National Energy Board
Office national de l'énergie

Canadian Energy Overview 2006

AN ENERGY MARKET ASSESSMENT MAY 2007

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CBM	coal bed methane
EIA	Energy Information Administration
EPP	Environmentally Preferred Power
ERCOT	Electric Reliability Council of Texas Inc.
ERO	Electric Reliability Organization
EUB	Alberta Energy and Utilities Board
FERC	Federal Energy Regulatory Commission
FRCC	Florida Reliability Coordinating Council
GDP	Gross Domestic Product
IESO	Independent Electric System Operator
IPSP	Integrated Power System Plan
LNG	liquefied natural gas
LPG	liquefied petroleum gas
M&NP	Maritimes and Northeast Pipeline Ltd.
MRO	Midwest Reliability Organization
NGLs	natural gas liquids
OPEC	Organization for Petroleum Exporting Countries
PADD	Petroleum Administration for Defence District
RFC	Reliability First Corporation
SERC	SERC Reliability Corporation
SPP	Southwest Power Pool
U.S.	United States
WCSB	Western Canada Sedimentary Basin
WECC	Western Electricity Coordinating Council
WTI	West Texas Intermediate

List of Units

b	barrels
b/d	barrels per day
Bcf/d	billion cubic feet per day
GJ	gigajoule
km	kilometres
kV	kilovolt
m	metres
m^3/d	cubic metres per day
Mcf	thousand cubic feet
MMcf/d	million cubic feet per day
Mb/d	thousand barrels per day
MMb/d	million barrels per day
MMbtu	million British thermal units
MW	megawatt
MW.h	megawatt hour
PJ	petajoules
$ or C$	Canadian dollars
US$	U.S. dollars
Tcf	trillion cubic feet
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. In terms of specific energy commodities, the Board regulates the exports and imports of natural gas as well as exports of oil, natural gas liquids (NGLs) and electricity. Additionally, the Board 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 keeping 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. In the past year, the Board issued a number of Energy Market Assessments (EMAs) on a wide range of energy commodities. In addition, it launched an *Energy Pricing Information for Canadians* section on its website as an additional means to keep Canadians informed on energy market developments.

Annually, the Board does a review of the past year's energy markets. This was previously included in the Board's Annual Report under the heading *Energy Overview*. In 2006, the Board decided to reduce the amount of energy information in its 2006 Annual Report. In its place, a more detailed analysis of energy commodities, markets, supply and trends is published in this standalone EMA, entitled *Canadian Energy Overview 2006*. This report is a summary of major developments in Canada's energy industry in 2006. The Board intends to produce this on an annual basis.

Introduction

The National Energy Board (NEB or the Board) monitors energy markets to objectively analyze energy commodities and inform Canadians about trends, events and issues. In the past year, the Board issued a number of Energy Market Assessments (EMAs) on a wide range of energy commodities. In addition, it launched an *Energy Pricing Information for Canadians* section on its website as an additional means to keep Canadians informed on energy market developments. The reports and related information can be found on the Board's website at http://www.neb-one.gc.ca.

In 2006, the Canadian energy market witnessed the continuing trend of high and volatile commodity prices. The year started with high crude oil prices and this upward trend continued into the summer months when crude oil reached record highs; however, in the fall and winter both natural gas and crude oil prices plunged because of high inventory levels and above normal temperatures in North America and Europe. By year end, crude oil prices had fallen by 20 percent from the highs reached in July.

Energy continued to be an important factor in the Canadian economy in 2006. The energy industry accounted for almost six percent of Canada's Gross Domestic Product (GDP) and 22 percent of the total value of Canadian exports in 2006. Canada's total energy demand in 2006 was 10,950 PJ, with secondary energy consumption increasing 1.1 percent compared with 2005. Demand for energy increased for space heating, industrial, residential and commercial sectors. Energy demand decreased in 2006 for transportation and non-energy sectors (e.g., feedstocks, greases).

Influenced by global events such as strong world oil demand growth, lack of spare production and refining capacity, and political instability in oil producing regions, crude oil prices averaged US$66 per barrel in 2006, an increase of about 17 percent from 2005. West Texas Intermediate (WTI) began the year at about US$61 per barrel, and reached a record US$78.40 per barrel in July, driven by concerns about the upcoming hurricane season and an escalation of conflicts in the Middle East. By year end crude oil closed at approximately US$61 per barrel, where it began the year.

For the first time in many years, 2006 saw the value of crude oil exports surpass the value of natural gas exports. Net crude oil export revenue which was roughly C$25 billion exceeded the value of net natural gas export revenue of C$24 billion. The gap narrowed significantly with the net value of crude oil exports rising from almost C$16 billion in 2005 to C$25 billion in 2006, an increase of 58 percent. Net natural gas export revenue declined from C$32 billion in 2005 to C$24 billion in 2006 a decrease of 24 percent.

Canadian crude oil production experienced supply interruptions in 2006 in both the oil sands and eastern Canada offshore. Nonetheless, production in Canada increased in the third quarter of 2006 with the return of Terra Nova, Syncrude and the Athabasca Oil Sands Project (AOSP) to full production levels. In 2006, average crude oil production was up six percent compared with 2005, to 416 508 m^3/d (2.62 MMb/d).

Average Canadian natural gas deliverability in 2006 was roughly the same as in 2005 as initial gains in output were gradually eroded over the course of the year by declines in drilling activity. Canadian natural gas consumption in 2006 was down 1.2 percent from the previous year as average temperatures were about 2.4°C above normal. Net natural gas exports (gross exports less imports) in 2006 were 249 million m^3/d (8.7 Bcf/d), about 4.2 percent lower than in 2005, a year when more Canadian natural gas was needed to offset U.S. natural gas supply losses from hurricanes.

The North American market emerged from the mild 2005-2006 winter with above-average levels of natural gas in storage. The recovery of U.S. natural gas supply and abundant storage caused natural gas prices to drift lower during 2006, although concerns of a repeat of the 2005 hurricane season slowed the decline. Prices crept up briefly in July and August as a heat wave across North America increased the use of gas-fired electric power for air conditioning. As the hurricane season passed with no disruptions, natural gas prices fell further. Canadian natural gas prices, measured at the Alberta Energy Company storage facility (AECO-C) hub in Alberta fell in late September to $3.44/GJ, their lowest point since the market bottomed out in 2002, before closing the year at $5.74/GJ.

Canadian revenues from gas exports also saw a year-over-year decrease due to the combination of lower export volumes and prices in 2006. Net export revenues were $24.4 billion, about a 24 percent reduction from 2005's net export revenues of $32.1 billion.

Electricity jurisdictions across Canada continued to focus on adequacy of supply and operating reliability. The trend has been to continue to develop generation sources such as fossil-fuelled generation, nuclear power and hydro electricity, but to also move beyond conventional sources. Ontario, for example, evolved its plan to phase out coal-fired generation. A number of jurisdictions also implemented programs designed to target their specific resource needs. The formation of the Electric Reliability Organization (ERO), authorized under the U.S. Energy Policy Act of 2005, was a major step in beginning to address the operating reliability concerns of the North American grid that came to the forefront following the 11 August 2003 blackout.

Although generation declined slightly, from 595 terawatt hours in 2005 to 586 terawatt hours in 2006, wind turbines, gas-fired generation and planned large hydro developments were dominant additions to future generation portfolios. Domestic demand was adequately met in 2006. Net exports declined 26 percent, from 23.6 terawatt hours in 2005 to 17.4 terawatt hours in 2006, following a strong export year in 2005. Net revenues declined from $1.9 billion in 2005 to $1.3 billion in 2006. Overall, exports were also impacted by milder weather in export markets, while reduced import costs largely reflected the availability of low cost power from U.S. sources.

Energy and the Canadian Economy

In 2006, the energy industry accounted for 5.9 percent of Canada's GDP and directly employed 345,000 people (two percent of the Canadian labour force). Energy export revenue totalled C$99 billion, which accounted for 22 percent of the value of all Canadian goods and services exported in 2006. This energy proportion has continually increased since 2002, when energy exports accounted for 12.5 percent of the value of total exports. Changes in 2006 net energy export revenues (the value of energy exports minus value of energy imports) from 2005 levels varied depending on the commodity. Net export revenues increased for crude oil and coal and coal products by 58 percent and 97 percent respectively, while net export revenues decreased for natural gas and electricity by 24 percent and 30 percent, respectively. In 2006, Canada's net energy export revenue was $50.9 billion, up from $45.4 billion in 2005, a 6 percent increase. This was largely driven by an increase in export revenue from crude oil and NGLs (Figure 2.1). The large increase in net export revenue from crude oil and NGLs enabled net export revenue from crude oil and NGLs to exceed net export revenue from natural gas for a calendar year.

Total energy production increased by four percent in 2006 compared with 2005. Petroleum and natural gas accounted for 38 percent and 37 percent, respectively, of total energy production in 2006. Hydroelectricity production accounted for seven percent of the total, a decrease of 1.4 percent from 2005. Coal production increased by four percent from 2005, accounting for nine percent of total energy produced in Canada in 2006. Strong global demand for thermal coal was expected to continue in 2006, but a balancing of supply and demand is thought to be occurring as Canada's coal exporters settled coking coal contracts for the 2006-07 coal year with slightly lower prices than for the

TABLE 2.1

Domestic Energy Production By Energy Source (petajoules)

	2002	2003	2004	2005	2006[a]
Petroleum[b]	6 049	6 365	6 517	6 404	6 739
Natural Gas	6 660	6 462	6 524	6 373	6 588
Hydroelectricity	1 245	1 198	1 207	1 289	1 271
Nuclear	824	817	986	1 009	1 090
Coal	1 430	1 326	1 476	1 494	1 554
Renewable and Other[c]	631	633	657	681	707
Total	**16 839**	**16 801**	**17 367**	**17 250**	**17 949**

(a) Estimates

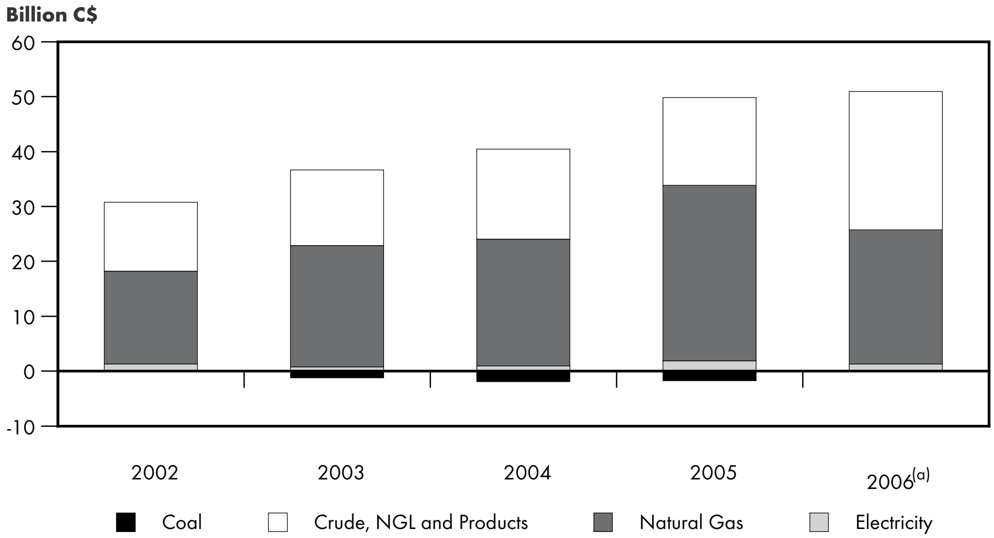
(b) Petroleum includes crude oil and gas plant natural gas liquids (NGLs)

(c) Includes steam, solid wood waste, spent pulping liquor and annual firewood

Source: Statistics Canada, NEB

FIGURE 2.1

Net Energy Export Revenues



Source: Statistics Canada, NEB

TABLE 2.2

Domestic Energy Consumption [a]
(petajoules)

	2002	2003	2004	2005	2006[b]
Space Heating	1 970	2 065	2 032	2 074	2 105
Transportation	2 250	2 242	2 346	2 383	2 357
Other Uses[c]	3 164	3 298	3 312	3 399	3 499
Non-Energy[d]	894	903	1 018	1 020	1 015
Electricity Generation[e]	1 911	1 850	2 029	2 068	1 973
Total	**10 189**	**10 358**	**10 737**	**10 944**	**10 950**

(a) Includes consumption of imported energy

(b) Estimates

(c) Includes energy used for space cooling and ventilation, appliances, water heating, as well as a variety of uses in the industrial sector.

(d) Includes energy used for petrochemical feedstocks, anodes/cathodes, greases, lubricants, etc.

(e) Includes producer consumption and losses as well as nuclear energy conversion requirements.

Source: Statistics Canada, Office of Energy Efficiency, NEB

2005-2006 coal year.[1] Production from renewable and other energy sources increased by 3.8 percent compared with 2005. This was partly due to increased wind energy coming online in several regions, and increases in solar energy and ethanol. Nuclear production increased by eight percent in 2006 compared with 2005.

