National Energy Board

Office national de l'énergie

Canadian Energy Overview 2007

AN ENERGY MARKET ASSESSMENT MAY 2008

Canada

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energy

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AUC	Alberta Utilities Commission
CBM	coalbed methane
CNSC	Canadian Nuclear Safety Commission
EIA	Energy Information Administration
EMA	Energy Market Assessment
ERCB	Alberta Energy Resources Conservation Board
EUB	Alberta Energy and Utilities Board
FEED	front-end engineering and design
GDP	gross domestic product
IESO	Independent Electric System Operator
IPPI	Industrial Product Price Index
LNG	liquefied natural gas
LPG	liquefied petroleum gas
MOU	Memorandum of Understanding
NEB or Board	National Energy Board
NGLs	natural gas liquids
NRCan	Natural Resources Canada
NYMEX	New York Mercantile Exchange
OPEC	Organization for Petroleum Exporting Countries
PADD	Petroleum Administration for Defence District
PSAC	Petroleum Services Association of Canada
U.S. or US	United States
WCSB	Western Canada Sedimentary Basin
WTI	West Texas Intermediate

List of Units

b/d	barrels per day
Bcf/d	billion cubic feet per day
GJ	gigajoule
kV	kilovolt
m^3/d	cubic metres per day
Mb/d	thousand barrels per day
MMb/d	million barrels per day
MMbtu	million British thermal units
MW	megawatt
PJ	petajoules
$ or Cdn$	Canadian dollars
US$	U.S. dollars
TW.h	terawatt hour

Foreword

The National Energy Board (NEB or the Board) is an independent federal agency that regulates several aspects of Canada's energy industry. Its purpose is to promote safety and security, environmental protection and efficient energy infrastructure and markets in the Canadian public interest within the mandate set by Parliament in the regulation of pipelines, energy development and trade. The Board's main responsibilities include regulating the construction and operation of interprovincial and international oil and gas pipelines as well as international and designated interprovincial power lines. The Board regulates pipeline tolls and tariffs for pipelines under its jurisdiction. The Board regulates the exports and imports of natural gas as well as exports of oil, natural gas liquids (NGLs) and electricity. The Board also regulates oil and gas exploration, development and production in frontier lands and offshore areas not covered by provincial or federal management agreements. The Board's advisory function requires it to keep under review matters over which Parliament has jurisdiction relating to all aspects of energy supply, transmission and disposal of energy in and outside Canada.

The NEB monitors energy markets to objectively analyze energy commodities and inform Canadians about trends, events and issues. Annually, the Board does a review of the past year's energy markets in this Energy Market Assessment (EMA), entitled *Canadian Energy Overview 2007*. This report is a summary of major developments related to energy in Canada in 2007.

INTRODUCTION

In the past year, the Board issued a number of Energy Market Assessments (EMAs) on a wide range of energy commodities. In addition, it released its *2007 Canada's Energy Future - Reference Case and Scenarios to 2030*. The report is a comprehensive energy supply and demand outlook for the years 2005 to 2030. These reports and related information can be found on the Board's website at http://www.neb-one.gc.ca.

In 2007, global energy markets were impacted by rising and fluctuating prices for crude oil and escalating finding and development costs. The year began with lower prices for crude oil and natural gas, primarily driven by above normal temperatures in North America and high inventory levels for crude oil, including petroleum products, and natural gas. By summer, crude oil prices were on the rise and eventually reached record highs in the fall and winter months. By year end, crude oil prices had risen by 76 percent from the lows witnessed in January. The rise in the price of crude oil was moderated in Canada with the appreciation of the Canadian dollar versus the U.S. dollar.

Energy continued to be an important factor in the Canadian economy. In 2007, the energy industry accounted for 5.6 percent of Canada's gross domestic product (GDP) and 19.7 percent ($90.0 billion) of the total value of Canadian exports. In 2007, the energy industry's capital and repair expenditure totalled $68.9 billion – about 35 percent of total private sector investment. Following a decrease in 2006, total secondary energy demand is estimated to have increased 2.8 percent between 2006 and 2007 to 10 976 PJ. This was supported by robust population growth and economic growth.

Influenced by global events such as strong world oil demand growth, lack of spare production and refining capacity, and political instability in some oil producing regions, crude oil prices averaged US$72 per barrel in 2007, an increase of about 10 percent from 2006. A commonly used international benchmark, West Texas Intermediate (WTI) began the year at about US$54 per barrel and reached a record US$99 per barrel in November, driven by a tight supply and demand balance, strong oil demand growth in the Middle East and Asia and a depreciating U.S. dollar making oil cheaper in oil consuming countries. By year-end, crude oil closed at approximately US$96 per barrel, significantly higher than where it began the year.

In 2007, the value of crude oil exports surpassed the value of natural gas exports. Net crude oil and products export revenue, which is estimated at roughly Cdn$25.7 billion, exceeded the value of net natural gas export revenue of Cdn$24.3 billion. The gap has narrowed from 2003, when the difference was approximately Cdn$8 billion, with natural gas having higher export revenues of the two commodities. Net natural gas export revenues have remained steady at Cdn$24.3 billion in 2006 and 2007, while net crude oil exports have increased to Cdn$25.7 billion in 2007, an increase of 18 percent compared with 2006.

Despite supply interruptions in 2007, average crude oil production was up seven percent compared with 2006, to 441 128 m^3/d (2.8 MMb/d). This increase reflects growing oil sands production, plus increases in production at the Terra Nova and White Rose Fields offshore eastern Canada.

In 2007, natural gas prices were lower and less volatile than they have been in recent years as a result of a well-supplied North American natural gas market. Warmer-than-normal weather during the winter of 2006-07 in North America, record U.S. imports of liquefied natural gas (LNG) during the summer of 2007 and increased natural gas production in several U.S. basins helped to maintain a very high inventory of natural gas in storage. As a result, North American natural gas prices at Henry Hub, the pricing point in Louisiana for natural gas traded on the New York Mercantile Exchange (NYMEX), ranged between US$6/MMBtu and US$8/MMBtu throughout the year. Natural gas is priced in American dollars; therefore, the appreciation of the Canadian dollar resulted in lower prices for Canadian consumers.

The combination of rising costs for natural gas development and lower natural gas prices in 2007 resulted in lower natural gas drilling and investment in Western Canada. Consequently, total natural gas related drilling was down significantly compared with 2006. Total Canadian natural gas production averaged 475 million m^3/d (16.8 Bcf/d), or roughly 2 percent less than in 2006. The decline was concentrated in the Western Canada Sedimentary Basin (WCSB). Total production declines were partially offset by slightly higher production on the East Coast. The East Coast increases were from a new onshore development in New Brunswick and from the effect of added compression offshore Nova Scotia.

Natural gas continued to supply a significant part of Canadian and North American energy requirements. In 2007, estimated Canadian natural gas consumption was about 233 million m^3/d (8.2 Bcf/d), or 46 percent of Canadian production. Although Canadian natural gas consumption in most end-use sectors remained flat or declined, oil sands development continued to be a significant and fast-growing sector for consumption. In 2007, the natural gas consumed for oil sands development was almost 32 million m^3/d (1.1 Bcf/d) - over three times the amount of gas used in 2000. Over one-third of domestic natural gas consumption continued to be directed toward residential and commercial use, primarily for space and water heating. Despite continued growth in floor space (i.e., the number and size of buildings) for these sectors, natural gas consumption remains flat as this growth has been largely offset by warmer weather in recent years.

Canadian natural gas exports were estimated to be 293 million m^3/d (10.4 Bcf/d), slightly higher than in 2006. Net exports (gross exports less imports) were about 260 million m^3/d (9.1 Bcf/d), about 4.4 percent higher than in 2006. Despite the higher export volumes, export revenues remained about the same as 2006 at $24.3 billion, reflecting the overall lower North American natural gas price.

Electricity jurisdictions continued to introduce initiatives in 2007 that were intended to address adequacy of supply and operating reliability. Such initiatives included conservation measures, clean energy programs and infrastructure additions. In order to promote electric reliability, efforts to upgrade and expand transmission infrastructure on international and provincial levels also continued. With respect to electricity supply, although conventional generation (e.g., coal, nuclear, natural gas and hydro generation) still prevails in the electric generation asset mix, alternative forms were included as supply source additions. In 2007, there was also a resurgence of interest in nuclear generation.

Overall, Canada's electricity demand was adequately met in 2007 with generation increasing from 585 terawatt hours in 2006 to 600 terawatt hours in 2007. Net exports increased from 17.4 terawatt hours in 2006 to 30.6 terawatt hours. Canada exported approximately $3.1 billion of electricity and imported a total of $1 billion in 2007 resulting in net revenues of $2.1 billion, compared to approximately $1.3 billion in 2006. Favourable water conditions in hydrogeneration provinces contributed to the strong electricity trade results.

Energy and the Canadian Economy

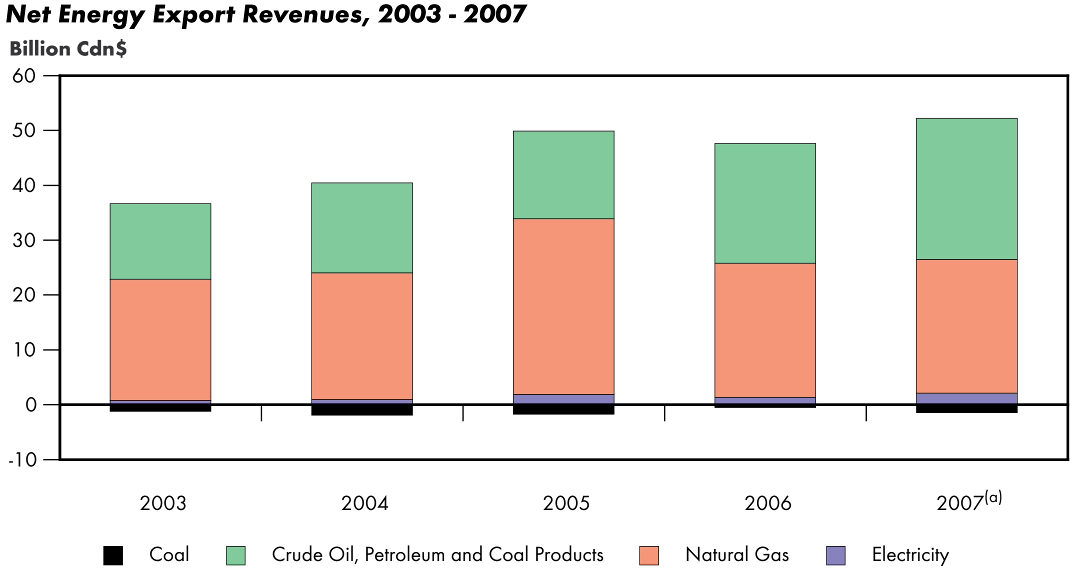
In 2007, the energy industry accounted for 5.6 percent of Canada's GDP and directly employed 372 200 people (2.2 percent of the Canadian labour force). Energy export revenue totalled $90 billion, which accounted for 19.7 percent of the value of all exports. The proportion has held roughly steady for the last three years and is double the 1990's average of 10 percent of export value.

Overall, net energy export revenues (the value of energy exports minus the value of energy imports) increased by almost eight percent from 2006 levels to $50.8 billion in 2007 (Figure 2.1). Historically, net natural gas exports have been larger than crude oil and products net export revenues; however, in 2006 the net export revenue of natural gas and crude oil and products were almost equal and in 2007, the net export revenue of crude oil and products was $2 billion greater than natural gas net export revenues. This is a result of increased export volumes and strong crude oil prices combined with the maturing natural gas basin in Western Canada and softening natural gas prices. Electricity net export revenue experienced growth between 2006 and 2007 as a result of favourable export opportunities south of the Canada/United States border and good water conditions in the hydrogenerating provinces such as, British Columbia, Manitoba and Quebec. Canada continued to be a net importer of coal in 2007.

Total energy production in Canada increased by 1.8 percent in 2007, largely due to increased petroleum production, as well as wind production (Table 2.1). Offsetting total growth in Canadian

F I G U R E 2 . 1

Net Energy Export Revenues, 2003 - 2007



(a) Estimate

Source: Statistics Canada, NEB

TABLE 2.1

Domestic Energy Production by Energy Source (petajoules)

	2003	2004	2005	2006	2007[a]
Petroleum[b]	6 479	6 667	6 545	6 862	7 235
Natural gas[c]	6 462	6 524	6 373	6 585	6 484
Hydroelectricity	1 198	1 206	1 291	1 271	1 302
Nuclear	820	989	1 007	1 072	1 020
Coal	1 326	1 476	1 494	1 554	1 586
Renewable and other[d]	633	657	681	709	733
Total	**16 918**	**17 519**	**17 391**	**18 053**	**18 360**

(a) Estimates

(b) Petroleum includes crude oil and gas plant natural gas liquids (NGLs), upgraded and non-upgraded bitumen and condensate

(c) Marketable natural gas

(d) Includes wind, solar, solid wood waste, spent pulping liquor and annual firewood

Source: Statistics Canada, NEB

production was a decline in natural gas production as a result of a slow down in drilling activity in Western Canada and decreased nuclear energy production due to plant outages during the year. Additional details on Canadian production trends in 2007 are provided in the following chapters.

Preliminary 2006 numbers suggest Canadian energy demand fell from 2005 levels as a result of decreased energy use across most end-use sectors. Initial estimates suggest a resurgence of energy demand growth in 2007. Total secondary energy demand is expected to increase to 10 976 PJ in 2007, which is 2.8 percent above 2006 levels (Table 2.2). Secondary or end-use energy demand is the energy used by the final consumer in Canada and is separated into four sectors: residential, commercial, industrial and transportation.

Canadian energy demand trends are driven by changes in population, economic conditions, energy prices, weather, conservation, technology and consumer preferences. Statistics Canada reports that the Canadian population increased by 1.8 percent in 2007, with net international migration accounting for two thirds of this growth. In comparison, the population increased by one percent

TABLE 2.2

Domestic Secondary Energy Consumption (petajoules)

	2003	2004	2005	2006[a]	2007[a]
Residential[b]	1 448	1 425	1 410	1 369	1 442
Commercial	1 444	1 459	1 363	1 300	1 347
Industrial[b][c]	4 704	4 853	5 203	5 252	5 323
Transportation	2 577	2 679	2 777	2 758	2 864
Total	**10 173**	**10 416**	**10 753**	**10 680**	**10 976**

(a) Estimates

(b) Includes biomass (wood and pulping liquor)

(c) Includes producer consumption energy use and non-energy use

Source: Statistics Canada, NEB

in 2006 and in 2005. This contributed to strong energy demand growth rates of 5.3 percent for the residential sector and 3.6 percent for the commercial sector (higher demand for services) in 2007.

Robust Canadian economic growth in 2007 contributed to energy demand growth in the commercial and industrial sectors. Canadian GDP was stronger in the first half of the year than in the second half and increased 2.7 percent between November 2006 and November 2007. The goods-producing industries' GDP increased by one percent and the service industries' GDP increased by 3.5 percent. The modest growth in the goods-producing industries' GDP could be the result of overall lower prices in 2007. The Industrial Product Price Index (IPPI) decreased 0.9 percent between December 2006 and December 2007. The largest decreases occurred in prices for motor vehicles and other transport equipment, metal and paper products, while prices for petroleum and coal products increased.

Transportation energy costs increased in 2007. For example, between December 2006 and December 2007 gasoline pump prices increased by 14.9 percent and the price for air transportation rose by 6.2 percent. Despite these higher prices, overall transportation energy consumption is estimated to be 3.8 percent higher in 2007. Motor gasoline sales were up 3.5 percent and diesel sales up 4.9 percent. Population growth and commercial and industrial growth helped push passenger and freight transportation demand higher, showing little, if any, price sensitivity.

2.1 Looking Ahead

There are indications that energy consumption trends could see shifts in several key areas. At a general level, growing anxiety regarding U.S. macroeconomic conditions, energy price concerns, potential supply constraints and heightened environmental awareness could influence consumer spending habits and therefore energy demand trends.

Government programs and policies could also impact energy demand trends over the next few years. Several significant energy and environment policies were confirmed or tabled at the provincial and federal level. The federal government's expanded portfolio of ecoAction initiatives includes energy efficiency for buildings, appliances and vehicles. Legislation has been passed for updates on the Model National Energy Code for Buildings. In addition, an expanded labelling program is ready for rollout. For electrical appliances and electronics, an expanded and more rigorous suite of appliance energy performance standards have been issued. New regulations are pending for lighting and electrical standby power limits.

