2.35
2003	2.58	2.40	2.45	2.45	2.45	2.35	2.40	1.85	2.35	2.40
2004	2.67	2.50	2.55	2.55	2.55	2.45	2.50	1.95	2.45	2.50
2005	2.75	2.60	2.65	2.65	2.65	2.55	2.60	2.05	2.55	2.60
2006	2.83	2.70	2.75	2.75	2.75	2.65	2.70	2.15	2.65	2.70
2007	2.91	2.75	2.80	2.80	2.80	2.70	2.75	2.20	2.70	2.75
2008	3.00	2.85	2.90	2.90	2.90	2.80	2.85	2.30	2.80	2.85
2009	3.10	2.95	3.00	3.00	3.00	2.90	2.95	2.40	2.90	2.95
2010	3.19	3.05	3.10	3.10	3.10	3.00	3.05	2.50	3.00	3.05
2011	3.28	3.20	3.25	3.25	3.25	3.15	3.20	2.65	3.15	3.20
2012	3.38	3.30	3.35	3.35	3.35	3.25	3.30	2.75	3.25	3.30
2013	3.48	3.40	3.45	3.45	3.45	3.35	3.40	2.85	3.35	3.40
2014	3.58	3.50	3.55	3.55	3.55	3.45	3.50	2.95	3.45	3.50
2015	3.69	3.65	3.70	3.70	3.70	3.60	3.65	3.10	3.60	3.65
2016	3.81	3.75	3.80	3.80	3.80	3.70	3.75	3.20	3.70	3.75
2017	3.92	3.90	3.95	3.95	3.95	3.85	3.90	3.35	3.85	3.90
Thereafter	3.92	3.90	3.95	3.95	3.95	3.85	3.90	3.35	3.85	3.90

(1) This forecast also applies to direct sales contracts and the Alberta gas reference price used in the crown royalty calculations.

(2) TransCanada Gas Services Limited formerly WGML(Historical prices are for WGML D1D2 category gas contracts).

(3) CanWest Purchase price paid on a $/Mcf basis at the wellhead. Gathering and processing charges on Westcoast facilities are incurred by CanWest.

Energy Update

D V I S O R Y

E S E A R C H

A P I T A L

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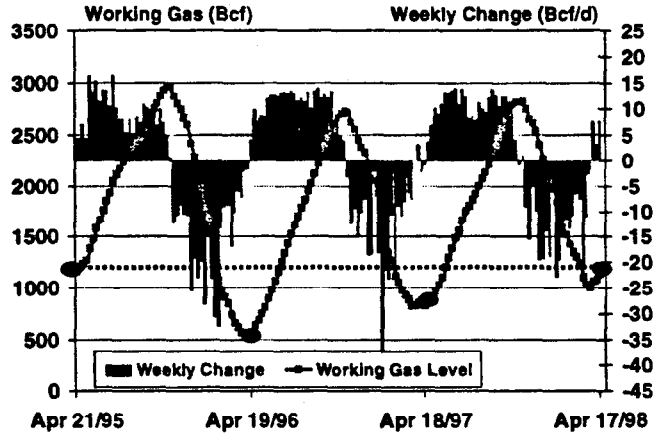
APRIL 1998

- Crude prices remain depressed and range bound — $US 15-16/B (WTI)
  - keys to recovery — firm evidence of output cuts, Iraq(?), stronger Southeast Asian economies
- Canadian heavy oil prices severely stressed
  - low light prices and wide quality differentials
- Medium/longer-term fundamentals for crude oil are attractive
- Natural gas prices remain very strong
  - supply is tight and demand is growing
  - considering upward revision to our 1998/99 forecasts
- 1997 Finding and Development Cost Results
  - all-in replacement costs for the ARC group averaged $7.34/BOE in 1997
  - up 10% from 1996, but within 4% of three year average
  - "reasonable" performance given record spending levels and upward cost pressures
- Oil and gas equities also range bound
  - "gassy" stocks clearly in favour
  - stronger oil prices key to broad improvement

U.S. Working Natural Gas Storage Levels



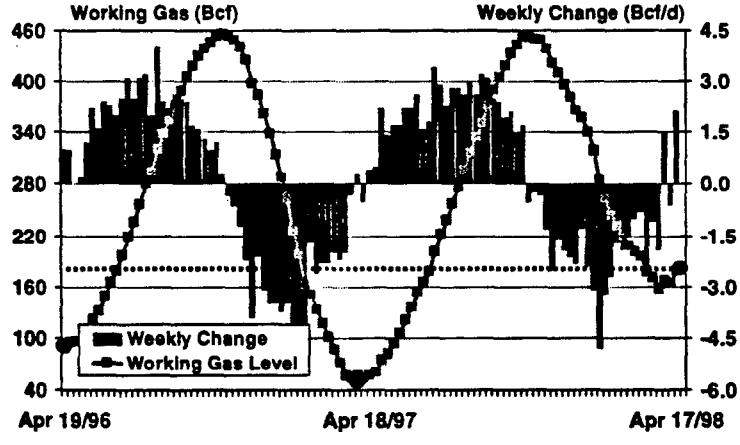
Source: American Gas Association, Weekly Storage Survey.

◆ Working gas storage levels for the U.S. were at 1,135 Bcf for the week ended April 17, the highest level at this point in the injection season since 1995. At this level, volumes are 24% and 79% higher than the 1997 and 1996 comparables, respectively, but 12% lower than the 1995 comparable.

◆ Injection rates averaged 7.7 Bcf/d for the week ended April 17, versus a 1995–97 comparable average rate of 0.2 Bcf/d. In two of these three years, gas was still being withdrawn from storage.

◆ Injection demand should be weaker than normal this summer barring erratic weather patterns. The summer injection season started with working gas storage levels at just over 1 Tcf at the beginning of April. This implies an average summer injection rate of 9.35 Bcf/d through to October 31, versus a 9.60 Bcf/d average rate for the last four years.

Canadian Working Natural Gas Storage Levels



Source: Canadian Gas Association, Weekly Storage Survey.

◆ In Canada, storage levels remain much higher than in 1997 or 1996. Surveyed working gas levels were 178 Bcf for the week ended April 17 versus a three-year average of 89 Bcf at the same time of year. At this level, storage is 215%, 101% and 151% higher than comparable levels in 1997, 1996 and 1995 respectively.

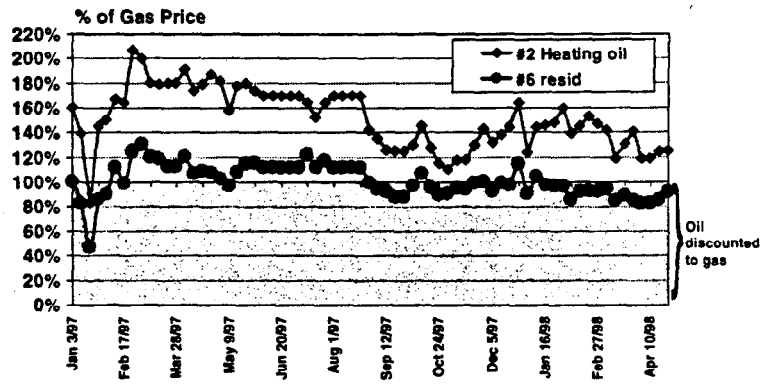
◆ Canadian injection demand should be weaker than normal this summer which could put downward pressure on prices. To reach 450 Bcf by October 31, an average summer injection rate of 1.4 Bcf/d through to October 31 is required, 22% lower than the 1995-97 comparable average of 1.8 Bcf/d.

◆ Fuel switching is site specific and largely limited to industrial boilers and dual fuel electric generators. Pricing parity between fuels is a function of relative burner tip prices, seasonal emission restrictions and commercial commitments. Hence substitution occurs at many different price levels rather than at any one price.

◆ Number #6 residual fuel oil began to look cheaper than natural gas in late August 1997. This leads us to believe that most potential switching has already occurred, and that we will not see a substantial further switching until parity with #2 fuel oil is approached.

◆ In the northeast U.S., 60–70% of steam generation capacity consuming in the order of 1 Bcf/d has dual fuel capability, implying a potential load loss of up to 0.7 Bcf/d. Other major dual fuel capable sites are in Florida and the Gulf Coast.

Oil vs Natural Gas Price Parity @ New York City Gate



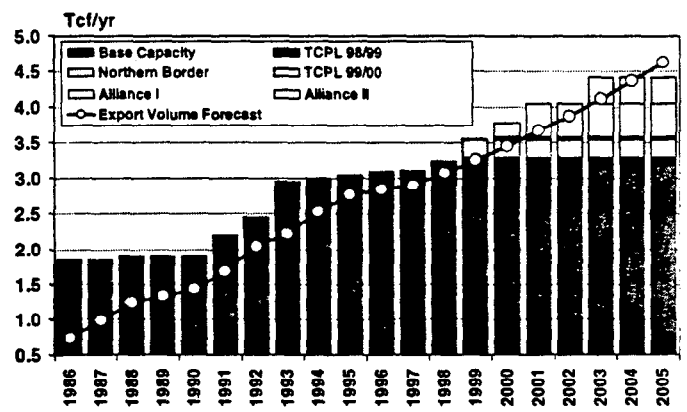
Source: Bloomberg.
Notes: Oil prices have been normalized on an energy basis relative to gas prices. Prices are for bulk purchases on the spot market. Gas prices are at the city gate mainly Texas Eastern Pipeline zone 3 deliveries and exclude local distribution charges. Sulphur content for No. 6 resid fuel is 0.3%. Oil prices are for New York City Harbor deliveries.

◆ Since 1995, export pipelines have been over 90% full, with some spare capacity to western and markets.

◆ If export sales grow at a 6% annual rate and announced export pipeline expansions are built, market access for these volumes will be assured for the next six to seven years. This bodes well for Canadian gas prices as they will be more directly linked to historically higher U.S. prices.

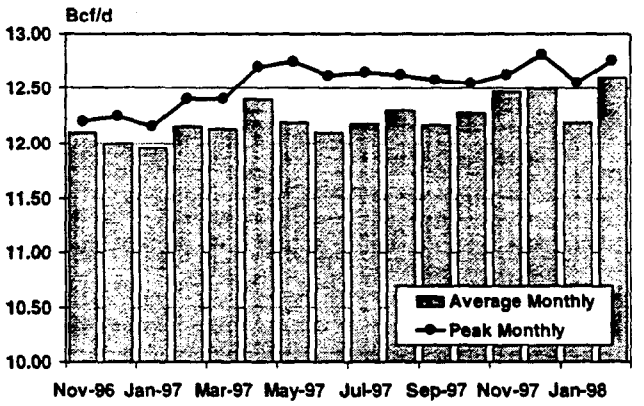
◆ We believe a 6% growth rate for Canadian gas exports will be challenging but achievable for the industry in an environment of higher prices. In our view, prices above $2.00/Mcf provide producers with sufficient returns to find and develop new reserves. For the past five year period, export sales have grown by 8% per annum. However, reserve life indices are now lower as production has risen faster than reserves so the industry has to "run harder" just to stand still.

Outlook for Canadian Gas Exports Capacity vs. Sales



Source: NEB, ARC Financial.

NOVA Field Receipts November 1996 - Present



Source: NOVA.

◆ NOVA Field receipts for February/97 averaged 12.60 Bcf/d, up 3.7% or 450 MMcfd from the February/96 level of 12.15 Bcf/d. This compares to an average 3.1% per annum rise over the November/94 - November/97 period. Preliminary data for March and April indicate little change in receipts.

◆ Assuming a 4% increase in receipts from the November 1997 level of 12.47 Bcf/d, means field receipts would be just under 13 Bcf/d by the scheduled start-up of the 1.1 Bcf/d Foothills and TCPL expansions.

- our 4% industry wide growth assumption is well below the 12% growth rate we are projecting for our ARC group of companies over the 1997–99 period. The difference is explained by acquisitions, the likelihood that the group falls short of production targets, and the fact that many large companies outside the group are facing declines.

North American Gas Drilling Activity Update

	1Q98	1Q97	1Q96	1Q95	1Q94	1Q93
U.S.						
Gas Wells Drilled	NA	818	700	820	1029	1010
% Gas[1]	NA	29%	28%	30%	37%	33%
Gas Rig Count[2]	599	496	413	372	411	352
Offshore Rig Count[2]	136	115	103	99	98	68
Canada						
Gas Wells Drilled	1255	1344	1187	1108	1206	465
% Gas[1]	43%	45%	49%	57%	57%	27%
Rig Count	499	464	402	385	374	279
Rig Utilization	88%	94%	87%	82%	83%	65%

Source: EIA, Nickle's Daily Oil Bulletin.

Notes: 1. % Gas is calculated as a function of successful oil and gas wells and excludes dry holes.

2. 1998 U.S. gas rig count is February year-to-date.

◆ Canadian gas directed drilling for 1Q98 was at 1,255 wells, down 7% from last year's level but slightly ahead of the 1994 comparable , which was a record year for gas drilling. The lower level relative to 1997 may be explained in part by the shorter winter season this year as a result of mild weather.

◆ Canadian gas directed drilling made up 43% of total wells drilled in 1Q98, lower than 1Q97's 45%. In fact, gas-directed drilling as a percentage of total drilling has been falling since 1994. This was due to the high level of heavy oil drilling in these years as well as the fact that producers need to see higher gas prices before re-committing to gas targets.

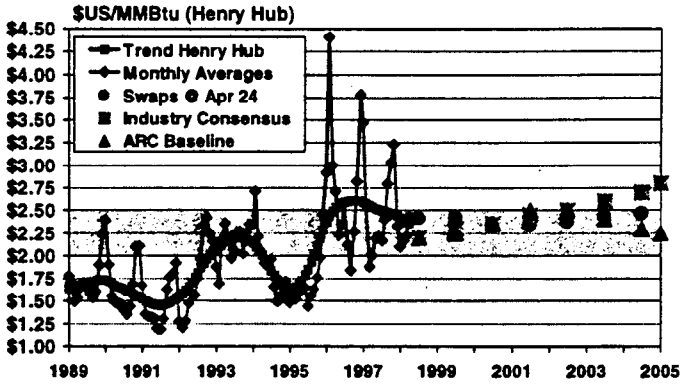
◆ The current U.S. rig fleet is the largest since 1990. Given bullish gas price outlooks and high decline rates, we anticipate this will be a very busy year for gas drilling south of the border.

◆ The Henry Hub spot price in April was $US 2.42/MMBtu, the highest price yet in 1998 and raising the year-to-date average to $US 2.23/MMBtu. The balance of the year price of $US 2.41/MMBtu now suggests a 1998 average price of $US 2.35/MMBtu, versus our baseline forecast of $2.20/MMBtu.

- we think the unusual situation of April prices exceeding winter prices is explained largely by weather, notably a winter with few extended cold snaps eliminated peaks off the price profile, and the expectation of a warm summer.

◆ For 1999, our baseline forecast is $US 2.25/MMBtu versus a forward price of $US 2.40/MMBtu. We will review our forecast over the next few weeks but at this point we still see increased Canadian imports and the lagged result of significantly higher U.S. drilling activity constraining Henry Hub prices next year.