Preliminary estimates indicate that total domestic energy consumption was flat from 2005 to 2006, but secondary energy demand (the total of the first four categories in Table 2.2) increased by 1.1 percent in 2006. This annual increase is lower than the five-year average annual change of two percent, largely due to the estimated decrease in transportation energy demand. Secondary energy

1 http://www.nrcan.gc.ca/ms/cmy/2005revu/coal_e.htm; a coal year refers to a 12-month period starting on April 1st and ending March 31st.

consumption per capita has increased at an average annual rate of 1.1 percent over the past five years. During the 2002 to 2006 period, Canadian total energy consumption increased on average 1.8 percent per year, compared with the rising average real GDP rate of 2.8 percent per year. This indicates a slight improvement in the energy intensity of the economy (Table 2.2).

> Weather and Energy Demand
>
> With over a third of domestic natural gas consumption directed toward residential and commercial uses, primarily space and water heating, natural gas consumption in Canada is heavily influenced by weather. Six of the warmest ten years on record have occurred within the past ten years.
>
> Environment Canada reported that the 2006 national average temperature was 2.4°C above normal, based on preliminary data. This ranks 2006 as the second warmest year, since nationwide records began in 1948.[2] The heating season of 2005-2006, which runs from November to March, was the warmest seen in over ten years (about seven percent warmer than the five-year average). In addition, 2006 experienced the second warmest summer on record. As a result of this weather, consumption of natural gas was weak over the winter of 2005/06, but higher than normal over the summer months. During such peak cooling times, natural gas is commonly called upon for electricity generation.

Space heating energy demand increased by 1.5 percent in 2006, due to increased activity in the residential and commercial sectors. Weather was not a factor, with heating degree days about seven percent lower than 2005. Industrial use and other residential and commercial uses increased by 3.0 percent and electricity producer consumption and losses decreased by 4.6 percent as electrical generation decreased. Transportation demand decreased by 1.1 percent in 2006 from 2005, possibly in response to sustained higher gasoline and diesel prices or behavioural changes including public transit, working from home and other changes in the freight sector. Non-energy demand was relatively flat, decreasing by 0.5 percent in 2006 from 2005.

2.1 Looking Ahead

In 2007, energy demand will largely be influenced by weather, energy prices and demand for goods and services. Government programs and policies will also affect energy demand not only this year but in future years. In addition, extension of daylight saving time by four weeks in Canada could reduce lighting electricity demand. The federal tax credit for public transit that commenced 1 July 2006 will have been in place for a full year, and its impacts on transportation demand may play a larger role in 2007. As well, 2007 will be the first full year with a GST rate of six percent, which is expected to increase demand for goods and services and may have an impact on energy used by the service and producing sectors. Any program or policy that impacts the personal disposable income levels of consumers and business profits, including other income and corporate tax changes, could impact demand for goods, services and energy to a degree.

Other plans for 2007 include a push toward informing Canadians about sustainable energy choices. Numerous new federal and provincial programs and policies on energy efficiency, energy technology, renewables and transportation come into effect in 2007. Many of these federal programs (e.g., ecoENERGY[3]) are revitalized versions of discontinued older programs and will not

2 Environment Canada – Climate Trends and Variations Annual 2006 http://www.msc-smc.ec.gc.ca/ccrm/bulletin/national_e.cfm

3 http://www.ecoenergy-ecoenergie.gc.ca/index-eng.cfm

significantly impact demand, particularly in the short term. The federal government has stated that emission intensity targets for large industrial final emitters will be in place in spring 2007. New federal incentives (details to be announced) for renewable energy will supplement several provincial renewable incentives, which will influence energy use and fuel mixes. For example, in Ontario, effective 1 January 2007, a wholesaler's annual gasoline sales must be at least five percent ethanol. This could be met by physically blending ethanol with gasoline or through the trading of renewable fuel credits. Other policies under development or not announced at time of writing could affect the demand for energy in 2007.

UPSTREAM OIL AND GAS ACTIVITY

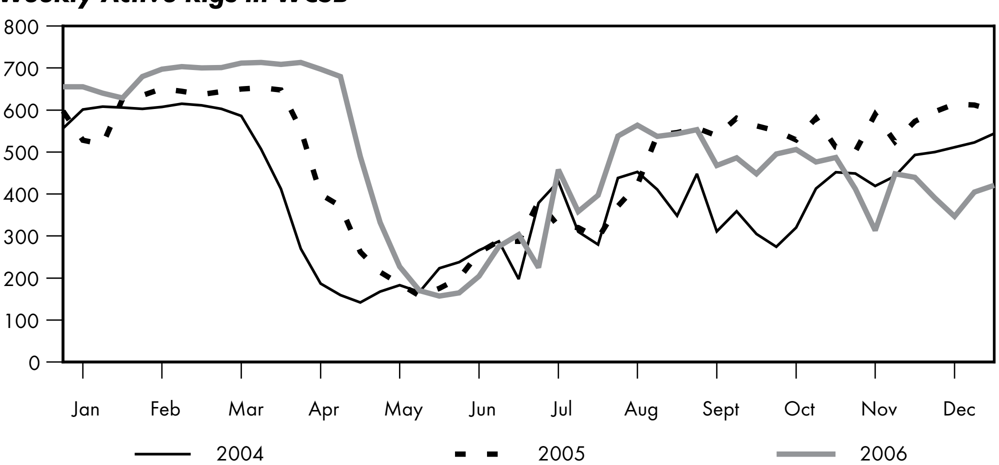
After hurricane-related supply disruptions in 2005, natural gas supply was plentiful in 2006. The North American market emerged from a mild winter with above-average storage levels. Despite high storage levels, North American prices remained relatively strong through the first three quarters of the year. This was largely due to fears of another active hurricane season and the possibility of supply disruptions. When the hurricane season did not materialize as expected, prices fell in late September to their lowest level since 2002. Many companies had hedged portions of their production and so were somewhat insulated from the downturn in prices.

Drilling activity in Canada was extremely high in the first half of the year, relative to previous years. High utilization resulted in shortages of services and materials, reduced drilling efficiency and increases in drilling costs. These contributed to significant escalations in upstream costs of at least 15 percent during the year. By the end of 2006, some analysts estimated full cycle costs for new gas developments were reaching roughly $7.60/GJ ($8.00/Mcf).

Oil prices remained sufficiently strong to accommodate increases in upstream costs, but declining gas prices did not. As a result, oil drilling activity increased in 2006, but gas drilling dropped off significantly in the second half of the year. Drilling budgets were consumed more quickly than anticipated and contributed to the second half slowdown. The strength of drilling activity in the first half of the year in the Western Canada Sedimentary Basin (WCSB) and the slowdown in the second half is indicated in Figure 3.1. On average, there were 473 drilling rigs operating per month in Western Canada compared with an average of 495 in 2005.

FIGURE 3.1

Weekly Active Rigs in WCSB



Source: Nickle's Daily Oil Bulletin

Every year the existing Western Canada natural gas production declines by about 20 percent and new wells are needed to replace this lost production. New wells on average have lower initial productivity than older wells. To fully offset productivity declines, drilling would have to increase by about four percent per year.

As shown in Figure 3.2, just over 22,000 wells were drilled in Western Canada in 2006, virtually the same number as in 2005. The number of oil wells drilled in the year rose by 16 percent to almost 5,600, while the number of dry and other wells declined. Natural gas wells drilled finished 2006 at just slightly below the previous year. As a result of the decline in gas economics relative to oil, the gas share of gas and oil wells drilled eroded marginally from 76 percent in 2005 to 73 percent in 2006.

The size of the Canadian drilling rig fleet increased significantly in 2006 from 764 to 837 rigs. New rigs entering the fleet are likely to be heavily utilized because they are more efficient and because their construction is often underwritten by multi-year term contracts with particular energy companies. Older less efficient rigs in the fleet are more likely to be unused during any drilling slowdown.

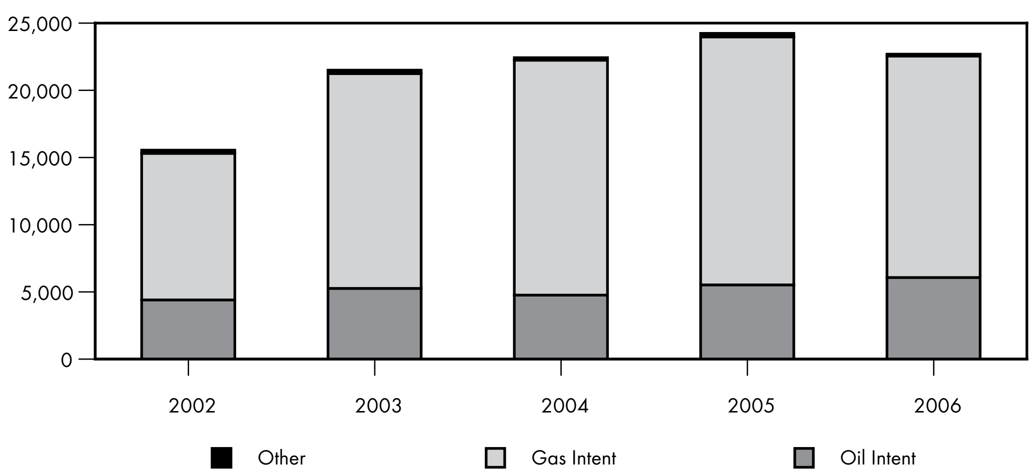
There has been strong growth in the number of drilling rigs with shallow depth capacity (less than 1850 metres) and coiled tubing units in particular. A coiled tubing unit is a specialized drilling rig that uses a long, continuous length of pipe with a downhole mud motor to turn the bit while drilling a well. This differs from a traditional drilling rig that uses jointed pipe with the bit often propelled from the rig floor or top of the drill pipe. These rigs have been purpose-built for drilling Horseshoe Canyon coal bed methane (CBM) wells and shallow gas. With this type of drilling being most heavily impacted by softening gas prices, the utilization of this portion of the rig fleet was below 2005 levels.

There has also been a strong emphasis on adding rigs with the capability to drill deep wells of over 3050 metres in depth. Deep rigs are highly versatile for Western Canada applications in that they can drill deeper wells on the west side of the basin, as well as long horizontal wells for heavy oil, in situ oil sands wells, and Mannville CBM.

Both U.S. gas and oil drilling were maintained at high levels throughout 2006 and contributed to an estimated 4.5 percent increase in U.S. gas deliverability in 2006[4]. Cost inflation also occurred in the U.S., but appears to have been less pronounced than in Canada.

FIGURE 3.2

Number of Wells Drilled in WCSB



Source: NEB Analysis of GeoScout Well Data

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Competition for land rights remained strong in 2006, with oil sands parcels leading the way. Total land sale payments in Western Canada were $4.19 billion, up 82 percent from 2005. Oil sands parcels represented $1.96 billion or 47 percent of the total. The average price per hectare rose to $761 in 2006 or 33 percent higher than in the previous year. The average price per hectare was distorted by the high price of oil sands parcels at $1,273 per hectare. Land not associated with oil sands was obtained at an average price of $549 per hectare.

In contrast to Western Canada's cash-bonus bid system to allocate land rights, the Frontier regions operate under a work commitment bid system. Exploration licences offshore Newfoundland attracted work bids of $32 million in 2006 or roughly $54 per hectare. Licences in remote areas off Labrador comprised a significant component of the bids and resulted in a significant drop in the average bid per hectare in 2006 compared to the $263/hectare average in 2005. After receiving no bids in 2005, exploration licences in the Beaufort and Mackenzie Delta area jumped to $52 million in 2006. Licensing in the Central Mackenzie Valley also picked up with a 16 percent rise in acreage and a 5 percent increase in the price per hectare.

Seismic survey activity in Western Canada during 2006 was slightly behind the previous year with the average number of active crews down from 15.9 to 14.1, a decrease of 11.6 percent. The industry continues to focus on development programs over exploration as the basin becomes more mature.

Total oil and gas capital expenditures in Canada rose by 17 percent in 2006 to $53 billion. Capital spending associated with oil sands projects jumped by 15 percent to $12 billion. Other spending rose by an estimated 18 percent. A significant portion of the spending increase was consumed by cost inflation and reduced efficiency associated with high industry utilization.

3.1 Looking Ahead

Major companies announced reductions in Canadian drilling budgets for 2007 with the expectation that lower utilization would assist in rolling back some of the service cost increases. Uncertainty regarding prices and high costs pressuring anticipated margins is also an important factor in explaining the reduced budgets. The biggest reductions in planned spending appeared to target CBM and shallow gas programs in central and southeast Alberta. Gas drilling activity in B.C. has also been significantly lower during the 2006-2007 winter than in the previous winter season. It is expected that oil drilling will remain relatively stable in 2007 while the number of gas wells drilled could fall by as much as 10 to 15 percent. Should this occur, gas deliverability could slip by roughly 28 million m^3/d (1 Bcf/d) by the end of 2007. A decline in deliverability of this size would likely cause gas prices to strengthen and lead to stronger drilling in 2008.