A significant proposal is the Regulatory Framework for Greenhouse Gas Emissions. In the near term (2007-2010) this includes a six percent per year improvement in emission intensity for major industries, giving an enforceable 18 percent reduction from 2006 emission intensity in 2010. These reductions could be achieved in part through energy efficiency improvements.

Several provinces have released energy plans, with targets, that address energy efficiency, energy conservation and renewable energy. One common element on the efficiency side is heightened building energy performance standards that could lead to improvements in baseline new building performance in many areas of the country. As well, ethanol regulations in various Canadian provinces are likely to bring about a shift in hydrocarbon fuel consumption trends.

Finally, changes to consumer preferences could also have an impact on energy demand trends in Canada in the longer term. Multi-family dwellings are increasing their share of households in Canada. In 2007, the share of multi-family dwelling construction was 50.9 percent – the largest since 1982 (51.5 percent). This could have a direct impact on residential energy demand in the future, as well as a possible indirect impact on passenger transportation energy demand.

Upstream Oil and Gas Activity

Measurement of upstream oil and gas activity includes acquisition of land rights, seismic programs, number of active drilling rigs, wells drilled and the capital expenditures involved.

Cost pressures associated with strong economic growth continued in 2007. Also adding to the cost is the trend in mature resource basins of new wells producing at lower rates and recovering less energy. Over the course of the year, crude oil prices gained sufficient strength relative to these costs to cause oil-related activity in Saskatchewan and Alberta to remain fairly strong. Conversely, natural gas prices remained stubbornly flat in the first half of the year before slipping further in the fall. The combination of rising costs and flat to declining prices eroded the economics of some of Western Canada's natural gas opportunities and caused investment to either be deferred or transferred to oil projects or to U.S. gas producing regions. In 2007, growth and escalating costs in oil sands projects required additional capital spending and may have diverted some investment from other oil and gas operations.

In a tightly balanced North American natural gas market, any pullback in Canadian drilling activity would be expected to lead to reduced production and eventually to higher prices, thereby providing the incentive to resume higher drilling levels. However, in 2007, mild temperatures, higher LNG imports and rising U.S. unconventional gas production offset any losses in Canadian output and prevented a sustained rise in prices that might have provided the incentive for increased Canadian drilling activity.

Drilling capacity in Western Canada continued to increase as new rigs commissioned during the 2005-06 period of peak drilling were added to the fleet. By the end of 2007, the size of the drilling fleet had grown to 897 rigs compared to 842 at the end of 2006.[1] On average, there were 339 drilling rigs operating per month in western Canada compared to an average of 473 in 2006. Figure 3.1 provides the weekly active rigs in Western Canada.

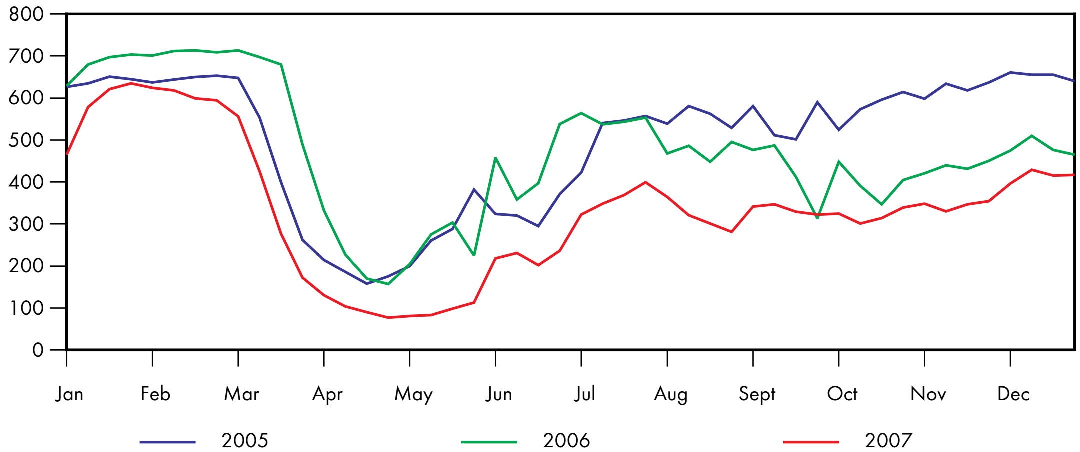
As shown in Figure 3.2, just over 18,000 wells were drilled in Western Canada in 2007. This is roughly 4,600 less than in 2006. The number of oil wells drilled in the year declined by six percent, with natural gas drilling down by 25 percent. As a result of the ongoing decline in gas economics relative to oil, the percentage of wells directed to natural gas slid to 68 percent from 73 percent in 2006.

Both U.S. gas and oil drilling were maintained at high levels throughout 2007 and contributed to an estimated three percent increase in U.S. gas deliverability as U.S. operations were less impacted by rising costs and declining well productivity. Rising unconventional gas production in the Rockies and south central states provided much of the increase with additional volumes from the start up of a Gulf of Mexico deep water development late in the year.

1 Canadian Association of Oilwell Drilling Contractors, Average Monthly Drilling Rig Count - Western Canada, www.caodc.ca/rigcountspg3.htm#mthdrill

FIGURE 3.1

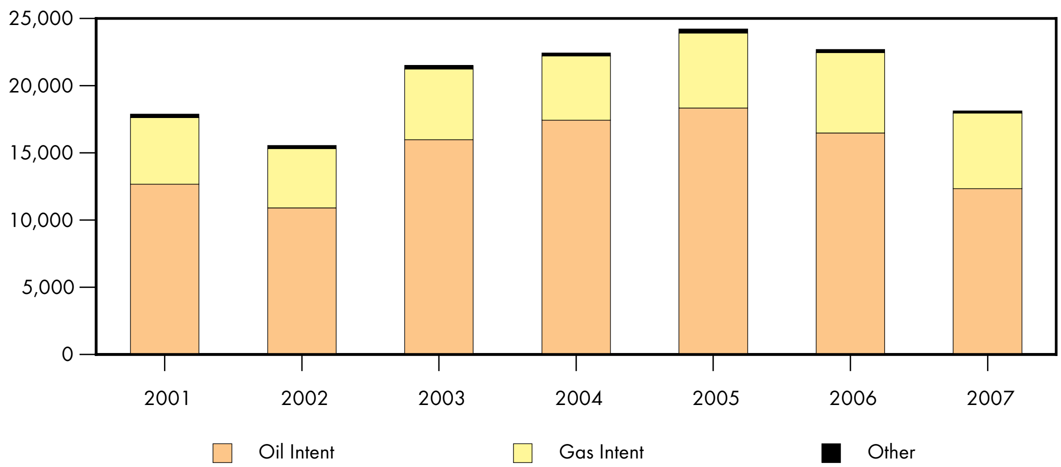
Weekly Active Rigs in WCSB



Source: Nickle's Daily Oil Bulletin

FIGURE 3.2

Number of Wells Drilled – Western Canada, 2001 - 2007



Source: NEB

With major land positions in the oil sands areas now established, land rights acquisition were scaled back in 2007. Total land sale payments in Western Canada were $2.66 billion, down 37 percent from the $4.19 billion paid in 2006. The moderation in oil sands land requirements represented over 85 percent of the reduction with sales of $0.65 billion over the year compared to $1.96 billion in 2006. The average price for oil sands land dropped by more than half to average just $573 per hectare compared with the $1,273 paid in 2006. Land not associated with oil sands continued to be of interest and was purchased at an average price of $697 per hectare, above the $549 paid in 2006. Areas in British Columbia with shale gas potential were of particular interest. A major purchase of exploration rights in the Beaufort Sea increased commitments for future drilling in the Northwest Territories by $613 million in 2007 compared to a $52 million increase in 2006. Acquisition of drilling rights in the Yukon, Newfoundland and New Brunswick amounted to $20 million, $1.5 million and $1.6 million, respectively, which is down from 2006 levels.

In December 2007, the *Canadian Oil and Gas Operations Act* (COGOA) was amended to give the NEB increased responsibility over pipelines in the frontier regions. In particular, it gave the

Board jurisdiction over traffic, tolls and tariffs. As a consequence of these changes, there were also amendments to the *Canadian Petroleum Resources Act* and the *National Energy Board Act*.

In 2007, the Canadian industry turned away from exploration activity with exploratory well completions down by 33 percent compared with 2006. Seismic survey activity in Western Canada during 2007 also fell markedly from the previous year with the average number of active crews dropping from 14.1 to 5.8. The significant drop in seismic activity signals that a recovery in exploration activity in 2008 is unlikely.

Total oil and gas capital expenditures in Canada fell by 10 percent in 2007 to an estimated $48 billion. Capital spending associated with oil sands projects is estimated to have jumped by 18 percent to $17 billion. Capital spending in all other areas of the industry dropped by an estimated 20 percent. During 2007, there was a shift in spending away from natural gas and toward oil, in recognition of the more attractive economics resulting from high oil prices.

3.1 Looking Ahead

Improving cost control has become a key objective for oil sands development. To reduce the likelihood of major cost overruns, proponents are investing more in front-end engineering and design (FEED) before initiating construction. A key component of this front-end work is employing more drilling rigs to drill additional test holes to better define the resource. Large capital expenditures are planned for oil sands projects in 2008 and will likely continue to divert some investment from conventional activities. At the same time, a joint industry-stakeholder group is calling on government to enact a partial moratorium on oil sands development in certain ecologically sensitive areas of the Athabasca region. The group has urged the government to suspend land lease sales in the affected areas until 1 January 2011.

Despite the likelihood of increased oil sands expenditures, overall 2008 capital spending in Canada's upstream oil and gas industry is expected to be down at least three percent from 2007. The most recent drilling forecast for 2008, which is from the Petroleum Services Association of Canada (PSAC), is particularly negative for natural gas activity in Western Canada with oil drilling projected to exceed natural gas drilling for the first time since 1997. Under the PSAC scenario, the number of gas wells drilled in 2008 in Western Canada could fall by a third from the already reduced level of 2007. Should natural gas prices increase somewhat through higher demand associated with more extreme weather and perhaps lower LNG imports, the shift from natural gas to oil may be less pronounced.

With reduced natural gas drilling in 2008, Canadian natural gas production will be lower than in 2007. Even with slightly higher drilling in 2008, conventional and heavy crude oil production is likely to continue to trend downward. While oil sands production is forecast to increase, conventional light and heavy crude oil production will continue their natural annual decline of roughly three percent.

CRUDE OIL

4.1 International Markets

In 2007, crude oil prices started the year significantly lower than the record $78 per barrel (intraday high) reached in July 2006. In January, the average price of crude oil was just over $54 per barrel. Continuing the trend of high and volatile energy markets, crude oil prices climbed by 76 percent and by year-end were approximately $96. With the appreciation of the Canadian dollar versus the U.S. dollar the percentage rise in the price of crude oil was less in Canada. The average price of crude oil in 2007 was around $72 per barrel.

Lower crude oil prices at the beginning of the year reflected mild weather across North America, continuing from the fourth quarter of 2006, as well as above normal petroleum product inventory levels and difficulties among the Organization for Petroleum Exporting Countries (OPEC) members in reducing their production. The subsequent rise in the price throughout the year was a result of geopolitical risks in Iraq, Nigeria, Iran and other producing regions; robust oil demand growth; increasing finding and development costs; continuing tight production and refining capacity; and the depreciating American dollar. In addition, OPEC's goal of reducing inventory levels by implementing production cuts was eventually successful, thereby limiting downward price pressure.

The year 2007 witnessed a number of key events that shaped the crude oil market. Mid-January and February brought colder than normal temperatures in key heating regions. This had the effect of drawing down inventories of petroleum products and crude oil from their maximum levels at the beginning of the year to below five-year averages by year-end. In March, WTI became disconnected from the rest of the world because of the influx of Canadian crude oil supply into Cushing, Oklahoma, a key pricing hub. This resulted in WTI trading at a discount to North Sea Brent and in early April this discount reached a record $6.37 per barrel. Historically, WTI has traded at a slight premium to Brent as shown in Figure 4.1.

Prices rose through the summer and fell with the onset of the hurricane season; however, despite the forecast of above average hurricane activity, there was no major damage or production losses.

Prices peaked in November with crude oil rising to a record $99.29 per barrel on the NYMEX. In the fourth quarter 2007, seasonal weather in key markets contributed to strong demand growth and resulted in the largest inventory decline in the U.S. since 1999. Year-end geopolitical events including, sabotage to oil infrastructure in Nigeria also pushed prices up in late December.

The U.S., the largest consumer of crude oil and Canada's most important trading partner, struggled with a weak currency, the sub-prime mortgage crisis and the ongoing large cost of the war in Iraq. The weakness in the U.S. dollar was instrumental in supporting oil demand growth outside of the U.S. because it made crude oil more affordable in countries with stronger currencies. Oil demand

FIGURE 4.1

WTI and Brent Oil Prices, 2003 - 2007

(a) Brent is the common benchmark for European crude oil pricing

Source: International Energy Agency

growth in developing countries continued to put added pressure on the ability of both OPEC and non-OPEC countries to supply enough of the right grades of crude oil to the market.

OPEC met three times during 2007. At its 15 March 2007 meeting in Vienna, OPEC agreed to extend its existing agreement which called for production cuts of 1.7 MMb/d (1.2 MMb/d in November 2006 and 500 Mb/d in February 2007). Speculation was that the reduction was actually 1.0 MMb/d. OPEC met on 11 September and announced that it would raise production by 500 Mb/d effective 1 November to meet rising winter demand in the northern hemisphere. By this time, crude oil prices had already risen to well over US$77 per barrel. At its meeting on 5 December, OPEC announced that it would leave production unchanged; in response, crude oil prices rose to $90 per barrel. OPEC also indicated that it would continue to monitor the market and meet again on 1 February 2008 and 5 March 2008.

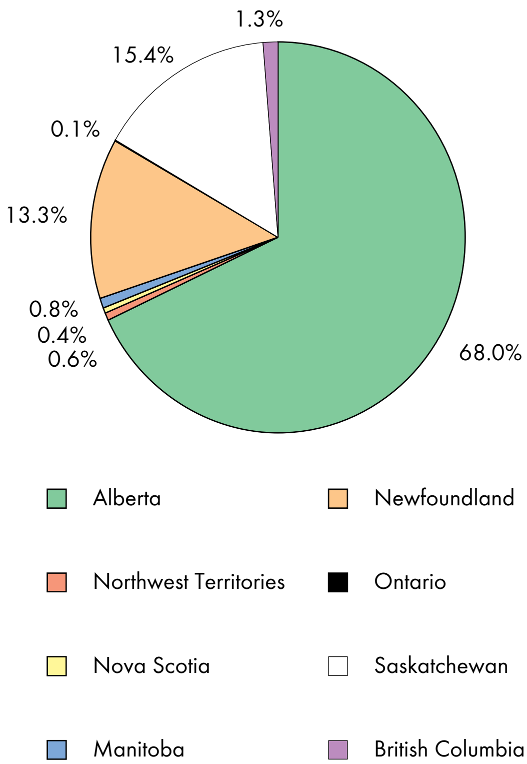
4.2 Canadian Oil Production and Reserves Replacement

In 2007, Canadian production of crude oil and equivalent averaged 441 128 m^3/d (2.8 MMb/d), an increase of seven percent from 2006 levels. This increase primarily reflects growing oil sands production from both in situ and surface-mining projects. As well, Canada's East Coast offshore production increased by 16 percent, reflecting an improvement in operational performance at the Terra Nova and White Rose fields compared with the previous year. Figure 4.2 illustrates crude oil production by province.

In 2007, production offshore Newfoundland and Labrador was 58 579 m^3/d (369 Mb/d). In Western Canada, crude oil and equivalent supply increased by four percent because of the increase in production from the oil sands. Conventional light crude oil production declined by three percent, reflecting the continuing decline of mature light oil reservoirs in the WCSB. This decline was significantly less than the long-term trend of five percent, because strong crude oil prices resulted in increased oil drilling, thereby slowing the rate of decline in the WCSB. Conventional heavy crude oil production levels also decreased by three percent, in line with the general decline that has developed since the production peak in 2001. Figure 4.3 illustrates crude oil production by type.