U.S. (Henry Hub) Natural Gas Price Expectations

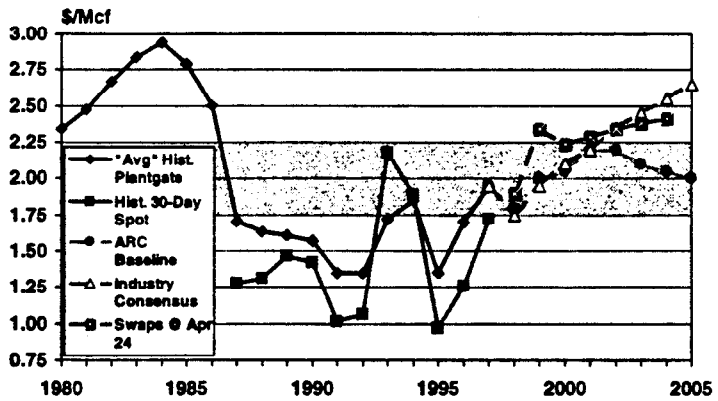


Source: Historical data from Natural Gas Week (spot cash). Swap prices from RBC DS. Industry consensus represented by Dobson's July 1997 survey of Canadian petroleum consultants.
Note: Trend Henry Hub was calculated by smoothing actual Henry Hub prices with a statistical technique called a Hodrick-Prescott filter.

◆ Our 1999 baseline of $2.00/Mcf for the average Alberta plantgate price is low when compared to recent forward market prices of $2.30 – 2.35/Mcf. If there is upside in Canadian gas prices in 1999, we believe it is largely found in a lower differential with NYMEX rather than higher NYMEX prices. Current forward market prices imply a spot price differential of $US 0.59/MMBtu for 1999 between NYMEX and Empress. Assuming normal weather demand in 1999, we could see differentials narrow well below this level if the supply response expected from Canadian gas drilling is insufficient to satisfy growing demand.

◆ We have never seen forward market expectations above industry consensus forecasts and our own as they currently are for the 1999-2001 period. On this basis, we will be reviewing our pricing assumptions over the next several weeks. We still see some downside risk over the next few months, however, due to high storage levels.

Alberta Natural Gas Price Expectations



Source: ARC Financial.
Note:Prices are netted back to the plantgate. ARC Baseline and Industry Consensus represent "average" prices. Swap prices are taken from RBC DS and are calculated based on average AECO bid/offer prices. Industry consensus represented by average of Dobson's January 1998 survey of consultants' forecasts.

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/Mcf)																
Henry Hub	1.69	2.75	2.53	2.20	2.25	2.35	2.50	2.50	2.40	2.30	2.25	2.30	2.34	2.39	2.44	2.48
$ 1998	1.80	2.87	2.60	2.20	2.21	2.26	2.36	2.31	2.17	2.04	1.96	1.96	1.96	1.96	1.96	1.96
Alberta Plantgate Gas Prices ($Cdn/Mcf)																
Domestic Sales																
Spot	1.01	1.27	1.69	1.68	2.10	2.10	2.43	2.37	2.17	2.05	2.00	2.03	2.08	2.13	2.18	2.28
Average	1.20	1.32	1.74	1.72	2.14	2.15	2.45	2.39	2.19	2.07	2.02	2.05	2.10	2.16	2.20	2.30
Export Sales				x.932												
Average	1.43	2.08	2.30	1.86	1.95	1.95	2.11	2.13	1.99	1.90	1.91	1.89	1.94	1.99	2.04	2.10
Total																
Average	1.35	1.70	1.95	1.80	2.00	2.03	2.24	2.22	2.08	1.99	1.99	2.00	2.04	2.09	2.14	2.19
$ 1998	1.44	1.77	2.01	1.80	1.96	1.95	2.12	2.05	1.89	1.76	1.73	1.70	1.71	1.71	1.72	1.73
Aggregator Prices ($Cdn/Mcf)																
TCGS	1.22	1.63	1.85	1.79	2.04	2.05	2.24	2.22	2.08	1.99	1.99	2.00	2.04	2.09	2.14	2.19
Pan Alberta	1.26	1.90	2.18	1.87	2.00	1.97	2.24	2.22	2.08	1.99	1.99	2.00	2.04	2.09	2.14	2.19
Progas	1.52	1.77	2.01	1.81	2.04	2.05	2.24	2.22	2.08	1.99	1.99	2.00	2.04	2.09	2.14	2.19
CanWest	1.29	1.58	1.83	1.73	2.01	2.02	2.15	2.15	2.03	2.00	1.94	1.99	2.04	2.09	2.13	2.18

Low Price Scenario

		1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
Henry Hub	$US/Mcf	1.69	2.75	2.53	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.04	2.08	2.12	2.16	2.21
	$ 1998	1.80	2.87	2.60	2.00	1.96	1.92	1.88	1.85	1.81	1.78	1.74	1.74	1.74	1.74	1.74	1.74
Alberta Spot	$Cdn/Mcf	1.01	1.27	1.69	1.45	1.60	1.70	1.73	1.72	1.72	1.72	1.68	1.70	1.75	1.79	1.83	1.92
Average Alberta	$Cdn/Mcf	1.35	1.70	1.95	1.62	1.71	1.68	1.59	1.59	1.58	1.68	1.65	1.67	1.70	1.75	1.79	1.84
	$ 1998	1.44	1.77	2.01	1.62	1.68	1.61	1.50	1.47	1.43	1.49	1.44	1.42	1.43	1.44	1.44	1.45

High Price Scenario

		1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
Henry Hub	$US/Mcf	1.69	2.75	2.53	2.45	2.50	2.50	2.50	2.50	2.50	2.50	2.50	2.55	2.60	2.65	2.71	2.76
	$ 1998	1.80	2.87	2.60	2.45	2.45	2.40	2.36	2.31	2.26	2.22	2.18	2.18	2.18	2.18	2.18	2.18
Alberta Spot	$Cdn/Mcf	1.01	1.27	1.69	2.03	2.57	2.54	2.52	2.53	2.49	2.49	2.49	2.50	2.51	2.49	2.49	2.51
Average Alberta	$Cdn/Mcf	1.35	1.70	1.95	2.16	2.52	2.52	2.51	2.50	2.50	2.50	2.50	2.55	2.54	2.58	2.66	2.68
	$ 1998	1.44	1.77	2.01	2.16	2.47	2.42	2.36	2.31	2.26	2.22	2.18	2.17	2.13	2.12	2.14	2.12

Notes:
1. General inflation assumed flat at 2% per annum.
2. Canadian prices based on $US/Cdn 0.71, 0.73, 0.76 exchange rate in 1998/99/2000 respectively, $US/Cdn 0.78 thereafter.
3. Alberta gas prices are at the plantgate – ie., before the deduction of field gathering, processing and compression costs.
4. CanWest prices are 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.

ZIFF ENERGY GROUP

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GAZ METROPOLITAN

February 1998

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Weather

Base Case - We expect some weather disruptions to occur throughout North America due to El Nino. A warmer and drier than normal winter (1997 - 1998) is likely in Western Canada, the Pacific Northwest and on the East Coast. From southern California to Florida it should be slightly cooler and wetter than normal. Similar conditions could extend throughout the summer, reducing power demand in the south but increasing it elsewhere. "La Nina" or colder than normal weather follows for the winter of 1998/1999. Normal weather conditions are assumed for the remainder of 1999 through the winter 2001/2002.

Low Case - A more extreme El Nino effect (i.e. warmer) would possibly extend into the winter of 1998/99. This case reflects fewer days of cold weather or slightly warmer than normal temperatures throughout the forecast period. A more extreme El Nino effect is also assumed for the last winter of the outlook.

High Case - Assumes that cold snaps the winter of 1997 - 1998 will raise consumption to normal levels, despite El Nino; followed by a return to normal weather conditions next summer. Coincidental cold snaps over large areas of North America usually occur, with the key consuming regions of the US (Chicago and Eastern Seaboard) being hit periodically. As well, each winter rough waters in the Gulf and frigid weather normally cause one or two incidences of production, wellheads, compression and gathering lines freezing up. While low storage deliverability does not appear to be a major factor for this upcoming winter, freeze-offs could cause some shippers to fall short on their pipeline nominations forcing some end users to conserve energy during cold snaps. La Nina or colder than normal weather is anticipated for the 1998/99 winter.

Medium Term Outlook for Alberta Prices

Ziff Energy's medium term (1998 - 2002) forecast of Alberta and US prices is presented in this segment.

Ziff Energy is projecting that the one month spot price at Empress will average $1.77/GJ in 1998. This is down slightly from the average annual price in 1997 of $1.87/GJ. Through the forecast period Ziff Energy expects the average annual price to remain in the $1.77/GJ range.

Alberta Gas Price Forecast - Major Assumptions

Supply

Drilling - Gas well completions reached 4,800 in 1997. Gas metres drilled (5,350), are up strongly and are 2 % higher than the record levels of 1994. This reflects a higher concentration of drilling in the deeper and more productive areas of Western Alberta and British Columbia. This strength will be sustained in 1998 in anticipation of expanded pipeline capacity in November 1998. Ziff Energy expects that the number of wells drilled in 1998 will exceed 3,800 (Figure 4.9 - p. 40). Since 1994, supply has accrued from robust drilling with reserve replacement rates over 110%. This supply, including augmented production from deeper completions in 1997, will meet the requirements of the expanded pipeline capacity requirements.

Higher Canadian gas prices will provide sustainable capital investment and cash flow for continued drilling activity. This will add supply as required for additional pipeline expansions in the outlook period, although supply will be tight for 6 - 9 months after the start-up of new capacity. This occurred with prior US/Canadian expansions: Iroquois in 1992 and PGT in 1994. Ziff Energy expects that drilling levels of 4,000 - 5,000 wells per year over the forecast period will support the base case forecast. Lower levels of drilling activity will begin to tighten supply and support the high price forecast scenario.

Transportation - Pipeline capacity from the Western Canadian Sedimentary Basin will increase, primarily for exports to the US A pipeline for Sable Island gas will also be constructed to reach the Northeast US market and to serve the Eastern Canadian (New Brunswick and Nova Scotia) market. In some instances, regulatory uncertainties remain relative to these Canadian pipelines in the timing, routes and the players who will ultimately provide additional capacity.

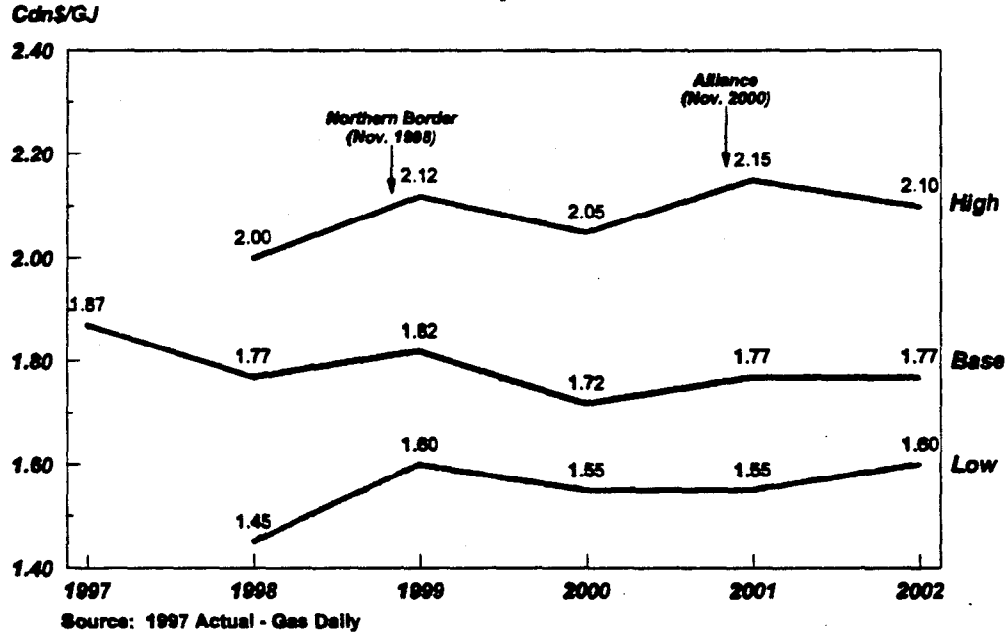
Prices will move toward the low case price scenario if there are delays in those the construction of export pipeline capacity projects. Towards the end of the forecast period it is likely that there will be an announcement of additional expansion of export capacity of 1 - 2 Bcf/d to serve demand in the Pacific Northwest and California and Nevada markets. This can be expected to support higher prices after 2002.

Storage - With the start-up in mid-1997 of the Sabine Alberta storage project (25 Bcf), the amount of storage gas should be modestly higher than the previous winter. The project is assumed to reach full capacity operation in 1998. No additional large storage projects in either producing or consumption areas in Canada are expected, some expansions of capacity will occur as sales increase. Storage levels in Canada and contracted US capacity should be sufficient to meet most periods of high demand. This will support the base case and low case forecasts.

Demand

Market Growth - Domestic demand is assumed to grow at 2%/year through the forecast period, per the recent forecast of domestic demand by the CGA (1997). Gas consumption for power generation accounts for a very low percentage of total Canadian gas demand. However, 4-5% growth in this sector is anticipated based on additional requirements for Ontario nuclear displacement and IPP growth (all gas) with deregulation. Ontario Hydro will likely convert restarted oil fired units to gas in the outlook period. Gas is also expected to displace some of the oil demand in the Maritimes with the start-up of the offshore Nova Scotia Sable Island project. Demand growth averaging 3% - 4% over the forecast period will support the high price scenario.

Figure 4.10
Annual Alta. Spot Price 1997 - 2002
at Empress



Source: 1997 Actual - Gas Daily

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THE OIL & GAS REPORT

April 1998 Volume 3 No. 4

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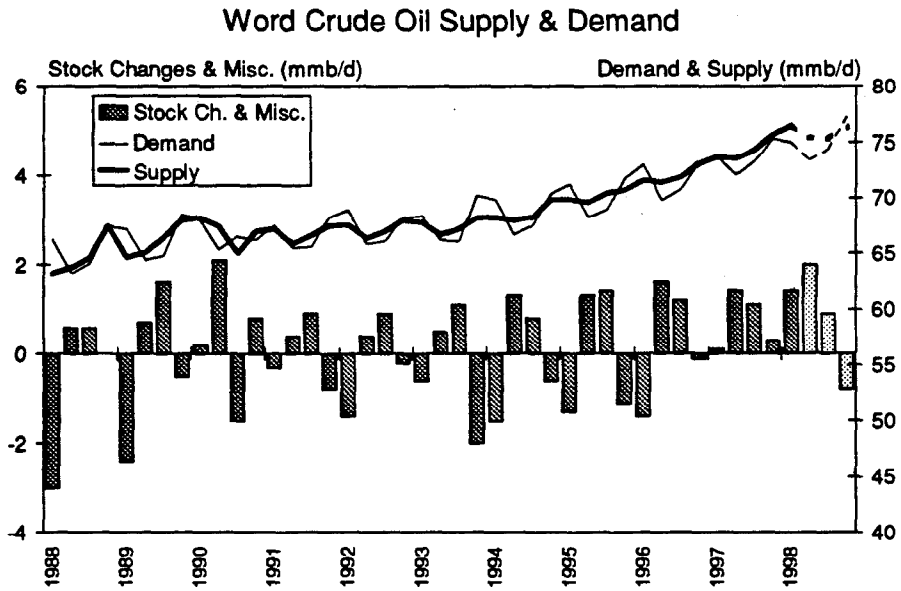
A Progressive Return To A Better Balanced Crude Oil Market



In This Issue

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

North American Natural Gas Outlook — Canada

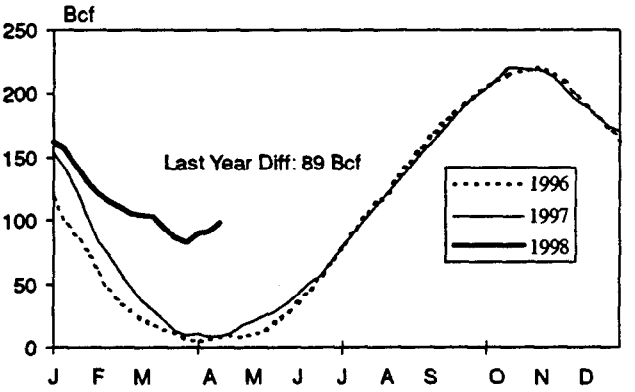
Underground Storage Much Higher Than Last Year.

