National Energy Board | Office national de l'énergie

# Canadian Energy Overview 2009

## AN ENERGY MARKET ASSESSMENT JUNE 2010

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| | |
|---|---|
| BPS | Bulk Power System |
| CanWEA | Canadian Wind Energy Association |
| CBM | Coalbed Methane |
| CCS | Carbon Capture and Storage |
| $CO_2$ | Carbon Dioxide |
| EIA | Energy Information Administration |
| EMA | Energy Market Assessment |
| ERCB | Energy Resources Conservation Board |
| FIT | Feed in Tariff |
| GDP | Gross Domestic Product |
| GEA | Green Energy Act (Ontario) |
| GHG | Greenhouse Gas |
| IEA | International Energy Agency |
| LNG | Liquefied Natural Gas |
| MOU | Memorandum of Understanding |
| NEB or Board | National Energy Board |
| NERC | North American Electric Reliability Corporation |
| NGLs | Natural Gas Liquids |
| NRCan | Natural Resources Canada |
| NSB | North Sea Brent |
| OECD | Organization for Economic Co-operation and Development |
| OPEC | Organization for Petroleum Exporting Countries |
| PADD | Petroleum Administration for Defense District |
| RES | Renewable Energy Standards |
| RRO | Regulated Rate Option |
| SAGD | Steam Assisted Gravity Drainage |
| WCSB | Western Canada Sedimentary Basin |
| WTI | West Texas Intermediate |

| | |
|---|---|
| b/d | Barrels per day |
| bbl | Barrel |
| Bcf/d | Billion cubic feet per day |
| BTU | British thermal unit |
| $ | Canadian dollars |
| GJ | Gigajoule |
| GW.h | Gigawatt hour |
| kW.h | Kilowatt hours |
| $m^3/d$ | Cubic metres per day |
| Mb/d | Thousand barrels per day |
| MMb/d | Million barrels per day |
| MMbtu | Million British thermal units |
| MMcf/d | Million cubic feet per day |
| Mt | Megatonne |
| MW | Megawatt |
| MW.h | Megawatt hour |
| PJ | Petajoules |
| 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 regulate pipelines, energy development and trade in the Canadian public interest[1] within the mandate set by Parliament. The NEB is active and effective in Canada's pursuit of a sustainable energy future.

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 NEB takes a lifecycle approach to all phases of a regulated facility including the application assessment and public hearing phase, the construction and post-construction phase, the operations and maintenance phase, and the abandonment phase.

For pipelines under its jurisdiction, tolls and tariffs are subject to Board regulation. The Board regulates the exports and imports of natural gas as well as exports of oil, natural gas liquids (NGLs) and electricity. The Board also regulates oil and gas exploration, development and production in frontier lands and offshore areas not covered by provincial or federal management agreements. The Board's advisory function requires it to keep under review matters over which Parliament has jurisdiction relating to all aspects of supply, transmission and demand for Canadian energy.

The NEB monitors energy markets to objectively analyze energy commodities and inform Canadians about trends, events and issues. Annually, the Board conducts a review of the previous year's energy markets in an Energy Market Assessment, entitled *Canadian Energy Overview*. This year's report, *Canadian Energy Overview 2009* is a summary of major developments related to energy in Canada in 2009.

If a party wishes to rely on material from this report in any regulatory proceeding before the NEB, it may submit the material, just as it may submit any public document. Under these circumstances, the submitting party in effect adopts the material and that party could be required to answer questions pertaining to the material.

This report does not provide an indication about whether any particular application will be approved or not. The Board will decide on specific applications based on the material in evidence before it at that time.

1 The public interest is inclusive of all Canadians and refers to a balance of economic, environmental and social issues that changes as society's values and preferences evolve over time. The Board weighs the relevant impacts of these interests when making its decisions.

# Executive Summary

The year 2009 clearly demonstrated the interrelationship between energy demand and supply and economic conditions in Canada. Along with the overall economic downturn, energy production and consumption declined, as did the employment in, and output of, the Canadian energy industry. Energy prices remained relatively low at the start of the year, continuing to be impacted by the financial crisis that plunged the global economy into a recession in the second half of 2008.

While global economic conditions captured much of the attention in 2009, many citizens remained concerned about energy and the environment. One of the biggest stories in energy and the environment for 2009 occurred at the UN Climate Change Conference. The conference took place in Copenhagen, Denmark in December and resulted in a non-binding agreement, the Copenhagen Accord. In Canada, the federal government announced a new emissions reduction target for Canada, 17 per cent below 2005 levels by 2020.

2009 was a recession[2] year, with Canada's gross domestic product (GDP) declining 2.5 per cent. The energy industry directly accounted for an estimated 6.7 per cent of Canadian GDP in 2009, down slightly from 2008. Energy is one of Canada's largest exports, and in 2009 it represented 23 per cent of the country's total exports. On average, energy prices were lower in 2009, resulting in a drop in energy export revenues to $81 billion from a record high level of $133 billion in 2008.

Oil export volumes increased while oil export revenues declined from 2008 because of lower crude oil prices. The continuing decline in conventional production in western Canada, and maintenance and natural pool decline on the east coast, offset oil sands production increases. Lower crude oil prices in the first half of 2009 resulted in the deferral or cancellation of many new oil sands projects lowering growth projections, as well as the shut-in of some production. Reductions in production by OPEC resulted in a narrower light-heavy crude oil price differential that benefited heavy crude oil and bitumen producers. Due to oil price recovery in the second half of 2009, and signs of global economic recovery, shut-in volumes and a number of deferred projects were reinstated.

Natural gas drilling activity in Canada was at its lowest level of the past decade in 2009 and consequently, natural gas production continued its decline. Canadian exports declined slightly because U.S. requirements were increasingly met by growing U.S. production, particularly from shale gas sources, and increased liquefied natural gas (LNG) imports. Natural gas export revenue dropped significantly because of the combined impact of lower gas prices and lower export volumes. Shale gas production in Canada grew slightly but did not offset the decline in conventional production.

2 In macroeconomics, a recession is commonly defined as a decline in a country's gross domestic product (GDP), or negative real economic growth, for two or more consecutive quarters.

Natural gas liquids (NGLs) production declined as natural gas production declined. In addition, economic conditions in the first half of 2009 depressed demand for petrochemical feed stocks, so many producers decided to leave the liquids in the natural gas streams.

Canadian electricity industry activity during 2009 focused on increasing renewable generation and improving the reliability of the grid, as well as encouraging conservation and improving efficiency. The economic downturn changed the economics of many planned projects and as a result, power projects in some provinces were deferred, downsized or cancelled. In 2009, electricity consumption continued its decline due to a mix of economic downturn, cooler summer weather, increased efficiency and conservation efforts. Of significance is the decrease in demand for industrial use in Ontario. Electricity prices remained relatively stable during the year with lower prices for natural gas lowering electricity costs in the provinces that rely on natural gas for power generation. Net exports decreased by eight per cent with export revenue falling considerably as a result. It is expected that an economic recovery in North America could lead to higher electricity prices and increased export revenues.

2009 was a difficult year for many global economies. Demand for energy was down and prices were down, which benefited energy consumers and challenged energy producers. In 2010, there is increased optimism that global economies are in the midst of a recovery. While increased energy prices generally have a negative impact on energy consumers, increased demand and prices for energy commodities tend to have a positive impact on the Canadian economy.

*Key Findings:*

- Energy and economy are highly integrated – overall energy production and consumption in Canada declined while the economy declined by 2.5 per cent
- On average, energy prices were lower in 2009, resulting in declines of energy export revenues from $133 billion to $81 billion, about 40 per cent
- Oil prices averaged about US$62/bbl in 2009, compared to about US$100/bbl in 2008
- There has been an eight per cent decline in per capita end-use energy demand over the last five years
- 2009 marks the first time Canada experienced negative year-to-year economic growth since 1991
- Canadians remained interested in environmental issues during the economic downturn

# Energy and the Canadian Economy

The Canadian economy in 2009 saw a continuation of the downturn that began in mid-2008. The financial crisis and the worsening economic conditions that characterized the latter half of 2008 led to concern from Canadians in 2009 that the recession could be deep and long-lasting. As the year progressed, the Canadian economy showed signs of a recovery and by year-end, Canadians were cautiously optimistic that a recovery was beginning.

Energy and the Canadian economy are highly integrated, and the energy industry was affected by the economic downturn. Table 2.1 features several key statistics highlighting the relationship between energy and the economy in Canada. It shows that the energy industry's direct contribution to GDP, export revenues, and labour force all fell in 2009 relative to 2008 levels. An important factor in this change was a decline in energy prices. As shown in Table 2.1, the average price of oil fell 38 per cent in 2009 relative to 2008 levels.

In 2009 net energy export revenue (the value of energy exports minus the value of energy imports) also fell compared with 2008 levels, from $73 billion to $42 billion, a 43 per cent decline (Figure 2.1).

**TABLE 2.1**

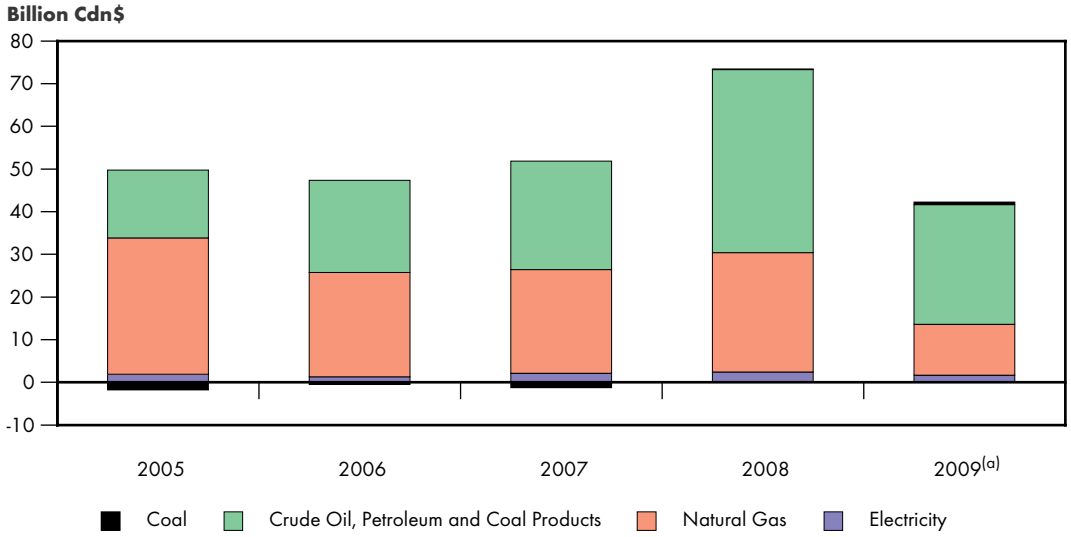
***Key Statistics on Energy and the Economy***

| | 2008 | 2009 | Difference, 2008-2009 |
|---|---|---|---|
| The energy industry's direct contribution to GDP (per cent) | 6.9 | 6.7 | -0.2 |
| Annual energy export revenues (Billion $) | 133 | 81 | -52 |
| The energy industry's direct contribution to export revenues (per cent) | 27 | 23 | -4 |
| Per cent of labour force directly employed by the energy industry | 2 | 1.8 | -0.2 |
| Monthly Average Oil Price ($US/bbl) | 99.57 | 61.65 | -37.92 |

Sources: Statistics Canada, Energy Information Agency

## FIGURE 2.1

***Net Energy Export Revenues, 2005-2009***




(a) Estimate

Sources: Statistics Canada, NEB

Net export revenue of natural gas fell nearly 60 per cent, marking the third year in a row that the net export revenue from crude oil exceeded that of natural gas.

Declining economic conditions contributed to a 3.2 per cent decrease in overall Canadian energy production in 2009 (Table 2.2). While petroleum and wind production did gain compared with 2008 levels, it was not enough to offset the declines in the other commodities.

## TABLE 2.2

***Domestic Energy Production by Energy Source (petajoules)***

| | 2005 | 2006 | 2007 | 2008 | 2009(a) | % Change, 2008-2009 |
|---|---|---|---|---|---|---|
| Petroleum(b) | 6 612 | 6 908 | 7 126 | 6 821 | 6 836 | 0.2% |
| Natural gas(c) | 6 559 | 6 589 | 6 481 | 6 395 | 6 029 | -5.7% |
| Hydroelectricity | 1 290 | 1 258 | 1 317 | 1 329 | 1 308 | -1.6% |
| Nuclear | 1 103 | 1 184 | 1 098 | 1 131 | 1 089 | -3.7% |
| Coal | 1 401 | 1 419 | 1 506 | 1 478 | 1 366 | -7.6% |
| Wind | 6 | 9 | 10 | 13 | 22 | 69.4% |
| Other(d) | 612 | 527 | 581 | 591 | 543 | -8.1% |
| **Total** | **17 583** | **17 895** | **18 120** | **17 758** | **17 193** | **-3.2%** |
| **Annual % Change** | **-0.3%** | **1.8%** | **1.3%** | **-2.0%** | **-3.2%** | |

(a) Estimates

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

(c) Marketable natural gas

(d) Includes solid wood waste, spent pulping liquor, wood and other fuels for electricity generation

Sources: NEB, Statistics Canada, Natural Resources Canada

**TABLE 2.3**

***Domestic Secondary Energy Consumption (petajoules)***

| | 2005 | 2006 | 2007 | 2008 | 2009[a] | % Change, 2008-2009 |
|---|---|---|---|---|---|---|
| Residential[b] | 1 396 | 1 335 | 1 439 | 1 463 | 1 467 | 0.3% |
| Commercial | 1 493 | 1 420 | 1 471 | 1 498 | 1 433 | -4.4% |
| Industrial[b][c] | 5 246 | 5 280 | 5 509 | 5 207 | 4 787 | -8.1% |
| Transportation | 2 479 | 2 479 | 2 590 | 2 587 | 2 515 | -2.8% |
| **Total** | **10 614** | **10 514** | **11 009** | **10 756** | **10 203** | **-5.1%** |
| **Annual % Change** | **-0.7%** | **-0.9%** | **4.7%** | **-2.3%** | **-5.1%** | |

(a) Estimates

(b) Includes biomass (wood and pulping liquor)

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

Sources: NEB, Statistics Canada

Domestic energy consumption also declined in 2009. Changes in population, economic conditions, energy prices, weather, conservation, technology, and consumer preferences all combine to shape Canadian energy use. Overall, there has been an eight per cent decline in per capita energy consumption over the last five years.

Secondary energy demand (also known as end-use demand) is the energy used by the final consumer in Canada (i.e., residential, commercial, industrial and transportation sectors). Initial estimates suggest a 5.1 per cent decline in total secondary energy use in 2009 (Table 2.3). Although the residential sector is expected to achieve some modest growth, consumption in the other three sectors decreased. For the industrial and transportation sectors, 2009 marks the second year in a row that declines were observed.

Economic conditions are perhaps the most important driver of energy demand. As noted previously, the 2.5 per cent decline in Canada's real GDP, an indicator of economic activity, marks the first time Canada experienced negative year-to-year economic growth since 1991.

Canadians closely watch fuel prices in the transportation sector. The Canadian yearly averages for regular gasoline and diesel retail pump prices in 2009 were 17 and 28 per cent lower, respectively, than average 2008 levels. These prices were also considerably less volatile in 2009. Despite lower and less volatile prices in 2009, energy use in the sector is estimated to have declined. This highlights the relative importance of the negative income effect associated with the economic downturn, again illustrating the significant interrelationship between energy and the economy.

## 2.1 Environmental Initiatives

The Copenhagen Conference was notable for several reasons, including its high public profile, which reflected the growing importance of climate issues across the globe, and the increased role of major developing countries in the negotiation process.

