QUARTERLY FOCUS

1998 NATURAL GAS IMPORT/EXPORT TRADE: A SECOND LOOK

The Focus feature that was included in the fourth quarter 1998 *Quarterly Report of Natural Gas Imports and Exports* ("*Report*") provided an overview of natural gas import/export activity for calendar 1998. This Focus feature, like the ones found in the *Report* issued in the first quarter of the past two years, provides additional information on the North American natural gas trade for the preceding year. Specifically, this Focus provides more volume and price information on our natural gas import trade with Canada; reviews volume and price trends with respect to natural gas exports to Mexico; looks at gas marketing developments in California and New England, two important regional markets for imported gas; examines recent developments with regard to Canadian gas imports under long-term contracts, and identifies the major importers and exporters transacting cross-border sales between the United States, Canada and Mexico.

1998 Natural Gas Trade with Canada

Canadian natural gas imports continue to be an increasingly important supplemental source of natural gas to the markets in the United States. Import volumes from Canada over the past thirteen years have increased by more than three-fold. **Figures 1 and 2** on the next two pages illustrate the significant growth over the past thirteen years (1986-1998) in Canadian gas exports to the United States and the growing importance of this trade to Canadian producers in terms of expanded markets and revenues generated from this cross-border trade.

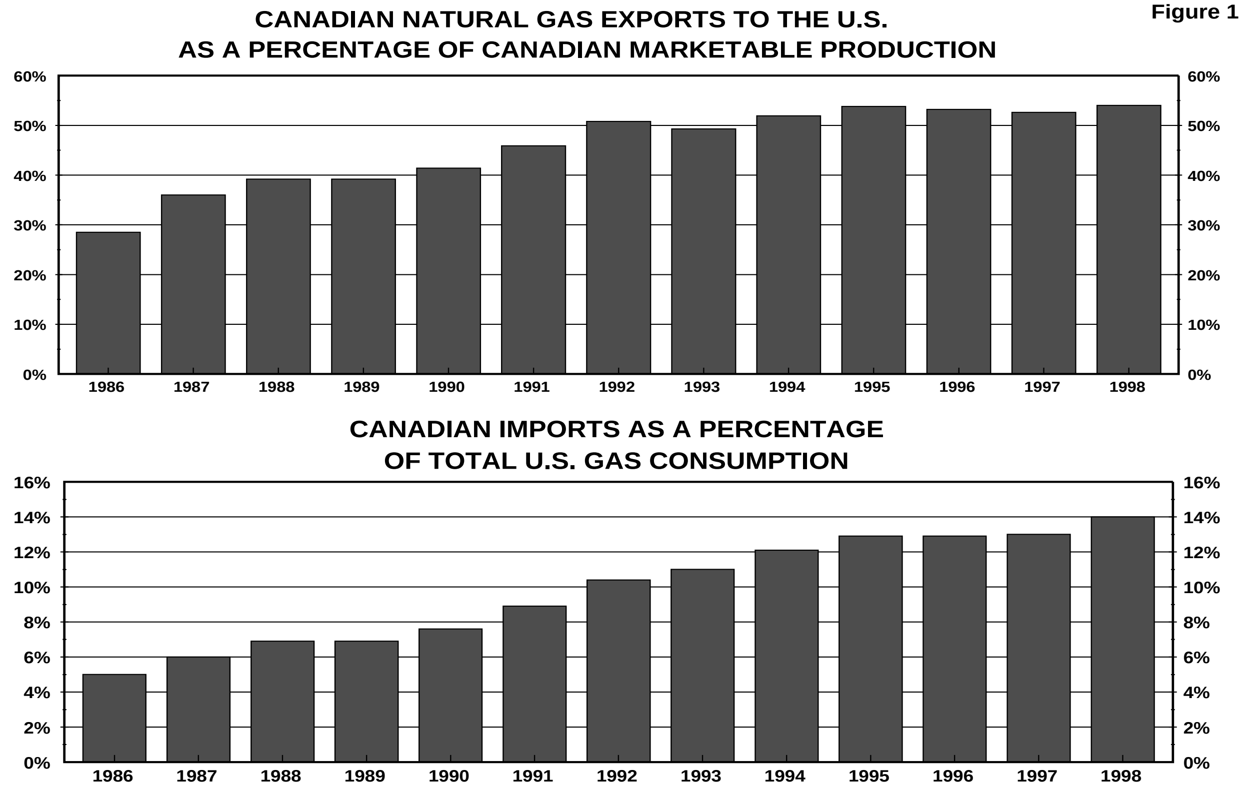
In **Figure 1**, the first bar chart shows Canadian gas exports to the U.S. as a percentage of its total marketable gas production. In 1998, Canadian natural gas exports represented 54 percent of the producers' total marketable production. In addition, it is estimated that these export sales represented over 59 percent of the Canadian gas producers' revenue stream as the average price of gas exports was somewhat higher than domestic gas sales. It seems likely that Canadian gas exports as a percentage of total marketable gas production could reach 60 percent over the next few years because gas markets in the U.S. are forecasted to grow at a faster rate than its domestic market. The second bar chart in **Figure 1** illustrates the growth in U.S. market shares for Canadian gas imports. As shown, Canadian natural gas imports as a percentage of total domestic gas demand has grown from 4.6 percent in 1986 to an estimated 14 percent in 1998.

Both of the indicators shown in the two bar charts included in **Figure 1** should continue their upward trend in the foreseeable future as recent projections by virtually all forecasters, including Natural Resources Canada (NRC) and the Energy Information Administration (EIA), show continuing growth in Canadian gas sales to the United States. The NRC's April 1999 annual report, titled *Canadian Natural Gas: Review of 1998 & Outlook to 2005 (Review & Outlook)*, forecasts that Canadian gas exports to the United States likely will reach 3.9 trillion cubic feet (Tcf) by the year 2005. The EIA, on the other hand, projects in its reference case forecast that Canadian natural gas imports will grow to 3.47 Tcf by 2005 and 4.91 Tcf by 2020 [*Annual Energy Outlook 1999,* DOE/EIA-0383(99), December 1998]. EIA's forecast assumes an annual growth rate in Canadian gas imports of 2.4% from 1997 to 2020 and an annual demand growth rate of 1.7% during the same time period.

Shown in **Figure 2** is the estimated annual revenues derived from exporting natural gas from Canada to the United States over the past thirteen years (1986-1998). In 1998, FE estimates that Canadian gas exports to the United States generated just over $5.8 billion in revenues, down slightly from last year's historic high of $6.1 billion. The drop in export revenues is the direct result of lower natural gas export prices in 1998 than in 1997. The average international border price for Canadian gas exports in 1998 was $1.91 per million British thermal units (MMBtu), compared with $2.11 per MMBtu the preceding year. Although Canadian gas exports increased by 5 percent over the 1997 level, the 9 percent decline in the average price for gas exports resulted in lowering the annual revenues generated from this trade. Although total gas export revenues, in U.S. dollars, declined to $5.8 billion in 1998, the overall returns (in Canadian dollars) to Canadian gas producers increased slightly in their combined domestic and export markets. This was due to a price increase for domestic gas sales and the fact that export sales are transacted in U.S. dollars, and the monetary exchange rate in 1998 showed a strengthening of the U.S. dollar vis-a-vis the Canadian dollar. The value of the U.S. dollar increased 7 percent, with the Canadian dollar averaging less than $0.70 (U.S.) for the year [NRC's *Review & Outlook*, pp. ii, 17].

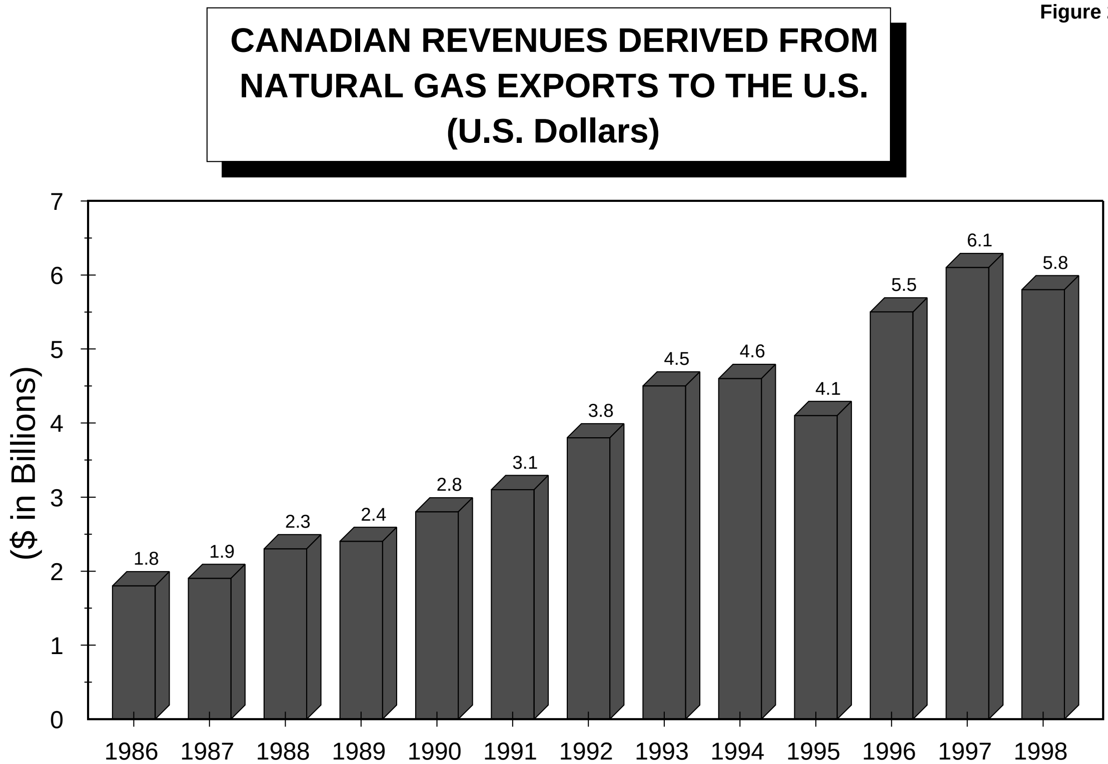
The drop in the average price for Canadian gas exports during 1998 was consistent with what occurred in the entire industry during the year. The EIA has reported that the average domestic wellhead price for natural gas in 1998 was $1.92 per MMBtu, which was $0.34, or 15 percent less than in 1997 [*Natural Gas 1998 Issues and Trends*, DOE/EIA-0560(98), June 1999, p. 5]. As a consequence, there has been a convergence in the average prices for domestic supplies compared with those coming from Canada as both were virtually the same in 1998. In 1997, the EIA estimated that the average Canadian gas export price was about 7 percent lower than domestic supplies [*Id.*, p. 13]. During 1998, 108 companies imported Canadian natural gas under short-term authorizations, and 105 companies used 242 gas purchase contracts to import volumes under long-term arrangements. These importers brought into the United States a record volume of 3,053 billion cubic feet (Bcf) of natural gas during the year. This represented an increase of 154 Bcf, or 5.3 percent over the 1997 total of 2,899 Bcf. Canadian natural gas exports to the United States have increased every year over the past twelve years (1986 - 1998). However, the rate of growth in 1998 was the highest since 1995, when imports grew 10.6 percent from the previous year. The growth in Canadian gas exports in 1998 is quite remarkable given the pipeline capacity constraints, the increased competition from oil caused by the huge drop in oil prices, and the 3 percent decline in U.S. gas consumption compared with the 1997 level.