Canadian Natural Gas Storage (Bcf)						
	Week Ended Apr. 17/98	Apr. 10/98	Change	Weekly % Chg.	% of Max. Cap. Used	Maximum Capacity
East	98	91	7	7.3	42	232
West	80	73	8	10.6	30	265
Total Canada	**178**	**164**	**14**	**8.8**	**36**	**497**

Inventories in Canada have started to increase again, having reached the minimum for the heating season at the end of March, at 157.3 Bcf versus 54.1 Bcf as of April 11 last year. At the minimum, inventories left were 31.6% and 10.9%, respectively, of total capacity.

The warmer-than-usual weather this year did not help consumption, and inventories were much higher than last year at the end of the heating season.

Natural Gas Storage - Cdn East



Source: Canadian Gas Assoc. *April 17/98*

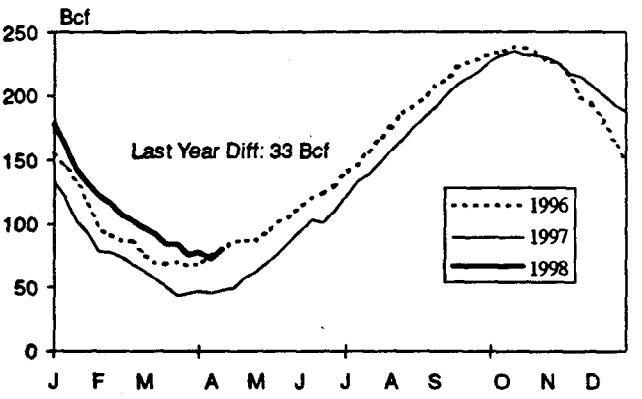
The table below shows the forecast storage levels at the beginning of the heating season, based on various injection assumptions for a 24-week period.

Injection Per Week (Bcf)	Total Injection (Bcf)	Total Gas In Storage At The Beginning Of The Heating Season (Bcf)	Percentage of Max. Capacity (%)
10	240	418	84.1
11	264	442	88.9
12	288	476	95.8

Injection this year should be about 100 Bcf less than last year, or about 4 Bcf per week. This is significant, representing about 570 mmcf/d.

Only reduced deliverability will help maintain the current spot price around current levels later on this summer and fall.

Natural Gas Storage - Cdn West



Source: Canadian Gas Assoc. *April 17/98*

Natural Gas Market In Canada

Deliverability Should Increase with Expanded Pipeline Capacity.

(mmcf/d)	January 1998	January 1997	% Chg.	12 Months Average 1997	12 Months Average 1996	% Chg.
Marketable Production (1)	16,650.4	16,207.4	2.7	15,104.8	14,852.9	1.7
Exports (2)	8,847.2	8,478.5	4.3	7,939.2	7,748.3	2.5
Canadian Sales (3)	9,484.3	9,757.4	-2.8	6,522.6	6,500.9	0.3
[(2) + (3)] / (1) (%)	110.1	112.5	-2.2	95.7	95.9	-0.2

The level of marketable production increased by 2.7% in January 1998. In absolute terms, it increased by 443 mmcf/d.

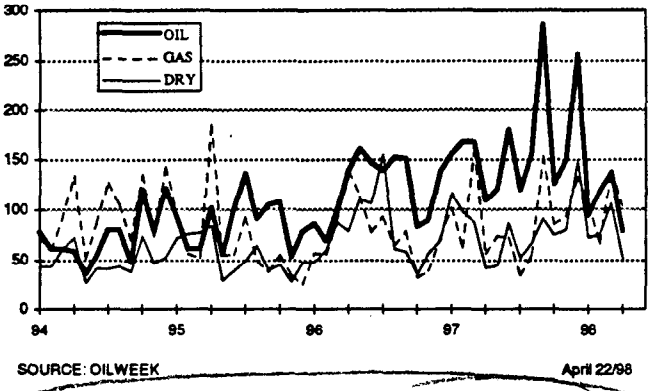
Exports were up 4.3%, or 368.7 mmcf/d, in January 1998. They were up 2.5% for the 12-month period ending that month, or 190.9 mmcf/d. Canadian sales were down 2.8% in January, or 273.1 mmcf/d, reflecting the mild weather this year. For the same 12-month period, they were up 0.3% or 21.7 mmcf/d.

Combined exports and Canadian sales represented 110.1% of marketable production in January 1998 versus 112.5% in January 1997. For the 12-month period ending January, comparative figures were 95.7% and 95.9%.

Year to date at the end of April 1998, the number of natural gas wells drilled represented 35.2% of total wells drilled versus 29.8% over the same period last year. In absolute terms, the number of natural gas wells drilled increased by 3.2%.

In the second week of April 1998, about 45.5% of all wells drilled were natural gas, 33.6% were crude oil and 20.9% were dry.

CANADIAN WELL COMPLETIONS



SOURCE: OILWEEK April 22/98

A switch to natural gas drilling seems to be taking place as a result of the relative pricing of both natural gas and crude oil.

The mild weather this winter has shortened the drilling period in northwestern Alberta and northeastern British Columbia. These areas are relatively gas prone. The focus this winter was still heavily on crude oil and as a result marketable production is showing limited increase.

With prospects of new pipeline capacity to be in operation this fall, this augurs quite well for natural gas prices down the road. We expect a substantial increase in the drilling of natural gas wells in the coming months. We expect the number of natural gas wells to surpass 6,000 in 1999.

Commodity Prices

Natural Gas Prices Revised Upwards.

	WTI (US$ / b)	Avg Cdn$	Equivalent WTI (Cdn$ / b)	Edmonton Light (Cdn$ / b)	Differential (Cdn$ / b)	Wellhead Natural Gas (Cdn$ / mcf)
1994	17.19	1.3656	23.47	22.26	1.21	1.95
95Q1	18.35	1.4065	25.82	24.78	1.04	1.51
95Q2	19.32	1.3709	26.48	25.53	0.94	1.42
95Q3	17.86	1.3554	24.21	23.16	1.05	1.31
95Q4	18.14	1.3555	24.59	23.66	0.93	1.50
1995	18.42	1.3721	25.27	24.28	0.99	1.44
96Q1	19.76	1.3689	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	22.15	1.3635	30.21	29.41	0.80	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	27.38	26.74	0.64	1.72
97Q4	19.87	1.4088	28.00	27.22	0.78	2.22
1997	20.61	1.3847	28.54	27.90	0.64	2.02
98Q1	15.96	1.4298	22.82	22.03	0.78	na
Apr 23	12.90	1.4362	18.53	20.99	-2.46	na
Yr To Date	15.85	1.4293	22.65	21.88	0.78	na

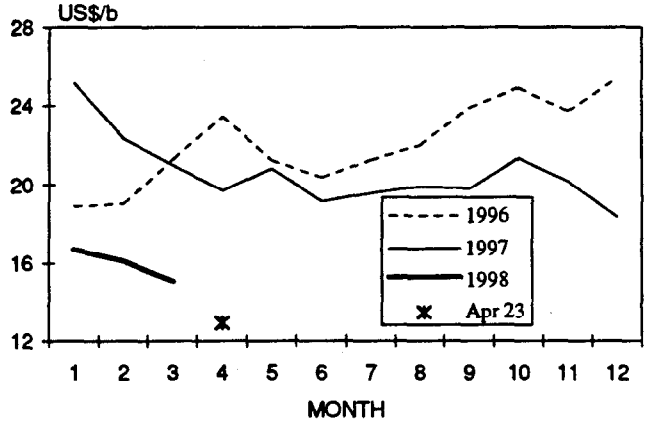
By mid-April 1998, the WTI crude oil was still trading in the US$15-US$16/b range. The decision of OPEC to cut production will produce its effects over time, as inventories are still building up in Q2/98.

For the time being, we are maintaining our WTI price forecasts of US$17/b this year and US$18.50/b for 1999. We are maintaining the WTI/Edmonton light differential of $0.75/b.

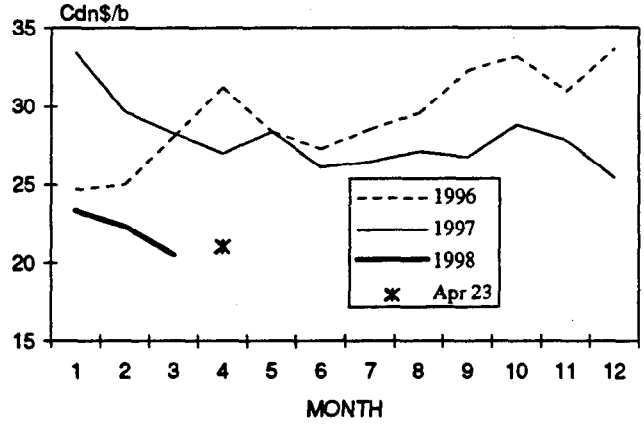
We are increasing our natural gas price forecasts from $1.80/mcf to $2.00/mcf for 1998 and from $2.00/mcf to $2.40/mcf for 1999. With AECO spot price in the $2.30-$2.40/mcf range, our previous forecasts appeared too conservative. However, the price should remain volatile.

Yearly comparisons for crude oil prices should not improve before Q1/99. For natural gas, the improvement could start as early as Q2/98.

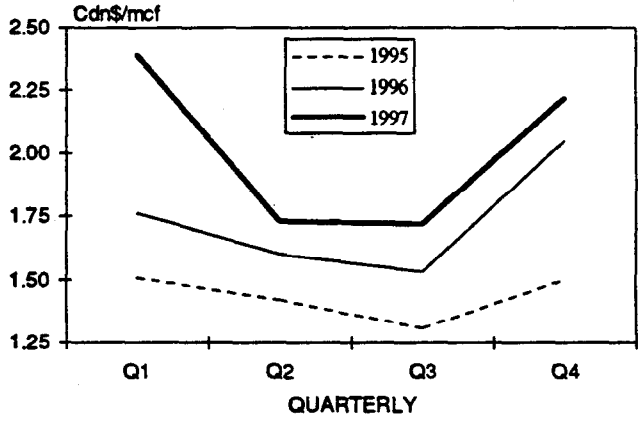
WTI



EDMONTON LIGHT



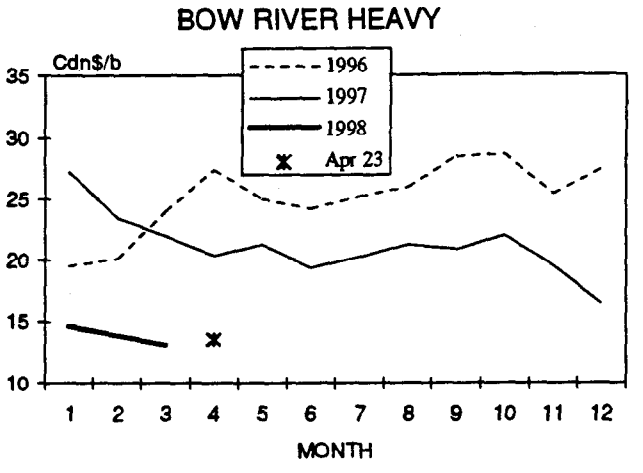
WELLHEAD NATURAL GAS

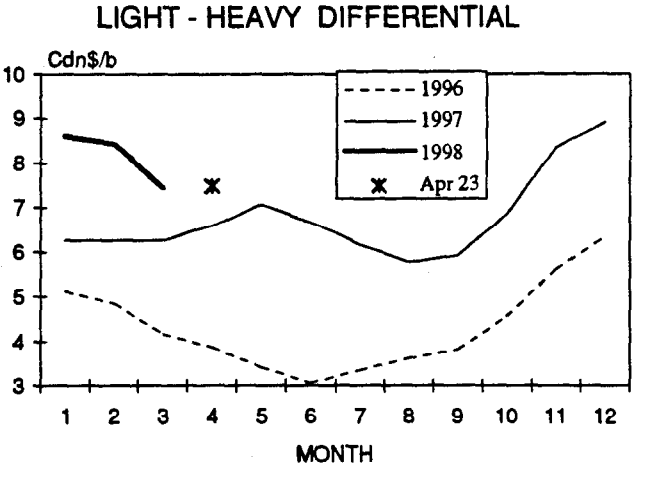


Commodity Prices

Modest Decline in the Differential.