There were several domestic environmental initiatives of note in 2009, suggesting that during the economic downturn Canadians remained interested in environmental issues. Environment Canada released draft legislation for a federal light duty fuel economy standard in December, while Quebec

### *The Copenhagen Accord*

The main result of the UN Climate Change Conference in Copenhagen, Denmark which occurred in December was *The Copenhagen Accord*. While the accord is not yet binding, many countries including Canada have agreed to its principles and will work toward starting its implementation in 2010.

The main terms of the accord are:

- **Temperature Goal:** limit the global temperature increase to two degrees Celsius. This goal is subject to review before 2015, perhaps to strengthen it.
- **Documentation of Emission Reduction Targets and Strategies:** Developed countries are to record their economy-wide emission targets for 2020. (Canada has done this, announcing its new target of 17 per cent below 2005 levels in 2020. This target matches the proposed target of the U.S.) Developing countries are to record their mitigation actions and strategies.
- **Measurement, Reporting, and Verification:** Developed countries are subject to international standards. Developing countries are to follow national standards which will be subject to international review and consultation, with the provision that national sovereignty will be respected. However, developing country actions which receive international support will be subject to the international guidelines.
- **Financing Developing Country Actions:** Developed countries collectively commit to supplying initial funds, and to mobilize funds for the future, for developing country mitigation and adaptation activities.
- **Establishment of Additional Tools:** The accord calls for the establishment of a variety of tools to facilitate the aforementioned initiatives.

also announced a fuel economy standard. In April 2010, the federal government announced a joint Canada-U.S. fuel efficiency standard, expected to improve the greenhouse gas performance of new light duty vehicles sold in Canada by 25 per cent in 2016, as compared to the 2008 average. On the renewable energy front, Ontario passed its *Green Energy Act*, designed to enable renewable energy projects and help Ontarians use energy more efficiently.

## 2.2 Looking Ahead

In 2009, Canadians were concerned about how deep and long-lasting the recession would be. In 2010, the big question is the strength of the recovery. Although risks remain, growth in the third and fourth quarters of 2009 suggests that economic growth will continue in 2010. An economic recovery will have a wide range of implications for the energy sector.

Another factor in looking ahead is the effect of the further development of environmental initiatives relating to climate change and the energy sector. Of key interest is the progress of such initiatives in the United States. Canada has indicated an intention to harmonize its legislation and policies with those of the U.S. in this area. Therefore, further developments in the U.S. are likely to have implications for the Canadian energy industry.

### *Potential for Economic Recovery in 2010*

One of the biggest issues in the near future for Canadian energy is whether or not the initial evidence of an economic recovery witnessed in 2009 turns into a robust upturn in economic activity in 2010. While there are considerable risks, all of the major banks are forecasting a strong economic outlook for Canada in 2010.

Main forces driving the recovery:

- Strong global economic growth, led by major emerging markets such as China, India, and Brazil which is increasing the demand for many commodities and putting upward pressure on their price.
- Economic stimulus activities, including fiscal and monetary measures.

Main risks to the recovery:

- High Canadian dollar putting downward pressure on the demand for Canadian exports.
- Faltering recoveries in Canada's major trading partners.

# Upstream Oil and Gas Activity

***Key Findings:***

- Lower demand for oil and natural gas led to lower prices and reduced upstream activity
- The total number of wells drilled in Canada was down about 50 per cent from 2008.

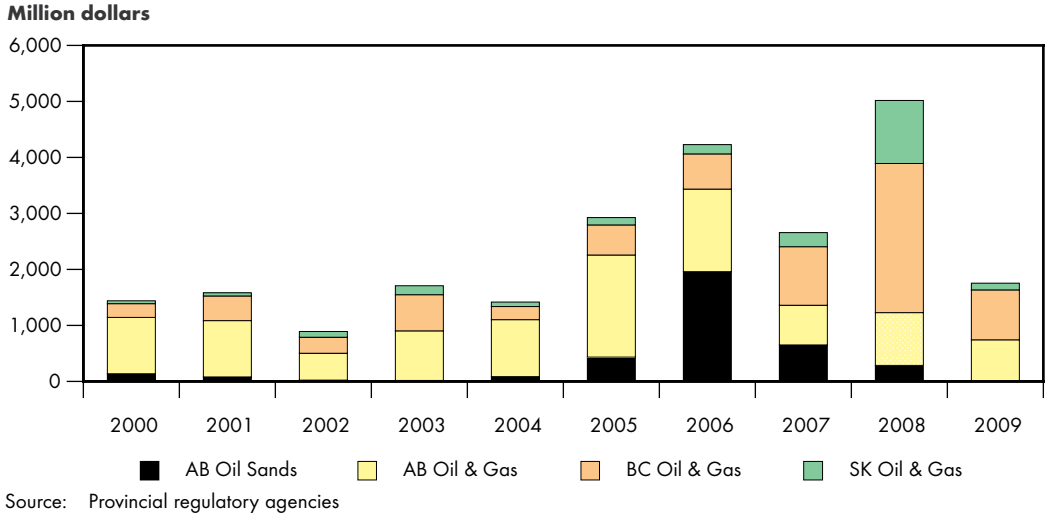
Upstream oil and gas activity can be measured in terms of dollars spent to acquire land rights, the number of active seismic crews, the number of active drilling rigs, the number of wells drilled and the capital expenditures involved.

The economic slowdown lowered the demand for crude oil and natural gas, which, in turn, lowered prices for these commodities. While crude oil prices stabilized in the first quarter of 2009 at around $US 40/bbl, natural gas prices continued to decline through most of the year, reaching lows not seen since 2002. The drop in oil and natural gas prices, compared to year-earlier levels, resulted in reduced drilling and the delay or cancellation of some energy projects, especially in Canada's oil sands. Lower drilling activity also led to a tempering of service industry costs.

Expenditures on petroleum and oil sands rights (Figure 3.1) were lower in 2009 than a year ago for Alberta, Saskatchewan, and British Columbia. The acreage of land rights sold (Figure 3.2), fell to the lowest levels since 1992. This was partially due to lower oil and natural gas prices, but also due to the large purchases of rights in recent years in Saskatchewan's Bakken and Shaunavon formations, Alberta's oil sands and British Columbia's Montney and Horn River Basin formations[3], making

**FIGURE 3.1**

***WCSB Oil, Gas, and Oil Sands Rights Expenditures, 2000-2009***




Source: Provincial regulatory agencies

3 See also *A Primer for Understanding Shale Gas*, available at http://www.neb-one.gc.ca/clf-nsi/rnrgynfmtn/nrgyrprt/ntrlgs/prmrndrstndngshlgs2009/prmrndrstndngshlgs2009-eng.html

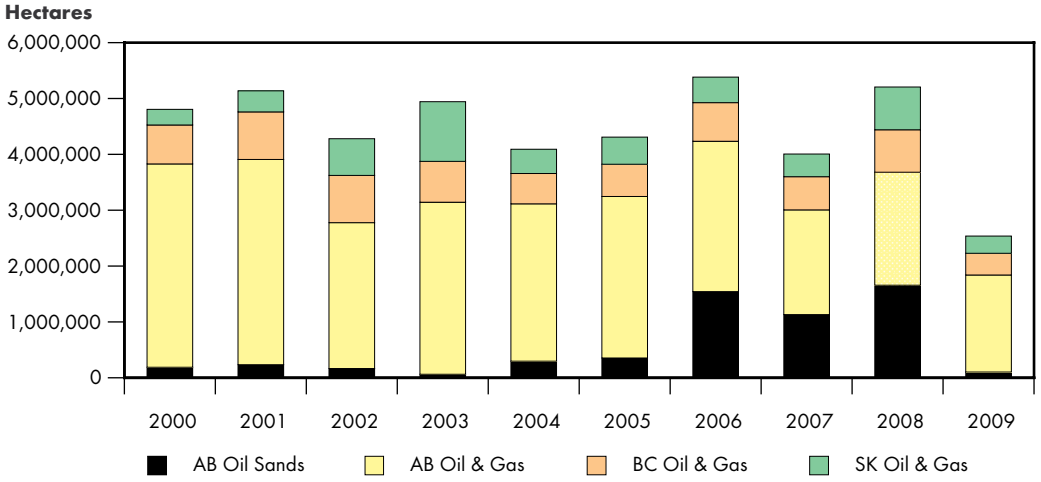
significantly less land available for auction in 2009. In particular, land activity in the oil sands virtually disappeared from 2008 to 2009.

Eastern Canada had $59.7 million under work bid commitments for 2009 on 1.06 million hectares of land. This marks a drop of nearly 90 per cent from last year when Nova Scotia alone received $353 million in work commitments and Newfoundland and Labrador received $319 million. The majority of 2009 work commitments came in a fourth quarter sale for rights in offshore Newfoundland and Labrador.

The number of active rigs in western Canada fell in 2009 (Figure 3.3) because of low oil and gas prices. Weekly rig activity fell by 41 per cent in 2009 to the lowest level since 1992. The three westernmost provinces all saw decreased rig activity, with Alberta having the highest decline at nearly 50 per cent and British Columbia with the lowest at approximately 25 per cent. Further, the total

**FIGURE 3.2**

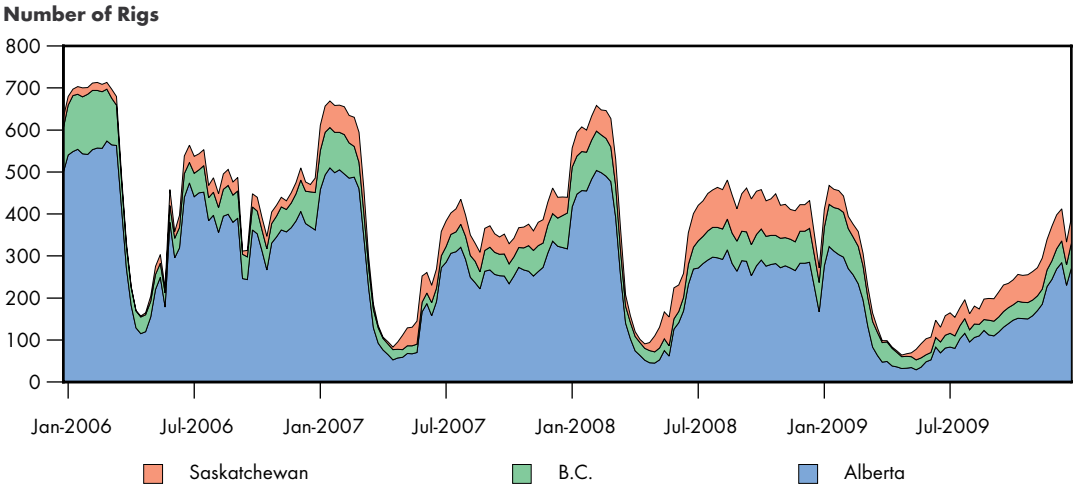
***WCSB Oil, Gas, and Oil Sands Rights Activity, 2000-2009***




Source: Provincial regulatory agencies

**FIGURE 3.3**

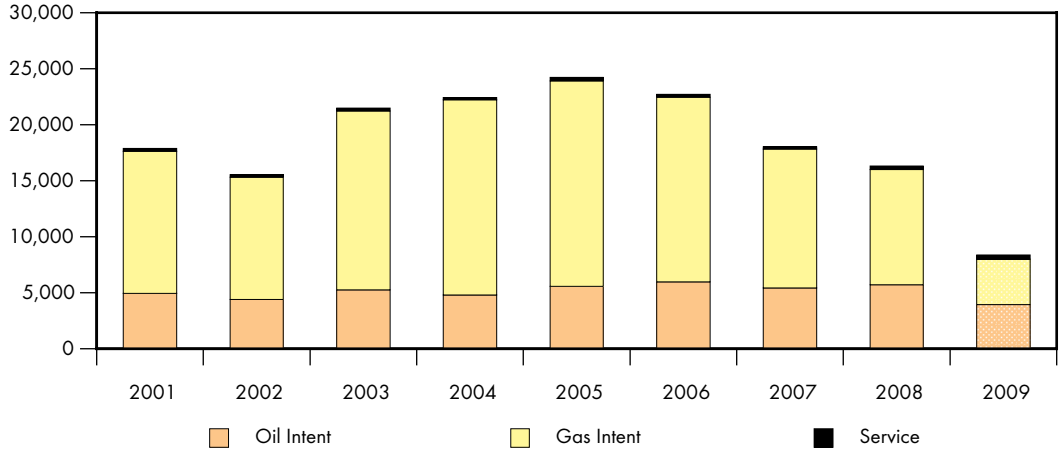
***Western Canada Rig Activity***




Source: Nickle's rig data

**FIGURE 3.4**

***Number of Wells Drilled – Western Canada, 2001-2009***




Source: NEB

metres drilled fell by 43 per cent as compared to 2008 levels to 12.5 million metres.[4] Despite this, the average length of wells drilled rose 15 per cent to 1 517 m as exploration companies increasingly relied on horizontal drilling.

The total number of wells drilled in Canada decreased about 50 per cent from 2008 levels, although the decrease was not evenly split between oil and gas (Figure 3.4). The number of wells targeting oil dropped by about one-third, while the number of wells targeting gas dropped by closer to two-thirds. Between 2003 and 2005, over 80 per cent of Canadian wells targeted natural gas. In 2009, natural gas drilling accounted for roughly 50 per cent of wells drilled.

Total oil and gas capital expenditures in Canada fell by one-third from 2008 levels to an estimated $33.3 billion. Capital spending associated with oil sands projects also fell by one-third to an estimated $13.5 billion.

## 3.1 Looking Ahead

A number of project postponements and cancellations marked a slow year for oil sands operators in 2009. During the fourth quarter, however, increased oil prices and improved forecasts led to producers reinstating certain deferred projects. Oil sands' spending is expected to rise by just over ten per cent in 2010 to $15.0 billion.

Industry has been forecasted to increase its total spending by almost ten per cent in 2010, to $36.4 billion.[5] The Petroleum Services Association of Canada has projected that 9 000 wells will be drilled in the Western Canada Sedimentary Basin (WCSB) in 2010, compared to 16 895 in 2008.

With oil prices rising above 2009 levels and the potential for gas prices to do the same, companies could begin acquiring drilling rights to additional prospective land surrounding the core areas of gas shales in British Columbia, the oil sands of Alberta, and the Bakken oil play in Saskatchewan. However, it is not likely to cause land sale proceeds to reach the highs seen in recent years.

4 Nickle's Daily Oil Bulletin.

5 Statistics Canada. *Private and Public Investment in Canada, Intentions.* 2010.

# Crude Oil and Petroleum Products

## 4.1 International Markets

For much of the first quarter of 2009, the near-month contract for West Texas Intermediate (WTI) traded below US$40/bbl. A recovery in global equity markets beginning in March led to gradually rising oil prices, although demand remained weak and global inventories remained high. Oil prices averaged about US$62/bbl in 2009, compared to about US$100/bbl in 2008 (Figure 4.1).

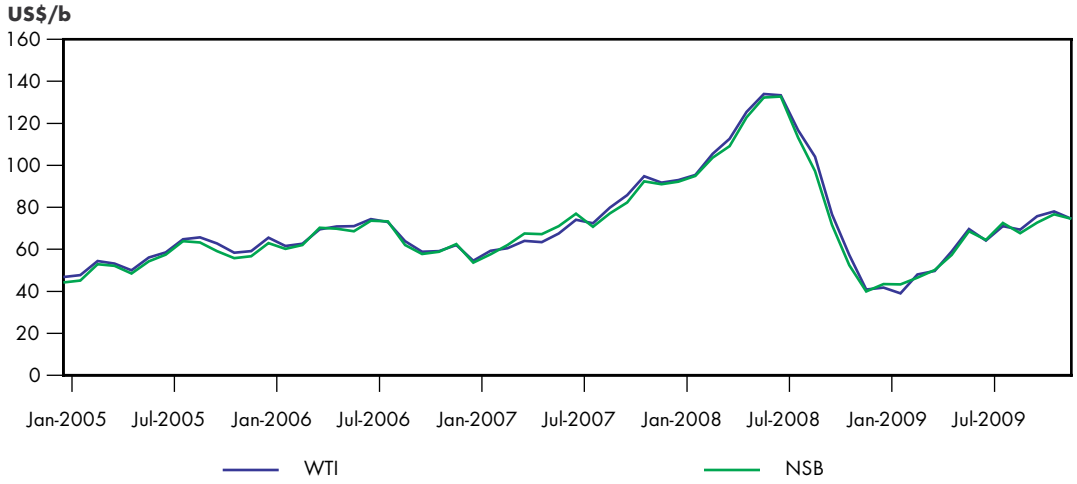
The drivers that led to record prices in the summer of 2008, including tight supply and demand conditions, substantial financial investment in commodities, and ongoing geopolitical risks were replaced by the reality that global oil demand had declined and inventories were rising to high levels. Against this backdrop, OPEC maintained the substantial production cuts it announced in late 2008. By June, WTI was trading at about US$70/bbl, nearly double the lows seen in January.