FIGURE 4.2

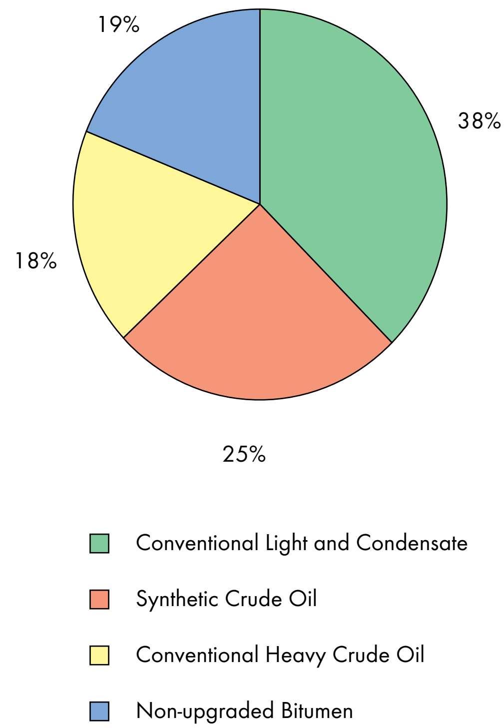
Crude Oil and Equivalent Production by Province



Source: NEB

FIGURE 4.3

Crude Oil and Equivalent Production by Type



Source: NEB

Despite the fact that remaining conventional established reserves are reduced by production each year, new discoveries, extensions to existing pools and revisions to reserve estimates in existing pools offset declines to reserve estimates. From 2002 to 2006, cumulative additions of conventional light and heavy crude oil to established reserves replaced 92 percent of production (Table 4.1).

The NEB's estimate of total remaining Canadian conventional crude oil and crude bitumen reserves at year-end 2006 (the last year for which there is mostly complete data available) is 32.5 billion cubic metres (205.1 billion barrels), an increase of less than one percent compared with 2005 (Table 4.2). Estimates of remaining established conventional crude oil reserves in Canada decreased by eight

TABLE 4.1

Conventional Crude Oil Reserves, Additions and Production, 2002-2006 (million cubic metres)

	2002	2003	2004	2005	2006	Total
Additions[a]	88.1	60.8	66.9	134.7	27.0	377.5
Production	81.0	85.6	82.7	78.8	82.1	410.2
Total Remaining Reserves	**690**	**663**	**640**	**696**	**640**	
Total Remaining Reserves (millions of barrels)	**4,342**	**4,172**	**4,027**	**4,382**	**4,033**	

(a) White Rose added in 2002

Source: Provincial Energy Agencies, Offshore Petroleum Boards, NEB

TABLE 4.2

Estimates of Established Reserves of Crude Oil and Bitumen at 31 December 2006 (million cubic metres)

Conventional Crude Oil	**Initial**	**Remaining**
British Columbia[a]	125.8	18.2
Alberta[b]	2 730.8	250.1
Saskatchewan[c]	890.1	170.0
Manitoba[d]	45.8	7.7
Ontario[e]	14.8	1.6
Northwest Territories, Nunavut and Yukon		
Arctic Islands and Eastern Arctic	0.5	0.0
Mainland Territories - Norman Wells and Cameron Hills	52.9	14.7
Nova Scotia - Cohasset and Panuke[d]	7.0	0.0
Newfoundland - Hibernia, Terra Nova and White Rose[d]	299.1	177.9
Total	**4 166.8**	**640.2**
Total (millions of barrels)	**26 250.8**	**4 033.3**
Crude Bitumen		
Oil Sands - Upgraded Crude[f]	5 590	5 008.0
Oil Sands - Bitumen[f]	22 802	22 520.0
Total	**28 392**	**27 528.0**
Total in millions of barrels	**178 870**	**173 426.0**
Total Conventional and Bitumen	**32 558.8**	**28 296.6**
Total Conventional and Bitumen (millions of barrels)	**205 120.8**	**178 268.6**

(a) British Columbia Ministry of Energy & Mines and NEB common database

(b) Alberta Energy Resources Conservation Board (ERCB) and NEB common database

(c) Saskatchewan Reservoir Annual 2004 with NEB estimated update

(d) Provincial Agencies or Offshore Boards, NEB estimate for Manitoba

(e) Canadian Association of Petroleum Producers

(f) ERCB Report – ST 98 2006

(Note: totals may not add because of rounding)

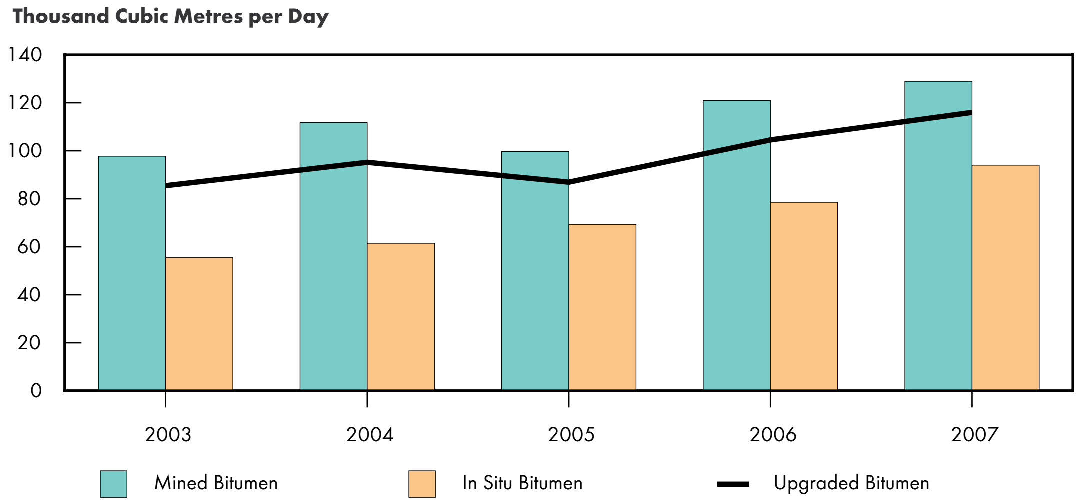
percent to 640.2 million cubic metres (4,167 million barrels) for 2006. Most of this decrease could be attributed to production significantly outpacing reserves additions in 2006. The remaining established crude bitumen reserves decreased slightly to 27.5 billion cubic metres (173.4 billion barrels) reflecting 2006 bitumen production.

4.3 Oil Sands

In 2007, oil sands production continued to expand and attract investment from domestic and foreign sources. Investment in Canada's oil sands is appealing because it is a large resource, Canada has a stable political and investment climate and there are a diminishing number of investment opportunities in other oil producing countries, due in part to increasing resource nationalism. As well, with high crude oil prices, oil sands development becomes more economic than in the past. Oil sands spending in 2007 is estimated to be about $18 billion.

F I G U R E 4 . 4

Crude Bitumen Production, 2003-2007



Source: Energy Resources Conservation Board (ERCB)

The fiscal environment for oil sands changed in the fourth quarter of 2007 with adjustments to Alberta royalties as well as changes to federal taxation measures. Royalty rates will now be determined by a sliding scale based on WTI prices, expressed in terms of real Canadian dollars. At prices up to Cdn$55 per barrel, royalty rates will actually remain identical to the previous royalty scheme, at one percent pre-payout and 25 percent post-payout. At prices above this point, rates would increase reaching a maximum of nine percent pre-payout and 40 percent post-payout at WTI $120 per barrel. All royalty payments will remain both tax deductible and eligible as expenditures for the purposes of calculating payout. The federal government announced cuts to corporate income tax rates, from 22.1 percent in 2007 to 15 percent in 2012. Industry analysts indicate that the net effect of changes to the Alberta royalty framework and federal tax changes will be neutral to moderately positive.

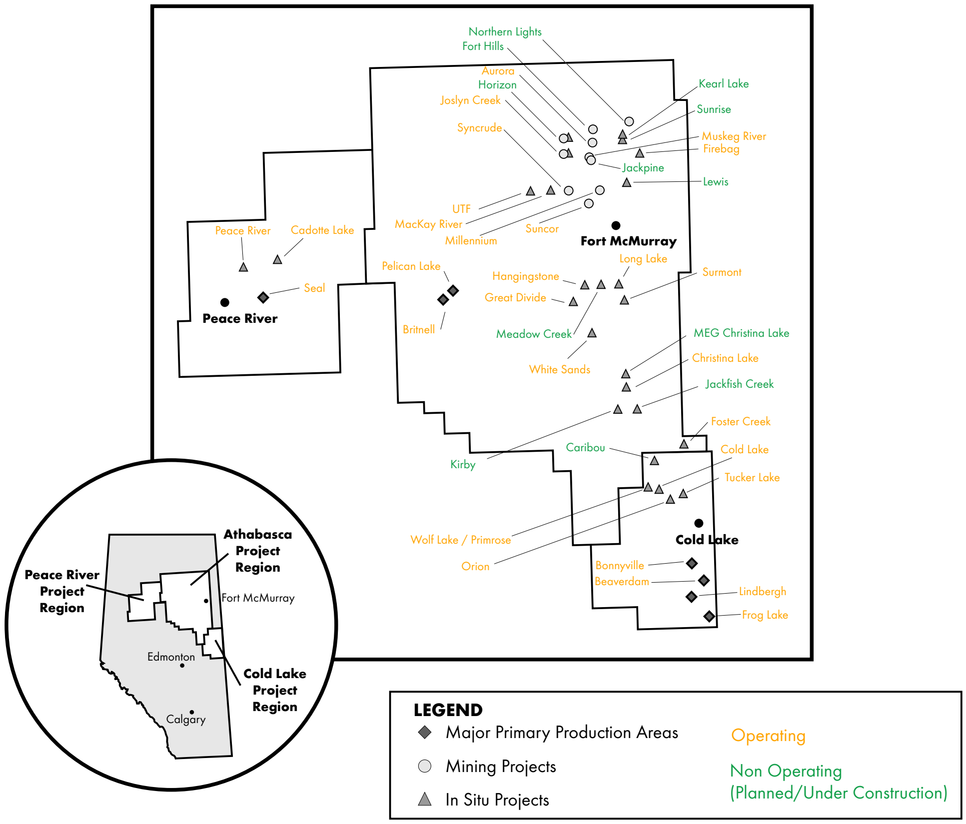
In 2007, bitumen production from mining and in situ operations totalled 223 000 m^3/d (1.4 MMb/d), an increase of 13 percent compared with 2006. In situ bitumen production increased by 20 percent to 94 000 m^3/d (592 Mb/d) (Figure 4.4). Two major in situ projects started up in 2007, the Surmont SAGD Project operated by ConocoPhillips and Total E&P Canada as well as the OPTI/Nexen Long Lake SAGD/Upgrader project (Figure 4.5). Bitumen from mining operations increased by nine percent to 129 000 m^3/d (813 Mb/d) and upgraded bitumen production increased by 11 percent to 104 600 m^3/d (659 Mb/d).

At Syncrude, upgraded bitumen production in 2007 reflected incremental volumes from the expanded Stage 3 facilities, which were operational throughout the year. However, this increased production was partially offset by unplanned maintenance on Coker 8-2 during the first quarter and planned maintenance on other units, including a turnaround of the LC-Finer. Further reductions occurred in the fourth quarter with Coker 8-3 outages that suspended production for approximately one week at the beginning of October and in early December. During the third quarter of 2007, Syncrude made the transition to producing the higher quality Syncrude Sweet PremiumTM (SSP) blend, with all production in the fourth quarter reflecting this switch. Syncrude production averaged 48 400 m^3/d (305 Mb/d), up by 15 percent from 2006.

At Suncor, oil sands production averaged 37 400 m^3/d (236 Mb/d) in 2007, compared with 41 300 m^3/d (260 Mb/d) in 2006. This decrease primarily reflects the impact of scheduled and unscheduled maintenance, which included a scheduled 50-day maintenance shutdown to portions of

FIGURE 4.5

Major Oil Sands Project Locations



In Situ Projects	***Operator***
Kirby	Canadian Natural Resources
Wolf Lake/Primrose	Canadian Natural Resources
Surmont	ConocoPhillips/Total
Great Divide	Connacher Oil and Gas
UTF (Dover)	Devon Energy
Jackfish Creek	Devon Energy
Christina Lake	EnCana
Foster Creek	EnCana
Caribou	Husky Energy
Sunrise	Husky Energy
Tucker Lake	Husky Energy
Cold Lake	Imperial Oil
Hangingstone	Japan Canada Oil Sands (JACOS)
Christina Lake	MEG
Long Lake	OPTI/Nexen Canada
White Sands	Petrobank
Lewis	Petro-Canada
MacKay River	Petro-Canada
Meadow Creek	Petro-Canada/Nexen
Peace River	Shell Canada
Firebag	Suncor Energy
Joslyn Creek	Total E&P Canada
Cadotte Lake	Shell
Orion	Shell

Mining Projects	***Operator***
Muskeg River	Albian Sands (Shell/Chevron/Western Oil Sands)
Jackpine Mine	Albian Sands (Shell/Chevron/Western Oil Sands)
Horizon*	Canadian Natural Resources
Kearl Lake	Imperial Oil
Suncor Base Mine	Suncor Energy
Millennium	Suncor Energy
Syncrude Base Mine	Syncrude Joint Venture
Aurora	Syncrude Joint Venture
Northern Lights	Synenco
Fort Hills	Petro-Canada/UTS Energy/Teck Cominco
Joslyn Creek	Total E&P Canada

Major Primary Production Areas

SEAL
Pelican Lake
Lindbergh
Frog Lake
Brintnell
Bonnyville
Beaverdam

* Includes plans for both in situ and mining

Source: NEB

Suncor's oil sands operation to tie in new facilities related to a planned expansion. Also affecting oil sands throughput were issues at Suncor's Firebag in situ operation which provides feedstock to the upgrading operations, where high levels of odorous emissions have resulted in an intervention by both Alberta Environment and the Alberta Energy and Utilities Board (EUB). Until emissions are reduced, production at Suncor's in situ operation has been capped by regulators at approximately 6 700 m^3/d (42 Mb/d) of bitumen.

Production at the Athabasca Oil Sands Project (AOSP) was disrupted by a 19 November fire that damaged one of two residue hydro-conversion units at the Scotford Upgrader, when a leak occurred and the vapour ignited. AOSP officials decided to move forward the planned maintenance for the upgrader and the associated Muskeg River mining complex which provides bitumen to the upgrader. One production train at the upgrader and the Muskeg River mine were in operation by year-end, with the restarting of the second production train completed in mid-January. Production for the year is estimated at 23 900 m^3/d, three percent above 2006 levels.

4.4 Crude Oil Exports and Imports

In 2007, crude oil exports averaged 294 411 m^3/d (1.85 MMb/d) which represents a year-on-year increase of three percent. Light crude oil exports, which include pentanes plus and synthetic crude oil (upgraded bitumen), represented 38 percent of all exports with the remaining 62 percent being exports of heavy crude oil.

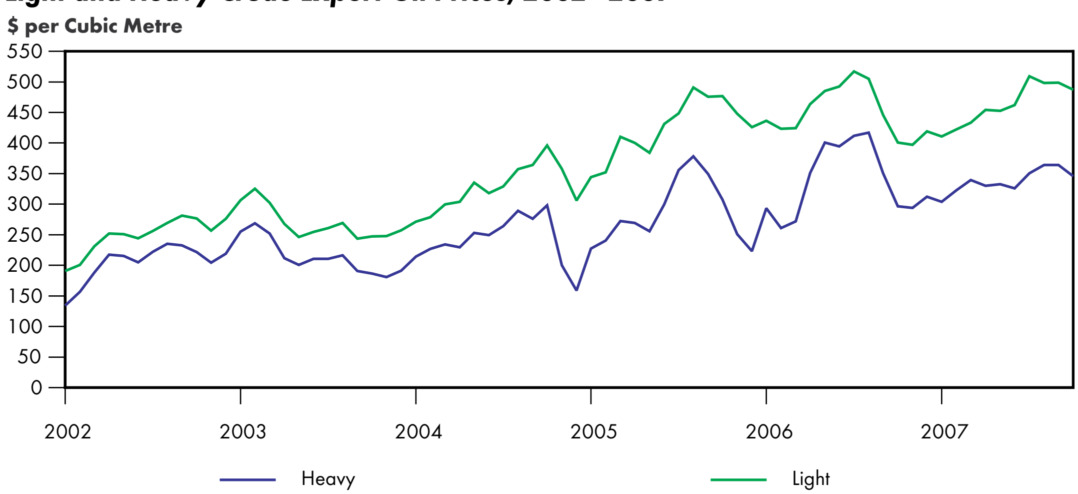
The estimated value of crude oil exports for 2007 is $41.2 billion compared with $39.3 billion in 2006. The estimate is based on projected export prices of $460 and $337 per cubic metre ($73 and $54 per barrel) for light crude oil and heavy crude oil, respectively (Figure 4.6).