	Edmonton Light (Cdn$ / b)	Bow River Heavy (Cdn$ / b)	Differential (Cdn$ / b)
1994	22.26	18.18	4.08
95Q1	24.78	21.72	3.06
95Q2	25.53	22.85	2.69
95Q3	23.16	20.05	3.11
95Q4	23.66	18.69	4.98
1995	24.28	20.82	3.46
96Q1	25.95	21.23	4.72
96Q2	29.02	25.58	3.44
96Q3	30.07	26.49	3.58
96Q4	32.60	27.13	5.48
1996	29.41	25.11	4.30
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	27.90	21.14	6.76
98Q1	22.03	13.88	8.15
Apr 23	20.99	13.51	7.47
Yr To Date	21.88	13.87	8.01





Year To Date

The differential between light and heavy crude oil has been shrinking recently as a result of the weakness in crude oil prices and shutdown in heavy crude oil production. Seasonally, the spread is usually weaker in the summer. **We are maintaining our differential forecast at $8.00/b for this year and $9.00/b for 1999.**

Commodity Price Forecast

	Crude Oil Price ($/bbl)					Natural Gas
	WTI US$/b	CDN$ US$/C$	Diff. C$/b	Edm. Lt. C$/b	Bow River Heavy C$/b	Corp. Avg. Reference Price C$/mcf
1994	17.19	0.732	1.21	22.26	18.18	1.95
1995	18.42	0.729	0.99	24.28	20.82	1.44
1996	22.15	0.733	0.80	29.41	25.11	1,74
1997	20.61	0.722	0.64	27.90	21.14	2.02
1998F	17.00	0.700	0.75	23.54	15.54	2.00↑
1999F	18.50	0.720	0.75	24.94	15.94	2.40↑

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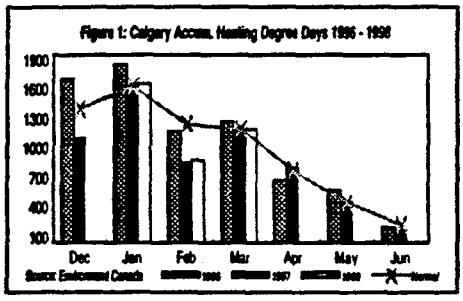
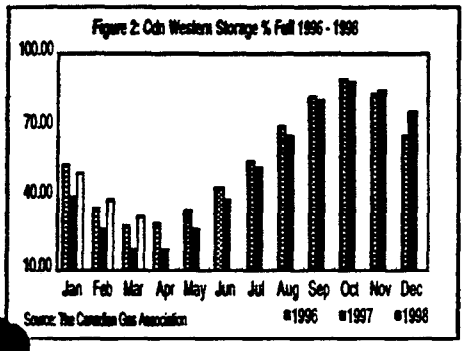
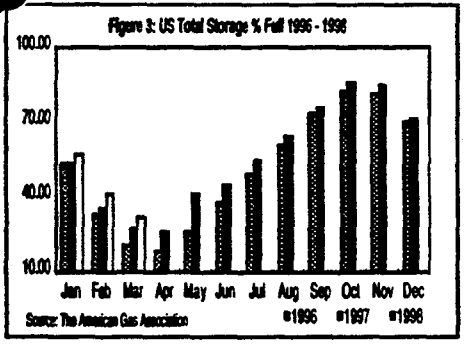
Monthly Canadian and US Market Analysis and Price Forecasts

April 1998 Volume 1, Number 5







Inside this Month ...

Market Summary

Canadian Market Overview

April Prices Increase Over March Prices

AECO/N.I.T. April spot prices averaged $1.78/GJ (Cdn$) representing a 13 cent increase over their March average of $1.65/GJ and up 33 cents from the April 1997 average of $1.45/GJ. One-month spot prices continue to ignore bearish fundamentals: March accumulated heating degree days for Southern Alberta totaled 1251 compared to the normal total of 1245 (see Figure 1. p. 1); Western Canadian storage as of March 27 was 28.37% full compared to 17.34% full for the same time last year (see Figure 2, p.1). Higher summer and winter term prices continue to push one-month spot prices higher, not the fundamental drivers.

In order to analyse the recent impact of term prices on one-month spot prices, correlation coefficients were computed. As listed in Table 1, correlation coefficients for the term November 1997 to March 1998 show AECO/N.I.T. one-month spot prices and term prices to have a strong positive correlation of 0.80. To further prove the strong impact which term prices are having on one-month spot prices, correlation coefficients were calculated between one-month spot prices and temperatures. Conversely, for the same time period, AECO/N.I.T. and Southern Alberta heating degree days have been moving in the opposite direction with a correlation coefficient of -0.73 — this runs quite counter to historical correlations. Interestingly, using a larger time interval, AECO/N.I.T. spot prices and term prices have a correlation coefficient of 0.62 while AECO/N.I.T. and Southern Alberta Heating degree days have a correlation coefficient of 0.53 This implies that historically both temperature and term prices have moved in the same direction as AECO/N.I.T. spot prices.

May Prices Expected to Increase

May spot prices for AECO/N.I.T. are forecast to increase over their April average following projected continued strength in AECO/N.I.T. term prices. Term prices have been increasing for several weeks now on speculation of inadequate supply this winter to feed the extra pipeline capacity which the Northern Border expansion will bring on stream in November. The most likely forecast projects May spot prices to average $1.95/GJ, up 17 cents from their April average of $1.78/GJ and up 19 cents from the May 1997 average of $1.76/GJ. At the time of writing, AECO/N.I.T. summer prices were averaging $2.15/GJ while winter prices were averaging $2.60/GJ. If term prices remain at these levels, AECO/N.I.T. May spot prices will approach the high forecast price of $2.08/GJ. On the other hand, if term prices fall significantly then the AECO/N.I.T. May spot price will gravitate toward the low forecast price of $1.89/GJ. In any event, it is quite clear that the market is moving into uncharted territory. The AECO/N.I.T. May spot price has never been over $2.00/GJ.

Table 1

Correlation Analysis - AECO/N.I.T. vs. Term Prices and Southern AB HDD

Time Interval	Oct96-Mar98	Oct96-Aug97	Sep97-Mar98	Oct96-Oct97	Nov97-Mar98
AECO/NT*	0.62	0.62	0.77	0.59	0.80
AECO/HDD	0.53	0.77	-0.30	0.74	-0.73

*Near Term (NT) defined as the closest term price to the present one-month spot price.

Source: Near Term prices (C$/GJ): TD Securities; AECO/N.I.T. One-Month Spot prices (C$/GJ): Canadian Enerdata Ltd.; Southern Alberta HDD: Environment Canada

Table 2
AECO/N.I.T. Historical Prices (C$/GJ)

	1996	1997	1998
Jan	1.35	2.16	1.40
Feb	1.50	2.69	1.47
Mar	1.43	1.68	1.65
Apr	1.31	1.45	1.78
May	1.19	1.76	-
Jun	1.08	1.66	-
Jul	1.09	1.55	-
Aug	1.17	1.46	-
Sep	1.14	1.48	-
Oct	1.17	1.73	-
Nov	1.41	1.98	-
Dec	2.02	1.71	-
Winter	1.34	1.99	1.64
Summer	1.16	1.58	-
One-Year	1.32	1.78	-

Table 3
AECO/N.I.T. Forecast Scenarios (C$/GJ)

	Most Likely	High	Low
May-98	1.95	2.08	1.89
Jun-98	1.70	1.82	1.62
Jul-98	1.57	1.67	1.48
Aug-98	1.61	1.68	1.44
Sep-98	1.50	1.56	1.44
Oct-98	1.64	1.71	1.57
Nov-98	1.89	1.99	1.79
Dec-98	2.04	2.20	1.86
Jan-99	2.29	2.52	2.08
Feb-99	2.38	2.53	2.02
Mar-99	2.09	2.26	1.73
Apr-99	1.92	2.10	1.58
May-99	1.82	1.95	1.66
Jun-99	1.84	1.93	1.72
Jul-99	1.78	1.82	1.65
Aug-99	1.68	1.77	1.64
Sep-99	1.64	1.71	1.61
Oct-99	1.77	1.85	1.72
Nov-99	2.01	2.13	1.93
Dec-99	2.17	2.34	2.03
Jan-00	2.42	2.65	2.21
Feb-00	2.49	2.64	2.13
Mar-00	2.16	2.33	1.80
Apr-00	2.00	2.17	1.65
Win 98	1.64	1.64	1.64
Sum 98	1.66	1.74	1.60
Win 99	2.14	2.30	1.90
Sum 99	1.78	1.88	1.65
1998	1.67	1.74	1.62
1999	1.95	2.08	1.78

Table 4
Gulf Coast Historical Prices (US$/MMBtu)

	1996	1997	1998
Jan	3.28	4.14	2.21
Feb	3.25	2.90	2.04
Mar	2.65	1.67	2.20
Apr	2.75	1.77	2.30
May	2.14	2.14	-
Jun	2.26	2.30	-
Jul	2.60	2.10	-
Aug	2.27	2.13	-
Sep	1.76	2.64	-
Oct	1.87	3.17	-
Nov	2.65	3.29	-
Dec	3.90	2.47	-
Winter	2.62	3.05	2.44
Summer	2.24	2.31	-
One-Year	2.62	2.55	-

Table 5
Gulf Coast Forecast Scenarios (US$/MMBtu)

	Most Likely	High	Low
May-98	2.39	2.46	2.31
Jun-98	2.41	2.49	2.34
Jul-98	2.43	2.51	2.36
Aug-98	2.45	2.52	2.37
Sep-98	2.45	2.52	2.37
Oct-98	2.46	2.54	2.39
Nov-98	2.60	2.68	2.52
Dec-98	2.72	2.80	2.64
Jan-99	2.73	2.81	2.65
Feb-99	2.58	2.66	2.51
Mar-99	2.44	2.52	2.37
Apr-99	2.31	2.38	2.23
May-99	2.27	2.35	2.20
Jun-99	2.26	2.34	2.19
Jul-99	2.27	2.34	2.19
Aug-99	2.27	2.34	2.19
Sep-99	2.27	2.34	2.19
Oct-99	2.29	2.36	2.22
Nov-99	2.42	2.49	2.34
Dec-99	2.55	2.63	2.48
Jan-00	2.57	2.65	2.49
Feb-00	2.47	2.54	2.39
Mar-00	2.37	2.44	2.29
Apr-00	2.25	2.32	2.17
Win 98	2.44	2.44	2.44
Sum 98	2.41	2.48	2.35
Win 99	2.61	2.69	2.54
Sum 99	2.28	2.35	2.20
1998	2.39	2.44	2.34
1999	2.39	2.46	2.31

Summer Prices Revised Upward

The AECO/N.I.T. average one-month spot price for the summer months (April to October) has been revised upward in light of a strong April index price and a forecast higher May price. The AECO/N.I.T. summer average is now projected at $1.66/GJ representing an 8 cent increase over last year's average of $1.58/GJ. If term prices remain strong, then the average one-month summer price forecast will approach the high average price of $1.74/GJ. If term prices fall off significantly, then the average one-month summer price will approach the low forecast of $1.60/GJ.

Both summer and winter term prices are expected to remain strong thus pressuring prompt month prices near or even higher than historical levels. However, the high forecast of $1.74/GJ still remains very conservative in light of bearish fundamentals that should factor into the equation sometime this summer.

U.S. Market Overview

April Prices Increase Over March Prices

April Gulf Coast spot prices averaged $2.30/MMBtu (US$) representing a 10 cent increase over March's average of $2.20/MMBtu and up 53 cents over April 1997s average of $1.77/MMBtu. April prices were higher for three main reasons: (i) cooler temperatures over most of the U.S. finally pushed storage withdrawal figures to 143 bcf on March 18 causing prices to break their low range in mid-March (total U.S. heating degree days for March were 606 representing an 8.9% increase from the same time last year); (ii) upward momentum in late March forced the re-emergence of fund buying with respect to the futures market, therefore upward technical strength increased; (iii) expectations of a hot summer due to lingering El Nino effects forced futures prices higher in late March (see Figure 4, p.2).

May Prices Expected to Increase Over April Prices

Gulf Coast spot prices for May delivery are forecast to average $2.39/MMBtu representing a 9 cent increase over April's average and still maintaining strength over May 1997s average of $2.14/MMBtu. Despite higher 1998 storage figures (see Figure 3, p.1) and forecast normal temperatures over the Eastern half of the U.S. for April, Gulf Coast prices are expected to increase following projected gains in NYMEX Henry Hub futures prices. At the time of writing, May Henry Hub futures prices were averaging $2.55/MMBtu following strong technicals and speculation of above normal temperatures for this summer.

Summer Prices Revised Upward

Gulf Coast average spot prices for the summer (April to October) have been revised upward following strong April prices and forecast stronger May prices. The summer Gulf Coast average is forecast at $2.41/MMbtu representing a 10 cent increase over last year's value of $2.31/MMBtu. Recently, climatologists are now calling for El Nino to push summer temperatures above normal thus causing increased cooling demand. Further, with power generators using less nuclear power, the demand for natural gas used in power generation could increase, especially if this summer is warmer than normal. In light of these new predictions, Gulf Coast summer prices will approach the high forecast price of $2.48/MMBtu if temperatures are significantly above normal. Conversely, if temperatures are below normal summer prices will approach the low forecast price of $2.35/MMBtu.

Figure 4: 1998 NYMEX Henry Hub Mar/Apr Contract Prices (US$/MMBtu)