Crude Oil and Natural Gas Liquids

4.1 International Markets

In 2006, world crude oil prices followed the trend of 2005 which was marked by continuing high and volatile prices, largely as a result of geopolitical concerns in Iran, Nigeria, Iraq and in other oil producing regions; continuing strong demand in Asia and the U.S.; tight production and refining capacity; and supply interruptions in Alaska.

The continuing impacts of Hurricanes Katrina and Rita were witnessed in 2006, with 27 percent of Gulf of Mexico crude oil production still shut-in. In February, attacks on oil facilities in Nigeria partially suspended export operations, shutting in 54 000 m^3/d (340 Mb/d) of production. As well, in a separate incident in Nigeria, onshore and offshore production of about 23 800 m^3/d (150 Mb/d) was shut-in. By March, crude oil prices had risen to over $62 per barrel. Prices peaked in July with crude oil rising to a record $78.40 per barrel (intra day high) on concerns that the conflict in Lebanon could spread to other Middle Eastern countries. The countries in the Middle East have over 56 percent of global crude oil reserves and account for over 31 percent of world production. In August, BP Oil Company temporarily shutdown its Alaska Prudhoe Bay oil field, which produces 63 500 m^3/d (400 Mb/d) of crude oil or about eight percent of U.S. domestic production, due to extensive pipeline corrosion on approximately 25 km of the pipeline. These events contributed to the high crude oil prices during the summer; however, by October, crude oil prices had dropped 20 percent to below US$60 per barrel. This large decline was due to the market's reaction to a lack of severe hurricane activity in oil producing areas in the Gulf of Mexico, robust petroleum product inventory levels and a softening of demand. In addition, many of the potential geopolitical situations in the Middle East and elsewhere had resulted in little or no impacts on crude oil supply. The average price for 2006 was about US$66 per barrel, an increase of 17 percent compared with 2005. Figure 4.1 illustrates the price of WTI and Brent for the years 2002 through 2006.

The sharp drop in crude oil prices in the autumn prompted action by the Organization for Petroleum Exporting Countries (OPEC). On 19 October 2006, OPEC agreed to reduce output by 190 500 m^3/d (1.2 MMb/d) effective 1 November 2006. This was the first time since April 2004 that OPEC had cut production to prop up crude oil prices. The cut was met with scepticism in the market and had little impact on price. As a result, an additional production reduction of 79 400 m^3/d (500 Mb/d) was announced following its 14 December 2006 meeting, effective 1 February 2007. In 2006, Angola applied for membership into OPEC and officially joined as of 1 January 2007. Angola, which produced approximately 238 000 m^3/d (1.5 MMb/d) in 2006, is the twelfth member of the group.

4.2 Canadian Oil Production and Reserves Replacement

In 2006, Canadian production of crude oil and equivalent averaged 416 508 m^3/d (2.6 MMb/d), an increase of six percent from 2005 levels. This increase reflects the return to production of all three

FIGURE 4.1

WTI and Brent Oil Prices

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

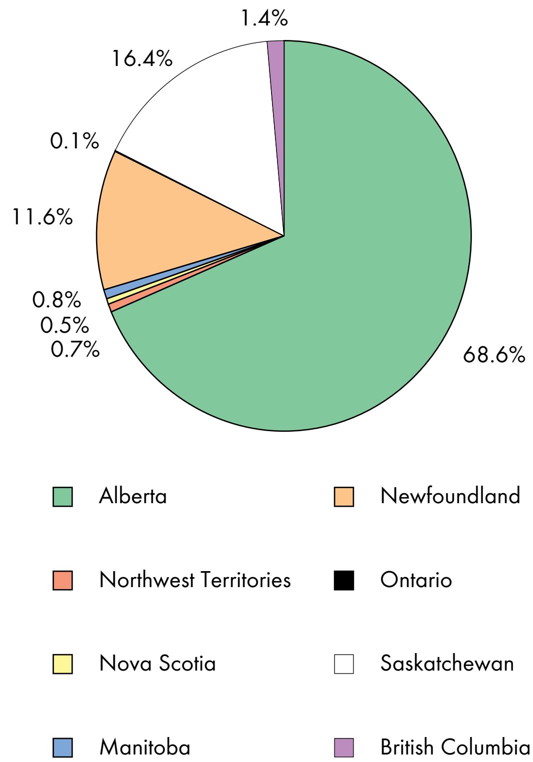
Source: IEA

integrated oil sands mining plants, expansions at others and increases in production at the Terra Nova and White Rose fields. Canada's East Coast offshore productive capacity increased by 30 percent, although actual production rose only one percent, due to operational problems at the Hibernia and Terra Nova fields. Figure 4.2 illustrates crude oil production by province.

Production offshore Newfoundland and Labrador was 50 547 m³/d (318 Mb/d) in 2006. In Western Canada, crude oil and equivalent supply increased by six percent in 2006. This was largely due to the increase in production at the oil sands. Conventional light crude oil production declined by two percent, reflecting the natural decline of light oil reservoirs in the WCSB. This decline was significantly less than 2005 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 declined by one 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 Production by Province



Source: NEB

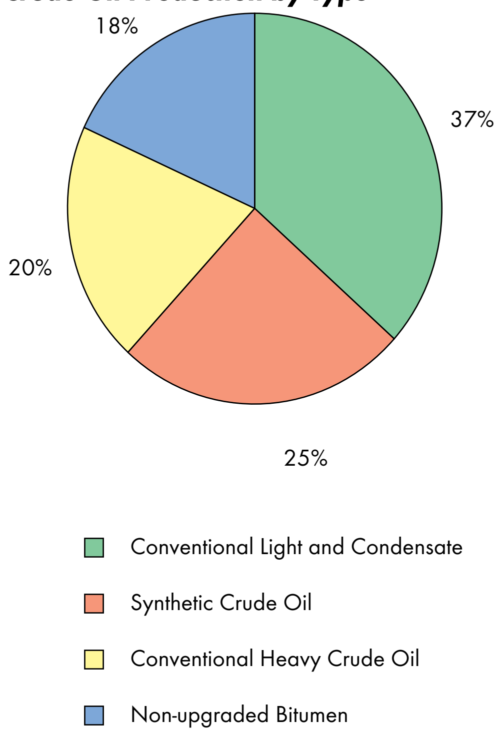
Although total production in 2006 was not up significantly, compared with 2005, production levels in the fourth quarter were strong. In 2007, Canadian crude oil production is expected to increase to 454 200 m³/d (2.9 MMb/d) or 9 percent compared with 2006 levels.

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 usually add to reserves. From 2001 to 2005, cumulative additions of conventional light and heavy crude oil to established reserves replaced 94 percent of production (Table 4.1).

The NEB's estimate of total remaining Canadian conventional crude oil and crude bitumen reserves at year-end 2005 (the last year for which there is mostly complete data available) is 32.5 billion cubic metres (204.9 billion barrels), an increase of less than one percent compared with 2004 (Table 4.2). Estimates of remaining established conventional crude oil reserves in Canada increased by nine percent to 695.6 million cubic metres (4,382 million barrels) for 2005 (Table 4.2). Most of this increase could be attributed to the increase in reserves for the Hibernia Field, offshore Newfoundland, with the remainder coming from Alberta and Saskatchewan. The remaining established crude bitumen reserves decreased slightly to 27.6 billion cubic metres (173.9 billion barrels) reflecting 2005 bitumen production.

FIGURE 4.3

Crude Oil Production by Type



Source: NEB

4.3 Oil Sands

In 2006, the oil sands continued to attract investment from a variety of sources, including multinationals, integrated producers and foreign national oil companies. This attraction is largely being driven by Canada's stable political and investment climate, the huge oil sands resource, and a diminishing number of investment opportunities in other oil producing countries. In 2006, oil sands spending was estimated to be almost $12 billion.

Investment in the oil sands is contributing to strong economic growth in Alberta and spin off opportunities in other provinces of Canada. In 2006, several trade delegations from other provinces visited Alberta to promote their manufacturing and services capability to the oil sands industry. A recent Canadian Energy Research

TABLE 4.1

Conventional Crude Oil Reserves, Additions and Production, 2001-2005 (million cubic metres)

	2001	2002	2003	2004	2005	Total
Additions[(a)]	35	88.1	60.8	66.9	134.7	385.5
Production	84	81	85.6	82.7	78.8	412.1
Total Remaining Reserves	**680**	**690**	**663**	**640**	**696**	
Total Remain Reserves (Millions of Barrels)	**4 279**	**4 342**	**4 172**	**4 027**	**4 382**	

(a) White Rose added in 2002

Source: Provincial Energy Agencies, Offshore Petroleum Boards, NEB

Institute (CERI) study[5], covering the period 2000-2020, indicates that in terms of GDP, employment and government revenues, the direct and indirect benefits of oil sands development accrue to all regions of Canada, with the federal government receiving the largest share of government revenues.

In 2006, bitumen production from mining and in situ operations totalled 194 700 m^3/d (1.2 MMb/d), an increase of 15 percent compared with 2005. In situ bitumen production increased by 10 percent to 76 700 m^3/d (483 Mb/d). Bitumen from mining operations increased by 18 percent to 118 000 m^3/d (743 Mb/d) and upgraded bitumen production increased by 18 percent to 102 800 m^3/d (761 Mb/d) (Figure 4.4).

The oil sands industry continued to struggle with operational problems in 2006. In 2005 Canadian crude oil production declined compared with 2004 because of unscheduled interruptions at the three major integrated mining and upgrading operations. Production rebounded in 2006 despite ongoing

TABLE 4.2

Estimates of Established Reserves of Crude Oil and Bitumen at 31 December 2005 (Million Cubic Metres)

Conventional Crude Oil	**Initial**	**Remaining**
British Columbia[a]	126.9	20.9
Alberta[b]	2 703.7	254.8
Saskatchewan[c]	893.2	197.8
Manitoba[d]	41.5	4.5
Ontario[e]	14.7	1.6
NWT (Nunavut) and Yukon		
Arctic Islands and Eastern Arctic[f]	0.5	0.0
Mainland Territories - Norman Wells and Cameron Hills	52.8	15.7
Nova Scotia - Cohasset and Panuke[d]	7.0	0.0
Newfoundland - Hibernia, Terra Nova and White Rose[d]	299.1	200.3
Total	**4 139.4**	**695.6**
Total (Millions of Barrels)	**26 078.2**	**4 382.3**
Crude Bitumen		
Oil Sands - Upgraded Crude[g]	5 590.0	5 052.0
Oil Sands - Bitumen[g]	22 802.0	22 549.0
Total	**28 392.0**	**27 601.0**
Total in Millions of Barrels	**178 870.0**	**173 886.0**
Total Conventional and Bitumen	**32 531.4**	**28 296.6**
Total Conventional and Bitumen (Millions of Barrels)	**204 947.8**	**178 268.6**

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

(b) Alberta Energy & Utilities Board and NEB common database.

(c) Saskatchewan Reservoir Annual 2003 with NEB estimated update

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

(e) Canadian Association of Petroleum Producers

(f) Bent Horn abandoned 1996

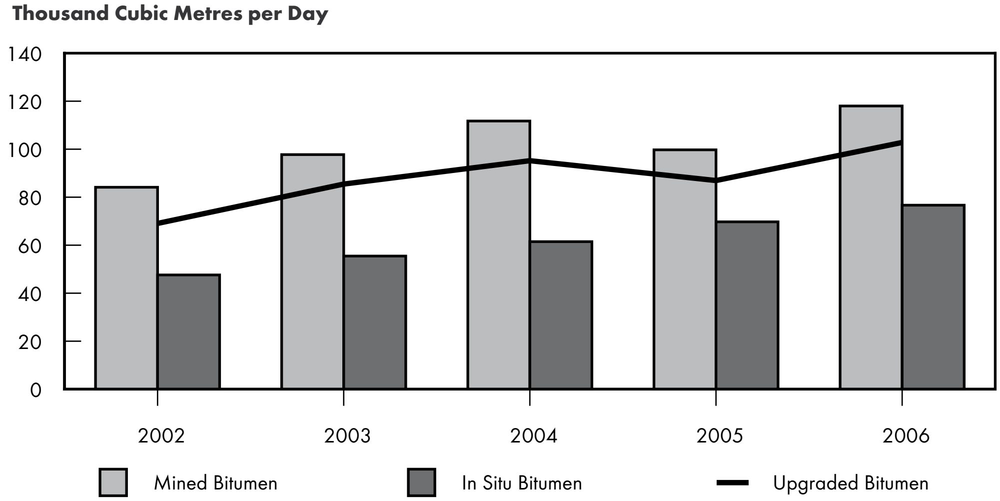
(g) Alberta EUB Reserves 2005 and Supply Outlook 2006-2015

Note: Totals may not add due to rounding

5 The Economic Impact of Alberta's Oil Sands - Canadian Energy Institute Study, No. 110, October 2005

FIGURE 4.4

Crude Bitumen Production, 2002-2006



Source: EUB

problems at the three major integrated mining and upgrading operations. In the first quarter 2006, the Syncrude Coker 8-1 underwent scheduled maintenance reducing its production. In May 2006, the Stage 3 expansion was brought on stream; however, production was suspended soon after because of odourous emissions. It took several months to rectify the problem and bitumen feed was re-introduced to Coker 8-3 at the end of August. This expansion was expected to ramp up production to 55 000 m^3/d (347 Mb/d), and in the fourth quarter 2006, Syncrude's production improved to 53 000 m^3/d (334 Mb/d) from 44 300 m^3/d (279 Mb/d) in 2005. In the first quarter 2006, production at the Athabasca Oil Sands Project was reduced by about 25 percent because of a torn conveyor belt and in the second quarter, planned maintenance was performed at both the Muskeg mine and the Scotford upgrader. The maintenance was expected to last about two months; however, this was extended because additional work was required. In the third quarter 2006, Suncor production was lower because of unplanned maintenance.