Heavy and light crude oils are traded in separate markets and accordingly, the prices for each vary as a result of the supply and demand for each crude type. Heavy crude has a smaller market and has higher refining costs and is usually discounted. The light–heavy price differential varies as a function of market conditions in each market. Extraordinary circumstances aside, the differential typically narrows in the summer months because of the higher demand for heavy crude oil during asphalt season and widens again in September.

On a dollar basis, the light–heavy differential or "heavy crude oil discount" averaged $153 per cubic metre ($24 per barrel) during 2007 with a sustained fourth quarter average of $199 per cubic metre ($30 per barrel). At one point in the fourth quarter, the heavy crude oil discount reached $284 per

FIGURE 4.6

Light and Heavy Crude Export Oil Prices, 2002 - 2007



Source: NEB

cubic metre ($45 per barrel) due in part to refinery problems in the U.S. PADD II market, which is a key market for heavy crude oil.

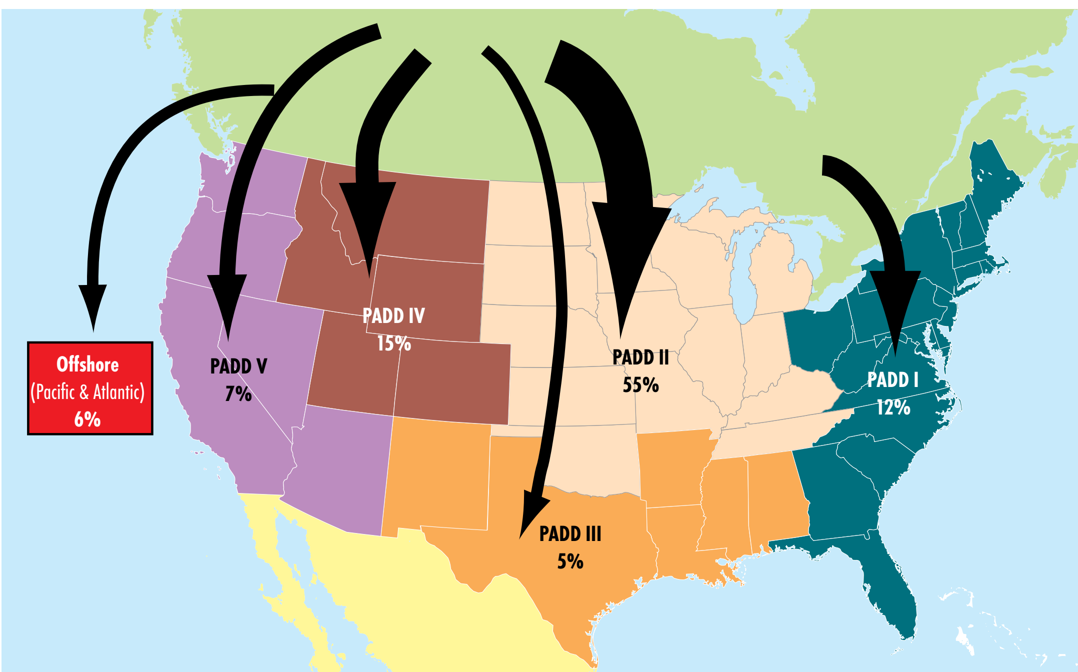
Capacity constraints on the three major oil export pipelines also contributed to the widening differential. The Enbridge and the Express/Platte systems were operating near capacity throughout 2007 forcing Canadian heavy crude oil producers to seek other markets for their crude oil. Trans Mountain was therefore over nominated most of 2007 as producers tried to transport their crude oil to the west coast. With the pipelines at capacity or under apportionment, there was a glut of Canadian heavy crude oil putting downward pressure on prices and contributing to the widening differential. In the short term, this situation is expected to continue to be driven by increases in oil sands production.

A number of pipeline applications were prepared and submitted to the Board in 2007. Enbridge submitted their Southern Lights, Alberta Clipper and Line 4 Extension applications which aim to expand system capacity in order to meet future production increases. The Canadian portion of TransCanada's 69 200 m^3/d (435 Mb/d) Keystone application (OH-1-2007) was approved by the Board in September 2007 and a subsequent application for extension to Cushing, Oklahoma was received in November. Enbridge's Southern Lights (OH-3-2007) and Alberta Clipper (OH-4-2007) applications were approved by the Board in the first quarter of 2008.

Canada remained the number one supplier of crude oil to the U.S. followed by Saudi Arabia and Mexico.[2] Saudi Arabia moved ahead of Mexico into the number two position during 2007. According to the Energy Information Administration (EIA) the U.S. imported on average 1.6 million m^3/d (10.0 MMb/d) with Canada supplying approximately 297 000 m^3/d (1.87 MMb/d). Over half

FIGURE 4.7

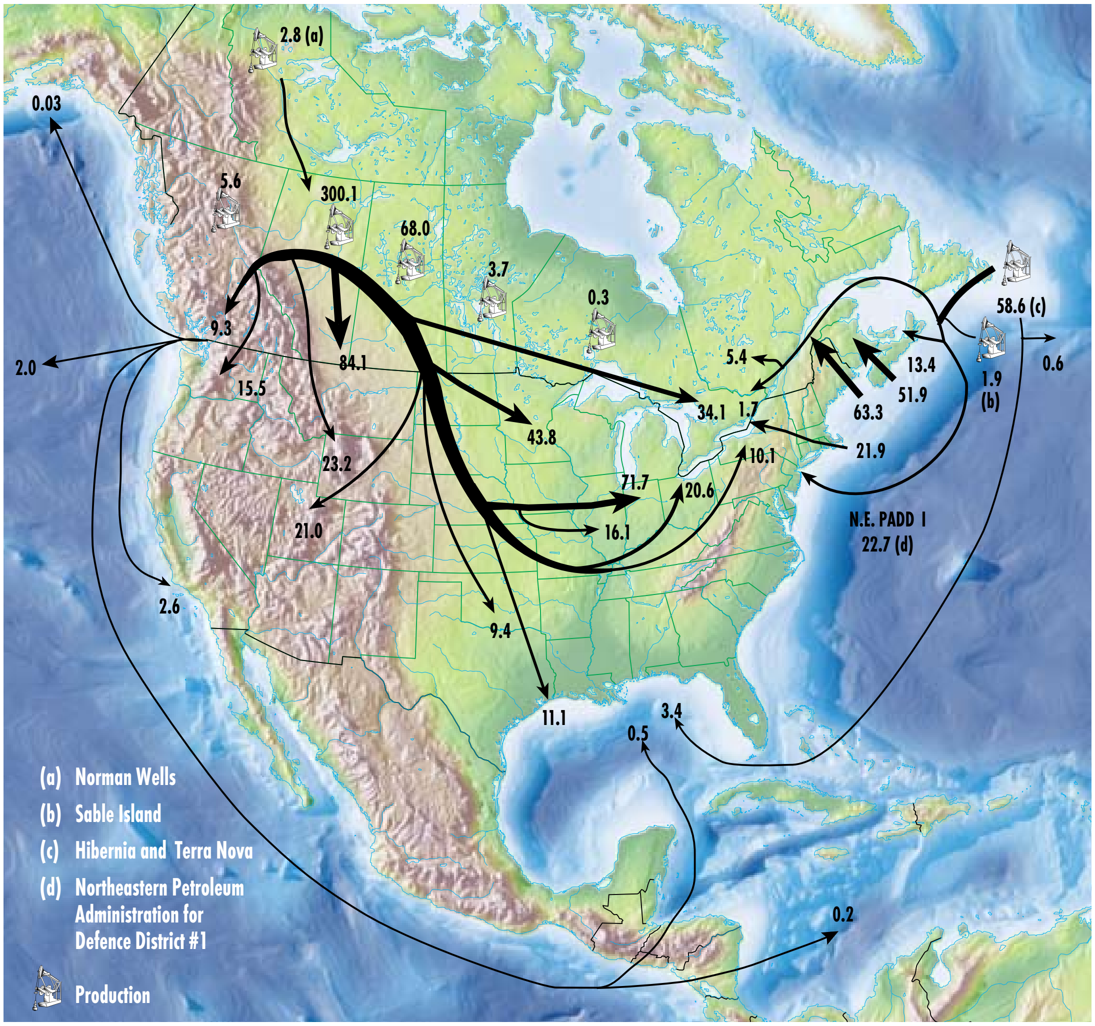
Deliveries of Canadian Crude Oil in 2007 (percent)



2 Canada accounted for 18.7 percent of U.S. imports, Saudi Arabia accounted for 14.5 percent and Mexico accounted for 14.1 percent.

FIGURE 4.8

Crude Oil Supply and Disposition – 2007 (thousand cubic metres per day)



(55 percent) of Canadian crude exports went to the U.S. Midwest (PADD II) market in 2007 making it the largest consuming region for Canadian crude oil (Figure 4.7, Figure 4.8).

Offshore eastern Canadian production continued to supply U.S. consumers. In 2007, over 81 percent of eastern Canadian crude oil exports were delivered to the U.S. east coast (PADD I). The remaining eastern Canadian exports were delivered to the U.S. Gulf Coast (16 percent) and the United Kingdon (3 percent).

Although Canada is a net crude oil exporter, imports still account for a significant portion of Canadian refinery demand. Refineries located in Ontario, Quebec, and Atlantic Canada source a portion of their crude oil from abroad, while western Canadian refineries are fully supplied by domestic production and do not import crude oil. In 2007, crude oil imports are estimated at 144 344 m³/d (909 Mb/d). This is an increase of six percent compared with 2006 and represents 48 percent of total Canadian refinery feedstock. OPEC countries supplied 49 percent of imported crude oil and 38 percent was delivered from the North Sea. The remaining 13 percent was split between North American producing nations (U.S. and Mexico) and other countries. In 2007, 80 percent of the Atlantic refining requirements were met by imports and the remaining 20 percent were met with eastern Canadian production. Quebec remained the largest regional importer of crude oil with 92 percent of their refining needs supplied from international sources. Ontario accounted for the remainder of imported crude volumes. Ontario refineries are increasingly sourcing crude oil supplies from Western Canada.

4.5 Oil Refining

There were 19 Canadian refineries operating at the end of 2007 with a total refinery capacity (distillation) of 324 500 m^3/d (2 MMb/d). The refineries and their locations are included in Table 4.3.

Canadian demand for petroleum products in 2007 is estimated at 281 960 m^3/d (1.77 MMb/d), an increase of 2.9 percent compared with 2006, reflecting the strong performance of the Canadian economy during the year. Refinery runs of crude oil in Canada in 2007 are estimated at 290 250 m^3/d (1.83 MMb/d), an increase of 1.6 percent over 2006 levels of 285 470 m^3/d (1.80 MMb/d). Capacity utilization also increased from 88.2 percent in 2006 to 89.7 percent in 2007. Refinery receipts of domestic crude oil grew 3.5 percent in 2007 to 153 500 m^3/d (965 Mb/d), with Western Canada

TABLE 4.3

Refineries in Canada

Company	Location	Capacity (m^3/d)	Capacity (b/d)
Atlantic Canada		**75 200**	**473,800**
Imperial Oil Limited	Dartmouth, N.S.	14 000	88,200
Irving Oil Limited	Saint John, N.B.	44 500	280,400
North Atlantic Refining (Harvest Energy)	Come-by-Chance, Nfld.	16 700	105,200
Quebec		**74 400**	**468,700**
Petro-Canada	Montreal	20 700	130,400
Shell Canada Limited	Montreal	20 700	130,400
Ultramar Limited	St. Romuald	33 000	207,900
Ontario		**74 400**	**468,700**
Imperial Oil Limited	Nanticoke	17 800	112,100
Imperial Oil Limited	Sarnia	19 300	121,600
Shell Canada Limited	Sarnia	11 100	69,900
NOVA Chemicals	Sarnia	12 700	80,000
Suncor Energy Products Inc.	Sarnia	13 500	85,100
Western Canada		**100 500**	**633,200**
Consumers Co-operative Refineries Ltd.	Regina, Sask.	13 500	85,100
Husky Energy Marketing Inc.	Lloydminster, Alta.	4 000	25,200
Imperial Oil Limited	Strathcona, Alta.	28 600	180,200
Moose Jaw Asphalt	Moose Jaw, Sask.	2 400	15,100
Petro-Canada	Edmonton, Alta.	21 900	138,000
Shell Canada Limited	Scotford, Alta.	20 000	126,000
Chevron Canada Limited	Burnaby, B.C.	8 300	52,300
Husky Energy Marketing Inc.	Prince George, B.C.	1 800	11,300
Total		**324 500**	**2,044,400**

Source: NEB

domestic receipts offsetting a reduction in eastern Canada receipts as a consequence of reduced production at Hibernia during February. Refinery receipts during 2007 were higher reflecting increased demand for crude oil from Canadian refineries, particularly in Quebec and the Atlantic Provinces, with smaller increases in Western Canada.

4.6 Main Petroleum Product Exports and Imports

Canada continued to be a net exporter of petroleum products, with the U.S. as its main destination. Exports of main petroleum products in 2007 are estimated to be 71 340 m^3/d (448.7 Mb/d), an increase of six percent compared with 2006. Increased availability of refined products in Canada, combined with tight refinery capacity in U.S. were the main drivers for this increase. Canadian imports declined by seven percent to 43 080 m^3/d (271.0 Mb/d) compared with 2006 also reflecting the reduced need for imports due to increased domestic supply of refined products. Exports to the U.S. were mainly to the East Coast (65 percent), followed by the U.S. Midwest and the U.S West Coast.

The estimated revenue in 2007 from main petroleum products, including partially processed oil, was $9.2 billion, up from $6.7 billion in 2006. Strong demand for gasoline and diesel fuel, rising crude oil prices and an unusual wave of refinery outages in U.S. and Canada boosted product prices during the first part of the year. Very high crude oil prices and low gasoline inventory levels supported gasoline prices most of the year. Distillate inventories remained near the middle of historical levels, but prices reached historical records at the end of the year.

TABLE 4.4

World Oil and Canadian Products Prices (cents per litre)

	2007	2006	Change	Total
Gasoline	97.7	101.8	+4.1	4.2
Diesel	97.1	101.1	+4.0	4.2
Furnace oil	82.5	86	+3.5	4.2
US$/b				
WTI (Cushing. OK)	66.05	72.34	+6.29	9.5
Edmonton Par	71.4	64.34	+7.06	11.0

Source: Fuel Focus Annual Review 2007 NRCan and Energy Information Agency

4.7 Product Prices

According to Natural Resources Canada (NRCan)[3], average Canadian retail product prices were approximately 4.2 percent higher in 2007 compared with 2006, reflecting increases in world crude oil prices. Retail gasoline prices in Canada increased from 98 cents/litre in 2006 to 101.8 cents/litre in 2007, with diesel fuel and furnace oil showing similar increases (Table 4.4). The price escalation in world crude oil markets had a lower than expected impact on Canadian retail prices of gasoline, diesel fuel and heating oil, as the strength of the Canadian dollar helped to offset higher crude oil prices, which are denominated in U.S. dollars.

Gasoline prices increased during the first half of 2007 because of a tight supply–demand balance in North America. Heavier than expected spring refinery maintenance combined with a number of refinery problems pushed gasoline inventories in the U.S. to low levels. In Canada, an unplanned outage at Imperial's Nanticoke refinery in February, combined with a strike at CN rail caused shortages of gasoline and diesel fuel in Ontario and Quebec. The tight gasoline balance in North American markets eased in September with the return of refineries from maintenance and the end of the summer driving season. Distillate fuels (heating oil and diesel) had adequate supply during the winter, with the exception of Western Canada, where a fire at the Shell Scotford upgrader in November contributed to product supply tightness in Western Canada.

3 Fuel Focus, 2007 Annual Review, NRCan, 11 January 2008

4.8 Looking Ahead

Crude oil prices continue to climb to record highs. This rise in crude oil prices has been driven by expectations of continued strength in global demand and geopolitical tensions in Nigeria and Venezuela. In addition, the continuing decline of the U.S. dollar is attracting investors to commodity markets, including crude oil. The global oil markets are pushing oil prices higher to slow global oil demand in a supply-constrained market. High crude oil prices in countries that import crude oil, such as the U.S., drives up inflation and slows economic growth. In Canada, the appreciation of the Canadian dollar versus the greenback has had a positive effect by making American manufactured goods less expensive and softens the increase in the price of gasoline. However, an appreciating Canadian dollar has hurt Canadian manufacturers and other sectors that rely on petroleum products for their operations, raising their input costs. Other key uncertainties this year will be the weather and the state of the U.S. economy.