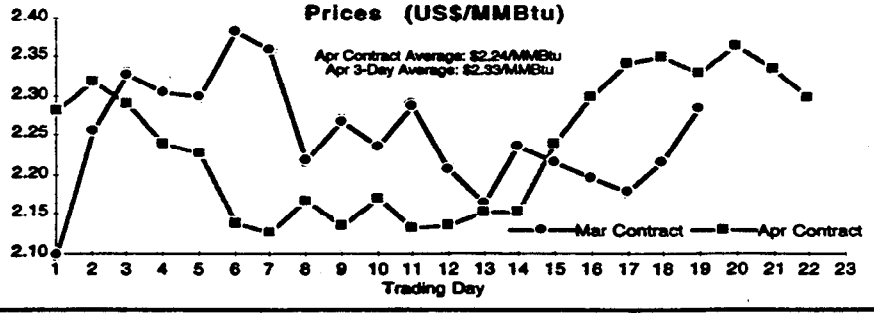


Table 6: One-Month Spot Price Forecasts, Most Likely Case*

	Alberta (C$/GJ)			B.C. Stn 2	Export (US$/MMBtu)				U.S. (US$/MMBtu)			(US$/MMBtu)	
Month	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													
May-97	1.57	1.76	1.83	1.70	1.34	1.43	1.94	2.33	2.14	1.63	2.03	1.98	2.10
Jun-97	1.65	1.66	1.70	1.59	1.32	1.39	2.14	2.54	2.30	1.53	2.16	2.12	2.33
Jul-97	1.59	1.55	1.60	1.54	1.23	1.40	2.01	2.32	2.10	1.44	2.15	2.13	2.22
Aug-97	1.57	1.46	1.47	1.37	1.09	1.20	2.03	2.33	2.13	1.39	2.19	2.12	2.15
Sep-97	1.73	1.48	1.51	1.51	1.19	1.37	2.40	2.70	2.54	1.47	2.50	2.42	2.51
Oct-97	2.07	1.73	1.82	1.80	1.51	1.54	3.02	3.35	3.17	2.06	3.00	3.04	3.22
Nov-97	2.37	1.98	2.13	2.31	2.86	2.47	3.28	3.66	3.29	3.06	3.37	3.26	3.51
Dec-97	1.95	1.71	1.92	1.68	1.40	1.75	2.46	2.87	2.47	1.92	2.35	2.42	2.68
Jan-98	1.77	1.40	1.91	1.45	1.85	1.83	2.13	2.43	2.21	2.04	2.24	2.18	2.27
Feb-98	1.59	1.47	1.70	1.60	1.46	1.47	1.96	2.19	2.04	1.68	2.07	1.90	2.04
Mar-98	1.68	1.65	1.99	1.57	1.16	1.48	2.14	2.42	2.20	1.86	2.24	2.10	2.23
Apr-98	1.73	1.78	1.99	1.88	1.41	1.60	2.20	2.47	2.30	1.90	2.37	2.22	2.33
Forecast Series												*Projected Series***	
May-98	1.80	1.95	2.15	1.91	1.56	1.58	2.28	2.55	2.39	1.93	2.40	2.27	2.38
Jun-98	1.71	1.70	1.84	1.65	1.37	1.60	2.32	2.58	2.41	1.86	2.27	2.31	2.41
Jul-98	1.69	1.57	1.71	1.58	1.38	1.62	2.34	2.60	2.43	1.86	2.25	2.32	2.42
Aug-98	1.68	1.51	1.66	1.54	1.36	1.63	2.35	2.62	2.45	1.87	2.25	2.33	2.44
Sep-98	1.70	1.50	1.65	1.63	1.60	1.64	2.34	2.62	2.45	1.87	2.25	2.33	2.44
Oct-98	1.75	1.64	1.80	1.75	1.69	1.65	2.36	2.64	2.46	1.88	2.26	2.35	2.45
Nov-98	1.86	1.89	2.04	1.94	1.81	1.74	2.47	2.78	2.60	1.98	2.36	2.45	2.58
Dec-98	1.96	2.04	2.21	2.08	1.96	1.86	2.60	2.91	2.72	2.13	2.49	2.57	2.70
Jan-99	2.04	2.29	2.47	2.26	2.01	1.92	2.61	2.92	2.73	2.18	2.54	2.58	2.71
Feb-99	2.01	2.38	2.54	2.26	1.89	1.82	2.46	2.77	2.58	2.06	2.42	2.44	2.57
Mar-99	1.86	2.09	2.22	2.03	1.72	1.67	2.31	2.62	2.44	1.90	2.27	2.30	2.44
Apr-99	1.73	1.92	2.05	1.83	1.49	1.46	2.09	2.47	2.31	1.66	2.05	2.10	2.30
May-99	1.65	1.82	1.93	1.71	1.33	1.31	1.99	2.43	2.27	1.49	1.91	2.09	2.27
Jun-99	1.65	1.84	1.97	1.70	1.28	1.26	1.98	2.42	2.26	1.44	1.86	2.09	2.26
Jul-99	1.64	1.78	1.92	1.66	1.26	1.24	1.99	2.43	2.27	1.42	1.85	2.09	2.26
Aug-99	1.61	1.68	1.83	1.60	1.26	1.23	1.99	2.43	2.27	1.42	1.85	2.09	2.27
Sep-99	1.60	1.64	1.80	1.58	1.26	1.23	1.99	2.43	2.27	1.42	1.85	2.00	2.27
Oct-99	1.65	1.77	1.94	1.66	1.28	1.25	2.01	2.45	2.29	1.43	1.87	2.02	2.29
Nov-99	1.76	2.01	2.18	1.85	1.39	1.34	2.13	2.59	2.42	1.54	1.97	2.13	2.41
Dec-99	1.86	2.17	2.36	2.00	1.53	1.47	2.25	2.73	2.55	1.69	2.10	2.25	2.54
Jan-00	1.94	2.42	2.61	2.17	1.58	1.52	2.27	2.75	2.57	1.75	2.15	2.26	2.56
Feb-00	1.92	2.49	2.67	2.18	1.52	1.47	2.17	2.64	2.47	1.68	2.08	2.17	2.46
Mar-00	1.78	2.16	2.30	1.94	1.42	1.38	2.08	2.54	2.37	1.58	1.99	2.09	2.36
Apr-00	1.69	2.00	2.13	1.80	1.29	1.27	1.97	2.41	2.25	1.45	1.87	1.99	2.25
Avg. Season^													
Winter 1998	1.87	1.64	1.93	1.72	1.75	1.80	2.39	2.71	2.44	2.11	2.45	2.37	2.55
Summer 1998	1.72	1.66	1.83	1.71	1.48	1.62	2.31	2.58	2.41	1.88	2.29	2.30	2.41
Winter 1999	1.95	2.14	2.30	2.11	1.88	1.80	2.49	2.80	2.61	2.05	2.42	2.47	2.60
Summer 1999	1.65	1.78	1.92	1.68	1.31	1.28	2.01	2.44	2.28	1.47	1.89	2.07	2.27
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	1.74	1.67	1.89	1.72	1.55	1.64	2.29	2.57	2.39	1.90	2.29	2.28	2.39
1999	1.75	1.95	2.10	1.84	1.48	1.43	2.15	2.56	2.39	1.64	2.04	2.18	2.38
2000	1.73	2.00	2.12	1.81	1.31	1.29	1.97	2.41	2.25	1.47	1.89	1.99	2.25
2001	1.73	2.00	2.12	1.80	1.28	1.25	1.99	2.43	2.27	1.44	1.86	2.01	2.27
2002	1.84	2.20	2.32	1.97	1.42	1.37	2.17	2.63	2.46	1.58	2.00	2.17	2.45

* 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.

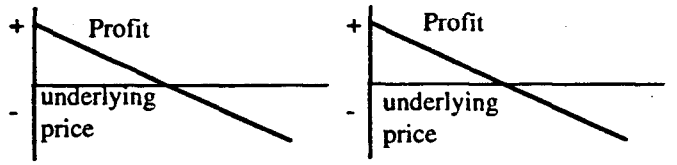
Feature Article: *Options as an Alternative to Hedging Present Risk*

The following article presents an independent view on forward price strategy and advantages of option pricing. Contributers are encouraged. Please contact Canadian Enerdata Ltd. if you would like to contribute to this section.

RELUCTANT TO USE OPTIONS? CHANCES ARE YOU ALREADY HAVE!

by Greg F. Shea

We hear quite often that a client is permitted by their board to hedge their price exposure using swaps, but not options. This is an interesting position from the perspective of a financial institution who, for its own books, is concerned only with price risk management and not about the instrument that achieves it. Take a look at the payout diagrams of the two structures below. Which one involves options and which one is a swap?



The answer, of course, is that the payout diagrams are identical. Selling a swap is exactly the same as buying a put option and selling a call option at the same strike price. Swaps are really just another option structure. Whereas a collar is an option structure with a spread between the strikes, a swap is an option structure with the same strikes. Any swap can be broken down into a put and a call. If you have done a swap, you have bought one option and sold another.

WHY USE OPTIONS?

Option structures are designed to allow a company to hedge and still express a price view. The majority achieve one of two things: enhance a swap rate by selling an option or provide more potential gain from a hedge by having the party buy an option. From a producer's perspective, these are the most popular structures (using the period April 1999 through October 1999 as a sample period):

April '99 Through October '99 Hedge Trasactions:

What Determines The Value of An Option?

Options are often inappropriately maligned as a hedging tool. I assume this is because their value is determined by factors that the hedger does not feel comfortable assessing. They see option pricing as the domain of mathematicians, when in fact value is determined by the same fundamentals that determine the underlying commodity price. As most people know, the value of options is determined by (other than strike price): the underlying price, the volatility of the underlying price, the time to expiry of the option, and interest rates.

In the relatively volatile energy markets, the impact of interest rates is dwarfed by the other factors, so it is insignificant as a determinant of value. Time to expiry only has value as a function of volatility. In a market with a volatility of zero, it does not matter how much time there is to expiry - the option value remains the same. This leaves the underlying price and its volatility as the primary determinants of option value and the primary determinants of the price and its volatility are fundamental factors such as supply, demand, and storage. Clearly people's perception of supply and demand determines the spot price and forward price curve. Equally, the level and availability of storage is the most important aspect of volatility. The participants in the physical market are the people with the most information regarding these factors, and therefore, are the best determinants of option value.

The moral is that options are not the "black box" some people think they are. They are as much determined by market fundamentals as swaps, and are very useful in expressing price views within a hedge.

Bankers Trust Company, Energy Risk Management
Vice President
Greg F. Shea

Mr. Shea joined Bankers Trust four years ago. He is responsible for the pricing, risk management, structuring, and origination of energy derivative transactions across North America. Currently based in Houston, he has been involved in the Canadian natural gas derivatives market since its inception in 1992. Bankers Trust is a recognized leader in providing energy risk management solutions to clients and offers an unparalleled array of risk management products.

April '99 Through October '99 Hedge Transactions:

Sumas
Producer Zero Premium Collar
Underlying market $1.60 US/MMBtu
(1) Buy a $1.40 floor
(2) Sell a $1.85 cap
The result of the above transactions:
Sumas index < $1.40, you receive $1.40
Sumas index > $1.85, you receive $1.85
Otherwise you receive monthly index

Producer Collar with Short Put
Underlying market $1.60 U.S/MMBtu
(1) Buy a $1.40 floor
(2) Sell a $2.05 cap
plus
(3) Sell a $1.25 floor
The results of the above three transactions:
Sumas index < $1.40 but > $1.25, you receive $1.40
Sumas index > $2.05, you receive $2.05
Sumas index < $1.25, you receive Sumas index plus $.15 ($1.40 less $1.25)

AECO/N.I.T.
Producer Zero Premium Collar
Underlying market $2.23 CAD/CJ
(1) Buy a $2.00 floor
(2) Sell a $2.50 cap
The result of the above transactions:
AECO/NIT index < $2.00, you receive $2.00
AECO/NIT index > $2.50, you receive $2.50
Otherwise you receive monthly index

Producer Collar with Short Put
Underlying market $2.23 CAD/GJ
(1) Buy a $2.00 floor
(2) Sell a $2.75 cap
plus
(3) Sell a $1.80 floor
The result of the above three transactions:
AECO/NIT index > $2.00 but > $1.80, you receive $2.00
AECO/NIT index > $2.75, you receive $2.75
AECO/NIT index < $2.00, you receive AECO/NIT index plus $.20 ($2.00 less $1.80)

Canadian Market Analysis

April Prices Up From March

AECO/N.I.T. spot prices for the month of April averaged $1.78/GJ, up 13 cents from March's average of $1.65/GJ and up 33 cents from April 1997s average of $1.45/GJ. Despite above normal storage levels (see Figure 2, p.1) and normal temperatures in Southern Alberta during March (see Figure 1, p.1), prices have been surging over the past several weeks following increasing term prices. At the time of writing, summer term prices were averaging a very strong $2.15/GJ and winter prices averaging $2.60/GJ. Term prices have been increasing on speculation of inadequate supply over both the summer and winter in anticipation of the Northern border expansion to the U.S. coming on stream later this year.

Table 7 (see below) analyses the relationship between AECO/N.I.T. one-month spot prices with both monthly Southern Alberta heating degree days and AECO/N.I.T. term prices. Near term prices are defined as the closest term to the present one-month spot price (e.g. the November 1997 spot price will be related to the winter term price). Correlation coefficients between October 1996 and March 1998 show AECO/N.I.T. spot prices being positively correlated with both near term prices and Southern Alberta heating degree days (0.62 and 0.53 respectively). However, further inspection shows the correlation coefficients moving in opposite directions when the analysis term is decreased into shorter time intervals. Analysis between September 1997 to March 1998 show the correlation coefficient at 0.77 which represents a strong positive increase between AECO/N.I.T. one-month spot prices and near term prices. Conversely, a correlation coefficient of -0.30 between AECO/N.I.T. prices and Southern Alberta heating degree days explains why warm temperatures in Southern Alberta have *not* had any impact on spot prices — in fact the two figures have been moving in the opposite direction since the fall. When the time interval is broken down even further (November 1997 to March 1998), the correlation coefficients become stronger, again in opposite directions. The relationship between AECO/N.I.T. spot prices and near term prices is now 0.80 whereas the relationship between AECO/N.I.T. and Southern Alberta heating degree days becomes -0.73. Clearly, term prices have been influencing AECO/N.I.T. spot prices more than above normal temperature this past winter.

April spot prices for Empress averaged $1.99/GJ experiencing no change from last month but up 43 cents from April 1997s average of $1.56. Falling interruptible transportation rates in March, due to less supply problems on NOVA, counterbalanced the impact of higher term prices (see Figure 5, p.5 for interruptible transportation rates). Station 2 April spot prices averaged $1.88/GJ, up 31 cents from last month's average of $1.57/GJ and up 47 cents from April 1997s average of $1.41/GJ. April Station 2 spot prices were much higher following increases in

Table 7

Correlation Coefficients - AECO/N.I.T. One-Month Spot Price vs. AECO/N.I.T. Near Term Prices and Southern Alberta Heating Degree Days

	Oct-96	Nov-96	Dec-96	Jan-97	Feb-97	Mar-97	Apr-97	May-97	Jun-97
AECO Spot	1.17	1.41	2.02	2.16	2.69	1.68	1.45	1.76	1.66
Near Term*	1.32	1.55	2.21	2.10	1.67	1.51	1.52	1.79	1.54
HDD	408	774	1406	1753	1686	908	1222	845	501
	Jul-97	Aug-97	Sep-97	Oct-97	Nov-97	Dec-97	Jan-98	Feb-98	Mar-98
AECO Spot	1.55	1.46	1.48	1.73	1.98	1.71	1.40	1.47	1.65
Near Term*	1.48	1.46	1.59	1.94	2.02	1.48	1.37	1.66	1.69
HDD	227	145	142	286	739	973	1148	1712	927

	Oct96-Mar98	Oct96-Aug97	Sep97-Mar98	Oct96-Oct97	Nov97-Mar98
AECO/NT	0.62	0.62	0.77	0.59	0.80
AECO/HDD	0.53	0.77	-0.30	0.74	-0.73

*Near Term defined as the closest term price to the present one-month spot price. All prices (C$/GJ).

Source: Near Term prices: TD Securities; AECO/N.I.T. One-Month Spot prices: Canadian Enerdata; Southern Alberta HDD: Environment Canada

Table 8

Empress Historical Prices (C$/GJ)

	1996	1997	1998
Jan	1.47	2.27	1.91
Feb	1.59	2.85	1.70
Mar	1.50	1.79	1.99
Apr	1.41	1.56	1.99
May	1.27	1.83	-
Jun	1.16	1.70	-
Jul	1.18	1.80	-
Aug	1.26	1.47	-
Sep	1.24	1.51	-
Oct	1.26	1.82	-
Nov	1.52	2.13	-
Dec	2.13	1.92	-
Winter	1.43	2.11	1.93
Summer	1.25	1.64	-
One-Year	1.41	1.87	-

Table 9

Empress Forecast Scenarios (C$/GJ)

	Most Likely	High	Low
May-98	2.15	2.34	2.09
Jun-98	1.84	2.01	1.77
Jul-98	1.71	1.84	1.62
Aug-98	1.66	1.75	1.59
Sep-98	1.65	1.73	1.60
Oct-98	1.80	1.88	1.73
Nov-98	2.04	2.15	1.94
Dec-98	2.21	2.38	2.05
Jan-99	2.47	2.60	2.34
Feb-99	2.54	2.72	2.37
Mar-99	2.22	2.34	2.09
Apr-99	2.05	2.22	1.87
May-99	1.93	2.06	1.95
Jun-99	1.97	2.05	2.03
Jul-99	1.92	1.96	1.97
Aug-99	1.83	1.93	1.80
Sep-99	1.80	1.88	1.77
Oct-99	1.94	2.02	1.88
Nov-99	2.18	2.30	2.09
Dec-99	2.36	2.53	2.21
Jan-00	2.61	2.77	2.47
Feb-00	2.67	2.87	2.48
Mar-00	2.30	2.47	2.13
Apr-00	2.13	2.25	2.00
Win 98	1.93	1.93	1.93
Sum 98	1.83	1.93	1.77
Win 99	2.30	2.44	2.16
Sum 99	1.92	2.02	1.90
1998	1.89	1.97	1.83
1999	2.10	2.22	2.03

Table 10

Alberta Field Historical Prices (C$/GJ)