4.4 Crude Oil Exports and Imports

Total crude oil exports, including pentanes plus and upgraded bitumen (synthetic crude), are estimated at 285 430 m^3/d (1.8 MMb/d), an increase of 25 830 m^3/d (163 Mb/d) from 2005. The 2006 total consisted of 36 percent light crude oil and equivalent and 64 percent blended heavy crude oil.

Prices remained relatively high throughout 2006. The estimated value of crude oil exports was $39.3 billion, compared with $32.0 billion in 2005. In 2006, the projected average light and heavy crude oil export prices were $448 and $338 per cubic metre ($71 and $54 per barrel), respectively, compared with $423 and $295 per cubic metre ($67 and $47 per barrel) in 2005.

Among other reasons, the light-heavy price differential varies as a function of crude oil market factors. For example, if there is an increase in the supply of heavy crude oil that exceeds demand, the differential will widen. Extraordinary circumstances aside, the differential typically narrows in the summer months due to the higher demand for heavy crude oil during asphalt paving season and then widens again in September.

In 2006, the average light-heavy price differential between Edmonton Par and Western Canada Select (WCS) was $142 per cubic metre ($23 per barrel) compared with $158 per cubic metre ($25 per barrel) in 2005. The differential was as wide as $219 per cubic metre ($35 per barrel) in February 2006 but subsequently narrowed with the start up of the reversed Enbridge Spearhead pipeline[6]. The pipeline historically operated a south-to-north service, but since March 2006, the pipeline has transported crude oil from Chicago, Illinois to Cushing, Oklahoma and enabled Western Canadian crude oil to access a new market. Similarly, in April, Mobil Pipeline Company's 20-inch Pipeline Reversal Project, from Patoka, Illinois to Nederland, Texas made the first delivery of Canadian crude to the U.S. Gulf Coast. Canadian crude oil is delivered to this line via the Enbridge Pipeline to Lockport, Illinois and the Mustang Pipeline to Patoka, Illinois.

According to the Energy Information Administration (EIA), Canada remained the leading export country to the U.S. for crude oil in 2006, ahead of both Mexico and Saudi Arabia. High oil demand throughout most of the year for diesel, motor gasoline and jet fuel resulted in North American refineries operating at over 95 percent of capacity. The U.S. Midwest is the most significant market for Western Canadian crude oil. The refining centers of Chicago, Illinois, Minneapolis/St. Paul, Minnesota and Toledo, Ohio consumed 49 percent of total Canadian crude oil exports in 2006.

The export market for eastern Canadian offshore production has been primarily the U.S. East Coast. In 2006, 82 percent of the offshore crude oil exports was delivered to the U.S. East Coast (referred to as Petroleum Administration for Defence District [PADD] I), 15 percent to the U.S. Gulf Coast and three percent to foreign markets.

Although Canada is a net exporter of crude oil, much of the requirements of eastern refineries are met with foreign produced crude oil. In 2006, crude oil imports were 136 500 m³/d (860 Mb/d) and represented 48 percent of total refinery feedstock requirements in Canada. Crude oil requirements for the Atlantic region and Quebec were met by imports as well as volumes of east coast domestic production. Ontario refiners received about 34 percent of their feedstock requirements from foreign sources in 2006. Imports into Ontario decreased by around 20 percent from 2005 due to greater volumes of feedstock requirements being supplied by east coast production in the first part of the year and use of more competitively priced Western Canadian crude oil. Over one third of all Canadian crude oil imports originated in the United Kingdom and Norway.

FIGURE 4.5

Light and Heavy Export Crude Oil Prices

Source: NEB

4.5 Oil Refining

As of 31 December 2006, there were 19 refineries in Canada with a total refining capacity of 324 500 m^3/d (2.0 MMb/d). The refineries and their locations are in Table 4.3.

During 2006, there were several proposals to build new refineries in the Atlantic Region. If built, they could transform this region into a major processing hub. Refineries in this region are located close to the major petroleum product markets in the U.S. Northeast and have access to foreign crude oil supplies in addition to east coast offshore production. In February, Newfoundland and Labrador Refinery Corporation proposed the construction of a refinery at Placentia Bay, Newfoundland that would have an initial processing capacity of 47 600 m^3/d (300 Mb/d) with the option to expand to 95 200 m^3/d (600 Mb/d). Production is slated to begin in late 2010 or 2011 and study results, revealed near the end of year, indicated that the project would be economically feasible. In late October, Irving Oil announced it was exploring the possibility of building a new refinery that could be in operation by 2012 or 2013 to complement its existing 47 600 m^3/d (300 Mb/d) refinery at Saint John, New Brunswick. The Nova Scotia government also attempted to attract an oil refinery to

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	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-operatives 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**	**2,000,000**

Source: NEB

Nova Scotia, which seemed to be less likely after Irving's announcement. However, at the end of the year, a fourth refinery project proposal was announced by a U.S. energy service company to build a refinery either in the Strait of Canso or at Sydney, Nova Scotia.

Not all refineries are configured to process a full range of crude oil types and, therefore, the growing output from the oil sands has become an increasingly important consideration for refiners. Several companies have already indicated that their refineries could be modified to process heavier crude oil. In November, Shell Canada Limited announced that it was exploring the potential of building a new heavy oil refinery near Sarnia, Ontario that could process up to 31 700 m^3/d (200 Mb/d). In addition, Suncor is re-tooling its refinery in Sarnia to further integrate its upstream production with its downstream assets. This would significantly increase the amount of oil sands production refined in Ontario from the estimated 15 900 m^3/d (100 Mb/d) refined in 2006.

Refinery production of main petroleum products in 2006 is estimated at 286 800 m^3/d (1.8 MMb/d), about 3 percent lower than in 2005. Demand for main petroleum products in Canada averaged 273 500 m^3/d (1.7 Mb/d), a two percent decrease from 2005. Refinery receipts of domestic crude oil averaged 150 300 m^3/d (945 Mb/d), essentially the same as in 2005. These refinery receipts were lower than expected with 2006 being the first full year of production from the White Rose field in offshore Newfoundland and Labrador. The potentially higher receipts were offset by unusually high maintenance levels at several refineries and production problems at the Terra Nova field. Commercial inventories of petroleum products in Canada closed the year slightly lower than in 2005.

4.6 Main Petroleum Product Exports and Imports

Canada remains a net exporter of main petroleum products including middle distillates (heating oil, jet fuel and diesel fuel), heavy fuel oil and gasoline. In 2006, exports of main petroleum products and partially processed oil are estimated at 51 500 m^3/d (324 Mb/d), a decrease of eight percent compared with 2005. Refinery outages and a heavy maintenance schedule at many refineries resulted in a decrease in refinery production and subsequently, there were less petroleum products available for export.

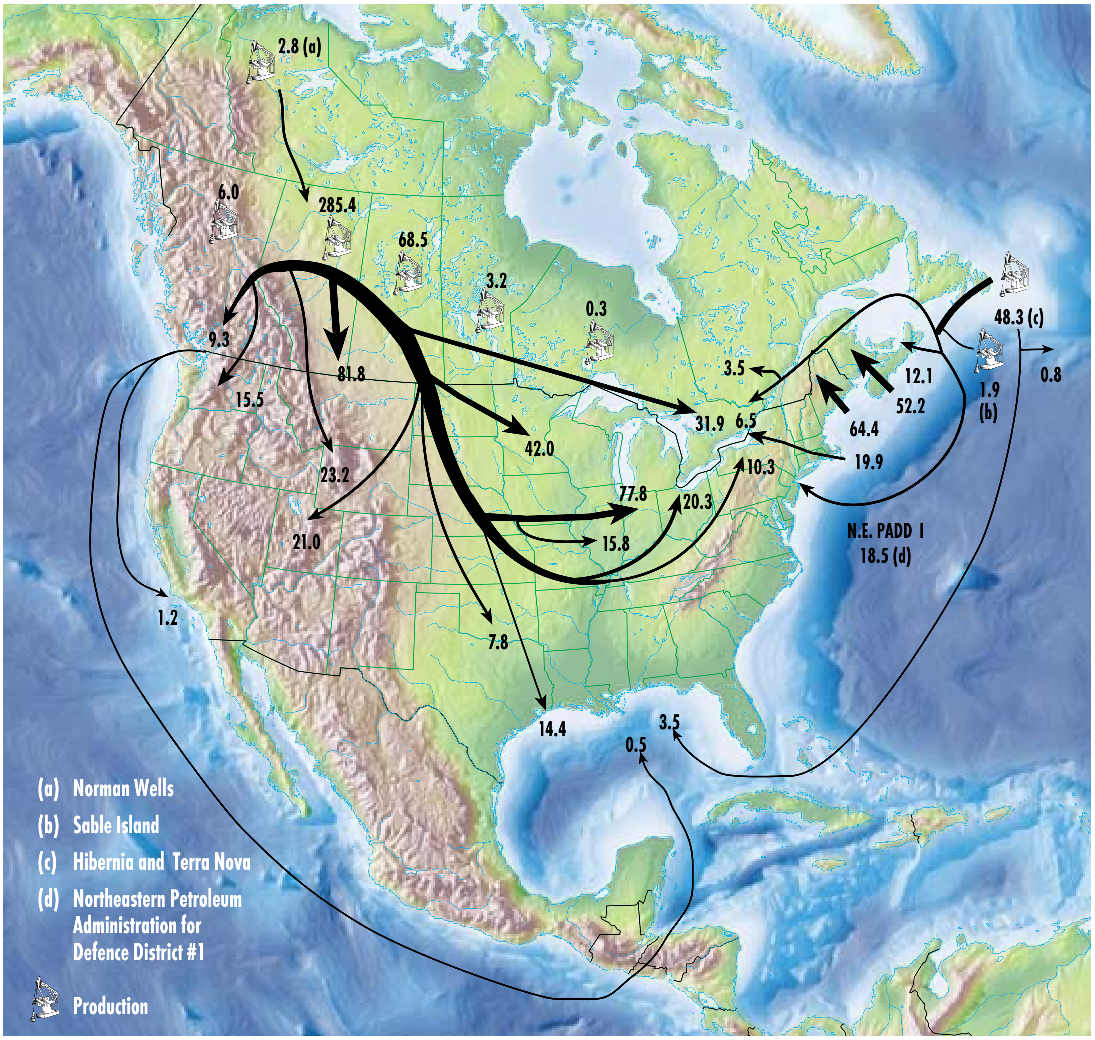
The estimated revenue in 2006 from main petroleum product exports, including partially processed oil was $7.4 billion, up from $6.2 billion in 2005. Strong demand in North America for gasoline and diesel fuel along with refinery outages in both Canada and the U.S. led to high product prices during the first half of 2006. Both gasoline and diesel fuel prices retreated in August prior to the end of the summer driving season, which is the Labour Day holiday in September. High inventory levels for gasoline and distillates in North America put further downward pressure on prices during the fall and winter.

The U.S. continued to be the largest buyer of Canadian produced petroleum products, which accounted for about 93 percent of total U.S. imports. Exports were also made to other destinations, such as, Europe, Mexico and the Caribbean. The U.S. East Coast continued to be the largest market, followed by the U.S. Midwest and the U.S Gulf Coast.

Imports of main petroleum products in 2006 are estimated at 33 800 m^3/d (212 Mb/d), a six percent increase from 2005.

FIGURE 4.6

Crude Oil And Equivalent Supply And Disposition – 2006 (Thousand Cubic Metres Per Day)



Source: NEB

4.7 Looking Ahead

It is expected that geopolitical events, production and refinery disruptions, and weather will be key price drivers in the coming year. 2007 began with crude oil hovering around US$60 per barrel, largely driven by above normal winter temperatures and high inventory levels for crude oil and refined petroleum products in North America. It is expected that recent announcements on refinery expansions and the construction of new refineries in eastern Canada could be finalized in the coming year.