***Key Findings:***

- Oil sands production grew to 49 per cent of total crude oil production
- Weak demand and high global inventory levels in first half of 2009 led to lower oil prices
- Despite a slight increase in the volume of crude oil exports, lower oil prices in the first half of the year resulted in lower export revenue for crude oil and petroleum products
- In the second half of the year, oil prices and activity levels increased
- Domestic prices for crude oil, gasoline and diesel were much lower compared with 2008

**FIGURE 4.1**

***WTI and North Sea Brent Oil Prices, 2005-2009***




Source: U.S. Energy Information Administration (EIA)

Over the second half of 2009, oil prices averaged about US$70/bbl. While the OECD economies experienced modest economic recovery, the oil market was supported by emerging economies including China which experienced stronger growth. The WTI near-month contract ended the year at about US$79/bbl.

## 4.2 Canadian Oil Production and Reserves Replacement

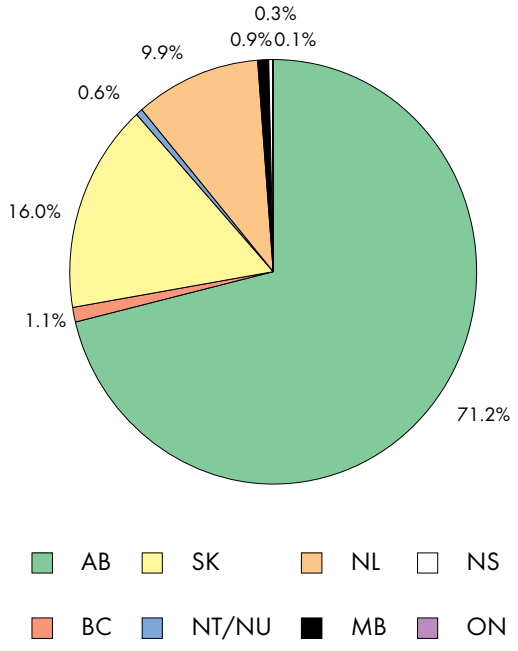
In 2009, Canadian production of crude oil and equivalent averaged 433 300 $m^3/d$ (2.73 MMb/d), an increase of less than one per cent from 2008 levels. Figure 4.2 illustrates crude oil production by province and shows that Alberta is the largest producer by a considerable margin, largely due to oil sands production. Oil sands production grew in 2009, but this gain was almost entirely offset by falling conventional crude oil production in the WCSB. On the east coast offshore production decreased, reflecting natural pool decline as well as some maintenance down time at the White Rose and Hibernia fields.

Figure 4.3 illustrates crude oil and equivalent production by type and shows that non-upgraded bitumen and synthetic crude oil, from the oil sands, now constitute about one-half of Canadian production.

While remaining conventional established reserves are reduced by production each year, these reductions are offset to some degree by new discoveries, extensions to existing pools and revisions to reserve estimates in existing pools. From 2004 to 2007, cumulative additions to established reserves of conventional light and heavy crude oil replaced 87 per cent of production (Table 4.1). In 2008 (the last year for which nearly-complete data is available), 80 per cent of production of conventional crude oil was replaced.

**FIGURE 4.2**

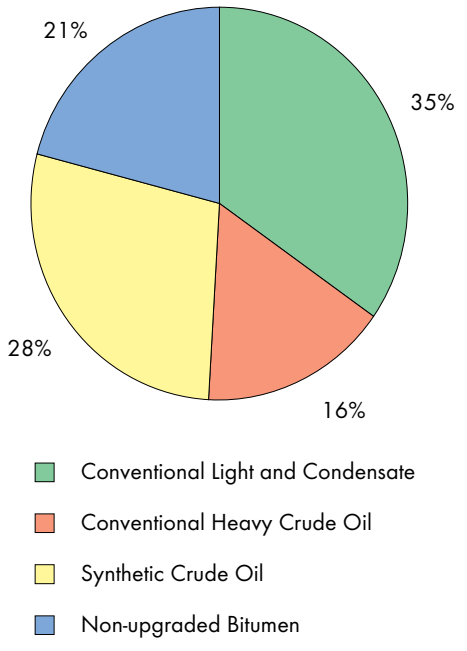
***Crude Oil and Equivalent Production by Province***




Source: NEB

**FIGURE 4.3**

***Crude Oil and Equivalent Production by Type***




Source: NEB

Estimates of remaining established conventional crude oil reserves in Canada decreased (Table 4.2). Most of this decrease can be attributed to production significantly outpacing reserves additions. The remaining established crude bitumen reserves decreased slightly, reflecting 2008 bitumen production.

**TABLE 4.1**

***Conventional Crude Oil Reserves, Additions and Production, 2004-2008 (million cubic metres)***

| | 2004 | 2005 | 2006 | 2007 | 2008 | Total |
|---|---|---|---|---|---|---|
| Additions | 66.9 | 134.7 | 27 | 50 | 62.5 | 341.1 |
| Production | 82.7 | 78.8 | 82.1 | 76 | 77.9 | 397.5 |
| **Total Remaining Reserves** | **640** | **696** | **640** | **614** | **599** | |
| **Total Remaining Reserves (millions of barrels)** | **4 027** | **4 382** | **4 033** | **3 871** | **3 774** | |

Source: Provincial Energy Agencies, Offshore Petroleum Boards, NEB

**TABLE 4.2**

***Estimates of Established Reserves of Crude Oil and Bitumen at 31 December 2008 (million cubic metres)***

| **Conventional Crude Oil** | **Initial** | **Remaining** |
|---|---|---|
| British Columbia[a] | 129.1 | 18.5 |
| Alberta[b] | 2 773.1 | 233 |
| Saskatchewan[c] | 926.1 | 180.7 |
| Manitoba[d] | 47.1 | 7.7 |
| Ontario[e] | 14.9 | 1.6 |
| Northwest Territories, Nunavut and Yukon | | |
| Arctic Islands and Eastern Arctic | 0.5 | 0 |
| Mainland Territories – Norman Wells and Cameron Hills | 52.8 | 12.7 |
| Nova Scotia – Cohasset and Panuke[d] | 7 | 0 |
| Newfoundland – Hibernia, Terra Nova and White Rose[d] | 302.5 | 144.8 |
| **Total** | **4 253.1** | **599** |
| **Total (millions of barrels)** | **26 794.5** | **3 773.7** |
| **Crude Bitumen** | | |
| Oil Sands – Mineable[f] | 6 157 | 5 487 |
| Oil Sands – Bitumen[f] | 21 935 | 21 585 |
| **Total** | **28 092.0** | **27 072.0** |
| **Total (millions of barrels)** | **176 980** | **170 554.0** |
| **Total Conventional and Bitumen** | **32 345.1** | **27 671.0** |
| **Total Conventional and Bitumen (millions of barrels)** | **203 774.1** | **174 327.3** |

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

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

(c) Canadian Association of Petroleum Producers/NEB estimates 2007.

(d) Provincial Agencies or Offshore Boards, NEB estimates for Manitoba 2007, Newfoundland 2008.

(e) Canadian Association of Petroleum Producers.

(f) ERCB Report - ST 98 2009.

Note: totals may not add due to rounding.

## 4.3 Oil Sands

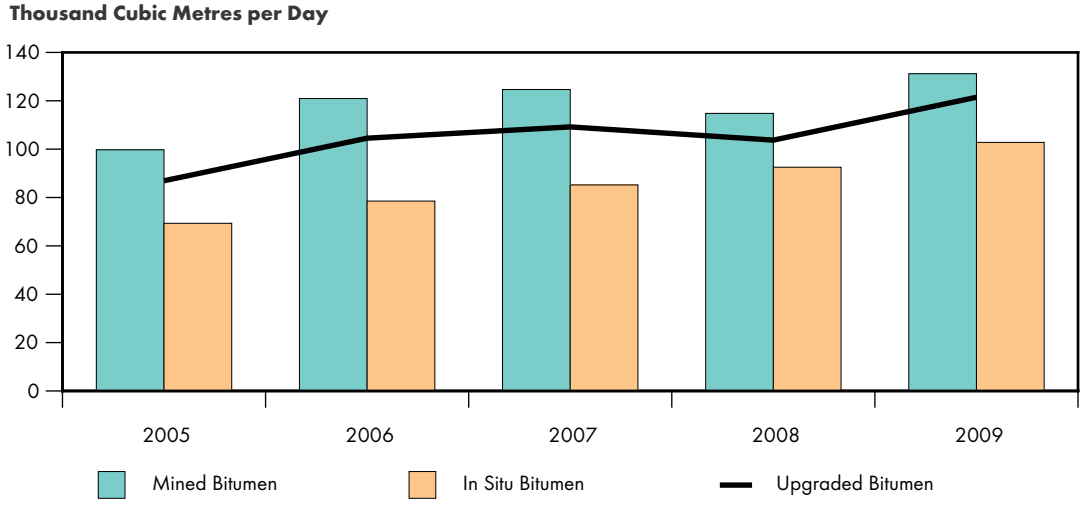
The global economic downturn and corresponding lower oil prices continued into the first quarter of 2009, and resulted in the deferral or cancellation of several new oil sands projects, as well as the shut-in of some production. By the fourth quarter, however, and with indications that the slow-down in development activity lowered construction costs of new projects by 20 per cent, there was renewed investment interest in Canada's oil sands. Oil sands capital expenditures, not including mergers and acquisitions, were estimated to be about $12 billion in 2009 compared with $16 billion in 2008.

In 2009, crude bitumen production (before processing) from mining and in situ operations totalled 234 000 $m^3/d$ (1.47 MMb/d), an increase of 13 per cent compared with 2008. In situ bitumen production increased by 11 per cent to 102 800 $m^3/d$ (648 Mb/d) while bitumen from mining operations increased by 14 per cent to 131 200 $m^3/d$ (827 Mb/d) (Figure 4.4). All of the mined bitumen, and about nine per cent of the in situ bitumen was upgraded, yielding 121 500 $m^3/d$ (765 Mb/d) of synthetic crude oil, an 11 per cent increase over 2008. Opti/Nexen's Long Lake project, which couples a surface upgrader with an in situ steam-assisted-gravity-drainage (SAGD) operation, is the first oil sands project to utilize gasification of bitumen residue, or asphaltenes, to produce syngas (synthetic gas) within the upgrader, hence minimizing the need to purchase and use natural gas for steam generation.

Oil sands producers are faced with a number of environmental challenges, including those associated with air emissions/quality, land disturbance/reclamation, and water use/quality. In the area of greenhouse gas (GHG) emissions, companies have made 2.6 million tonnes of reductions – the equivalent of taking 550,000 cars off the road.[6] In addition, more than 80 per cent of water drawn by industry from the Athabasca River is recycled.[7]

**FIGURE 4.4**

***Crude Bitumen Production, 2005-2009***




Source: NEB

6 Oil Sands Developers Group, Oil Sands Facts, September 2009. http://www.oilsandsdevelopers.ca/wp-content/uploads/2009/10/OSDG-Fact-Booklet-2009.pdf

7 Ibid.

### *Oil Sands Tailing Ponds*

Oil sands tailings are a mixture of water, clay, sand and residual bitumen that result from oil sands mining operations. They are stored in large ponds where the clay/water mixture is left to settle. In 2009, tailings ponds covered an area of 130 square kilometres (an area the size of the city of Vancouver).[1]

In February 2009, the ERCB issued Directive 74, *Tailings Performance Criteria and Requirements for Oil Sands Mining Schemes*, which applies to all mineable oil sands operations. It requires the reduction of fluid tailings, their capture in ERCB-approved dedicated disposal areas and their conversion to trafficable deposits, which mean they can be walked upon and bear the weight of heavy equipment within a given time frame. There are many different technologies being researched and tested.

1 Terra Simieritsch, Pembina Institute, Backgrounder: Oil Sands Tailings and Directive 074, December 2009. http://pubs.pembina.org/reports/tailings-directive-074-backgrounder.pdf

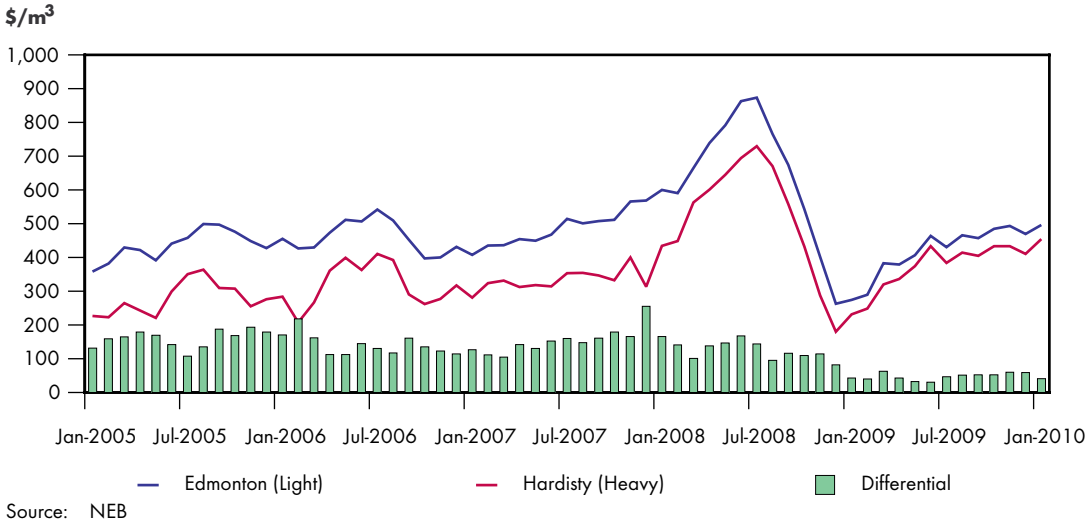
## 4.4 Crude Oil Exports and Imports

In 2009, crude oil exports averaged approximately 291 900 $m^3/d$ (1.84 MMb/d), an increase of two per cent compared with 2008. The average light and heavy crude oil export prices were $417 per cubic metre and $369 per cubic metre ($66 and $58 per barrel), respectively, compared with $647 and $520 per cubic metre ($103 and $83 per barrel) in 2008 (Figure 4.5). The estimated value of crude oil exports for 2009 is $38.9 billion compared with $60 billion in 2008. The drop is attributable to lower crude oil prices.

Heavy and light crude oils are traded in separate markets and, accordingly, the prices for each vary as a result of the supply and demand for each crude type. Heavy crude oil has a smaller market, higher refining costs and generally yields lower volumes of high value products such as gasoline and, as a

**FIGURE 4.5**

***Light and Heavy Crude Oil Export Prices***




Source: NEB

result, is usually discounted. The differential typically narrows in the summer months because of increased use of heavy crude oil used in the production of asphalt and widens again in September.

The light-heavy differential averaged $47.87/m^3 ($7.60/bbl) during 2009, much narrower than 2008. Although pipeline capacity can impact the light-heavy differential, other factors played a larger role in setting the differential in 2009. These factors included: reduced global consumption causing a drop in overall prices which impacted light crudes more than heavy crudes; increased demand for heavy crude oil with the addition of new heavy conversion capacity; and reduced supply of medium to heavy sour crude stemming from OPEC production cuts. The differential is expected to remain narrow in the medium term.