	1996	1997	1998
Jan	1.62	2.77	1.80
Feb	1.61	2.28	1.59
Mar	1.60	1.39	1.68
Apr	1.51	1.44	1.73
May	1.41	1.57	-
Jun	1.37	1.65	-
Jul	1.38	1.59	-
Aug	1.38	1.57	-
Sep	1.20	1.57	-
Oct	1.28	2.07	-
Nov	1.79	2.37	-
Dec	2.36	1.95	-
Winter	1.50	2.12	1.88
Summer	1.36	1.64	-
One-Year	1.54	1.85	-

Table 11

Alberta Field Forecast Scenarios (C$/GJ)

	Most Likely	High	Low
May-98	1.80	1.93	1.72
Jun-98	1.71	1.84	1.63
Jul-98	1.69	1.80	1.60
Aug-98	1.68	1.78	1.59
Sep-98	1.70	1.80	1.61
Oct-98	1.75	1.85	1.66
Nov-98	1.86	1.98	1.76
Dec-98	1.96	2.10	1.84
Jan-99	2.04	2.20	1.90
Feb-99	2.01	2.18	1.86
Mar-99	1.86	2.03	1.72
Apr-99	1.73	1.89	1.59
May-99	1.65	1.80	1.57
Jun-99	1.65	1.78	1.58
Jul-99	1.64	1.75	1.56
Aug-99	1.61	1.72	1.54
Sep-99	1.60	1.70	1.53
Oct-99	1.65	1.75	1.57
Nov-99	1.76	1.87	1.67
Dec-99	1.86	1.99	1.75
Jan-00	1.94	2.09	1.81
Feb-00	1.92	2.09	1.78
Mar-00	1.78	1.95	1.65
Apr-00	1.69	1.85	1.56
Win 98	1.87	1.87	1.87
Sum 98	1.72	1.82	1.65
Win 99	1.95	2.09	1.82
Sum 99	1.65	1.77	1.56
1998	1.74	1.82	1.68
1999	1.75	1.89	1.65

Table 12
Station 2 Historical Prices (C$/GJ)

	1996	1997	1998
Jan	1.40	2.45	1.45
Feb	1.51	2.65	1.60
Mar	1.44	1.33	1.57
Apr	1.14	1.41	1.88
May	1.14	1.70	-
Jun	1.12	1.59	-
Jul	1.17	1.54	-
Aug	1.23	1.37	-
Sep	1.18	1.51	-
Oct	1.38	1.80	-
Nov	2.22	2.31	-
Dec	3.07	1.68	-
Winter	1.43	2.35	1.72
Summer	1.19	1.56	-
One-Year	1.50	1.78	-

Table 13
Station 2 Forecast Scenarios (C$/GJ)

	Most Likely	High	Low
May-98	1.91	1.99	1.81
Jun-98	1.65	1.69	1.58
Jul-98	1.58	1.68	1.50
Aug-98	1.54	1.62	1.47
Sep-98	1.63	1.71	1.55
Oct-98	1.75	1.84	1.66
Nov-98	1.94	2.05	1.83
Dec-98	2.08	2.23	1.94
Jan-99	2.26	2.45	2.08
Feb-99	2.26	2.48	2.06
Mar-99	2.03	2.25	1.82
Apr-99	1.83	2.05	1.63
May-99	1.71	1.89	1.62
Jun-99	1.70	1.86	1.64
Jul-99	1.66	1.79	1.59
Aug-99	1.60	1.70	1.54
Sep-99	1.58	1.66	1.52
Oct-99	1.66	1.75	1.59
Nov-99	1.85	1.96	1.75
Dec-99	2.00	2.14	1.87
Jan-00	2.17	2.35	2.00
Feb-00	2.18	2.39	1.99
Mar-00	1.94	2.16	1.75
Apr-00	1.80	2.01	1.60
Win 98	1.72	1.72	1.72
Sum 98	1.71	1.77	1.64
Win 99	2.11	2.29	1.95
Sum 99	1.68	1.81	1.59
1998	1.72	1.78	1.65
1999	1.84	2.00	1.73

Table 14
Sumas Historical Prices (US$/MMBtu)

	1996	1997	1998
Jan	1.25	4.10	1.85
Feb	1.19	2.32	1.46
Mar	1.15	1.06	1.16
Apr	0.93	1.13	1.41
May	0.93	1.34	-
Jun	0.89	1.32	-
Jul	0.96	1.23	-
Aug	1.01	1.09	-
Sep	1.01	1.19	-
Oct	1.10	1.51	-
Nov	2.18	2.86	-
Dec	3.34	1.40	-
Winter	1.23	2.60	1.75
Summer	0.97	1.26	-
One-Year	1.33	1.71	-

Table 15
Sumas Forecast Scenarios (US$/MMBtu)

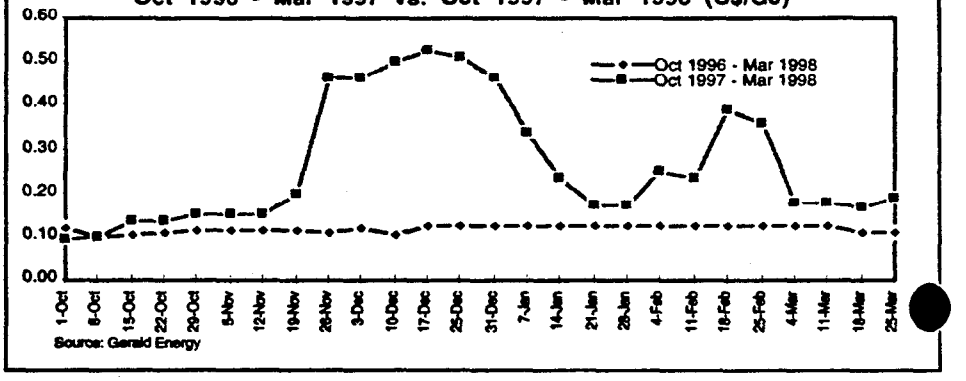
	Most Likely	High	Low
May-98	1.56	1.65	1.47
Jun-98	1.37	1.46	1.29
Jul-98	1.38	1.47	1.30
Aug-98	1.36	1.45	1.28
Sep-98	1.60	1.72	1.49
Oct-98	1.69	1.81	1.56
Nov-98	1.81	1.94	1.68
Dec-98	1.96	2.09	1.82
Jan-99	2.01	2.15	1.87
Feb-99	1.89	2.02	1.76
Mar-99	1.72	1.85	1.60
Apr-99	1.49	1.60	1.37
May-99	1.33	1.44	1.22
Jun-99	1.28	1.38	1.17
Jul-99	1.26	1.37	1.16
Aug-99	1.26	1.37	1.15
Sep-99	1.26	1.37	1.15
Oct-99	1.28	1.39	1.17
Nov-99	1.39	1.50	1.28
Dec-99	1.53	1.65	1.41
Jan-00	1.58	1.71	1.46
Feb-00	1.52	1.63	1.40
Mar-00	1.42	1.53	1.30
Apr-00	1.29	1.40	1.18
Win 98	1.75	1.75	1.75
Sum 98	1.48	1.57	1.40
Win 99	1.88	2.01	1.75
Sum 99	1.31	1.42	1.20
1998	1.55	1.62	1.48
1999	1.48	1.59	1.36

AECO/N.I.T. April spot prices.

Export prices on the westcoast increased following strength in the futures market and cooler temperatures in the Pacific Northwest during March. March heating degree days totaled 426 in the Pacific region representing a 13.9% increase from the same time last year. As a result, April Sumas spot prices averaged $1.41/MMBtu, up 25 cents from their March average of $1.16/MMBtu and up 28 cents from April 1997s average of $1.13/MMBtu. Likewise, Kingsgate spot prices for April averaged $1.60/MMBtu representing a 12 cent increase over March's average of $1.48/MMBtu and up 35 cents from April 1997s average of $1.25/MMBtu.

Niagara spot prices for April averaged $2.47/MMBtu, up 5 cents from last month and up 43 cents from April 1997s average of $2.04/MMBtu. Prices were higher following strong NYMEX Henry Hub bid week prices (see Figure 4, p.2) despite warmer temperatures in the Mid-Atlantic region during March. Heating degree days for the region totaled 746 representing a 9.13% decrease from the normal value and a 8.47% decrease from the same time last year.

Figure 5: Transportation (Empress - AECO Buy/Sell)
Oct 1996 - Mar 1997 vs. Oct 1997 - Mar 1998 (C$/GJ)



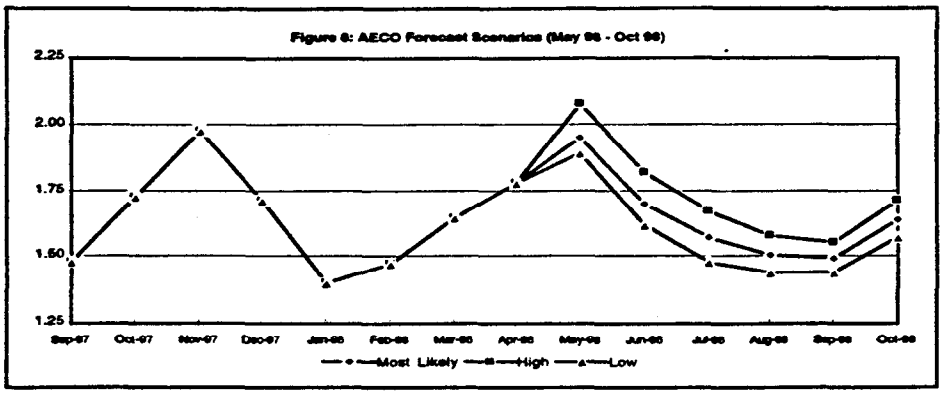
May Prices Expected to Increase Following Strong Term Prices

Due to the continued bullish nature of both summer and winter term prices, May spot prices are forecast to increase over their April prices. As mentioned above, fundamental drivers such as storage and winter temperatures have had zero impact on one-month spot prices. Rather, as shown in Table 7, spot prices have been tracking term prices very closely. This momentum is expected to continue as market perception of inadequate supply for the winter also continues.

In conjunction with the above term price assumptions, the most likely forecast scenario assumes normal weather across Canada for the month of April since weather has had virtually no impact on prices this past winter. AECO/N.I.T. May spot prices are forecast at $1.95/GJ, up 17 cents from April's average and up 19 cents from May 1997s average of $1.76/GJ. Similarly, Empress prices are expected to average $2.15/GJ for May representing an increase of 16 cents over April and up 32 cents from May 1997s average of $1.83/GJ. Interruptible transportation rates are expected to remain fairly stable at $0.18 during April. Station 2 May prices are forecast at $1.91/GJ, up 3 cents from April's average and up 21 cents from May 1997s average of $1.70/GJ.

All export prices are forecast to increase following strong term prices and projected strength in futures prices. Meteorologists have recently been predicting a hot summer for most of the U.S. due to the lingering effects of El Nino (see U.S. Analysis, p. 8 for further details); therefore, U.S. futures prices for the summer have been increasing. As a result, Sumas spot prices for May are expected to average $1.56/MMBtu, up 15 cents from April's average and up 22 cents from May 1997s average of $1.34/MMBtu. Kingsgate prices for May are forecast to

remain strong at $1.58/MMBtu, down only 2 cents from last month but up 15 cents from May 1997s average of $1.43/MMBtu. Kingsgate prices are forecast to decrease slightly following only small gains in Rockies prices. May Niagara spot prices are forecast to average $2.55/MMBtu, up 8 cents from last month's average and up 22 cents from May 1997s average of $2.33/MMBtu. Niagara prices are forecast to increase following projected gains in U.S. Gulf Coast prices.



Summer Term Prices Revised Upward

In light of very strong April spot prices (particularly domestic prices) and forecast higher May spot prices, average summer one-month spot prices have been revised upward. It appears that strong summer prices are helpeing one-month spot prices to mainatain their strength. However, there still exists a credible downside (as analysed in the March issue of The *Natural Gas Lookout*). One-month spot prices could fall over the next five months if either the speculative bubble bursts due to new supply and/or demand information or bearish fundamentals finally impact prices more than they have recently been doing. In any event, it will be quite interesting to see how the price picture unfolds as the market has now entered the injecting season.

The most likely average summer price forecast for AECO/N.I.T. is now $1.66/GJ, up 8 cents from last year's average of $1.58/GJ. Similarly, Empress average summer prices are projected at $1.83/GJ, up 19 cents from last year and Station 2 average summer prices are forecast at $1.71/GJ, up 15 cents from last year.

Export average summer prices have also been revised upward. Sumas prices are forecast to average $1.48/MMBtu representing a 22 cent increase over last summer; Kingsgate average summer prices are projected at $1.62/MMBtu, up 25 cents from last year; Niagara prices are expected to average $2.58/MMBtu for the summer, up 6 cents from one year prior.

If fundamentals start to impact prices in a greater fashion over the next five months, prices will approach the low forecast scenario: AECO/N.I.T. - $1.60/GJ; Empress - $1.77/GJ; Station 2 - $1.64/GJ; Sumas - $1.40/MMBtu; Kingsgate - $1.53/MMBtu; Niagara - $2.51/MMBtu.

If Alberta term prices maintain high levels and the market continues to ignore bearish fundamentals, prices will approach the high forecast scenario: AECO/N.I.T. - $1.74/GJ; Empress - $1.93/GJ; Station 2 - $1.77/GJ; Sumas - $1.57/MMBtu; Kingsgate - $1.71/MMBtu; Niagara - $2.65/MMBtu.

Overall, using AECO/N.I.T. average one-month spot prices for the summer term as an example, summer prices have not been this strong since 1993 and 1994 when summer averages were $1.99/GJ and $1.78/GJ respectively. However, in those previous summers, fundamental variables such as weather were the main drivers. This year, speculation without a doubt has been the key.