The NEB in its most recent crude oil production forecast has estimated that crude oil production will increase by 9.1 percent compared with 2006; however, crude oil production continues to be plagued by outages in the oil sands region and offshore eastern Canada.

NATURAL GAS

5.1 North American Natural Gas Markets

In 2006, 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 WCSB with Alberta producing roughly 80 percent. British Columbia and Saskatchewan contribute roughly 16 and four percent, respectively, of the total from the WCSB.

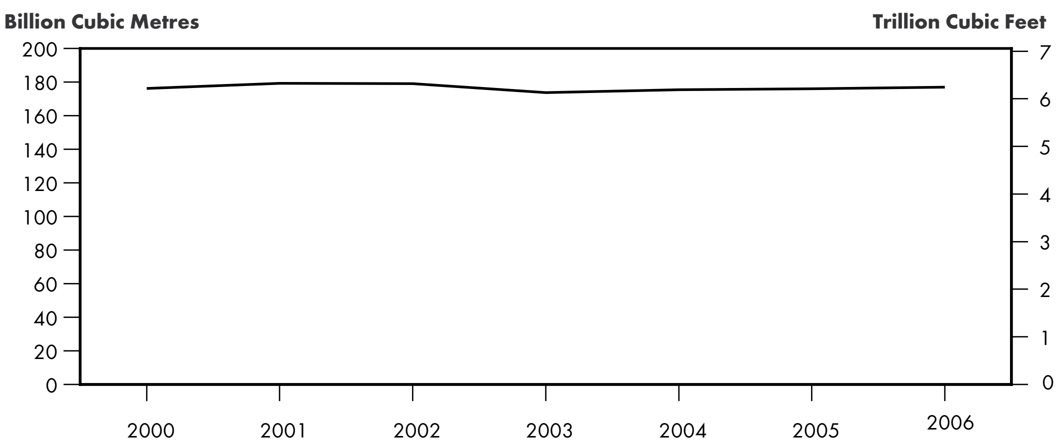
The Canadian and U.S. natural gas markets operate as one large integrated market. This means that events in any region such as changes in transportation costs, infrastructure constraints or weather will have effects on the other regions. Most Canadian and U.S. natural gas production comes from areas 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.

5.2 Natural Gas Production

Canadian natural gas production in 2006 averaged 484.8 million m^3/d (17.1 Bcf/d), roughly the same as in 2005. Western Canada experienced record drilling activity during the first half of the year followed by a pull back in the second half. Consequently, the number of new gas wells completed in 2006 was just slightly below 2005. By virtue of being in production longer, the greater number

FIGURE 5.1

Canadian Marketable Gas Production



Source: CAPP Statistical Handbook (NEB estimate for 2006) of wells drilled earlier in the year had a more positive impact on 2006 production than the reduced drilling in the second half of the year. As a result, average production was maintained in 2006 without an increase in the number of new gas well completions.

On the east coast, Sable production continued to vary between about 300 and 400 MMcf/d in 2006. The installation of offshore compression in 2006 is expected to allow Sable gas production to be maintained or increased by producing the remaining gas more quickly. The platform and compression deck was installed in May and connected to the pipeline in September. Final testing and commissioning occurred during the remainder of the year.

Onshore production from the McCully field in New Brunswick is expected to tie into the Maritimes and Northeast pipeline (M&NP) by the second quarter of 2007.

Regarding east coast production, EnCana and the Province of Nova Scotia signed a benefits agreement for the proposed Deep Panuke project. This represents one of many steps that may lead to development of the project, with 2010 estimated to be the earliest that gas production could potentially occur.

North American gas production has recovered to pre-hurricane levels, with increased onshore production in the U.S. Rockies, Texas, Oklahoma and Arkansas regions offsetting continued declines in the offshore Gulf of Mexico. There were no hurricanes in the Gulf of Mexico causing damage to production facilities in 2006.

Liquefied natural gas (LNG) imports into the U.S. increased early in the summer as new LNG production entered the market. As storage filled and prices fell, fully laden LNG tankers were parked in mid-ocean waiting for improved market conditions and were eventually diverted to European and Asian markets. Although the U.S. has a capacity to import over 150 million m^3/d (5.2 Bcf/d) of LNG through five LNG terminals, average LNG imports for the year were 45 million m^3/d (1.6 Bcf/d) or roughly eight percent less than in 2005.[7]

5.3 Natural Gas Reserves

The NEB's estimate of remaining marketable gas reserves at the end of 2005 (the last year for which data is available), is 1 619 billion cubic metres (57.2 Tcf) (Table 5.1). Reserve additions were 250 billion cubic metres (8.8. Tcf) in 2005 and replaced 142 percent of annual production. The rise in remaining reserves reflected increased exploration and improved recovery in known gas fields as a consequence of the strong increase in natural gas prices during 2005. Initial reserves increased in Alberta, British Columbia and Saskatchewan in 2005 while Ontario and frontier regions remained unchanged. With the decline in natural gas prices in 2006, some of the price-related increase in reserves during 2005 may be reversed.

5.4 Canadian Natural Gas Consumption

Approximately one quarter of all energy consumed in Canada is natural gas with estimated consumption in 2006 of about 226 million m^3/d (8.0 Bcf/d), or about 46 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 to

7 Gaul, Damien and Platt, Kobi, Short-Term Energy Outlook Supplement: U.S. LNG Imports – The Next Wave, U.S. Energy Information Administration, January 2007, pp. 2 & 10, www.eia.doe.gov/emeu/steo/pub/LNG_Jan2007.pdf

produce electricity. In 2006, these sectors consumed approximately 189 million m³/d (6.7 Bcf/d) of natural gas (Figure 5.2). Figure 5.2 also shows that Canadian gas demand for heating, industrial use and electric power generation (included within "direct sales") has been fairly flat, or declining. Growing amounts of natural gas have been seen in the "other" category that includes line pack fluctuation, gas used in the natural gas pipeline system, and lost and unaccounted volumes.

Over one third of domestic natural gas consumption is directed toward residential and commercial uses, primarily space and water heating. Despite continuing growth in residential and commercial

TABLE 5.1

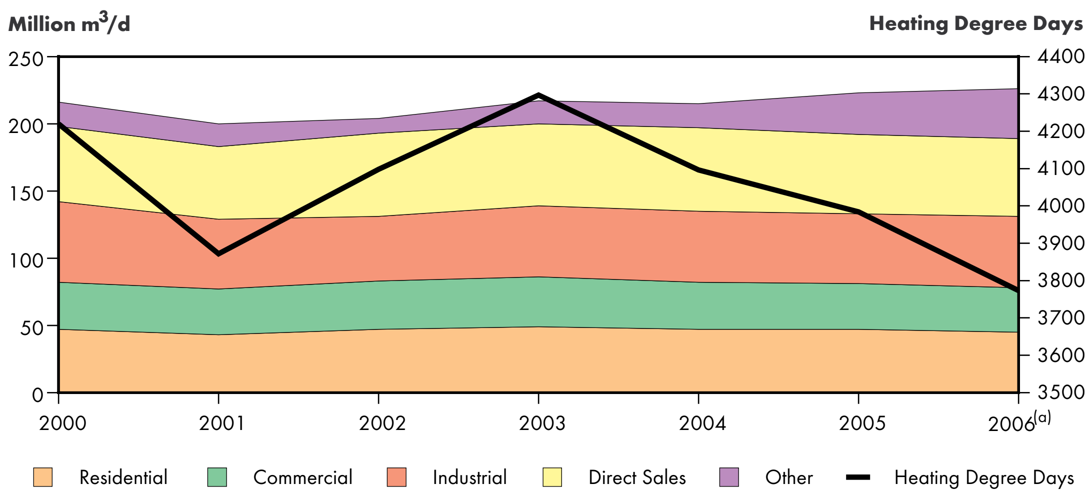
Natural Gas Reserves

(billion m^3) At Year-end 2005	Natural Gas Reserves Initial Reserves	Cumulative Production	Remaining Established Reserves
British Columbia	854.9	492.1	362.8
Alberta	4 672.4	3 552.4	1 119.9
Saskatchewan	248.7	167.1	81.6
Subtotal - WCSB	**5 776.0**	**4 211.6**	**1 564.3**
Ontario	46.8	33.8	13.0
Nova Scotia Offshore	55.0	26.5	28.5
Mainland NWT & Yukon	29.3	15.8	13.4
Mackenzie Delta	0.3	0.1	0.2
Subtotal - Frontier	**84.6**	**42.4**	**42.1**
Total Canada	**5 907.4**	**4 287.8**	**1 619.4**

Source: Nova Scotia and Newfoundland Offshore Petroleum Boards for estimates of reserves for the East Coast offshore; NEB for estimates of reserves in the Mainland Territories and Mackenzie Delta; Alberta EUB Alberta's Energy Reserves 2005 and Supply/Demand Outlook 2006-2015; Saskatchewan Reservoir Annual 2003 (Updated by NEB from CAPP data); British Columbia Hydrocarbon and ByProducts Reserves (British Columbia Ministry of Energy and Mines); CAPP Statistical Handbook for Ontario

FIGURE 5.2

Canadian Total Gas Consumption and Heating Degree Days



(a) Estimates

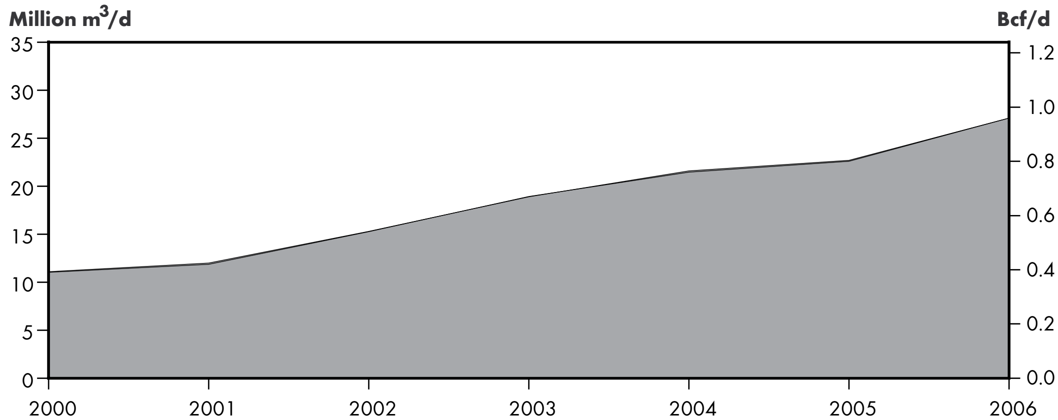
Source: Statistics Canada, NEB and Canadian Gas Association floorspace, actual natural gas consumption has decreased slightly since 2000. Under more "normal" winter weather conditions, such as in 2002-2003, natural gas use could have been higher. In addition to weather effects, higher and more volatile natural gas prices have moderated natural gas consumption, particularly in the price-sensitive industrial sectors.

In contrast to these declines in natural gas consumption, one fast-growing sector for natural gas consumption is the Alberta oil sands. Figure 5.3 shows the natural gas consumption for oil sands operations from 2000 to 2006. In 2005, operational problems at the three major integrated mining/upgrading plants resulted in a reduction in natural gas consumption. Operations returned to normal in 2006 and consumption was approximately 27.1 million m³/d (0.96 Bcf/d): almost three times the amount of gas used in 2000.