In 2008, Canadian crude oil production is expected to increase to 443 000 m^3/d (2.8 MMb/d) or 2.2 percent compared with 2007 levels, led by two major oil sands projects. The CNRL Horizon project, which features surface mining and upgrading, is scheduled to start operations mid-year. The Opti/Nexen Long Lake project, which features in situ SAGD extraction and upgrading, is also due to start the upgrading portion by mid-year, with the in situ production initiated in late 2007. Decline rates for conventional crude oil in the WCSB are expected to be moderate based on relatively higher levels of oil drilling and the success of the Bakken oil play in southeast Saskatchewan and southwest Manitoba.

Refineries

In the last several years there have been a number of announcements concerning refinery expansions and the construction of new refineries. In this regard, there has been little done in the past year; however, 2008 could witness more action on this front. Most of the announced projects are located in the Atlantic region, but new capacity is also being considered for Ontario and Western Canada (Table 4.5).

TABLE 4.5

Proposed Refinery Expansions in Canada

Company	Location	Capacity (m^3/d)	Capacity (b/d)	Estimated Completion
Atlantic Canada		**95 200**	**600,000**	
Newfoundland and Labrador Refinery Corp.	Placentia Bay, Nfld	47 600	300,000	2010-2011
Irving Oil	St. John, N.B.	47 600	300,000	2015
Quebec		**6 400**	**40,000**	
Ultramar Limited*	St. Romuald	6 400	40,000	2008
Ontario		**23 800**	**250,000**	
Shell Canada Ltd.	St. Clair	23 800	250,000	2013
Western Canada		**4 700**	**30,000**	
Consumers Co-operative Refinery Ltd.*	Regina, Sask.	4 700	30,000	2012
Total		**130 100**	**920,000**	

* Expansion

In the Atlantic region, refiners have taken advantage of their favourable location being close to the huge U.S. east coast market and with easy access to both imported and domestic crude oil. This has enabled refiners in this region to build sizeable export-oriented refineries. Recently, growing demand in the U.S northeast and limitations on expanding refinery capacity in the U.S. have made it attractive to increase capacity in Atlantic Canada. In November 2007, Irving Oil submitted its environmental assessment plan to provincial and federal regulators for its Eider Rock Refinery project. The new 47 600 m^3/d (300 Mb/d) refinery, initially proposed in October 2006 would be built near the company's Canaport deepwater crude oil receiving terminal and the existing Irving refinery in Saint John, New Brunswick. The plant's design would allow the flexibility to run a wide variety of crude oil from Canada and overseas, and, at the same time, maximize the production of light products (gasoline, naphtha, jet and diesel fuel), instead of heavier products such as bunker fuel and asphalt. Recently, BP signed a Memorandum of Understanding (MOU) with Irving to work together on the next phase of the project. The project has an estimated cost of between $5 and $7 billion, with an expected in-service date of 2015.

In October, Newfoundland and Labrador Refinery Corporation obtained environmental approval for its proposed $4.6 billion refinery project at Placentia Bay, Newfoundland. Construction on the new refinery with an initial capacity of 47 600 m^3/d (300 Mb/d), would start in the first quarter of 2008, with an expected in-service date of 2011.

In Quebec, Ultramar Ltd. is expanding its crude oil processing capacity by 6 300 m^3/d (40 Mb/d) at its St. Romuald, Quebec refinery, raising total capacity to 41 300 m^3/d (260 Mb/d) by the second quarter of 2008. Petro-Canada also has plans to add a new 4 000 m^3/d (25 Mb/d) deep conversion (coking) unit at its Montreal refinery that would allow it to process incremental volumes of foreign heavy crude oil at the facility. If the company proceeds with the project in 2008, construction would be completed by the end of 2009.

In Ontario, Shell has continued with its plans to build a new 23 800 m^3/d to 31 700 m^3/d (150 to 200 Mb/d) heavy crude oil refinery at St. Clair, near Sarnia, Ontario. The company initiated the environmental assessment for the project under terms already approved by the provincial government in June 2007. If Shell proceeds with the project in 2009, the refinery would be completed in 2013 and would incorporate part of the existing Sarnia facility. In December 2007, Suncor announced that the upgrading project at its Sarnia refinery was nearing completion. The new facilities, built at a cost of $960 million, would increase the amount of oil sands crude oil processed at the refinery by up to 6 300 m^3/d (40 Mb/d) and would allow for the production of ultra low sulphur diesel.

In Western Canada, Consumers Co-operative Refineries Ltd. announced in January 2008 a $1.9 billion expansion of its refinery in Regina, Saskatchewan. The project would increase the capacity of the plant from 15 900 m^3/d to 20 600 m^3/d (100 to 130 Mb/d). Pending regulatory approval, the expected in-service date is 2012.

NATURAL GAS

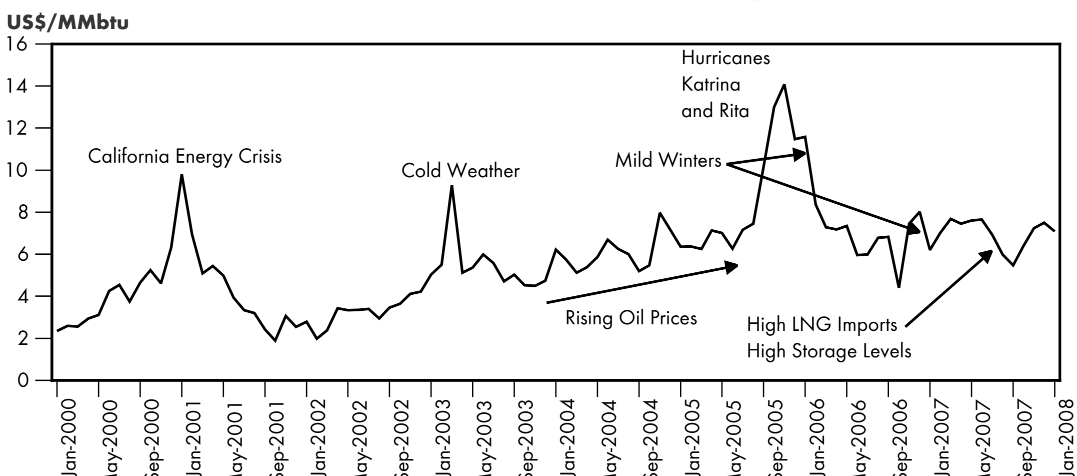
5.1 North American Natural Gas Markets

In 2007, Canada produced about one quarter of the combined natural gas production of Canada and the U.S. Almost 98 percent of Canadian gas is produced from the Western Canada Sedimentary Basin (WCSB) with Alberta producing roughly 79 percent. British Columbia and Saskatchewan contribute roughly 16 and five percent, respectively, of total WCSB production. The Canadian and U.S. natural gas markets operate as one large integrated market. This means that events in any region such as changes in transportation costs, infrastructure constraints or weather will have effects on the other regions. Most Canadian and U.S. natural gas production comes from areas roughly following the continental divide, from the Gulf of Mexico to the Northwest Territories. Demand is spread across the continent but is concentrated in densely populated areas and in areas of intense industrial activity. Canadian gas production is connected to the North American gas market through a network of thousands of kilometres of pipelines that allows buyers to purchase and transport natural gas from a number of supply sources across the continent.

Figure 5.1 shows that natural gas prices have been extremely volatile in recent years. Since 2001, a lack of spare productive capacity in North America has resulted in tight market conditions that have contributed to high and volatile natural gas prices. The price of natural gas is particularly sensitive to real and anticipated weather events and this can result in large swings.

F I G U R E 5 . 1

North American Gas Price Trends – Henry Hub 3-day Average Price



Source: GLJ Publications Inc.

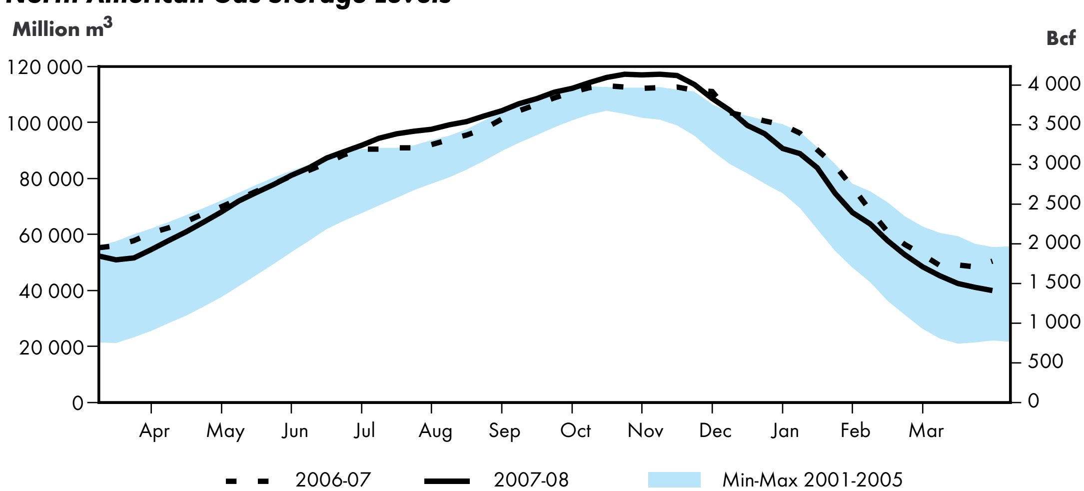
Natural gas prices can be sensitive to crude oil prices. Some consumers can switch between natural gas and fuel oil for their heating needs, particularly in the U.S. northeast and southeast. This competition provides a link, albeit imperfect, between oil prices and natural gas prices, such that an increase in crude oil prices can support an increase in the price of natural gas. Natural gas prices in North America, as measured by the 3-day average at the Henry Hub, shows that 2007 prices were about five percent lower than the 2006 average and less volatile.

Natural gas is produced at a steady rate throughout the year whereas its consumption is seasonal. To balance supply with demand, gas is injected into underground storage in the summer and withdrawn in the winter months. April is the beginning of the typical storage injection season (Figure 5.2). Above-normal temperatures in the winter of 2006-2007 left large volumes of natural gas in North American gas storage facilities at the beginning of April, about seven percent below the record-breaking April 2006 levels. Gas prices weakened through the spring and summer as large volumes of LNG were imported in to the US. By September, LNG imports receded by about half of the summer rate, as European and Asian LNG pre-winter demand increased. Natural gas storage in North America, particularly in the U.S., exceeded the 2006 levels by the end of October, to reach a new record high before entering the 2007-2008 winter heating season in November. Despite the high storage levels and mild early winter temperatures, natural gas prices rose from the late-September low.

Canadian natural gas prices, measured at the AECO hub in Alberta, began 2007 at $6.04/GJ and reached a low of $4.11/GJ in late August before closing the year at $6.12/GJ, following the trend of the U.S. Henry Hub price (Figure 5.3). Prices in eastern Canadian markets are cited at the Dawn hub, which is located near underground storage facilities in southwestern Ontario, and include a component of transportation and storage costs (see Figure 5.4).[4] The Dawn price began the year at US$5.94/MMBtu and reached a low of US$5.46/MMBtu in early September. The Dawn price rose gradually through autumn and early winter to close the year at US$7.62/MMBtu.

FIGURE 5.2

North American Gas Storage Levels

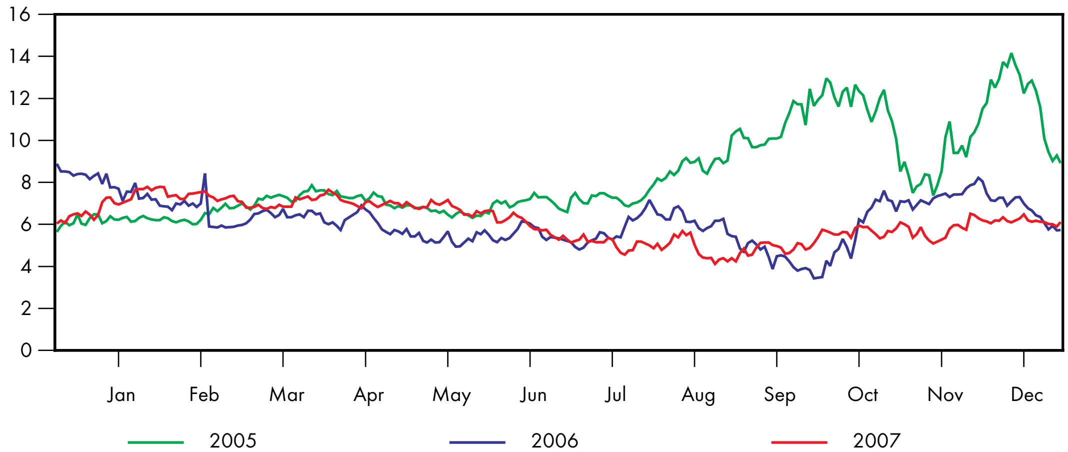


Source: Canadian Enerdata Ltd., NEB estimates, U.S. Energy Information Administration

4 Dawn trades are in US$/MMBtu

FIGURE 5.3

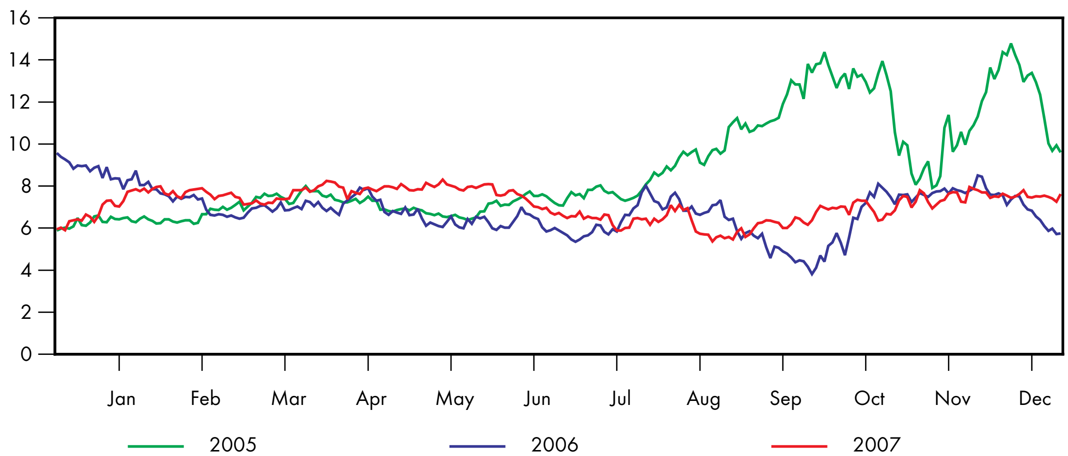
Daily AECO-C Price
Cdn$/GJ



Source: Platts

FIGURE 5.4

Daily Dawn Price
US$/MMBtu



Source: Platts

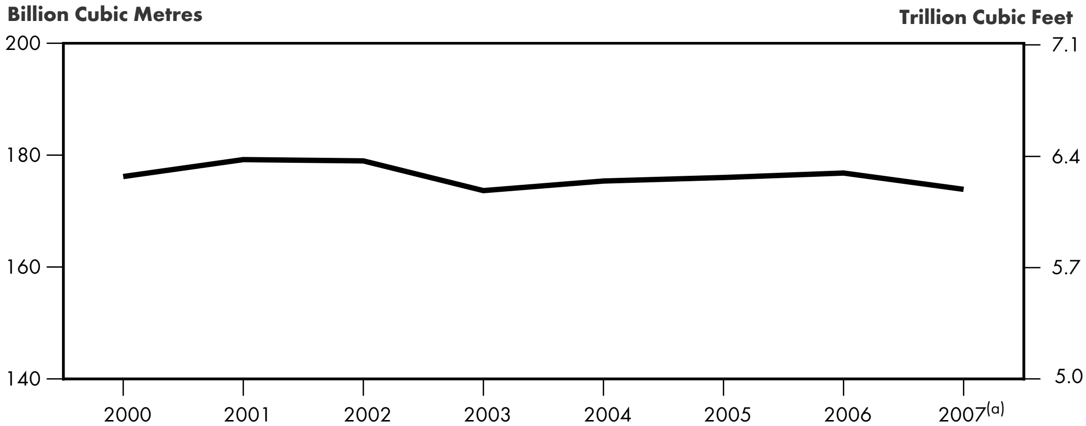
5.2 Natural Gas Production

Canadian natural gas production in 2007 averaged 476.5 million m^3/d (16.8 Bcf/d). This is roughly two percent less than in 2006. Western Canadian production remained relatively stable through the first half of the year as wells drilled during the first half of 2006 were connected into the pipeline system and brought on stream. The impact of reduced drilling was felt in the second half of the year with production slipping by an average of about 12.7 million m^3/d (0.4 Bcf/d).