Figure 1



Sources: Statistics Canada, Natural Resources Canada, company filings with FE.

Figure 2



Sources: 1992 - 1998 estimates derived from company filings with FE; 1986 - 1991 estimates from *Natural Gas Monthly,* [DOE/EIA - 0130 (97/08), table SR7, page XIV].

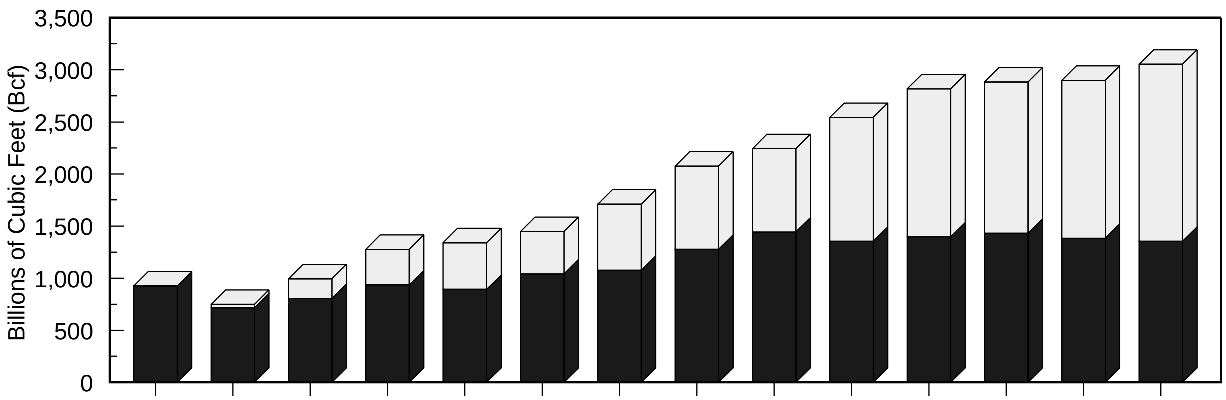
With regard to U.S. natural gas exports to Canada during 1998, there were a total of 16 firms making sales of 45.3 Bcf of natural gas to Canada at an average price of $2.17 per MMBtu. Exports to Canada in 1998 decreased by 7 percent over the 1997 level of 59.1 Bcf. All of the natural gas export transactions were accomplished under the Department of Energy's (DOE) two-year "blanket" export authorizations (for gas sales contracts of two years or less). Like previous years, most of the natural gas exports to Canada occurred at the Michigan exit points of Detroit (24.9 Bcf) and St. Clair (11.4 Bcf). These two exit points accounted for 80 percent of all natural gas exports to Canada during the year. [The 1998 natural gas exports of 45.3 Bcf reflect exports to Canada on an equity (sales) basis rather than on a custody (physical movements) basis; total gas exports on a **custody only basis** equaled 40 Bcf for the year.]

As stated earlier, the weighted average international border price of Canadian natural gas imported into the United States during 1998 was $1.91 per MMBtu. This represented a decrease of 9 percent over last year's average price of $2.11 per MMBtu. Under DOE's two-year "blanket" import authorizations (for gas purchase contracts of 2 years or less), the average border price of gas supplies imported from Canada in 1998 was $1.74 per MMBtu. This price represented a drop of over 5 percent from last year's average price of $1.84 per MMBtu for short-term Canadian imports. Under DOE's long-term import authorizations (for gas purchase contracts longer than two years), the average border price was $2.14 per MMBtu, or a decline of 11 percent from last year's average price of $2.40 per MMBtu. For the purposes of comparison, the estimated average domestic wellhead price for marketable production in 1998 was $1.96 per thousand cubic feet [*Natural Gas Monthly*, DOE/EIA-0130, May 1999, Table 4 (p. 12)], and the average NYMEX futures price for natural gas in 1998 was $2.16 per MMBtu. Therefore, the average NYMEX futures price in 1998 was $0.25 per MMBtu or 13 percent higher than the average price of $1.91 per MMBtu for Canadian gas supplies.

Of the 3,053 Bcf of Canadian gas imported in 1998, 55.7 percent (1,699 Bcf) was imported under DOE's short-term import authority, while 44.3 percent (1,354 Bcf) was imported under its long-term authority. 1998 represented the fourth straight year in which more Canadian natural gas was imported under DOE's short-term import authorizations than under its long-term import authorizations. The drop in long-term imports in 1998 may be attributed to the termination of 14 long-term gas supply contracts used to fuel cogeneration facilities in the Mid-Atlantic states (see Table 2) and the dropping of Canadian gas purchases by Southern California Edison due to its sale of its gas-fired power plants. Comparing 1998 Canadian imports with 1997 imports by type of DOE authorization used, volumes imported under short-term arrangements showed a robust 12.5 percent increase, while imports under long-term arrangements fell by 2.5 percent. **Figure 3** below illustrates the steady growth in the use of short-term import authorizations over the past 14 years (1985-1998). Although the general trend of short-term import sales replacing long-term import sales is likely to continue in 1999, this trend may be less pronounced during the next couple of years with the completion of several new pipelines. The financing of major pipeline projects usually results in long-term transportation commitments and these, in turn, usually have underlying long-term gas purchase arrangements.

Figure 3

CANADIAN NATURAL GAS IMPORTS BY TYPE OF IMPORT AUTHORIZATION
1985 - 1998



	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998
Long-Term Imports* ■	923	716	805	935	893	1,041	1,076	1,278	1,443	1,355	1,396	1,432	1,389	1,354
Short-Term Imports** □	3	33	188	341	446	407	634	798	801	1,189	1,420	1,451	1,510	1,699
TOTAL IMPORTS	926	749	993	1,276	1,339	1,448	1,710	2,076	2,244	2,544	2,816	2,883	2,899	3,053
Short-Term Imports as a % of Total Imports	***0.3***	***4.4***	***18.9***	***26.7***	***33.3***	***28.1***	***37.1***	***38.4***	***35.7***	***46.7***	***50.4***	***50.3***	***52.1***	***55.7***

* Imports made under gas purchase contracts longer than 2 years.
** Imports made under gas purchase contracts which are 2 years or less.

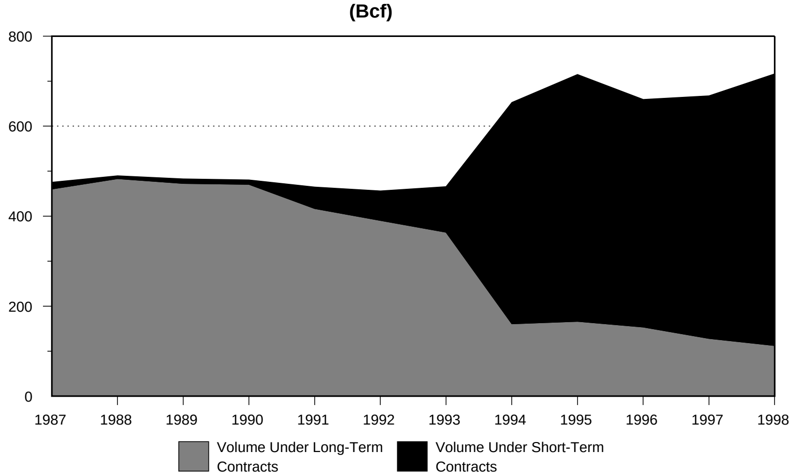
Canadian Gas Marketed in California

Figure 4 shows the volume of Canadian natural gas marketed in California under both short-term and long-term contracts during the past 12 years (1987 - 1998). As shown in **Figure 4**, most Canadian gas sales to California consumers prior to 1993 were transacted under long-term supply contracts; however, beginning in 1994 and in every subsequent year, the great majority of Canadian gas volumes now marketed in the California market are now done under short-term supply arrangements (contracts of 2 years or less). During 1998, a total of 721.4 billion cubic feet (Bcf) of Canadian natural gas was marketed in California. This represents an increase of 47.6 Bcf , or a 7 percent increase over the 1997 level of 673.8 Bcf. Approximately 83.7 percent of the Canadian volumes marketed in California were under short-term gas supply contracts.