Canada remained the number one supplier of crude oil to the U.S. followed by Mexico and Saudi Arabia.[8] According to the EIA, the U.S. imported approximately 307 000 $m^3/d$ (1.9 million b/d) of crude oil from Canada, which equates to roughly 21 per cent of their total imports of 1.4 million $m^3/d$ (9.1 million b/d).

The U.S. market is divided into regions called Petroleum Administration for Defense Districts or PADDs (Figure 4.6). In aggregate, Canada exported more oil to PADD II than any other region. Almost all Canadian exports were delivered to U.S. destinations in 2009, with small volumes sent to other regions of the world.

In 2009, crude oil imports were estimated to be 128 400 $m^3/d$ (809 Mb/d). This is a decrease of five per cent compared with 2008 and represented approximately 50 per cent of total Canadian refinery supply. Canada imports crude oil from a number of sources, including: OPEC, the North Sea and

**TABLE 4.3**

***Crude Oil Exports by Type and Destinations – 2009 (volume – $m^3/d$)***

| Market | Light | Medium | Heavy | Synthetic | Blended Bitumen | Total |
|---|---|---|---|---|---|---|
| PADD I | 21 289.80 | 102.30 | 5 829.70 | 1 063.80 | 48.00 | 28 333.60 |
| PADD II | 26 111.50 | 8 165.00 | 50 681.30 | 43 905.60 | 56 610.40 | 185 473.80 |
| PADD III | 3 155.10 | 69.40 | 3 586.00 | 2.20 | 10 866.10 | 17 678.80 |
| PADD IV | 3 892.70 | 760.50 | 21 875.40 | 6 220.50 | 2 025.20 | 34 774.30 |
| PADD V | 12 845.90 | 0.00 | 0.00 | 7 500.20 | 2 924.90 | 23 271.00 |
| **Total U.S.** | **67 295.00** | **9 097.20** | **81 972.40** | **58 692.30** | **72 474.60** | **289 531.50** |
| Other | 52.10 | 27.40 | 157.20 | 247.40 | 1 902.30 | 2 386.40 |
| **Total** | **67 347.10** | **9 124.60** | **82 129.60** | **58 939.70** | **74 376.90** | **291 917.90** |

Notes:

PADD - Petroleum Administration for Defense District (see Figure 4.7)

Light – greater than 30 API

Medium – between 25 and 30 API

Heavy – less than 25 API

Synthetic – upgraded bitumen of any API

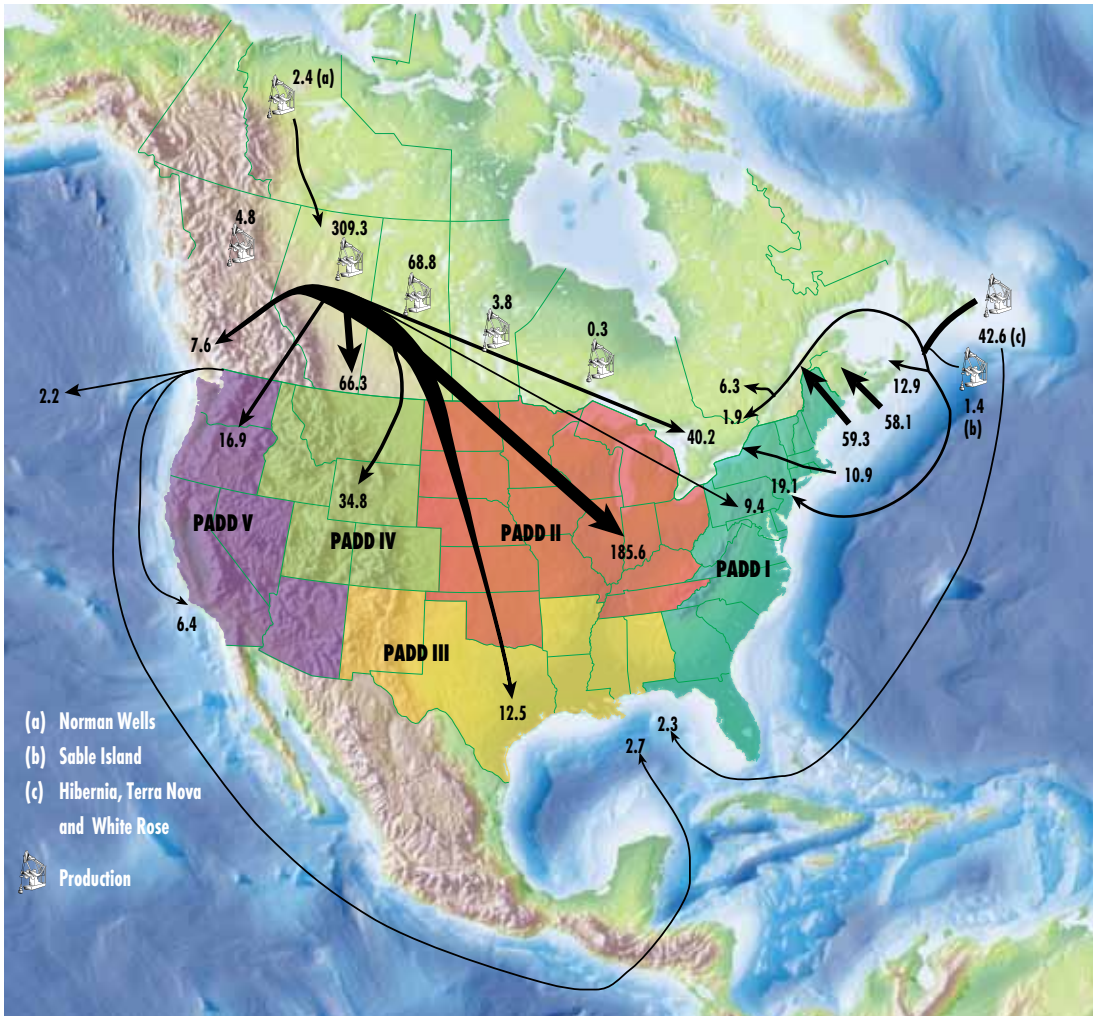
Blended Bitumen – Bitumen blended with light hydrocarbons and/or synthetic crude oil

Source: NEB Estimates

8 U.S. Energy Information Administration (EIA).

FIGURE 4.6

***Crude Oil Supply and Disposition, 2009***
***(thousand cubic metres per day)***




Source: NEB

North America. An estimated 86 per cent of the Atlantic refining requirements were met by imports and the remaining 14 per cent came from offshore eastern Canada production. Quebec is the most reliant on imported crude oil with 89 per cent of its refining needs supplied from international sources. Ontario accounted for the remainder of imported crude volumes. Ontario refineries are increasingly sourcing crude oil supplies from western Canada.

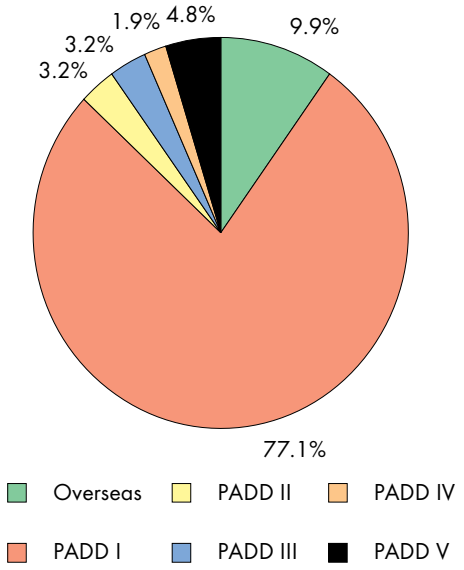
## 4.5 Oil Refining

There were 19 Canadian refineries operating at the end of 2009 with a total refinery capacity of 334 700 $m^3/d$ (2.1 MMb/d).

Canadian consumption of petroleum products in 2009 is estimated at 238 600 $m^3/d$ (1.5 MMb/d), a four per cent decline from 2008. Refinery runs, refinery capacity utilization and refinery receipts of domestic crude oil all decreased in 2009 compared with 2008. The decrease in refinery receipts of domestic crude oil was due in part to the reduction in refinery runs because of planned and unplanned

**FIGURE 4.7**

***Product Exports by Destination, 2009***




Source: NEB

refinery maintenance. Extended refinery outages in western Canada in the fall resulted in a shortage of gasoline and diesel.

## 4.6 Main Petroleum Product Exports and Imports

Canada is a net exporter of petroleum products. Exports of main petroleum products in 2009 are estimated to be 54 024 $m^3/d$ (339 Mb/d), a marginal decrease from 2008. The primary destination was the U.S. east coast market (PADD I) with overseas exports being the second largest market (Figure 4.7).

The estimated revenue in 2009 from exports of main petroleum products, including partially processed oil, was $8.2 billion, down from about $10.5 billion in 2008.

## 4.7 Product Prices

According to Natural Resources Canada (NRCan)[9], average Canadian retail product prices were approximately 26 per cent lower in 2009 compared with 2008. Retail gasoline prices in Canada decreased in 2009 compared with 2008 (Table 4.4). The price of diesel fuel, which is closely linked with economic activity, dropped more than gasoline.

**TABLE 4.4**

***World Oil and Canadian Products Prices***

| Product | 2008 (cents/litre) | 2009 (cents/litre) | Change | Change (%) |
|---|---|---|---|---|
| Gasoline | 114 | 94.6 | -19.4 | -17% |
| Diesel | 124.9 | 89.6 | -35.3 | -28% |
| Furnace oil | 113.2 | 76.2 | -37 | -33% |
| WTI (US$/bbl, Cushing, OK) | 99.67 | 61.95 | -37.8 | -37.80% |
| Edmonton Par (Cdn$/bbl) | 102.73 | 65.36 | -37.4 | -36.40% |

Source: NRCan, EIA, NEB

## 4.8 Looking Ahead

For 2010, the emerging economies led by China and India, are expected to continue to perform well, and moderate growth is likely in the U.S., Europe and Japan. Oil demand growth in Asia is expected to lead to rising prices for both crude oil and gasoline this summer. In this regard, OPEC may decide to increase production in the second half of the year, if prices move above $US80/bbl. Oil prices are forecast to be slightly above that level in 2010. In 2010, production from the oil sands will continue to grow because of already established, and expansions to, existing projects.

9 Natural Resources Canada, Fuel Focus, 2009 Annual Review, 15 January 2010.

# NATURAL GAS

## 5.1 North American Natural Gas Markets

***Key Findings:***

- The average price of natural gas was half of what it was in 2008
- Natural gas production was eight per cent less than in 2008 and net export revenues declined by 57 per cent
- Evaluation and development of shale gas continued
- In 2009, Canada received its first LNG import at the Canaport facility
- Overall natural gas consumption was stable

Together, the Canadian and U.S. natural gas markets operate as one large integrated market. This market offers the benefit of flexibility with numerous supply and transportation options. Events in any one region will affect the other regions.

In 2009, more than a fifth of North American natural gas was produced in Canada. About 98 per cent of Canadian gas came from the WCSB, with Alberta producing roughly 76 per cent of that. British Columbia and Saskatchewan contributed approximately 18 and four per cent, respectively, of total Canadian production. Production from the WCSB remained steady through the first half of the year at 432 million $m^3$ per day (15.2 Bcf/d) before declining by nearly ten per cent in the second half of the year to 393 million $m^3$ per day (13.98 Bcf/d). Production from the east coast also declined in 2009 due to maintenance at the Sable Offshore Energy Project.

Supply in the U.S. was relatively steady over the year largely due to gains in unconventional gas production; however, there was also reduced natural gas consumption in the industrial sector primarily due to the economic downturn. North American natural gas prices, represented by the Henry Hub price[10], declined through the first three quarters of the year (Figure 5.1) and averaged US$3.95/MMBtu. The benchmark for Western Canadian natural gas is the Intra-Alberta/NIT trading price[11], which followed a similar path as the Henry Hub price, and averaged $3.81/GJ, approximately half of that in 2008.

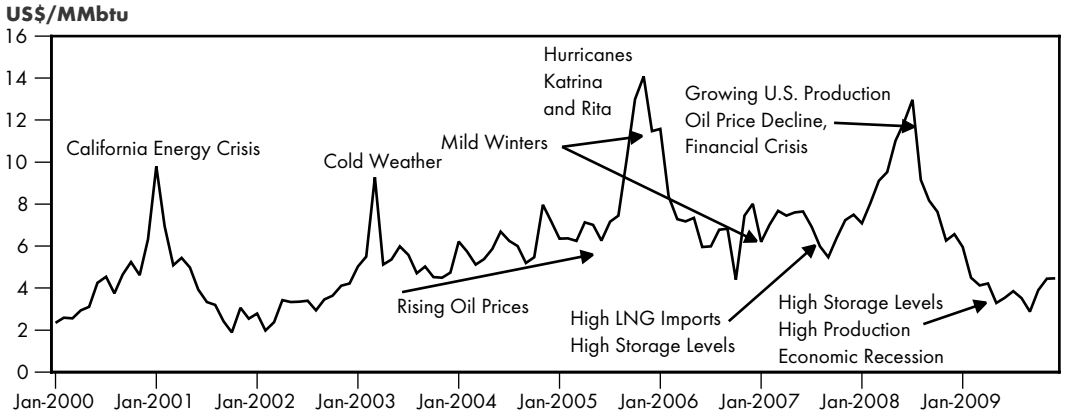
Gas consumption is normally higher in the winter months than in the summer months because there is greater need for space heating in the winter. However, gas production tends to remain relatively constant year round. To balance production with consumption, gas is injected into underground storage in the summer and withdrawn in the winter. April is the beginning of the typical storage injection season (Figure 5.2). Gas storage inventories were at near normal levels at the start of 2009. Spring was characterized by growing storage inventories as the economic downturn began to slow industrial gas consumption. By May, storage inventories began to exceed the five-year range for that time of year. Storage continued to fill at an above-normal pace and by the end of October, the usual

10 The Henry Hub price for natural gas is the benchmark natural gas price for North America.

11 The Intra-Alberta/NIT price is also known as the AECO price. Historically, AECO was the name of a group of storage fields located in southeastern Alberta and operated by the Alberta Energy Company (now EnCana) and the Nova Inventory Transfer (NIT) is a title transfer service operated by TransCanada PipeLines Limited.

**FIGURE 5.1**

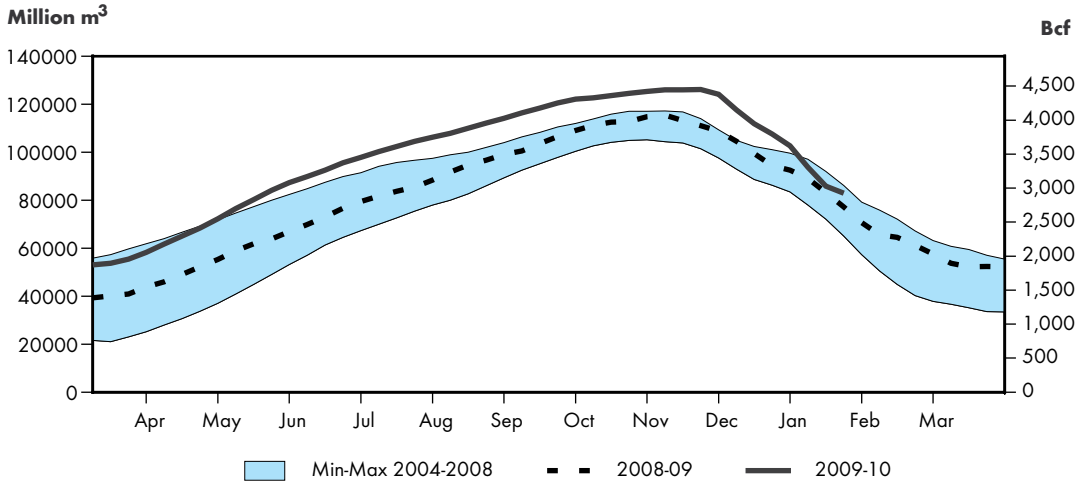
***North American Gas Price Trends – Henry Hub (Monthly average)***




Source: GLJ Publications Inc.