Table 16
Niagara Historical Prices (US$/MMBtu)

	1996	1997	1998
Jan	3.72	5.13	2.43
Feb	3.85	3.31	2.19
Mar	4.79	2.01	2.42
Apr	3.08	2.04	2.47
May	2.38	2.33	-
Jun	2.60	2.54	-
Jul	2.92	2.32	-
Aug	2.53	2.33	-
Sep	2.06	2.70	-
Oct	2.10	3.35	-
Nov	3.21	3.66	-
Dec	4.43	2.87	-
Winter	3.37	3.62	2.71
Summer	2.52	2.52	-
One-Year	3.14	2.88	-

Table 17
Niagara Forecast Scenarios (US$/MMBtu)

	Most Likely	High	Low
May-98	2.55	2.63	2.47
Jun-98	2.58	2.67	2.50
Jul-98	2.60	2.69	2.52
Aug-98	2.62	2.70	2.54
Sep-98	2.62	2.70	2.54
Oct-98	2.64	2.72	2.56
Nov-98	2.78	2.86	2.70
Dec-98	2.91	2.99	2.82
Jan-99	2.92	3.01	2.84
Feb-99	2.77	2.85	2.68
Mar-99	2.62	2.70	2.53
Apr-99	2.47	2.55	2.39
May-99	2.43	2.51	2.36
Jun-99	2.42	2.50	2.34
Jul-99	2.43	2.50	2.35
Aug-99	2.43	2.51	2.35
Sep-99	2.43	2.51	2.35
Oct-99	2.45	2.53	2.37
Nov-99	2.59	2.67	2.51
Dec-99	2.73	2.82	2.65
Jan-00	2.75	2.84	2.67
Feb-00	2.64	2.72	2.56
Mar-00	2.54	2.62	2.46
Apr-00	2.41	2.48	2.33
Win 98	2.71	2.71	2.71
Sum 98	2.58	2.65	2.51
Win 99	2.80	2.88	2.71
Sum 99	2.44	2.52	2.36
1998	2.57	2.62	2.51
1999	2.56	2.64	2.48

Table 18
Kingsgate Historical Prices (US$/MMBtu)

	1996	1997	1998
Jan	1.15	3.74	1.83
Feb	1.25	2.32	1.47
Mar	1.11	1.19	1.48
Apr	1.04	1.25	1.60
May	1.00	1.43	-
Jun	0.87	1.39	-
Jul	0.93	1.40	-
Aug	0.99	1.20	-
Sep	0.97	1.37	-
Oct	1.03	1.54	-
Nov	1.61	2.47	-
Dec	2.68	1.75	-
Winter	1.12	2.35	1.80
Summer	0.98	1.37	-
One-Year	1.24	1.75	-

Table 19
NYMEX HH 3-day Projected Scen. (US$/MMBtu)

	Most Likely	High	Low
May-98	2.38	2.44	2.29
Jun-98	2.41	2.47	2.32
Jul-98	2.42	2.49	2.33
Aug-98	2.44	2.50	2.35
Sep-98	2.44	2.50	2.35
Oct-98	2.45	2.52	2.37
Nov-98	2.58	2.65	2.49
Dec-98	2.70	2.77	2.61
Jan-99	2.71	2.79	2.63
Feb-99	2.57	2.64	2.48
Mar-99	2.44	2.50	2.35
Apr-99	2.30	2.36	2.21
May-99	2.27	2.33	2.18
Jun-99	2.26	2.32	2.17
Jul-99	2.26	2.32	2.17
Aug-99	2.27	2.32	2.17
Sep-99	2.27	2.32	2.17
Oct-99	2.29	2.34	2.20
Nov-99	2.41	2.47	2.32
Dec-99	2.54	2.61	2.45
Jan-00	2.56	2.63	2.47
Feb-00	2.46	2.52	2.37
Mar-00	2.36	2.42	2.27
Apr-00	2.25	2.30	2.15
Win 98	2.55	2.55	2.55
Sum 98	2.41	2.46	2.33
Win 99	2.60	2.67	2.51
Sum 99	2.27	2.33	2.18
1998	2.39	2.43	2.33
1999	2.38	2.44	2.29

RÉPONSE DE SCGM À UNE DEMANDE D'INFORMATION

Origine : Audience du 29 octobre 1998

Demandeur : ACIG

Engagement 17

Demandes :

Réconcilier les informations contenues à la pièce SCGM-3 doc.1.14.1 avec la pièce SCGM-3, doc.1.14, page 3 colonne mai 1998.

Réponses

ARC FINANCIAL CORPORATION : PAGE 25 Colonne « Domestic Sales Average », Année 1999 :	2,14 $can/mcf Plant Gate ou 2,20 $/GJ à Empress
Enerdata LTD : Page 5 table 9 Moyenne octobre 1998 à sept 1999	2,10 $/Gj à Empress
Gilbert Laustsen Jung Ass. : Table 2 Colonne « Alberta Plant Gate Average Current	2,00 $/mmbtu Plant Gate ou 2,10 $/GJ à Empress
Mc Daniel Associates : Colonne Alberta Average $can/mmbtu, année 1999	1,95$can/mmbtu Plant Gate ou 2,05 $/Gj à Empress
Nesbitt Burns : page 8 Année 1999	2,40 $can/mcf PlantGate ou 2,45 $/GJ à Empress
Sproule; page 4 Colonne Alberta direct sales, année 1999	1,92 $can/mmbtu PlantGate ou 2,00 $/GJ à Empress
Ziff Energy Group : page 46 Figure 4,10 Base case 1999	1,82 $/GJ à Empress

Notes :

A) Facteurs de conversion : 1 Gigajoule = 0,932 mmbtu
1 Gigajoule = 0,932 mcf

B) Fais de livraison entre Plant Gate et Empress : 0,22 $/GJ

C) Lorsque les données mensuelles ou trimestrielles pour 1998 et 1999 n'étaient pas disponibles, nous avons utilisé l'année calendrier 1999 comme indicateur de la période oct. 1998-sept. 1999. En effet, nous avons jugé qu'il n'était pas opportun de faire nos propres hypothèses sur la répartition trimestrielles des données annuelles. Par ailleurs un tel exercice aurait donné lieu à des résultats très peu différents.

DÉVELOPPEMENT DE MARCHÉ

Présentation à la Régie de l'Énergie

Témoins: ***Daniel Bazinet***
Yves D'Amour
Jacques Laroche
Michel L. Roy

DÉVELOPPEMENT DE MARCHÉ

PLAN DE PRÉSENTATION

DÉVELOPPEMENT DE MARCHÉ

CONTEXTE

- **Situation économique**
- **Détérioration de la situation concurrentielle**

⇨ ***Baisse des retraits de 13,5 BCF par rapport au dossier de mai 98***

⇨ ***Besoin d 'utiliser la flexibilibé mazout et bi-énergie pour les clients du moyen débit afin de préserver les volumes à risque***

DÉVELOPPEMENT DE MARCHÉ

GRANDES ORIENTATIONS

- **Maintenir et accroître les volumes chez les clients existants**
- **Poursuivre le développement des marchés existants:**
  - ➤ **Commercial, institutionnel, industriel (CII)**
  - ➤ **Grandes entreprises**
- **Pénétrer de nouveaux marchés prometteurs**
  - ➤ **Résidentiel**
  - ➤ **Gaz naturel pour véhicules (GNV)**
- **Concentrer sur le développement sur réseau et réaliser certaines extensions de réseau rentables**

DÉVELOPPEMENT DE MARCHÉ

RENTABILITÉ DU PLAN DE DÉVELOPPEMENT 1998-1999								
Marché	Nombre de clients	Volumes		Immobilisations (000 $)		Contribution tarifaire (000 $)		
		10^3m^3	Bcf	Const. et frais généraux	PRC	5 ans	1 an	Tri (%)
Petit et moyen débits	4 390	95 161	3,36	32 157	13 345	**(12 850)**	**(1 624)**	16,28
Grandes entreprises	34	207 926	7,34	19 382	2 062	**(3 965)**	**(510)**	13,54
Total	4 424	303 087	10,70	51 539	15 407	**(16 815)**	**(2 134)**	15,75

Évolution Linéaire

DÉVELOPPEMENT DE MARCHÉ

DEMANDES SPÉCIFIQUES

- **Autoriser pour les tarifs 1, 3 et M, la réactivation du programme de flexibilité mazout et le maintien du programme de flexibilité bi-énergie**
- **Autoriser les montants requis pour le développement du GNV**

REPONSE DE SCGM À UNE DEMANDE D'INFORMATION

Origine : Audience du 23 octobre 1998
Demandeur : Régie de l'énergie

Engagement 8

Demande :

Fournir les résultats sommaires de l'analyse de marché effectué pour évaluer le potentiel de marché du GNV.

Réponse

Nous avons effectué un analyse préliminaire du marché du transport dans le but d'évaluer la taille du marché du parc de véhicules sur réseau gazier. Nous avons également réalisé des entrevues avec des gestionnaires de flottes de véhicules afin de comprendre le processus de décision pour l'acquisition des véhicules de transport. Les résultats sommaires sont les suivants :

1. Taille du marché

   Une segmentation par type de véhicule a été réalisée parmi les organisations opérant plus de cinq véhicules aptes à convertir au gaz naturel. La segmentation est la suivante :

   - Automobiles et camions légers;
   - Autobus;
   - Camions lourds et semi-lourds;
   - Véhicules de service.

   L'ensemble de ces segments représente, au Québec, un potentiel évalué, dans un premier temps, à quelque 25 BCF de consommation annuelle. De plus, nous avons évalué, à l'intérieur de ces segments, les marchés qui semblent les plus prometteurs pour le GNV. Ces marchés sont :

REPONSE DE SCGM À UNE DEMANDE D'INFORMATION

Origine : Audience du 23 octobre 1998
Demandeur : Régie de l'énergie

Engagement 8

Demande :

Fournir les résultats sommaires de l'analyse de marché effectué pour évaluer le potentiel de marché du GNV.

Réponse

- Municipalité;
- Transport urbain;
- Transport scolaire;
- Grande entreprise et secteur public et parapublic.

Ces marchés plus spécifiques représentent pour la Société un potentiel préliminaire de 12 BCF de consommation annuelle.

2. Processus de décision d'achat

Les entrevues réalisées avec les gestionnaires de flottes nous permettent de mieux comprendre les préoccupations de ces derniers pour l'achat de véhicules et la gestion des flottes.

Suite à l'information obtenue, nous avons élaboré la séquence du processus de décision d'achat des véhicules. Le modèle élaboré est le suivant :

a) Critères fonctionnels : ces critères sont les conditions minimales à rencontrer et pour lesquels les organisations ne peuvent envisager de compromis sur les aspects fonctionnels (ex. : espace de chargement, puissance du moteur, etc.).

REPONSE DE SCGM À UNE DEMANDE D'INFORMATION

Origine : Audience du 23 octobre 1998
Demandeur : Régie de l'énergie

Engagement 8

Demande :

Fournir les résultats sommaires de l'analyse de marché effectué pour évaluer le potentiel de marché du GNV.

Réponse

b) Critères de gestion de flotte : ce sont les considérations reliées aux politiques administratives ou encore à la culture de l'organisation (ex. : entretien des véhicules, localisation des utilisateurs, etc.).

c) Les critères économiques : ce sont les facteurs basés sur le coût d'acquisition, les frais d'opération et la valeur de revente du véhicule.

L'évaluation de la taille de marché et une meilleure compréhension des différents segments de la clientèle nous encouragent à poursuivre notre recherche pour la desserte du gaz naturel pour véhicules. La prochaine étape de notre recherche portera sur les éléments suivants :

- Le degré d'acceptation du produit;
- L'évaluation du taux de pénétration;
- L'évaluation du réseau d'infrastructure du GNV;
- La rentabilité du projet pour le distributeur gazier et la clientèle;
- L'offre commerciale pour la clientèle visée.

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Gaz Métropolitain

Source d'avenir

ecoACTION2000

Voir critères d'admissibilité à l'intérieur

RÉPONSE DE SCGM À UNE DEMANDE D'INFORMATION

Origine : Lettre du 14 août 1998
Demandeur : GRAME/UDD

Question 3.3.2

Référence : SCGM-3, Document 3, page 8, ligne 13 à 15

Demande :

A. Si vous raccordez 750 résidences en 1998-1999 et 2 500 résidences par année 5 ans plus tard, peut-on considérer que c'est uniquement de l'hydroélectricité que vous remplacerez pour le chauffage et les autres usages ?

Réponse

Non, parmi les raccordements de 750 résidences en 1998-1999, seulement 210 remplaceront de l'électricité pour la chauffe et les autres usages. Dans 292 résidences, du mazout sera remplacé et dans les 248 autres, un peu d'électricité pour des usages autres que le chauffage sera déplacé.

Même chose pour le raccordement des 2 490 résidences à la cinquième année et pour les années subséquentes. Dans 1 400 résidences, de l'électricité sera remplacée pour la chauffe et autres usages, 590 résidences déplaceront du mazout et les 500 autres déplaceront un peu d'électricité pour des usages autres que le chauffage.

RÉPONSE DE SCGM À UNE DEMANDE D'INFORMATION

Origine : Lettre du 14 août 1998
Demandeur : GRAME/UDD

Question 3.3.2

Référence : SCGM-3, Document 3, page 8, ligne 13 à 15

Demande :

B. À combien d'équivalent tWh correspond la consommation de ces résidences ?

Réponse

Voici la ventilation détaillée de l'électricité déplacée dans ces résidences :

Année	Nombre de Clients	Volume (1000 m³)	Consommation (tWh)
1	458	379	0,0036
2	745	995	0,0095
3	995	1 664	0,0159
4	1 300	2 238	0,0214
5	1 900	3 134	0,0300
Total	5 398	8 410	0,0805

La méthode de conversion est la suivante :

- 1 295 000 m^3 X 35 911 BTU/m^3 X 0,91/3 413 BTU/kWh

N.B. Le taux d'efficacité des appareils de troisième génération est d'environ 91 %.

DÉVELOPPEMENT RÉSIDENTIEL

Présentation à la
Régie de l 'Énergie

Témoins: ***Daniel Bazinet***
Michel L. Roy

DÉVELOPPEMENT RÉSIDENTIEL

PLAN DE PRÉSENTATION

DÉVELOPPEMENT RÉSIDENTIEL

CONTEXTE DES ANNÉES 80

- **Subventions gouvernementales pour l'extension des réseaux gaziers et conversion du mazout vers le gaz naturel et l'électricité**
- **Raccordement de 10 000 clients résidentiels par année**
- **Période de grands surplus d'électricité**
- **Commercialisation agressive de l'électricité**
- **Domination de la plinthe électrique dans le marché résidentiel**

⇨ ***Gaz Métropolitain délaisse le développement du résidentiel en 1988***

DÉVELOPPEMENT RÉSIDENTIEL

CONTEXTE À PARTIR DE 1995

- **Changement de comportement des consommateurs qui recherchent:**
  - ➤ **Plus grand confort**
  - ➤ **Style de vie (foyer, cuisinière, sèche-linge, chauffe-eau, etc.)**
  - ➤ **Économie**
- **Demande de la Régie du Gaz Naturel de reprendre le développement résidentiel** [financé avec la diminution du risque]

⇨ ***Gaz Métropolitain entreprend quelques projets tests***

DÉVELOPPEMENT RÉSIDENTIEL

CONTEXTE ACTUEL

- **Le verglas:**
  - ➤ **Remise en question des consommateurs de la grande dépendance face à l'électricité**
  - ➤ **Recherche d'équipements autonomes**
  - ➤ **Demande croissante des promoteurs, constructeurs et municipalités pour un meilleur accès au gaz naturel**

⇨ ***Gaz Métropolitain accélère le développement du marché résidentiel***

DÉVELOPPEMENT RÉSIDENTIEL

MARCHÉS VISÉS

- **Autonomie et ajout d'équipement chez la clientèle existante**
- **Offrir le gaz naturel aux clients potentiels sur réseau**
  - ➤ **Chauffage**
  - ➤ **Périphériques**
- **Pénétration de la nouvelle construction résidentielle**

⇨ ***Le développement de ces trois marchés est essentiel à l'atteinte des objectifs visés***

DÉVELOPPEMENT RÉSIDENTIEL

RESSOURCES REQUISES

	000 $
• **Main-d'œuvre et support à la vente**	
➤ **Main d'œuvre additionnelle (10 postes)**	**685**
➤ **Dépenses diverses reliées à la main d'œuvre**	**65**
➤ **Achat de banques de données, formation de partenaires, etc.**	**150**
• **Communication, publicité, support promotionnel des promoteurs**	**1 000**
Total	**1 900**

⇨ ***Le montant de 1,9 million $ est déjà inclus dans le dossier tarifaire***

DÉVELOPPEMENT RÉSIDENTIEL

DEMANDE SPÉCIFIQUE

- **Tarif résidentiel spécifique aux projets de nouvelle construction résidentielle qui incorpore la contribution additionnelle tarifaire requise du consommateur**

REPONSE DE SCGM À UNE DEMANDE D'INFORMATION

Origine : Audience du 23 octobre 1998
Demandeur : Régie de l'énergie

Engagement 3

Demande :

Fournir le détail du budget requis pour le positionnement grand public de 435 000 $ inclus au budget spécial résidentiel.