The average international border price of these short-term supplies in 1998 remained almost the same as last year's price ($1.57 v. $1.55 per MMBtu). The remaining Canadian gas volumes (16.3 percent) were marketed under long-term contracts at an average international border price of $1.39 per MMBtu; this compares with the 1997 price of $1.78, or a price reduction of almost 22 percent. The large price decline for Canadian long-term gas supplies is directly attributed to a 24 percent decline in the price of Canadian gas imported by the largest long-term importer, Pan-Alberta Gas (U.S.) Inc. (successor to Northwest Alaskan Pipeline Company). During 1998, this company's share of the long-term import market in California was almost 72 percent and the average price of its Canadian gas supplies dropped from $1.69 to $1.29 per MMBtu. Based on preliminary figures published by the Energy Information Administration (EIA) in its *Natural Gas Monthly*[DOE/EIA-130 (May 1999), Tables 15-19], total natural gas deliveries to California in 1998 increased by 19.8 Bcf, or 1.1 percent from the 1997 level (1,870.1 v. 1,850.3 Bcf). EIA's preliminary demand breakdown by sector shows that gas consumption grew substantially in the residential and commercial sectors, but this growth was largely offset by declines in gas use in the industrial and electric utilities sectors. The overall modest growth in gas demand during 1998 is consistent with the supply and demand forecasts found in the *1998 California Gas Report* (*1998 Report*) . The *1998 Report*, which is the most current in a series of biennial reports prepared by the California gas and electric utilities in accordance with a directive issued by the California Public Utilities Commission, forecasts that natural gas demand will grow at an annual rate of 1.0 percent from 1998 to 2015. The *1998 Report* estimates that gas use will grow in all sectors, except for the Enhanced Oil Recovery market, which is expected to decline by 2.7 percent per year through the forecast period. In addition, the *1998 Report* also states that the highest potential for growth in gas demand are with the natural gas vehicle market and the electric generation sector.

Figure 4

CANADIAN NATURAL GAS EXPORTS TO CALIFORNIA UNDER LONG-TERM AND SHORT-TERM CONTRACTS OVER THE PAST ELEVEN YEARS: 1987 - 1998 (Bcf)

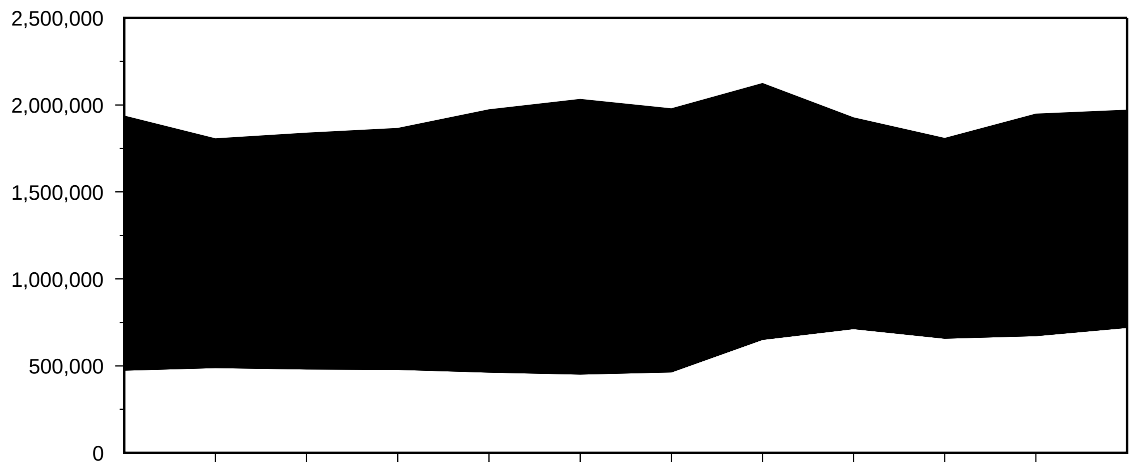


Notes: Long-term contracts are defined as supply contracts which are over two years in length and short-term contracts are defined as supply contracts which are two years or less in duration. The data are from filings submitted by natural gas importers to the Office of Fossil Energy.

Figure 5 shows Canadian natural gas marketed in California as a percentage of total gas consumption for the State during the past twelve years (1987 - 1998). This figure merely displays the annual market shares for Canadian gas in California during this time period. With the advent of a more competitive marketplace and improved pipeline infrastructure for transporting Canadian gas to California, the market share for Canadian gas has grown by 10 percent, increasing from 24.6 percent in 1987 to 36.6 percent in 1998. Similar to almost all other regions in the country, the price of Canadian gas supplies sold in the California market declined in 1998, compared with 1997 prices. The average international border price of Canadian gas supplies delivered to California declined from $1.59 per MMBtu in 1997 to $1.54 per MMBtu in 1998, resulting in the capture of a larger portion of the California gas market. Although overall gas demand in the State grew only 1.1 percent, Canadian gas sales to the State grew by 7.1 percent.

Figure 5

CANADIAN NATURAL GAS MARKETED IN CALIFORNIA AS A PERCENTAGE OF TOTAL STATE GAS CONSUMPTION (MMCF)



	1987	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998
Canadian Gas Supplies to CA	475,449	489,807	482,935	480,493	464,676	452,642	465,561	652,628	714,695	659,435	673,804	721,411
Total Gas Consumption	1,934,909	1,804,452	1,837,831	1,864,057	1,970,709	2,030,564	1,976,397	2,123,310	1,925,110	1,807,314	1,946,945	1,968,881
% Share of the CA Market	**24.6**	**27.1**	**26.3**	**25.8**	**23.6**	**22.3**	**23.6**	**30.7**	**37.1**	**36.5**	**34.6**	**36.6**

Sources: Consumption data for 1987 thru 1997 obtained from the ***Natural Gas Annual*** (DOE/EIA-0131); 1998 consumption figure is an FE estimate based on preliminary EIA data. Canadian natural gas supplies marketed in California are from reports filed by importers with FE.

Natural Gas Imports Into New England

Historically, natural gas use in New England played a relatively minor role in meeting the region's energy supply needs due to the region's geographical location at the end of the domestic interstate natural gas transmission system. However, an improved and expanded gas pipeline infrastructure, particularly to allow Canadian gas to serve the area, has resulted in a dramatic increase in the use of gas in the region over the past decade. Over the past ten years (1988 - 1997), natural gas consumption in New England has grown by 283.8 Bcf, or nearly 81 percent (351.6 v. 635.4 Bcf). In comparison, natural gas consumption for the entire country grew by only 21.5 percent during the same time period. In 1998, however, gas consumption in New England is estimated to have declined to 565.1 Bcf, falling just over 70 Bcf from last year's impressive high. All end-use sectors (industrial, commercial, residential, and electric utilities) recorded drops in gas usage this year. Contributing to this year's lower level of consumption were the above normal temperatures during the heating season and the drop in oil prices, which, in turn, resulted in some fuel switching in the industrial and electric utility sectors. Despite this year's drop in volumes, the New England gas market continues to be one of the most active markets in the country, and, based on a series of recent projections, will most likely be so in the foreseeable future. The EIA forecasts a 2.5% annual growth in natural gas demand for New England through the year 2020; this compares with a projected annual growth rate of 1.7 percent for the entire country [*Annual Energy Outlook 1999*, DOE/EIA-0383(99), December 1998]. In another forecast, the Gas Research Institute (GRI) estimates that gas demand in New England will grow 3 percent annually through 2015. Under both the EIA and GRI forecasts, increased gas use for electricity generation is the principal force behind the increased demand. For example, EIA forecasts a 4.8 percent annual growth rate in gas use in the electricity sector from 1997 through 2020.