**FIGURE 5.2**

***North American Gas Storage Levels***




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

start to the winter storage withdrawal season, North American natural gas inventories were at their highest level ever: 24.5 billion $m^3$ (4 394 Bcf). Despite a very cold December in much of Canada and the U.S., storage inventories were still well above the five-year range by the end of 2009.

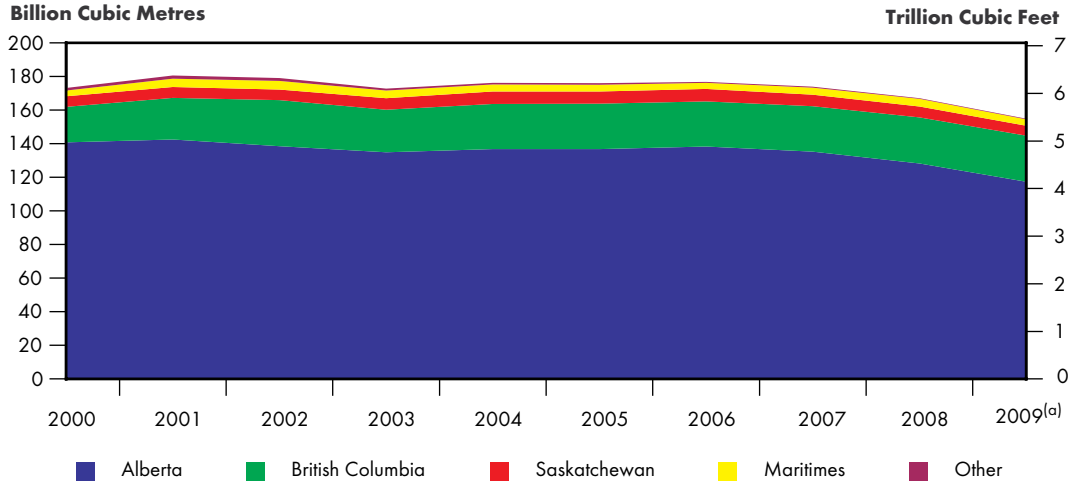
## 5.2 North American Natural Gas Supply

Canadian natural gas production averaged 423 million $m^3$/day (14.8 Bcf/d) in 2009. This is 21 per cent of North American production, down from 25 per cent in 2006. Further, Canadian production was eight per cent less than in 2008 (Figure 5.3). The most significant event during the year was the shutting in of many gas wells in September because of very low gas prices, which reduced Canadian production by about 30 million $m^3$/d (1.1 Bcf/d) over the course of a few weeks.

No region in Canada showed an increase in production in 2009, although British Columbia's production remained essentially flat. In Alberta and Saskatchewan, production declines were due to reduced gas-drilling activity. Production added from new wells no longer offsets or surpasses production declines from older wells. Maritimes production fell 20 per cent, largely due to planned and unplanned maintenance at the Sable Offshore Energy Project, but also as a result of decreases in onshore production.

**FIGURE 5.3**

***Canadian Marketable Gas Production, 2000-2009***




(a) Estimates

Sources: Provincial and territorial regulatory agencies

### *Conservation of natural gas resources*

Most provincial regulatory bodies dealing with oil and gas are directed to ensure that the resource is exploited in a way to maximize production and to reduce or even eliminate wasteful practices.

The ERCB of Alberta has been encouraging oil producers to reduce the venting and flaring of solution gas.[1] Solution gas is natural gas that is dissolved in oil at higher pressures underground and, when the oil is exposed to lower pressures at the surface, the gas is expelled. Sometimes this gas is produced at wells in low quantities and therefore may not meet economic thresholds to be shipped via gas pipelines. However, industry cooperation with the ERCB has reduced solution gas venting and flaring by 60 per cent from 1996 to 2008. This has resulted in a reduction in GHG emissions, and has increased the conservation of the solution gas resource from 92 to 95 per cent.

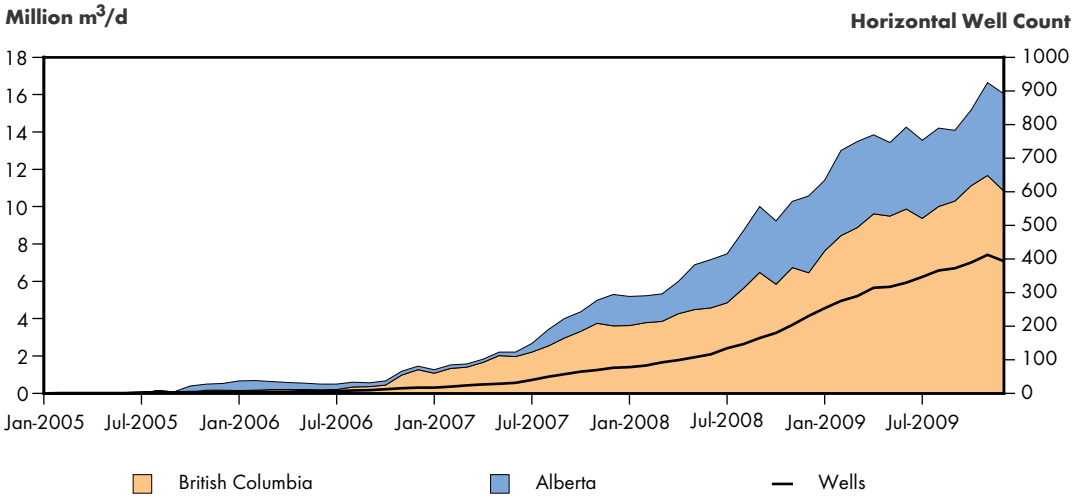
The BC Oil and Gas Commission has also taken steps to reduce venting and flaring of natural gas, with aims of cutting the volume in half by 2011 and eliminating it entirely by 2016[2]. Solution gas flaring and venting in B.C. has been reduced by 86 per cent from 1996 to 2008. Further, flaring and venting from all natural gas production has been reduced by 19 per cent from 1996 to 2008, while British Columbia's raw natural gas production increased by over 42 per cent over the same period. Saskatchewan, which had seen growth in gas flaring over the past several years as oil production rose, is also working towards reducing flaring with a plan similar to Alberta's and is expected to release draft guidelines by June 2010.

1 Energy Resources Conservation Board. ST60B-2009: Upstream Petroleum Industry Flaring and Venting Report, 2008. Released July 2009.

2 BC Oil and Gas Commission. Flaring, Incinerating and Venting Reduction Annual Report. Released September 2009.

## FIGURE 5.4

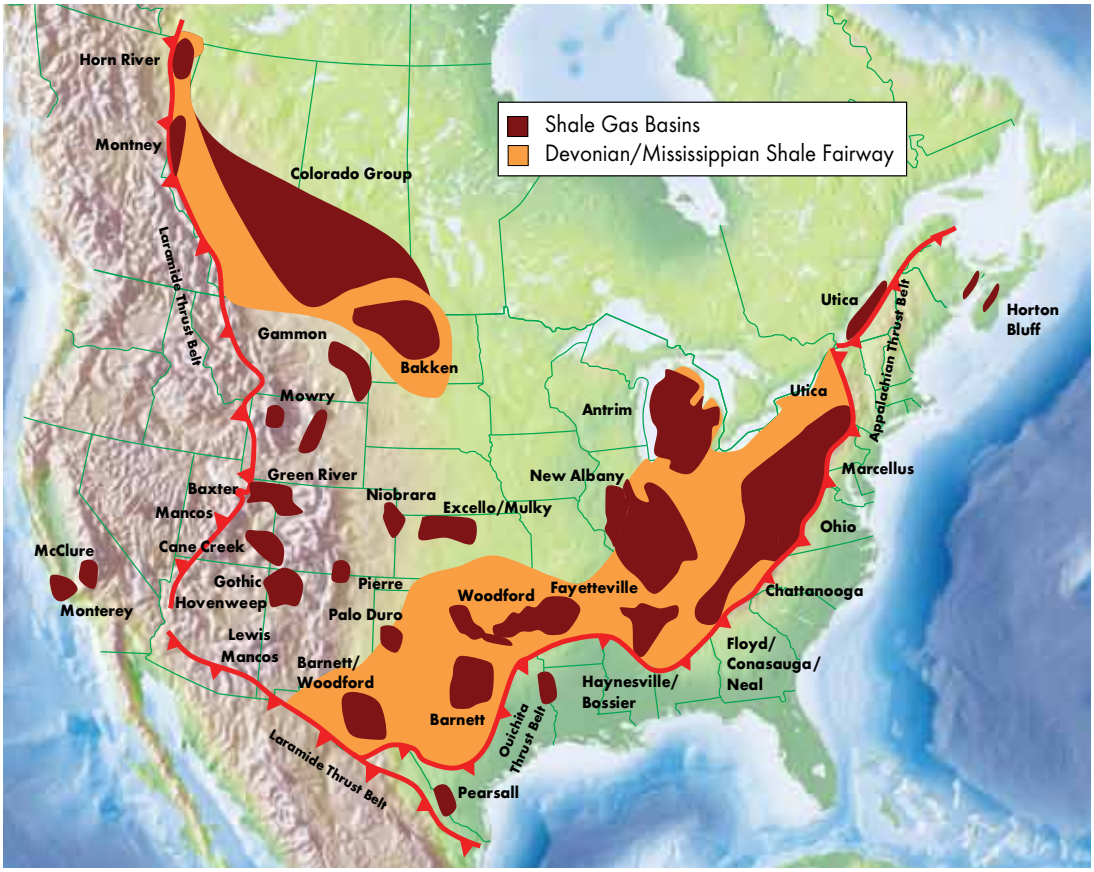
### *Montney Raw Natural Gas Production*




Source: Geovista production data

## FIGURE 5.5

### *Major Shale Gas Prospects in North America*




Source: modified from Ziff Energy Group

Note: The triangles attached to the red lines represent mountain fronts, where the triangles point in the direction of landmass that has been overridden by the mountains (i.e. a thrust fault).

Interest in Canadian shale gas (Figure 5.5) continued in 2009. Despite the decline in gas prices, development of the Montney hybrid-shale and tight-gas play continued and its production increased from 2008 levels (Figure 5.4). Horn River Basin shale saw about three dozen wells producing gas by year-end 2009, although specific estimates of total gas production are unavailable at the time of writing. Horn River Basin shale gas production is expected to reach 13 million $m^3/d$ (0.5 Bcf/d) by 2012.[12] Since Horn River shale gas is approximately 12 per cent carbon dioxide ($CO_2$), there have been a number of proposed projects for carbon capture and sequestration (CCS) facilities associated with its production. However, cost issues have shelved at least one CCS project and it remains to be seen whether other such projects will go ahead as proposed.

In eastern Canada, several wells were drilled in the Utica Shale in Quebec, including a few horizontal wells, with variable but encouraging results. Finally, the Frederick Brook Member of the Horton Bluff Group in New Brunswick had significant gas flow from a vertical well.

There remains significant resource potential in coalbed methane (CBM) even though industry has increasingly focused its efforts on Canadian shale gas. Production of CBM in 2009 averaged approximately 30 million $m^3/d$ (0.85 Bcf/d)[13] of marketable gas, a small increase, yet notable because of the overall reduction in natural gas production across western Canada. In 2009, the first commercial CBM production in British Columbia took place in the Hudson Hope area last year.

### *Canaport LNG – Canada's first LNG Import Terminal*

In 2009, the Canaport LNG terminal received its first cargo of LNG from Trinidad and Tobago and became Canada's first operating LNG import terminal. Co-owned by Repsol and Fort Reliance (Irving Oil Limited), Canaport LNG is a year-round port located in Saint John, New Brunswick.

At the terminal, LNG is received from specially-built ships and stored in large refrigerated tanks. When natural gas is required in the market, the LNG is re-gasified and delivered to market via the 145 kilometre Brunswick Pipeline. At this time, Canaport has an output capacity of about 28.3 $m^3/d$ (1 Bcf/d) and can store 480,000 $m^3$ of LNG (9.9 Bcf gas equivalent) in three storage tanks.

Since its inaugural cargo, Canaport LNG has received regular LNG shipments and has provided an additional source of gas supply into the regional marketplace. Since making its first delivery in July, gas send-out from the terminal has exceeded 970 million $m^3$ (35 Bcf), and has averaged over 6 million $m^3/d$ (200 MMcf/d). With the arrival of winter weather, send-outs since December 2009 have been even higher, averaging over 10 million $m^3/d$ (350 MMcf/d).

12 National Energy Board. *Short-term Canadian Natural Gas Deliverability 2010-2012*. March 2010. Available at http://www.neb-one.gc.ca/clf-nsi/rnrgynfmtn/nrgyrprt/ntrlgs/ntrlgsdlvrblty20102012/ntrlgsdlvrblty20102012-eng.html

13 Includes some commingled production from non-coal strata.

North American LNG[14] imports increased despite lower natural gas consumption and growth in U.S. natural gas production. Growth in world LNG supply, plus reduced natural gas consumption in parts of Asia and Europe due to the global economic recession, led to moderately higher levels of LNG imports coming to North America, which served largely to fill the expanded natural gas storage capacity.

North American LNG imports averaged 43.9 million $m^3/d$ (1.55 Bcf/d) up from 37.7 million $m^3/d$ (1.33 Bcf/d in 2008). Canaport LNG, Canada's first LNG import terminal (located in Saint John, New Brunswick), became operational in June 2009. This increased the total North American import capacity to over 430 million $m^3/d$ (15 Bcf/d) spread at twelve facilities (in addition to Canaport, there are two in Mexico and nine in the U.S.).

## 5.3 Natural Gas Reserves

The NEB's estimate of remaining marketable gas reserves[15] at the end of 2008 is 1 709 billion $m^3$ (60.3 Tcf) (Table 5.1). This is up 118 billion $m^3$ (4.2 Tcf) from year-end 2007 as reserve additions replaced 170 per cent of annual production in 2008. Major reserves growth came from additions of B.C. Montney shale gas and Alberta tight gas.

**TABLE 5.1**

***Canadian Natural Gas Reserves***

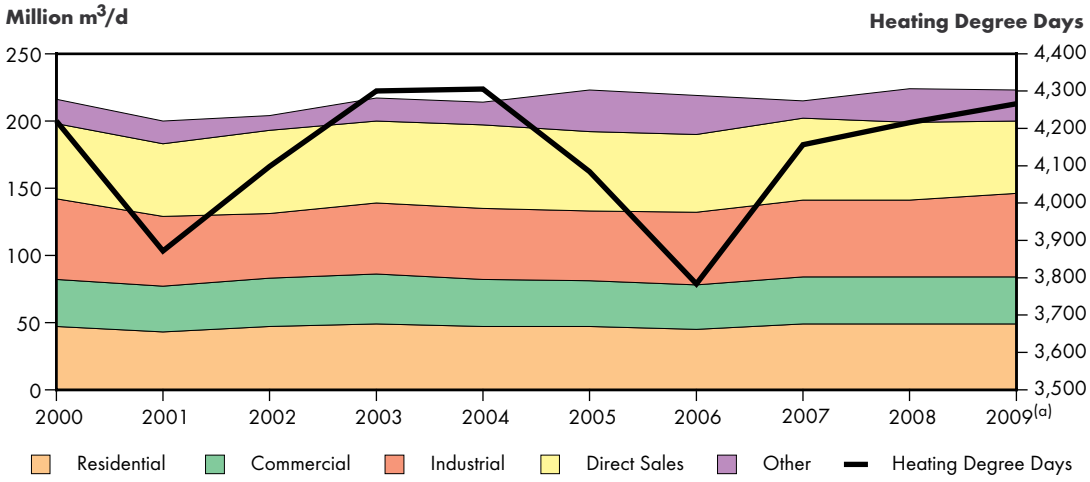
| (million $m^3$) At Year-end 2008 | Natural Gas Reserves | | |
|---|---|---|---|
| | Initial Reserves | Cumulative Production | Remaining Established Reserves |
| British Columbia | 1 071.1 | 573.3 | 496.6 |
| Alberta | 5 048.7 | 3 950.5 | 1 098.2 |
| Saskatchewan | 262.7 | 191.4 | 71.3 |
| **Subtotal – WCSB** | **6 382.5** | **4 715.2** | **1 666.1** |
| Ontario | 54.3 | 34.6 | 19.7 |
| New Brunswick | 4.1 | 0.1 | 4.0 |
| Nova Scotia Offshore | 55.0 | 40.5 | 14.5 |
| Mainland NWT & Yukon | 29.1 | 16.2 | 12.8 |
| Mackenzie Delta | 0.3 | 0.1 | 0.2 |
| **Subtotal – Frontier** | **88.5** | **56.8** | **27.5** |
| **Total Canada (million $m^3$)** | **6 525.3** | **4 806.6** | **1 713.3** |
| **Total Canada (trillion cubic feet)** | **230.3** | **169.7** | **60.5** |

14 National Energy Board. *Liquefied Natural Gas – "A Canadian Perspective"*. February 2009. Available at http://www.neb-one.gc.ca/clf-nsi/rnrgynfmtn/nrgyrprt/ntrlgs/lqfdntrlgscndnprspctv2009/lqfdntrlgscndnprspctv2009-eng.html

15 Natural gas reserves are defined as the total amount of marketable gas in discovered pools that can be extracted in current economic conditions.