Figure 5.4 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

FIGURE 5.3

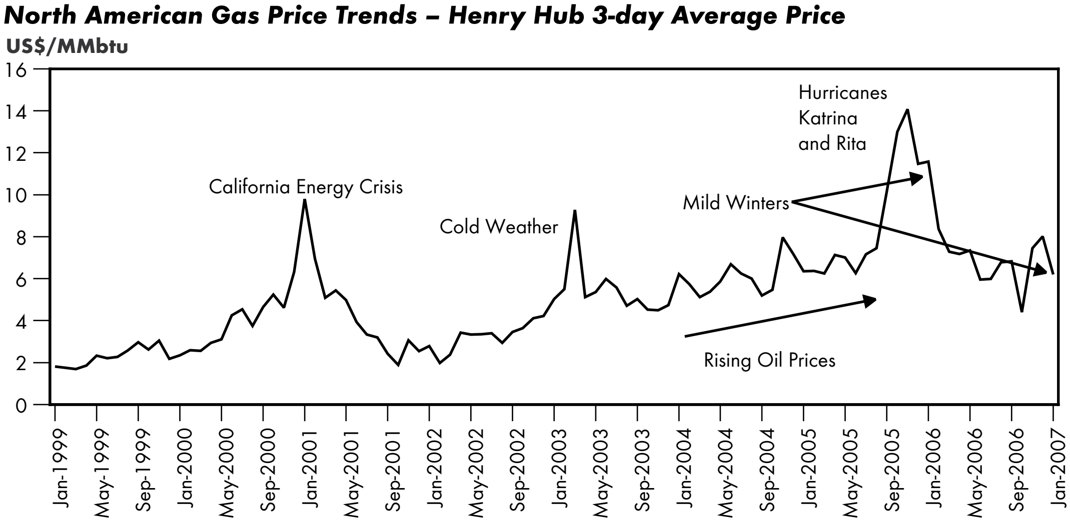
Average Annual Natural Gas Consumption for Oil Sands Operations



Source: NEB and EUB

FIGURE 5.4

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



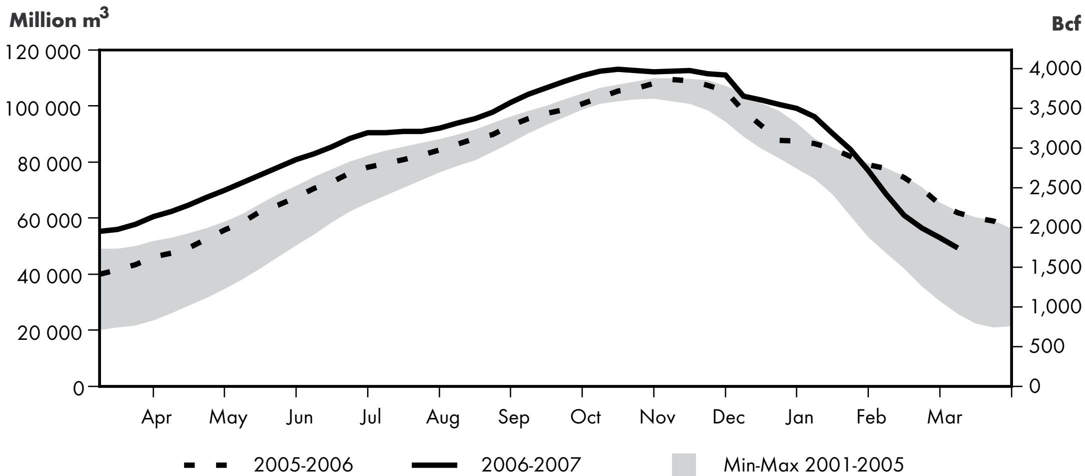
Source: GLJ Energy Publications Inc.

contributed to high and volatile natural gas prices. The price of natural gas is particularly sensitive to weather events and this can result in large swings. In general, some consumers can switch between natural gas and fuel oil, particularly in the U.S. Northeast and Southeast. This competition provides the link between oil prices and natural gas prices, such that an increase in crude oil prices will generally support an increase in the price of natural gas.

Above normal temperatures in the winter of 2005-2006 left record volumes of natural gas in North American gas storage facilities at the beginning of April. April is the beginning of the typical storage injection season (Figure 5.5). Prices remained relatively weak all year as injections into storage continued. Canadian natural gas prices, measured at the AECO hub in Alberta, began 2006 at $8.89/GJ and reached a low of $3.44/GJ in late September before closing the year at $5.74/GJ (Figure 5.6). There was some strengthening of prices in July and August as a heat wave across most of the large North American population centres resulted in increased electric power demand for air conditioning. The summer heat wave's strong call on natural gas prompted an unprecedented

FIGURE 5.5

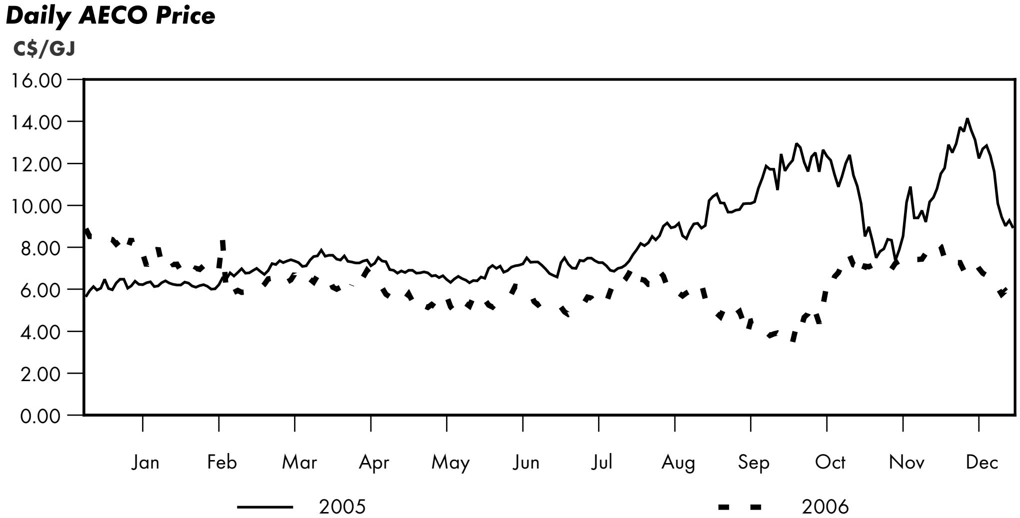
North American Gas Storage Levels



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

FIGURE 5.6

Daily AECO Price



Source: Platts

summer withdrawal from storage in the U.S. Storage facilities in Canada continued to fill, albeit at a slower than normal pace, during that period; subsequently, storage levels in Canada stayed within the five year average. Despite the summer withdrawal in the U.S., natural gas storage in North America, particularly in the U.S., reached new record high levels before entering the 2006-2007 winter heating season in November.

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 and are reported in US$/MMBtu (see Figure 5.7). The price of natural gas at Dawn followed a similar path through 2006. The Dawn price began the year at US$9.58/MMBtu and reached a low of US$3.82/MMBtu in late September. The Dawn price recovered closing the year at US$5.74/MMBtu.

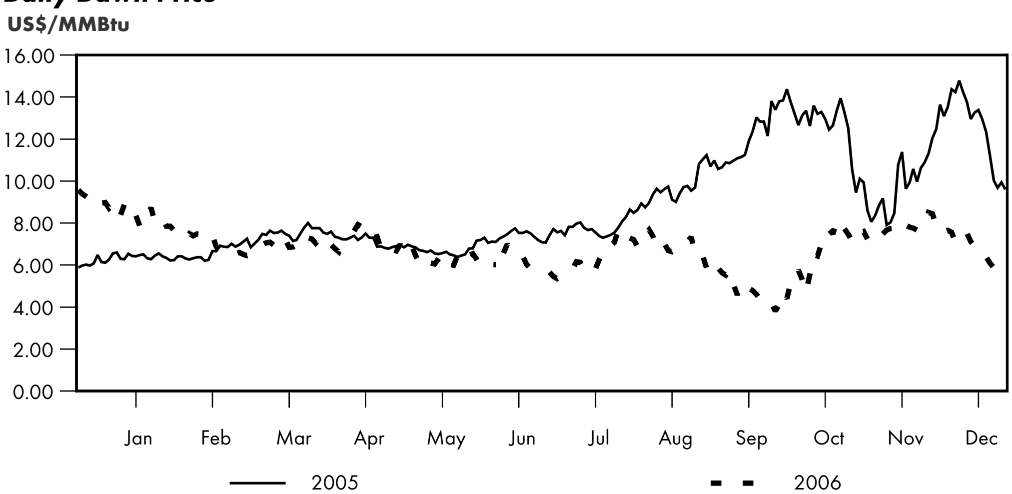
5.5 Canadian Natural Gas Exports and Imports

Natural gas exports for 2006 were estimated to be about 275 million m^3/d (9.6 Bcf/d), or about 16 percent of estimated U.S. consumption. The U.S. Central/Midwest and Northeast regions are Canada's largest export markets. Natural gas is also exported to California and the Pacific Northwest. Canada is a net exporter of natural gas; however, an estimated 26.4 million m^3/d (0.9 Bcf/d) of gas was imported into Ontario from the U.S. in 2006.

Overall, exports of natural gas to the U.S. were lower in 2006 than 2005 (Figure 5.8). The gross volume of Canadian gas exported to the U.S. was down 4.8 percent in 2006 compared with the previous year. Net exports (gross exports less imports) for 2006 were 249 million m^3/d (8.7 Bcf/d), about 4.2 percent lower than the 2005 net export volume of 260 million m^3/d (9.1 Bcf/d). The turbulent weather conditions of 2005 were a contributing factor to this shift with U.S. production losses in the Gulf of Mexico due to Hurricanes Katrina and Rita. In response to the U.S. production losses, Canadian gas exports to the U.S. increased. Consistently above-normal temperatures in the U.S. (particularly in the northern Plains, Great Lakes region and parts of the Northeast and California) in the first quarter of 2006 resulted in lower natural gas demand, and consequently, lower U.S. imports of Canadian gas. Extremely warm temperatures developed in the summer months across major population centres in the U.S. resulting in an increase in gas exports to meet air-conditioning requirements.

FIGURE 5.7

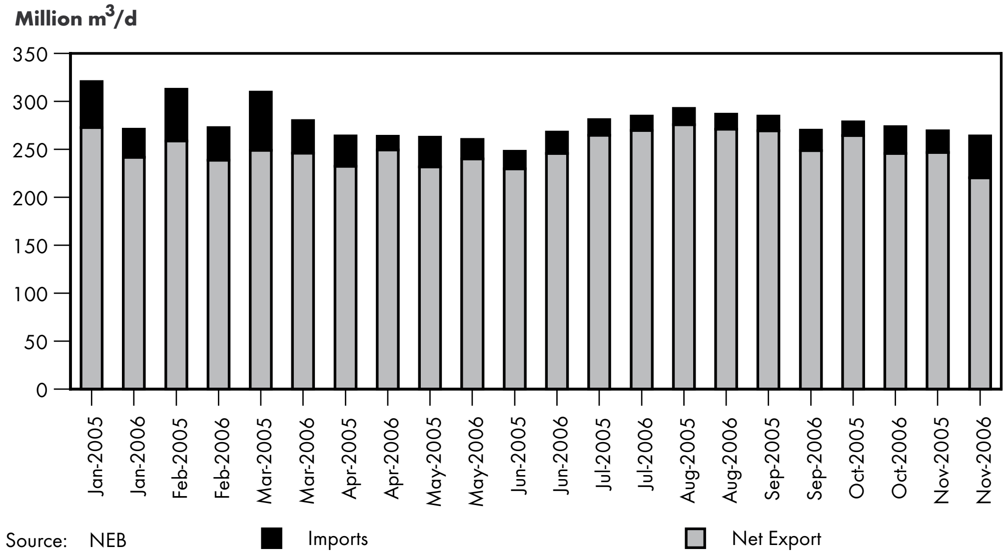
Daily Dawn Price



Source: Platts

FIGURE 5.8

Monthly Export and Import Volumes



Source: NEB

Overall, Canadian revenues from gas exports also saw a year-over-year decrease due to the combination of comparatively lower export volumes and prices of 2006. The average export price was down 19 percent over the previous year, which resulted in net export revenues of $24.4 billion, about 24 percent below 2005 net export revenues of $32.1 billion.