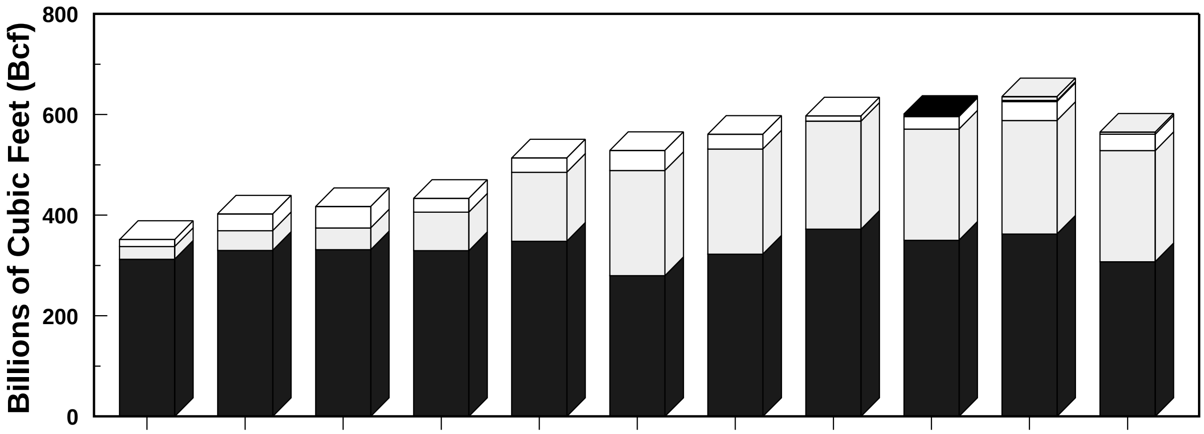
Several projects designed to enhance the infrastructure of this region currently are underway to meet this projected demand growth. The Portland Natural Gas Transmission System (PNGTS), completed earlier this year, commenced deliveries in early March. The PNGTS interconnects with the Trans Québec & Maritimes Pipeline on the international border near Pittsburg, New Hampshire, and from here, travels to Westbrook, Maine and other downstream facilities which will serve New England. Another major effort, the Maritimes & Northeast Pipeline Project, is scheduled to begin deliveries of natural gas in November 1999. This project will bring for the first time new gas supplies from the Sable Island Offshore Energy Project of Nova Scotia to new markets in eastern Canada and New England. In addition, the Atlantic LNG project commenced shipping LNG from a new liquefaction facility in Trinidad to the Distrigas facilities in Everett, Massachusetts. The first delivery of this supply occurred on May 6, 1999. According to the New England Gas Association (NEGA), these three projects will increase the region's infrastructure capability by over 30% [*Id*., p.7]. NEGA also states that there are new local distribution companies (LDCs) being formed, or existing LDCs expanded to meet new market demand in Maine, New Hampshire and Vermont.

During the past eleven years, natural gas imports have played a critical role in supplying New England's growing gas market. **Figure 6** on the next page shows that from 1988 to 1997, natural gas imports marketed in New England have increased by 233.7 Bcf (39.3 v. 273.0), or almost six-fold. Although gas consumption in 1998 fell an estimated 11% from the 1997 level, imports as a percentage of total consumption rose 2.6%. This increase was due to the fact that domestic supplies this year fell much more quickly than imports. In fact, the consumption of domestic supplies dropped 15.2% from the 1997 level, as compared to imports, which fell by only 5.6%. **Figure 6** also depicts the sources of natural gas marketed in new England from 1988 through 1998. The graph highlights the increased reliance of the region on imported gas supplies during this time period. Natural gas imports as a percentage of total regional gas consumption grew from 11.2% to 45.6%.

Figure 6

Sources of Natural Gas Marketed in New England

(1988 - 1998)



	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998
Domestic Supplies	312.3	329.9	331.4	329.6	348.2	279.8	322.6	372.2	350.0	362.4	307.5
Canadian Supplies	25.4	39.3	43.1	76.6	137.0	209.1	209.0	214.6	221.1	225.8	220.8
Algerian Supplies	13.9	33.0	42.5	27.1	28.5	39.6	29.1	10.5	25.0	37.6	32.7
U. Arab Emirates	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	4.4	2.4	0.0
Australian	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	7.2	4.1
TOTAL SUPPLIES	351.6	402.2	417.0	433.3	513.7	528.5	560.7	597.3	600.5	635.4	565.1

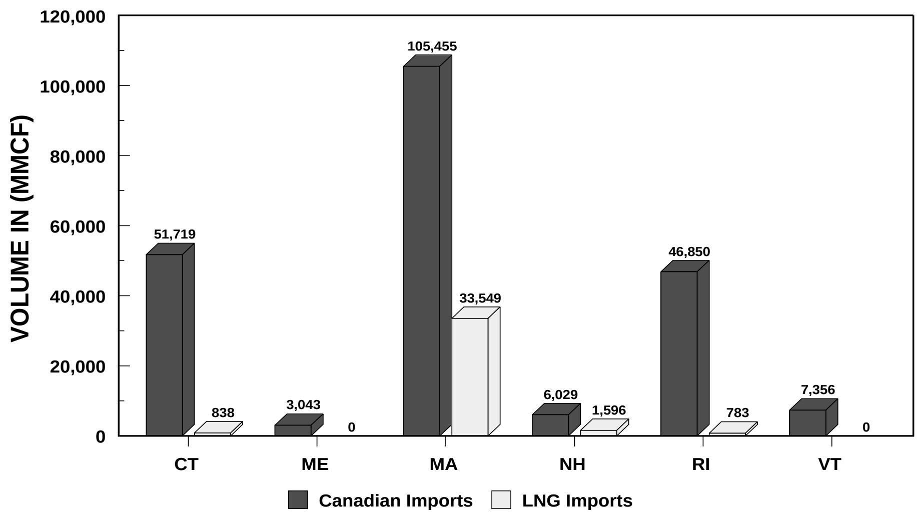
Imports as a % of Total Consumption	**11.2**	**18.0**	**20.5**	**23.9**	**32.2**	**47.1**	**42.5**	**37.7**	**41.7**	**43.0**	**45.6**

Sources: Natural gas consumption data from 1988 - 1997 came from EIA's *Natural Gas Annual* (DOE/EIA - 0131); 1998 consumption figure is an estimate from FE based on EIA data; Import data are derived from company filings made with FE.

Figure 7 shows the source and distribution of natural gas imports marketed during 1998 in the 6 states comprising New England. As shown, the bulk of the imports destined for sale in New England is sold in the state of Massachusetts. About 48 percent of the total Canadian gas import volumes and 91 percent of the LNG volumes imported from Algeria and Australia that are marketed in New England are sold in this state. In 1998, 88 percent of the volumes were imported under long-term arrangements and 12 percent were imported using short-term arrangements. The New England Region relies more heavily on long-term import arrangements than in any other region of the country.

Figure 7

NATURAL GAS IMPORTS SUPPLYING NEW ENGLAND - 1998

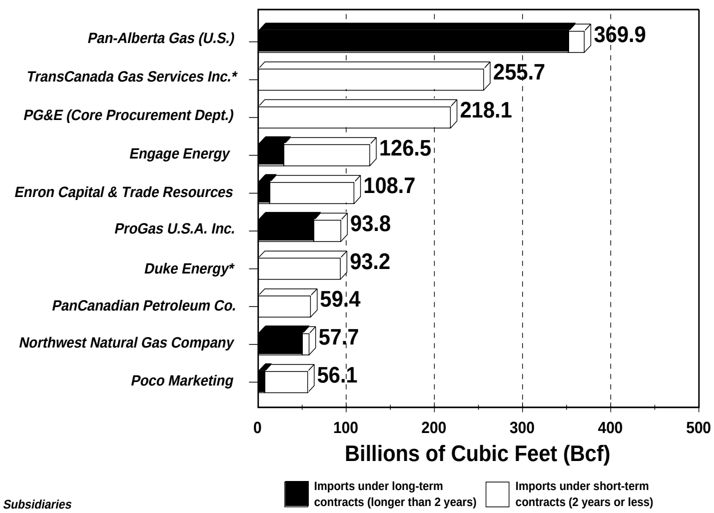


Source: Quarterly filings by natural gas importers to FE.
These figures represent sales rather than imports; therefore, data differs slightly from import total.

Figure 8 lists the top ten importers of Canadian natural gas for the year. These ten firms imported a total of 1,440.2 Bcf of natural gas, or over 47 percent of the total Canadian gas imported for the year. **Figure 8** also indicates whether the imports were made under short-term or long-term import authorizations. About 64 percent of the volumes imported by this group of importers was done under DOE's short-term import authority and 36 percent was under long-term import authority. Eight out of the top ten Canadian natural gas importers listed in 1998 were also among the top ten companies listed for 1997. This year's additions to the list include Poco Marketing Ltd. and Engage Energy. Engage Energy, the result of a marketing alliance between Coastal Gas Marketing and Westcoast Gas, replaced Coastal as the fourth largest importer this year. Among the top importers in 1998, there were only two end-users: a combined electric/gas utility and an LDC. The rest of the importers were marketers, producer affiliates, or gas aggregators.

Figure 8

TEN LARGEST IMPORTERS OF CANADIAN NATURAL GAS IN 1998

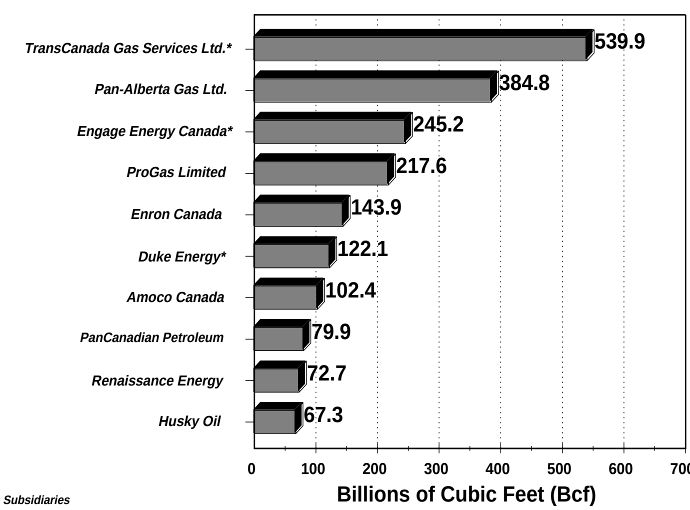


*Includes Subsidiaries

Figure 9 lists the ten largest suppliers of Canadian natural gas to the United States in 1998. The volumes supplied by each company include both short-term and long-term sales. Eight out of ten of these suppliers were also on the list of top gas suppliers for 1997. The two additional companies listed include Renaissance Energy, up from eleventh last year, and Husky Oil. As shown, most of the top suppliers of Canadian natural gas to the United States in 1998 were gas aggregators. The top ten suppliers of Canadian natural gas listed in **Figure 9** supplied almost 65 percent of all Canadian gas imports during 1998 (1975.8 Bcf).