**FIGURE 5.6**

***Canadian Natural Gas Consumption and Heating Degree Days***




(a) Estimates

(b) Heating degree days (HDD) is an index calculated to reflect the demand for energy needed for heating homes, businesses, etc. HDD is the cumulative number of degrees in a year for which the mean temperature falls below 18.3 degrees C.

Sources: Statistics Canada, NEB Estimates and Canadian Gas Association

## 5.4 Canadian Natural Gas Consumption

Approximately one quarter of all energy consumed by Canadians is natural gas. In 2009 estimated consumption was about 223 million $m^3/d$ (7.8 Bcf/d) or about 54 per cent of Canadian production.

Natural gas is consumed in the residential and commercial sectors for space heating, and in the industrial sector for process heat. It is also used as a building block in chemical production, as well as to produce electricity. Canadian gas consumption for heating, industrial use and electric power generation (included within "direct sales") has been fairly constant since 2000 (Figure 5.6).

As for other forms of energy, 2009 saw an overall decrease (one per cent) in Canadian gas consumption due to less industrial activity across North America. Contrary to this trend, lower natural gas prices and Ontario's ongoing coal phase-out plan contributed to an increase in gas use for power generation in that province for the January to October 2009 period as compared to year-earlier levels.

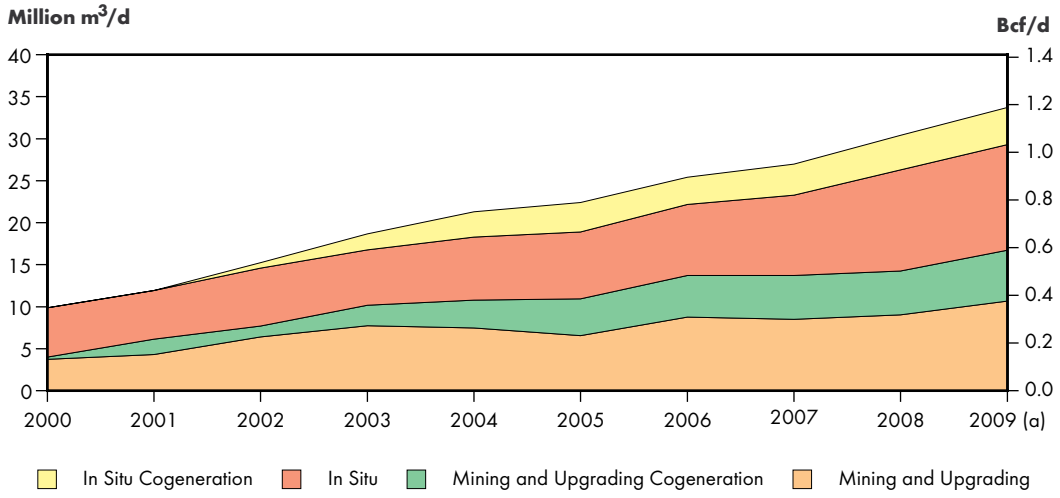
Natural gas consumption in the Alberta oil sands sector continued its decade-long rise in 2009 (Figure 5.7). Natural gas is used in both the generation of electricity and steam. Steam is used for in situ oil production and in the production of hydrogen to upgrade bitumen into synthetic crude oil blends. Consumption of natural gas in 2009 was approximately 34 million $m^3/d$ (1.2 Bcf/d), ten per cent higher than in 2008 and almost four times the amount of gas used a decade earlier.

## 5.5 Canadian Natural Gas Exports and Imports

In 2009, natural gas exports were about 252 million $m^3/d$ (8.9 Bcf/d) or 14 per cent of estimated U.S. consumption (Figure 5.8). Although U.S. consumption of natural gas in 2009 is estimated to be only marginally lower than in 2008, increased U.S. production and higher LNG imports pushed Canadian gas exports to the U.S. down by ten per cent compared to the previous year, while imports were 30 per cent higher. Net exports (gross exports less imports) for 2009 were 196 million $m^3/d$ (6.9 Bcf/d).

## FIGURE 5.7

***Average Annual Natural Gas Requirements for Oil Sands Operations***

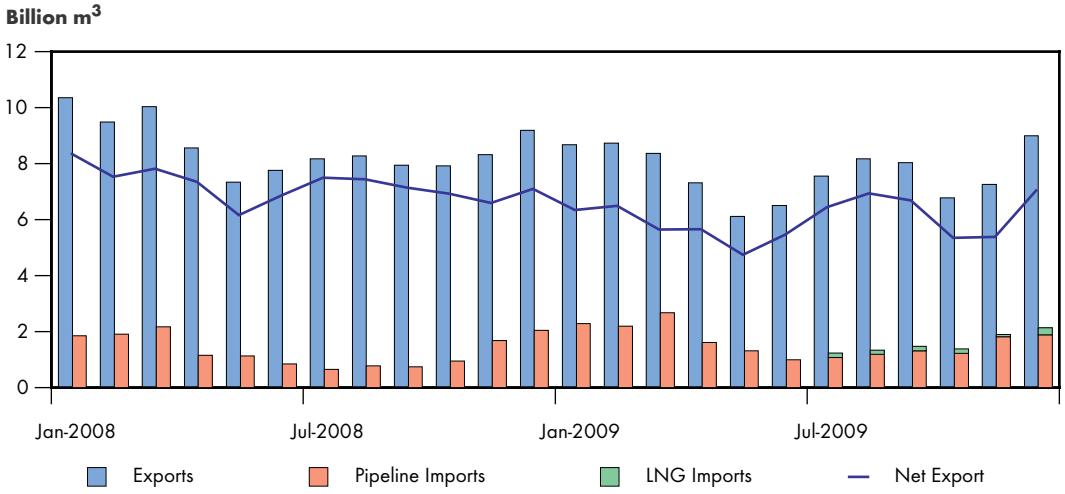



(a) Estimates

Sources: NEB and ERCB

## FIGURE 5.8

***Monthly Canadian Natural Gas Exports and Imports, 2008-2009***

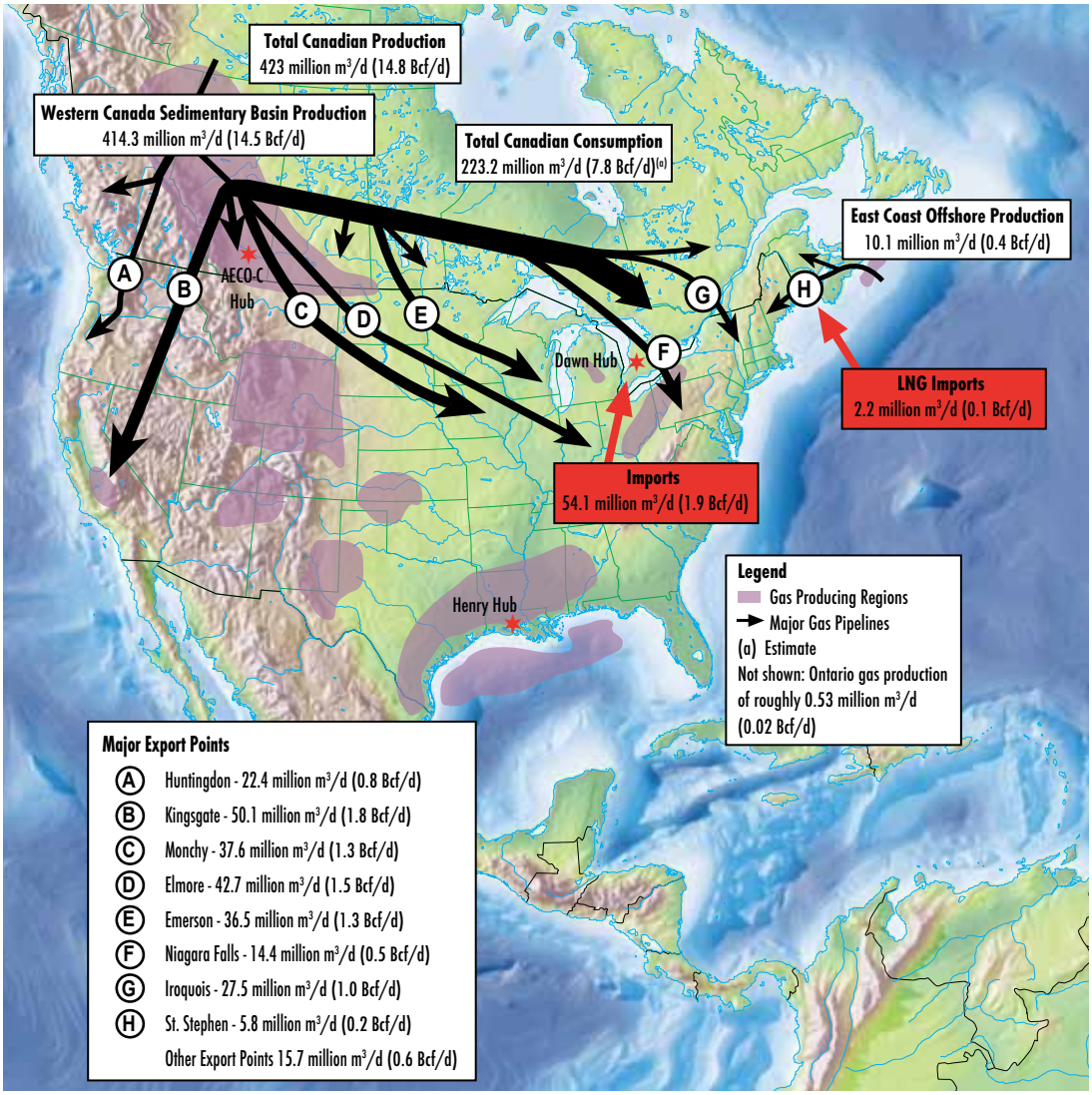



Source: NEB

Annual revenues from Canadian gas exports also dropped in 2009 because of lower commodity prices and lower export volumes. The average export price in 2009 was less than half of the average export price in 2008 resulting in net export revenues of only about $11.9 billion in 2009, compared to $27.9 billion in 2008.

FIGURE 5.9

***Natural Gas Supply and Disposition, 2009***




## 5.6 Natural Gas Liquids (excluding Pentanes Plus)

Prices for propane and butane rose in the latter half of 2009 because of the return of demand from the petrochemical sector in North America. Propane prices at Mont Belvieu, Texas the main NGL trading hub in the U.S., rose from a monthly average of 80.7 US cents per gallon in January 2009 to 125.8 US cents per gallon in December 2009. The average annual propane price at Mont Belvieu for 2009 was 89.1 US cents per gallon.

Canadian propane production in 2009 decreased by 7.0 per cent over 2008. Propane production from gas plants in 2009 was 24 597 m3/d (154.7 Mb/d), while production from refineries rose 8.5 per cent to 3 765 m3/d (23.7 Mb/d).

Butane production in Canada in 2009 was 22 688 m3/d (142.7 Mb/d), virtually unchanged from 2008 figures. Higher butane production from refineries (increase of 12.8 per cent from 2008) made up for

lower butane production from gas plants (decrease of 7.8 per cent from 2008). Refinery production of butane was 8 664 m3/d (54.5 Mb/d), while butane production from gas plants was 14 024 m3/d (88.2 Mb/d).

Canadian production of ethane from gas plants in 2009 was 38 338 m3/d (241.1 Mb/d), a decline of 1.2 per cent from 2008 production. Declining domestic natural gas production has reduced the amount of natural gas available for liquids extraction and is partly responsible for declining liquids production. Weak economic conditions in the first half of 2009 depressed demand for petrochemical feedstocks, such as ethane.

Propane exports in 2009 were 15 817 m3/d (99.5 Mb/d), declining 9.9 per cent from 2008. Exports of butane in 2009 were 4 509 m3/d (28.4 Mb/d), an increase of 7.6 per cent over last year. Propane exports declined due to lower production and economic conditions in the U.S. which reduced demand. Exports of butane have declined since 2002, but the trend reversed direction starting in 2008. PADD II (Midwest) remains the largest market for propane and butane exports, followed by PADD I (East Coast).

For propane, the impact of lower prices and lower export volumes in 2009 was significant: revenues were 36 per cent lower than 2008 at $1.5 billion. Compared to 2008, lower butane prices resulted in a 21.5 per cent decline in 2009 butane export revenues, which were to be $555 million. The increase in export volumes of butane mitigated the decline in butane export revenues.

## 5.7 Looking Ahead

Because natural gas prices are expected to rise from their 2009 lows in 2010, drilling activity in western Canada could also rise. However, natural gas-related activity is expected to remain relatively low compared to historical levels and Canadian production of natural gas will likely continue to fall in the short term.[16] In 2009 there were advances in Canadian shale gas development and evaluation and this trend is likely to continue throughout 2010.

The expectation of increasing use of natural gas for gas-fired power generation in Ontario could potentially result in increased imports of natural gas from U.S. pipeline infrastructure to deliver into the eastern Canadian transportation hub. Gas supply delivered to the hub located near Dawn, Ontario, has become increasingly diverse in recent years, accessing gas from growing shale gas supplies in the U.S.

16 National Energy Board. *Short-term Natural Gas Deliverability 2010-2012*, March 2010. Available at http://www.neb-one.gc.ca/clf-nsi/rnrgynfmtn/nrgyrprt/ntrlgs/ntrlgsdlvrblty20102012/ntrlgsdlvrblty20102012-eng.html.

# ELECTRICITY

## 6.1 Regional Initiatives

***Key Findings:***

- On the supply-side continued attention to renewable generation and reliable infrastructure
- On the demand-side, there was continued emphasis on conservation and efficiency improvements
- Generation from hydroelectric, nuclear and thermal sources was lower because of the economic downturn
- Electricity consumption continued its decline in 2009
- Electricity prices remained relatively stable during the year
- Lower prices for natural gas reduced generation costs in the provinces that rely on natural gas for power generation

Canadian electricity markets significantly differ from other energy markets as they are generally shaped by provincial government policies. In 2009 many regional initiatives focused on policies and programs to achieve set objectives. A number of these regional initiatives are discussed below.

### *Western Canada*

In the fall of 2009, British Columbia's Minister of Energy, Mines and Petroleum Resources announced that BC Hydro will no longer use the 50-year old natural gas-fired Burrard Thermal Generating Facility to meet the Province's firm energy needs. Consistent with the government's Climate Action Plan, the BC Energy Plan, and the *Utilities Commission Act*, this decision allows BC Hydro to continue acquiring cost-effective, clean and renewable power.