On the East Coast, Sable production ramped up in the first half of the year as operation of the new compression facility became more consistent. In the second half, production stabilized at around 11.5 million m^3/d (0.41 Bcf/d) or about 33 percent higher than at the start of 2007. Additional production from the onshore McCully field in New Brunswick commenced midway through the year and gradually increased to represent about seven percent of the region's production.

FIGURE 5.5

Canadian Marketable Gas Production, 2000 - 2007



(a) Estimate

Development of the Deep Panuke gas project was initiated in 2007 following regulatory approval and a commercial decision to proceed. The earliest that gas production might occur is in 2010.

U.S. onshore production continued to increase in 2007 mainly through additional unconventional gas from Texas, Oklahoma, Arkansas and Rockies regions. Near the end of the year, a major deep water gas project in the Gulf of Mexico also began production. For the second consecutive year, there was no hurricane damage to U.S. production facilities in the Gulf of Mexico. As a result, average U.S. dry gas production for 2007 is estimated at 1 496 million m^3/d (52.8 Bcf/d) or roughly 62 million m^3/d (2.2 Bcf/d) higher than in 2006.

The U.S. has LNG import capacity of over 158.6 million m^3/d (5.6 Bcf/d) through six LNG terminals. In 2007, average LNG imports were 59.5 million m^3/d (2.1 Bcf/d), well above the 45.3 million m^3/d (1.6 Bcf/d) imported in 2005. LNG imports into the U.S. increased by an average 29.4 million m^3/d (1.0 Bcf/d) from March through August of 2007. The increase was aided by a mild winter leaving European gas storage relatively full and encouraging the diversion of cargoes to the U.S. LNG imports fell back after August as LNG demand increased in Japan to compensate for reduced nuclear output.

5.3 Natural Gas Reserves

The NEB's estimate of remaining marketable gas reserves at the end of 2006 (the last year for which data is available), is 1 647 billion cubic metres (58.1 trillion cubic feet) (Table 5.1). Reserve additions were 198 billion cubic metres (7.0 trillion cubic feet) in 2006 and replaced 116 percent of annual production. The rise in remaining reserves reflected exploration and improved recovery in known gas fields. Initial reserves increased in Alberta, British Columbia, Saskatchewan and Ontario in 2006 while frontier regions remained unchanged.

5.4 Canadian Natural Gas Consumption

Approximately one quarter of all energy consumed in Canada is natural gas with estimated consumption in 2007 of about 226 million m^3/d (7.97 Bcf/d), or about 47 percent of Canadian production. Natural gas is primarily consumed in the residential and commercial sectors for space heating, in the industrial sector for process heat, as a building block in chemical production, and

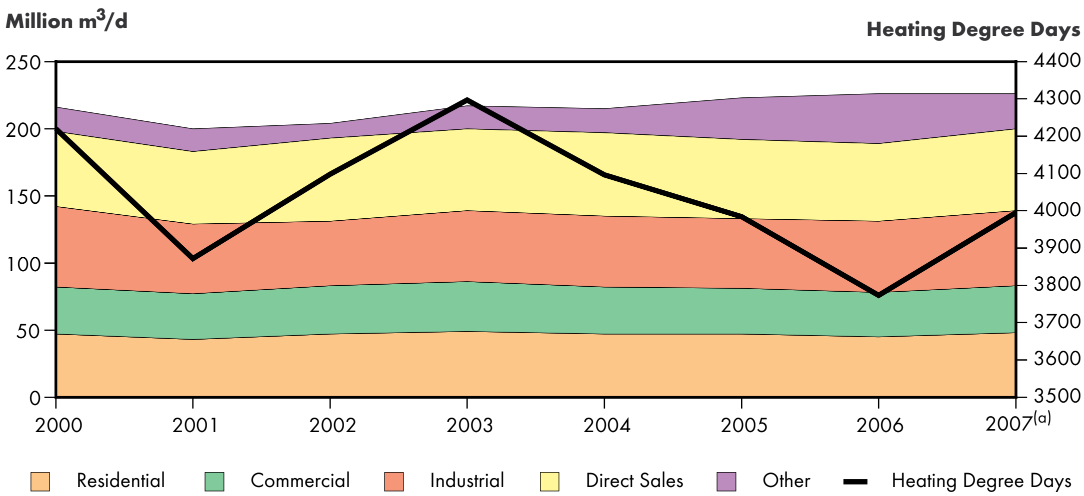
TABLE 5.1

Canadian Natural Gas Reserves, Year-end 2006 (10^9m^3)

(10^9m^3) At Year-end 2006	Natural Gas Reserves		
	Initial Reserves	**Cumulative Production**	**Remaining Established Reserves**
British Columbia	899.2	519.1	380.1
Alberta	4798.7	3 683.5	1 115.2
Saskatchewan	268.3	175.3	93.0
Subtotal - WCSB	**5 966.2**	**4 377.9**	**1 588.3**
Ontario	54.2	34.2	20.0
Nova Scotia Offshore	55.0	30.1	24.9
Mainland NWT & Yukon	29.3	16.2	13.1
Mackenzie Delta	0.3	0.1	0.2
Subtotal - Frontier	**84.6**	**46.4**	**38.2**
Total Canada	**6 105.0**	**4 458.5**	**1 646.5**
Total Canada (trillion cubic feet)	**215.5**	**157.4**	**58.1**

FIGURE 5.6

Canadian Total Gas Consumption and Heating Degree Days



(a) Estimate

Source: Statistics Canada, NEB Estimates and Canadian Gas Association

to produce electricity. Figure 5.6 also shows that Canadian gas demand for heating, industrial use and electric power generation (included within "direct sales") has been fairly flat since 2000. Larger amounts of natural gas have been seen, in recent years, in the "other" category that includes line pack fluctuation[5], gas used in the natural gas pipeline system, and lost and unaccounted volumes.

Despite continuing growth in residential and commercial floor space, actual natural gas consumption in this sector has changed little since 2000, and this is attributed, at least in part, to mild winter

5 Line pack is the volume of gas contained within a pipeline system at any point in time.

weather. Four of the past seven years rank among Canada's top 10 warmest years.[6] 2006 was the second warmest on record; based on preliminary data, 2007 ranks as the thirteenth warmest year, since nationwide records began in 1948. Besides weather effects, higher and more volatile natural gas prices have moderated natural gas consumption, particularly in the price-sensitive industrial sectors. In addition, the appreciating Canadian dollar over the past five years, has also adversely affected the Canadian manufacturing sector, which may result in lower manufacturing activity and consequently, lower natural gas consumption.

A fast growing sector for natural gas consumption is the Alberta oil sands. Figure 5.7 shows the natural gas consumption for oil sands operations from 2000 to 2007. Natural gas is used in both the generation of electricity and steam. Steam is used for in situ oil production and in the production of hydrogen to upgrade bitumen into synthetic crude oil blends. Consumption of natural gas in 2007 was almost 32 million m^3/d (1.13 Bcf/d) - over three times the amount of gas used in 2000. Although, the oil sands industry is a large natural gas user, efforts are under way to reduce its dependence on this fuel. This includes pursuing energy efficiency improvements as well as the adoption of alternative fuels and technologies, such as bitumen gasification, which will provide the bulk of fuel requirements and feedstock in the OPTI/Nexen Long Lake SAGD/Upgrader project, which began production operations in late 2007.

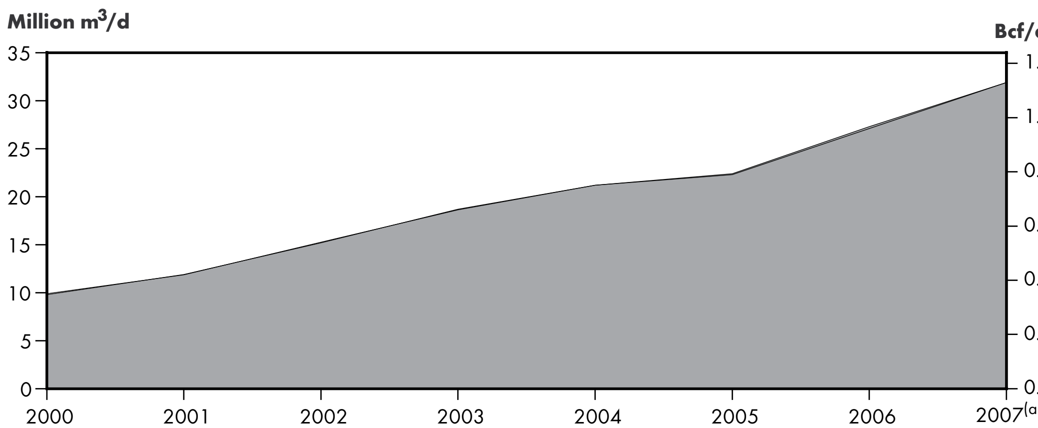
In the longer-term, it is expected that the application of bitumen gasification will gradually gain momentum in both in situ and upgrading operations. As well, the application of other technologies such as toe-to-heel air injection (THAI™) and Multiphase Superfine Atomized Residue (MSAR) will begin to play a role. Therefore, although natural gas demand in oil sands applications is expected to increase, it does not increase at the same rate as oil sands production.

5.5 Canadian Natural Gas Exports and Imports

Natural gas exports for 2007 were 294 million m^3/d (10.4 Bcf/d) or about 17 percent of estimated U.S. consumption. The U.S. Central/Midwest and Pacific Northwest regions are Canada's largest export markets, with some volumes exported to the U.S. northeast. Overall, exports of natural gas

FIGURE 5.7

Average Annual Natural Gas Requirements for Oil Sands Operations



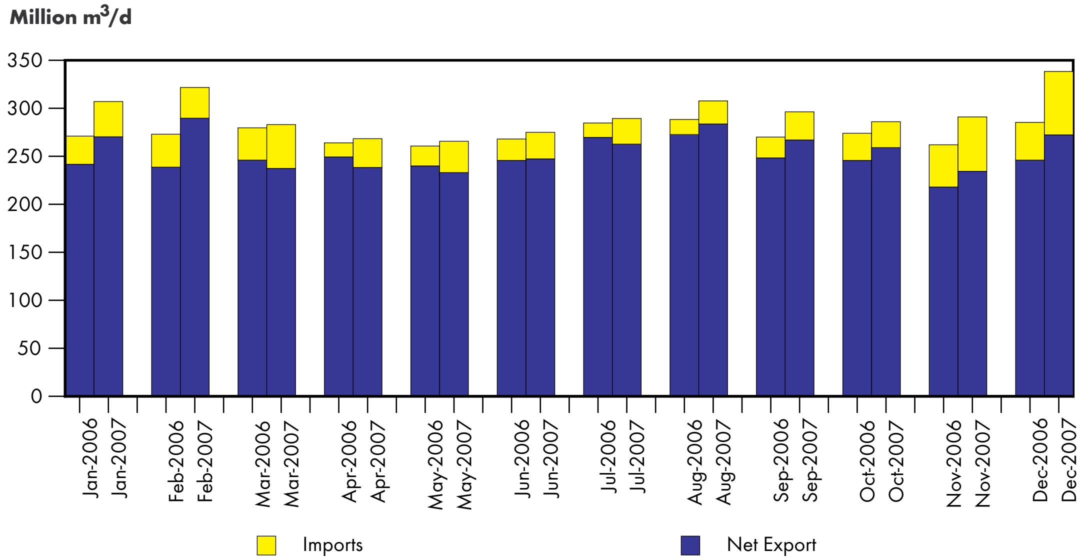
(a) Estimate

Source: NEB and Alberta Energy Resources Conservation Board

6 Environment Canada, Climate Trends and Variations Bulletin, Annual 2007, 28 January 2008. http://www.msc-smc.ec.gc.ca/ccrm/bulletin/national_e.cfm

FIGURE 5.8

Monthly Export and Import Volumes



Source: NEB

to the U.S. were higher in 2007 than 2006 (Figure 5.8). The extremely warm weather conditions of 2006 resulted in lower natural gas consumption and consequently, lower U.S. imports of Canadian gas. Therefore, the relatively cooler 2007 temperatures saw gas exports to the U.S. increase over 2006 levels.

The gross volume of Canadian gas exported to the U.S. was up 7.5 percent in 2007 compared with the previous year. Net exports (gross exports less imports) for 2007 were 258 million m^3/d (9.1 Bcf/d), about 4.4 percent higher than the 2006 net export volume of 247 million m^3/d (8.7 Bcf/d). Reduced Canadian gas drilling did not start to see the impact of lower Canadian gas production until the last quarter of 2007. Above-average storage inventories throughout 2007 also helped meet natural gas consumption in Canada as exports increased and natural gas production declined.

Overall, Canadian revenues from gas exports in 2007 were very similar to 2006. Although there was an increase in export volumes, the average export price was about five percent lower in 2007 than in 2006 resulting in net export revenues of $24.3 billion, almost the same as net export revenues in 2006.

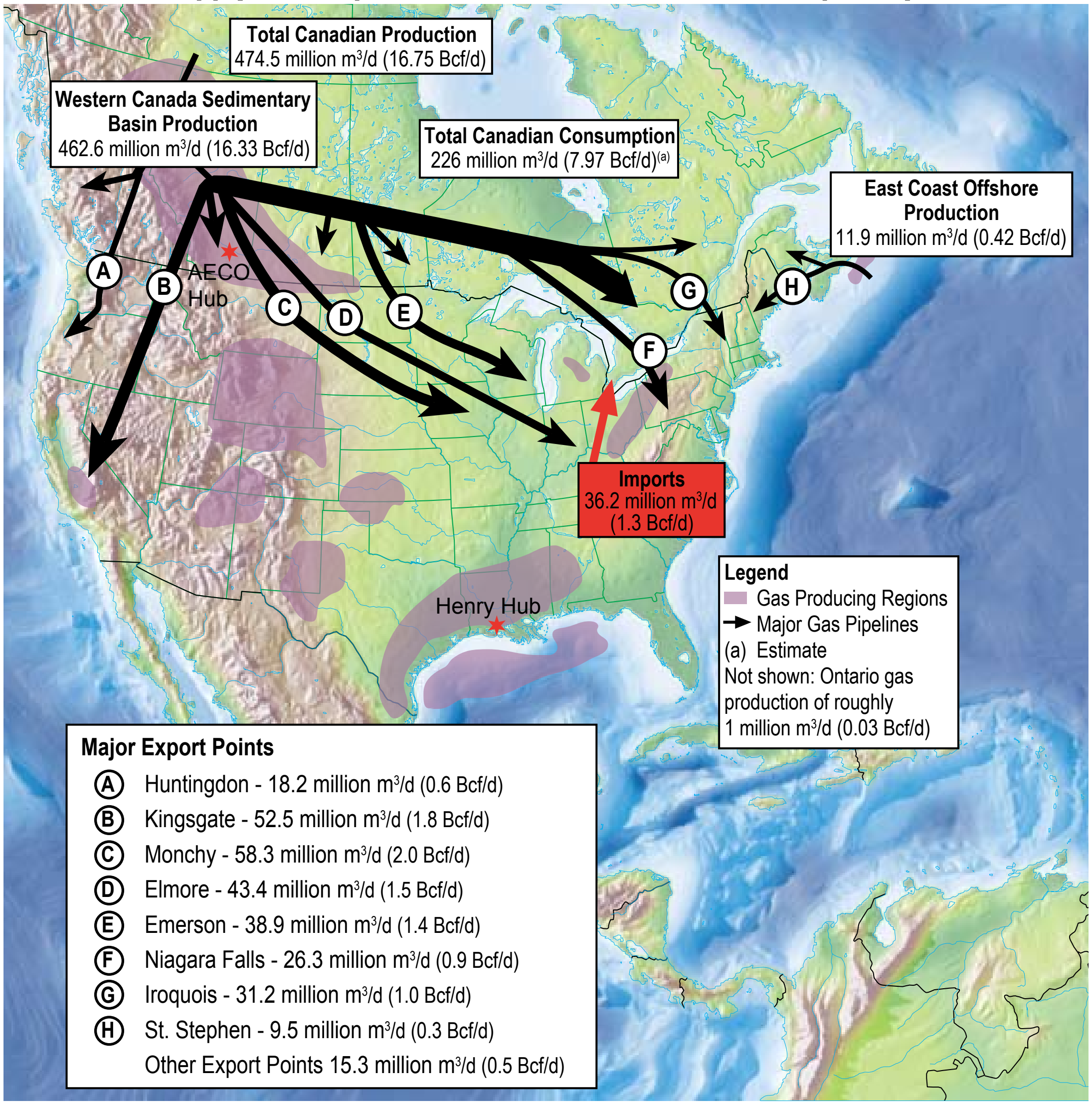
Canada is a net exporter of natural gas; however, 36.2 million m^3/d (1.3 Bcf/d) of gas was imported into Ontario from the U.S. in 2007 (Figure 5.9). Pipeline infrastructure allows gas to flow along a choice of pipeline options when destined to eastern markets. As a result, Ontario may import natural gas if it is economic.