Figure 9

TEN LARGEST SUPPLIERS OF CANADIAN NATURAL GAS IN 1998



*Includes Subsidiaries

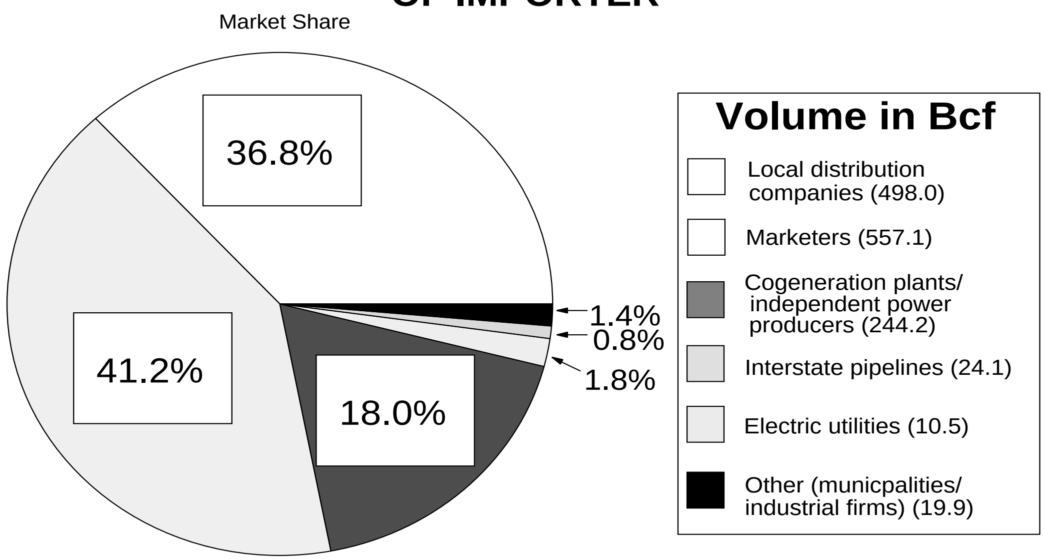
Long-Term Imports from Canada

As illustrated in **Figure 3** on page iv, the importation of Canadian natural gas under long-term contracts continues to diminish in importance vis-a-vis short-term, spot market purchases over the past 14 years (1985 - 1998). Natural gas imports from Canada under both long-term and short-term contracts have grown during this period; however, short-term imports have grown at a much faster rate, particularly during the past 5 years. For example, during the past four years (1994-1998), long-term imports have remained at virtually the same level, while short-term imports have grown by almost 43 percent (1,189 v. 1,699 Bcf). Although there has been a diminishment in importance for long-term imports over the past 14 years, we believe that these long-term import arrangements will continue to play an important role in overall gas trade with Canada in the foreseeable future.

Figure 10 shows what type of importer was purchasing Canadian natural gas under long-term supply contracts during 1998. Comparing 1998 imports with 1997, there was an overall decline of 2.5 percent (1,354 v. 1,389 Bcf). The figure indicates, by type of importer, the actual volumes imported and percentage of market share. Comparing 1998 with 1997, there were only two import categories which experienced growth in terms of volume imported and percentage of market share: the “municipalities/industrial firms” category increased by 55.5 percent (19.9 v. 12.8 Bcf) and the “marketers” category grew by 5.2 percent (557.1 v. 529.4 Bcf). The “interstate pipelines” category remained virtually the same as last year, but all other importer categories experienced declines. The following categories experienced reduced purchases of Canadian gas under long-term contracts in 1998: “local distribution companies” by 7.5 percent (498.0 v. 538.2 Bcf); “cogeneration plants/independent power producers” by 5.4 percent (244.2 v. 258.0 Bcf); and “electric utilities” by 60.5 percent (10.5 v. 26.6 Bcf). The large decline in gas imports by the “electric utilities” category was directly the result of the termination of four long-term contracts by Southern California Edison. As of June 1998, Southern California Edison had completed the sale of all 12 of its gas-fired power plants, thereby eliminating its need of gas import supplies.

Figure 10

1998 CANADIAN NATURAL GAS IMPORTS UNDER LONG-TERM IMPORT AUTHORIZATIONS BY TYPE OF IMPORTER



Total long-term imports: 1,354 Bcf

Notes:

Long-term Canadian gas imports totaled 1,354 Bcf in 1998. Imports by Northwest Alaskan Pipeline Company were included in the "marketers" category; imports by combined gas/electric utilities were included in the "local distribution companies" category.

Despite the general trend in the diminishing importance of long-term gas supply contracts in our gas import trade with Canada, these types of supply contracts continue to be negotiated and relied on by importers, particularly when new pipeline facilities are being built to facilitate new import volumes. **Table 1** lists eleven new long-term gas import arrangements which commenced operation during calendar 1998. As shown, all of these contracts became operational during the last two months of the year and all have a term of 10 years. The aggregate daily contract quantity under these eleven contracts totals 259.6 MMcf per day, or 94.7 Bcf per year. As shown**,** the vast majority of these arrangements (91%) were negotiated by marketers; and over 78 percent of the volumes are dedicated to gas markets in the Midwest, with the remaining volumes destined for Northeastern markets.

Table 1

NEW LONG-TERM CANADIAN GAS SUPPLY CONTRACTS WHICH WERE ACTIVATED DURING 1998

IMPORTER	START-UP DATE	DCQ* (MMcf)	TERM (Years)	POINT OF ENTRY	MARKET(S) SERVED
Engage Energy U.S.	11/01/98	30.5	10	Noyes, Minnesota	WI
Engage Energy U.S.	11/01/98	49.0	10	St. Clair, Michigan	MI
Engage Energy U.S.	11/01/98	25.0	10	Noyes, Minnesota	MI
Enron Capital & Trade	11/01/98	9.0	10	Niagara Falls, New York	NY/PA
Enron Capital & Trade	11/01/98	30.4	10	Noyes, Minnesota	MI
Enron Capital & Trade	12/22/98	42.0	10	Port of Morgan, Montana	IL/MN
ProGas U.S.A.	11/01/98	26.5	10	Noyes, Minnesota	MI
Renaissance Energy (US)	11/01/98	23.4	10	Niagara Falls, New York	NY
Rock-Tenn Company	11/01/98	2.2	10	Highgate Springs, Vermont	VT
U.S. Gypsum Company	11/01/98	13.6	10	Niagara Falls, New York	NY/MD/OH
Vermont Gas Systems	12/01/98	8.0	10	Highgate Springs, Vermont	VT
***** TOTAL**		**259.6**			

* Daily Contract Quantity

During 1998, the new long-term import contracts which became operational were more than offset by the termination of 17 long-term gas supply contracts, totaling 268 MMcf per day, or 97.8 Bcf per year. Fourteen of the gas supply contracts terminated were used to fuel cogeneration facilities. **Table 2** lists the gas supply contracts of cogeneration plants which were terminated, the location of the facility, the daily contract quantity in each of the gas purchase contracts, the Megawatt capacity of each of the cogeneration plants, and the name of the purchaser of power generated from each of these plants. Most of the terminated gas supply arrangements for these cogeneration units had terms in the range of 15 to 20 years. As indicated, all of these facilities were located in the State of New York and every sale of electrical output from these facilities went to the Niagara Mohawk Corporation. The combined daily gas quantity for all fourteen gas supply contracts totaled 201.7 MMcf, or 73.6 Bcf per year.

Table 2

Long-Term Gas Supply Contracts of Cogeneration Facilities Which Were Terminated in 1998

Name of Importer/Facility	Location of Plant	Daily Contract Quantity (MMcf)	Size of Facility (MWs)	Sale of Electrical Output
1. AG-Energy, L.P.	Ogdensburg, New York	17.5	79	Niagara Mohawk
2. Cogen Energy Technology	Castleton-on Hudson, New York	14.0	60	Niagara Mohawk
3. Encogen Four Partners	Buffalo, New York	15.6	62	Niagara Mohawk
4. Fulton Cogen	Fulton, New York	6.0	47.4	Niagara Mohawk
5. Indeck Energy Services of Oswego	Oswego, New York	12.3	50.4	Niagara Mohawk
6. Indeck-Yerkes Energy Services	Tonawanda, New York	12.3	53	Niagara Mohawk
7. Kamine/Besicorp Beaver Falls	Croghan, New York	16.1	79.9	Niagara Mohawk
8. Kamine/Besicorp Carthage	Carthage, New York	14.2	49.9	Niagara Mohawk
9. Kamine/Besicorp Natural Dam	Gouverneur, New York	12.5	58	Niagara Mohawk
10. Kamine/Besicorp South Glens Falls	South Glens Falls, New York	14.2	49.9	Niagara Mohawk
11. Kamine/Besicorp Syracuse	Geddes, New York	16.3	79.9	Niagara Mohawk
12. LG&E Westmoreland Rensselaer	Rensselaer, New York	18.0	79	Niagara Mohawk
13. Megan-Racine Associates	Canton, New York	11.7	49	Niagara Mohawk
14. Power City Partners, L.P.	Massena, New York	21.0	79	Niagara Mohawk
***** TOTALS**		**201.7**	**876.4**	