5.6 Natural Gas Liquids (excluding Pentanes Plus)

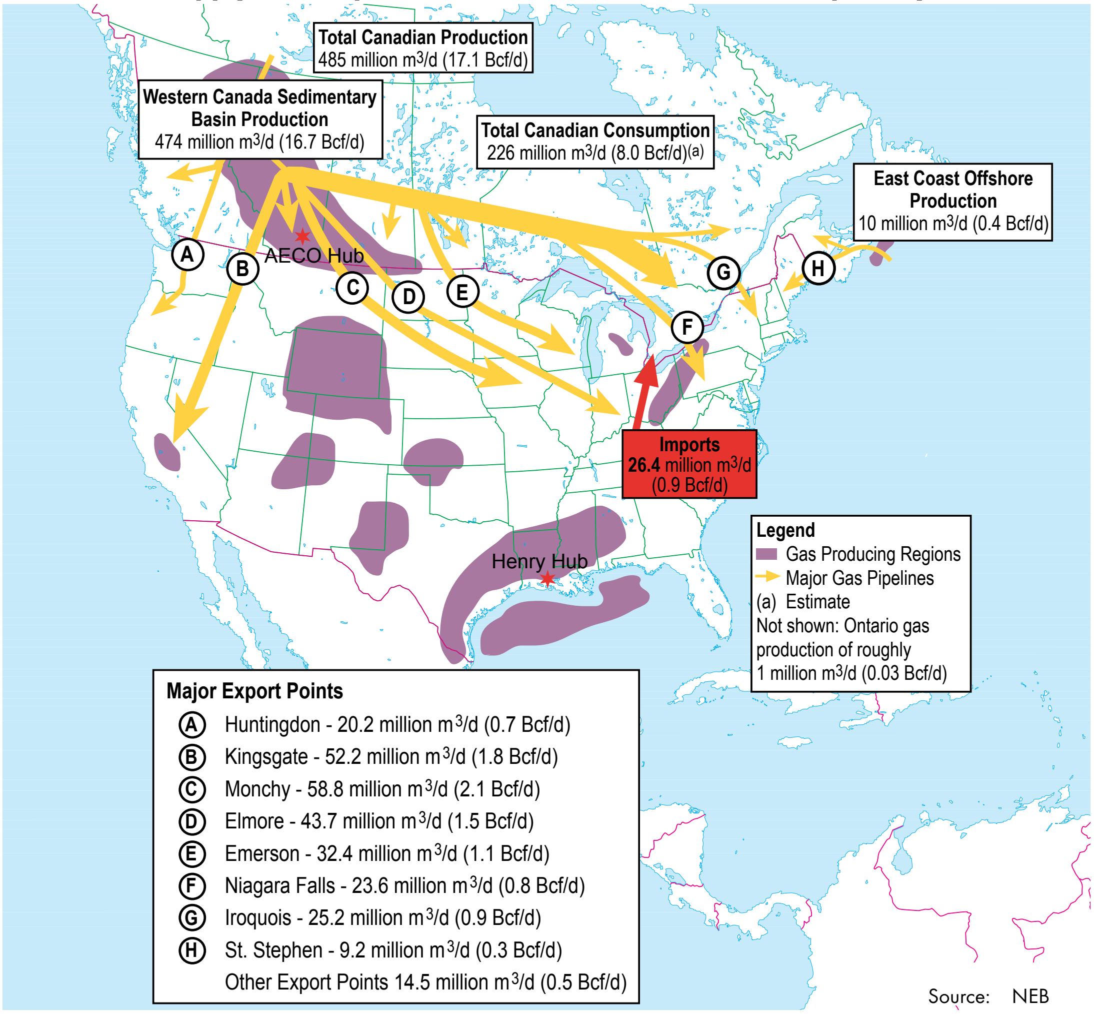
Natural gas liquids (NGLs) refer to the liquid hydrocarbon products extracted from the natural gas stream and are initially recovered as a hydrocarbon mix. The component parts can then be further separated into marketable products such as ethane, propane and butanes. Propane and butanes are also produced from crude oil refining and upgrading processes - products from these processes are also referred to as liquefied petroleum gases (LPG). It is estimated that in 2006, 87 percent of propane and 69 percent of butane supplies came from natural gas production.

High propane prices, supported by high crude oil prices in the first half of the year and low natural gas prices in the second half of the year, created a favourable environment for propane extraction during 2006. Propane production increased by about three percent to 28 800 m^3/d (181 Mb/d). Strong feedstock demand in the petrochemical sector for propane also helped keep prices high in North America. Ethane and butane production from gas plants remained relatively unchanged at 40 500 m^3/d (255 Mb/d) and 16 900 m^3/d (106 Mb/d), respectively.

In 2006, refinery production for both propane and butane declined from 2005 levels due to lower conventional crude oil production and maintenance at oil sands mining operations. Refinery production of propane is estimated at 3 500 m^3/d (22 Mb/d), an 11 percent decrease since 2005. Butane refinery production declined marginally by one percent because of 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 of the total export volume. Estimated 2006 propane exports declined by 12 percent to 18 000 m^3/d (113 Mb/d) and butane exports decreased by nine percent to 4 500 m^3/d (28 Mb/d).

Natural Gas Supply and Disposition – 2006 (Million Cubic Metres per Day)



Source: NEB

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 butane export volume was caused by strong diluent demand in the Alberta heavy oil sector.

The higher prices for propane almost offset lower propane export volumes, resulting in estimated 2006 export revenue of $2.1 billion, three percent lower than in 2005. Higher butane prices resulted in 2006 export revenue for butane totalling $622 million, one percent lower than in 2005. Export revenue for the two commodities combined totalled almost $2.7 billion.

5.7 Looking Ahead

To meet growing natural gas demand, a number of LNG re-gasification facilities have been proposed for sites in Canada. Figure 5.10 outlines these proposed facilities and their capacities and proposed start-up dates.

Changing natural gas market dynamics in Canada are being driven by rising natural gas use by Alberta's oil sands and increasing demand for natural-gas-fired power generation, especially in Ontario. Currently natural gas for power generation in Ontario accounts for about ten percent of

Ontario's total gas consumption; however, the potential for an increase in natural gas consumption is high, primarily driven by the provincial government's decision on power generation in response to air quality concerns. In the past year, 650 MW of new gas-fired power generation was installed in the province.

FIGURE 5.10

Proposed Canadian LNG Projects (Bcf/d)

Location	Terminal	Company	Capacity	Proposed on Stream Date
1. Goldboro, Nova Scotia	Keltic LNG	Keltic Petrochemicals Inc. and Maple LNG	1.0	2009
2. Saint John, New Brunswick	Canaport LNG	Repsol YPF and Irving Oil	1.0	2008
3. Rivière-du-Loup, Quebec	Gros Cacouna LNG	Petro-Canada and TransCanada Pipelines Ltd.	0.5	2009
4. Québec City, Quebec	Rabaska	Gaz Métro, Enbridge and Gaz de France	0.5	2009
5. Ridley Island, British Columbia	WestPac LNG	WestPac Terminals Inc.	0.3	2009
6. Emsley Cove, British Columbia	Kitimat LNG	Gavelston Energy	0.6	2009
7. Point Tupper, Nova Scotia	Statia LNG	Statia Terminals Canada Partnership	0.5	n/a
8. Saguenay, Quebec	Énergie Grande-Anse	Saguenay Port Authority and Énergie Grande-Anse Inc.	1.0	n/a

ELECTRICITY

6.1 Market Development Initiatives

Regional jurisdictions across Canada continued to introduce initiatives aimed at ensuring that adequate supply will be available to meet short-term and long-term demand requirements. The focus on conventional generation sources (e.g., fossil-fuelled generation, nuclear power and hydro electricity) has continued, yet more attention is being put on emerging generation technologies (e.g., wind, biomass and small hydro), investment in transmission infrastructure and demand-side management.

Jurisdictions that experienced periods of tight supply due to high demand responded by increasing generation capacity and transmission capability and introducing market enhancements. For instance, Ontario implemented a number of initiatives to address short-term supply adequacy following reliability challenges experienced during the summer of 2005. In 2006, the province introduced a Standard Offer Program designed to promote small, renewable energy generating projects by making it easier and more cost effective for businesses and entrepreneurs to sell renewable power to the grid by setting a fixed price for the projects. The program is expected to add up to 1,000 MW over the next 10 years.

Much long-term planning is occurring as well. For example, in an effort to meet its longer-term needs, Yukon Energy Corporation filed a 20-year resource plan with the Yukon Utilities Board that addresses resource needs from 2006 to 2025. Proposals include three generation projects and one new transmission line to be in place by 2012.

Jurisdictions are also increasingly using demand-side management initiatives as they develop their resource plans. One example is Ontario's Emergency Load Reduction Program that was introduced in 2006. The program enables major electricity consumers to reduce electricity consumption or to use backup generation on demand by the province's Independent Electric System Operator (IESO). The IESO will pay organizations up to $600 per MW.h for reducing consumption. The program is designed for use in emergency conditions when other options for maintaining reliability are limited.

Resource plans in other regions used programs that focus on both demand-side (conservation and improved energy efficiency) management initiatives and supply-side (generation) increases. For example, the Government of Quebec released its *Energy Strategy 2006 - 2010* in June of 2006. The policy consists of three main objectives: improving energy efficiency and energy savings to 4.7 TW.h in 2010 and to 8.0 TW.h by 2015; a complementary development of hydro and wind power equating to $25 billion in investment that includes 4,500 MW in new hydro projects, and the development of 4,000 MW of wind generation by 2015; and finally, technological innovation. A major objective of the strategy is to increase exports to Ontario and the U.S.

Ontario introduced its Integrated Power System Plan (IPSP), a comprehensive public engagement process coordinated by the Ontario Power Authority. The IPSP will develop the measures necessary to accommodate phasing out coal–fired generation (a recent assessment by the Ontario Power Authority suggests retirement of all coal-fired plants by 2015) and meet Ontario's power needs over the next 20 years. A combination of supply-side and demand-side measures will be used. Renewable generation supply and other diverse generation resources are expected to play a significant role in these plans.

Furthermore, jurisdictions demonstrated that addressing the reliability of supply can be a joint initiative. For instance, a cooperation accord was signed on 2 May 2006 by the energy ministers of Canada's four western provinces and three Arctic territories to help develop and secure energy supplies for the future. Under the accord, each jurisdiction indicated they would harmonize their separate regulatory regimes and better co-ordinate the evaluation and approval of energy development projects.

Electricity prices increased in a number of Canadian jurisdictions in 2006. Increases in demand and higher fuel costs led to a number of provinces and utilities receiving approvals for rate increases from their regulators.

6.2 Electric Reliability Organization (ERO)

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.

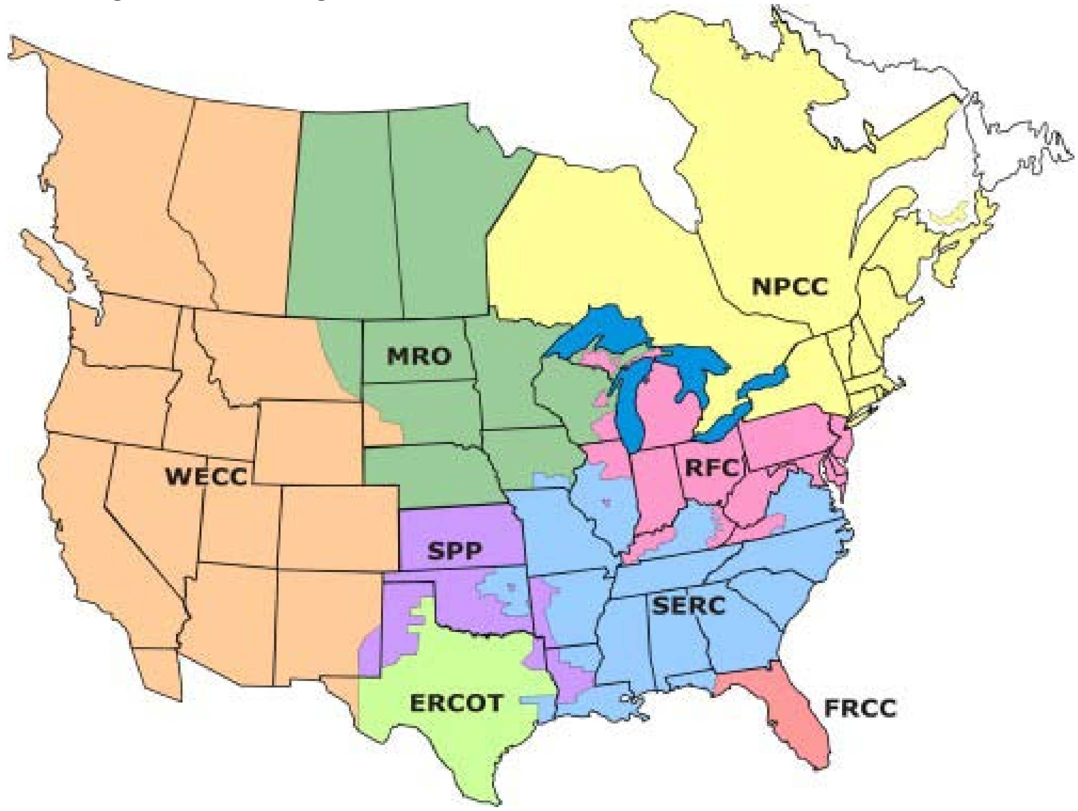
On 20 July 2006, the Federal Energy Regulatory Commission (FERC) certified the North American Electric Reliability Corporation (NERC) as the newly formed Electric Reliability Organization (ERO). In its role as the ERO, NERC has the legal authority to enforce reliability standards on the owners, operators and users of the bulk power system, rather than relying on the system of voluntary compliance overseen by NERC's predecessor, the North American Electric Reliability Council. The creation of the ERO is authorized in the U.S. under the Energy Policy Act of 2005 and was supported by the recommendations made by the Power Outage Task Force following the 23 August 2003 blackout. The ERO commenced operations in January 2007.

On 14 September 2006 the NEB signed a Memorandum of Understanding recognizing NERC as the ERO. The memorandum promotes reliability standards for international power lines under the NEB's jurisdiction in Canada. A number of provinces either enacted legislation or introduced legislation to effectively recognize the NERC as the ERO.

Infrastructure enhancement initiatives took place on a variety of levels in 2006. Some projects were targeted to address more localized issues through upgrades. For example, on 7 July 2006, the British Columbia Transmission Corp. received approval from the British Columbia Utilities Commission to build two new underwater 230 kV lines between the British Columbia mainland and Vancouver Island. This project follows the June 2005 cancellation of the Duke Point Power Project, a gas-fired generation project on the island, because of the risk the plant would not be built on time. The $250 million project will replace the two deteriorating 138 kV cables from the mainland. The new lines are expected to be completed by October 2008. An environmental assessment review process was still being conducted at the end of 2006.