Réponse

Détail du budget positionnement grand public

	000 $
➢ Commandites d'émissions de télévision, spécialisées dans la rénovation et la construction résidentielle, de façon à faire valoir les avantages du gaz naturel, la simplicité d'installation des différents équipements, etc. (Habitaction, Complètement Marteau, etc.)	280,0
➢ Promotion, via des envois ciblés (90 000), des offres commerciales pour la clientèle potentielle sur réseau (densification) : • production et impression de 12 brochures avec enveloppes et papier en-tête; • fusion, adressage et manutention des brochures; • mise à la poste; • relances.	155,0
Total	**435,0**

REPONSE DE SCGM À UNE DEMANDE D'INFORMATION

Origine : Audience du 23 octobre 1998
Demandeur : Régie de l'énergie

Engagement 5

Demande :

Fournir les instructions transmises, si écrites, au promoteur pour lui permettre d'expliquer la surprime chargée par l'application de l'article 3.5 des tarifs.

Réponse

Aucune documentation spécifique n'existe pour expliquer aux promoteurs l'application de l'article 3.5 des tarifs. Toute l'information requise de la part du promoteur apparaît au contrat de vente de gaz naturel (ci-joint) que ce dernier doit faire signer au client acheteur au moment de la transaction. C'est justement cet élément que nous voudrions modifier en remplaçant l'application de l'article 3.5 par un tarif spécifique pour les projets de développement résidentiel et qui n'impliquerait plus le promoteur.

CONTRAT DE VENTE DE GAZ NATUREL
PROJET DOMICILIAIRE -_____

ENTRE: **SOCIÉTÉ EN COMMANDITE GAZ MÉTROPOLITAIN**, agissant par son associée commanditée Gaz Métropolitain inc. ayant sa principale place d'affaires au 1717, rue du Havre, Montréal, (Québec), H2K 2X3
(«Société»)

ET: Nom du Client: _____
Adresse: _____
(«Client»)

1. VENTE DE GAZ NATUREL

La Société s'engage à vendre au Client, et ce dernier s'engage à acheter de la Société du gaz naturel pour tous ses besoins en chauffage et eau chaude domestique pour l'immeuble sis à l'adresse du Client mentionnée ci-dessus ("adresse de service") pour une période de 5 ans et ce, à compter du _____;

2. CONDITIONS DE VENTE

Le prix de vente de gaz naturel applicable aux volumes retirés à l'adresse de service, est celui du tarif général adopté par la Régie du gaz naturel et modifié de temps à autre en fonction des décisions rendues par cette dernière. Cependant, considérant que le présent contrat constitue un nouveau contrat conclu avec un nouveau client, le prix de transport et de distribution du gaz naturel sera fixe pour une période de 5 ans débutant à la date mentionnée à la clause 1 ci-dessus;

3. Considérant l'investissement fait par la Société pour la mise en place des infrastructures gazières, le Client s'engage à payer à la Société en plus du prix de vente prévu ci-dessus, la somme mentionnée ci-après:

Option A ☐ Une somme de 1 553 $ payable par chèque à la Société, à la signature de la présente entente;
Option B ☐ 33,00$/mois pour une période de cinq (5) ans à compter de l'entrée en vigueur du présent contrat.

Les montants dus par le Client en vertu de l'options B seront facturés au Client à même sa facturation mensuelle de consommation de gaz naturel;

4. Le Client pourra, à son choix, bénéficier d'un mode de paiement égaux pour sa facturation de gaz selon les modalités établies par la Société;

5. Lors de la vente de la propriété sise à l'adresse de service, le Client s'engage à faire assumer par l'acquéreur de la propriété l'obligation mentionnée ci-dessus à la clause 3 ou de rembourser immédiatement à la Société le solde impayé de son obligation;

6. Tout montant impayé à la date d'échéance indiquée sur la facture, se verra appliquer le supplément de recouvrement prévu aux Tarifs;

7. Le présent contrat ne lie la Société que lorsqu'il aura été signé par le représentant dûment autorisé de la Société à l'endroit indiqué ci-dessous.

Signé à _____ Signé à _____
ce ____e de _____ 199____ ce ____e de _____199___

SOCIÉTÉ EN COMMANDITE GAZ MÉTROPOLITAIN
par son associée commanditée
Gaz Métropolitain, Inc.

CLIENT:

Par:_____ Par:_____

Nom:_____ Nom:_____

Titre:_____ Titre:_____

REPONSE DE SCGM À UNE DEMANDE D'INFORMATION

Origine : Audience du 23 octobre 1998
Demandeur : Régie de l'énergie

Engagement 6

Demande :

Suite à la campagne du verglas, donner le nombre de clients qui ont exprimé leur intérêt au gaz naturel et combien ont converti (ou sont en processus de conversion) par source d'énergie déplacée.

Réponse

Suite aux événements de la crise du verglas, la Société a reçu un grande nombre d'appels de la clientèle existante pour connaître la possibilité d'obtenir un équipement de chauffage d'appoint au gaz naturel ou pour savoir comment faire fonctionner leur système de chauffage sans apport d'électricité. D'autre part, nous avons reçu plusieurs demandes de renseignements de clients potentiels pour raccorder leur maison au réseau gazier. Le tableau ci-dessous présente l'augmentation de la demande de renseignements à nos différents points de contact avec la clientèle.

Segment résidentiel

Évaluation de la demande de renseignements entre la période de janvier à mai 1997 et de celle de janvier à mai 1998

Point de contact	Nombre d'appels/jour Moyenne janv. à mai 97	Nombre appels/jour Moyenne janv. à mai 98	% d'augmentation
Centre d'appareils	111	200	80,1 %
Centre accrédité OptionGaz	148	301	102,7 %
Service à la clientèle	677	773	14,2 %

Il ne nous est pas possible d'identifier pour le moment le nombre d'appels reçus par source d'énergie.

REPONSE DE SCGM À UNE DEMANDE D'INFORMATION

Origine : Audience du 23 octobre 1998
Demandeur : Régie de l'énergie

Engagement 6

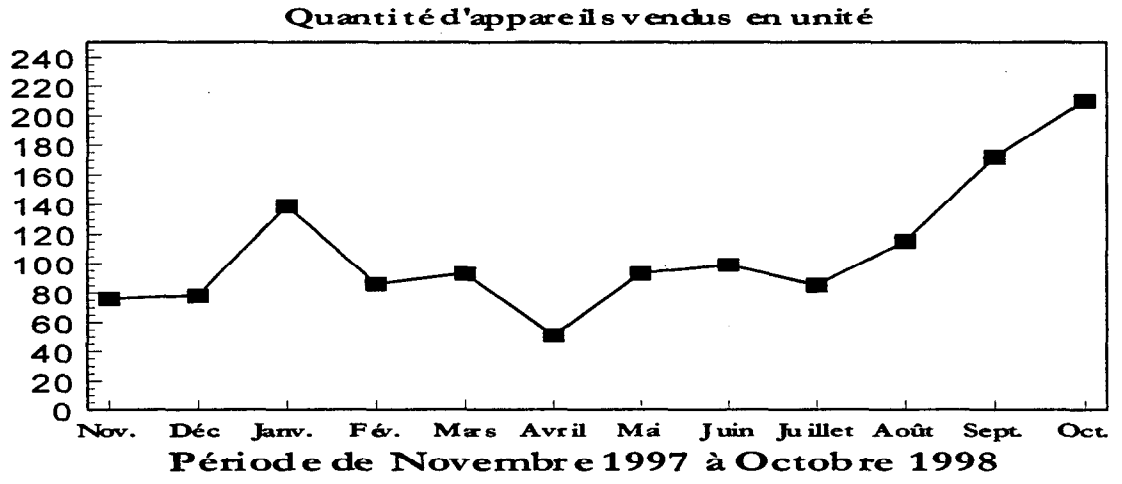
Demande :

Suite à la campagne du verglas, donner le nombre de clients qui ont exprimé leur intérêt au gaz naturel et combien ont converti (ou sont en processus de conversion) par source d'énergie déplacée.

Réponse

Le tableau ci-dessous présente les ventes mensuelles d'équipements toutes catégories du centre accrédité OptionGaz de novembre 1997 à octobre 1998.

VENTE D'APPAREILS PAR OTIONGAZ



Les nouveaux produits résidentiels étant disponibles dans le marché depuis seulement quelques semaines, nous ne sommes pas en mesure, pour le moment, de fournir à la Régie les statistiques reliées à la conversion des équipements selon les différentes sources d'énergie.

REPONSE DE SCGM À UNE DEMANDE D'INFORMATION

Origine : Audience du 23 octobre 1998
Demandeur : Régie de l'énergie

Engagement 7

Demande :

Refaire la pièce SCGM3-doc. 3.5a) avec un prix de la marchandise de 2,65 $/GJ.

Réponse

A	B	C	D	E
Consommation type m^3	Facture gaz naturel	Facture électrique ($)	Facture électrique (C ÷ A) (cents/m^3)	Facture électrique TD équivalent (D – marchandise gaz 10,04 cents/m^3) (cents/m^3)
1 500	685	741	49,431	39,4
2 000	871	997	49,870	39,8
2 500	1 051	1 253	50,134	40,1
3 000	1 228	1 512	50,397	40,4
3 500	1 405	1 770	50,573	40,5
4 000	1 580	2 030	50,748	40,7
4 500	1 754	2 288	50,836	40,8
5 000	1 927	2 542	50,836	40,8

REPONSE DE SCGM À UNE DEMANDE D'INFORMATION

Origine : Audience du 23 octobre 1998
Demandeur : Régie de l'énergie

Engagement 19

Demande :

Fournir les hypothèses retenues quant à l'implication de Hydro-Québec dans le secteur du résidentiel qui ont servi à établir nos propres prévisions de retrait dans le secteur résidentiel.

Réponse

Les prévisions de SCGM à l'égard des retraits dans le secteur résidentiel sont établies à partir de scénarios propres à la Société. Aucune hypothèse spécifique n'est faite à l'égard de l'implication d'Hydro-Québec dans le secteur résidentiel, c'est-à-dire que nous présumons que la présence de cette dernière dans le résidentiel va demeurer la même.

REPONSE DE SCGM À UNE DEMANDE D'INFORMATION

Origine : Audience du 23 octobre 1998
Demandeur : Régie de l'énergie

Engagement 4

Demande :

Quantifier l'impact sur la facture résidentielle de la hausse du prix du gaz naturel de 2,10$/GJ à 2,65$/GJ.

Réponse

COMPARATIF DES COÛTS D'OPÉRATION POUR LE CHAUFFAGE ET L'EAU SANITAIRE CONSOMMATIONS ANNUELLES						
Scénario avec tarif de 1998						
Consommation type (m^3)	Transport et distribution (cents/m^3)	Marchandise gaz (cents/m^3) (à 2,65 $/GJ)	Marchandise gaz (cents/m^3) (à 2,10 $/GJ)	Facture totale 2,65 $/GJ ($)	Facture totale 2,10 $/GJ ($)	Impact annuel de 2,10 $ à 2,65 $/GJ ($)
2 500	32,00	10,04	7,95	1 051	999	52
3000	30,90	10,04	7,95	1 228	1 166	63
3 500	30,09	10,04	7,95	1 405	1 331	73
4 000	29,46	10,04	7,95	1 580	1 496	84
Scénario avec tarif de 1999 proposé						
2 500	32,45	10,04	7,95	1 062	1 010	52
3 000	31,33	10,04	7,95	1 241	1 178	63
3 500	30,51	10,04	7,95	1 419	1 346	73
4 000	29,87	10,04	7,95	1 596	1 513	83

L'impact de la hausse du prix de la marchandise de 2,10 $ à 2,65 $ le GJ se chiffre à environ 52$ par année pour une résidence type consommant annuellement 2 500 m^3 par année pour ses besoins de chauffage et d'eau chaude sanitaire.

EFFICACITÉ ÉNERGÉTIQUE

Présentation à la
Régie de l'Énergie

Témoin: Michel L. Roy

EFFICACITÉ ÉNERGÉTIQUE

PLAN DE PRÉSENTATION

EFFICACITÉ ÉNERGÉTIQUE

CONTEXTE

Gaz Métropolitain:

- **Appuie depuis longtemps l'idée de travailler à améliorer l'efficacité énergétique**
- **Voit l'efficacité énergétique à trois volets:**
  - ➤ **L'économie d'énergie**
  - ➤ **L'efficacité des équipements**
  - ➤ **L'efficacité économique**

EFFICACITÉ ÉNERGÉTIQUE

CONTEXTE

- **A mis en place plusieurs mesures au cours des dix dernières années, visant les trois volets:**
  - ➤ **Documents d'information**
  - ➤ **Développement et assistance technologique (DATECH)**
  - ➤ **R&D et CTGN**
  - ➤ **Programme d 'aide à la réalisation d'études énergétiques (PAIRE)**
  - ➤ **Programme de rétention par rabais à la consommation (PRRC)**
  - ➤ **Programme DuoGaz**
  - ➤ **Programme PréGaz**
  - ➤ **Etc.**

EFFICACITÉ ÉNERGÉTIQUE

ÉCONOMIQUE POUR LE DISTRIBUTEUR

- **Situation particulière de SCGM:**
  - ➤ **Coûts marginaux < coûts moyens**
- **Aucun programme d'efficacité énergétique n'est donc rentable sur la seule base des coûts évités**
- **Certains programmes d'efficacité énergétique rentables pour les clients pourront être supportés par SCGM pour d'autres considérations tels:**
  - ➤ **Maintien de la clientèle**
  - ➤ **Ajout de charge chez la clientèle**
  - ➤ **Raccordement de nouveaux clients**

EFFICACITÉ ÉNERGÉTIQUE

STATUT DU DOSSIER

- **Dépôt à la Régie de notre vision (préliminaire) quant à l'efficacité énergétique**
- **Lancement d'un programme d'efficacité énergétique visant à réduire la consommation de la clientèle résidentielle (PréGaz)**
- **Nécessité de discussions avec la Régie et les intervenants sur le plan de ressources à venir**
- **Finalisation et dépôt du plan global en efficacité énergétique à la lumière du plan de ressources**
- **Lancement d'autres programmes d'efficacité énergétique pour d'autres secteurs de marché**

EFFICACITÉ ÉNERGÉTIQUE

RESSOURCES PUBLIQUES

	000 $
• Formation, publicité et promotion des outils	140
• Frais administratifs:	
➤ Études et suivi	300
➤ Main d'œuvre	170
	610