5.6 Natural Gas Liquids (excluding Pentanes Plus)

Natural gas liquids (NGLs) refer to the liquid hydrocarbon products extracted from the natural gas stream and are initially recovered as a hydrocarbon mix. The component parts can then be further separated into marketable products such as ethane, propane and butanes. Propane and butanes are also produced from crude oil refining and upgrading processes. Products from these processes are sometimes referred to as liquefied petroleum gases (LPG). In 2007, it is estimated that 88 percent of propane and 67 percent of butane supplies came from natural gas production.

F I G U R E 5 . 9

Natural Gas Supply and Disposition – 2007 (million cubic metres per day)



Propane prices remained high throughout 2007 driven largely by rising crude oil prices and strong feedstock demand in the petrochemical sector in North America. The high price, however, did not result in higher production levels for propane. In 2007, propane production from gas plants decreased by about five percent to 26 600 m^3/d (168 Mb/d). This decrease can be attributed to lower drilling rates for natural gas because of depressed natural gas prices and higher drilling costs. Ethane and butane production from gas plants decreased slightly to 42 250 m^3/d (266 Mb/d) and 15 400 m^3/d (97 Mb/d), respectively.

In 2007, refinery production for both propane and butane increased from 2006 levels due to higher conventional crude oil production and the return from maintenance of upgraders at oil sands mining operations. Refinery production of propane is estimated at 3 800 m^3/d (24 Mb/d), a six percent increase. Refinery butane production increased by four percent to meet strong Canadian domestic demand for butane as a heavy oil diluent.

The U.S. Midwest continues to be Canada's largest market for propane and butanes, accounting for about 60 percent and 45 percent, respectively, of the total export volumes of NGLs. Estimated 2007 propane exports declined by seven percent to 17 500 m^3/d (110 Mb/d) and butane exports decreased by 13 percent to 3 800 m^3/d (24 Mb/d). The decrease in propane exports was mainly due to lower heating demand caused by mild weather during most of the winter season in North America; whereas, the lower butanes export volume was caused by strong diluent demand in the Alberta heavy oil sector.

Despite lower propane export volumes in 2007, propane prices were slightly higher and this resulted in the estimated export revenue increasing by three percent to $2.1 billion. Butane prices were also marginally higher in 2007; however, export volumes were lower resulting in a decline of six percent to $555 million. Export revenue for the two commodities combined, totalled almost $2.7 billion.

5.7 Looking Ahead

In the coming years, it is expected that North American demand for natural gas will continue to outpace the growth in domestic supplies. In Canada, natural gas supply from new sources such as frontier regions, LNG, coalbed methane (CBM) and shale gas will be increasingly required to supplement declining supply from the conventional sources of the WCSB and Sable Island to meet growing demand. Significant incremental requirements for natural gas in Canada will come from growing gas consumption in oil sands developments in Alberta and new gas-fired electrical generation in Ontario which will help displace existing coal-fired electricity generation and meet growing electricity demand.

Liquefied Natural Gas

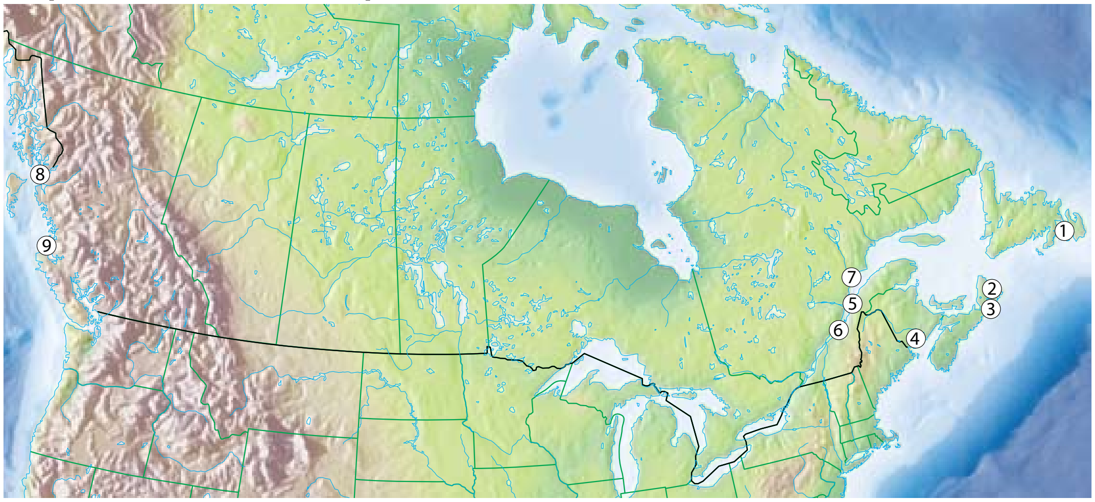
To meet the growing North American demand for natural gas, it is expected that natural gas from the global LNG market will become an increasingly important component of North America supply. Proven reserves of natural gas worldwide are about 20 times larger than the proven natural gas reserves of North America. Continued development of liquefaction capacity in producing regions and growth in the global LNG shipping fleet will enable North American markets to access greater LNG supply in the world market.

In anticipation of growing natural gas requirements in North America, there are numerous proposals to expand existing U.S. terminals and construct new LNG receiving facilities in North America, including several proposed projects in Canada as summarized in Figure 5.10. However, there is uncertainty around the number of LNG terminals that may eventually be built in Canada. The experience in the U.S. is that these terminals do not operate at full capacity but rather the amount of LNG received is dependent on the relative price of North American gas markets. The Canaport LNG facility in Saint John, New Brunswick is currently under construction and its scheduled in-service date is late 2008.

These potential changes in Canada's natural gas supply and demand have important implications to both existing pipeline transportation systems and proposed new pipeline and LNG projects. Facilities that connect significant new gas supply from new sources such as the North and LNG or significant changes in regional demand (e.g., oil sands in Alberta and electricity generation in Ontario) will have the potential to influence markets and alter the utilization and gas flow on existing pipelines. In turn, these changes may impact the tolls and associated costs in using those pipelines. For example, the introduction of new gas supply in eastern Canada could result in greater utilization or flow reversals in regional pipelines and may also affect the flow of supply from traditional sources and pipelines. Similarly, greater demand in Alberta or Ontario can alter the flow and availability of natural gas to adjacent regions.

FIGURE 5.10

Proposed Canadian LNG Projects (Bcf/d)



Location	Terminal	Proponent(s)	Capacity	Proponents' Estimated On-Stream Date
1. Placentia Bay, Newfoundland	Grassy Point LNG	Newfoundland LNG Ltd.	LNG Storage & Trans-shipment	2010
2. Point Tupper, Nova Scotia	Statia LNG	Statia Terminals Canada Partnership	0.5	n/a
3. Goldboro, Nova Scotia	Maple LNG	4Gas and Suntera Canada Ltd.	1.0	2010
4. Saint John, New Brunswick	Canaport LNG	Repsol YPF and Irving Oil	0.8	2008
5. Rivière-du-Loup, Quebec	Gros Cacouna LNG	Petro-Canada and TransCanada Pipelines Ltd.	0.5	2012
6. Québec City, Quebec	Rabaska	Gaz Métro, Enbridge and Gaz de France	0.5	2011
7. Saguenay, Quebec	Énergie Grande-Anse	Saguenay Port Authority and Énergie Grande-Anse Inc.	1.0	2012
8. Bish Cove, British Columbia	Kitimat LNG	Galveston LNG	1.0	2010/11
9. Texada Island, British Columbia	Texada Island LNG	WestPac LNG Corporation	0.5	n/a

The expected introduction of LNG close to Canadian markets has also heightened the awareness of end-users and distributors to the potential issues related to gas composition and quality. Consequently, pipelines will need to work closely with their customers to establish gas quality standards and monitor processes to ensure compatibility with existing equipment and end-use operation.

ELECTRICITY

6.1 Market Development Initiatives

Growth in the electricity industry continued as regional jurisdictions made efforts to maintain adequate supply and reliable operation. Initiatives implemented over 2007 included conservation measures, clean energy programs and infrastructure additions. Governments also continued to play a role in the development of the electricity industry.

A number of jurisdictions introduced plans for conservation initiatives as a means of managing their supply and demand balance. In February 2007, the Government of British Columbia released its energy plan, *A Vision for Clean Energy*, which includes conservation targets for the province. Additionally, in late August, the Ontario Power Authority (OPA) filed an application for approval of its *Integrated Power System Plan*, a 20-year plan for the province's electricity system that includes electricity conservation measures. Ontario revealed evidence that its electricity demand growth was moderating, a result attributed to conservation initiatives already implemented.

In 2007, Hydro-Québec launched construction at Eastmain-1-A/Sarcelle/Rupert, in the James Bay region. This project would add 8.5 terrawatt hours to Quebec's annual hydroelectric output. In September, the fifth and final generating unit at Mercier, in the Outaouais region, went into operation. Concurrently, Hydro-Québec stepped up work at the Outaouais substation, a cornerstone of the new, 1 250 megawatt interconnection with Ontario that got off the ground in late 2006.

The contribution of wind power to the resource plan was enhanced in 2007 with the commissioning of the 100.5 megawatt L'Anse-à-Valleau facility in November. This is the second of eight wind farms slated for construction in the Gaspé region by the end of 2012. These agreements signed with private companies will add 990 megawatts of wind power. In September, following the closing of the 2005 tender call for an additional 2 000 megawatts, Hydro-Québec received 66 bids from 30 proponents for a total of 7 724 megawatts.

An interesting development in Quebec in 2007 resulted from an oversupply of electricity in the province. The rapid increase in wind and hydroelectric developments in recent years combined with an economic slowdown has led to a temporary oversupply of electricity. To deal with this situation, Hydro-Québec has agreed to pay TransCanada to stop production of electricity at their Becancour plant.

The environment continued to be at the forefront of government policy actions. Clean energy programs that are designed to reduce greenhouse gas emissions were introduced at both federal and provincial levels. The Federal Government announced in January 2007 that it would invest $230 million over four years to develop clean energy technologies. The plan, called the *ecoEnergy Technology Initiative*, will fund research for technologies involved in clean-coal, carbon sequestration, reducing oil sands' environmental impact, new end-use technologies such as hydrogen and fuel cells, and energy efficient buildings and industry. The initiative will also develop technologies for producing and using renewable energy from clean sources, such as wind, solar, tidal and biomass. It will focus on advancing research in these areas and will fund demonstrations through public–private partnerships, although the details of the plan are not yet available. As well, British Columbia's new energy plan, for example, calls for all new and existing electricity generation to be net zero greenhouse gas emissions by 2016 and has eliminated any plans for coal-fired generation. Additionally, clean or renewable electricity generation will account for at least 90 percent of total generation.

An ongoing requirement across the country is the need for new or upgraded transmission. A number of transmission plans and projects were proposed in 2007. In addition to Ontario's periodic review of its Integrated Power System Plan, British Columbia and Alberta announced 10-year transmission system plans. The focus of British Columbia's plan is to maintain the reliable performance of its existing infrastructure and build new capacity to meet customer demand. Alberta's plan is intended to help the province keep up with forecasted demand and economic growth by addressing both demand growth and generation development needs. In September 2007, Newfoundland and Labrador released their first energy plan titled *Focusing our Energy*. The 35-year energy plan is designed to help the province achieve self-reliance and prosperity and to help develop sustainable green energy solutions.

With the need for new and improved generation and transmission facilities across Canada, common challenges in the approval process have arisen. One such challenge is the increased sensitivity toward obtaining public acceptance of these projects. Public acceptance is increasingly important in the management of the project approval process.

Government regulation of the electricity industry continues to evolve. For example, under Special Direction 9, the British Columbia Utilities Commission may now approve projects that anticipate demand for electricity service over a period of time. This will enable the British Columbia Transmission Corporation to investigate a new system expansion plan to prevent transmission congestion before it occurs. Also, in June 2007, the Government of Alberta announced that it would separate the Alberta Energy and Utilities Board (EUB) into two entities - the Energy Resources Conservation Board (ERCB) and the Alberta Utilities Commission (AUC), effective 1 January 2008. The new legislation was designed to promote efficiency in Alberta's regulatory system.

Electricity prices increased in a number of Canadian jurisdictions in 2007 because of the cumulative effects of higher fuel costs in recent years and higher costs for new generation and transmission investments. Figure 6.1 provides a cross-country perspective on residential electricity prices in 2006 and 2007 for representative cities in each province. Predominantly hydroelectric-generating provinces (B.C., Manitoba and Quebec) tend to have lower electricity prices while jurisdictions with gas-fired and oil-fired generation tend to have higher prices.

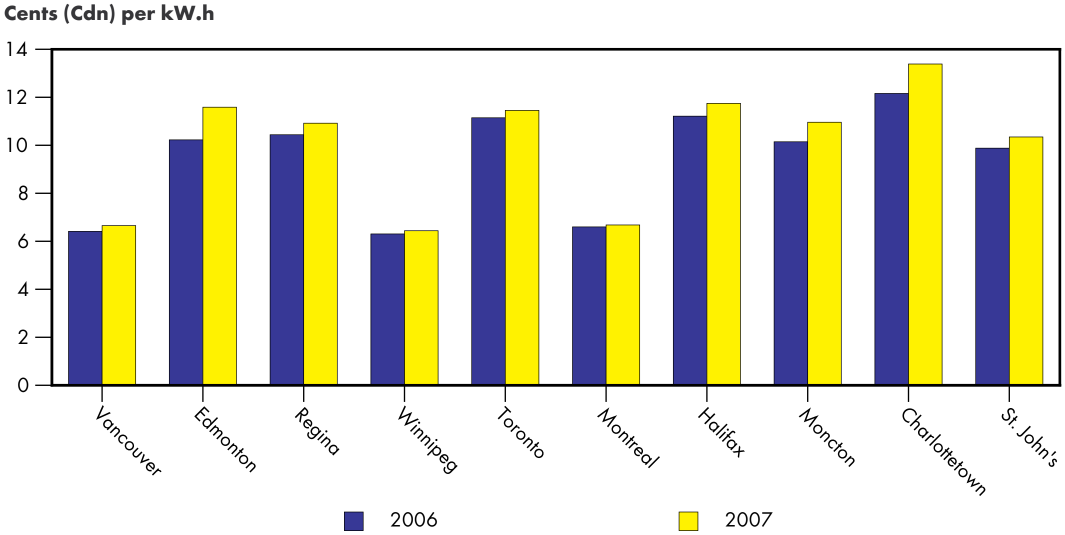
6.2 Electric Reliability

There are two main aspects to reliability: adequacy of supply achieved through sufficient generation and transmission capacity; and, operating reliability, achieved through operating and maintaining the bulk power system elements so as to withstand disturbances or contingencies and continue operations. In Canada, the reliability of the bulk transmission systems continues to be a focus of the electric industry, regulators and policy makers.

In August 2007, following up on a recommendation made by the Canada–U.S. task force, which examined the causes of the August 2003 power outage in Ontario and the U.S. Northeast, the Board published a report entitled *Reporting of Electric Reliability Information by Canadian Entities*. The

FIGURE 6.1

Canadian Residential Electricity Prices



Source: Hydro-Québec: Comparison of Electricity Prices in Major North American Cities, 2006 and 2007

report concluded that compiling reliability performance information to enable an assessment of reliability trends would be useful to industry, regulators, policy makers and the public. The report also concluded that the North American Electric Reliability Corporation (NERC) was making efforts directed toward compiling this information and therefore, the need for another entity to provide an independent source of reliability information in Canada is not justified at this time.