F I G U R E 6 . 1

NERC Regions and Subregions



- Mandatory reliability standards are administered by NERC's regional reliability organizations including the Northeast Power Coordinating Council (NPCC) (Ontario, Québec and the Maritimes), the Midwest Reliability Organization (MRO) (Saskatchewan and Manitoba) and the Western Electricity Coordinating Council (WECC) (British Columbia and Alberta).
- Provincial government agencies and the NEB have regulatory oversight in their respective jurisdictions in Canada.
- The FERC has regulatory oversight over the NERC in the U.S.

Other projects addressed local needs through the expansion and addition of new transmission lines. The EUB approved ATCO Electric's application to reinforce the northwestern transmission system. The $300 million in planned transmission upgrades northwest of Edmonton includes one 138 kV line and one 240 kV line by 2009 and one 240 kV line by 2014.

Quebec also made intra-provincial investments in transmission infrastructure in 2006. Projects included a variety of infrastructure additions including two 69 kV lines, one 315 kV line, and new and upgraded substations.

Provinces and utilities worked together to accomplish supply reliability initiatives. Ontario and Quebec reached an agreement on 14 November 2006 to develop an inter-provincial transmission line linking their grids to reduce the need to import from the U.S when demand exceeds capacity. When constructed, the line could add up to 1,250 MW of power to Ontario from Quebec, therefore increasing the stability of Ontario electricity supply. The line is expected to be operational in 2010.

International reliability initiatives moved forward on several fronts. On 15 September 2006, the NEB approved the first merchant international transmission line. Sea Breeze Converter Corporation was approved to build a 150 kV power line from Vancouver Island to Port Angeles, Washington.

New Brunswick also began the construction of its 345 kV international transmission line in November 2006. The Board approved the line following the EH-2-2002 proceeding. The line will connect the transmission systems of Maine and the three Maritime provinces and will extend from Point Lepreau, New Brunswick to the U.S. border at Woodland, Maine. The expected in-service date is December 2007.

In an effort to address potential operational reliability concerns and avoid putting additional stress on its transmission system, the Alberta Electric System Operator (AESO) announced in May that there would be a 900 MW upper limit for wind generation in the province. The main reason cited for this decision was the potential reliability problems associated with managing wind generation on the Alberta integrated energy system. At the end of 2006, Alberta had 384 MW of wind generation capacity.

6.3 Electricity Generation

At the end of 2006, Canada's total installed generation was 122,898 MW, an increase of 54 MW from 2005. Total Canadian electricity generation declined slightly from 597 TW.h in 2005 to 589 TW.h in 2006 (Table 6.1). Hydro electric generation declined from 358 TW.h in 2005 to 353 TW.h in 2006. The decrease occurred despite the adequate water season for hydro generating provinces. Thermal generation declined slightly from 152 TW.h in 2005 to 141 TW.h in 2006. This change can be attributed, in part, to the milder weather experienced across the country throughout the year. Additional generation support came from the restart of Ontario Power Generation's Pickering A, Unit 1 of approximately 500 MW in November 2005 which helped to increase nuclear generation from 87 TW.h in 2005 to 94 TW.h in 2006. Hydro electric, thermal and nuclear generation accounted for 60, 24 and 16 percent of total Canadian generation, respectively.

A strategy for increasing capacity continued to include diversification of generation, which was largely achieved through the requirement for generation projects that use emerging technologies. This strategy was partially supported by rising long-term fuel costs for thermal generators. An advantage of capacity additions from emerging technologies (such as wind power) is the often shorter construction lead time.

Following the second phase of a request for proposals issued in May 2005 for 45 MW of capacity under its Environmentally Preferred Power (EPP) program, SaskPower selected a wind farm (25 MW) and three heat-recovery units at natural gas pipeline compressor station sites (5.1 MW each). The EPP program is designed to meet new load growth to 2010 with smaller generation projects that produce no new greenhouse gases and contribute to environmental sustainability.

British Columbia's December 2005 call for power to purchase 285 MW by 2010 resulted in a response that had a high concentration of renewable projects. In an attempt to become less reliant on imports, BC Hydro awarded, and the British Columbia Utilities Commission approved, 38 projects that will supply 1,439 MW to the grid. The projects include 29 hydro electric, three wind, two biomass, two waste-heat and two coal/biomass generators. All projects are to be online by 2010.

Wind generation projects grew across the country becoming an increasingly larger component of generation portfolios in many provinces. Capacity more than doubled in 2006, to 1,460 MW year end from just over 680 MW in 2005. Ontario had the biggest increase in 2006 with nearly 400 MW

TABLE 6.1

Electricity Production[(a)]
(Terawatt Hours)

	2002	2003	2004	2005	2006[(b)]
Hydroelectric	345.9	332.9	335.1	358.4	353.1
Nuclear	71.3	70.7	85.3	86.8	94.3
Thermal	161.6	160.7	150.9	151.8	141.1
Total	**578.8**	**564.3**	**571.3**	**597.0**	**588.5**

(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

of wind projects, bringing the province's total to 413 MW at the end of the year. Several provinces continue to move forward with new planned projects. According to the Canadian Wind Energy Association, by the end of 2006, Canada ranked twelfth in the world in terms of wind energy capacity.

New natural-gas-fired generation continued to experience strong growth. For example, the Ontario Power Authority awarded a contract to TransCanada Corporation to build a 683 MW gas-fired generation facility. This is in addition to the 550 MW Portlands Energy Centre and the 880 MW Goreway Station, which were awarded contracts earlier in the year.

In 2006, there was a continued resurgence in large hydro generation projects. An agreement was signed on 14 June 2006 between Manitoba Hydro and the Nisichawayasihk Cree Nation to develop the 200 MW Wuskwatim hydro generation station. The $1.2 billion project is estimated to be completed in 2012. Manitoba Hydro also moved forward with its proposal to construct the Conawapa generating station, a 1,250 MW development in northern Manitoba. If constructed, the $5 billion generating station will be the province's largest. Additionally, Quebec's Eastmain 1-A 890 MW hydro project received provincial and federal approval in November and December, respectively.

In Labrador, the government announced that it would take the lead in developing the proposed Lower Churchill River hydro electric project. If it goes ahead, the project would be built and operated by Newfoundland & Labrador Hydro. The earliest date the project would start generating electricity would be 2015. A final decision on whether to proceed with the project is expected to be made in 2009.

6.4 Electricity Demand

During 2006, electricity demand was adequately met across the country as temperatures remained mild, particularly during the winter heating season. However, through the summer, some transmission systems were challenged.

Ontario is the only province where the peak electricity load is in the summer. The IESO experienced two extremes that taxed its system on 1 August 2006. First the province experienced a record high demand (approximately 27,000 MW versus a capacity of approximately 31,000 MW) and then on 3 September 2006 it experienced a record low (off-peak) demand (approximately 12,000 MW). The low demand resulted in a negative price of -$3.10 per MW.h. This negative price occurred because suppliers were willing to pay to run their generating units in order to meet their minimum generation output requirements.

Although a region's physical system may be balanced from an overall supply and demand perspective, short-term, tight balance conditions can still occur. Such was the case in Alberta on 24 July 2006 when the following events occurred within the same critical timeframe stressing the province's generation: three coal units were offline for scheduled maintenance; two units tripped offline; hot weather increased electricity demand; and lightning reduced the use of the Alberta/British Columbia intertie. The result was rotating blackouts. The situation was mitigated by co-ordination with other regions and voluntary demand reductions within the province.

6.5 Electricity Exports and Imports

Compared to 2005, which was a favourable water year for hydro electricity generation, net exports decreased 26 percent in 2006 to 17.4 TW.h due to an increase in imports. Net exports were up four percent from the five-year average of 16.7 TW.h.

Exports declined four percent to 41.2 TW.h and were 14 percent above the five-year average of 36.1 TW.h. Imports increased by 23 percent in 2006 to 23.8 TW.h. Additionally, export revenues declined 21 percent from $3.15 billion in 2005 to $2.50 billion in 2006. Canada imported $1.18 billion of electricity in 2006 compared with $1.27 billion in 2005, a decline of eight percent. The impact on exports can be attributed to the milder weather in export regions throughout 2006, while lower cost power helped support the increase in imports.

Hydro electric generation is the largest single source of generation in Canada. Therefore, a strong export year largely depends on the major hydro generating provinces of British Columbia, Manitoba, Ontario and Quebec. These provinces were the largest exporters of electricity in 2006 consisting of 13 percent, 30 percent, 22 percent and 28 percent of total Canadian exports, respectively. Hydro generating provinces actively trade to take advantage of off-peak and on-peak prices south of the border, importing electricity in order to store water behind their reservoirs for future generation opportunities. The largest importers of electricity were British Columbia, Ontario and Quebec accounting for 51 percent, 27 percent and 11 percent of total Canadian imports, respectively.

FIGURE 6.2

International and Interprovincial Transfers of Electricity[a] (Gigawatt Hours)

6.6 Looking Ahead

Looking forward, jurisdictions will continue to implement measures to ensure an adequate supply of electricity. Emerging technologies are expected to make up a larger percentage of generation portfolios, although this is still quite small relatively speaking. Wind is expected to lead the way in this growth. Increases in demand-side management will result as initiatives gain momentum to curb demand growth. Governments, system planners and electric utilities are likely to support greater implementation of these technologies. Investment in transmission infrastructure will be required to meet electricity supply and operating reliability requirements. Additionally, jurisdictions will continue initiatives to cooperate with each other for supply and operating reliability purposes.

Electricity rates will increase over the longer term as fuel prices and operating costs rise and new infrastructure is added. Short-term price fluctuations will be influenced by weather and the occurrence of temporary tight supply situations.

Electricity industry participants will continue to look for export opportunities to the U.S. A favourable export year will depend on water conditions in the hydro generation provinces and demand for cooling and heating in the summer and winter months, respectively.

Conclusion

The importance of the energy sector to the Canadian economy continues to grow, accounting for 5.9 percent of total GDP and C$99 billion of export revenues in 2006. Export revenues grew by 19 percent compared with 2005 and accounted for 22 percent of the value of all exports. While export volumes continue to climb and export revenue grows, the trend in Canada appears to be increasing awareness of energy efficiency and consumption patterns.

Canadians are beginning the journey to more efficient use of energy. In 2006, energy consumption increased by only 1.1 percent, compared with the five-year annual average of two percent. During the 2002 to 2006 period, Canadian total energy demand on average increased by 1.8 percent per year, compared with the rising average real GDP rate of 2.8 percent per year. Energy intensity has therefore improved during this time. This improvement is largely in transportation demand, suggesting that Canadians are responding to higher fuel prices by altering their driving behaviour. However, other factors such as government initiatives, growing awareness about conservation, and warmer winter temperatures are also likely key contributors.

The increasing importance of oil production to Canada's economy is indicated by the oil export revenues which increased to C$39.3 billion dollars, surpassing export revenues generated from natural gas exports for the first time in many years. Investment in the oil sands is contributing to strong economic growth in Alberta and spin-off opportunities in other provinces. Looking forward, oil sands expansion is expected to continue at an aggressive pace, which will have a continuing positive effect on crude oil export revenues, but will also require extension of markets and pipeline capacity in Canada and the U.S.

Weather has a tremendous impact on prices and consumption for natural gas in North America, and warmer winter temperatures resulted in reduced gas export volumes and revenues in 2006.

The generally lower natural gas prices that have been experienced over the last 18 months have been a major factor in the overall reduction in gas-directed drilling effort that began around mid-2006. To date, the overall impact of the lower drilling levels on gas production has been slight, but, going forward, lower gas drilling levels can be expected to exert further downward pressure on WCSB gas production volumes.

Overall, Canadian consumption of natural gas is expected to rise over the foreseeable future, in part related to growing oil sands demand in Alberta and replacement of coal-fired generation in Ontario. This increase would be taking place in an environment of flat or declining domestic natural gas production. Against this backdrop, projects are being proposed to bring LNG into Canada to support domestic consumption and exports to the U.S. market

In 2006, various jurisdictions of the Canadian electricity industry introduced a number of initiatives to ensure adequacy of supply. Looking to the future, adequacy of supply and operating reliability will continue to be in the forefront. Mainstay generation sources such as fossil-fuelled generation, nuclear power and hydro-electricity will see more support from emerging technologies (i.e., wind, biomass and small hydro), and investment in transmission infrastructure and demand-side management.

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	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.
Coiled tubing drilling rig	A specialized drilling rig that uses a long, continuous length of pipe with a downhole mud motor to turn the bit while drilling a well. The continuous pipe arrives coiled on a spool and is straightened as it enters the well and rewound on the spool as it is withdrawn. This differs from a traditional drilling rig that uses jointed pipe with the bit often propelled from the rig floor or top of the drill pipe. Coiled tubing drilling operations proceed quickly compared to using a jointed pipe drilling rig because pipe connection time is eliminated when withdrawing and reinserting the drill pipe in the well during drilling operations. Being smaller, a coiled tubing drilling rig requires less surface area to operate and is more readily moved between locations.
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 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.