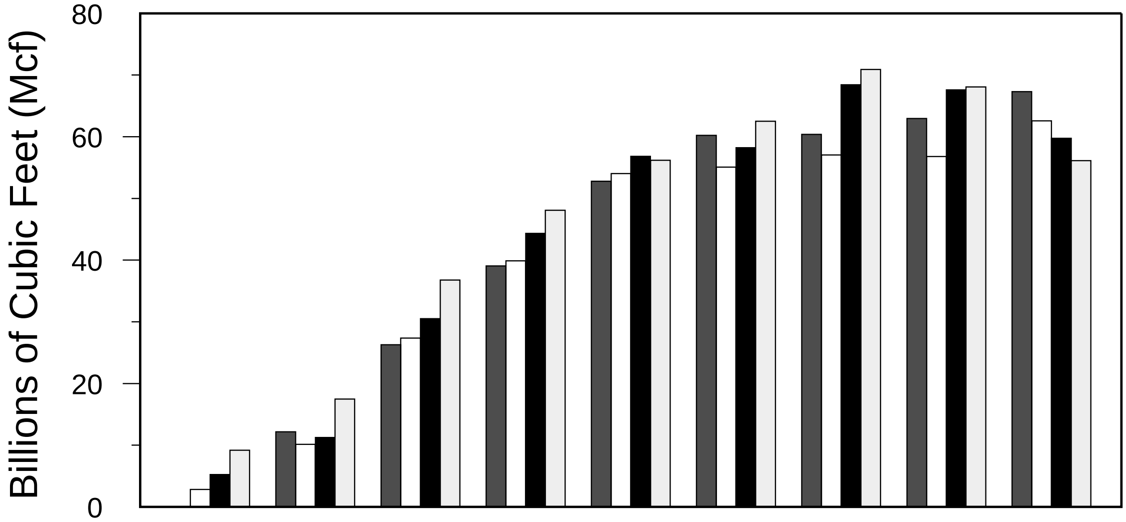
The termination of these gas supply contracts of cogeneration facilities is the direct result of the electric restructuring efforts by the State of New York over the past few years. New York, along with 17 other States, have taken actions to restructure their electric power industry. The electric restructuring measures adopted by New York were designed to make the production, transmission and sale of electricity more efficient and competitive. Much of the impetus behind State restructuring efforts was created by the actions taken by the Federal Energy Regulatory Commission (FERC) in its issuance of Orders 888 and 889 in 1996. These Orders were issued in order to be in compliance with provisions found in the Energy Policy Act of 1992 (EPACT). EPACT required the FERC to develop rules to remove impediments to competition in U.S. wholesale electricity trade. Orders 888 and 889 were designed to eliminate monopoly power over the transmission of electricity by (1) mandating public utilities to file open-access nondiscriminatory transmission rates; (2) developing a system which would create "real-time" information on prices and availability of capacity; and (3) separating generation from transmission functions.

When the cogeneration units listed in **Table 2** were built, Niagara Mohawk had exclusive rights to sell electricity in its market area and was permitted to pass along the costs of purchasing power to its customers in its rates. The 1978 Public Utilities Regulatory Policy Act (PURPA) required utilities to buy power from cogeneration and small independent power producers (IPPs) at their "avoided cost" regardless of the need for such power. Subsequently, much of the power generated by the cogeneration plants and independent power producers became expensive as electric utilities tried to become leaner and more efficient in controlling their costs, yet they were still required to take independently produced power under PURPA. In order to free themselves from these uncompetitive power sales agreements and in an effort to transition into a more competitive environment, some utilities in States undergoing electric restructuring have had to renegotiate their PURPA contracts by either reassigning the contract, or making buy out settlements. In turn, many of the cogeneration and IPP plants have had to take similar action with their gas suppliers, where possible, by canceling, settling, or reassigning gas supply contracts until new electricity sales agreements can be made. Niagara Mohawk, the purchaser of the electric power generated by the cogeneration facilities shown in **Table 2**, recognized that the power purchased from these facilities was above competitive-market levels, and therefore designed a master restructuring agreement to terminate or restructure most of its IPP contracts during the past two years. In exchange for the termination or restructuring of these power sales contracts, Niagara Mohawk agreed to give these cogeneration units, as well as other IPPs, $3.6 billion in cash and shares of its stock. The current operational status of the cogeneration plants listed in **Table 2** varies; some have been resold to other parties, others have renegotiated their gas supply arrangements in order to make their produced power more competitive and are still operational or on standby, while others are in the process of being dismantled.

Despite the current non-utility generation sector (NUGS) contract problems, these long-term supply contracts were the principal force behind the growth in long-term import arrangements during the 1990's. The principal reason why long-term imports from Canada have not declined more rapidly than noted above, has been the substantial growth in the use of long-term gas supply contracts by the NUGS, particularly during the early part of the decade. **Figure 11** shows Canadian natural gas imported under long-term contract for use by the NUGS from 1990 through 1998. Since 1990, over half of all new investment in electricity generation has been the result of new capacity built by the NUGS. As shown, Canadian natural gas suppliers have made substantial gains in capturing a significant portion of the growing NUGS market during this decade. This market was virtually nonexistent ten years ago, but in 1998 it represented 18 percent of the gas imported from Canada under long-term contracts. During the 1990's, gas imports by the NUGS represented about 80 percent of the entire incremental growth under long-term gas import arrangements. **Figure 11** shows that the gas import level for the NUGS peaked in 1996 and has declined slightly over the past two years. The decline in volumes imported is the result of some gas contract problems, and the fact that no new gas-fired NUGS facilities that have come on-line during the past couple of years.

Figure 11

CANADIAN NATURAL GAS IMPORTED UNDER LONG-TERM CONTRACTS FOR USE BY NON-UTILITY GENERATION SECTOR

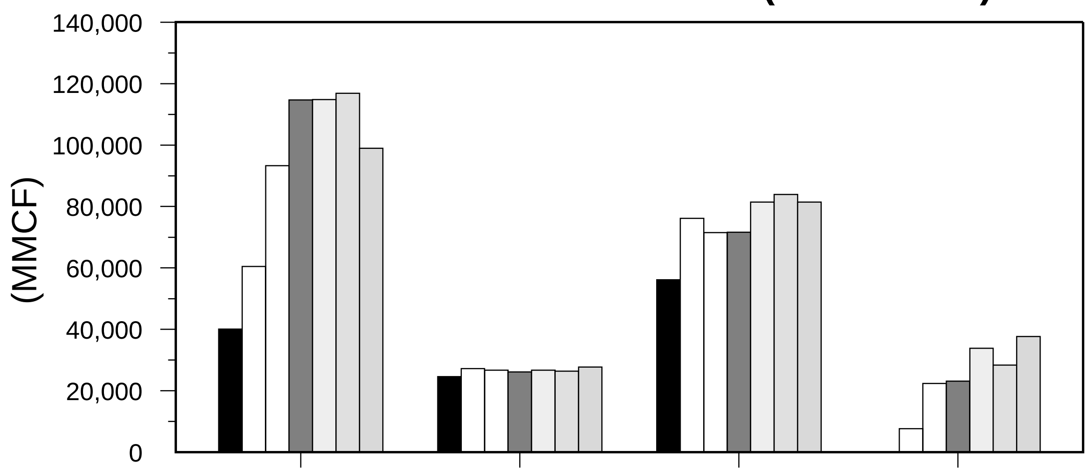


	1990	1991	1992	1993	1994	1995	1996	1997	1998
1st Quarter	0	12,168,540	26,267,706	39,059,827	52,778,420	60,237,525	60,380,474	62,961,870	67,305,325
2nd Quarter	2,826,685	10,138,259	27,353,191	39,899,381	54,028,210	55,079,443	57,045,832	56,803,831	62,569,168
3rd Quarter	5,241,535	11,259,507	30,520,425	44,346,566	56,829,959	58,235,949	68,413,292	67,602,541	59,734,539
4th Quarter	9,190,775	17,468,059	36,779,576	48,097,201	56,188,521	62,501,176	70,903,947	68,084,348	56,117,733
Total (Mcf)	17,258,995	51,034,365	120,920,898	171,402,975	219,825,110	236,054,093	256,743,545	255,452,590	245,726,765

Figure 12 illustrates the geographical distribution of Canadian long-term gas sales to the NUGS from 1992 through 1998. As shown, there has not been any aggregate growth in sales to this market segment during the past three years. As discussed above with the termination of 14 contracts in the State of New York, sales to NUGS declined in the Mid-Atlantic region, but increased somewhat in the Pacific Northwest region. Although there have not been any new cogeneration facilities built over the past couple of years which utilize Canadian gas, two projects currently are under construction in the State of Maine; i.e., Androscoggin, Rumford Power. These two facilities, when operational, will increase gas use by the NUGS in New England by about 33 Bcf per year.