During 2009, BC Hydro launched the second phase of its two-phase "Bioenergy Call for Power" to provide the province with additional sources of clean electricity, while diversifying rural economies heavily based on the forest industry. Phase Two has a two-stream call process, one for larger-scale projects and the other for community-level electricity supply solutions.

The Province of Alberta passed the *Electric Statutes Amendment Act, 2009* (formerly Bill 50), eliminating the "needs hearing" for four transmission infrastructure projects deemed to be "critical" by the Alberta government.

SaskPower's supply strategy included the introduction of a Demand Response Program as a cost-effective option to ensure that its power system supports Saskatchewan's current and future economic growth. Qualified industrial customers will have the option to reduce or shift their electricity use when requested by SaskPower if, for example, the province is experiencing high demand or system constraints. A Demand Response Program increases operational flexibility and delays the need for construction of additional generation facilities and transmission lines.

The Government of Manitoba introduced proposed legislation, *Manitoba Hydro Amendment and Public Utilities Board Amendment Act* (Bill 20) that gives it the ability to adopt and regulate mandatory North American standards for generating and transmitting electricity in Manitoba.

### *Ontario*

The *Green Energy Act* (GEA) was passed in spring 2009 to accelerate development of renewable generation and drive the expansion of transmission and distribution systems. The GEA enabled the launch of the Feed In Tariff (FIT) and microFIT programs in fall 2009 which solicit renewable generation project proposals from a variety of producers including homeowners, businesses, independent power producers, local distribution companies, and communities. Both programs have local content requirements designed to create green industries in Ontario. Projects are expected to create 20 000 jobs and enable development of green energy in areas otherwise inaccessible to the grid.

### *Quebec and Atlantic Canada*

The Quebec government announced its policy to reduce GHG emissions by 20 per cent below 1990 levels by 2020. The initiatives to implement this policy will largely focus on the transportation industry, which contributes up to 40 per cent of the province's emissions. The government committed to implementing a cap and trade system by 2012 and is committed to the development of renewable energy sources, such as wind and hydro with the synergies to be explored between the two resources.

The Nova Scotia government launched its *2009 Energy Strategy* in January. The strategy legislates that by 2020, the province will reduce GHGs to at least ten per cent below 1990 levels. The electricity sector is the province's largest contributor, accounting for 50 per cent of GHG emissions. To reduce the electricity sector's carbon footprint, the government focused on two key elements: increase conservation and efficiency by 20 per cent by 2020 and obtain 25 per cent total electricity supply from low-impact renewable sources by 2015 through Renewable Energy Standards (RES).

#### *Renewable Energy Standards (RES)*

Renewable Energy Standards require load-serving entities to source a percentage of their energy supply from renewable resources by a specified target year. Establishing RES is often seen as one of the stronger options policy makers have in addressing climate change issues by decreasing the electricity industry's overall emissions.

The structures of these standards vary greatly between provinces/states. They tend to promote the use of locally available clean or renewable resources. In areas where coal is abundant, RES might include "alternative energy" such as waste coal or coal gasification. Those with abundant hydro-electricity are inclined to include hydro in their criteria for clean and renewable energy. Harmonizing definitions across jurisdictions is difficult.

As of 2009, three provinces (NS, NB, PEI) and 30 states (including the District of Columbia) have RES in place, whereas seven provinces (BC, AB, SK, MB, ON, QC, NF) and six states have other targets and goals.

### *Territories*

In 2009, the Yukon government released its *Energy Strategy for Yukon*. The Report identified two central electricity targets to achieve by 2020: a 20 per cent increase in efficiency and a 20 per cent increase in renewable supply. Also, the Minister of Energy, Mines and Resources announced that Yukon is developing policies to foster development of renewable energy sources. The policies will focus on independent power production and net metering.

## 6.2 Electricity Prices

Canadian electricity prices are determined in regional markets. Prices in most jurisdictions are regulated and based on the cost of providing service to consumers including a regulated rate of return on generation, transmission and distribution assets. Costs are approved by provincial and, in some cases, municipal regulators. When required, the cost of new generation, usually higher than costs of "heritage assets,"[17] must also be approved and rolled in, resulting in higher average costs. This model is followed in all provinces and territories except Alberta, where generation costs are based on competitive wholesale markets. Ontario is a hybrid of the two methodologies, with a blend of heritage pricing for coal, nuclear and hydro plants and market-based pricing for new generation.

Figure 6.1 shows the monthly average prices in the Alberta and Ontario wholesale markets over the past two years. Due to adequate supply and decreased demand, the level and volatility of these prices were lower in 2009.

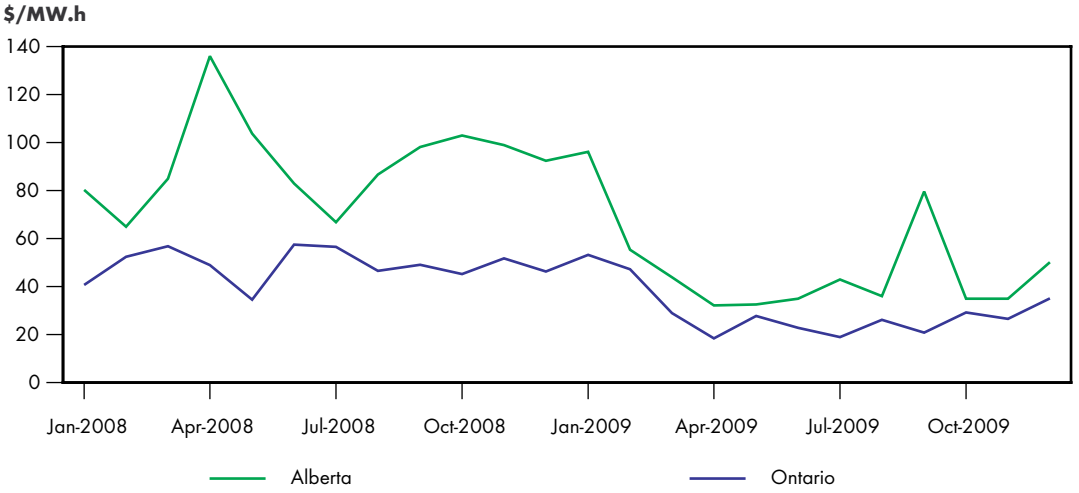
Prices tend to be lowest in hydro-based provinces such as British Columbia, Manitoba, and Quebec, which benefit from a high proportion of low-cost heritage assets, such as hydro-generating facilities that have minimal fuel costs and largely amortized capital costs. Electricity prices are most volatile in Canadian jurisdictions that rely on fossil fuels for generation, and are increasing most in those areas that require costly new generation and transmission.

Figure 6.2 charts the year-over-year average cost of electricity for a typical household in various Canadian cities based on rates in effect as of 1 April 2008 and 1 April 2009.

Residents in Alberta have the option to pay either a competitive contract rate, or the default Regulated Rate Option (RRO) which is set monthly. For the last four years, the RRO has been increasingly based on the next-month projected cost of electricity and less on the long-term projection. As of July 2010, it will be based entirely on the short-term cost. The difference in Edmonton's RRO from

**FIGURE 6.1**

***Monthly Average Wholesale Electricity Market Prices – Alberta and Ontario***

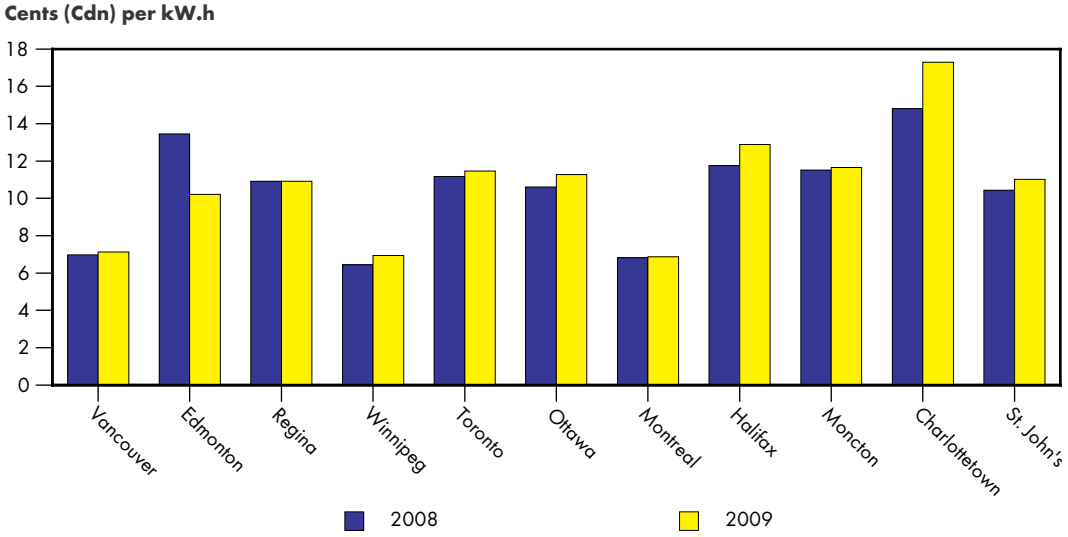



Sources: Alberta Electric System Operator, Independent Electric System Operator of Ontario

17 An amount of energy and capacity determined by the existing generation assets that resulted from past decisions under a previous market regime. This energy is generally sold into the marketplace at a price reflecting historical costs.

**FIGURE 6.2**

***Canadian Residential Electricity Prices***




Source: Hydro-Québec, based on 1 April rates and a consumption level of 1 000 kW.h per month

April 2008 (9.7 cents/kW.h) to April 2009 (7.2 cents/kW.h) represents most of the decrease shown for Edmonton prices.

The cost of electricity for residents in PEI has risen in recent years due to increased commodity prices, decreased availability of lower cost generation, and changes to rate structures and use of deferral accounts.

## 6.3 Electric Reliability

Reliable operation of the Bulk Power System (BPS) requires both an adequate supply of generation and reliable operation of generation and transmission facilities despite power system disturbances and contingencies. Reliability standards are an important tool in ensuring that the BPS meets this goal.

Reliability standards developed by the North American Electric Reliability Corporation (NERC) and/or by NERC's regional reliability organizations are mandatory in the U.S. In Canada, the individual provinces are adopting either the NERC standards or compatible standards. For instance, NERC standards were adopted through legislation in British Columbia and Alberta. Similar legislation in Manitoba has been passed and is expected to be proclaimed in 2010. NERC standards are mandatory in Ontario and New Brunswick through the market rules governing transmission in those provinces. NERC standards are applicable in Saskatchewan through contractual agreements with the Midwest Reliability Organization (NERC's regional reliability organization). In Quebec, reliability standards are developed by TransÉnergie and approved by la Régie de l'énergie, the provincial energy regulator. In an effort to increase awareness, NERC has begun publishing reliability indicators on its web site. Some parties suggest that the effects of mandatory reliability standards are reflected in the absence of outages due to poor vegetation management[18] from July to September 2009, the first such absence in six years.

18 Trimming or removing vegetation, such as trees, surrounding electric power lines that can potentially create a serious public safety hazard or cause interruptions to electrical services.

## 6.4 Electricity Generation

In 2009, Canadian electricity generation decreased by four per cent from 2008 (Table 6.1) largely due to decreased demand caused by the economic downturn. Hydroelectric generation was slightly lower reflecting the poor water conditions experienced over the summer in British Columbia. Thermal generation continued to decline and decreased ten per cent from 2008 levels. Coal-fired generation also decreased as a result of Ontario's goal to phase-out coal-based assets by 2014. Contributing to lower nuclear production is the continued outage for refurbishment of nuclear generators: Point Lepreau in New Brunswick and Bruce A Units 1 and 2 in Ontario. Wind and tidal production increased by 70 per cent from 2008 levels. However, wind generation only accounted for one percent of Canadian electricity production in 2009.

**TABLE 6.1**

***Electricity Production (TW.h)***

| | 2005 | 2006 | 2007 | 2008 | 2009 |
|---|---|---|---|---|---|
| Hydroelectric | 358.4 | 349.5 | 365.8 | 369.3 | 363.4 |
| Nuclear | 86.8 | 92.4 | 88.2 | 88.6 | 85.3 |
| Thermal | 157.3 | 147.7 | 149.6 | 139.1 | 124.7 |
| Wind & Tidal | 1.6 | 2.5 | 2.9 | 3.6 | 6.1 |
| **Total** | **604.2** | **592** | **606.5** | **600.6** | **575.3** |

Note: Wind generation for 2008-2009 estimated based on CanWEA data.

Sources: 2005 to 2009: Statistics Canada 57-202
2008-2009: CanWEA, Statistics Canada 127-0002

Even in the presence of increased government incentives, the current economic environment has made financing of new projects difficult and as a result, projects in some provinces have been deferred, downsized or cancelled. Some jurisdictions no longer need to build new generation or refurbish existing assets in the short-term. Nevertheless, generation projects continued to develop throughout Canada in 2009.

### *Hydro*

Canadian hydroelectric jurisdictions continue to focus on small and large hydro developments and refurbishments. BC Hydro signed electricity purchase agreements for 19 small hydro[19] projects to be owned, built and operated by independent power producers. Hydro Québec is also investing in small hydro developments with 150 MW to be purchased from small hydroelectric generating stations.

The Joint Keeyask Development Agreement was signed in May 2009 to outline the partnership arrangements for First Nations' participation in development projects with Manitoba Hydro. In addition to new generation facilities, refurbishments to existing facilities are taking place in Manitoba, British Columbia and Quebec. These investments create efficiencies and extend the life of heritage assets in some cases by at least 30 years.

### *Natural Gas*

New capacity of natural gas-fired generation is mostly attributed to new builds both in Ontario and Alberta where approximately a total of 2 350 MW came online in 2009. According to the Ontario Independent Electric System Operator (IESO), natural gas has surpassed coal and now represents 24 per cent of the province's supply mix.

19 Between 2 MW and 50 MW

### *Coal*

In Canadian jurisdictions where coal is a significant part of the mix, such as Ontario, Alberta, Saskatchewan and Nova Scotia, the economics of phasing-out coal compared to investment in compliance technologies continues to be explored. Ontario Power Generation announced in 2009 that they will close four coal-fired generation plants by October 2010. Alberta is upgrading existing coal-fired plants with compliance technologies. With the assistance of funding from the federal and provincial governments, progress is being made with respect to Carbon Capture and Storage (CCS) projects. (See text box on the Swan Hills project.)

***Alberta's Swan Hills In Situ Coal Gasification, Combined Cycle Power Plant and Carbon Capture and Storage Project***

On 1 December 2009 the Alberta government announced that it had signed a letter of intent with Swan Hills Synfuels for $285 million in funding from the Carbon Capture and Storage Fund. This project combines in situ coal gasification, $CO_2$ capture and sequestration in nearby oilfields and the construction of a 300 MW combined cycle power plant to run on the synthetic gas (syngas) produced.

This project has several parts, including the production of syngas underground in a coal bed, facilities to separate out $CO_2$, a combined cycle power plant to produce electricity and an enhanced oil recovery project that will sequester the carbon dioxide. While all of these technologies have been used in the past, this is the first time in Canada that they will have been combined in one project.

In situ coal gasification involves pumping oxygen down 1 400 metres underground into a coal seam, where it combines with the coal and saline water, normally found at that depth, to produce syngas, a mixture of hydrogen, methane, carbon dioxide, and carbon monoxide.

Once the syngas is brought to the surface the carbon monoxide is reacted with water to produce carbon dioxide and additional hydrogen, and the $CO_2$ is separated out and sent to an enhanced oil recovery project, where it is injected underground to boost production of oil from older wells. Enhanced oil recovery using $CO_2$ is a mature technology, limited mainly by access to reliable supplies of carbon dioxide.