Cross-border jurisdictions continued to express interest in new interconnections. In February 2007, the Province of New Brunswick and State of Maine signed an MOU that outlined a timeframe for researching and creating actions that will enhance cross-border interconnections. In recent years there have been discussions of an east–west Canadian power grid at the provincial and federal levels. The most recent support for this initiative occurred in August 2007 when the country's premiers encouraged the concept of a national transmission grid to ensure Canadians benefit fully from the country's energy resources. Although no commitment was made, support for enhanced transmission facilities was evident.

In spring 2007, the Board issued a permit to Montana Alberta Tie Ltd. to construct and operate the Canadian portion of an international power line between Lethbridge, Alberta and Great Falls, Montana. The planned 230 kilovolt line is expected to be 347 kilometres long, of which, 130 kilometres will be in Canada. This is the second merchant line the Board has approved, the first being Seabreeze in September 2006, and will be the first major interconnection between Alberta and the U.S. Additionally, the 345 kilovolt international power line extending from Point Lepreau generating station in New Brunswick to a point near Woodland, Maine was energized in December 2007. The Board had approved the application for this line in May 2003.

Regional infrastructure projects continued to move forward in 2007 as jurisdictions worked to maintain and improve the reliability of their systems. One such project that addresses cross-border relationships is the 1 250 megawatt interprovincial transmission line between Ontario and Quebec. Hydro-Québec Équipement began construction of the line's Outaouais converter station in the municipality of L'Ange-Gardien in mid 2007. The new facilities would increase the energy interchange between Quebec and Ontario to nearly 3 000 megawatts. In addition to supplying Ontario with renewable energy, the interconnection would improve the reliability of transmission for serving Quebec loads. This first phase of the proposed line is expected to be completed in 2009.

The Alberta government and the Alberta Electric System Operator (AESO) removed a 900 megawatt wind threshold in September 2007. The threshold, introduced in May 2006, had been introduced in an effort to address potential operational reliability concerns associated with integrating wind generation into the Alberta electric system, thereby avoiding additional stress on the transmission system. The system operator now believes that recent and near-term enhancements to the southern Alberta grid will enable it to manage wind-associated issues, and thus removed the cap which was seen as delaying the growth of this green power source. At the end of 2007, Alberta had over 520 megawatts of wind generation capacity, an increase from 384 megawatts in 2006.

In September 2007, the planned 500 kV Edmonton–Calgary transmission line proceedings were cancelled by the EUB and applications to construct and operate the line put on hold. The transmission line was intended to strengthen the Alberta grid by alleviating system constraints and improving system efficiency by providing southern load centres access to generation in the north of the province. Including this project, Alberta's 10-year transmission plan estimates $1.5 billion in investments to address its foreseen supply and reliability issues.

6.3 Electricity Generation

Generation needs continued to be addressed across Canada through province-by-province planning. Alternative forms of generation (e.g., wind generation, small hydro, biomass) are being proposed. Additionally, there has been a resurgence of interest in nuclear generation, which, along with other conventional generation types (e.g., natural gas-fired generation and hydrogeneration) dominate the generation mix. The environment and environmentally favourable types of generation continue to be taken into account when jurisdictions plan for future needs.

Wind generation capacity increased to 1 770 megawatts, an increase of more than 300 megawatts from 2006, which, according to the Canadian Wind Energy Association, is enough energy to power 537 000 homes. Nuclear generation is attractive for its low, or no, emissions and potential large addition to generation capacity. In 2007, Energy Alberta proposed to build a nuclear generator in north-central Alberta. An application was filed with the Canadian Nuclear Safety Commission (CNSC) in August. The plant would generate 2 200 megawatts of electricity and could come online in 2017. Subsequently, on 13 March 2008, Bruce Power Alberta announced its purchase of Energy Alberta's assets related to the nuclear plant development. On the same day, Bruce Power filed an application with CNSC to prepare the site for a nuclear plant which could generate 4 000 megawatts of electricity. Additionally, Ontario continues to reassess its nuclear program and New Brunswick is investigating the option of adding a second nuclear reactor at its Point Lepreau site.

Another large generation project, which began construction in January 2007, was Quebec's Eastmain-1-A, a $5.0 billion dollar hydroelectric project. The 900 megawatt dam, the first major project in over a decade for the province, is located in northern Quebec and is expected to come online in 2009. Also, Manitoba Hydro and the Nisichawayasihk Cree Nation formally entered into a joint venture to build the 200 megawatt Wuskwatim Generating Station. The $1.3 billion dollar hydroelectric-generation facility is scheduled for completion in 2012.

In Ontario, two large combined-cycle gas-fired power plants are scheduled to come online. The Greenfield Energy Centre will provide 1 005 megawatts of capacity and is scheduled for commercial operations early in 2008, and the St. Clair Energy Centre will provide 570 megawatts of capacity and is scheduled for commercial operations in early 2009.

SaskPower cancelled plans for construction of a 300 megawatts clean coal project because of uncertainties regarding cost and timing. Instead they opted for more conventional and cheaper natural gas-fired generation, wind power and renewables to meet the province's electricity needs to 2014. However, the feasibility work on the 300 megawatts facility has provided confidence that the technology can succeed in Saskatchewan. In early 2008, an industry-SaskPower partnership received federal funding in support of a smaller, 100 megawatts clean coal demonstration project. This project is expected to be fully operational in 2015.

Total Canadian electricity generation increased from 585 terawatt hours in 2006 to 600 terawatt hours in 2007 (Table 6.1). Hydro electric generation increased from 351 terawatt hours in 2006 to 362 terawatt hours in 2007. The increase can be attributed to favourable water conditions in hydroelectric-generating provinces. Thermal generation increased from 142 terawatt hours in 2006 to 150 terawatt hours in 2007. Lower natural gas prices that supported increased thermal generation can be attributed, in part, to the change. Nuclear generation decreased from 92 terawatt hours in 2006 to 88 terawatt hours in 2007 largely because of a number of plant outages over the year.

6.4 Electricity Demand

In 2007, Canadian electricity demand was adequately met from domestic generation and imports. However, unexpected challenges, such as extreme weather events, system failures and unplanned outages can impact reliability and the supply/demand balance.

One such unplanned event resulted in southern Saskatchewan being without electricity for several hours on the morning of 18 September 2007. The exact cause of the blackout is still unknown but it is believed to have been caused by a storm that tripped several transmission lines in Minnesota. A task force, that includes 25 organizations, is being coordinated by the North American Electric Reliability Corporation to discover the exact cause.

Short-term supply/demand tightness was experienced in two Canadian jurisdictions during summer 2007. In Ontario, the Independent Electricity System Operator (IESO) issued an appeal for energy conservation at the end of June and beginning of August 2007. Hot weather was a factor in both alerts. In Alberta, the Alberta Electric System Operator issued five separate alerts as the system reached four new summer demand peaks in July 2007, the final peak demand being 9 321 megawatts. Normal summer consumption is usually in the range of 8 000 to 8 500 megawatts. Hot weather was a factor in the alerts in addition to a large, annual increase in demand.

TABLE 6.1

Electricity Production[a]
(terawatt hours)

	2003	2004	2005	2006	2007[b]
Hydroelectric	332.9	335.1	358.6	351.1	361.8
Nuclear	70.7	85.3	86.8	92.4	87.9
Thermal	160.7	150.9	151.8	141.6	150.1
Total	**564.2**	**571.3**	**597.2**	**585.1**	**599.7**

(a) Source: Statistics Canada Energy Statistics Handbook. Table 8.2 Utility Generation of Electricity in Canada and Table 8.3 Industry Generation of Electricity in Canada

(b) Estimates

6.5 Electricity Exports and Imports

Canadian electricity jurisdictions tend to be winter-peaking systems and so the largest imports of electricity from the United States typically occur during the winter when local heating requirements are highest.

Exports increased 23 percent from 40.8 terawatt hours in 2006 to 50.1 terawatt hours in 2007 and were 37 percent above the five year average of 36.5 terawatt hours. Imports decreased from 23.4 terawatt hours in 2006 to 19.6 terawatt hours in 2007. In 2007, imports were about six percent below the five year average of 20.8 terawatt hours. Canada exported approximately $3.1 billion of electricity in 2007 compared to $2.4 billion in 2006, an increase of 28 percent. Import revenues for 2007 totalled $1.0 billion, down from $1.2 billion the previous year, or a nine percent decrease.

Net exports increased by 76 percent from 17.4 terawatt hours in 2006 to 30.6 terawatt hours in 2007. In 2007, net exports were nearly double the five-year average of 15.7 terawatt hours. Figure 6.2 illustrates international and interprovincial transfers of electricity.

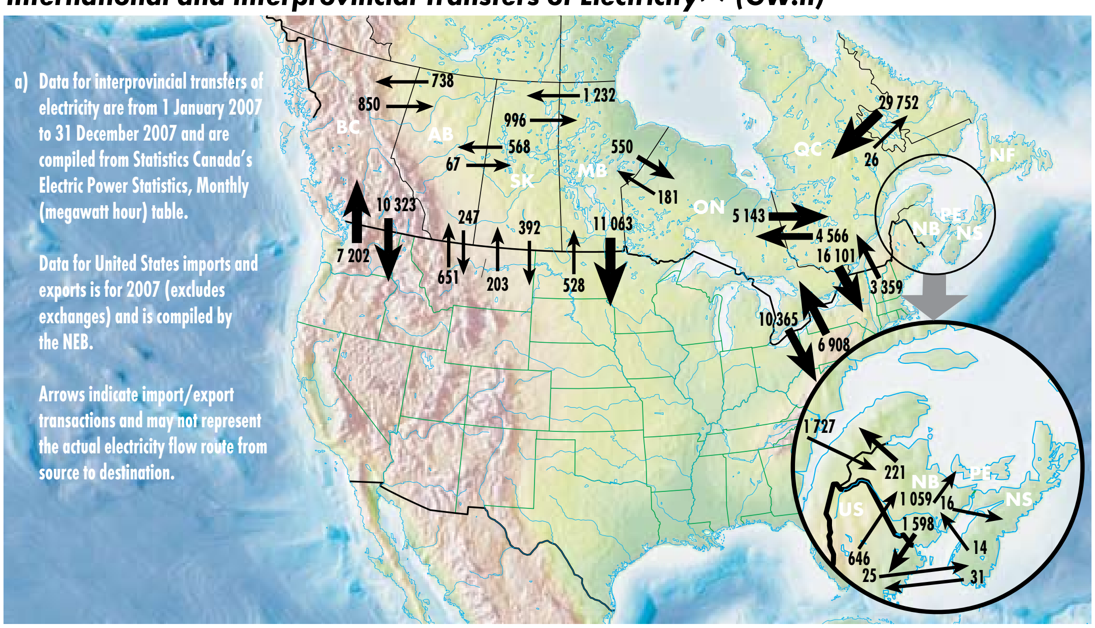
The overall increase in exports and export revenues can be attributed to favourable water conditions in hydroelectric-generating provinces that allowed for strong exports and enabled the provinces to capitalize on higher electricity prices in the U.S. The good water conditions also allowed the provinces to reduce their need for electricity imports.

6.6 Looking Ahead

The path followed in recent years by provincial jurisdictions in planning for adequate and reliable supplies of electricity is expected to continue. This includes the coming to fruition of many of the supply side initiatives already begun and the impact of conservation and improved efficiency should become evident in at least some provinces.

FIGURE 6.2

International and Interprovincial Transfers of Electricity[(a)] (GW.h)



Exports and imports are expected to continue to be a significant source of revenue and provide reliability for those provinces interconnected with adjacent U.S. regions. Export revenues will continue to be dominated by hydroelectric-generation provinces. Jurisdictions are expected to continue initiatives toward improving interconnections both interprovincially and internationally.

Electricity rates will continue to be affected by fuel prices, changes in operating costs and the impact of adding new infrastructure. Short-term price fluctuations in competitive wholesale markets will be influenced by weather and the occurrence of temporary tight supply situations. The specific impact on final consumers (residential, commercial and industrial) will depend on the electricity rate decisions of the provincial regulators and the extent to which provincial markets have deregulated electricity prices. Alberta and Ontario remain the jurisdictions furthest along in implementing market prices.

Conclusion

Canada is endowed with an abundance of natural energy resources. This abundance is a source of national pride and provides Canadians with a range of energy choices. Ensuring that Canadians have timely and relevant energy information so they can make informed energy choices is part of the National Energy Board's strategic plan. One of the ways the Board achieves this objective is through this review of Canadian energy markets over the last year. In 2007, Canadian energy markets continued to function well and there were sufficient energy supplies available to meet the energy needs of Canadians.

Energy is essential to our daily lives. It is also an important economic driver, accounting for 5.6 percent of our GDP and almost 20 percent or $90 billion of the total value of Canadian exports. Net energy exports increased by almost eight percent in 2007 to $50.8 billion, led by increases in the value of oil and electricity exports. The energy industry also accounts for about 35 percent or $68.9 billion of total private sector investment. This contributes to the economic prosperity of our entire country and helps guarantee the high standard of living we enjoy.

2007 marked a year of rising and fluctuating energy prices and Canadians were not isolated from this phenomenon. While Canada is a net exporter of crude oil, natural gas and electricity, high energy costs can still be a burden for consumers and industry. The growing strength of the Canadian dollar compared to the U.S. dollar helped mitigate some of the impact of rising global energy prices on Canadian consumers. Despite higher energy costs, Canadian energy demand increased by 2.8 percent, reflecting strong population and economic growth, particularly in the first half of 2007.

Growing investment in Canadian natural resources, particularly the oil sands, have propelled Canada into a major role in the global energy market. The oil sands resource has attracted financial capital from multi-national companies looking to invest in a country with a stable government and sound economic policy. Canada is one of the few countries in the world with significant potential to increase its energy production, particularly oil output. Increased oil sands production and investment has led to strong economic growth in Alberta, contributed to provincial and federal government revenues, and provided spin-off opportunities in other provinces.

The National Energy Board's vision is to be an active, effective and knowledgeable partner in the responsible development of Canada's energy sector for the benefit of Canadians. Canadians will face challenges as we continue to learn to manage our energy resources in a more responsible way. Much remains to be done. Canadians, however, have the will, the resources and the know-how to make the changes that will move our society toward a sustainable future.

Glossary

Bitumen or crude bitumen	A highly viscous mixture, mainly hydrocarbons heavier than pentanes. In its natural state, it is not usually recoverable at a commercial rate through a well because it is too thick to flow.
Coalbed methane	Is a form of natural gas extracted from coalbeds. Coalbed methane, often referred to as CBM, is distinct from a typical sandstone or other conventional gas reservoir as the methane is stored within the coal by a process called adsorption.
Conventional crude oil	Crude oil, which at a particular point in time, can be technically and economically produced through a well using normal production practices and without altering the natural viscous state of the oil.
Conventional gas	Refers to natural gas from all sources other than CBM.
Deliverability	The amount of natural gas a well, reservoir, storage reservoir or producing system can supply at a given time.
Diluent	Any lighter hydrocarbon, usually pentanes plus, added to heavy crude oil or bitumen in order to facilitate its transport on crude oil pipelines.
Hub	A geographic location where large numbers of buyers and sellers trade a commodity and where physical receipts and deliveries occur.
In situ recovery	The process of recovering crude bitumen from oil sands other than by surface mining.
Line pack	The actual amount of gas in a pipeline or distribution system.
Marketable gas	Natural gas that has been processed to remove impurities and natural gas liquids. It is ready for market use.
Natural gas liquids	Those hydrocarbon components recovered from natural gas as liquids. These liquids include, but are not limited to, ethane, propane, butanes and pentanes plus.

Oil sands	Sand and other rock material that contains bitumen. Each particle of oil sand is coated with a layer of water and a thin film of bitumen.
Pentanes plus	A mixture mainly of pentanes and heavier hydrocarbons obtained from the processing of raw gas, condensate or crude oil.
Reserves – Established	The sum of the proven reserves and half probable reserves.
Reserves – Initial Established	Established reserves prior to deduction of any production.
Reserves – Proven	Reserves recoverable under current technology and present and anticipated economic conditions, specifically demonstrated by drilling, testing or production.
Reserves – Remaining	Initial reserves less cumulative production at a given time.