Figure 12

CANADIAN NATURAL GAS SUPPLIES DELIVERED UNDER LONG-TERM CONTRACTS TO NON-UTILITY GENERATION SECTOR BY GEOGRAPHIC REGION (1992 - 1998)



	Mid-Atlantic	Midwest	New England	Pacific Northwest	***ALL REGIONS***
1992	40,051	24,603	56,103	0	***120,757***
1993	60,459	27,204	76,109	7,631	***171,403***
1994	93,296	26,684	71,462	22,368	***213,810***
1995	114,715	26,107	71,644	23,114	***235,580***
1996	114,793	26,698	81,407	33,846	***256,744***
1997	116,855	26,356	83,901	28,340	***255,453***
1998	98,979	27,704	81,395	37,649	***245,061***

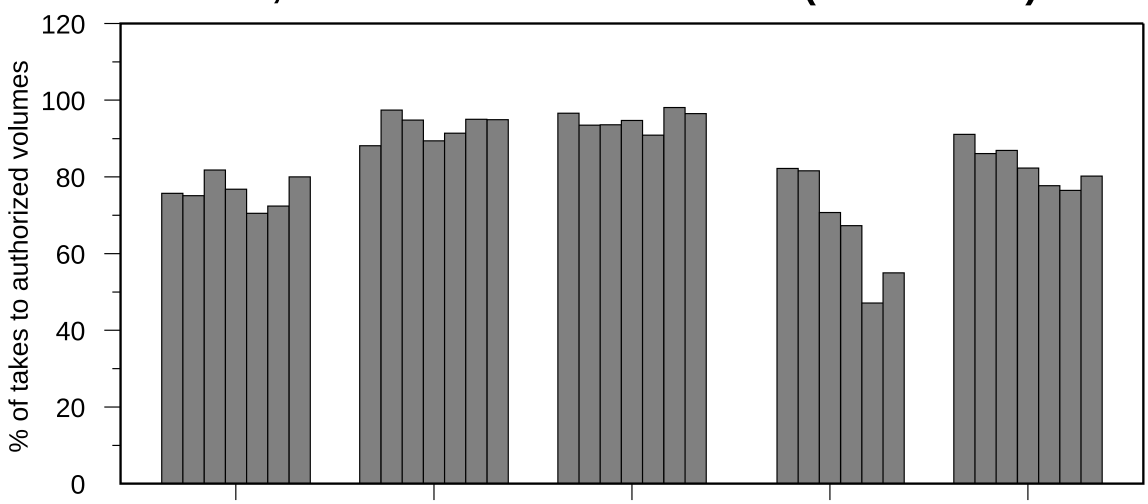
Note: *These data do not include small volumes of sales to other regions; e.g., South Atlantic.*

Historically, long-term gas contracts supplying the NUGS have experienced a relatively high load factor (percentage of takes to authorized volumes). **Figure 13** shows from 1992 through 1998 the load factors of long-term Canadian natural gas contracts serving the NUGS, by geographic region. As shown in the graph, the average load factor for **all** regions declined from a high of 91.1 percent in 1992 to an annual low of 76.5 percent in 1997. In 1998, the average load factor rebounded from the 1997 low to 80.2 percent.

The two regions which have experienced consistently high load factors have been the Midwest and New England. The Pacific Northwest and Mid-Atlantic regions continue to have contractual problems. The reduced use of natural gas by the NUGS in the Pacific Northwest is due to the continued abundance of less expensive hydroelectricity and in the Mid-Atlantic Region there appear to be more economic alternatives available.

Figure 13

LOAD FACTORS OF LONG-TERM CANADIAN NATURAL GAS CONTRACTS SERVING THE NON-UTILITY GENERATION SECTOR, BY GEOGRAPHIC REGION (1992 - 1998)



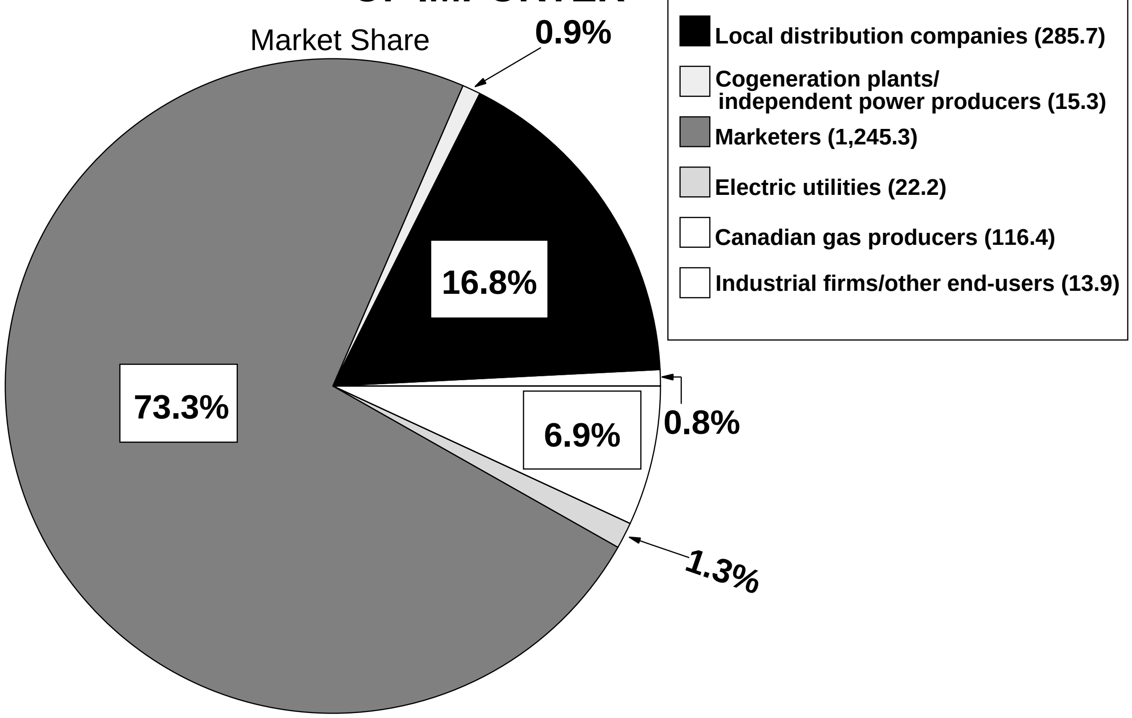
	Mid-Atlantic	Midwest	New England	Pacific Northwest	ALL REGIONS
1992	75.7	88.1	96.6	N/A	91.1
1993	75.1	97.4	93.5	82.2	86.1
1994	81.8	94.8	93.6	81.6	86.9
1995	76.8	89.4	94.7	70.7	82.3
1996	70.5	91.4	90.9	67.3	77.7
1997	72.4	95.0	98.1	47.1	76.5
1998	80.0	94.9	96.5	55.0	80.2

The next two graphs provide information on Canadian natural gas imported under DOE's short-term blanket authorizations during 1998. As mentioned earlier, Canadian natural gas imports under this type of import authority have exceeded the volume imported under long-term authority for the past four years. **Figure 14** below identifies, by class of importer, the market share of those who imported Canadian natural gas in 1998 under short-term import authorizations. As displayed in **Figure 14**, there were three principal types of short-term importer: marketers, LDCs, and Canadian gas producers or their U.S. affiliates.

These three types of importer brought in almost 97 percent of the total short-term Canadian natural gas imports in 1998. Comparing 1998 with 1997, the "marketers" category achieved significant growth in market share due to an increase of 19.8% in volumes imported (1,245.3 v. 1,039.2). Categories experiencing a decline in volumes this year include the "Local Distribution Companies" (285.7 v. 295.2), and the "Electric Utilities" (22.2 v 38.8). The "Cogeneration Plants/Independent Power Producers" and "Industrial/Other" categories each saw modest growth this year, and the "Canadian Gas Producers" category remained virtually unchanged.

Figure 14

1998 CANADIAN NATURAL GAS IMPORTS UNDER SHORT-TERM IMPORT AUTHORIZATIONS BY TYPE OF IMPORTER

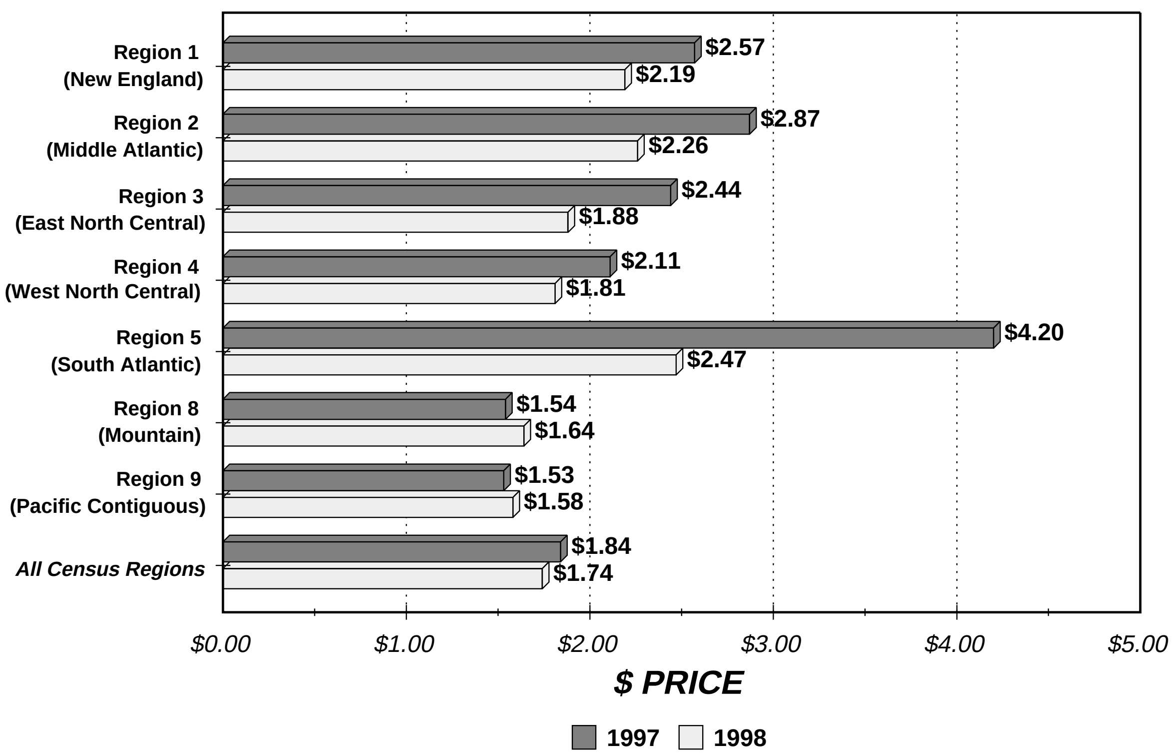


Total short-term imports: 1,699 Bcf

Figure 15 shows for 1997 and 1998 the weighted average international border price for Canadian natural gas imported under short-term contracts by Census Region. Over 98 percent of all short-term Canadian natural gas sales to the United States in 1998 were concentrated in five Census Regions (2,3,4,8,9), as was the case over the past few years, and almost 51 percent of this year's volumes were marketed in Census Region 9 (Pacific Contiguous). As indicated, the average border price for **all** short-term imports in 1998 was $1.74 per MMBtu, compared with $1.84 per MMBtu in 1997, a decline of 5.4 percent.