Separating $CO_2$ from the methane and hydrogen in this type of facility is much easier than capturing it from the exhaust of a coal fired power plant, both because there is a higher concentration of $CO_2$ and it is easier to separate $CO_2$ from light molecules like hydrogen or methane (found in syngas) than heavier molecules of nitrogen, which make up the majority of the exhaust stream of a coal fired power plant.

Once the $CO_2$ has been removed, the clean syngas will be sent to a 300 MW combined cycle power plant. A combined cycle power plant consists of one or more combustion turbines connected to generators and a heat recovery steam generator that uses the combustion turbine exhaust to make steam which is sent to a steam turbine connected to another generator. Natural gas combined cycle power plants are a mature technology, with high efficiency and the lowest emissions per mega-watt hour of electricity produced of any fossil fuel power plant. The combustion turbines in the Swan Hills project will have to be modified slightly to run on syngas instead of natural gas, but the presence of hydrogen in the syngas means the Swan Hills plant should produce about half the $CO_2$ of a comparable natural gas power plant, much of which will be captured, or a quarter of the $CO_2$ of a conventional coal plant of the same size.

Construction on this project is expected to begin in 2011, with it entering service in 2015.

### *Nuclear*

New Brunswick's Point Lepreau nuclear plant is expected to return to service by February 2011 following refurbishment. In Ontario, the provincial government put plans on hold to build new nuclear facilities, although refurbishments to existing facilities are being considered. In late 2009 the Government of Canada issued an invitation for investor proposals to purchase the Atomic Energy of Canada Limited CANDU Reactor Division.

### *Wind and Other Renewables*

As of 2009, Canada has wind development in every province with the addition of B.C.'s 102 MW Bear Mountain Wind Park. Canada's total installed wind capacity now exceeds 3 300 MW. Canadian wind power development projects were hindered in 2009 in several provinces due to financing difficulties.

Since 2007, approximately 10 900 MW (including wind) have been registered with Canada's ecoENERGY Renewable Power Fund. Of the total projects, 1 100 MW were expected to complete commissioning in 2009. Solar, biomass and hydro projects in Ontario and British Columbia represent approximately 260 MW of the expected commissioned projects in 2009, with wind accounting for the remaining new capacity. There were also additional biomass projects that were awarded through various requests for proposals in Nova Scotia, British Columbia, and Quebec. The end of 2009 also witnessed Canada's first solar farm (29 MW) near Napanee, Ontario becoming operational.

#### *Wind Integration: Opportunities and Challenges*

While wind power has a number of unique benefits, its intermittent nature presents a challenge in integrating large amounts into existing power systems. Wind may not always be available at the required location so cannot be relied upon for base-load requirements. Intermittent wind power therefore implies that another energy source must be available to alleviate the impact on electric system reliability. There are a number of measures that can mitigate wind intermittency concerns, including wind availability forecasting, a robust transmission system and synergy with other generation systems.

Advanced daily or hourly forecasts for wind speed and wind turbine generation are valuable, as this provides system operators with time to respond to changes. Of particular use to electric system operators is advanced notice of extremely high wind speeds to prevent damage to the equipment.

A robust transmission system can support the integration of wind generation by drawing on the generation resources of a neighbouring region. Denmark, which has little hydro generation, can still support over 20 per cent wind capacity because its transmission system connects it to hydro resources in Norway and Sweden.

Based on technical studies and experience in Europe and in the U.S., a predominantly thermal system is expected to be able to function normally with up to 10 per cent of its installed generating capacity being wind turbines, whereas a mainly hydro-based system could support up to 20 per cent installed wind capacity. With additional investment in transmission, control systems and back-up generation, installed capacity of wind generation can be increased to 15 per cent for predominantly thermal systems and 30 per cent for hydro systems.

### *Tidal Energy Generation*

As of 2009 there are only three tidal power plants in the world that use first generation dam or barrage technology[1]. Nova Scotia Power's Annapolis Tidal Power has been operational since 1984 and employs this type of technology. Engineers have now developed in-stream tidal technology that uses the natural flow of tides. These turbines are attached to the ocean floor through a sub-sea gravity base and operate like an underwater windmill by using tide flow to turn an impeller. In-stream tidal turbines can connect to the grid for performance testing, safety monitoring and environmental assessments. In a study conducted by the Electric Power Research Institute, the Bay of Fundy was identified as an ideal location to deploy in-stream tidal technology. In November 2009 the Irish firm, OpenHydro, in partnership with Nova Scotia Power, launched the Bay of Fundy's first commercial scale 1 MW in-stream turbine.

This technology and industry are still in the infancy stage and over the next few years it will be important to monitor the impact of ice on the turbines and address underwater site challenges. Advocates argue that of all the renewable energy technologies, tidal power is the most predictable, reliable and dispatchable. Both the Government of Canada and Nova Scotia are in support of the new technology and the potential for a new marine energy industry. OpenHydro and Nova Scotia Power received $9 million from the province for research and development costs.

Source: Electric Power Research Institute, Ocean Tidal and Wave Energy – Renewable Energy Technical Assessment Guide – TAD-RE: 2005 Product ID: 1010489

1 Barrages are basically dams across the full width of a river where it empties into another body of water, in this case, the Bay of Fundy. Barrages make use of the potential energy between high and low tides.

## 6.5 Electricity Demand

In 2009, electricity demand continued to decline, falling five per cent compared with 2008 levels (Table 6.2). Behind this story of reduced consumption is a mix of increased efficiency, conservation efforts, cooler summer weather and the slower economy's effects on power use. In particular, the economic downturn has significantly decreased industrial use of electricity in Ontario, where consumption decreased by ten per cent from 2008. However, factors that influence lower levels of electricity demand can sometimes be overpowered by extreme weather. For example, in December 2009, Alberta experienced severe cold weather; resulting in a record demand peak, much higher than had been forecasted for the 2009 winter season.

**TABLE 6.2**

***Electricity Generation and Disposition (TW.h)***

| | 2005 | 2006 | 2007 | 2008 | 2009 |
|---|---|---|---|---|---|
| **Supply** | | | | | |
| Total Generation | 604.2 | 592 | 606.5 | 600.6 | 575.3 |
| Imports | 18.7 | 22.1 | 18.4 | 23.5 | 18.3 |
| **Total Supply** | **622.8** | **614.1** | **625** | **624.1** | **593.6** |
| **Disposition** | | | | | |
| Demand | 580.5 | 574.3 | 575.6 | 568.4 | 540.3 |
| Exports | 42.3 | 39.7 | 49.3 | 55.7 | 53.3 |
| **Total Disposition** | **622.8** | **614.1** | **625** | **624.1** | **593.6** |

Sources: 2005 to 2009: Statistics Canada 57-202, NEB
2008-2009: CanWEA, Statistics Canada 127-0002, NEB

Jurisdictions that experienced decreases in electricity demand ranging from two to three per cent were PEI, New Brunswick, Saskatchewan, Alberta and British Columbia. New Brunswick generated lower levels of electricity and imported 34 per cent more energy from other provinces compared to 2008. Quebec, Nova Scotia, and Newfoundland and Labrador experienced a drop in electricity consumption of between four and five per cent. Ontario experienced the largest decline as a result of the impact of the economic recession on industries like pulp and paper, steel, mining and auto manufacturing. As a result, the province experienced frequent levels of surplus baseload generation, requiring the Ontario IESO to direct the shutdown of nuclear units. Manitoba experienced an increase of one per cent. Electricity consumption trends in the territories varied in comparison to 2008. Yukon's electricity use rose by 17 per cent, from, among other things, increased mining development. The Northwest Territories remained relatively stable at 2008 levels and Nunavut experienced an increase of three per cent.

## 6.6 Electricity Exports and Imports

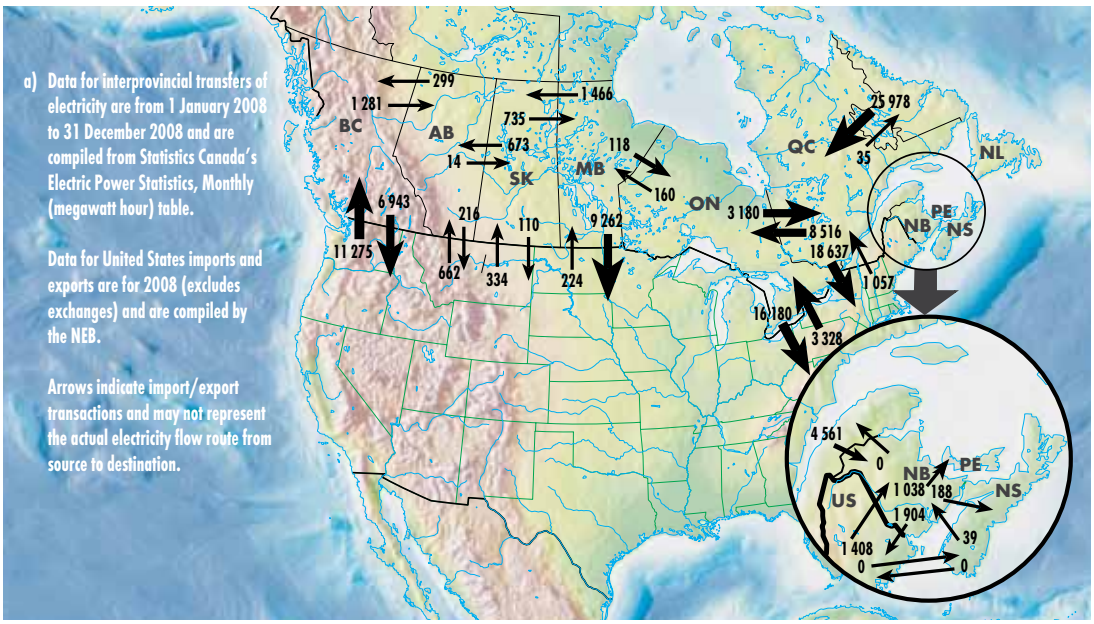
Electricity exports decreased four per cent and imports decreased 22 per cent (Table 6.2). The result was a slight year-over-year increase in net exports to the United States. The value of electricity traded between Canada and the U.S. (the sum of export revenue and import costs) decreased by 41 per cent as a result of lower trade levels coupled with lower wholesale market prices.

Canadian electricity jurisdictions tend to be winter-peaking systems, and so the largest imports of electricity from the U.S. typically occur during the winter when local heating requirements are highest. The large hydro-electric capacity of some provinces (Quebec, B.C., Ontario and Manitoba) generally enables exporters to benefit by exporting when prices are high (in the middle of the day) and importing when prices are low (off-peak hours).

With the decrease in consumption, the supply margins in most provinces were high, and the need to import was significantly reduced. One exception to this was in the Maritimes, as the continued refurbishment of Point Lepreau contributed to increased imports during the winter months. Another

**FIGURE 6.3**

***International and Interprovincial Transfers of Electricity, 2009 (GW.h)***



contributing factor to decreased trade was the relatively low precipitation and reservoir levels in 2009. Following a year of abundant hydro resources, some provinces, B.C. in particular, increased imports.

## 6.7 Looking Ahead

The driver for investment in the industry now includes a focus on renewable energy programs. Renewable energy has been advocated through provincial and federal government policies with incentives to fund the development of sources such as hydro, wind, solar, biomass and efficiency technologies like smart grid and carbon capture and storage linked to coal fired generation. Regional projects and developments with an emphasis on sustainability continue to evolve, such as installing smart meters to enable and improve demand-side management, address efficiency and reliability concerns, and manage the growth of renewable energy.

Canadian electricity consumers, from residential to industrial, have a greater number of programs and incentives designed to aid in efficient energy consumption. Programs offer funds and resources to local governments, developers, and institutions to support informed choices about energy management and increased efficiency through planning, development and implementation of district energy systems.

Moving forward, participants in the electricity sector will continue to focus their efforts towards supply side management that incorporates renewable generation and ensuring reliable infrastructure as well as demand side management with conservation and efficiency improvement programs. Efforts in the U.S. to pursue sustainable energy options may well result in increased electricity trade as both countries seek to optimize their renewable resources and transmission interconnections.

# Conclusion

In 2009 the economic downturn led to decreases in both the consumption and the production of energy in Canada. This impacted energy prices and reduced export volumes resulting in less Canadian energy export revenue. Despite this reduction, energy still contributed 22 per cent of the total Canadian export revenue in 2009. By year-end, there were signs that the economy was improving, and 2010 began with increased optimism that an economic recovery was underway.

Canadians remained interested in environmental issues. There were a number of announcements by governments at the federal and provincial levels to deal with sustainable development and environmental issues. The issue of climate change continued to have a high profile at the international level.

Per capita energy demand has declined by eight per cent over the last five years. However, while suggesting that Canadians are taking steps to reduce consumption, it is not always clear how much of reduced consumption is due to conservation and how much can be attributed to other factors such as weather and the economic slowdown.

The natural gas industry continued to evolve. There was a shift toward more prolific deep-basin tight gas in Alberta and Montney gas in northeastern B.C. As a result of low drilling activity, production and natural gas exports were down. The development of shale gas continued and the availability of LNG to North America increased in 2009 with the first receipt in Canada at Canaport. Total natural gas consumption was stable, but industrial consumption, with the exception of the oil sands, was lower than in previous years.

The average price for crude oil (Edmonton Par) was $65/bbl in 2009, considerably lower than the $102/bbl in 2008. Lower crude oil prices negatively impacted industry performance, including less land bonuses for oil sands leases and reduced value of crude oil exports and refined petroleum products. Lower crude oil prices had a positive impact, by lowering the cost of gasoline, diesel fuel and heating oil for consumers. The second half of the year featured a recovery in oil sands development. In spite of some minor shut-in of production, oil sands production grew based on the momentum established in previous years.

In 2009, electricity activity continued to focus on renewable generation and reliable infrastructure, as well as conservation programs. Generation from hydroelectric, nuclear and thermal sources was lower than in 2008. Wind production, although a small portion of total generation, continued its trend of strong growth. Electricity consumption continued its decline due to a mix of factors such as the economic downturn, cooler summer weather, increased efficiency and conservation. Prices for electricity remained generally stable with lower prices for natural gas reducing costs in those provinces that rely on natural gas for power generation.

# GLOSSARY

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| AECO/NIT price | Now known as the Intra-Alberta/NIT price. Historically, AECO was the name of a group of storage fields located in southeastern Alberta and operated by the Alberta Energy Company (now EnCana) and the Nova Inventory Transfer (NIT) is a title transfer service operated by TransCanada PipeLines Ltd. |
| Coalbed methane | Is a form of natural gas extracted from coalbeds. Coalbed methane, often referred to as CBM, is distinct from a typical sandstone or other conventional gas reservoir, as the methane is stored within the coal by a process called adsorption. |
| Condensate | A mixture comprised mainly of pentanes and heavier hydrocarbons recovered as a liquid from field separators, scrubbers or other gathering facilities or at the inlet of a natural gas processing plant before the gas is processed. Also known as natural gasoline. |
| Conventional natural gas | Conventional natural gas is gas contained in geological formations that is produced by expansion of the gas molecules into the well bore. In this report, it has a sub-category called tight gas that others may consider as unconventional natural gas. However, there is no agreed-upon regulatory definition accepted for use in Canada at this time, so it is kept as a sub-category of conventional gas. |
| Distillate | Fraction of crude oil; a general classification of fuels that includes heating oil, diesel fuel and kerosene. |
| Henry Hub | The biggest hub where the benchmark price is established for natural gas in North America. It is the pricing point for natural gas futures contracts traded on the New York Mercantile Exchange. It is located in the state of Louisiana at the interconnection of numerous intra and interstate natural gas 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 | Recovery techniques which apply heat or solvents to heavy oil or bitumen reservoirs beneath the earth. |

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| Light-heavy differential | The price difference between heavy and light crude oil. |
| 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. |
| Spot price | The current delivery price of a commodity being traded on the spot market. |
| Thermal generation | Energy conversion in which fuel is consumed to generate heat energy which is converted to mechanical energy and then to electricity. |