Figure 15 also illustrates the price split among the various regions. Although there is still a discrepancy in price between the east and west, this year saw a narrowing of the wide price gap that has existed over the past few years between the Western states (Census Regions 8 & 9) and the rest of the country. In particular, Census Regions 1, 2, 3, and 4 witnessed substantial drops in price this year of 14.8, 21.3, 23.0, and 14.2 percent, respectively. Census Region 5 (South Atlantic) showed the highest average natural gas price Canadian supplies during 1998 at $2.47/MMBtu.

Figure 15 **THE WEIGHTED AVERAGE PRICE IN 1997 & 1998 FOR CANADIAN NATURAL GAS IMPORTED UNDER SHORT-TERM CONTRACTS BY CENSUS REGION ($/MMBtu)**



Mexican Gas Trade

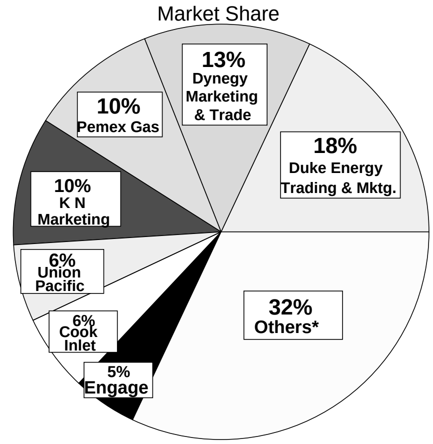
The last four graphs provide information on Mexican gas trade during 1998. **Figure 16** identifies the 23 firms that exported a total of 53.1 Bcf of natural gas to Mexico in 1998, and indicates the market share of the seven largest exporters. Duke Energy was the year's largest exporter of natural gas to Mexico, replacing the spot K N Marketing held last year. Although there was a total of 23 exporters in 1998, Duke Energy and the other top six gas exporters represented about 68 percent of the Mexican import market.

Figure 17 shows the 14 companies that imported a total of 14.5 Bcf of Mexican natural gas into the United States, down almost 16 percent from the 1997 level (17.2 Bcf). In 1998, almost 93 percent of the gas entered the United States at Hidalgo, Texas on the Texas Eastern Pipeline. The remaining volumes entered the country at El Paso, Texas (approximately 7 percent) and Penitas, Texas (.3 percent). The number of companies importing Mexican natural gas this year was down from last year's total of 20. Mexican sources predict that exports to the United States will continue to grow; however, Mexico is expected to be a net importer of gas during the foreseeable future.

Figures 18 and **19** on the next page provide monthly volume and price information with regard to natural gas exports to Mexico over the past three years (January 1996 - December 1998). Natural gas exports to Mexico this year were the highest since 1995, when volumes reached 61.3 Bcf. The 1998 annual weighted average price was $2.02 per MMBtu, falling almost 17% from last year's price of $2.43 per MMBtu.

FIRMS THAT EXPORTED NATURAL GAS TO MEXICO IN 1998

Figure 16



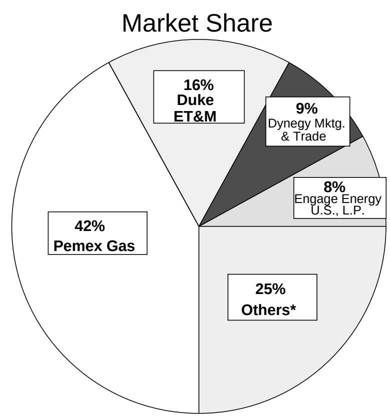
Total Exports: 53.1 Bcf

Others*

Amoco Energy Trading Corporation
Anadarko Trading Company
Applied LNG Technologies USA, L.L.C.
Burlington Resources Trading Inc.
Coral Energy Resources, L.P.
Conoco Inc.
Coral Energy Resources, L.P.
Dist. De Gas Natural De Mexicali
El Paso Energy Marketing Company
Ener-Son of U.S.A.
Enron Capital & Trade Resources Corp.
Noram Energy Services, Inc.
Onyx Gas Marketing Company, L.C.
PG&E Texas Industrial Energy, L.P.
Producers Energy Marketing LLC
Sempra Energy Trading Corporation
Tristar Gas Marketing Company
West Texas Gas, Inc.
Williams Energy Services Company

Figure 17

FIRMS THAT IMPORTED NATURAL GAS FROM MEXICO IN 1998



Total Imports: 14.5 Bcf

Others*

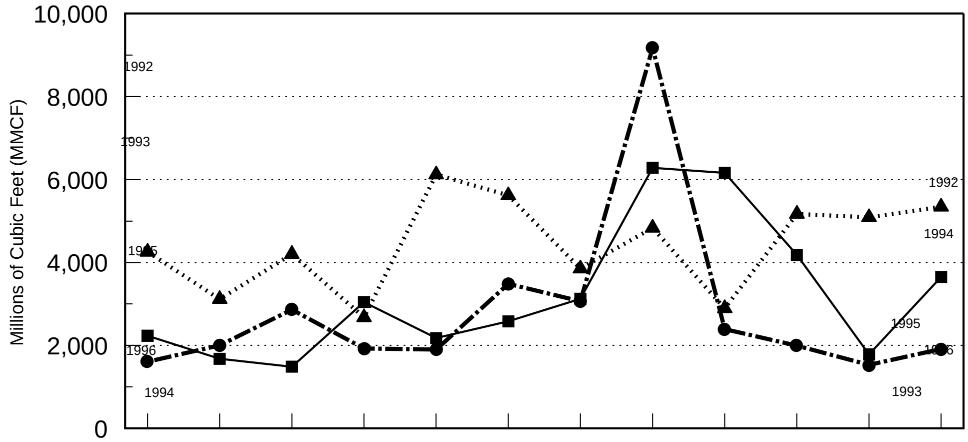
Amoco Energy Trading Corporation
Anadarko Trading Company
Conoco Inc.
Coral Energy Resources, L.P.
Enron Capital & Trade Resources Corp.
Noram Energy Services, Inc.
Onyx Gas Marketing Company, L.C.
Producers Energy Marketing LLC
Sempra Energy Trading Corporation
Union Pacific Fuels, Inc.

Figure 18

NATURAL GAS EXPORTS TO MEXICO

1996 - 1998

MONTHLY VOLUMES



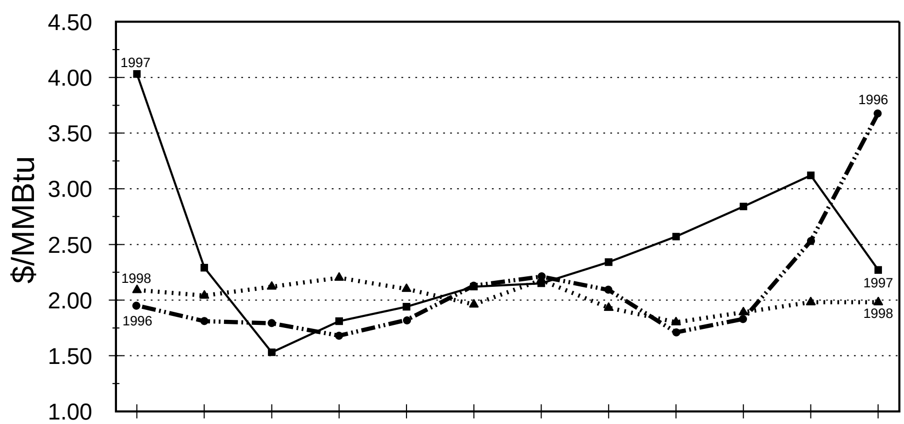
		JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	***TOTAL***
1996	-·-·	1,607	2,000	2,860	1,924	1,899	3,486	3,062	9,176	2,389	1,990	1,533	1,914	***33,840***
1997	—	2,231	1,677	1,486	3,044	2,177	2,579	3,122	6,282	6,159	4,182	1,782	3,650	***38,372***
1998	·····	4,257	3,117	4,202	2,675	6,119	5,617	3,852	4,835	2,892	5,170	5,088	5,342	***53,165***

Figure 19

NATURAL GAS EXPORTS TO MEXICO

1996 - 1998

WEIGHTED AVERAGE PRICE



		JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	***AVG***
1996	-·-·	1.95	1.81	1.79	1.68	1.82	2.13	2.21	2.09	1.71	1.83	2.53	3.68	***2.09***
1997	—	4.03	2.29	1.53	1.81	1.94	2.12	2.15	2.34	2.57	2.84	3.12	2.27	***2.43***
1998	·····	2.09	2.04	2.12	2.20	2.10	1.96	2.18	1.93	1.80	1.89	1.98	1.98	***2.02***